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Model Documentation

Natural Gas Transmission and Distribution Model

of the National Energy Modeling System

Volume I

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MASTER

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For Further Information...

The Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System is developed and maintained by the Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting. General questions concerning the NGTDM may be addressed to James S. Diemer (202/586-6126), Natural Gas Transmission and Distribution Project Leader. Documentation questions should be addressed to Phyllis Martin (202/586-9592).

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This report documents the archived version of the NGTDM that was used to produce the natural gas forecasts presented in the *Annual Energy Outlook 1995*, (DOE/EIA-0383(95)). 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. This report represents Volume I of a two-volume set. Volume II reports on model performance, detailing convergence criteria and properties, results of sensitivity testing, comparison of model outputs with the literature and/or other model results, and major unresolved issues.

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 1996.

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1. Introduction

The Natural Gas Transmission and Distribution Model (NGTDM) is the component of the National Energy Modeling System (NEMS) that is used to represent the domestic natural gas transmission and distribution system. NEMS was developed in the Office of Integrated Analysis and Forecasting of the Energy Information Administration (EIA). NEMS is the third in a series of computer-based, midterm energy modeling systems used since 1974 by the EIA and its predecessor, the Federal Energy Administration, to analyze domestic energy-economy markets and develop projections. From 1982 through 1993, the Intermediate Future Forecasting System (IFFS) was used by the EIA for its analyses, and the Gas Analysis Modeling System (GAMS) was used within IFFS to represent natural gas markets. Prior to 1982, the Midterm Energy Forecasting System (MEFS), also referred to as the Project Independence Evaluation System (PIES), was employed.

NEMS was developed to enhance and update EIA's modeling capability by internally incorporating models of energy markets that had previously been analyzed off-line. In addition, greater structural detail in NEMS permits the analysis of a broader range of energy issues. The time horizon of NEMS is the midterm period, approximately 20 years in the future.[1] In order to represent the regional differences in energy markets, the component models 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 using a market-based approach[2] to energy analysis, as had the earlier models. 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 models represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international models. The primary flows of information between each of these models are the delivered prices of energy to the end user and the quantities consumed by product, Census Division, and end-use sector. The delivered prices of fuel encompass all the activities necessary to produce (or 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.

An integrating routine controls the execution of each of the component models. The modular design provides the capability to execute models individually, thus allowing independent analysis with, as well as development of, individual models. This modularity allows the use of the methodology and level of detail most appropriate for each energy sector. NEMS solves by iteratively calling each model in sequence until the delivered prices and quantities of each fuel in each region have converged within tolerance both within individual models and between the various models, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Model solutions are reported annually through the midterm horizon. A schematic of the NEMS is provided in Figure 1-1, while a list of the associated model documentation reports is in Appendix C.

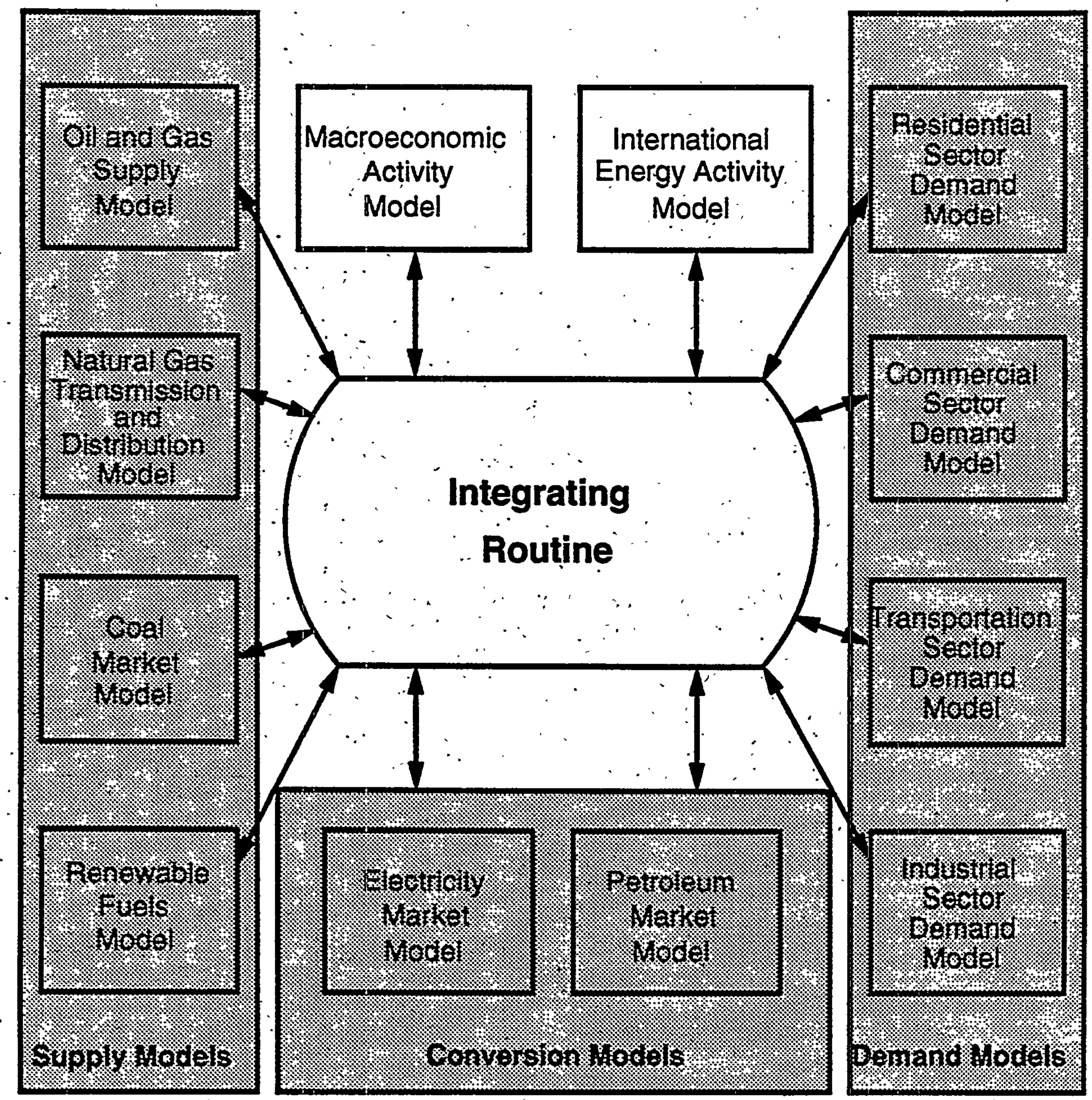
The NGTDM is the model within the NEMS that represents the transmission, distribution, and pricing of natural gas. The model also includes representations of the end-use demand for natural gas, the production of domestic natural gas, and the availability of natural gas traded on the international market based on information received from other NEMS models. The NGTDM determines the flow of natural gas in an aggregate, domestic pipeline network, connecting domestic and foreign supply regions with 12 demand regions. The methodology employed allows the analysis of impacts of regional capacity constraints in the interstate natural gas pipeline network and the identification of primary pipeline capacity expansion requirements. There is an explicit representation of core and noncore markets

[1]For the *Annual Energy Outlook 1995* the NEMS was executed for each year from 1990 through 2010.

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

[3]The NEMS is composed of 13 models and a system integration routine. These components are frequently referred to as "modules" in other NEMS related publications; however, in this publication they will all be referred to as "models." Footnotes will be added when the formal name is different from the referenced name. The components of the NGTDM will be referred to as "modules."

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



for natural gas transmission and distribution services, and the key components of pipeline tariffs are represented in a pricing algorithm. 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 NGTDM consists of four modules: the Annual Flow Module, the Capacity Expansion Module, the Pipeline Tariff Module, and the Distributor Tariff Module. A model abstract is provided in Appendix A.

This report documents the archived version of the NGTDM that was used to produce the natural gas forecasts used in support of the *Annual Energy Outlook 1995*, DOE/EIA-0383(95). 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 the EIA to provide adequate documentation in support of its models (Public Law 94-385, Section 57.b.2).

This report represents Volume I of a two-volume set. Volume II reports on model performance, detailing convergence criteria and properties, results of sensitivity testing, comparison of model outputs with the literature and/or other model results, and major unresolved issues. Subsequent chapters of this report provide:

- An overview of the NGTDM (Chapter 2)
- A description of the interface between the NEMS and the NGTDM (Chapter 3)
- An overview of the solution methodology of the NGTDM (Chapter 4)
- The solution methodology for the Annual Flow Module (Chapter 5)
- The solution methodology for the Distributor Tariff Module (Chapter 6)
- The solution methodology for the Capacity Expansion Module (Chapter 7)
- The solution methodology for the Pipeline Tariff Module (Chapter 8)
- A description of model assumptions, inputs, and outputs (Chapter 9).

The archived version of the model is available from the National Energy Information Center (NEIC) and is identified as NEMS95 (part of the National Energy Modeling System archive package as archived for the *Annual Energy Outlook 1995*, DOE/EIA-0383(95)).

The document includes extensive appendices to support the material presented in the main body of the report. Appendix A presents the model abstract. Appendix B lists the major references used in developing the NGTDM. Appendix C lists the various NEMS Model Documentation Reports that are cited throughout the NGTDM documentation. Appendix E provides tables of variable names, definitions, and sources for all the historical data used in the model. Appendix F provides tables of variable names, definitions, and sources for all major model parameters and assumptions. Appendix G documents the derivation of all empirical estimations used in the NGTDM. A variable cross reference tables is provided in Appendix H. A mapping of equations presented in the documentation to the relevant subroutine in the code is provided in Appendix I. Appendix J presents an extensive list defining the model variables. Lastly, Appendix K documents the switches that have been built into the model to conduct automated sensitivity analysis.

2. Overview

The purpose of this chapter is to provide a brief overview of the Natural Gas Transmission and Distribution Model (NGTDM) and its capabilities. The NGTDM is the component of the National Energy Modeling System (NEMS) that represents the mid-term natural gas market. The NGTDM models the Lower 48 States U.S. natural gas transmission and distribution network that links the suppliers (including importers) and consumers of natural gas, determining the regional market clearing natural gas end-use and supply (including border) prices. The demand regions modeled are the 12 NGTDM regions (Figure 2-1). These regions are based on the 9 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. Forecasts are reported annually through 2010 for natural gas end-use prices in the residential, commercial, industrial, electric generation, and transportation sectors.

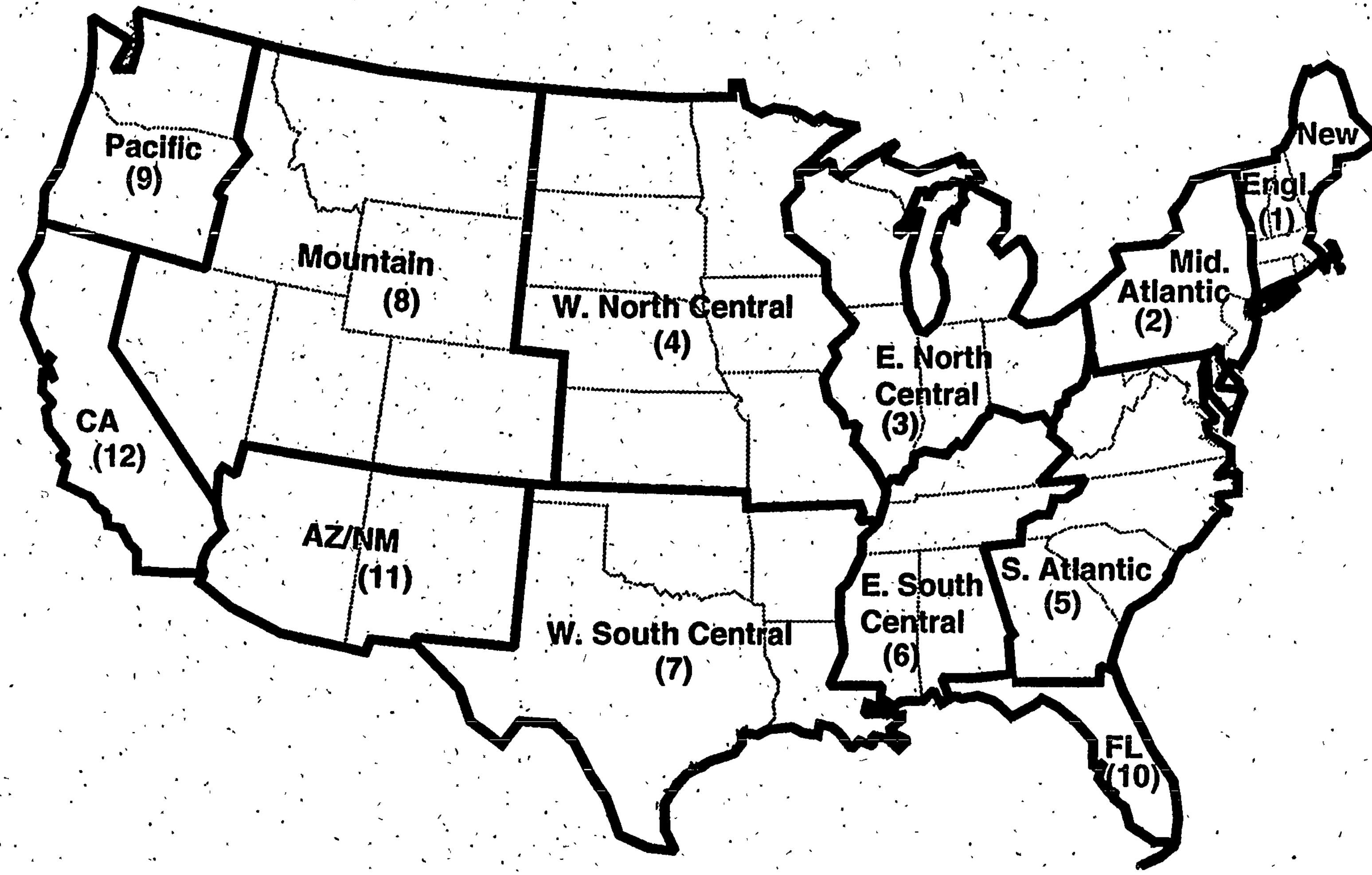
The model structure consists of four major components. The Annual Flow Module (AFM) is the integrating module of the NGTDM. It simulates the natural gas price determination process by bringing together all major economic and technological factors that influence regional natural gas trade in the United States. The Capacity Expansion Module (CEM) forecasts the development of new natural gas pipeline and storage facilities and sets maximum annual utilization rates based on a seasonal analysis of supply capabilities and demand requirements. The Pipeline Tariff Module (PTM) represents the development of firm/interruptible tariffs for transportation and storage services provided by interstate pipeline companies. The Distributor Tariff Module (DTM) represents the development of markups for distribution services provided by local distribution companies and for transmission services provided by intrastate pipeline companies. The modeling techniques employed are linear programs for the AFM and the CEM, an accounting algorithm for the PTM, and an empirical process based on historical data and competing fuel prices for the DTM.

The NGTDM provides a number of key modeling capabilities that were not available in its predecessor model, the Gas Analysis Modeling System (GAMS). These capabilities give the NGTDM the ability to:

- Represent interregional flows of gas and pipeline capacity constraints
- Represent regional supplies
- Represent different types of transmission service (firm and interruptible)
- Calculate emissions associated with pipeline fuel use
- Determine the amount and the location of additional pipeline and storage facilities on a regional basis
- Capture the economic tradeoffs between pipeline capacity additions and increases in regional storage capability
- Provide a peak/off-peak, or seasonal analysis capability in the area of capacity expansion
- Quantify capital investment in capacity expansion
- Distinguish customers by category (core and noncore) in end-use sectors.

These capabilities will be described in greater detail in the subsequent chapters of this report which describe the individual modules of the NGTDM.

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



Model Objectives

The purpose of the NGTDM is to derive natural gas end-use and wellhead 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 elements of the natural gas market: the supply element, the demand element, and the transmission and distribution network that links them. The domestic supply, imports, and demand representations are provided as inputs to the NGTDM from other National Energy Modeling System (NEMS) modules. The representations of the key features of the transmission and distribution network, which include interregional network capacities and transmission and distribution service pricing, are the focus of the various components of the NGTDM.

The need to model these specific characteristics of the natural gas industry stems from the structural changes that have taken place in the industry over the last 10 years. These changes include complete deregulation of the wellhead market, the unbundling of pipeline services, and the introduction of competitive forces related to pipeline expansion decisions, and transmission and distribution service pricing. Some of these changes have already had a large effect on the market, while other changes have recently been initiated and have yet to provide a significant impact on the prices and availability of services. Two key factors support the need to include an explicit representation of the transmission and distribution of natural gas within NEMS. The first is the substantial decline in wellhead prices which results in the acquisition cost of the commodity itself generally being less than half of the end-use price. The second is the ongoing evolution of the market. This ongoing evolution also supports the need for significant flexibility in how prices for transmission and distribution services are represented in the NGTDM and how the interregional flows respond to prices over time. Because of this, the NGTDM is a completely new system that provides, in addition to mid-term forecasts of end-use prices, forecasts of prices for, availability of, expansion of, and utilization of interstate natural gas pipeline services.

Prior to model development, a working paper was compiled by the EIA to establish the specific requirements for the overall NEMS, as well as for each of the component modules.[4] Requirements pertaining specifically to the NGTDM were based on: (1) recent analyses performed with EIA's IFFS/GAMS forecasting system, (2) limitations of GAMS, (3) the regulatory reform agenda of the Federal Energy Regulatory Commission (FERC), and (4) Department of Energy (DOE) policy initiatives as outlined in the National Energy Strategy.[5] These requirements, along with recommendations from a recent Model Quality Audit of the GAMS by the Office of Statistical Standards,[6] yielded a list of design guidelines for the NGTDM that support a broad array of desired analyses. Based on these guidelines, the NGTDM needed to:

- Represent pipeline capacity limitations exiting the major producing regions and entering the major market areas
- Employ a solution procedure based on an interregional trade equilibrium model that attempts to minimize simultaneously the global costs of supply and transportation subject to gas supplies available in each region, regional demand requirements, and pipeline capacity constraints
- Incorporate a transmission/storage capacity expansion/planning module that would recognize on-going, and planned/announced capacity expansion projects, as well as other capacity expansion needs throughout the forecast period
- Have the ability to determine endogenously market based rates for pipeline transportation services
- Have the ability to partition the natural gas market to apply either market based or cost based rates to specific segments of end-use sectors or to the market as a whole

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[4]Energy Information Administration, Office of Integrated Analysis and Forecasting, "Requirements for a National Energy Modeling System," December 12, 1991.

[5]*National Energy Strategy*, First Edition, 1991/1992 (Washington, DC, February 1991).

[6]Carpenter, Paul R., *Review of the Gas Analysis Modeling System* (Boston, MA: Incentives Research, Inc., August 1991).

- Employ a short-run supply curve that includes a direct representation of marginal sources of supply

- Represent Canadian and Mexican pipeline gas trade and liquefied natural gas trade

- Account for emissions of criteria pollutants that are emitted as a by-product of the natural gas transmission and distribution industry

- Account for capital investment requirements of storage and capacity expansion projects in the transmission and distribution sector.

During the development of the model methodology, a study was made of existing models and modeling techniques that might be used to meet the above requirements. Based on this study and the reports mentioned previously, it was determined that no model currently in existence could satisfy the NEMS requirements, and thus a new model was needed. The results of the study are presented in Appendix D. Documents that were referenced in support of the model development effort are listed in Appendix B.

The following sections provide brief overviews of the four components of the NGTDM.

Annual Flow Module

The Natural Gas Annual Flow Module (AFM) is the main integrating module of the NGTDM. One of its major functions is to simulate the natural gas price determination process. The AFM brings together all major economic and technological factors that influence regional natural gas trade in the United States. The economic considerations include the demand for and the supply of natural gas, competition from substitute fuels and conservation options, and competition from imported natural gas.

The AFM integrates all components of the NGTDM (the AFM itself, the Capacity Expansion Module, the Pipeline Tariff Module and the Distributor Tariff Module). Through this integration process, the AFM derives average annual natural gas prices (wellhead, city gate, and end-use) that reflect an interregional trade market equilibrium among competing gas supplies, end-use sector consumption and transportation routes. End-use prices are derived for both core and noncore markets. Within NEMS the classification of customers as core versus noncore is predetermined.

The historical evolution of the price determination process simulated by the AFM is depicted schematically in Figure 2-2. Until recently, 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 employed, more pricing flexibility is being introduced, particularly in the interstate pipeline industry. Pipeline companies are also offering a range of services under competitive and market-based pricing arrangements. Additionally, new players—for example marketers of spot gas and brokers for pipeline capacity—have entered the market, creating new links connecting suppliers with end-users. The marketing links will become increasingly complex in the future.

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) is currently driving the prices for interruptible transmission service and is beginning to have an effect on firm service prices. Currently, there are significant differences across regions in pipeline capacity utilization.[7] These regional differences are evolving as new pipeline capacity is constructed to relieve the capacity constraints in the Northeast and on the West Coast, and to expand markets in the Midwest. As capacity changes take place, prices of services should adjust accordingly to reflect new market conditions.

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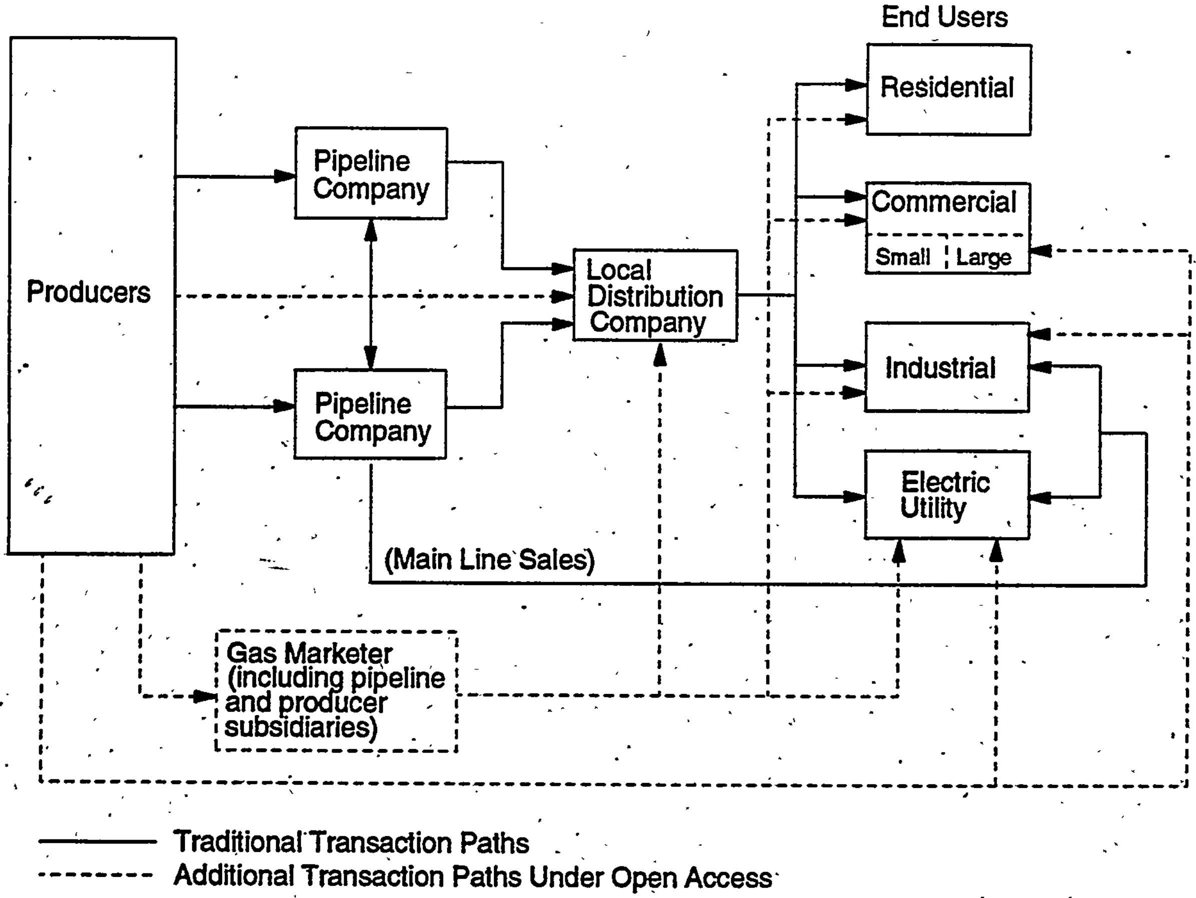
[7]Energy Information Administration. *Capacity and Service on the Interstate Natural Gas Pipeline System, 1990: Regional Profiles and Analyses*, DOE/EIA-0551 (Washington, DC, May 1992).

Figure 2-2. Principal Buyer/Seller Transaction Paths for Natural Gas Marketing



Federal initiatives (most recently compiled in FERC Order No. 636) are reducing barriers to market entry and are encouraging the development of more competitive markets for pipeline services. Potential mechanisms used to make the transmission sector more competitive include the widespread capacity releasing programs, market-based rates, and the formation of market centers with deregulated upstream pipeline services. Some combination of these mechanisms will probably be used. As the outcome is unknown at this point, the AFM is not designed to model any specific type of program. It is instead designed to simulate the overall impact of the movement towards market based pricing of transmission services.

The regional supply detail in the AFM, in conjunction with the AFM representation of pipeline capacity, supports analysis of regional shifts in supply and demand patterns. Regional differences in marginal sources of supply are also captured. Finally, the AFM addresses: transmission fuel consumption and losses; emissions associated with transmission fuel consumption; the evolution of a North American natural gas market; and capacity rationing (accomplished via the pricing of services).

Capacity Expansion Module

The primary purpose of the Capacity Expansion Module (CEM) is to simulate the decision-making process for expanding pipeline and/or storage capacity in the U.S. gas market. In simulating gas pipeline capacity expansion, the CEM: (1) determines the amount of pipeline and storage capacity to be added between or within regions in the NGTDM, and (2) establishes effective (or practical) maximum annual utilization rates for each of the interregional pipeline routes represented in the Annual Flow Module. Maximum utilization rates (or load factors) on pipeline routes are established to capture the impact of variations in seasonal demand on the maximum amount of gas which can practically flow between regions within a year. Pipeline and storage capacity additions are used in the Annual Flow Module (in combination with the maximum load factors) to set limits on annual interregional flows and to set working gas storage levels. These capacity additions are also used in the Pipeline Tariff Module when determining future storage rates and interregional pipeline tariffs.

The CEM was designed to address the guidelines that support a broad array of desired analyses and policy questions to be answered, such as:

- What impact will the increased demand for natural gas attributable to greater market penetration of new end-use gas technologies have on the utilization of the U.S. pipeline grid and requirements for new capacity? In what regions is capacity likely to be added?

- What might be the impact of a proactive natural gas policy on the utilization of pipeline capacity and the need for pipeline expansion?

- How will unbundling and the increasingly market-oriented pricing of gas supply and transmission services affect the differences between delivered prices for residential/commercial and industrial and electric generators sector gas users?

Regulation affecting the demand for gas and the supply of gas, such as emissions controls and tax credits, are modeled within the demand models of NEMS and the Oil and Gas Supply Model, respectively. The Pipeline Tariff Module and the Distributor Tariff Module provide tariffs to the CEM. Therefore, regulations affecting the setting of rates are specified within these two tariff modules, and are subsequently incorporated within the CEM. When the NGTDM is used to analyze the impact of new regulations which will increase or decrease expansion costs, these adjustments will be incorporated within the Pipeline Tariff Module, where the interstate tariffs associated with expanded pipeline or storage capacity are calculated, (e.g., incremental versus rolled-in rates for new capacity). Within the CEM, parameters can be set to capture the impact of changes in lead times associated with the regulatory approval process for pipeline and storage expansion.

The design of the CEM is consistent with the NEMS requirements for modeling natural gas pipeline capacity and capacity expansion: "The model will respond to external decisions (assumptions) about throughput capacity for natural gas facilities including the expansion of facilities (interstate pipelines, storage and import facilities), and maintenance and replacement of facilities, as well as the associated costs. The output reports will contain capacity requirements and utilization rates distinguished by region."[8]

Pipeline Tariff Module

The primary purpose of the Pipeline Tariff Module (PTM) is to compute tariffs for transportation and storage services provided by interstate pipeline companies. These tariffs are used within the Annual Flow Module to derive supply and end-use prices and within the Capacity Expansion Module to derive capacity additions. The tariffs are computed for individual pipeline companies, then aggregated to the major gas pipeline corridors or arcs (in the United States) specified in the NGTDM network, as described in Chapter 4. An accounting system is used to track costs and compute rates under various rate design and regulatory scenarios. Tariffs are computed for both firm and interruptible transportation and storage services. Transportation tariffs are computed for interregional arcs defined by the NGTDM network. These network tariffs represent an aggregation of the tariffs for individual pipeline companies supplying the network arc. Storage tariffs are defined at regional NGTDM network nodes, and, likewise, represent an aggregation of individual company storage tariffs. 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 module cannot address competition for pipeline or storage services along an aggregate arc or within an aggregate region, respectively.

[8]Energy Information Administration, *Requirements*, pp. 12-13.

Since the tariffs determined by the PTM represent an aggregation of individual pipeline companies, the PTM is not designed to address the issue of analyzing competition within a regional pipeline corridor. It should also be noted that the PTM 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 Module.

Pipeline tariffs for transportation and storage services represent a significant portion of the price of gas to end-users. Consumers of natural gas are grouped generally into two categories: (1) those who 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 who 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) purchase firm transportation services, while the latter group (noncore customers) purchase interruptible services. 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 PTM transportation and storage rates to core customers are based on the average cost-of-service provided by the pipeline to all of its comparably situated core customers.

The actual reservation and usage fees (tariffs) that pipelines are allowed to charge are 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. A fundamental decision in cost-based rate design is the apportionment of costs among customer classes. How costs are apportioned determines the extent of differences in the rates charged to different classes of customers and for different types of service. For example, the more fixed costs that are included in usage fees, the more noncore customers share in paying pipeline costs. However, transferring a larger share of fixed costs to reservation fees leads to core customers bearing a larger share of system costs. The PTM is designed to provide flexibility in allocating fixed and variable costs to core and noncore customers so that various policy initiatives may be examined.

Since requirements of noncore customers generally are not taken into account in determining the peak-day delivery requirements of pipeline systems, the availability of capacity to serve these customers during peak consumption periods can be limited, and interruptions can occur. FERC sets maximum and minimum rates a pipeline is allowed to charge for interruptible service; thus, pipeline companies are allowed to offer discounts from the maximum usage fee at their discretion provided they do not unduly discriminate among customers. Since rates may be discounted to the variable cost of moving gas, and the major portion of the pipeline costs are fixed costs, the pipelines have considerable discretion in setting rates. Additionally, various rate making policy options currently under discussion by FERC may 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, transportation rates based on marginal costs will be significantly above the full cost of service rates.

Fixed and variable cost allocation in the PTM rate base specification provides flexibility in modeling a pipeline company's response to recent FERC regulatory decisions to unbundle pipeline sales and transportation services, and to encourage market-based responses to competition. The cost allocation is specified at the pipeline company-level. After individual company revenue requirements are determined, they are aggregated across companies to the arc-level specified by the NGTDM network. The PTM estimates maximum and minimum interruptible transportation service rates which are used to determine interruptible service arc-level tariff bounds. These bounds constrain market-determined rates provided by the NGTDM to noncore customers. The maximum rate computed by the PTM is the full cost-of-service rate (currently the 100-percent load factor rate). The minimum rate is the variable cost of transporting gas. The effective rate charged in the Annual Flow Module in capacity-constrained markets is based on marginal costs and, on occasion, exceeds the maximum rate computed by the PTM. A planned enhancement of the NGTDM involves imposing a limit on these interruptible rates.

Theoretically, the PTM could compute either incremental or rolled-in (average) rates for new capacity, thus allowing a more comprehensive analysis of the results of supply and demand shifts on capacities and flow patterns, as well as a more representative analysis of the pricing of natural gas transportation and distribution services.[9]

Distributor Tariff Module

The primary purpose of the Distributor Tariff Module (DTM) is to determine the components of end-use prices that are regulated by State and local authorities. These consist 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. Although the distribution service performed by local distribution companies and the transportation service performed by intrastate carriers are distinct activities, separate distribution and intrastate markups are not determined. Rather, the DTM determines a volumetric charge which covers the cost of providing distribution or transportation services from the city gate to the end user. This charge represents the difference between the price to the customer and the price to the local distribution company (or intrastate carrier) at the city gate. Where end-use service is distinguished by service type (firm or interruptible), the DTM provides separate firm and interruptible distribution markups.

The DTM represents firm markups to the residential, commercial, industrial, and electric generators sector customers based on historical data. Transportation sector and electric generation sector interruptible service markups are based on the prices of competing fuels. User-specified parameters allow adjustment of the markups to account for shifts due to regulatory policy. Many of these modeling choices are the result of data limitations.

Distribution markups represent a significant portion of the price of gas to customers. These customers include the residential, commercial, industrial, electric generators, and transportation (compressed natural gas vehicles) sectors. Each sector has different distribution service requirements. For example, residential, transportation and most commercial sector customers require guaranteed on-demand (firm) service because natural gas is their only fuel option. In contrast, portions of the industrial, electric generators, and commercial sectors may not rely solely on guaranteed service because they can either periodically terminate operations or switch to other fuels. Thus, commercial, industrial, and electric generators customers can elect to receive some gas supplies through a lower priority (and lower cost) interruptible (transportation) service. During periods of peak demand, services to these sectors can be interrupted in order to meet the natural gas requirements of core customers.

The actual 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 DTM does not explicitly determine cost-of-service distribution markups from revenue requirements because the availability of cost-specific data needed to determine revenue requirements is limited for local distribution companies and intrastate pipeline companies.[10] Instead, the markups are either determined from historical data or are based on the economic value of service as determined by the cost of competitive fuels. Firm service markups and interruptible markups to the industrial sector are based on historical data. Natural gas vehicles (NGV) sector markups

[9]Throughout the report, reference will be made to the current formulation of the NGTDM where incremental rates will be used as a market test for capacity expansion, and where the AFM will use rolled-in rates in solving for flows and prices in the firm market and market-based rates for the interruptible market. However, the capability exists within the PTM to compute different types of rates allowing it, and thus the NGTDM, to respond to different rate design and regulatory scenarios.

[10]EIA data surveys currently do not collect the cost components required to derive revenue requirements and cost-of-service for local distribution companies and intrastate carriers; nor are these data collected by other public or private sources. 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 Version I. This data collection may be considered for a future development effort.

are based on the cost of service to the end user and the cost of competitive fuel. Electric generators sector interruptible service markups are based on value of service as reflected in competing fuel prices.

Since the markups determined by the DTM represent an aggregation of individual local distribution companies and intrastate pipeline companies, this module is not designed to address the issue of analyzing competition for distribution services within a region. It should also be noted that the DTM deals only with issues at an aggregate regional level, and thus does not capture the impacts of State-specific regulations on intrastate tariffs and by-pass issues. Finally, the procedures used by the DTM to estimate markups are limited by the types and availability of data.

3. Interface Between the NEMS and the NGTDM

This chapter presents the general role that the Natural Gas Transmission and Distribution Model (NGTDM) plays in the NEMS. First a general description of the NEMS is provided, along with an overview of the NGTDM. Second, the data passed to the NGTDM from other NEMS models will be described along with the methodology used within the NGTDM to transform these prior to their use in the model. The natural gas demand representation provided to the NGTDM from the Electricity Market Model (EMM) and from the end-use demand models of NEMS is described, followed by a section on the natural gas supply interface. Finally, the information that is passed to other NEMS models from the NGTDM will be described.

A Brief Overview of NEMS and the NGTDM

The 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 9 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 models to compute the end-use prices and consumption of the fuels represented.[11] The end-use demand models—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 models 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 models determine the end-use prices needed in order to supply the amount of fuel demanded by the customers, as determined by the demand models. 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 between the Oil and Gas Supply Model (OGSM) and the demand models in NEMS, including the EMM. The NGTDM determines the price and flow of dry natural gas supplied internationally from the contiguous U.S. border[12] or domestically from the wellhead (and indirectly from natural gas processing plants) to the domestic end-user.[13] 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. The primary data flows between the NGTDM and the other oil and gas models in NEMS, the Petroleum Market Model (PMM) and the OGSM, are depicted in Figure 3-1.

Functionally, each of the demand models in NEMS provides the level of natural gas that would be consumed at the burnertip by the represented sector at a given end-use price; and the OGSM provides the level of natural gas which would be produced (or imported) at the wellhead (or border crossing) for a given supply price. The NGTDM uses this information to build "short-term" supply or demand curves which are used to approximate a given model's response to prices within a limited range.[14] Given these short-term demand and supply curves, the NGTDM model solves for the end-use, wellhead, and border prices that represent a natural gas market equilibrium, while accounting for the cost and market for transmission and distribution services (including its physical and regulatory constraints). These solution prices, and associated production levels, are in turn passed to the OGSM and the demand models,

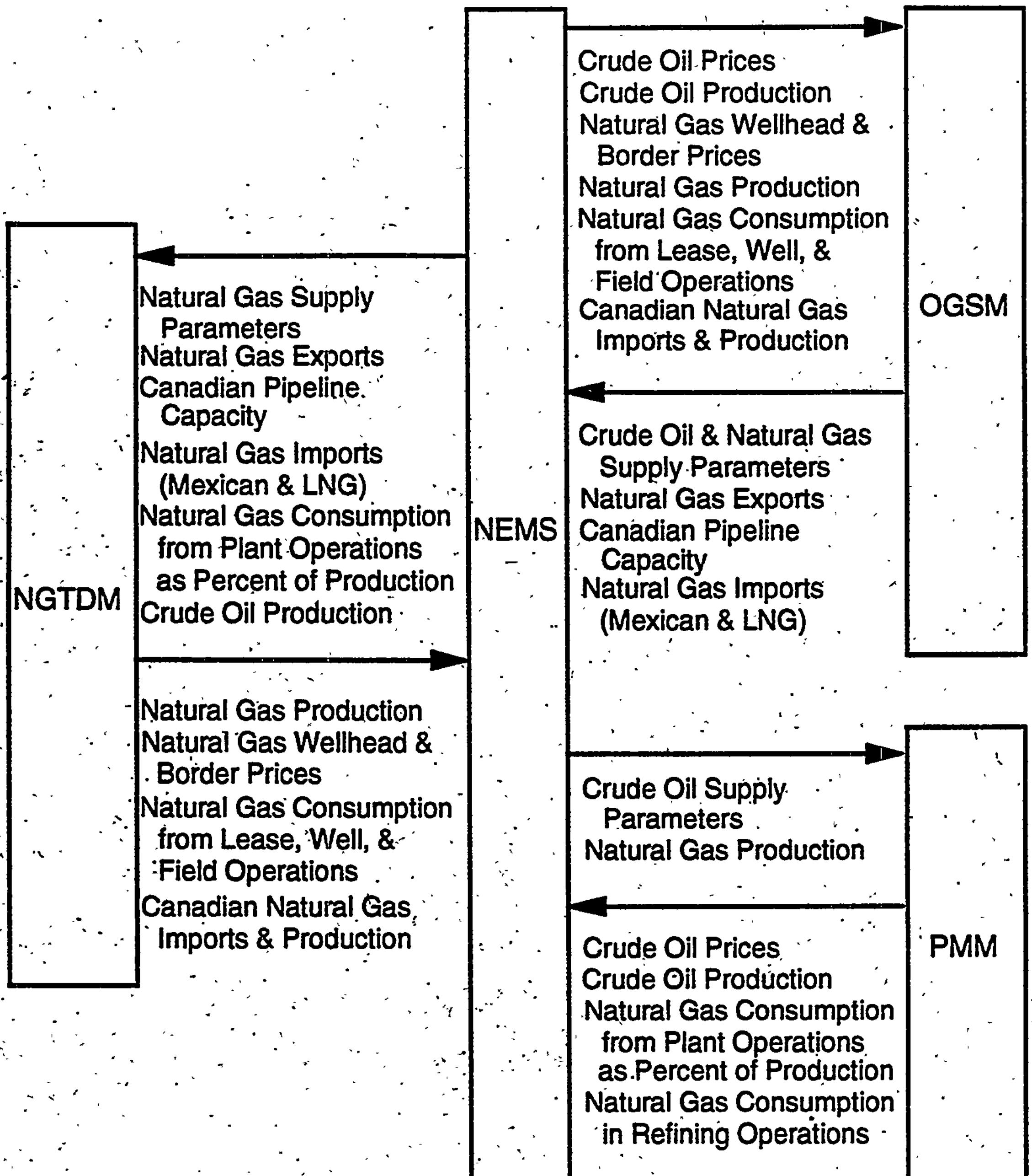
[11] A more detailed description of the NEMS system. including the convergence algorithm used, can be found in "National Energy Modeling System Integrating Module Documentation Report." DOE/EIA-M057, December 1993.

[12] 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 and Hawaii are modeled separately from the contiguous United States within the NGTDM.

[13] Natural gas exports are also represented within the model.

[14] Special parameters are provided by OGSM for the construction of supply curves for domestic nonassociated natural gas production and by EMM for the construction of demand curves for natural gas consumed by electric generators that can use residual fuel oil as an alternate.

Figure 3-1. **Primary Data Flows Between Oil and Gas Models of NEMS**



including the EMM, as primary input variables. In addition to the basic calculations performed within these models, the parameters which define the natural gas supply or demand curves used in the NGTDM are updated (as appropriate) to reflect the prices most recently provided by the NGTDM.

The NGTDM model is composed of four primary components or modules: the Annual Flow Module, the Capacity Expansion Module, the Pipeline Tariff Module, and the Distributor Tariff Module. The Annual Flow Module is the central module of the NGTDM, since it is used to derive flows and prices of natural gas in conjunction with an annual natural gas market equilibrium. Conceptually the Annual Flow Module is a simplified representation of the natural gas transmission and distribution system, structured as a network composed of nodes and arcs. The other three primary components serve as satellite modules to the Annual Flow Module, providing parameters which define some of the characteristics of these nodes and arcs. Other parameters for defining the natural gas market (such as supply and demand curves) are derived based on information passed from other NEMS models. The Capacity Expansion Module provides the Annual Flow Module with regional underground storage capacities and maximum annual flow limits along each of the arcs in the network. The Pipeline and Distributor Tariff Modules provide price parameters for establishing the tariffs to be charged along each of the interregional, intraregional, and distribution arcs. Data are also passed back to these satellite modules from the Annual Flow Module and between the satellite modules themselves.

The NGTDM is called once for each iteration of NEMS, but all modules are not run for every call. The Pipeline Tariff Module and the Capacity Expansion Module are executed once for each forecast year, on the first iteration of each year and the last iteration of each year, respectively. The Annual Flow Module and the Distributor Tariff Module are executed once every NEMS iteration. The calling sequence of and the interaction among the NGTDM modules is as follows for each year of execution of NEMS:

- First Iteration:

  The Pipeline Tariff Module determines tariffs for interstate pipeline company transportation and storage services, using a cost based simulation, and establishes tariff curves for pipeline and storage expansion.

- Each Iteration:

  The Distributor Tariff Module determines markups for intrastate transmission and distribution services based on historical data and alternate fuel prices. Next, the Annual Flow Module incorporates tariffs from the Pipeline Tariff Module and markups from the Distributor Tariff Module into a linear program that solves for interregional flows based on supply availability, demand requirements, and pipeline capacity constraints. The linear program determines a market equilibrium solution by maximizing consumer and producer surpluses, while minimizing supply and transportation costs, thus determining natural gas end-user and supply prices and domestic production. Pipeline capacity constraints for the first year (or years) of execution are determined from historical data. Subsequent year's constraints are taken from the previous year's Capacity Expansion Module results.

- Last Iteration:

  The Capacity Expansion Module employees the pipeline and storage expansion curves calculated in the Pipeline Tariff Module and expected future supply availability and consumption levels from other models in the NEMS. The Capacity Expansion Module represents two natural gas market seasons within a linear program structure to determine pipeline and storage capacity expansion (beyond planned additions) for a future year, by minimizing the pipeline and storage expansion costs required to meet the expected consumption levels of natural gas. The resulting pipeline capacity build requirements and seasonal flow patterns are used to establish effective limits on the annual load along pipelines, for use in the Annual Flow Module. In addition, annual net storage withdrawals for the firm and interruptible service networks are set based on resulting peak/offpeak flows to and from storage in the Capacity Expansion Module.

The primary outputs from the NGTDM, which are used as input in other NEMS models, result from establishing a natural gas market equilibrium solution: end-use prices, wellhead and border crossing prices, and associated production and Canadian import levels. In addition, the model provides a forecast of lease and plant fuel consumption, pipeline fuel use and the corresponding emissions, as well as pipeline and distributor tariffs, pipeline and storage capacity expansion, and interregional natural gas flows. The capital investments associated with the expansion of pipeline and storage capacity are provided to the macroeconomic model of NEMS.

Natural Gas Demand Representation

Natural gas which is produced within the United States is consumed in lease and plant operations, delivered to consumers, exported internationally, and consumed as 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 is set equal to an exogenously specified percentage (Appendix F, Table F2) of dry gas production. Gas consumed in natural gas processing plants is similarly calculated, however, the percentages that are used are provided by the Petroleum Market Model. Pipeline fuel use depends on the amount and distance of gas transported and distributed in each region, as described in Chapter 5. The level of natural gas exports are currently determined exogenously to NEMS and passed to the NGTDM from the OGSM model. Exports are distinguished by six Canadian and three Mexican border crossing points, as well as for exports of liquefied natural gas to Japan from Alaska. The representation of gas delivered to consumers is described below.

Classification of Natural Gas Consumers

Natural gas that is delivered to consumers is represented within the NEMS at the Census Division level and by five primary end-use sectors:[15] residential, commercial, industrial, transportation, and electric generation. These demands are further distinguished by customer class (core or noncore), reflecting the type of natural gas transmission and distribution service that is predominately purchased. The "core" customers require guaranteed service, particularly during peak days/periods during the year. The "noncore" customers require a lower quality of transmission services and therefore, consume gas under a less certain and/or less continuous basis. In the NGTDM, the core customers are assumed to purchase firm transmission services and the noncore customers are assumed to purchase interruptible transmission services.

Currently in NEMS, all customers in the transportation, residential, and commercial sectors are classified as core.[16] Within the industrial sector the noncore segment includes the industrial boiler market and refineries. The noncore segment of the electric generation sector is further separated into two subclasses, depending on the alternative fuel a plant would burn should natural gas be unavailable or relatively uneconomic. The subclass of noncore electric generation plants that has the option of burning distillate fuel in lieu of natural gas is referred to as "competitive-with-distillate." The second subclass of noncore plants can burn either natural gas or residual fuel oil and is therefore referred to as "competitive-with-residual fuel." The electric generating units defining each of the three customer classes modeled are as follows: (1) core—gas steam units or gas combined cycle units, (2) competitive-with-distillate—dual-fired turbine units or gas turbine units, (3) competitive-with-residual—dual-fired steam plants (consuming both natural gas and residual fuel oil). Within the NGTDM, natural gas is exported to Mexico under firm transmission service and to Canada under interruptible transmission service.

For any given NEMS iteration within a forecast year, the individual demand models in NEMS determine the level of natural gas consumption for each region and customer class at the end-use 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 (set to zero if fixed consumption levels are required) as a basis for building a short-term demand curve. These curves are used

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[15]Natural gas burned in the transportation sector is defined as compressed natural gas that is burned in natural gas vehicles; and the electric generation sector includes all electric power generators except cogenerators.

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

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 model during the next NEMS iteration to determine the consumption level that the model would actually forecast at this price. The NGTDM disaggregates the Census division regional consumption levels into the regional representation that the NGTDM requires. The demand curve representation and the regional mapping for the electric generation sector differ from the other NEMS sectors as described in the following sections.

Regional Representations of Demand

Natural gas consumption levels by all nonelectric[17] sectors are provided by the NEMS demand models for the 9 Census divisions, the primary integrating regions represented in the NEMS. Alaska and Hawaii are included within the Pacific Census Division. The EMM represents the electricity generation process for 13 electricity supply regions—the 9 North American Electric Reliability Council (NERC) Regions and 4 selected NERC Subregions (Figure 3-2). Electricity generation in Alaska and Hawaii is handled separately. Within the EMM, the electric generators' consumption of natural gas is disaggregated into subregions which can be aggregated into Census Divisions or into the regions used in the NGTDM.

With the few following 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 and Hawaii are not connected to the rest of the Nation by pipeline and are therefore treated separately from the contiguous Pacific Division in the NGTDM. Second, Florida receives its gas from 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 Annual Flow Module are referred to as the "NGTDM Regions" (as shown in Figure 2-1).

As can be seen in Figure 3-2, the regions which are 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 the regions (NGTDM/EMM) resulting from the combination of the NGTDM regions overlapped with the EMM regions, translated to the nearest State border (Figure 3-3). For example, the South Atlantic NGTDM region (number 5) includes three NGTDM/EMM regions (also subregions of EMM regions 1, 3, or 9). 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 of the NGTDM/EMM regions.

The consumption levels for each of the nonelectric sectors are disaggregated from the 9 Census divisions to the 12 NGTDM regions by applying historically based shares which are held constant throughout the forecast (Appendix F, Table F6). 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. Within the NGTDM, a relatively simple module (described later) was included for approximating the consumption of natural gas by each nonelectric sector in Alaska. These estimates, combined with the consumption levels provided by the EMM for consumption by electric generators in Alaska, are also used in the calculation of the production of natural gas in Alaska.

Natural Gas Demand Curves for Nonelectric Sectors

While the primary analysis of energy demand takes place in the NEMS demand models, the NGTDM itself directly incorporates limited price responsive demand curves to speed the overall convergence of NEMS and to improve the

[17]The "nonelectric" sectors refer to sectors that do not produce electricity using natural gas, (i.e., the residential, commercial, industrial, and transportation demand sectors.)

Figure 3-2. Electricity Market Model (EMM) Regions

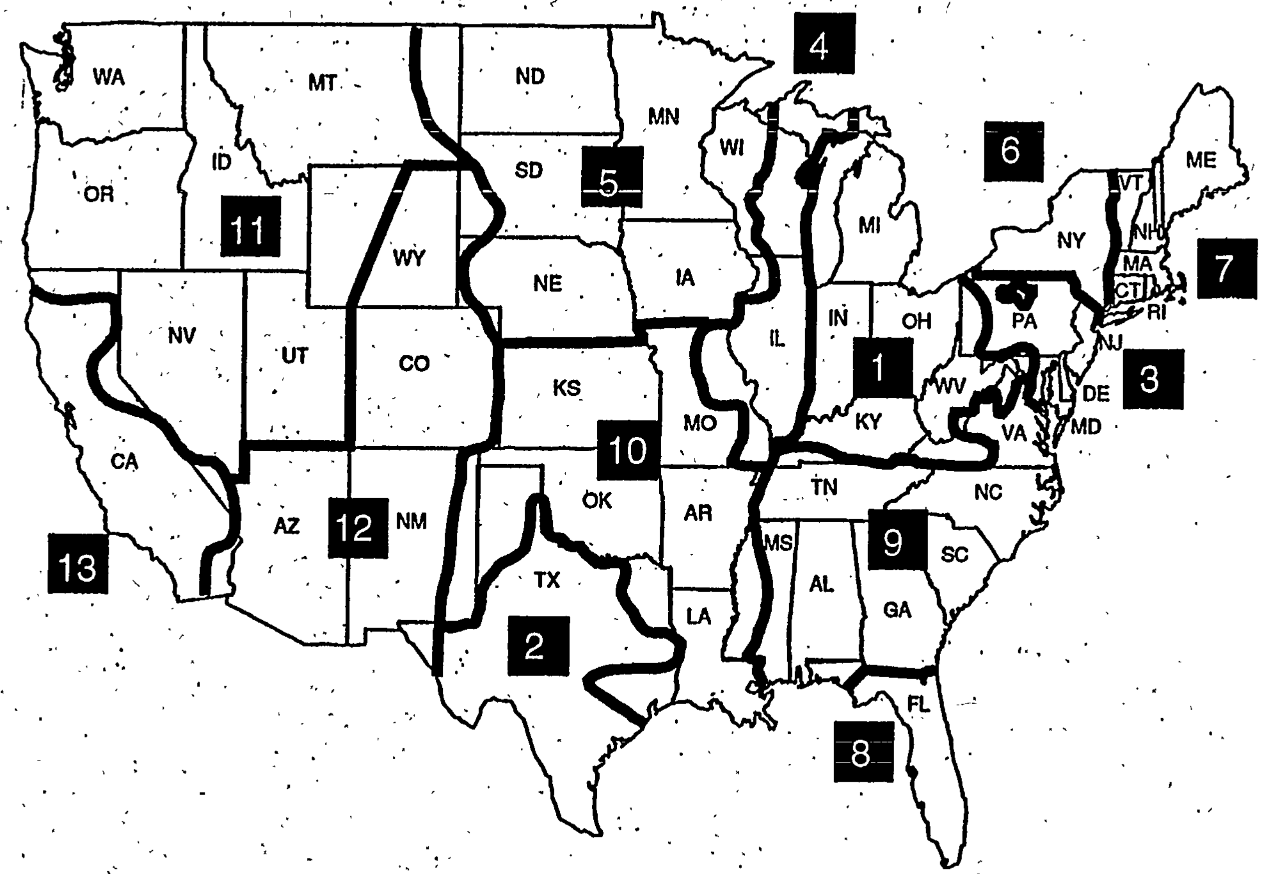
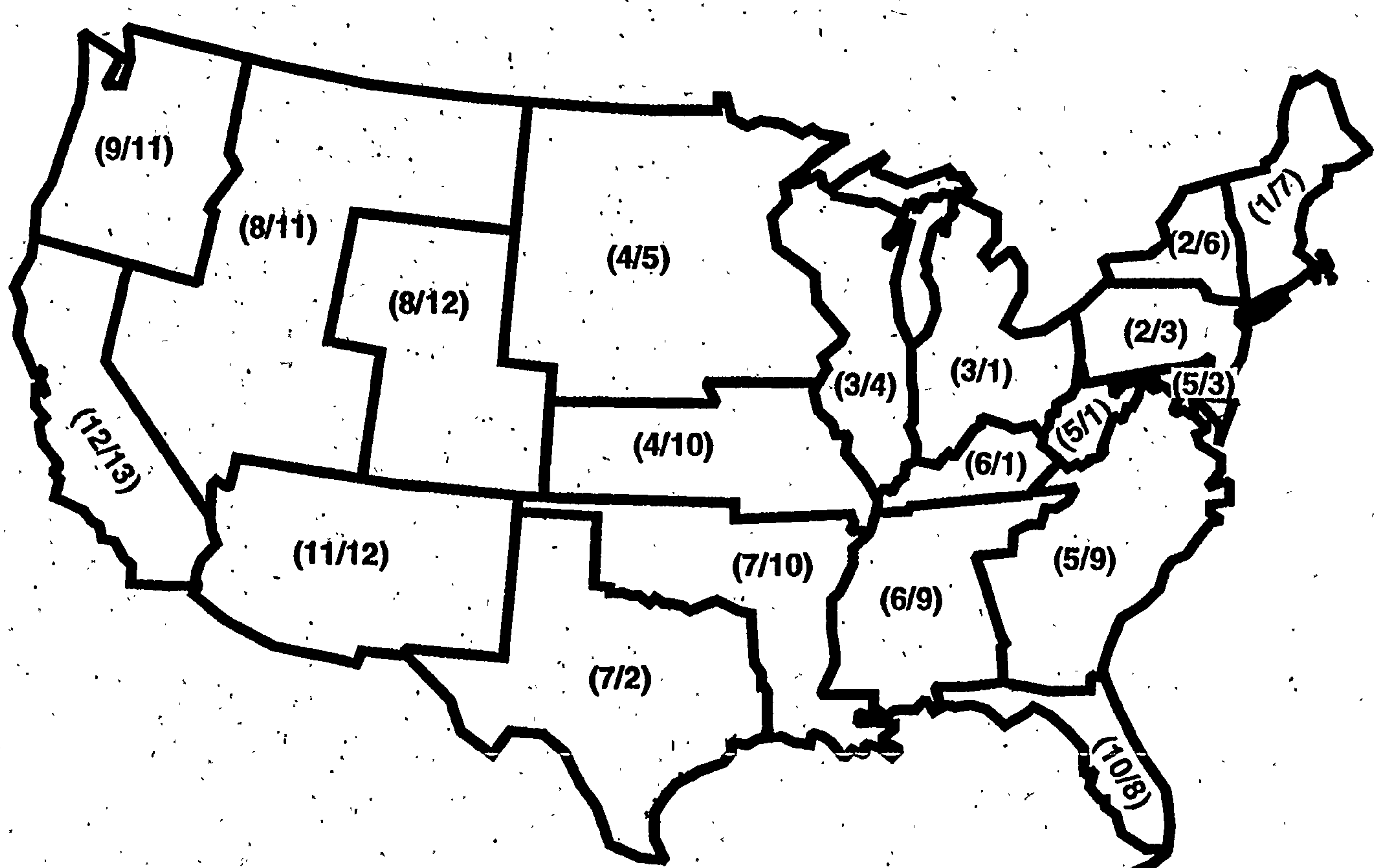


Figure 3-3. Natural Gas Transmission and Distribution Model/Electricity Market Model (NGTDM/EMM) Regions



(NGTDM Region Number/EMM Region Number)

quality of the results obtained when the NGTDM is run as a stand-alone model. The NGTDM may also be executed to determine end-use prices for fixed consumption levels (represented by setting the price elasticity of demand in the demand curve equation to zero). These demand curves are defined within a limited range around the price/quantity pair solved for during the most recent NEMS iteration. The form of the demand curves for the firm transmission service type for each nonelectric sector and region is:

$$NGTDM\_CRVNONUFX_{s,r} = QBAS\_NONU\_F_{s,r} * (PRICE / NONU\_PR\_F_{s,r})^{NONU\_ELAS\_F_s} \quad (1)$$

where,

$NONU\_PR\_F_{s,r}$	=	end-use price to core sector s in NGTDM region r in the previous NEMS iteration (dollars per Mcf)
$QBAS\_NONU\_F_{s,r}$	=	natural gas quantity which the NEMS demand models indicate would be consumed at price NONU_PR_F by core sector s in NGTDM region r (Bcf)
$NONU\_ELAS\_F_s$	=	short-term price elasticity of demand for core sector s (Appendix F, Table F36) Note: Demand curves can be represented with fixed consumption levels by setting elasticities equal to zero.
PRICE	=	end-use price at which demand is to be evaluated (dollars per Mcf)
$NGTDM\_CRVNONUFX_{s,r}$	=	estimate of the natural gas which would be consumed by core sector s in region r at the price PRICE (Bcf)
s	=	core sector (1-residential, 2-commercial, 3-industrial, 4-transportation)

The form of the demand curve for the nonelectric interruptible transmission service type is identical, with the following variables substituted: NGTDM_CRVNONUIX, NONU_PR_I, QBAS_NONU_I, and NONU_ELAS_I.

Natural Gas Demand Curves for Electric Generators

Natural gas demand by electric generators is represented somewhat differently in the NGTDM from the nonelectric demands because of greater cross price affects. Within the EMM natural gas consumption in the short-term depends first on the dispatch order of the gas burning plants, which is a function of the price of gas relative to the price of fuels burned by other powerplants, and second, on the percentage of gas used in dual-fired plants. If a change in the relative fuel prices results in a change in the dispatch order (relative to a base), the associated consumption level for natural gas burned by electric generators is likely to change as well. However, with the general exception of the competitive-with-residual plant types, the gas consumption level of electric generators is unlikely to respond to changes in the gas price that do not affect the dispatch order. The dispatching of powerplants is represented in the EMM, not in the NGTDM. Therefore, in the NGTDM, the gas consumption by electric generation within the core and competitive-with-distillate service types is fixed at the values calculated by the EMM in the previous NEMS iteration.

In the EMM, natural gas consumption by plants classified as competitive-with-residual can change significantly in response to a different price even with no switch in the merit order. Consumption levels can change because these plants can switch between burning natural gas and burning residual fuel oil, which has historically been priced competitively with natural gas. A representation of the natural gas demand response within the EMM for the competitive-with-residual plant types is incorporated in the NGTDM. This representation will be relatively accurate within a range of natural gas prices which do not lead to a merit order change. Within the NGTDM, the competitive-with-residual plants either see the same price as the competitive-with-distillate plants or a lower price when it is deemed economically advantageous (i.e., the resulting price is at least as great as the minimum variable cost to supply the natural gas, but not high enough to result in a loss of market share to petroleum suppliers). To facilitate this determination, the EMM provides the NGTDM with additional parameters to anticipate more closely the demand response within the EMM to a change in the competitive-with-residual price.

Since the demand for natural gas in the competitive-with-residual class within the EMM is a function of the relative price of the two competing fuels, the demand curve to represent this customer class is specified within the NGTDM as a function of the price of natural gas relative to the price of residual fuel oil to electric generators, as illustrated in Figure 3-4. For a given demand for electricity and a given dispatch order for a region within the EMM, there is a maximum (GSHRMAX) and a minimum (GSHRMIN) level of natural gas which would be consumed by the competitive-with-residual class (represented by the vertical lines in the figure). GRATMIN is the lowest price ratio which would result in a consumption level equal to GSHRMIN, and GRATMAX is the highest price ratio which would result in a consumption level equal to GSHRMAX. For each NGTDM/EMM region, the EMM provides these price/quantity pairs to the NGTDM based on the dispatch order from the current NEMS iteration. These are two of the four price/quantity pairs provided by the EMM, which the NGTDM connects to form a piece-wise linear demand curve for the competitive-with-residual class within the electric generation sector. The EMM also provides the quantity of gas (GSHRPAR) that would be consumed at the price ratio which represents parity (GRATPAR), and the quantity of gas that would be consumed at the natural gas price (converted to a price ratio in the NGTDM) which was sent to the EMM in the previous NEMS iteration (SHROLD and RATOLD). Within the NGTDM the residual fuel oil price to electric generators (used in converting the price ratio into a natural gas price) is held constant at the level established in the previous NEMS iteration and is calculated as a quantity-weighted average of the low-sulfur and high-sulfur residual fuel prices (QRLELGR, QRHELGR) to the electric generation sector.

Natural Gas Supply Interface

The primary categories of natural gas supply represented in the NGTDM for the contiguous Lower 48 States are nonassociated and associated-dissolved gas from onshore and offshore regions, pipeline imports from Mexico and Canada, liquefied natural gas imports, gas transported via the Alaskan Natural Gas Transportation System (ANGTS), synthetic natural gas produced from coal and from liquid hydrocarbons, and other supplemental supplies. The only supply categories from this list which are allowed to vary within the NGTDM in response to a change in the current year's natural gas price are synthetic natural gas produced from liquid hydrocarbons and nonassociated gas from onshore and offshore regions. 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 which varies with a change in the oil production in the current forecast year. The annual oil production level is determined in the Petroleum Market Model and can vary between each iteration of NEMS.

Within the OGSM, natural gas supply activities are modeled for the 13 supply regions (6 onshore, 3 offshore, and 3 Alaskan geographic areas) shown in Figure 3-5. A separate component of the OGSM models the foreign sources of natural gas which are transported via pipeline from Canada and Mexico, and by way of oceanic vessels in liquefied form (liquefied natural gas). Six Canadian and three Mexican border crossings demarcate the foreign pipeline interface between the OGSM and the NGTDM. Supplies from the four existing liquefied natural gas terminals are also represented (as supply points) in the NGTDM, although only two of the four existing terminals are currently in operation. The annual levels of liquefied natural gas imports are determined in the OGSM and are provided to the NGTDM at the beginning of each forecast year. Similarly the OGSM establishes the level of gas which will flow into the contiguous United States via the ANGTS.

Supplemental Gas Sources

Sources for synthetically produced natural gas are geographically specified in the NGTDM based on current plant locations. Synthetic gas from coal is exogenously specified, independent of the price of natural gas in the current forecast year. The Coal Module of NEMS sets the annual forecast of natural gas produced from the Great Plains Coal Gasification Plant in North Dakota, whereas a price responsive supply curve is incorporated within the NGTDM for synthetic gas production from liquid hydrocarbons (currently produced only in Illinois). Synthetic gas production from liquid hydrocarbons in Illinois is represented in the NGTDM using a statistically estimated function based on the associated region's natural gas price:

Figure 3-4. Example Natural Gas Demand Curve for Competitive-With-Residual Fuel Oil Class of Electric Generators

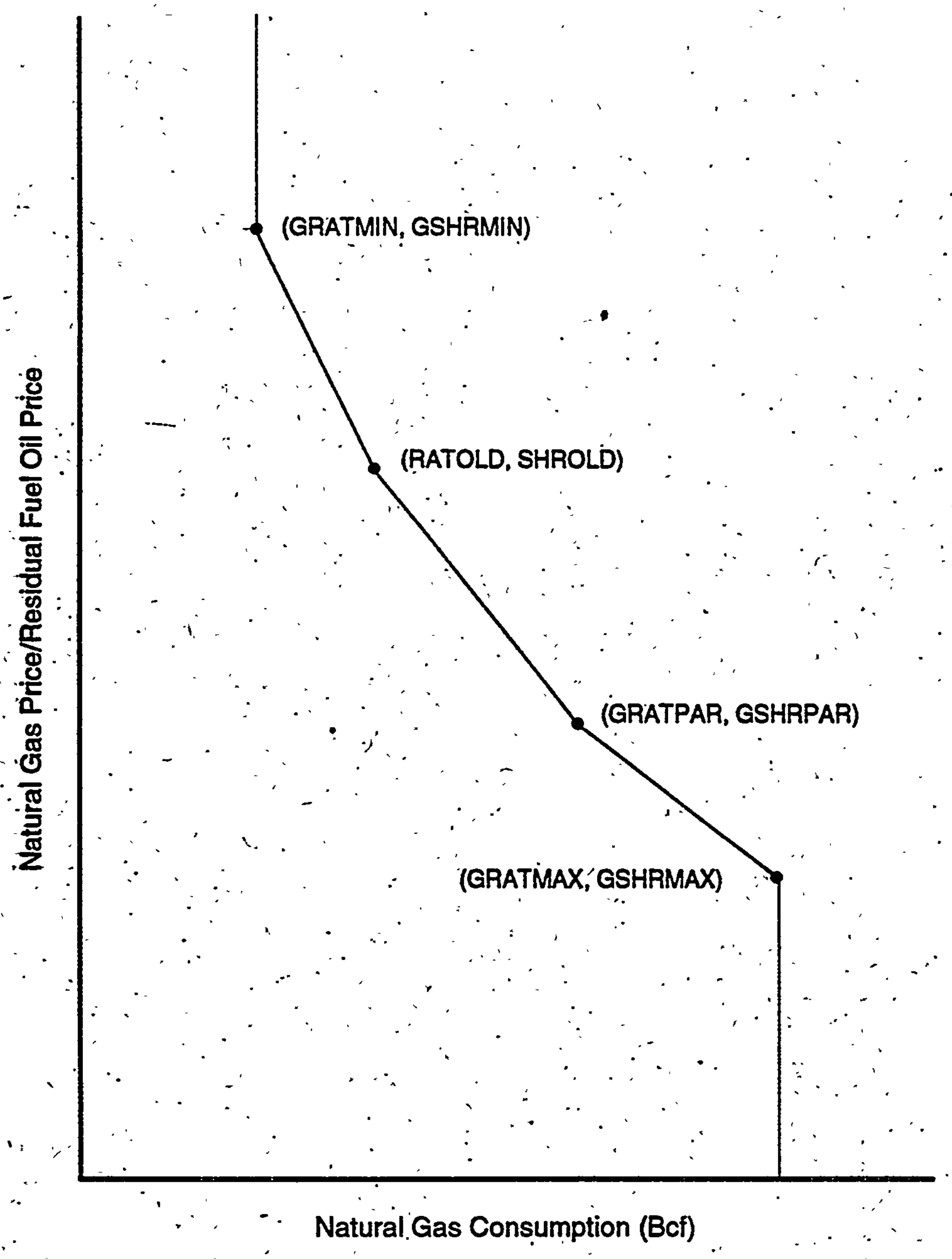
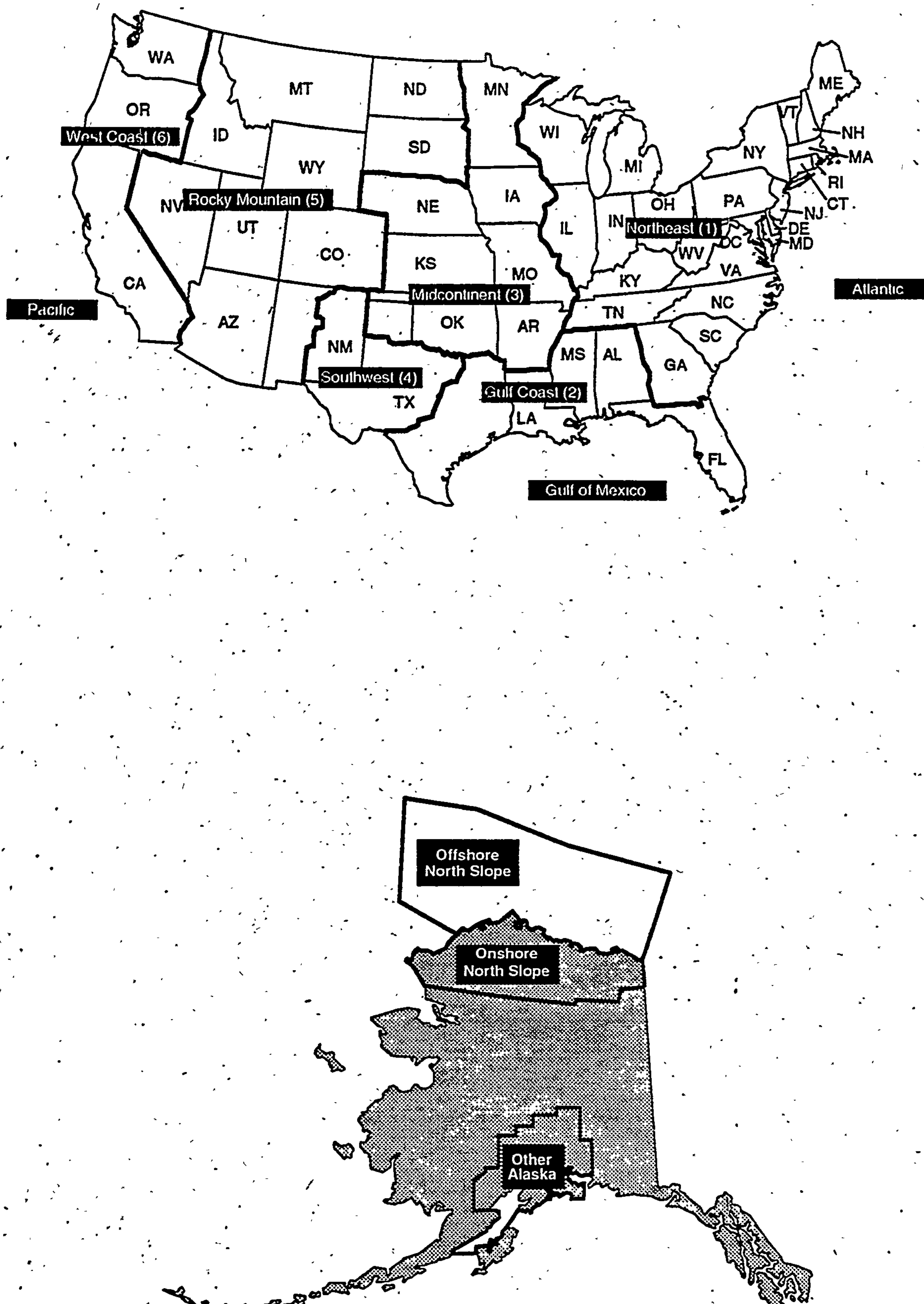


Figure 3-5. Oil and Gas Supply Model (OGSM) Regions



$$VAL = SNGA1 * VALUE^{SNGA2} \tag{2}$$

where,

VAL	=	synthetic gas production from liquid hydrocarbons in Illinois (Bcf)
VALUE	=	firm service natural gas market price in the East North Central Census Division (which contains Illinois), (dollars per Mcf)
SNGA1, SNGA2	=	estimated parameters (Appendix G, Table G3)

The synthetic gas production level resulting from the above equation is limited to be no less than an exogenously specified minimum (Appendix F, Table F1) and not to increase by more than 50 percent above the level in the previous forecast year. Synthetic gas production from liquid hydrocarbons in Hawaii is held constant throughout the forecast at an historically based level (Appendix F, Table F1), as are other supplemental supplies[18] (Appendix F, Table F12).

Natural Gas Imports Via Pipeline

The OGSM provides most of the parameters used in the NGTDM for representing the imports of gas from Mexico and Canada into the United States by pipeline. Border crossing points are established at each NGTDM region adjoining an international border. The annual import levels for gas from Mexico are generated exogenously and passed to the NGTDM via the OGSM. The OGSM also provides parameters for defining a national Canadian natural gas supply curve, an exogenous forecast for consumption of natural gas in Canada, and additional parameters for representing the transmission system for gas within Canada, including an exogenous forecast of the physical capacity of natural gas pipelines crossing the border into the United States. Within the NGTDM, this physical capacity limit is multiplied by an exogenously specified utilization rate to establish a maximum effective capacity limit for flow of gas from Canada into the United States. "Effective capacity" is defined as the maximum annual physically sustainable capacity of a pipeline times an assumed maximum likely utilization rate, based on the expected seasonal demand profiles of the customers being served.

The functional form of the Canadian natural gas supply curve is represented as follows:

$$CN\_PRODUC = OGRESCAN_{2,y} * OGPRRCAN_{2,y} * \left(1 + OGELSCAN_{2,1} * \frac{CN\_WELPRC - CN\_WPRCLAG}{CN\_WPRCLAG}\right) \tag{3}$$

where,

CN_PRODUC	=	Canadian domestic natural gas production in year y (Bcf)
$OGRESCAN_{2,y}$	=	Canadian natural gas reserves in beginning-of-year y (from OGSM in Bcf)
$OGPRRCAN_{2,y}$	=	expected natural gas production-to-reserves ratio in Canada in year y (from OGSM as fraction)
$OGELSCAN_{2,1}$	=	estimated short run price elasticity of extraction for Canada (from OGSM)
CN_WPRC	=	average Canadian wellhead price in year y (dollars per Mcf)
CN_WPRCLAG	=	average Canadian wellhead price in year y-1 (dollars per Mcf) [for the first forecast year this is set to CN_WELPRC89, (Appendix E, Table E3)]

The amount of natural gas available to flow into the United States from Canada is calculated as:

where,

[18]Other supplemental supplies include propane-air, refinery gas, coke oven gas, manufactured gas, biomass gas, and air injection for Btu stabilization.

$$TOT\_BRDQ = CN\_PRODUC - \frac{OGCNCON_{2,y} - (CANFLO\_OUT_y + \sum_{i=1}^{6} OGQNGEXP_{i,y}) * (1 - OGCNEXLOSS)}{1 - OGCNDMLOSS} \tag{4}$$

TOT_BRDQ	=	total gas available to flow into the United States from Canada (measured at the wellhead), (Bcf)
CN_PRODUC	=	Canadian domestic natural gas production in year y (Bcf)
$OGCNCON_{2,y}$	=	consumption of natural gas in Canada (from OGSM in Bcf)
$CANFLO\_OUT_y$	=	gas flowing into Canada which was originally produced in Canada[19] in year y (Bcf)
$OGQNGEXP_{i,y}$	=	exports of gas from the United States into Canada by border crossing i in year y (from OGSM in Bcf)
OGCNDMLOSS	=	percentage of gas produced in Canada to satisfy Canadian demand that is consumed in transit (from OGSM as fraction)
OGCNEXLOSS	=	percentage of gas produced in the United States to satisfy Canadian demand that is consumed in transit within Canada (from OGSM as fraction)

If the value of TOT_BRDQ exceeds the total effective capacity of the natural gas pipelines used to flow gas into the United States from Canada, then it is assumed that the share of TOT_BRDQ which will flow across each of the representative border crossings in the model (CN_FLOSHR) will be equivalent to that border crossing's share of the total effective capacity. Under most likely model scenarios this has been shown to be true in the 2010 time frame. However, if available Canadian supplies are less than total effective pipeline capacity across the border, the allocation of TOT_BRDQ to each of the six border crossings is calculated as follows:

$$CN\_FLOSHR_i = (OGCNPARM1 * \frac{CN\_FLOLAG_i}{\sum_{i=1}^{6} CN\_FLOLAG_i}) + (1 - OGCNPARM1) * \frac{(CN\_BRDPRC_i - OGCNPMARKUP_i)^{OGCNPARM2}}{\sum_{i=1}^{6} (CN\_BRDPRC_i - OGCNPMARKUP_i)^{OGCNPARM2}} \tag{5}$$

where,

CN_FLOSHR_i	=	the share of the gas available to flow from Canada into the United States to flow across border crossing i (fraction)
CN_FLOLAG_i	=	the amount of gas which flowed from Canada into the United States across border crossing i in the previous year (adjusted for pipeline additions[20] in year y), (Bcf)
OGCNPARM1	=	parameter which reflects the importance of the historical flow pattern in the determination of actual allocation of gas (from OGSM, 0 < OGCNPARM1 < 1)
OGCNPARM2	=	parameter which reflects the responsiveness of the flow pattern to differentials in border prices netbacked to the wellhead (from OGSM, OGCNPARM2 = 1)
CN_BRDPRC_i	=	the market price at border crossing i (dollars per Mcf)
$OGCNPMARKUP_i$	=	assumed markup from the average Canadian wellhead price to border crossing i (from OGSM in dollars per Mcf)

If the resulting shares indicate flow levels across some border crossings which exceed their maximum effective capacity level, then the "unflowable" portion is made available at border crossings with available pipeline capacity,

[19] A significant amount of natural gas flows into Minnesota from Canada on an annual basis only to be routed back to Canada through Michigan (and a very small amount through Montana). The amount of gas entering the United States that is not imported from Canada, and the percentage of this amount which travels back through Michigan, are set at exogenously specified levels for the forecast (Appendix F, Table F9).

[20] The 1990 capacity additions for the Canadian import arcs are specified exogenously (Appendix E, Table E3).

and the values for the variable CN_FLOSHR are adjusted accordingly. These shares are ultimately used in the calculation of the Canadian wellhead price:

$$CN\_WELPRC = \sum_{i=1}^{6} CN\_FLOSHR_i * (CN\_BRDPRC_i - OGCNPMARKUP_i) \quad (6)$$

where,

CN_WELPRC	=	Canadian wellhead price (dollars per Mcf)
CN_FLOSHR_i	=	the share of the gas available to flow from Canada into the United States to flow across border crossing i (fraction)
CN_BRDPRC_i	=	the market price at border crossing i (dollars per Mcf)
$OGCNPMARKUP_i$	=	assumed markup from the average Canadian wellhead price to border crossing i (from OGSM in dollars per Mcf)

The system of equations which represents the pricing and flow of gas from Canada into the United States can not be solved in a top/down fashion, but requires an iterative process due to the interrelationships involved. Furthermore, the solution algorithm used within the NGTDM requires prespecified supply curves (or fixed supply levels) at each border crossing before solving. A short-term supply curve is generated for a single border crossing point, through the use of the equations shown above, by holding the border prices for the other crossing points at their solution values from the previous NEMS iteration (or the previous year, in the first iteration).[21]

Supply Curves for Domestic Dry Gas Production

Most of the parameters for generating short-term supply curves for dry natural gas production are provided to the NGTDM by the OGSM. The six onshore OGSM regions within the contiguous United States do not generally share common borders with the NGTDM regions. As was done with the EMM regions, the NGTDM represents onshore supply for the 17 regions resulting from overlapping the OGSM and NGTDM regions (Figure 3-6).

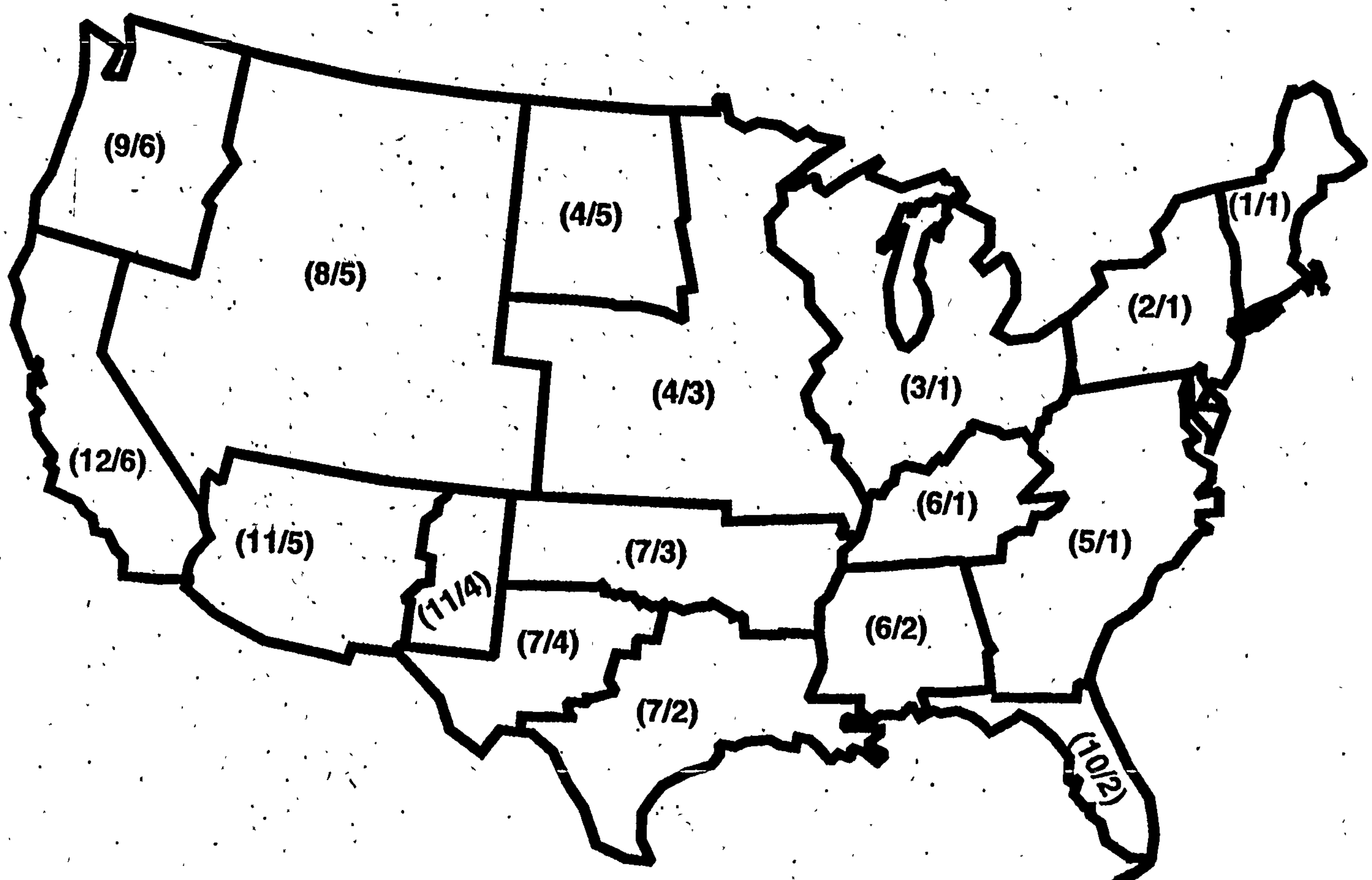
These supply curves are defined as being net of lease and plant fuel consumption (i.e., the amount of dry gas available for market after any necessary processing and before being transported via pipeline). Within the NGTDM, dry gas production is delineated by two categories, nonassociated and associated-dissolved production. Nonassociated 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. Whereas, 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.

Associated-Dissolved Gas Production

The production of associated-dissolved gas is established as a function of the level of crude oil production (an output of the Petroleum Market Model) and the relative price of natural gas at the wellhead to imported crude oil. Over the short term, associated-dissolved production is assumed not to vary with a change in the price of natural gas (except in as much as the oil production level might be indirectly impacted by a change in the gas price). The Petroleum Market Model forecasts domestic crude oil production by the 3 offshore and 6 onshore OGSM regions. The NGTDM calculates associated-dissolved gas production for each of these 6 onshore regions and disaggregates the resulting quantities into the 17 NGTDM/OGSM regions using historically based shares, as follows:

[21]An initial value is exogenously specified for CN_BRDPRC (Appendix E, Table E3).

Figure 3-6. Natural Gas Transmission and Distribution Model/Oil and Gas Supply Model (NGTDM/OGSM) Regions



(NGTDM Region Number/OGSM Region Number)

$$ADGPRDON_r = SHR\_AD17_r * ADG\_TO\_OIL_o * (365.25 * RFQTDCRD_{o,y}) * PFACT \quad (7)$$

$$\text{with,} \quad PFACT = \left(\frac{OGWPRNG_{13,y-1} / (IT\_WOP_{y-1}/5.6)}{PGAS\_TO\_POIL} \right)^{PALPHA}$$

where,

$ADGPRDON_r$	=	associated-dissolved gas production for NGTDM/OGSM region r (Bcf)
SHR_AD17_r	=	assumed share of the related OGSM region's associated-dissolved gas production which is in NGTDM/OGSM region r [Appendix F, Table F5 (fraction)]
$RFQTDCRD_{o,y}$	=	the crude oil production in the related OGSM region o in year y (from the Petroleum Market Model in millions of barrels per day)
$ADG\_TO\_OIL_o$	=	average historical (1987-1992) associated-dissolved gas production to oil production ratio [Appendix F, Table F49 (fraction)]
PGAS_TO_POIL	=	average historical (1987 to 1992) natural gas wellhead price to world crude oil price ratio (0.6431)
PALPHA	=	assumed parameter (0.191)
$OGWPRNG_{13,y-1}$	=	average natural gas wellhead price in the lower 48 States in the previous forecast year [the 13th array position holds the lower 48 State average]
IT_WOP_{y-1}	=	average crude oil import price in the previous forecast year

[Note: The form of this equation will be modified in the near future.]

The equation for associated-dissolved gas in the 3 offshore regions ($ADPRDOF_r$) is identical to the onshore equation once the SHR_AD17 term is removed. Total domestic production is the sum of nonassociated and associated-dissolved production.[22]

Optional Functional Forms for Nonassociated Gas Production Function

The NGTDM includes the option of selecting one of three different functional forms for the supply curve for nonassociated dry natural gas production (net of lease and plant fuel) in the domestic onshore and offshore regions. All three forms are constructed from a common key point (or price/quantity pair) which is based on an expected extraction rate, estimated in the OGSM. The "expected" or base production level from an onshore region is calculated as follows:

$$BASE\_Q_r = OGRESNGON_r * OGPRRNGON_r * PER \quad (8)$$

where,

$BASE\_Q_r$	=	expected nonassociated production (net of lease and plant), NGTDM/OGSM region r (Bcf)
$OGRESNGON_{r,y}$	=	dry gas reserves at the beginning-of-year y in onshore NGTDM/OGSM region r (from OGSM in Bcf)
$OGPRRNGON_{r,y}$	=	expected extraction rate in year y from reserves in onshore NGTDM/OGSM region r (from OGSM as fraction)
PER	=	1 - $PCTLSE\_SUPL_r$ - $PCTPLT\_PADD_{p,y}$, a factor for netting lease and plant fuel out of dry gas production (fraction)
$PCTPLT\_PADD_{p,y}$	=	percent of dry gas production which is consumed in natural gas processing plant operations, for PADD[23] region p in year y (from the PMM as fraction)

[22] Within the FORTRAN code, the functions used to generate supply curves for total dry gas production include variables for associated-dissolved production, effectively shifting the nonassociated gas production curves to the right along the quantity axis to create a total production curve. (For convenience in the code, the synthetic production of gas from coal is similarly added to the total production curve.)

[23] Petroleum Administration for Defense Districts (PADD) are the regions modeled in the PMM. The PADD region which most overlaps the indicated NGTDM/OGSM region is used in this and other equations, as necessary.

$PCTLSE\_SUPL_r$	=	percent of dry gas production which is consumed in well, field, and lease operations [Appendix F, Table F2 (fraction)] Note: For the offshore regions $BASE\_Q_r = OGRESNGOF_{r,y} * OGPRRNGOF_{r,y}$.

The price (BASE_P) associated with BASE_Q is based on the average solved for wellhead price in the region over the previous two forecast years.[24] A multiplicative benchmark factor is applied in setting BASE_P to calibrate the model to the 1994 and 1995 national average natural gas wellhead price forecast in the *Short Term Energy Outlook*, DOE/EIA-0202 (94/3Q). This factor was held constant (at 0.98) throughout the forecast period (Appendix F, Table F44). The amount the production will vary from BASE_Q is a function of how different the wellhead price (at which the function is being evaluated) is from BASE_P. The calculation of the additional quantity of production (DEL_Q_r)[25] which would result at a given wellhead price (VALUE) is different under each of the three options.[26] Options one and two are presented below, with option 3 following.

Option 1:

$$DEL\_Q_r = BASE\_Q_r * OGELSNGON_{r,y} * (VALUE - BASE\_P_r) / BASE\_P_r \tag{9}$$

where,

$OGELSNGON_r$	=	estimated short-term price elasticity (from OGSM), for offshore regions the variable $OGELSNGOF_r$ is used

Option 2:

$$DEL\_Q_r = BASE\_Q_r * ELAS * (VALUE - BASE\_P_r) / BASE\_P_r \tag{10}$$

where,

If $VALUE \geq BASE\_P_r$

$ELAS = PARM\_SUPCRV2_1$, (user specified short-term price elasticity, assumed to be less than one, Appendix F, Table F37)

If $VALUE < BASE\_P_r$

$ELAS = PARM\_SUPCRV2_2$, (user specified short-term price elasticity, assumed to be greater than one, Appendix F, Table F37)

Option 1 is symmetric for price increases and decreases. Option 2 assumes production responds more strongly to price declines than to increases. The justification for incorporating a different elasticity above and below the "expected" production level on the supply curve is that producers have a vested interest in selling close to their planned for or expected production level. Much lower than anticipated gas sales do not allow the producer the necessary cash flow to stay in business. In such cases, prices would be lowered enough to increase sales and resulting revenues. However, there are practical upper limits on the rates of extraction from reserves, causing an upward push on the price when there are market pressures to produce at elevated extraction rates.

Option 3 is a combination of Options 1 and 2. In a close range around the base point (plus or minus an assumed percentage —$PARM\_SUPCRV3_1$— of the base quantity), the short-term wellhead price elasticity ($PARM\_SUPCRV3_2$) does not change from one side of the base point to the other (as in Option 1), but is assumed to be highly inelastic. Outside of this range, the short-term price elasticities are set to the same values used under Option 2. However, these segments of the curve are shifted (left, below the base price, and right, above the base price) to intersect the end points of the segment of the curve running through the base point, as follows:

---

[24] For the first forecast year, the value for BASE_P is set to the 1989 national average wellhead price (Appendix E, Table E2).

[25] If DEL_Q_r is negative, the resulting production level will be less than $BASE\_Q_r$.

[26] A model user can select one of the three functional forms for the supply curves by setting the variable TYP_SUPCRV equal to either 1, 2, or 3, accordingly. For generating the forecast published in the *Annual Energy Outlook 1994*, option 3 was selected.

Option 3:

$$DEL\_Q_r = (BASE\_Q_r*PARM) + (1+PARM)*BASE\_Q_r*ELAS*(VALUE-BASE\_P_r)/BASE\_P_r \quad (11)$$

where,

If VALUE is within the range $BASE\_P_r \pm (BASE\_P_r * PARM\_SUPCRV3_1 / PARM\_SUPCRV3_2)$
PARM = 0.
ELAS = $PARM\_SUPCRV3_2$

If VALUE is greater than $BASE\_P_r + (BASE\_P_r * PARM\_SUPCRV3_1 / PARM\_SUPCRV3_2)$
PARM = $+ PARM\_SUPCRV3_1$
ELAS = $PARM\_SUPCRV2_2$

If VALUE is less than $BASE\_P_r - (BASE\_P_r * PARM\_SUPCRV3_1 / PARM\_SUPCRV3_2)$
PARM = $- PARM\_SUPCRV3_1$
ELAS = $PARM\_SUPCRV2_1$

The assumed values for all of the parameters and elasticities shown above are presented in Appendix F, Table F37.

Figure 3-7 graphically depicts an example of how a region's supply curve would appear under each of the three options.

After establishing a value for DEL_Q_r for a specified wellhead price in a given region, the corresponding total dry gas production would be calculated as:

$$NGPRD\_L48 = BASE\_Q_r+DEL\_Q_r+(ADGPRDON_r*PER) \quad (12)$$

where,

NGPRD_L48 = dry gas production in onshore NGTDM/OGSM region r (Bcf)

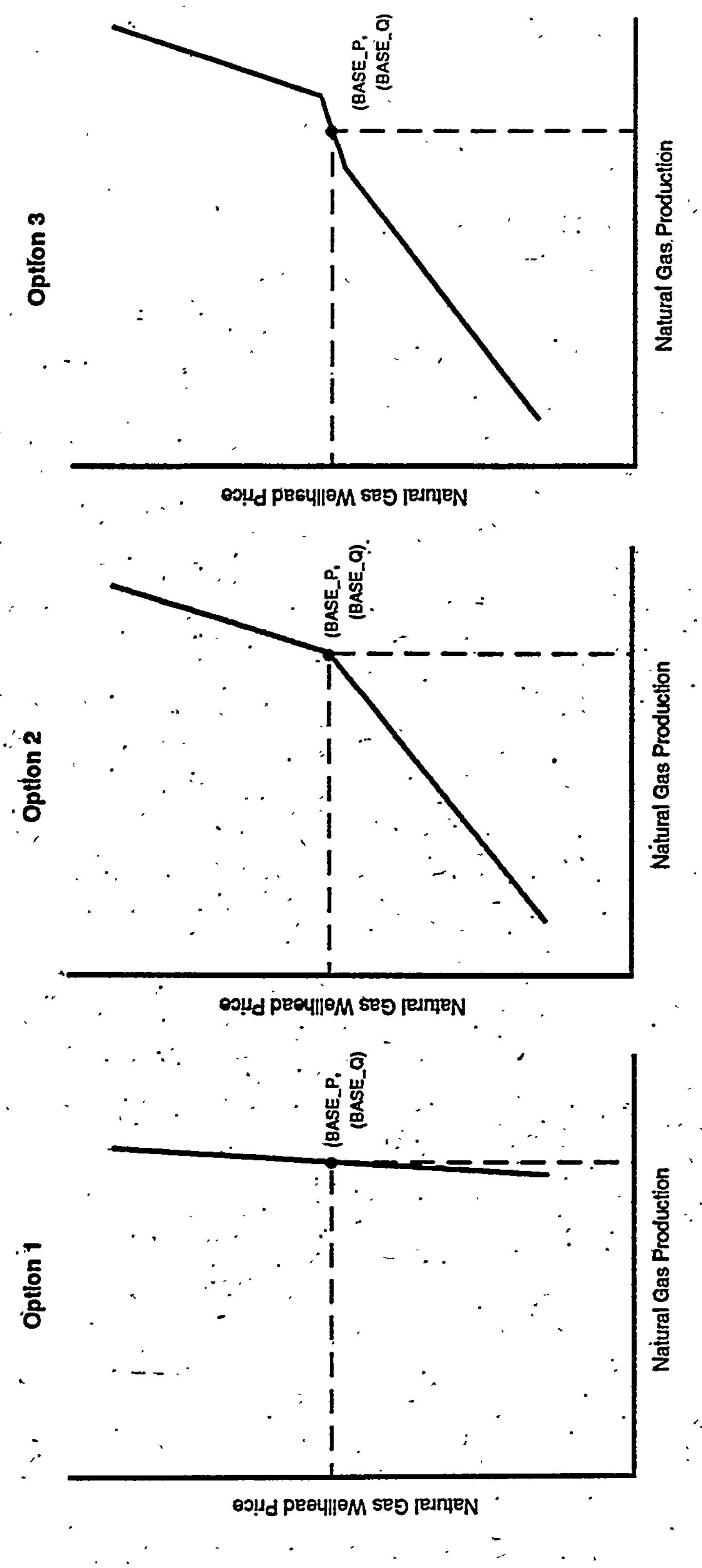
For an offshore region, the corresponding variables used in the code are NGPRD_OCS and $ADGPRDOF_r$ (with PER set to 1).

For control purposes, upper and lower limits are placed on the nonassociated dry gas production levels established within the NGTDM. The lower and upper limits imposed on nonassociated gas production in each NGTDM/OGSM onshore and offshore region are BASE_Q times PARM_MINPR and PARM_MAXPR, respectively (Appendix F, Table F11).

Alaskan Natural Gas Module

Currently natural gas which 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. The NEMS demand models provide a forecast of natural gas consumption for the total Pacific Census Division, which includes Alaska. Within the NGTDM Alaskan natural gas consumption for all sectors is estimated and is subtracted from the core market consumption levels in the Pacific Division for deriving estimates of contiguous Pacific Division consumption levels. The consumption of gas by Alaskan residential and commercial customers is a function of a forecast for the number of customers (exogenously derived) and the landed cost of crude oil imports (forecast within the NEMS):

Figure 3-7. Nonassociated Natural Gas Supply Curve Options



$$\text{(res):}\quad QALK\_NONU\_F_d = EXP(AK\_C_1) * WOPLAG^{AK\_C_2} * AK\_RN_y^{AK\_C_3} / 1000. \tag{13}$$

$$\text{(com):}\quad QALK\_NONU\_F_d = EXP(AK\_D_1) * WOPLAG^{AK\_D_2} * AK\_CN_y^{AK\_D_3} / 1000. \tag{14}$$

where,

$QALK\_NONU\_F_d$	=	consumption of natural gas by residential (d=1) or commercial (d=2) customers in Alaska (Bcf)
WOPLAG	=	landed cost of crude oil in the previous forecast year [the 1989 value used in forecast year 1990 is a data input, Appendix E, Table E18] (dollars per barrel)
AK_C	=	estimated parameters for residential consumption equation (Appendix G, Table G1)
AK_D	=	estimated parameters for commercial consumption equation (Appendix G, Table G1)
AK_RN_y	=	number of residential customers (exogenously specified, Appendix G, Table G2)
AK_CN_y	=	number of commercial customers (exogenously specified, Appendix G, Table G2)

The consumption of gas by Alaskan industrial customers is a function of the landed cost of crude oil imports and time:

$$\text{(ind):}\quad QALK\_NONU\_F_d = (\ AK\_E_1 + (AK\_E_2 * WOPCUR) + (AK\_E_3 * (T))\ )\ /\ 1000. \tag{15}$$

where,

$QALK\_NONU\_F_d$	=	consumption of natural gas by industrial customers (d=3), (Bcf)
WOPCUR	=	average national landed cost of crude oil in the current forecast year [the 1989 value used in forecast year 1990 is a data input, Appendix E, Table E18] (dollars per barrel)
AK_E	=	estimated parameters for industrial consumption equation (Appendix G, Table G1)
T	=	time parameter, where T=1 for 1969 (the first historical data point) and T=CNTYR+21 in forecast year CNTYR (where CNTYR equals 1 for 1990, 6 for 1995, etc).

The use of natural gas in compressed natural gas vehicles in Alaska is assumed to be negligible.

At a sectoral level, Alaskan consumption is disaggregated into the total delivered to customers in South Alaska (AK_CONS_S) versus a North Alaska (AK_CONS_N) total using historically derived shares (Appendix F, Table F10). This distinction is needed for the derivation of natural gas production forecasts for the north and south regions [not accounting for the additional production necessary should the Alaskan Natural Gas Transportation System (ANGTS) open], as follows:

$$\text{(S. AK):}\quad AK\_PROD_{r=1} = (EXPJAP + AK\_CONS\_S)\ /\ (1 - AK\_PCTLSE_{r=1} - AK\_PCTPLT_{r=1} - AK\_PCTPIP_{r=1}) \tag{16}$$

$$\text{(N. AK):}\quad AK\_PROD_{r=2} = AK\_CONS\_N\ /\ (1 - AK\_PCTLSE_{r=2} - AK\_PCTPLT_{r=2} - AK\_PCTPIP_{r=2}) \tag{17}$$

where,

AK_PROD_r	=	dry gas production in South (r=1) or North (r=2) Alaska (Bcf)
AK_CONS_S	=	total gas consumption by customers in South Alaska (Bcf)
AK_CONS_N	=	total gas consumption by customers in North Alaska (Bcf)
EXPJAP	=	quantity of gas liquefied and exported to Japan (from OGSM in Bcf)
AK_PCTLSE_r	=	assumed percent of gas production which is consumed in lease operations in region r (fraction)
AK_PCTPLT_r	=	assumed percent of gas production which is consumed in plant operations in region r (fraction)

AK_PCTPIP_r	=	assumed percent of gas production which is consumed as pipeline fuel in region r (fraction)

The variables for AK_PCTLSE, AK_PCTPLT, and AK_PCTPIP are based on historical percentages (Appendix F, Table F7) and are held constant throughout the forecast, with the exception that PCTLSE is decreased by 50 percent should ANGTS become fully operational. (These variables are also used to estimate the consumption levels for pipeline fuel and lease and plant fuel in Alaska.) The OGSM provides a forecast of natural gas exports to Japan, the level of flow through ANGTS which would reach the contiguous U.S. border when and if it is connected, and the maximum production level for South Alaska (currently used only as a verification check in the NGTDM). The production of natural gas in Alaska which is necessary to support ANGTS is derived in the NGTDM using the flow level at the border established in OGSM, and assumed values for PCTLSE, PCTPLT, and PCTPIP related to production to be marketed via ANGTS.

Estimates for natural gas wellhead and end-use prices in Alaska are roughly estimated in the NGTDM for proper accounting, but have a very limited impact on the NEMS system. The average Alaskan wellhead price over the North and South regions (not accounting for the impact should ANGTS be connected) is calculated as:

$$AK\_WPRC = AK\_F_1+(AK\_F_2*WPRLAG)+(AK\_F_3*(AK\_PROD_1+AK\_PROD_2)) \tag{18}$$

where,

AK_WPRC	=	average Alaskan natural gas wellhead price (dollars per Mcf)
AK_PROD_r	=	dry gas production in Alaskan region r (1=South; 2= North) (Bcf)
WPRLAG	=	average Alaskan natural gas wellhead price in previous forecast year (dollars per Mcf) [the 1989 value used in forecast year 1990 is a data input, Appendix E, Table E18]
AK_F	=	estimated parameters (Appendix G, Table G1)

However, if ANGTS is connected, the wellhead price in North Alaska is overwritten to be equal to the price at the U.S./Canadian border crossing point, most representative of where ANGTS will connect, plus an assumed markup. With the exception of the industrial sector, end-use prices are set equal to the average wellhead price resulting from the equation above plus a fixed markup (Appendix F, Table F8). The Alaskan industrial sector price is calculated as:

$$PALK\_NONU\_F_s = AK\_G_1+(AK\_G_2*WOPCUR) \tag{19}$$

where,

$PALK\_NONU\_F_s$	=	price of natural gas to Alaskan industrial customers (s=3), (dollars per Mcf)
WOPCUR	=	landed price of crude oil in current forecast year (dollars per barrel)
AK_G	=	estimated parameters (Appendix G, Table G1)

Historically, the industrial price was shown to vary more in response to the crude oil price and much less in response to the natural gas wellhead price.

4. Overview of Solution Methodology

The previous chapter described the function of the NGTDM within the NEMS. 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 modules within the NGTDM is presented, along with an overview of the solution methodology used by each module.

NGTDM Regions and the Pipeline Flow Network

General Description of the NGTDM Network

In the NGTDM, a transmission and distribution network (Figure 4-1) simulates the interregional flow of gas in the contiguous United States. 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. 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 one direction and other pipelines flowing in the opposite direction.[27] Bidirectional flows can also be the result of directional flow shifts within a single pipeline system due to seasonal variations in flows.

Flows are further represented by establishing arcs from the transshipment node to each demand sector/subregion represented in the NGTDM region. A demand group 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).

Figure 4-2 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. Arcs are also established from nodes at the international borders to represent exports. Each transshipment node has one or more arcs flowing in from each supply source represented. These supply points may represent onshore or offshore production, liquefied natural gas imports, synthetic natural gas production, gas produced in Alaska and transported via the Alaska Natural Gas Transportation System, or Canadian or Mexican imports in the region. In addition, each onshore supply region also includes any synthetic natural gas produced from coal, as well as other supplemental supplies. Finally, annual net underground storage withdrawals, transported under firm and interruptible service, are accounted for at each transshipment node.

Once all of the types of end-use destinations and supply sources are defined for each transshipment node, a general network structure results. Each transshipment node does not necessarily have all supply source types flowing in, or all demand source types flowing out. For instance, the transshipment nodes at the Canadian border may only have Canadian supply defined going into the node. Additionally, 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

[27] Historically, one out of each pair of bidirectional arcs in Figure 4-1 represents a relatively small amount of gas flow during the year. These arcs are referred to as "the bidirectional arcs" and are identified as going from 9 to 8, 11 to 8, 4 to 8, 11 to 7, 4 to 7, 3 to 4, 5 to 6, 5 to 3; 2 to 3, 2 to 5, 6 to 7, and 1 to 2. Minimum flows constraints are established for these arcs at historically observed flow levels.

Figure 4-1. Natural Gas Transmission and Distribution Model Network

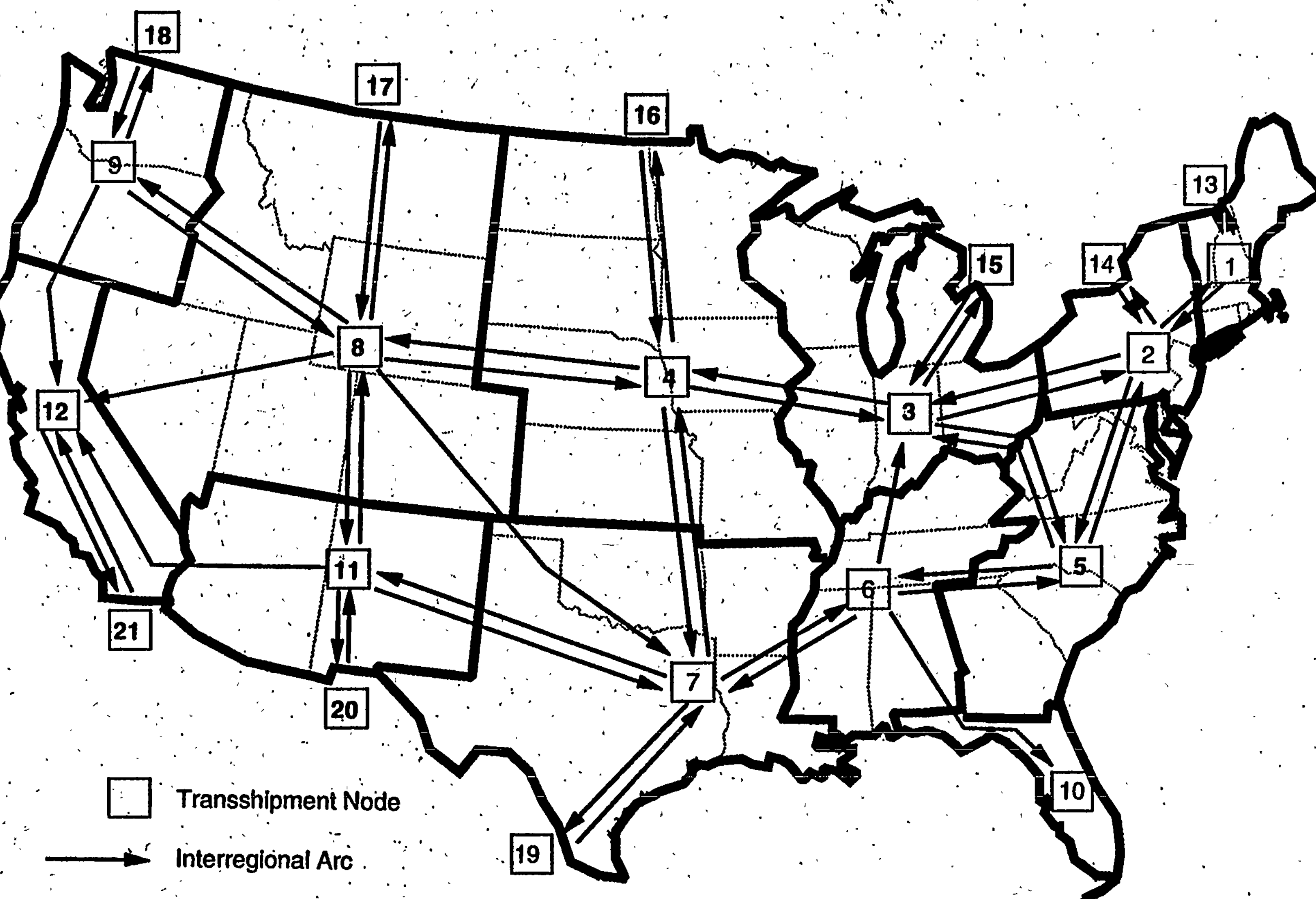
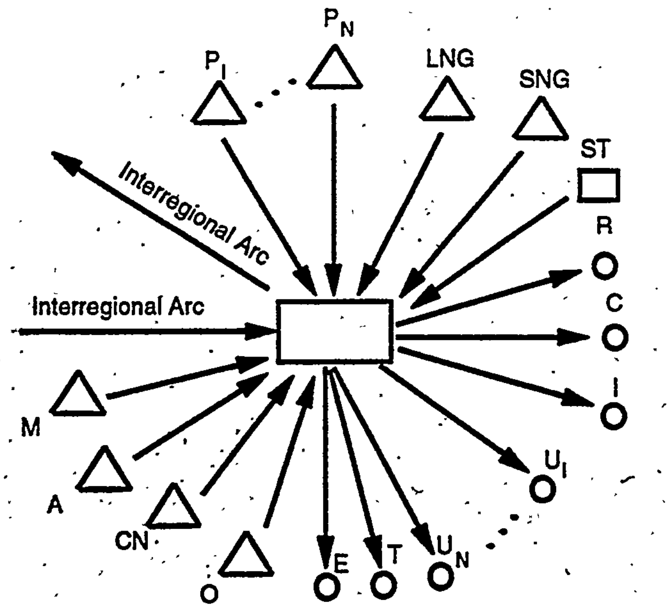


Figure 4-2. Transshipment Node



- Transshipment Node
- Supply Point
- Demand Point
- Storage Point

P_i - Production in NGTDM/OGSM Region i
LNG - Liquefied Natural Gas
SNG - Synthetic Natural Gas
O - Offshore Supplies
CN - Canadian Supplies
A - Alaskan Supplies
M - Mexican Supplies
R - Residential Demand
C - Commercial Demand
I - Industrial Demand
U_i - Electric Utility Demand in NGTDM/EMM Region i
T - Transportation Demand
E - Exports
ST - Net Storage Withdrawals

node in the network are listed in Table 4-1. This table also indicates in tabular form the mapping of Electricity Market Model regions and Oil and Gas Supply Model regions to NGTDM regions, (Figures 3-4 and 3-7 in Chapter 3).

As described in earlier chapters, there are significant differences in market structure and dynamics between the firm and interruptible service markets. The basic network structure separately represents the flow of gas within the firm and interruptible service markets within the Annual Flow Module. Conceptually this can be thought of as two parallel networks, with three areas of overlap. First, the firm and interruptible transmission service flows along each arc are interrelated and their sum is constrained to the pipeline capacity available along the arc. Second, the firm and interruptible service networks share common supply sources. At each supply source there is a single price regardless of whether the supplies are used to meet core or noncore demand (or both), because it is assumed that the supply component of the market will remain fully competitive.[28] Third, the quantity of net injections transported under interruptible service into underground storage is equal to the net withdrawals from storage in the same region that are to be transported under firm service. The actual levels of underground storage injections and withdrawals associated with the firm and interruptible service markets are determined within the Capacity Expansion Module (since it contains a seasonal representation) and used within the Annual Flow Module.

Specifications of a Network Arc

Each arc of the network has associated parameters (inputs) and model variables (outputs). The parameters that define an arc are the pipeline direction, available capacity, the tariffs, the percentage of gas which travels on the arc that is lost or used (in power compressor stations) along the way, a mileage indicator, and a minimum flow level (Figure 4-3). In the case of bidirectional arcs, the arc with an historically lower flow rate is identified as a "bidirectional" arc for special handling.

Once a model solution has been reached (i.e., the quantity of the natural gas flow along each interregional arc is determined), pipeline fuel use associated with interregional transfers (from transshipment node to transshipment node) can be computed for each arc by multiplying the percentage loss of gas (given by the efficiency parameter) by the flow along the arc. In turn, the emissions (carbon, carbon monoxide, carbon dioxide, sulfur oxides, nitrogen oxides, volatile organic compounds, and methane) associated with the consumption of pipeline fuel can be estimated. (Details are given in Chapter 5.)

For the firm service market the pipeline tariff (indicated as "TAR" in subsequent equations) is a function of two basic parameters: a usage fee and the revenue the pipeline is collecting from customers who have reserved capacity on the pipeline. Since the NGTDM does not explicitly represent the capacity reserved on a pipeline, this revenue is allocated over the amount of gas that is expected to flow on the arc rather than the amount of space reserved. Therefore, the reservation fee (the per-unit fee for reserving capacity on a pipeline) is not explicitly calculated. It is instead approximated as the total revenue from reservation fees divided by the amount of gas expected to flow. Thus, the total pipeline tariff for the firm service market is the sum of the usage fee and this approximation of the reservation fee. For the interruptible service market, the tariff parameter is simply a per-unit usage fee (as specified by the Pipeline Tariff Module). It is not necessary for the firm and interruptible usage fees to be equal.

For the arcs from the transshipment nodes to the end-use sectors, the parameters defined are capacities, tariffs, and the percentage of gas used in compressor stations. The tariffs represent the sum of several charges or adjustments, including interstate pipeline tariffs in the region, intrastate pipeline tariffs, and distributor markups when applicable. The model variable associated with each of these arcs is the flow along the arc, which is equal to the amount of demand satisfied plus gas consumed in compressor stations. For arcs from supply points to transshipment nodes, the parameters are capacities, tariffs, minimum flows, and compressor station usage. In this case the tariffs represent gathering charges and can also be used to represent an annual differential between supplies satisfying core versus

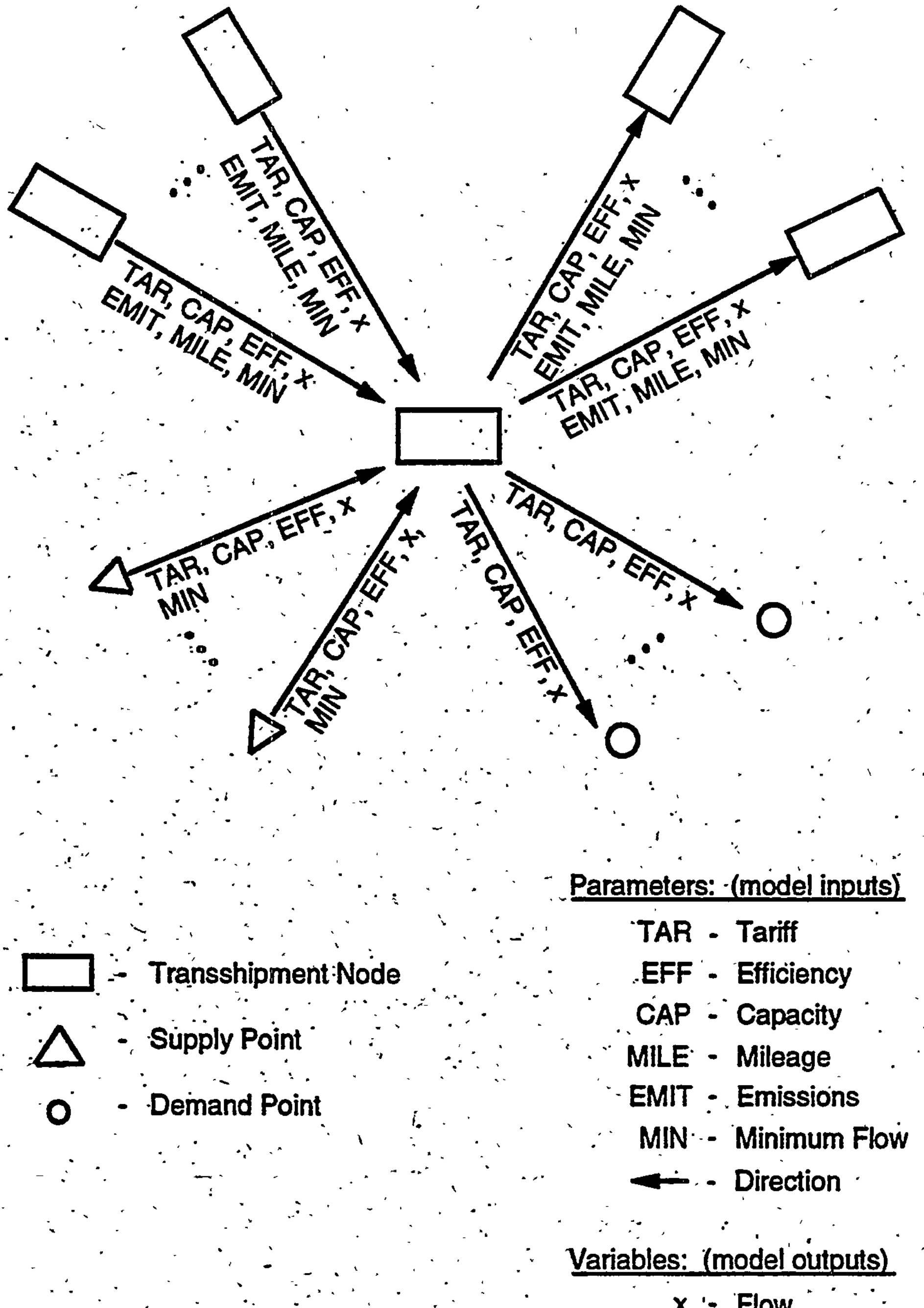
[28]Due in part to the seasonal load differences between core and noncore consumption, there are reasons to believe that the supply prices to the two markets are different on an annual basis. Structurally, the model is designed to handle such a supply price differential, but the supporting data have yet to be developed.

Table 4-1. Demand and Supply Types at Each Transshipment Node in the Network

Transshipment Node	Demand Types	Supply Types
1	R, C, I, T, U(1/7)	P(1/1), LNG Everett Mass.
2	R, C, I, T, U(2/6), U(2/3)	P(2/1)
3	R, C, I, T, U(3/1), U(3/4)	P(3/1), SNG
4	R, C, I, T, U(4/5), U(4/10)	P(4/3), P(4/5)
5	R, C, I, T, U(5/1), U(5/3), U(5/9)	P(5/1), LNG Cove Pt Maryland, LNG Elba Island Georgia, Atlantic Offshore
6	R, C, I, T, U(6/1), U(6/9)	P(6/1), P(6/2)
7	R, C, I, T, U(7/2), U(7/10)	P(7/2), P(7/3), P(7/4), LNG Lake Charles Louisiana, Offshore Louisiana, Gulf of Mexico
8	R, C, I, T, U(8/11), U(8/12)	P(8/5)
9	R, C, I, T, U(9/11)	P(9/6)
10	R, C, I, T, U(10/8)	P(10/2)
11	R, C, I, T, U(11/12)	P(11/4), P(11/5)
12	R, C, I, T, U(12/13)	P(12/6), Pacific Offshore
13	Canadian Exports	Canadian Imports
14	Canadian Exports	Canadian Imports
15	Canadian Exports	Canadian Imports
16	Canadian Exports	Canadian Imports
17	Canadian Exports	Canadian Imports
18	Canadian Exports	Canadian Imports, Alaskan Supply
19	Mexican Exports	Mexican Imports
20	Mexican Exports	Mexican Imports
21	Mexican Exports	Mexican Imports

R - Residential demand; C - Commercial demand; I - Industrial demand; T - Transportation demand
U(n1/n2) - Electric generator's demand in NGTDM/EMM region (n1/n2) as shown in Figure 3-3
P(n1/n2) - Production in NGTDM/OGSM region (n1/n2) as shown in Figure 3-6 (also includes synthetic natural gas from coal and other supplemental supplies)
SNG - Synthetic Natural Gas from liquid hydrocarbons
LNG - Liquified Natural Gas

Figure 4-3. Network Parameters and Variables



noncore demands.[29] Minimum flows are set on supply arcs by splitting the assumed minimum production levels for each source (described in Chapter 3) into firm and interruptible components based on the relative levels of core and noncore consumption in the Lower 48 States. Although capacity limits can be set for the arcs to and from end-use and supply arcs, respectively, the current version of the model does not impose such limits on the flows along these arcs.

In an effort to represent potential interruptions in transportation service to the noncore market, a "relief valve" was put in the system. The noncore demand requirements can optionally be met through a highly priced "backstop" supply source, which is made directly available at the end-user nodes. Backstop supply is designed to be used only in the event that pipeline capacity (existing plus capacity to be built for the firm service market) is not sufficient to meet the noncore demand requirements. Backstop supply displaces noncore consumption which would be expected not to transpire in the Annual Flow Module due to fuel switching or generally lower consumption levels in response to higher gas prices. The incorporation of backstop supply is a modeling tool and is not intended to represent a real supply source.

Note that any of the above parameters, supplies, or demands may be set equal to zero. For instance, some pipeline arcs may be defined in the network that currently have zero capacity 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 Modules and Their Interrelationships

The NEMS generates an annual forecast of the outlook for U.S. energy markets for the years 1990 through 2010. Although the NGTDM is executed for each iteration of each forecast year solved by the NEMS, it is not necessary that all of the individual components of the model be executed for all iterations. Of the NGTDM's four components or modules, the Capacity Expansion Module and the Pipeline Tariff Module are executed only once per forecast year. The Annual Flow Module and the Distributor Tariff Module are executed every iteration of each forecast year. A process diagram of the NGTDM is provided in Figure 4-4, showing the general calling sequence.

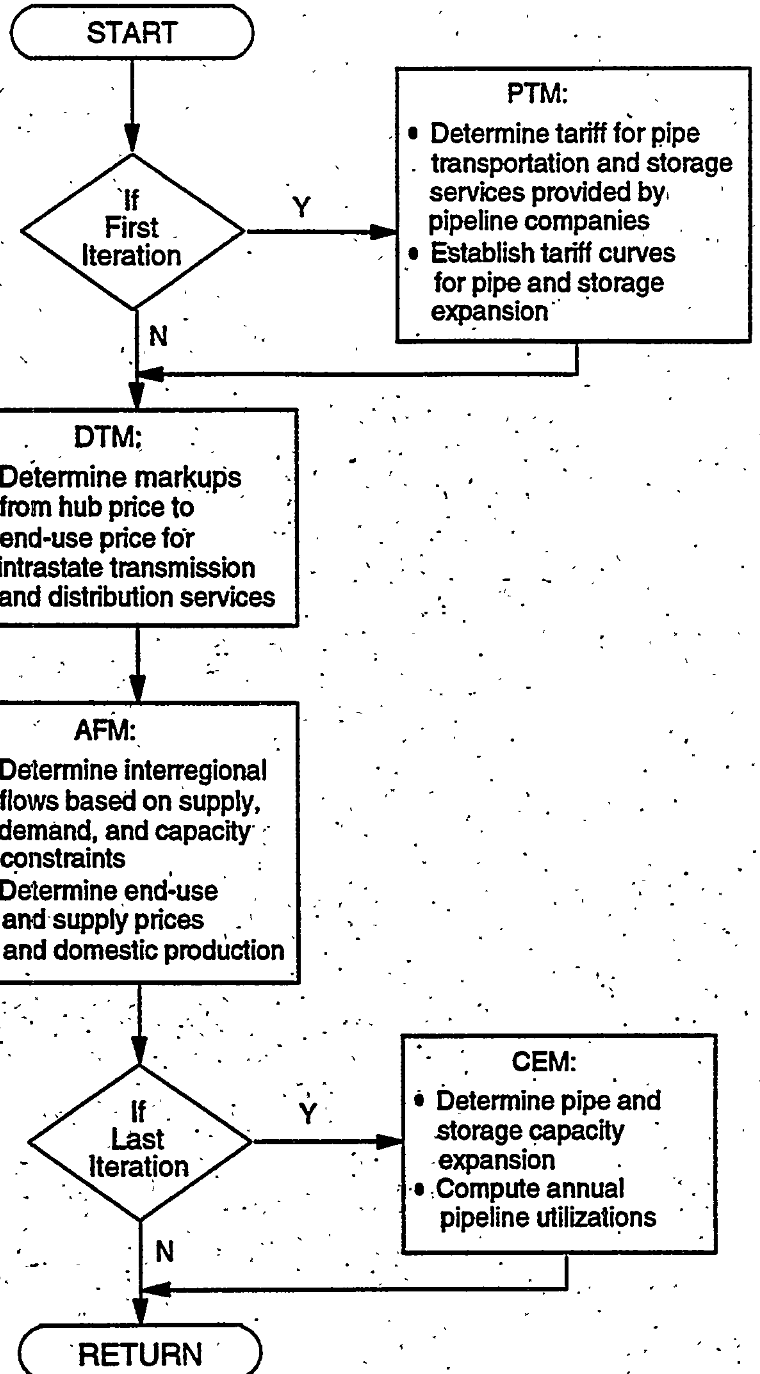
The primary function of the Capacity Expansion Module is to forecast interregional pipeline and underground storage expansions and basic seasonal load profiles. Using this information from the Capacity Expansion Module and other data, the Pipeline Tariff Module uses an accounting process to derive interregional and intraregional pipeline tariffs for firm and interruptible transmission service to be used in the Annual Flow Module and the Capacity Expansion Module. The Distributor Tariff Module provides distributor tariffs for use in the Annual Flow Module and the Capacity Expansion Module. The Distributor Tariff Module must be called each iteration because some of the distributor tariffs are based on alternate fuel prices (e.g., residual fuel oil) which may change from iteration to iteration. Finally, using the information provided by other NGTDM modules and other NEMS models, the Annual Flow Module solves for natural gas prices and quantities which reflect a market in equilibrium for the current forecast year. A brief summary of each of the NGTDM modules follows.

The Annual Flow Module

The Annual Flow Module (AFM) is considered the central module within the NGTDM, with the Capacity Expansion Module, Pipeline Tariff Module, and Distributor Tariff Module (in addition to other NEMS models) providing it with critical information. Its objective is to determine the market equilibrium associated with natural gas supplies, demands, and transportation costs, thereby generating supply and end-use prices and production levels for use by other NEMS models. Formulated as a linear program, the AFM determines a market equilibrium by maximizing the sum of consumer and producer surplus, while minimizing transmission and distribution charges, subject to system constraints. As the name indicates, it has been designed to represent annual flows from supply points to demand points traveling along a pipeline network. As defined above, the network in the AFM represents firm and

[29] Tariffs on the supply arcs are currently set to zero.

Figure 4-4. NGTDM Process Diagram



interruptible service markets separately along parallel networks, connected only at the supply points and through capacity constraints along the network arcs.

To accomplish its goal, the AFM uses regional price curves to represent regional supplies and demands. These curves represent linear approximations of the price response that can be expected from the more detailed NEMS models that provide the parameters used to build the curves. Each forecast year the Oil and Gas Supply Model provides the parameters to build the supply curves, and each iteration the demand models provide the parameters to build the demand curves.

The Capacity Expansion Module, Pipeline Tariff Module, and Distributor Tariff Module also provide data required by the AFM. The Capacity Expansion Module provides pipeline capacity additions, pipeline utilizations for firm flows and total flows, and net storage withdrawal levels associated with the firm and interruptible service markets. The Pipeline Tariff Module calculates interregional and intraregional pipeline tariffs for both firm and interruptible service. Similarly, the Distributor Tariff Module provides the AFM with markups for local distribution and intrastate transportation services.

Annual firm flow results from the AFM are provided to the Pipeline Tariff Module and the Capacity Expansion Module. The Capacity Expansion Module uses these flows to set minimum flows for its capacity expansion forecasts and the Pipeline Tariff Module uses them to determine realized revenues and in setting unitized pipeline tariffs. The AFM also provides the Pipeline Tariff Module with realized tariffs (see Chapter 5) along each arc in the network providing interruptible service.

The Capacity Expansion Module

The Capacity Expansion Module (CEM) is the only module in the NGTDM that includes a seasonal representation of the natural gas market. In each NEMS forecast year, the CEM determines incremental pipeline and storage capacity required to satisfy expected firm service demands in a future year based on an analysis of the expected supply, storage, and transportation requirements. The peak and off-peak seasons are analyzed, concurrently within the CEM, to determine pipeline and storage capacity needs. The storage decision affects the need for pipeline capacity upstream from the storage facility and influences the relative utilization of the pipeline between the peak and off-peak seasons. A brief description of the seasonal network used in the CEM is presented next, followed by an overview of the model solution methodology.

Seasonal Network Representation in the Capacity Expansion Module

The basic network structure defined for the CEM is nearly identical to the general NGTDM network described above, with the exception that a two-period (peak and off-peak) representation of the annual market is now being modeled. The "peak period" is defined as the months in the year with distinctly higher levels of natural gas consumption on a national basis.[30] As in the Annual Flow Module, interregional flows to satisfy firm transmission service are handled separately from the flows to satisfy interruptible service, both in the peak and off-peak periods.

Conceptually the Capacity Expansion Module consists of four parallel networks. Each network represents the flow of gas either during the peak period under firm service, the off-peak period under firm service, the peak period under interruptible service, or the off-peak period under interruptible service. Interaction between the two periods occurs primarily through the use of storage. Arcs are established from each off-peak firm and interruptible transshipment node to the storage point in the region to represent storage injections. Likewise, arcs are established from each storage point into the associated transshipment nodes in both the firm and interruptible peak period networks. These arcs represent storage withdrawals in the peak period to be transported under firm and interruptible service to satisfy core and noncore demands, respectively. An additional link between the two periods occurs due to the existence of

[30]The data inputs to the Capacity Expansion Module define the months designated as peak versus offpeak. Currently the data in the Capacity Expansion Module reflect a peak period from December through April. Due to a lag in the reporting of monthly consumption data, November falsely appears to be a "nonpeak" month. This should be corrected in the future once a method is developed for generating adjusted monthly consumption data.

annual supply sources as opposed to separate peak and off-peak supply. Thus, supply from each supply source in a region is available to both the peak and off-peak transshipment node in the region, and arcs are established to allow for these flows. An illustration of the two-period network is shown in Figure 4-5 for a base network with three transhipment nodes. For simplicity, the example does not show the further disaggregation of the network into its firm and interruptible components.

Overview of the CEM Solution Methodology

The functional requirement for the CEM is to make natural gas pipeline and storage capacity expansion decisions and to estimate corresponding pipeline and storage utilization levels based on assumptions similar to those used by the natural gas industry. The CEM has been designed as a seasonal natural gas transportation model, with storage serving as a link between supplies and seasonal demands. As with the Annual Flow Module, both firm and interruptible services are also represented. Formulated as a linear program, the objective is to minimize production and transportation costs, as well as costs associated with pipeline and storage expansion decisions. Although the basic network structure, its parameters (inputs), and its model variables (outputs) have been designed to be similar to that in the Annual Flow Module, some elements had to be defined as seasonal.

The CEM is executed within the NGTDM once at the end of each forecast year to determine the pipeline and storage expansion which will come on line "n" years in the future. Capacity is expanded to accommodate the transmission service needs of core consumers that are expected to occur in that year. The parameter "n" represents the average number of years in which the decision to expand capacity cannot be reversed due to contractual obligations. The results generated by the CEM during the current forecast year do not affect the current forecast year's market solution, but are used in the Annual Flow Module and the Pipeline Tariff Module when the NGTDM determines a natural gas market equilibrium solution for the n^{th} year in the future.

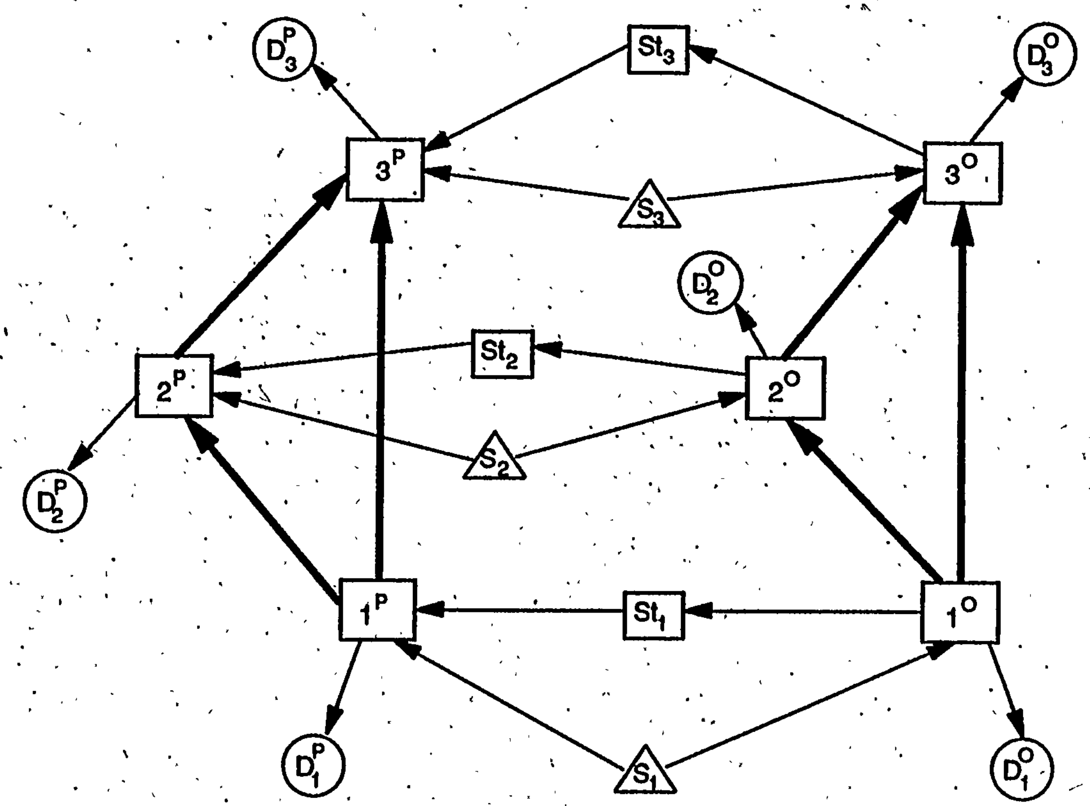
The data inputs for the CEM from the NEMS system include macroeconomic parameters from the Macroeconomic Activity Model of NEMS, as well as expected values for natural gas consumption levels in future years. The NEMS Integration Routine provides the CEM with estimates of future natural gas consumption levels for the nonelectric sectors, while the Electricity Market Model estimates future consumption by electric generators based on existing and planned electricity generation plant capacities. Parameters are provided by the Oil and Gas Supply Model to the CEM for estimating potential future supply levels. In addition, minimum interregional firm service flow constraints (based on Annual Flow Module solution values in the previous forecast year) are set in the CEM to represent the inertia of core customers from annually switching pipeline routes used in transporting their natural gas (e.g., due to long-term contract commitments).

The CEM uses the same regions and end-use sectors defined within the Annual Flow Module. However, the Annual Flow Module is an annual model; whereas, the CEM requires a seasonal analysis to represent more accurately the decision to expand pipeline and/or storage capacity to meet peak-day core market demands. The CEM includes a methodology for converting from annual to seasonal (peak and off-peak) consumption levels, as well as a means for capturing core peak-day requirements in the capacity expansion decision. The factors for estimating seasonal load patterns are historically based model inputs which are held constant throughout the forecast in the current model. Future model enhancements may allow for the representation of structural changes in seasonal consumption patterns (e.g., demand side management, changing building structures, and/or technological innovations).

Dry gas production is represented in the CEM with a price responsive equation (or curve) developed from inputs from the Oil and Gas Supply Model. Although the supply representation within the CEM reflects annual levels, the formulation allows for upper bounds to be set on the level of supply available within the peak or off-peak period from each supply source (formulated as the annual supply times the percentage of the year represented by the given period). Furthermore, the seasonal variation in wellhead prices is accounted for by including a positive adjustment "tariff" on the arcs connecting a supply source to the peak period network and a negative adjustment factor on the arcs to the offpeak period network (Appendix F, Table F43).

The Foreign Natural Gas Module of the Oil and Gas Supply Model sets pipeline capacity limits on the pipelines that cross the Canadian border at the six border crossings specified in the Annual Flow Module. These capacities are

Figure 4-5. Example Two-Period Network



n^t - transshipment node in region n for period t

D_n^t - demand point in region n for period t

S_n - supply point in region n

St_n - storage point in region n

P - peak period

O - off-peak period

used to establish capacity expansion requirements for the connecting pipe on the U.S. side of the border, and as a basis for setting the potential flow of gas across the border within the CEM.

Storage is used to satisfy peak season consumption by injecting gas into storage in the off-peak period and withdrawing the gas during the peak season. Thus, storage is considered a supply source in the peak period, and a demand requirement in the off-peak period. This limits the amount of off-peak capacity that is available on an interruptible basis for consumption in the period.

The Pipeline Tariff Module provides interregional pipeline tariffs and storage charges associated with existing and incremental expansion of regional pipeline and storage facilities. This information is sent to the CEM in the form of storage and pipeline "capacity supply curves." These "capacity supply curves" are based on exogenously specified capital cost curves for expansion and on macroeconomic parameters from the NEMS Macroeconomic Activity Model.

If the CEM determines that pipeline (or storage) capacity will be added, the Pipeline Tariff Module will in turn adjust the associated revenue requirements (and resulting tariff parameters) for the year in which the new capacity is scheduled to come on-line to account for the expansion costs. In addition, the pipeline capacities and seasonal utilization patterns established in the CEM are used in defining maximum annual interregional flow constraints in the Annual Flow Module, reflecting the impact of the variation in seasonal demand on pipeline loads. The seasonal storage injections and withdrawals are used as a basis for setting annual net storage withdrawals by core and noncore customers in the Annual Flow Module. The Pipeline Tariff Module also uses the levels of storage and pipeline capacity expansion established in the CEM when determining the associated capital expenditures (an input to the Macroeconomic Activity Model of the NEMS).

The Pipeline Tariff Module

The Pipeline Tariff Module (PTM) is executed within the NGTDM once each forecast year to calculate pipeline and storage tariffs for the Annual Flow Module and the Capacity Expansion Module. The tariffs calculated within the PTM are computed for individual pipeline companies and are then aggregated as required. An accounting system is used to track costs and compute rates under various rate design and regulatory scenarios. Tariffs are computed for both storage and firm and interruptible transportation services. Transportation tariffs are computed for interregional arcs defined by the NGTDM network. These network tariffs represent an aggregation of the tariffs for individual pipeline companies supplying the network arc. Storage tariffs are defined at regional NGTDM network transhipment nodes, and likewise, represent an aggregation of individual storage company tariffs. These tariffs are for transmission services only and do not include the price of gas.

More specifically, the PTM computes (1) reservation costs assigned to firm transportation service customers, (2) usage fees for firm transportation service, (3) minimum transportation rate for interruptible service, (4) maximum transportation rate for interruptible service, and (5) rates for storage service. For fully regulated services, cost-of-service based revenue requirements are computed by the PTM and are used within the Annual Flow Module to price transportation services. Where markets are competitive or are loosely regulated (i.e., interruptible transportation), the Annual Flow Module uses a marginal pricing structure which incorporates maximum and minimum rates for service, set by the PTM in determining the actual rate charged. The resulting rate should be within the bounds of the minimum and maximum rates computed by the PTM.[31]

The impacts of the capacity expansion decisions made in the Capacity Expansion Module are reflected in the pipeline tariffs computed by the PTM. The Capacity Expansion Module determines the location and quantities of additional pipeline capacity and storage facilities at the aggregate level represented by the NGTDM network. Interregional pipeline or regional annual storage capacity expansion requirements are provided by the Capacity Expansion Module to the PTM. Also, since capacity expansion decisions need to take into account the marginal changes in pipeline tariffs in response to increased capital requirements, the PTM initially establishes tariffs (reservation fee) associated

[31]The NGTDM compares the effective tariff (i.e., the difference between the price at two adjoining nodes) to ascertain if the limit was violated. Currently the model does not have a correcting mechanism if the constraint is violated and simply reports the occurrence in a report. A more proper response mechanism will be employed in subsequent versions of the model.

with a series of incremental expansions. Many of the calculations of components of the revenue requirements require the use of macroeconomic variables that are provided by the NEMS Macroeconomic Activity Model.

The Distributor Tariff Module

The Distributor Tariff Module (DTM) determines markups for distribution and intrastate transportation services provided by local distribution companies and intrastate pipeline companies. Empirically derived or value-of-service estimated volumetric charges are determined by the DTM and are used within the Annual Flow Module as markups for local distribution and intrastate transportation services. The markups represent an incremental charge added by local distribution companies and intrastate pipeline companies and passed to the end user. The markups are determined for distribution arcs from each NGTDM transshipment node to each end-use sector. For noncore customers in the Annual Flow Module, these markups are generally reevaluated once the linear program has solved.

Depending on the end-use sector, the markups either are derived from historical data or represent the value of service as determined from alternative fuel prices. Historical data are used to develop initial natural gas distributor markups to core customers, while value of service (or alternative fuel prices) are used to develop markups for the transportation sector and for noncore electric generation customers. Distributor markups for noncore industrial customers are based on estimated historical end-use prices and are held constant throughout the forecast. Core distributor markups are assumed to decline over the forecast period. Since alternative fuel prices are used as a basis for estimating markups to noncore customers, the DTM is executed during each NGTDM iteration so that these markups more accurately reflect the actual alternative fuel prices. For the electric generation sector, markups are computed for the three classes of customers in each NGTDM/EMM region.

5. Annual Flow Module Solution Methodology

As a key component in the NGTDM, the Annual Flow Module (AFM) determines the market equilibrium between supply and demand of natural gas. 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 limitations, and mass balances. Structurally, the AFM consists of a network of regions connected by a parallel system of pipelines designed to service two types of customers, core and noncore. Supplies are defined as total regional supplies available to both parallel networks, while demands are defined separately as core or noncore regional demands. Because of the characteristics of these two markets, pipeline tariffs are rated differently along the same arc. To achieve market equilibrium, the AFM has been formulated as a linear program which maximizes consumer plus producer surpluses while minimizing transportation costs.[32] Supply and demand prices and quantities, as well as resulting flow patterns, are obtained from the linear programming solution and sent to other NGTDM modules or other NEMS models after some processing. A simple system diagram of the information flowing to and from the AFM is presented in Figure 5-1. A brief explanation of how supplies and demands are represented in the AFM, how the linear program has been formulated for the AFM, and how the AFM results are processed for the other NGTDM modules and NEMS models is presented below.

Network Characteristics in the AFM

As described earlier, the AFM network consists of two parallel networks (firm and interruptible service), each containing 12 regions (or nodes), 6 Canadian border crossing nodes, and 3 Mexican border crossing nodes. Net storage withdrawals are represented at 10 of the 12 regional nodes for both firm and interruptible services. Arcs connecting the nodes are characterized by pipeline efficiencies, physical capacities, pipeline tariffs, minimum flows, and maximum utilizations. The efficiencies are exogenously defined (Appendix F, Table F19) and represent reduction in flows due to pipeline fuel consumption. Pipeline tariffs (defined in the Pipeline Tariff Module) represent fees for moving gas along pipelines. Pipeline tariffs in the core market include reservation and usage fees while pipeline tariffs in the noncore market are composed solely of usage fees. Minimum flows are defined for each arc in order to maintain continuity in flows from one model year to the next. Maximum pipeline utilizations (established in the Capacity Expansion Module) are defined to maintain consistency between capacity expansion decisions and flow patterns. Finally, a designated percentage of the pipeline capacity is not allowed to be used, to represent the capacity that would not be released, and is held as a safety margin under normal weather conditions (Appendix F, Table F41).

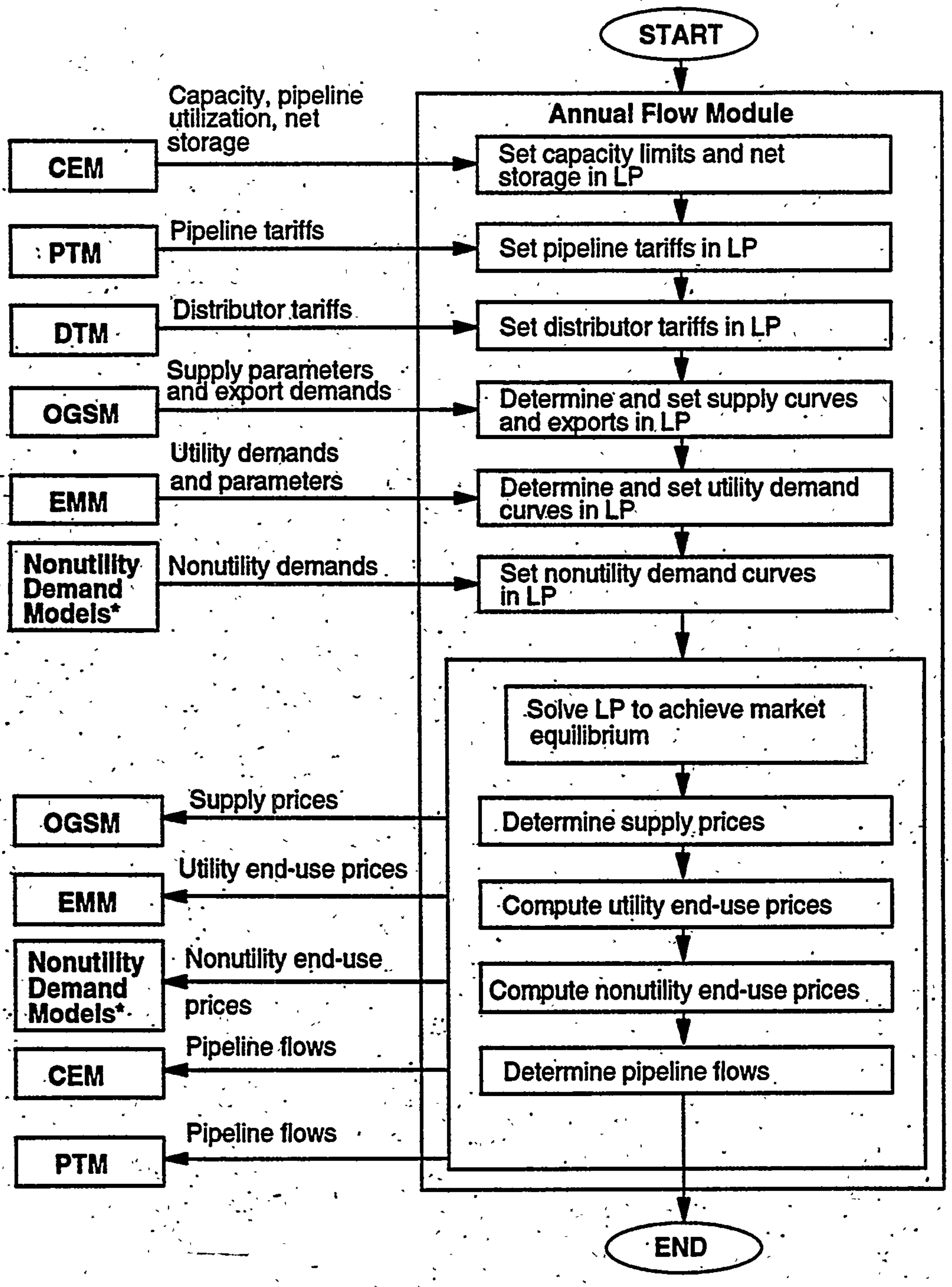
Supply and Demand Representations

Supply and demand are represented as price curves in each region in the AFM network. These curves represent estimates of short term responses that can be expected from the NEMS models that provide the AFM with regional supply and demand levels. Demand is defined as core or noncore and tied exclusively to either the firm or interruptible service network, respectively; while supply is defined as total supply available (in most cases) to either network. The supply and demand types are addressed below.

Supply in the AFM includes production sources (onshore, offshore, and Alaska), imports (Canadian and Mexican by pipeline, and as liquefied natural gas), synthetic natural gas (from liquids and coal), and other supplemental supply. Of these, the liquefied natural gas, Mexican imports, Alaska production, and other supplemental supply categories are considered to be constant (or fixed). Supplies with fixed levels are assumed to be available only to the firm network, while supplies with variable levels (i.e., relatively price responsive in the short-term) are available to either network.

[32]Adapted from the Project Independence Evaluation System (PIES) model.

Figure 5-1. Annual Flow Module System Diagram



*Residential Demand Model, Commerical Demand Model, Industrial Demand Model, and Transportation Demand Model

Some supply quantities are provided directly by the Oil and Gas Supply Model and/or other NEMS models, while others are determined within the NGTDM, as described in Chapter 4. Onshore and offshore production and Canadian imports are determined within the NGTDM based on parameters provided by the Oil and Gas Supply Model, whereas the Oil Gas Supply Model establishes the level of natural gas flowing into the contiguous United States via the Alaskan Natural Gas Transportation System (ANGTS), as well as the liquefied natural gas quantities imported through the four gasification terminals modeled by the NGTDM. Synthetic natural gas from liquids in Illinois is determined by the NGTDM (as a function of the associated region's market price), with synthetic natural gas from Hawaii held constant throughout the forecast. Natural gas from coal in North Dakota is provided by the Coal Market Model. Finally, other supplemental supplies are set to historical levels by the NGTDM and held constant throughout the forecast. Table 4-1 provides more detail on the regional representation of natural gas supply in the NGTDM.

Another type of supply (or pseudo supply) available is backstop supply; however, it is undesirable for the system to use this supply source. Backstop supply is designed to be used only if the system has insufficient supply or pipeline capacity to meet a minimum level of demand. If it is used, a high price is sent to the demand models which, in turn, are expected to respond by sending lower demand levels. Backstop supply is priced high[33] in order to prevent it from becoming economically attractive.

Demand includes end-use sector demands as well as exports (Canadian and Mexican). As mentioned above, end-use sector demands are defined for both firm and interruptible services. Although demands for both types of service are represented by demand curves, core demands are kept nearly constant while noncore demands are allowed to vary more depending on sector type. Export demands are set exogenously in the Oil and Gas Supply Model and are assigned as core or noncore within the NGTDM using exogenously specified shares (Appendix F, Table F28).

AFM Linear Program Formulation

A linear programming algorithm has been developed to determine the least cost approach to achieving an equilibrium between the supply and demand for natural gas in the AFM. Equilibrium occurs when the "price" at which consumers are willing to purchase a product is equal to the "price" at which producers together with transporters are willing to supply the product to the end-user. Economically, this is the point where the sum of consumers' surplus and producers' surplus is maximized.[34] The methodology employed in solving the natural gas supply and demand equilibrium assumes that marginal costs are the basis for determining market-clearing prices to noncore customers and that core customers are charged the average price of gas delivered to the associated region. The problem is based on a transmission and distribution system composed of two parallel networks. These two networks serve as a means of distinguishing between firm and interruptible transmission and distribution services, and are interconnected only at supply points and through capacity constraints. This section defines the linear programming methodology used to establish a market equilibrium in the AFM, from which supply and end-use prices are obtained. First, the representation of consumer plus producer surplus used in the objective function is derived, then a general description of the entire formulation is presented, followed by the explicit mathematical equations.

Derivation of the Representation of Consumer and Producer Surplus

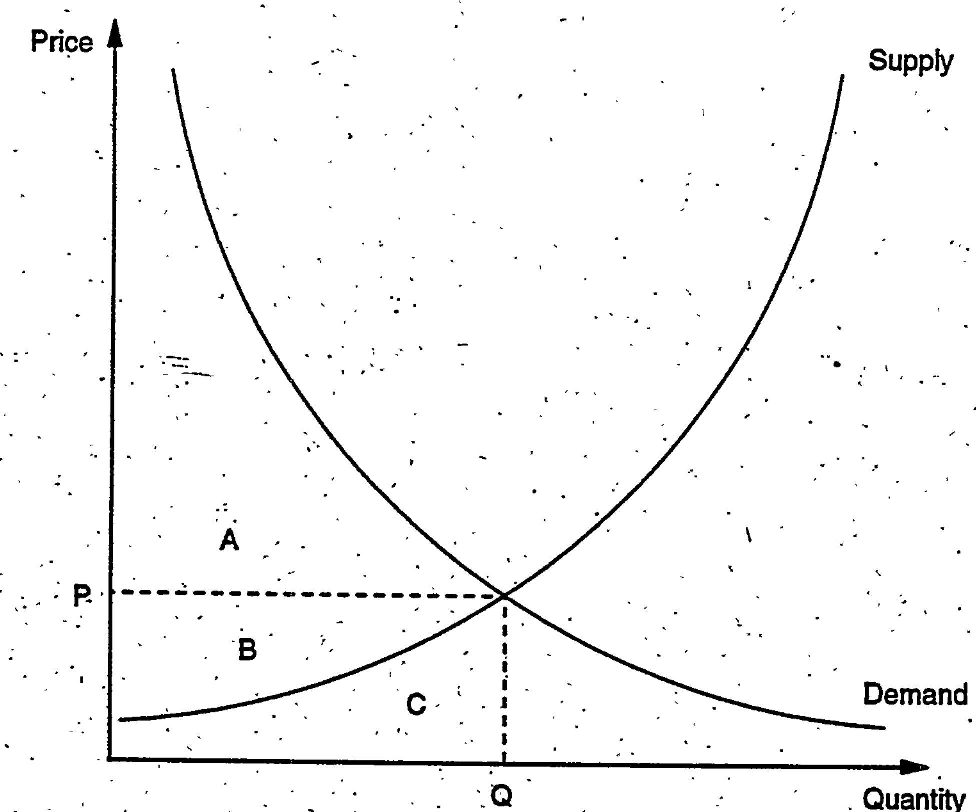
The objective of the linear program designed for the AFM is to determine a market equilibrium between the supply and demand of natural gas. As mentioned above, this occurs when the sum of consumers' surplus and producers' surplus has been maximized. Figure 5-2 illustrates this sum as the area under the demand curve (A+B+C) minus the area under the supply curve (C) to the left of the point of market equilibrium (P,Q). This section describes the computation of the area under the supply and demand curves that are used in the objective function equation.

A method for determining the area under the demand curve is established by first representing the demand curves as step functions, as shown in Figure 5-3. A base quantity and price are given and n steps on either side of the base

[33]The backstop supply price is a user input, currently defaulted at $20.00 (1987$/MCF).

[34]Adapted from the Project Independence Evaluation System (PIES) model.

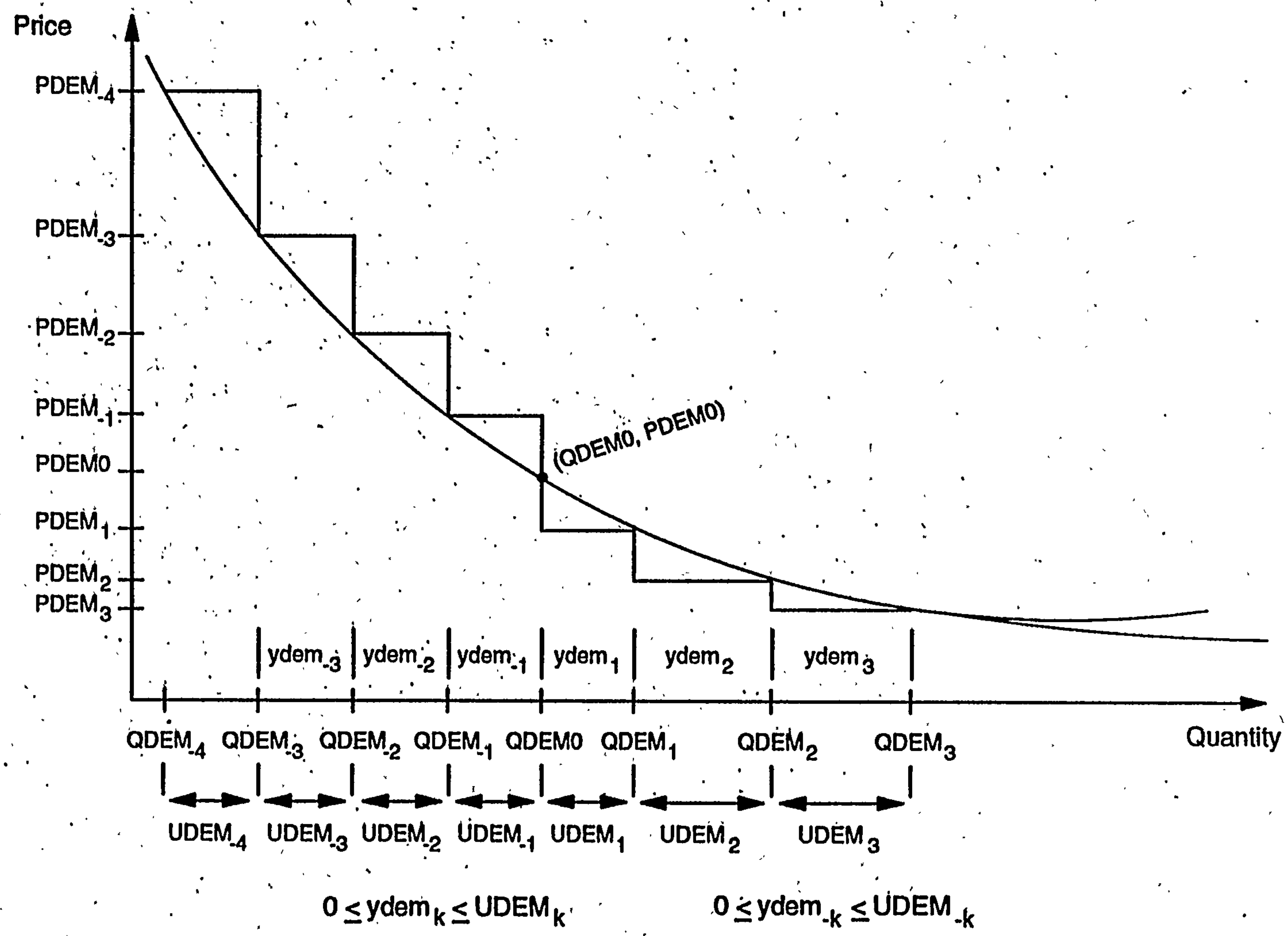
Figure 5-2. Supply and Demand Curves



Area A: Consumers' Surplus
Area B: Producers' Surplus
Area C: Total Cost to the Producers

P: Price at Market Equilibrium
Q: Quantity at Market Equilibrium

Figure 5-3. Approximation of Area Under the Demand Curve



point are defined. Toward this end, let (QDEM0,PDEM0) represent a known point (the base point) on the curve and an estimate of where the model will solve. The parameters $UDEM_{-k}$ and $UDEM_k$ are defined as the incremental quantities represented by each step on the curve (i.e., the length of each step on the demand curve), and $PDEM_{-k}$ and $PDEM_k$ represent the corresponding actual prices. Note that the subscript k identifies the k^{th} step on the curve to the right of the point (QDEM0,PDEM0), and the subscript -k corresponds to the k^{th} step on the curve to the left of (QDEM0,PDEM0).

If ydem is defined as the total deviation from the base point, then introduce the set of model variables $ydem_k$ and $ydem_{-k}$ which are used to define ydem. Each variable represents a portion of the length of the specified step, such that:

$$0 \leq ydem_k \leq UDEM_k$$
$$0 \leq ydem_{-k} \leq UDEM_{-k}$$

and,

$$ydem = \sum_{k=1}^{n} ydem_k - \sum_{k=1}^{n} ydem_{-k} \tag{20}$$

In order for ydem to represent the distance either to the right or left of the initial point (QDEM0,PDEM0), the following conditions must hold. If ydem is greater than zero, then each $ydem_{-k}$ is at the lower bound of zero; and, if ydem is less than zero, then each $ydem_k$ is equal to zero. If ydem is equal to zero, then each $ydem_k$ and $ydem_{-k}$ is equal to zero, and the model solved at (QDEM0,PDEM0).

In short, the demand curve is represented as a step function by defining an initial point on the curve (PDEM0,QDEM0), n $ydem_k$ variables, n $ydem_{-k}$ variables, and the corresponding prices.

Given the above conditions for the relationship between $ydem_k$ and $ydem_{-k}$, the area under the demand curve is approximated by:

$$\sum_{k=1}^{n}(PDEM_k * ydem_k - PDEM_{-k} * ydem_{-k}) + C \tag{21}$$

where,

C	=	the area under the demand curve from 0 to QDEM0
$\Sigma\ PDEM_k{*}ydem_k$	=	the area under the demand curve from QDEM0 to step k.
$\Sigma\ PDEM_{-k}{*}ydem_{-k}$	=	the area under the demand curve from step -k to QDEM0

Note that C is a constant since the demand curve and QDEM0 are given. The variable ydem represents the distance either to the right or left of the initial point (QDEM0,PDEM0), and the equation approximates the integral evaluated from zero to that point.

The area under the demand curve as calculated in the above equation is incorporated in the objective function of the linear program with some modifications. First, the model is formulated as a minimization problem requiring the signs of the coefficients on the equation representing the area under the demand curve to change. Second, since the inclusion of a constant in the objective function does not change the model solution, the C term is excluded from the objective function. As a result, the following term becomes a part of the objective function:

$$\sum_{k=1}^{n}(PDEM_{-k} * ydem_{-k} - PDEM_k * ydem_k) \tag{22}$$

When the area to the right of QDEM0 (ydem greater than zero)[35] is being calculated, the following properties must hold:

(1) At most one $ydem_k$ is not equal to zero or $UDEM_k$.

(2) If $ydem_k$ is not equal to one of its limits, then $ydem_j$, for all j less than k, is equal to its upper limit $UDEM_j$; and $ydem_j$, for all j greater than k, is equal to its lower limit of zero.

At optimality, the conditions listed above for ydem can be shown to hold.[36] If the optimal quantity satisfied is on step k of the demand curve, i.e., $ydem_k$ is not at either of its bounds, then $ydem_j$, for j less than k must be at its upper bound ($UDEM_j$), because it will always be more beneficial to bring in more of quantity $ydem_j$ than to bring in any of $ydem_k$ since the coefficient of $ydem_j$ is negative and $PDEM_j$ greater than $PDEM_k$. Similarly, $ydem_j$ for j greater than k will be zero because it will not be beneficial to bring in any of $ydem_j$ before bringing in all of $ydem_k$ since the coefficient of $ydem_j$ is negative and $PDEM_j$ is less than $PDEM_k$. Furthermore, $ydem_{-j}$ for all j will be zero because it will not be beneficial to bring in any of $ydem_{-j}$ since its coefficient is positive.

Likewise, if the optimal quantity satisfied corresponds to step -k (some quantity must be subtracted from the base demand), where $ydem_{-k}$ is not at either of its bounds, then $ydem_{-j}$, for j less than k, must be at its upper bound ($UDEM_{-j}$), because it will always be more beneficial to subtract more of quantity $ydem_{-j}$ than to subtract any $ydem_{-k}$, since the coefficient of $ydem_{-j}$ is positive and $PDEM_{-j}$ is less than $PDEM_{-k}$. Similarly, $ydem_{-j}$, for j greater than k, will be zero because it will not be beneficial to subtract any of $ydem_{-j}$ before subtracting all of $ydem_k$, since the coefficient of $ydem_{-j}$ is positive and $PDEM_{-j}$ is greater than $PDEM_{-k}$. Furthermore, $ydem_j$ for all j will be zero even though the coefficient of $ydem_j$ is negative. This can be deduced by observing that if the quantity at $ydem_j$ were above zero, the increase in quantity would have to be negated by increasing $ydem_{-k}$, which has a higher price, thus causing the objective function to rise.

Supply Curves

As with the demand curves, the area under the supply curve can be estimated by first representing the supply curves as step functions and then summing the area under the steps on each curve. This is accomplished in a manner similar to the methodology used for demand curves; however, the base point (QSUP0,PSUP0) is assumed to be at QSUP0 equals zero. Thus, the ysup is represented only by $ysup_k$ and the supply term in the objective function becomes $\Sigma\, PSUP_k * ysup_k$. The base point (QSUP0, PSUP0) is set at the solution value (gas production, wellhead price) resulting from the previous NEMS iteration. The size of each ysup is set progressively larger as k increases, therefore allowing for smaller gradations around the base point (to better approximate the original supply curve). For the first two NEMS iterations, the size of each ysup is exogenously specified. Subsequently, the step sizes are decreased (as the NEMS converges to an equilibrium solution) based on the difference in the wellhead price solutions from the previous two NEMS iterations.

General Description of the AFM Linear Program Formulation

The objective of the linear program designed for the AFM is to determine a market equilibrium between the supply and demand of natural gas. Since the network consists of multiple supply sources, multiple demand points, and transshipment arcs, transportation costs also must be included. Thus, system equilibrium will occur when the sum of <u>all</u> the consumers' surplus, <u>all</u> the producers' surplus, and <u>all</u> the transportation costs (negative) is maximized. After translating this into a cost minimization problem, the follow objective function results.

$$\text{minimize} \qquad \{ \text{transportation costs} - (\Sigma \text{ (consumer surplus)} + \Sigma \text{ (producer surplus)}) \}$$

[35]The analogous properties hold for the left of QDEM0 (ydem less than zero).

[36]See page B-16 in the PIES model documentation for a complete description.

where,

Σ (consumer surplus) + Σ (producer surplus) =
(the area under the demand curve to the left of equilibrium)-
(the area under the supply curve to the left of equilibrium)

Capacity flow constraints are defined for each interregional arc in the overall network. Two types of constraints have been defined. One limits total annual flows along an arc and the other serves to limit annual firm service flows along the arc. The total flow constraint is an inequality constraint defined to ensure that total flow (firm plus interruptible) along an arc does not exceed the maximum allowable annual flow along the pipeline. The maximum allowable flow is defined as the maximum physical capacity (adjusted for normal weather representation) times the maximum total utilization (defined by the Capacity Expansion Module) for that arc. Similarly, the firm flow constraint is an inequality constraint defined to ensure that firm flow along an arc does not exceed the maximum allowable annual firm flow along the pipeline. The maximum allowable firm flow is defined as the maximum physical capacity (adjusted for normal weather representation) times the maximum firm utilization (defined by the Capacity Expansion Module) for that arc. The resulting constraints are given below for each interregional arc.

For each interregional arc i,j:

(flow on the arc to satisfy the core market) + (flow along an arc to satisfy the noncore market) ≤ ((physical capacity on the arc) * (1 - weather adjustment factor for normal weather) * (annual capacity utilization factor for total flow))

(flow on the arc to satisfy the core market) ≤ ((physical capacity on the arc) * (1 - weather adjustment factor for normal weather) * (annual capacity utilization factor for firm flow))

A mass balance constraint exists for each transshipment node in each parallel network. These constraints ensure that the total input to a node equals the total output from the node (including net storage withdrawals). In general, gas flowing into a transshipment node comes from other transshipment nodes, supply points, and (in some cases) storage, while gas flowing from a transshipment node goes to demand points, other transshipment nodes, and (in some cases) storage. Storage flows in the AFM are assumed to be constant for a particular year (defined by the Capacity Expansion Module) and are represented as net withdrawals (i.e., natural gas flowing out of storage to a node minus natural gas flowing into storage from a node). Net withdrawals are defined separately for the firm and interruptible networks. A general transshipment node mass balance constraint is listed below for both networks.

For each firm service transshipment node i:

(flow into a transshipment node from another firm service transshipment node) + (flow into a transshipment node from supply points in the region) + (net storage withdrawals corresponding to firm service) - (losses) = (flow out of the transshipment node to other firm service transshipment nodes) + (flow out of the transshipment node to core market demand points in the region)

For each interruptible service transshipment node i:

(flow into a transshipment node from another interruptible service transshipment node) + (flow into a transshipment node from supply points in the region) + (net storage withdrawals corresponding to interruptible service) - (losses) = (flow out of the transshipment node to other interruptible service transshipment nodes) + (flow out of the transshipment node to noncore demand points in the region)

A mass balance constraint also is included for each core and noncore demand point. This constraint ensures that the quantity allocated to an end-use point equals the quantity demanded at that point. Demands in the AFM can vary by region and are defined by demand curves. It is the linear approximations to these curves that are used to represent demands in the linear programming problem. Although these curves allow demands to drop to levels below base level demands in an effort to achieve a market equilibrium, supply or pipeline utilization limits may prevent some regional demands from being met. In order to prevent the linear program from going infeasible, a highly priced backstop supply is available at each demand point. If backstop supply is needed, high prices result and the other NEMS models will respond with lower demands. General transshipment node mass balance constraints are listed below for both parallel networks.

> (flow out of a transshipment node to core market demand points in the region) + (flow from a backstop supply point to core market demand points in the region) - (losses) = (quantity consumed at that node for firm service)

> (flow out of a transshipment node to noncore demand points in the region) + (flow from a backstop supply point to noncore demand points in the region) - (losses) = (quantity consumed at that node for interruptible service)

Each supply point also has a mass balance constraint represented. Since gas may flow from a supply point to a transshipment node (in the same region) in either the firm or interruptible network, this constraint ensures that the total quantity flowing from the supply point equals the amount supplied. The constraint states that total supply is equal to the portion of supply flowing to the firm network plus the portion of supply flowing to the interruptible network. The general constraint is presented below.

> (quantity supplied from the supply curve) = (flow from the supply point to a transshipment node to satisfy the core market) + (flow from the supply point to the transshipment node to satisfy the noncore market)

Due to the nature of a linear program, an optimal solution will not allow flow to occur simultaneously on a primary arc from Region A to Region B and on its bidirectional arc from Region B to Region A because such a situation would incur higher transportation costs (as compared with a case where flow occurs only in one direction and represents net flow). Since an arc in the network may represent an aggregation of some pipelines flowing one direction and other pipelines flowing the opposite direction, flows along bidirectional arcs need to be explicitly represented. This is accomplished by setting minimum flows along the bidirectional arcs in both the firm and interruptible networks equal to historically observed levels (Appendix F, Table F20). The general equations are presented below.

> (flow along the bidirectional arc to satisfy the core market) ≥ (minimum firm flow requirement for the arc)

> (flow along the bidirectional arc to satisfy the noncore market) ≥ (minimum interruptible flow requirement for the arc)

Minimum levels are also set for flows along primary arcs within the firm network. These minimum flows help to generate some continuity in flow patterns (which may not always occur in a linear programming environment) that are generally associated with core market contract demands. These minimum levels are a percentage (Appendix F, Table F32) of flows resulting from last year's solution,[37] and are defined as lower bounds on the flow variables. The general bound equation follows.

> (flow along the primary arc to satisfy the core market) ≥ (minimum firm flow requirement for the arc)

Nominal minimum flows are also defined for flows along primary arcs in the interruptible network. As with the firm network, the minimum flows are set equal to a percentage (Appendix F, Table F32) of the flows resulting from the last forecast year's solution, and are defined as lower bounds on the flow variables. This is represented in the following bound equation.

> (flow along the primary arc to satisfy the noncore market) ≥ (minimum interruptible flow requirement for the arc)

[37]In the first forecast year, minimum flows are assigned as a percentage of historically derived flows for 1990 (Appendix F, Table F20).

Minimum flows are defined on the arcs (to the firm and interruptible transshipment nodes) from the supply sources which are not already specifically targeted for either the firm or interruptible network. This is done to insure that each of these sources supplies a reasonable mix of natural gas to both the core and noncore markets. The sum of the minimum flows from each of these supply sources is set equal to the associated minimum supply level (described in Chapter 3). The firm/interruptible split used in setting minimum flows for all of these arcs is equal to the national core and noncore consumption split (after accounting for the supplies specifically targeted to a particular firm or interruptible network). This is represented in the following bound equation.

(flow along the supply arc to satisfy the core market) ≥ (minimum firm flow requirement for the arc)

(flow along the supply arc to satisfy the noncore market) ≥ (minimum interruptible flow requirement for the arc)

Finally, a number of bound constraints are needed to completely describe the step functions for the supply and demand curves. These bounds serve to define the lengths of each of the steps on the linearized curves.

Mathematical Specification of the AFM Linear Program Formulation

This section presents the set of equations which completely defines the linear programming formulation for the AFM. This set consists of an objective function, flow constraints, mass balance constraints, and bounds on model variables.

The objective function has been defined as the market equilibrium between natural gas supplies and demands, including relevant transportation costs and backstop supply. This has been translated into the following objective function equation.

$$\begin{aligned}
\underset{x,ysup,ydem,qzz}{\text{minimize}}\ & \sum_{i,j} TAR^F_{i,j}*x^F_{i,j} + \sum_{i,j} TAR^I_{i,j}*x^I_{i,j} + \sum_{s,i} TAR^F_{s,i}*x^F_{s,i} + \sum_{s,i} TAR^I_{s,i}*x^I_{s,i} \\
& + \sum_{i,d} TAR^F_{i,d}*x^F_{i,d} + \sum_{i,d} TAR^I_{i,d}*x^I_{i,d} + \sum_{i,d} PZZ^F_{i,d}*qzz^F_{i,d} + \sum_{i,d} PZZ^I_{i,d}*qzz^I_{i,d} \\
& + \sum_{s,i}\sum_{k=1}^{c}(PSUP_{s,i,k}*ysup_{s,i,k}) \\
& - \sum_{i,d}\sum_{k=1}^{n}(PDEM^F_{i,d,k}*ydem^F_{i,d,k} - PDEM^F_{i,d,-k}*ydem^F_{i,d,-k}) \\
& - \sum_{i,d}\sum_{k=1}^{n}(PDEM^I_{i,d,k}*ydem^I_{i,d,k} - PDEM^I_{i,d,-k}*ydem^I_{i,d,-k}) \qquad (23)
\end{aligned}$$

where,

the subscripted indices are:

i,j, and m	=	transshipment node
d	=	demand point
s	=	supply point
st	=	storage point
k	=	step on the curve
c	=	number of steps on the supply curve
n	=	number of steps represented to the left or right of the initial demand point (QDEM0,PDEM0)
i,j	=	arc connecting transshipment nodes i and j
i,d	=	arc from transshipment node i to demand point d
s,i	=	arc from supply point s to transshipment node i

st,i	=	arc from transshipment node i to storage point st
i,st	=	arc from transshipment node i to storage point st

the superscripted indices are:

F	=	firm
I	=	interruptible

the parameters are:

TAR	=	per unit reservation fee and usage fee (dollars per Mcf)
EFF	=	efficiencies (fraction)
PCAPMAX	=	physical capacity (Bcf)
WTHRXCAP	=	weather factor for normal weather (fraction) [Appendix F, Table F41]
AUTILZ	=	pipeline utilization (from Capacity Expansion Module as fraction)
MINF	=	minimum flow requirement (Bcf)
PZZ	=	price of backstop supply (set to an arbitrarily high value), (dollars per Mcf)
PSUP	=	prices on the supply steps (dollars per Mcf)
PDEM	=	prices on the demand steps (dollars per Mcf)
QDEM0	=	base demand level (Bcf)
QSTR	=	net withdrawals from storage (Bcf)
UDEM	=	size of demand step (Bcf)
USUP	=	size of supply step (Bcf)
LSUP	=	minimum supply level (Bcf)

the variables are:

$x_{i,j}$	=	flow from i to j (Bcf)
$ydem_{i,d,k}$	=	for demand point (i,d), amount of corresponding demand step taken (Bcf)
$ysup_{s,i,k}$	=	for supply point (s,i), the amount of supply step k taken (Bcf)
$qzz_{i,d}$	=	amount of backstop supply used for demand point (i,d), (Bcf)

Capacity Constraint Along Each Arc i,j:

$$x^F_{i,j} + x^I_{i,j} \leq PCAPMAX_{i,j} * (1 - WTHRXCAP_{i,j}) * AUTILZ^T_{i,j} \tag{24}$$

$$x^F_{i,j} \leq PCAPMAX_{i,j} * (1 - WTHRXCAP_{i,j}) * AUTILZ^F_{i,j} \tag{25}$$

Mass Balance Constraints at Each Transshipment Node (m):

$$\sum_i x^F_{i,m} * EFF_{i,m} + \sum_s x^F_{s,m} * EFF_{s,m} + QSTR^F_{st} = \sum_d x^F_{m,d} + \sum_i x^F_{m,i} \tag{26}$$

$$\sum_i x^I_{i,m} * EFF_{i,m} + \sum_s x^I_{s,m} * EFF_{s,m} + QSTR^I_{st} = \sum_d x^I_{m,d} + \sum_i x^I_{m,i} \tag{27}$$

Mass Balance Constraints at Each Demand Point (i,d):

$$x_{i,d}^{F} * EFF_{i,d} + qzz_{i,d}^{F} = QDEM0_{i,d}^{F} + \sum_{k=1}^{n}(ydem_{i,d,k}^{F} - ydem_{i,d,-k}^{F}) \tag{28}$$

$$x_{i,d}^{I} * EFF_{i,d} + qzz_{i,d}^{I} = QDEM0_{i,d}^{I} + \sum_{k=1}^{n}(ydem_{i,d,k}^{I} - ydem_{i,d,-k}^{I}) \tag{29}$$

Mass Balance Constraint at Each Supply Point (s,i):

$$\sum_{k=1}^{c} ysup_{s,i,k} = x_{s,i}^{F} + x_{s,i}^{I} \tag{30}$$

Minimum Bounds on Flows Along Bidirectional Arcs (i,j):

$$x_{i,j}^{F} => MINF_{i,j}^{F} \tag{31}$$

Minimum Bounds on Flows from Each Designated Supply Point (s,i):

$$x_{s,i}^{F} => MINF_{s,i}^{F} \tag{32}$$

$$x_{s,i}^{I} => MINF_{s,i}^{I} \tag{33}$$

Minimum Bounds on Flows Along Primary Arcs (i,j):

$$x_{i,j}^{F} => MINF_{i,j}^{F} \tag{34}$$

$$x_{i,j}^{I} => MINF_{i,j}^{I} \tag{35}$$

The following bound constraints also must be defined for the steps on the supply and demand curves:

$$\begin{array}{rcl} 0 \leq & ydem^{F}_{i,d,k} & \leq UDEM^{F}_{i,d,k} \\ 0 \leq & ydem^{F}_{i,d,-k} & \leq UDEM^{F}_{i,d,-k} \\ 0 \leq & ydem^{I}_{i,d,k} & \leq UDEM^{I}_{i,d,k} \\ 0 \leq & ydem^{I}_{i,d,-k} & \leq UDEM^{I}_{i,d,-k} \\ LSUP_{s,i,k} \leq & ysup_{s,i,k}^{I} & \leq USUP_{s,i,k} \end{array}$$

For the most part LSUP is zero, except on the first step of the supply curve where a minimum supply level may be defined.

Thus, the above equations mathematically specify the linear program objective function and the model constraints. The linear programming solution is obtained using a commercial software package designed to solve these problems.

Processing of AFM Results

The AFM is responsible for providing other models within NEMS with natural gas end-use and supply prices and quantities which correspond to a market equilibrium between natural gas supply and demand. In addition, the AFM must provide NEMS with resulting pipeline fuel consumption, lease and plant consumption, and emissions levels associated with the network results, as well as realized tariffs for the noncore market for the Pipeline Tariff Module to process. Once the linear programming problem is solved, these principal model forecast results are processed using information extracted from the resulting matrix. For example, since the AFM solves at a regional level which differs somewhat from the NEMS Census divisions and other model's regional definitions (as described in Chapter 3), the AFM results must be aggregated into the regions required by the receiving models prior to being passed to NEMS. Another major processing step is the calculation of average market prices to the core customers. The various methodologies used to generate these model results are presented below.

Supply Prices and Quantities

The AFM provides wellhead prices and quantities for onshore, offshore, Alaska, and Canadian production, for Canadian, Mexican, and liquefied natural gas imports (at the border crossing), and for synthetic natural gas and other supplemental supplies. With the exception of Canadian import and wellhead prices, these values are obtained directly from the linear programming solution with little or no processing required (i.e., to translate information from one regional representation to another). Some of these results are passed to the Oil and Gas Supply Model, the Petroleum Market Model and the Coal Market Model for processing, while others are passed to NEMS for convergence and reporting purposes.

To determine Canadian import and wellhead prices, a netback pricing routine is used. For Canadian import prices, this involves taking the price at the node nearest to the border crossing node and reducing it by the tariff along the arc connecting the two nodes. For example, since Canadian imports from border crossing node 13 go into node 1 on the AFM network (see network defined in Chapter 4), the Canadian import price at node 13 is the node price at node 1 minus the tariff along arc 13 -> 1. Similarly, Canadian wellhead prices are determined by first taking each of the Canadian imports prices (at the border crossing) and subtracting the corresponding Canadian markups from the wellhead, and then taking a quantity-weighted average of the results (adjusted for losses).

End-Use Prices

The AFM provides regional end-use prices for the Electricity Market Model (electric generation sector) and the other NEMS demand models (nonelectric sectors). For the nonelectric sectors, prices correspond to core and noncore service at the Census Division level. However, for the electric generation sector, prices are determined for three types of customers (core segment, segment competitive with residual oil, and segment competitive with distillate oil) at two different regional levels (the Census Division level and the NGTDM/EMM subregion level). End-use prices for some sectors/segments within the model are easily determined from the AFM linear programming solution, while others are determined through more rigorous procedures.

End-use prices corresponding to the noncore, nonelectric sector for each Census Division are easily determined from the NGTDM regional prices produced by solving the AFM linear program. Once retrieved from the linear programming solution, the NGTDM regional prices are aggregated into Census Division level results (using a simple quantity-weighted averaging technique) and converted into the appropriate units.

End-use prices for core services cannot be taken directly from the linear programming solution because the linear program prices natural gas at the margin when, in fact, prices for the core segment need to be represented as average prices. A methodology has been established to calculate average regional transshipment node prices, from which average end-use prices for the core segment can be determined. This methodology is based on the premise that the NGTDM network (discounting bidirectional flows) can be viewed as having a quasi "tree" structure, with the primary supply sources at the bottom (or root) and the more distant demand regions at the top. Using this tree structure, average firm transshipment node prices are calculated starting from the root and moving up to the top branches. At each regional transshipment node, the average price is calculated as a quantity-weighted average of gas coming from other regions and gas produced within the region. Gas produced from other regions is priced at the average transshipment node price in the other region, plus the cost based tariff to move the gas from the other region. Note that average prices are calculated after the linear program has been solved. This should not directly impact other NGTDM model results (e.g., interregional flows) since core demands are relatively inelastic to price changes (reflected in the fact that the model assumes a price elasticity of zero for the core demand curves).

End-use prices for core customers in a region are then set by adding the intraregional tariff and the distributor tariff to the average regional transshipment node price. These regional prices are then aggregated to the Census Division level using a simple quantity-weighted average technique and converted to the appropriate units.

Electric generation sector prices are sent to the Electricity Market Model at the NGTDM/EMM subregion level and to NEMS (for convergence and reports) at the Census Division level. The Electricity Market Model requires prices to be reported for all three market segments, while NEMS requires that prices for the competitive markets be combined into an average noncore price. Different methodologies are used to determine the delivered natural gas price to each of the three electric generation market segments. Electric generation sector prices to core customers in each NGTDM/EMM region are determined by adding the intraregional tariff and the distributor tariff to the average associated NGTDM regional firm transshipment node price (defined above), processed to represent the appropriate regions (NGTDM/EMM subregions for the Electricity Market Model and Census Divisions for NEMS), and converted into the proper units. Electric generation sector prices to the competitive (residual and distillate) segments are calculated based on their corresponding competitive fuel price (see Chapter 6 for details). Next, a quantity-weighted averaging routine is used to combine the two competitive segments into a single average end-use price to send to NEMS.

Pipeline Fuel Consumption and Associated Emissions

For each arc of the network, pipeline fuel consumption is calculated by multiplying the flow on the arc by the percentage (specified as a fraction) lost due to pipeline fuel use. This percentage lost is 1 minus the efficiency specified along the arc as a data input. (In addition, a multiplicative scaling factor is used to calibrate these results to equal the most recent national historical pipeline fuel consumption.) The pipeline fuel use along each arc of the network must be translated to fuel use by NGTDM region. This disaggregation is accomplished by multiplying the fuel use on each arc by regional shares based on the mileage of pipe in a given region (Appendix F, Table F39). A similar loss factor is applied along each intraregional arc to account for losses accrued in the distribution process.

Pipeline fuel consumption is used as a basis for calculating the emissions which result from pipeline compressor engine use. Both reciprocating engines and gas turbines are used to power compressors. The latter engines outnumber the former by a factor of approximately 3.3, primarily because they accommodate higher capacity flows at a greater efficiency. However, the reciprocating engines allow for greater variation in flows and are able to send flows in both directions along the pipe. According to estimates by Argonne National Laboratory (presented in the *NES Environmental Analysis Model (NESEAM): ANL Technical Memorandum*, Section "Natural Gas" of the Appendix C), 77 percent of the engines used for pipeline transportation are gas turbines and 23 percent are reciprocating piston compression engines.

The NGTDM quantifies eight types of pollutants discharged by the combustion of natural gas at gas pipeline compressor stations: total carbon, nitrogen oxides, sulfur oxides, carbon monoxide, carbon dioxide, methane, volatile organic compounds, and particulate. Since data on particulate emissions are not available and particulate emission levels are assumed to be small, estimates for particulate emissions are not included. Estimates for the discharge levels of the other pollutants are calculated as functions of the pipeline fuel consumption. In the last five years, pipeline fuel consumed by the compressor stations represents about 3.6 percent of the annual amount of gas delivered to consumers. Natural gas pipeline emissions by NGTDM region are calculated as the product of the annual pipeline fuel consumption in the region times an emissions factor, as follows:

$$EMNT_{r,p,y} = QGPTR_{r,y} * EMISRAT_p / (CFNGC * 2205.0) \tag{36}$$

where,

p	=	subscript that designates any of the eight types of pollutants discussed above (1-total carbon, 2-carbon monoxide, 3-carbon dioxide, 4-sulfur oxides, 5-nitrogen oxides, 6-volatile organic compounds, 7-methane, 8-particulates)
$QGPTR_{r,y}$	=	annual pipeline fuel consumption in year y for Census Division r (Trillion BTU)
$EMISRAT_p$	=	emissions factor (Appendix F, Table F25) (lb/MMCF)

CFNGC	=	Conversion factor (Trillion BTU/BCF)
$EMNT_{r,p,y}$	=	natural gas pipeline annual emissions, in thousand metric tons (MMT) in Census Division r and year y.

[Note: The constant 2205.0 in the equation converts the result in pounds to metric tons.]

A separate carbon emissions routine within the NEMS overrides the emissions levels calculated within the NGTDM and establishes the final reported carbon emissions levels for the NEMS.

Realized Pipeline Tariff

The Pipeline Tariff Module provides the AFM with a minimum and maximum usage fee, as well as an estimated usage fee for use in the model for transporting gas between regions under interruptible service. Once the linear program is solved, the realized tariff along each arc in the network equals the difference between the market clearing prices at the two connected transshipment nodes. If the natural gas flow along the arc is less than its capacity limit, the realized tariff equals the usage fee assigned when the linear program was formulated. If the flow along the arc is at its limit, the realized tariff will be greater than (or possibly equal to) the usage fee originally specified and could exceed its maximum allowed level. A check is made to identify any realized tariff greater than its allowed maximum. Currently no adjustment is made within the model if this maximum is exceeded, although it typically is not.

6. Distributor Tariff Module Solution Methodology

This chapter discusses the solution methodology for the Distributor Tariff Module (DTM) of the Natural Gas Transmission and Distribution Model (NGTDM). The DTM develops markups that are applied to regional hub prices[38] to derive end-use prices. The markups are intended to capture the various pricing strategies employed by intrastate carriers and distributors. Markups are determined separately for the residential, commercial, industrial, electric generator, and transportation (compressed natural gas vehicle) sectors. Within the DTM, residential, commercial, and natural gas vehicle customers are classified as core customers. It is assumed that they receive all of their natural gas under firm (or near-firm) transportation agreements. Markups for the industrial sector and electric generators are segmented by core and noncore markets. It is assumed that core customers in these two end-use sectors receive all of their natural gas under firm (or near-firm) transportation agreements. In contrast, it is assumed that noncore industrial and electric generator customers transport their gas under interruptible or short-term capacity release transportation agreements.

The purpose of the DTM is to determine core and noncore (where applicable) markups for each end-use sector.[39] Distributor markups to core customers are based on the cost of providing service to the end user. The core market markups are derived from historical data although various model parameters and assumptions may modify the historical markups throughout the forecast period. Historical markups, model parameters, and assumptions are used because publicly available data are insufficient to develop a cost-based accounting methodology similar to the approach used for interstate pipeline tariffs in the Pipeline Tariff Module.

End-use prices for industrial noncore customers are established by adding a markup to the natural gas interruptible service supply price at the regional market hub. These markups are endogenously derived as the difference between estimated historical 1993 end-use prices[40] and the NGTDM regional interruptible service hub price.

Electric utilities balance the mix of their generating capacity against generation cost and fuel availability. To meet demand, utilities provide a mix of electric generation technology to satisfy their generation requirements while minimizing generation costs. A large portion of this technology depends on a single energy source--coal-fired steam turbine power plants, for example. However, a significant portion of the technology is dual-fired which can switch between different fuels depending upon the cost and availability of alternative fuels.

Utilities respond to seasonal changes in fuel cost and availability by switching their dual-fired capability to lower cost fuels and by increasing the utilization of lower cost generating capacity. Thus during winter months when space heating demand for natural gas is at peak levels, utilities switch from natural gas to distillate and residual fuel oils, among others, to supply a portion of their generating capacity. For example, in the Central Atlantic Region the share of natural gas-based electric generation, on average, declines from 10 percent during summer months to 3 percent in winter months. During the same period, the share of fuel oil-based electric generation, on average, increases by 6 percent.[41]

Since the bulk of the electric generating technology using natural gas is switchable to other fuels, the electric generators sector contracts predominantly for interruptible service. Some electric generation technologies, however, use natural gas as their sole energy source, so a portion of the electric generators sector's requirements also is for firm service.[42]

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[38]The hub price is equal to the market clearing price of all supplies at the transhipment node in the region in which the gas is consumed.

[39]The DTM determines distributor markups separately for each end-use sector. This modularity of design makes it easier to revise the pricing structure to accommodate future market changes or increased availability of data.

[40]Historical noncore industrial prices (Table E8, Appendix E) were based on data from the 3/31/94 draft version of *Manufacturing Consumption of Energy 1991*.

[41]Energy Information Administration, "Effects of Interruptible Natural Gas Service: Winter 1989-1990," Office of Oil and Gas, July 1991.

[42]Texas is the only State in which a significant portion of electric utility natural gas contracts are for firm service.

The electric generators sector markups are based on a characterization of electric generation technology drawn from various EIA data surveys.[43] In addition to technology type, the data surveys provide historical information on natural gas consumption volumes. For modeling purposes, electric generators natural gas demand is distinguished by three service types: core market service, noncore market service where gas competes with residual fuel oil, and noncore market service where gas competes with distillate fuel oil. Each service type is characterized by electric generation technology as follows:

- Core market service—dedicated gas steam and gas combined cycle generating units
- Noncore market services competitive-with-residual fuel oil—dual-fired steam generating units that are primarily switchable to residual fuel oil
- Noncore market services competitive-with-distillate fuel oil—gas-only[44] and dual-fired turbines.

A detailed discussion of how the DTM determines markups and end-use prices for each end-use sector is presented in subsequent sections of this chapter.

Markups and End-Use Pricing in Core Markets

Residential, Commercial and Industrial Sectors

Residential, commercial, and industrial core market end-use prices are comprised of four components: (1) the regional hub price of natural gas, (2) the firm tariff for intraregional movements of natural gas on the interstate network, (3) a markup covering the costs of distribution and intrastate pipeline services, and (4) a benchmark factor. The latter three components are consolidated into a markup. In establishing the final end-use price, both the markup and the supply price at the hub are adjusted for an efficiency representing fuel use for the services required to move natural gas from the regional hub to the end user. The primary equation for determining end-use prices is provided below:

$$NONU\_PR\_F_{i,j} = (NG\_AVGPR\_F_j + NONU\_DTAR\_F_{i,j}) \;/\; NEFF\_PIPE_{j,i} \tag{37}$$

where,

NONU_PR_F	=	end-use price for firm service provided to non electric sectors (dollars per Mcf)
NG_AVGPR_F	=	hub price for firm service [from Annual Flow Module solution matrix (dollars per Mcf)].
NONU_DTAR_F	=	markup for firm service provided to non electric sectors, before adjusting for pipeline fuel use (dollars per Mcf)
NEFF_PIPE	=	efficiency for services provided to transport natural gas from the regional hub to end-use customers [Appendix F, Table F19 (fraction)]
i	=	end-use sector index
j	=	region index.

The firm service markup is comprised of three separate cost components as presented in the following equation:

$$NONU\_DTAR\_F_{i,j} = DIST_{i,j} + PTAR\_F_{j,j} + BENCHF_{i,j} \tag{38}$$

where,

[43] The EIA surveys include Forms EIA-767, "Steam-Electric Plant Operation and Power Plant Design Report," EIA-860, "Annual Electric Generator Report," EIA-759, "Monthly Power Plant Report," and FERC Form 423, "Monthly Report on Cost and Quality of Fuels for Electric Plants."

[44] Gas-only turbines are competitive with distillate fuel oil since these generating units may be displaced by distillate-fired units.

NONU_DTAR_F	=	markup for firm service provided to non electric sectors, before adjusting for pipeline fuel use (dollars per Mcf)
DIST	=	markup for firm distributor and intrastate pipeline services [Appendix F, Table F21 (dollars per Mcf)]
PTAR_F	=	markup for intraregional firm service provided by interstate pipelines within region j [from the Pipeline Tariff Module (dollars per Mcf)]
BENCHF	=	benchmark factor (dollars per Mcf)
i	=	end-use sector index
j	=	region index (j,j equates to intraregional activity).

During the forecast period, the markup for firm distributor and intrastate pipeline services is adjusted each year based on a user-specified adjustment factor (NONU_DTARF_DECL). For the AEO95, it is assumed that the firm markup declines at a rate of 1 percent per year.

The benchmark factor is derived internally from differences in historical end-use prices and the end-use prices derived by the NGTDM for the years historical data are available, and is primarily used to calibrate the model against actual historical data. For the first iteration of the first model forecast year (1990) of the simulation, the DTM sets the benchmark factors to zero. For subsequent iterations and years of the historical period (1990 through 1993), the benchmark algorithm computes benchmark factors. For example, the benchmark factors for the residential sector are computed using the following equation:

$$BENCHF_{i=1,j,t} = HPGFRSGR_{j,t} - NONU\_PR\_F_{i=1,j,t} \tag{39}$$

where,

BENCHF	=	benchmark factor for the residential sector, i=1 (dollars per Mcf)
HPGFRSGR	=	historical natural gas end-use price for the residential sector [Appendix E, Table E8 (dollars per Mcf)]
NONU_PR_F	=	end-use price for core service provided to the residential sector, i=1 (dollars per Mcf)
t	=	model year index
i	=	end-use sector index (i=1 for residential sector)
j	=	region index.

[Note: A similar equation is used for the commercial and industrial sectors with HPGFRSGR replaced with HPGFCMGR or HPGFINGR, respectively, and with the index i set to 2 or 3.]

When the model converges for historical years, the benchmark factors from the last iteration are assigned to the array HISBENCHF. After the historical period (i.e., model year 1993) is completed, the benchmark algorithm sets the benchmark factors equal to the benchmark factor for 1992 for the residential and commercial sectors and sets the benchmark factor equal to the benchmark factor for 1993 for the industrial sector. The benchmark factor is held constant for all the forecast years.

Before completing the processing of the end-use prices, the DTM checks the prices against a minimum threshold price of $0.00001 per Mcf. The purpose of this check is to send a nonzero price to the NEMS Integrating Module in situations where there is no demand for a sector in a region. Should the end-use price be very small, the price is reset to the last price that is available (either from a previous iteration, model year, or historical period) for the sector and region.

Transportation Sector

The transportation sector includes the use of compressed natural gas as a vehicle fuel. The price of natural gas used for pipeline fuel is not included in the price of natural gas delivered to the transportation sector. Pipeline fuel is priced at the market clearing price of gas supplies at the transhipment node at the origin of the arc on which the natural gas is transported.

Two pricing methodologies are available for deriving end-use prices for compressed natural gas used as a vehicle fuel (VNG). The first methodology (called the historical markup method) uses a markup derived from the historical prices reported in EIA's *Natural Gas Annual*.[45] The historical VNG fuel prices do not include all Federal and State taxes or the full cost of dispensing the fuel. The second methodology (called the full cost price method) develops a markup for VNG using an algorithm that takes into consideration cost components of supplying and dispensing VNG, Federal and State taxes, and the price of motor gasoline to commercial customers. The DTM offers the flexibility to transition to the full cost price methodology in a user specified forecast year. The DTM can also phase in the full cost price methodology over a period of years specified by the user. This capability was incorporated to reflect the expectation that the market for VNG will undergo a transition during the forecast period. The pricing transition is intended to capture the evolution of the market from government/industry sponsored demonstration programs to large scale commercial use. These two pricing methodologies and the phase-in method are presented below.

In the historical markup method, the price of VNG is a function of the firm service hub price, an historical markup, and an efficiency as shown in the following equation:

$$NONU\_PR\_F_{i=4,j} = (NG\_AVGPR\_F_j + NONU\_DTAR\_F_{i=4,j}) \,/\, NEFF\_PIPE_{i=4,j} \tag{40}$$

where,

NONU_PR_F	=	end-use price for core service provided to the transportation sector, i=4 (dollars per Mcf)
NG_AVGPR_F	=	hub price for firm service [from Annual Flow Module solution matrix (dollars per Mcf)]
NONU_DTAR_F	=	markup for core service provided to the transportation sector (i=4), before adjusting for pipeline fuel use (dollars per Mcf)
NEFF_PIPE	=	efficiency for services provided in transporting natural gas from the regional hub to compressed natural gas vehicle customers, i=4 [Appendix F, Table F19 (fraction)]
i	=	end-use sector index (i=4 for transportation sector)
j	=	region index.

The transportation sector markup (NONU_DTAR_F) is held constant throughout the period the historical markup method is used. The markup is set equal to the difference between the regional historical price of VNG for the last year that historical VNG price data are available to the NGTDM (1992) and the regional hub price of firm natural gas supplies as determined within the Annual Flow Module. This derivation is shown in the following equation:

$$NONU\_DTAR\_F_{i=4,j} = HPGFTRGR_{j,h} * NEFF\_PIPE_{i=4,j} - NG\_AVGPR\_F_j \tag{41}$$

where,

NONU_DTAR_F	=	markup for core service provided to the transportation sector (i=4), before adjusting for pipeline fuel use (dollars per Mcf)
HPGFTRGR	=	historical natural gas end-use price for the core transportation sector [Appendix E, Table E8 (dollars per Mcf)]
NEFF_PIPE	=	efficiency for services provided in transporting natural gas from the regional hub to compressed natural gas vehicle customers, i=4 [Appendix F, Table F19 (fraction)]
NG_AVGPR_F	=	hub price for firm service [from Annual Flow Module solution matrix (dollars per Mcf)]
i	=	end-use sector index (i=4 for transportation sector)
j	=	region index
h	=	index for last year historical data are available.

[45] Energy Information Administration, *Natural Gas Annual 1992*, DOE/EIA-0131(92) (Washington, DC, November 1993).

Under the full cost price method a markup for VNG is derived as a function of the full cost of delivering VNG to alternate fuel vehicles. The full cost markup is initially set equal to the sum of the industrial core market markup, the cost of dispensing VNG at a high volume service station, State motor vehicle fuel tax applied to VNG, and Federal motor vehicle fuel tax applied to VNG as shown in the following equation:

$$NONU\_DTAR\_F_{i=4,j} = NONU\_DTAR\_F_{i=3,j} + RETAIL\_COST + STAX_j + FTAX \tag{42}$$

where,

NONU_DTAR_F	=	markup for core service provided to the transportation sector (i=4) and to the industrial sector, i=3 (dollars per Mcf)
RETAIL_COST	=	cost of dispensing VNG [Appendix F, Table F27 (dollars per Mcf)]
STAX	=	State motor vehicle fuel tax applied to VNG [Appendix F, Table F27 (dollars per Mcf)]
FTAX	=	Federal motor vehicle fuel tax applied to VNG [Appendix F, Table F27 (dollars per Mcf)]
i	=	end-use sector index (i=4 for transportation sector, i=3 for industrial sector)
j	=	region index.

To assure the competitiveness of VNG relative to motor gasoline within a region, the full cost markup is checked against a maximum markup that is derived from the commercial motor gasoline price and the hub price for firm natural gas supplies within the region, as follows:

$$DTAR\_MAX = PTAR\_F_{j,j} + PERCDISC * (AFP_j * NEFF\_PIPE_{i=4,j} - NG\_AVGPR\_F_j - PTAR\_F_{j,j}) \tag{43}$$

where,

DTAR_MAX	=	maximum tariff for VNG within region j (dollars per Mcf)
PTAR_F	=	markup for intraregional (j,j) firm service provided by interstate pipelines [from the Pipeline Tariff Module (dollars per Mcf)]
$NEFF\_PIPE_{i=4}$	=	efficiency for services provided for transporting natural gas from the regional hub to the VNG dispensing facility [Appendix F, Table F19 (fraction)]
PERCDISC	=	discount [Appendix F, Table F27 (fraction)]
AFP	=	alternative fuel price [commercial motor gasoline price (dollars per Mcf)]
i	=	end-use sector index (i=4 for transportation sector)
j	=	region index (j,j equates to intraregional activity).

If the full cost VNG markup exceeds the maximum competitive markup, the full cost markup is set equal to the maximum competitive markup.

In years when the model is making the transition from the historical markup to the full cost markup, a composite markup is derived by applying weights to the two markups. The weight applied to the historical markup is derived in the equation below:

$$BETA = 1 - (CURIYR - STPHASE)/(EPHASE - STPHASE) \tag{44}$$

where,

BETA	=	markup weight (fraction)
CURIYR	=	current model year (1=1990, 2=1991,,, 26=2010)
STPHASE	=	year that transition begins (STPHASE=3, for 1992)
EPHASE	=	year that transition ends (EPHASE=16, for 2005).

In deriving the composite markup, the BETA weight is applied to the historical markup and a weight equal to (1.0-BETA) is applied to the full cost markup.

Similar to the other sectors, the transportation price is checked against a minimum price ($0.00001 per Mcf). The purpose of this check is to pass nonzero prices to the NEMS Integrating Model in situations where there is no natural gas demand by a sector in a region. Should the end-use price be very small, the price is reset to the last price that is available (either from a previous iteration, model year, or historical period) for the sector and region.

Electric Generators

The core market markup to the electric generator sector from the regional firm service hub is comprised of two components: (1) a markup for intraregional services provided by interstate pipelines and (2) a benchmark factor to calibrate the model to historical data. The benchmark factor must at least cover a user-specified minimum distribution fee (URFLOOR, Appendix F, Table F29). The equation for the firm service markup is shown below:

$$UTIL\_DTAR\_F_{j,n} = PTAR\_F_{j,j} + UBENCH_k \tag{45}$$

where,

UTIL_DTAR_F	=	markup for core market service provided to electric generators, includes intrastate pipeline services and distributor services before adjusting for pipeline fuel use. (dollars per Mcf)
PTAR_F	=	markup for intraregional (j,j) core market service provided by interstate pipelines [from the Pipeline Tariff Module (dollars per Mcf)]
UBENCH	=	benchmark factor (dollars per Mcf)
j	=	NGTDM region index (j,j equates to intraregional activity)
n	=	Electricity Market Model region index
k	=	region index (NGTDM/EMM).

[Note: A factor (TILT) for shifting distribution costs between end-use service categories is also added to UTIL_DTAR_F, but is currently set to zero (Appendix F, Table F29).]

Benchmark factors for historical years are derived from differences in historical prices and model generated prices for the historical period as shown below:

$$UBENCH_k = HPGFELGR_{k,t} - UTIL\_PR\_F_{j,n} \tag{46}$$

where,

UBENCH	=	benchmark factor (dollars per Mcf)
HPGFELGR	=	historical natural gas end-use price for core market service to electric utilities [parameters for derivation in Appendix E, Table E17 (dollars per Mcf)]
UTIL_PR_F	=	end-use price for core market service to electric utilities, from the Annual Flow Module solution matrix (dollars per Mcf)
k	=	region index (NGTDM/EMM)
t	=	model year index
j	=	NGTDM region index
n	=	Electricity Market Module region index.

After the historical period is completed, the maximum regional benchmark factor to be used in the forecast period is set equal to the average of the benchmark factors for the last 2 years that historical data are available (1992 and 1993). The minimum benchmark factor in a region is equivalent to the assumed minimum distribution fee (URFLOOR). Over the next UBENYRD years (Appendix F, Table F29), the applied benchmark factor in a region is scaled down from its maximum level to its minimum level plus a percentage (UBENPER, Appendix F, Table F29) of the difference between the maximum and the minimum levels.

Similar to the other sectors, the core market electric generator sector price is checked against a minimum price ($0.00001 per Mcf). The purpose of this check is to send a nonzero price to the NEMS Integrating Model in situations where there is no demand for firm natural gas service by electric generators in a region. Should the end-use price be very small, the price is set to the last price that is available (either from a previous iteration, model year, or historical period) for the sector and region.

Noncore Markups and End-Use Prices

Industrial Sector

End-use prices for industrial noncore customers are established by adding a markup to the natural gas supply price for the noncore segment at the regional market hub. These markups are endogenously derived as the difference between estimated historical 1993 end-use prices[46] and the NGTDM regional noncore hub price as follows:

$$NONU\_DTAR\_I_{i=3,j} = HPGIIN_j - NG\_MAGPR\_I_j \qquad (47)$$

where,

$NONU\_DTAR\_I_{i=3}$	=	markup for interruptible service provided to the industrial sector, before adjusting for pipeline fuel use (dollars per Mcf)
HPGIIN	=	historical natural gas end-use price for the noncore industrial market [Appendix E, Table E8 (dollars per Mcf)]
NG_MAGPR_I	=	hub price for noncore service [from Annual Flow Module solution matrix (dollars per Mcf)]
i	=	end-use sector index (i=3 for industrial sector)
j	=	region index.

The industrial noncore markup is held constant throughout the forecast period.

Electric Generator Markup- Competitive-with-Residual Fuel Oil

Natural gas priced competitive-with-residual fuel oil is marketed to dual-fired electric generating units that are switchable to residual fuel oil. The markup for this category is based on the value of service to the sector as determined by the competing residual fuel oil price. The alternative fuel price used in deriving the markup for natural gas prices is set equal to the quantity weighted average price of high and low sulfur residual fuel oil delivered to electric generators. If the total quantity of residual fuel oil delivered to electric generators in a region is small (less than 1000 MMBtu) the alternative fuel price is set equal to either the high or low sulfur residual fuel oil price. The price chosen is based on fuel quality with the largest quantity consumed in the region. The markup is derived from the following equation:

$$UTIL\_DTAR\_IR_{j,n} = PR\_MIN * UEFF\_PIPE_{j,k} - NG\_MAGPR\_I_j \qquad (48)$$

where,

UTIL_DTAR_IR	=	markup for noncore market service provided to electric generators switchable to residual fuel oil (dollars per Mcf)
PR_MIN	=	minimum price of natural gas (dollars per Mcf)

[46]Historical noncore industrial prices (Table E8, Appendix E) were based on data from the 3/31/94 draft version of *Manufacturing Consumption of Energy 1991*.

UEFF_PIPE	=	efficiency for services provided in transporting natural gas from the regional hub to end-use customers [Appendix F, Table F19 (fraction)]
NG_MAGPR_I	=	hub price for noncore service [from Annual Flow Module solution matrix (dollars per Mcf)]
j	=	NGTDM region index
n	=	Electricity Market Module region index.

The core markup serves as an upper bound to the noncore markup derived in the above equation. The price PR_MIN is set equal to (1) a discounted alternative fuel price or (2) the interruptible natural gas price solved for in the Annual Flow Module, whichever is the greater price. The discounted alternative fuel price is the product of the alternative fuel price times a discount factor. The discount factor is the lesser of the gas to residual oil price ratio provided by the Electricity Market Module (GRATMAX, which is equal to the price at which electric generators will use the maximum amount of available gas) or the gas to residual fuel oil price ratio exogenously specified by the user [NGRATMAX, (Appendix F, Table F23)]. The noncore natural gas price solved for in the Annual Flow Module will equal the noncore hub price (NG_MAGPR_I) in region j plus the markup for interregional service provided by interstate pipelines ($PTAR\_I_{jj}$) plus the minimum distribution fee (URFLOOR). This algorithm will maximize the use of natural gas in markets where natural gas competes with residual fuel oil subject to the condition that full cost recovery takes place, and will also ensure that gas is not priced below the highest price at which electric generators will use the maximum gas available.

Electric Generator Markup- Competitive-with-Distillate Fuel Oil

Natural gas priced competitive-with-distillate fuel oil is marketed to gas turbines and dual-fired turbines that are switchable to distillate fuel oil. This markup is based on the value of service to the sector as determined by the alternative distillate fuel oil price. The markup is defined as the difference between the product of 1) a discount factor for region j [UDPD1, (Appendix F, Table F23)] multiplied by the price of distillate fuel oil to electric utilities in the region and 2) the noncore natural gas price at the regional hub (NG_MAGPRI_j).

The competitive-with-distillate fuel oil markup for services is constrained by maximum and minimum values. If the markup derived from the discounted alternative fuel price exceeds the core market electric generators markup, the value is set equal to the electric generator sector core market distribution markup minus a user specified discount (UDFLOOR, currently set at $0.10 in 1987 dollars per Mcf). If the markup derived from the discounted alternative fuel price is less than a minimum markup, the markup is set to the minimum. The minimum markup is the greater of either the competitive-with-residual fuel oil markup or a user-specified minimum threshold markup that equals the sum of the intraregional interstate pipeline tariff and UDFLOOR.

7. Capacity Expansion Module Solution Methodology

The Capacity Expansion Module (CEM) is a component of the Natural Gas Transmission and Distribution Model (NGTDM). Its function is to determine future interstate pipeline and storage capacity expansion requirements, firm and total pipeline utilization estimates, and net storage withdrawal levels to meet core and noncore demand for use by the Annual Flow Module and/or the Pipeline Tariff Module. A flow diagram illustrating the general structure of the CEM is provided in Figure 7-1. These results are determined based on an equilibrium between expected changes in gas consumption levels and supply availability corresponding to a CEM forecast year (represented as the Annual Flow Module model year "t" plus look-ahead years "n").[47] Like the Annual Flow Module, it is structured as a transportation network servicing both core and noncore customers; however, it bases its capacity and storage utilization/expansion decisions on seasonal firm service loads, thus accounting for peak period and off-peak period consumption requirements. This two-period network structure allows for a more accurate representation of the capacity build decisions and storage requirements, as well as a mechanism for setting maximum utilization levels for the Annual Flow Module. It is important to note that without the total market (core and noncore) being represented in the CEM, natural gas production levels cannot be properly represented and maximum utilization levels cannot be properly determined.

Formulated as a linear program, the CEM determines the capacity expansion and flow decisions which correspond to the least cost solution for achieving an equilibrium between expected supply and demand levels for natural gas. It is designed to determine pipeline and storage expansion and utilization levels that correspond to satisfying core and noncore demands represented in both the peak and off-peak periods. Price curves for storage and pipeline expansion are employed to represent the costs associated with expansion options. The decision to expand capacity in the model is based on the criterion that peak period firm service requirements for design weather conditions[48] must be met. Thus, when current capacity levels are fully utilized, the model simultaneously determines the relative difference in price to the consumer among the following activities: (1) adding more pipeline capacity, (2) adding more storage capacity to enable the transfer of gas to a core customer in the peak period, (3) adding no more pipeline or storage capacity but taking an alternate route, and/or (4) temporary interruptions of supplies to some noncore customers. Given that the price to the consumer is a combination of the wellhead price, the transportation charge, and the storage fee, the availability of supply and its relative regional price are included in this determination. The location and amount of pipeline and/or storage capacity expansion determined by the CEM serve to satisfy the Nation's expected firm service requirements for the lowest price to the consumer.

For this model to operate properly, a number of parameters are derived. Some are derived from data passed from other NEMS models, such as supply curve coefficients and expected core and noncore consumption levels. Others are based on the results from other NGTDM modules, such as the price (or tariff) curves for interregional pipeline and storage capacity expansion provided by the Pipeline Tariff Module. Finally, some of the parameters for the CEM are based on exogenously determined relationships and are assigned directly within the module.

The following sections present the CEM in more detail. The methodologies used to represent supply, demand, pipeline capacity price curves, and storage capacity price curves used in the CEM are presented first. Then, a general description of the CEM linear program is presented, followed by a mathematical specification. Finally, the methodologies used to calculate the maximum pipeline utilizations and the net storage flows used by the Annual Flow Module are provided. The variables for which the CEM solves are: (1) the flows along each arc (including flows associated with storage), (2) the incremental pipeline capacity expansion required for each arc, and (3) the storage capacity expansion required for each region.

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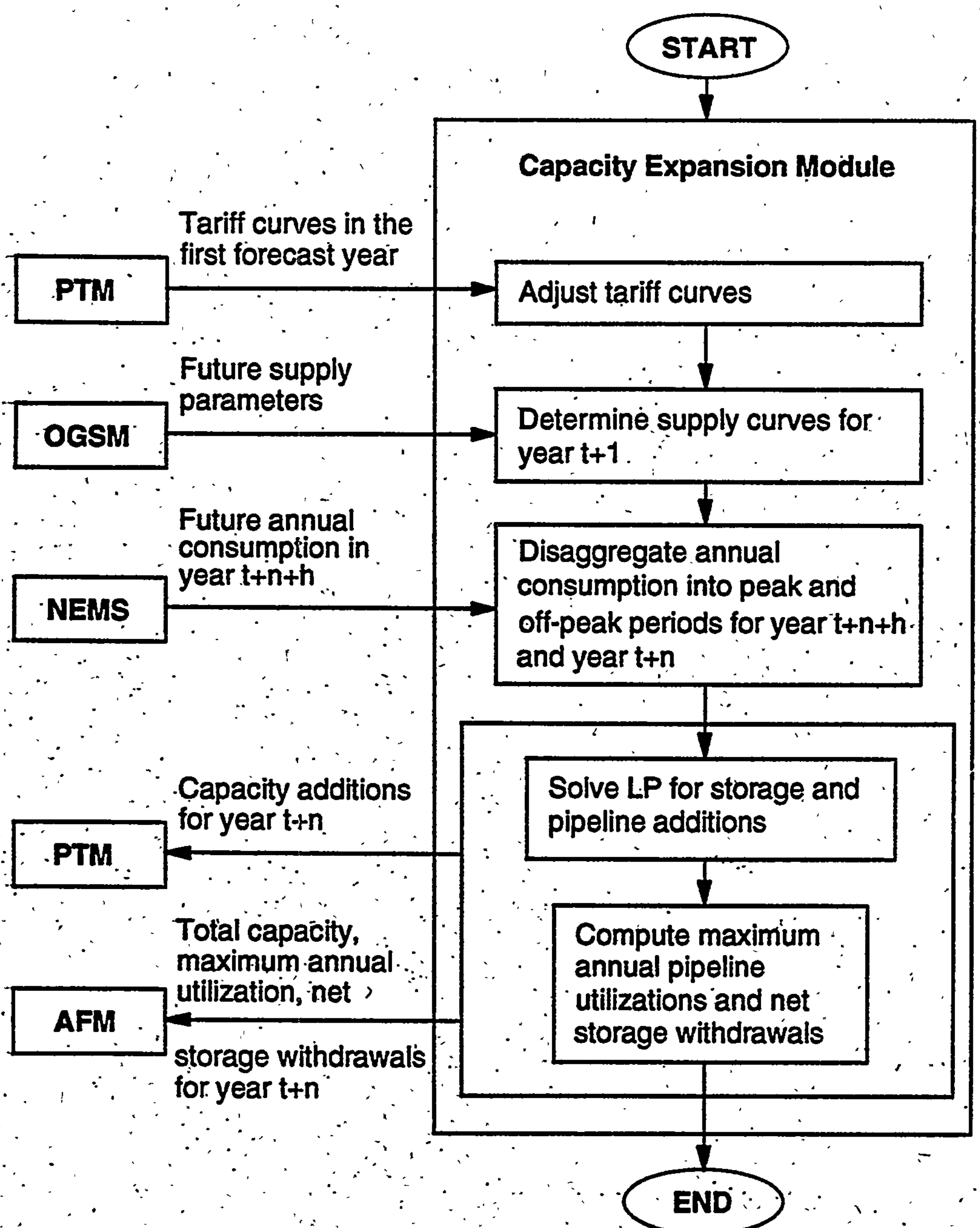
[47]The look-ahead year n is an input parameter that represents the minimum planning horizon for constructing new pipeline and storage capacity in the CEM.

[48]Design weather is defined as the pattern of temperatures which results in degree days which are a certain percent colder than normal. Firm service customers (primarily local distribution companies) use demand estimates under design weather conditions for assessing their future need for firm pipeline transportation service.

Figure 7-1. Capacity Expansion Module System Diagram



Supply Representation

As with the Annual Flow Module, natural gas supply sources have been classified into the following basic categories: onshore and offshore dry gas production, Canadian and Mexican imports, liquefied natural gas imports, Alaskan gas transported via the Alaskan Natural Gas Transportation System, synthetic natural gas, and other supplemental supplies. Of these categories, all except onshore, offshore, and synthetic natural gas production are considered to be constant (or fixed) supplies within the CEM each year. The approach used to represent variable[49] supply sources is similar to that used in the Annual Flow Module. When a supply source is designated as fixed, the annual production is split into peak and off-peak levels based on assumed shares (SUP_PKSHR, Appendix F, Table F30). When a supply source is designated as variable, the portion of the annual production which can be used in either period is capped at assumed percentages of the annual production (SUP_PUTILZ and SUP_OUTILZ, Appendix F, Table F30).

Dry Gas Production

Both onshore and offshore dry gas production levels are a function of regional beginning-of-year natural gas reserve levels and expected production-to-reserves ratios, with functional forms identical to those used in the Annual Flow Module. The parameters defining these supply curves (provided by the Oil and Gas Supply Model) correspond to production levels for the year following the Annual Flow Module forecast year (current model year plus 1) and, therefore, serve as an approximation for supplies available to the CEM in the CEM forecast year (defined as current model year plus n). As in the Annual Flow Module, maximum and minimum supply levels are represented for each region. The minimum supply is defined as a specified percentage (PARM_MINPR, Appendix F, Table F11) below the product of the reserves and the production-to-reserves ratio. Likewise, the maximum supply is determined to be a specified percentage (PARM_MAXPR, Appendix F, Table F11) above the product of the reserves and the production-to-reserves ratio.

Natural Gas Pipeline Imports

Imports from Mexico and Canada for each CEM forecast year are represented in the CEM for each border crossing node. Mexican imports are represented as constant supply available to the firm network only. These imports are provided directly by the Oil and Gas Supply Model as annual supplies. The CEM then uses exogenously defined values (Appendix F, Table F30) to split these annual numbers into seasonal supply levels (peak and off-peak splits). Canadian imports are determined from Canadian pipeline capacities and utilizations. Canadian pipeline capacities are provided by the Oil and Gas Supply Model, while utilizations are defined by the NGTDM. Utilizations correspond to firm and interruptible networks and are composed of two categories: seasonal and annual. Seasonal utilizations (Appendix F, Table F34) are exogenously defined for the NGTDM and kept constant throughout the model. Annual utilizations, however, are calculated by the CEM in the previous forecast year and are based on imports resulting in that year. The Canadian produced natural gas which passes through the United States on its way to Canadian markets (as described in Chapter 3) is split into peak and off-peak levels based on assumed shares (CANFLO_PFSHR, Appendix F, Table F30). Both Mexican and Canadian imports are represented as fixed supplies each year in the CEM.

Liquefied Natural Gas Imports and the Alaskan Natural Gas Transportation System

The levels of liquefied natural gas imports into the four designated entry points, and the level of gas entering the United States via the Alaskan Natural Gas Transportation System, are provided to the CEM, as well as the Annual Flow Module, by the Oil and Gas Supply Model. For both of these sources, the level of supply assumed in the CEM

[49]The production levels for variable supply sources are endogenously determined within the CEM as a function of the natural gas price.

for a future forecast year, is the level of supply the Annual Flow Module will actually see in that forecast year, (i.e., the CEM operates under perfect foresight with regard to these two supply categories).

For the *Annual Energy Outlook 1995*, the liquefied natural gas imports are provided by the Oil and Gas Supply Model. To accomplish this, the solution price from the Annual Flow Module at the nearest associated market node is provided to the Oil and Gas Supply Model at the end of each forecast year. This price is used as a basis for deciding whether or not the capacity at the associated gasification plant will be expanded. The Oil and Gas Supply Model assumes that any added capacity will not be available for use until at least "n" years (as defined in the CEM) after the decision is made to expand. The decision to build is not reversed, even if the price in intervening years falls below the originally required threshold price. The utilization rates for the gasification plant capacities are set exogenously. Because of the lead time for these builds, the Oil and Gas Supply Model is able to provide the CEM with the import levels for liquefied natural gas for "n" years beyond the current forecast year.

Within the Oil and Gas Supply Model, the initial build (for those segments not already in existence) and the potential expansion decisions for the Alaskan Natural Gas Transportation System is structurally identical to the method used for endogenously forecasting the expansion of liquefied natural gas gasification facilities. Therefore, the representation of the Alaska Natural Gas Transportation System in the CEM likewise is similar to the approach taken for representing liquefied natural gas imports in the CEM. Natural gas supplied by Alaska Natural Gas Transportation System is provided by the Oil and Gas Supply Model based on the border price at the U.S./Canadian border adjoining the Pacific Census Division. The Oil and Gas Supply Model assumes that the final pipeline connection (and any subsequent expansions) of the Alaska Natural Gas Transportation System will be completed at least "n" years after the referenced border price is high enough to recover costs for the completion of the project.

Associated-Dissolved Gas, Synthetic Natural Gas, and Other Supply Sources

Three supply categories remain: associated-dissolved gas from oil, synthetic natural gas from coal, and other supplemental supplies. Associated-dissolved gas production is represented as a constant supply in both the Annual Flow Module and the CEM, and is determined from the average daily crude oil production levels (provided by the Petroleum Market Model) and the gas-to-oil price ratios (obtained from previous year results). The level of associated-dissolved production set within the Annual Flow Module is used in the CEM. Similarly, synthetic production of natural gas from coal for each model year is provided by the Coal Market Model and is represented as a constant supply within the Annual Flow Module[50] and, therefore, also within the CEM. Since both of these supply categories correspond to current year levels, they serve as an approximation for synthetic natural gas from coal and associated-dissolved gas available to the CEM in the CEM forecast year (defined as Annual Flow Module forecast year plus n). Synthetic natural gas produced from liquid hydrocarbons is treated as a variable supply type within the CEM. The quantity of synthetic natural gas produced is calculated as a function of the market price for natural gas, with the same functional form and constraints used in the Annual Flow Module. Finally, since other supplemental supplies are assumed to remain constant throughout the forecast in the Annual Flow Module, they also are assumed constant in the CEM (Appendix F, Table F12).

Demand Representation

Demands within the CEM include end-use consumption, export demands, and pipeline fuel consumption. As with the Annual Flow Module, end-use and export demands for forecast years beyond the current model year are defined by other models within NEMS, while pipeline fuel is accounted for through exogenously defined pipeline efficiencies (Appendix F, Table F19). End-use consumption levels are provided on an annual basis by region (Census or NGTDM/EMM) and type of service (firm or interruptible[51]), and are considered to be fixed demands in the CEM.

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[50]Each forecast year, the Coal Market Module of NEMS estimates the amount of natural gas which will be produced from coal. The current system does not provide a mechanism for estimating these levels beyond the current forecast year. Such an enhancement will be considered in the future.

[51]For the electric utility sector, the interruptible service class is further subdivided into "competitive with distillate" and "competitive with residual fuel oil," as described in Chapter 3.

Similarly, export demand forecasts are provided on an annual basis for each border crossing node and are defined to be fixed; however, Canadian exports are assumed to service noncore customers only while Mexican exports service only core customers.

Since the CEM is a seasonal model, each of the annual levels must be separated into peak and off-peak consumption. The CEM contains exogenously specified percentages for disaggregating these annual consumption levels into peak and off-peak periods. These shares (Appendix F, Tables F3 and F4 for consumption, Table F30 for exports) have been estimated using historical monthly consumption data reported by sector and region, combined with annual estimates of demands for firm and interruptible service. Historically observed heating degree days have been included in the residential and commercial sector estimates so that the resulting shares reflect normal weather patterns (average monthly heating degree days). A future model enhancement may be to establish these peak/off-peak shares endogenously. For example, seasonal shifts in the demand for electricity (as represented within the Electricity Market Model) could be used as a basis for endogenously determining shifts in seasonal demands for natural gas by the electric generators sector. Likewise, seasonal shares for the other sectors could be specified at a more disaggregate level, such as by type of end-use (e.g., space heating).

The forecast years and regions representing end-use sector consumption in the CEM differ from one sector to another. For the industrial, transportation, and electric generators sectors, forecast consumption levels correspond to "n" years beyond the current model year, while residential and commercial consumption levels correspond to "n+h" years beyond the current model year. The "n" represents the number of years required to construct a pipeline and the "h" corresponds to the planning horizon used by a local distribution company when assessing capacity requirements.[52] As for regional representation, electric generators consumption forecasts are defined by NGTDM/EMM regions (Chapter 3), while consumption forecasts for the other end-use sectors are specified by Census Divisions. As in the Annual Flow Module, estimates of Alaskan natural gas consumption are generated in the CEM in order to derive separate consumption levels for the Pacific Contiguous Division. Similarly, consumption levels within three of the Census Divisions are further subdivided to form separate NGTDM regions using the same fixed historically derived shares as are used in the Annual Flow Module. These splits include: Florida split from the rest of the South Atlantic Division, California split from the rest of the Pacific Contiguous Division, and Arizona and New Mexico split from the rest of the Mountain Division.

Consumption forecasts are provided by a number of different sources. The Electricity Market Model provides consumption forecasts for the electricity generating sector, and the NEMS system provides consumption forecasts for the other non-core end-use sectors and the core industrial sector. The consumption forecasts for the core residential, commercial, and transportation customer classes, however, are estimated within the NGTDM and are based on a maximum growth rate applied to the current year consumption levels (up to a maximum level). More specifically, the forecasted consumption level equals the current year consumption level times a growth rate. If this value exceeds a maximum level defined by the NEMS system, then the forecast level is set equal to the maximum level. If, however, the current year level exceeds the maximum level, then zero growth[53] is assumed and the forecast level is set equal to the current year level.

Pipeline Capacity Price Curve

Initial pipeline capacity price curves are developed by the Pipeline Tariff Module at the beginning of the forecast. These curves are based on estimates of capital costs of expansion and parameters (such as interest rates) from the NEMS macroeconomic model. (See Chapter 8 for a complete description of how these tariffs are calculated.) Each cost curve represents the per unit reservation charge on a particular interregional arc based on the annual physical capacity (design day capacity[54] times 365). The base quantity (initial step) represents the existing pipeline capacity for the base year (Appendix E, Table E6). The corresponding price is the base year reservation charge (i.e., the demand charge) expressed on a per unit basis. Subsequent steps represent incremental expansion and the

[52]These variables were defined as follows in the *Annual Energy Outlook 1995*: n=2, h=0.

[53]It is assumed that consumption levels will not decline.

[54]A pipeline's design day capacity (or certificated capacity) represents a level of service that can be maintained over an extended period of time and may not represent the maximum throughput capability of the system on any given day.

corresponding incremental tariff. It is assumed that the price curve is nondecreasing. To keep the curve increasing when additional capacity is expected to result in declining prices (such as when incremental capacity expansion is the result of added compression), the step on the curve associated with this additional capacity is held at the price associated with the previous step, i.e., the step representing the level of capacity without the addition. A generic pipeline capacity price curve is presented in Figure 7-2. The QCAP represents the capacity along an arc, and the PCAP represents the corresponding unit cost. The UCAP is the maximum capacity that can be used on each step (the length of the step), and the ycap represents how much capacity was needed for a given solution.

In forecast year t, the CEM determines the capacity expansion for year t+n (the CEM forecast year). Therefore, each year the CEM must adjust the price curves based on capacity expansion which was determined in the previous CEM forecast year, and set to come on-line in year t+n-1. Specifically, the quantity associated with the base step on the curve will be adjusted to equal the capacity which will exist on the arc at the end of year t+n-1. Note that adjustments to the curve have already been made in previous CEM forecasts to reflect expansion in any of the intervening years to year t+n-1. The associated base level tariff is determined as a quantity weighted average of the tariffs corresponding to the current year (t) capacity and the capacity additions made during years t+1, t+2,...t+n-1. The original tariff levels defined for the remaining steps (i.e., the capacity addition steps) are then adjusted upward by a specific price delta to ensure that existing pipeline capacity is sufficiently utilized (on a national level) before a decision to add new capacity is made.

Storage Capacity Price Curve

Initial working gas storage capacity price curves are determined by the Pipeline Tariff Module at the beginning of the forecast. These curves are based on estimates of capital costs of expansion, costs of holding base gas in storage, and parameters (such as interest rates) from the NEMS macroeconomic model. (See Chapter 8 for a complete description of how these tariffs are calculated.) Each cost curve represents the storage charge per unit (PSTR) as a function of the annual working gas capacity for a particular region. This storage charge is exclusive of any transportation costs to move gas to or from storage areas. The base quantity (initial step) represents the existing working gas storage capacity (Appendix F, Table F33). The corresponding price is the initial storage charge per unit. Subsequent steps represent incremental expansion and the corresponding incremental charge. The final step on the curve represents an upper limit on working gas storage capacity expansion due to known physical limits in a region (Appendix F, Table F26) or other nonprice dependent factors. A generic working gas storage capacity price curve is presented in Figure 7-3. The QSTR represents the storage capacity at a node, and the PSTR represents the corresponding unit storage cost. The USTR is the maximum storage capacity that can be used on each step (the length of the step), and the ystr represents how much storage was needed for a given solution.

Each year the CEM must adjust these working gas storage price curves based on the current capacity levels, similar to the adjustment made to the pipeline capacity price curves. Specifically, the quantity associated with the base step on the curve is adjusted to equal the working gas storage capacity which exists in the region at the end of year t+n-1, where t is the current model year and n is the number of years beyond the current model year for which the CEM is determining expansion. Since in model year t the capacity expansion for year t+n is being determined, the base step includes working gas capacity for current year t as well as the capacity expansions defined in years t+1,t+2,...,t+n-1. The associated base level tariff is determined as a quantity-weighted average of the tariff associated with the existing capacity and the tariffs for each of the previously determined expansions for years t+1, t+2,..., t+n-1, as well as the original base storage capacity in model year t. As with the pipeline capacity price curves, the original tariff levels defined for the remaining steps are then adjusted upward by a specific price delta. This measure ensures that existing storage capacity is sufficiently utilized (on a national level) before new storage capacity gets added.

Linear Program Formulation

A linear programming (LP) framework is used in the CEM as the basis for determining expansion requirements for pipeline and storage facilities. As described in Chapter 4, the CEM structure is based on a natural gas transmission and distribution system composed of four parallel networks interconnected at the supply points and the storage points.

Figure 7-2. Pipeline Capacity Price Curve

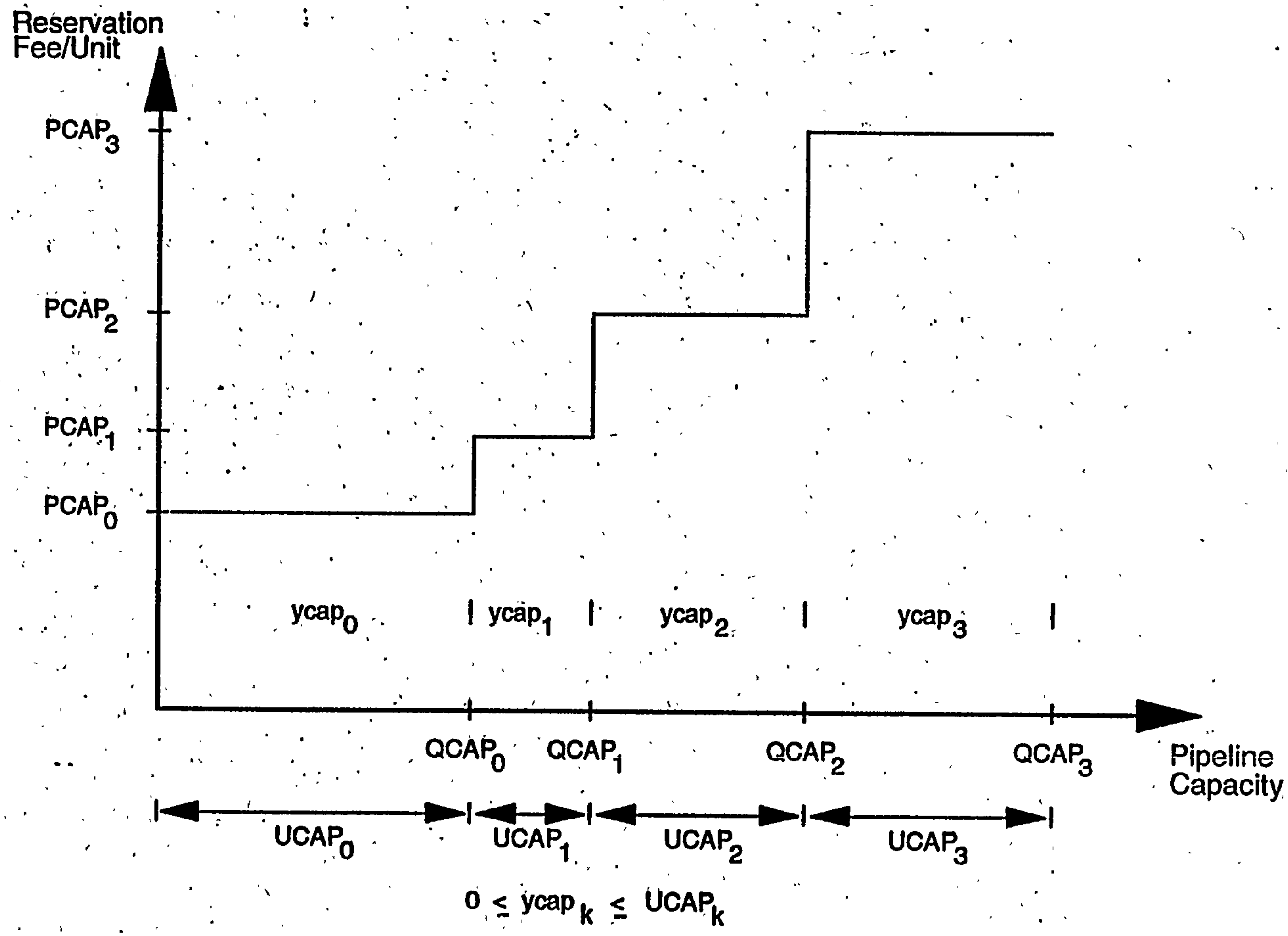
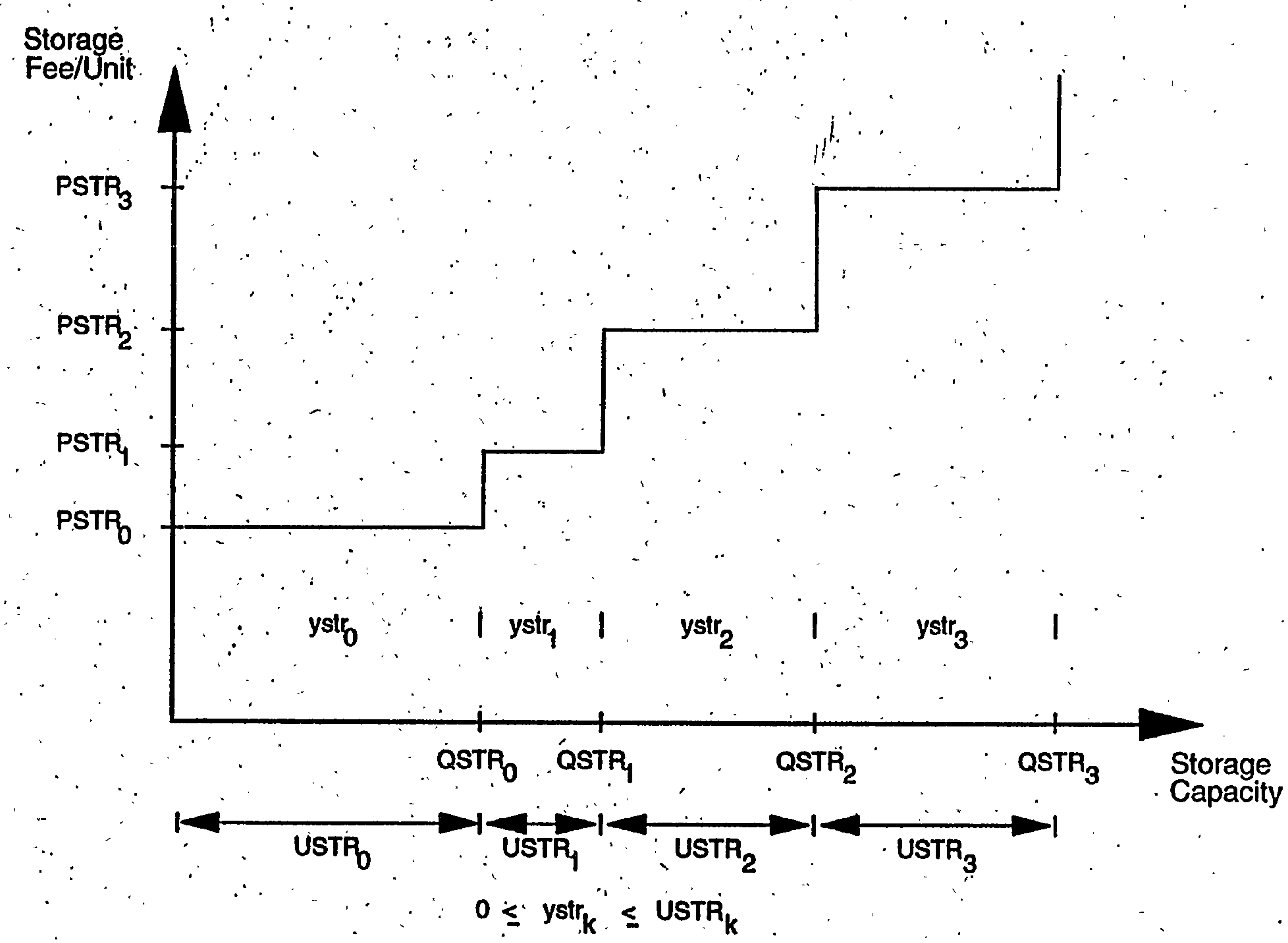


Figure 7-3. Storage Capacity Price Curve



These networks serve to represent the seasonal nature (peak and off-peak) and types of service (firm and interruptible) associated with the natural gas market. Thus, peak firm, peak interruptible, off-peak firm, and off-peak interruptible service are modeled by the four networks. The CEM LP is solved in two phases: The first phase establishes pipeline and storage capacity expansion requirements, and the second establishes final firm, interruptible, peak and off-peak flows. This section describes the CEM LP formulation, the process used to determine the pipeline and storage capacity expansion requirements, and the methodology used to define annual pipeline utilizations and net storage results.

General Description of the Linear Program Formulation

The objective of the linear program designed for the CEM is to minimize the cost of supplying and transporting natural gas to the end-user, subject to operational and supply constraints, with the requirement to satisfy all demand for firm service under design weather conditions. This section gives a general description and justification of the linear programming formulation (objective function and constraints), and a subsequent section includes the explicit mathematical equations representing the formulation.

The objective function has been formulated to minimize costs. These costs include the costs of supplies, transportation along the established network, and costs of additional pipeline and storage capacity. The objective function can be represented as follows:

minimize {transportation costs + supply costs + pipeline expansion costs + storage expansion costs + backstop supply costs}

A mass balance constraint is included for each transshipment node. This constraint ensures that the total input to the node equals the total output from the node. In general, gas flowing into a transshipment node comes from other transshipment nodes, supply points, and (in some cases) storage, while gas flowing from a transshipment node goes to demand points, other transshipment nodes, and (in some cases) storage. Flows into and out of storage have been defined to be network dependent because gas generally is injected into storage in the off-peak period and used to satisfy core customer demand during the peak period. (Peak noncore customers also may draw from storage if it is not needed for core customers.) Therefore, in the linear program formulation, gas flows into a regional storage point from transshipment nodes (in the same region) on the off-peak firm and interruptible service networks, and flows out of the same storage point to transshipment nodes (again in the same region) on the peak firm and interruptible service networks. A general transshipment node mass balance constraint is listed below for each of the four parallel networks.

For each peak period firm service network transshipment node:

> (flow into the transshipment node from other peak period firm service network transshipment nodes) + (flow into the transshipment node from supply points in the region) + (flow into the transshipment node from storage in the region) - (losses) = (flow out of the transshipment node to peak period core demand points in the region) + (flow out of the transshipment node to other peak period firm service network transshipment nodes)

For each peak period interruptible service network transshipment node:

> (flow into the transshipment node from other peak period interruptible service network transshipment nodes) + (flow into the transshipment node from supply points in the region) + (flow into the transshipment node from storage in the region) - (losses) = (flow out of the transshipment node to peak period noncore demand points in the region) + (flow out of the transshipment node to other peak period interruptible service network transshipment nodes)

For each off-peak period firm service network transshipment node:

> (flow into the transshipment node from other off-peak period firm service network transshipment nodes) + (flow into the transshipment node from supply points in the region) - (losses) = (flow out of the transshipment node to storage in the region) + (flow out of the transshipment node to off-peak period core demand points in the region) + (flow out of the transshipment node to other off-peak period firm service network transshipment nodes)

For each off-peak period interruptible service network transshipment node:

> (flow into the transshipment node from other off-peak period interruptible service network transshipment nodes) + (flow into the transshipment node from supply points in the region) - (losses) = (flow out of the transshipment node to storage in the region) + (flow out of the transshipment node to off-peak period noncore demand points in the region) + (flow out of the transshipment node to other off-peak period interruptible service network transshipment nodes)

A mass balance constraint also is included for each storage point. This constraint ensures that the total gas input into storage equals the total gas output from storage, net of losses (Appendix F, Table F22). As mentioned above, gas flows to storage from the off-peak period firm and interruptible service networks, and gas flows out of storage to the peak period firm and interruptible service networks. The flow comes from and goes to the transshipment node corresponding to the same region as the storage point. A mass balance constraint for storage is presented below.

For each storage point:

> (flow of gas into a storage point from the off-peak period firm service network transshipment node) + (flow of gas into a storage point from the off-peak period interruptible service network transshipment node) - (losses) = (flow of gas out of the storage point to the peak period firm service network transshipment node) + (flow of gas out of the storage point to the peak period interruptible service network transshipment node)

Each demand point also has a mass balance constraint represented. This constraint ensures that the quantity allocated to the end-use point equals the expected consumption level associated with that point. All expected core market demand (peak and off-peak) must be satisfied; however, pipeline and storage facilities can only be built to meet peak core demands. It is assumed that the resulting capacity levels will be sufficient to accommodate flows to satisfy core off-peak period requirements. Since new facilities are not built for the satisfaction of noncore demand, a backstop supply is a modeling structure introduced to represent the portion of the noncore demand for natural gas which cannot be satisfied by conventional supply sources and must be interrupted. A general transshipment node mass balance constraint is listed below for each of the four parallel networks.

For each peak period core demand point:

> (flow from a peak period firm service network transshipment node in a region to a peak period core demand point in the region) - (losses) = (quantity consumed at that peak period core demand point).

For each peak period noncore demand point:

> (flow from a peak period interruptible service network transshipment node in a region to a peak period noncore demand point in the region) + (backstop supply) - (losses) = (quantity consumed at that peak period noncore demand point)

For each off-peak period core demand point:

> (flow from an off-peak period firm service network transshipment node in a region to an off-peak period core demand point in the region) - (losses) = (quantity consumed at that off-peak period core demand point)

For each off-peak period noncore demand point:

> (flow from an off-peak period interruptible service network transshipment node in a region to an off-peak period noncore demand point in the region) + (backstop supply) - (losses) = (quantity consumed at that off-peak period noncore demand point)

Supply utilization constraints are included for each supply point, and are represented as peak supply constraints and off-peak supply constraints. Since gas may flow from a supply point to a transshipment node (in the same region) in any of the four parallel networks, these supply constraints ensure that the flows (including losses) do not exceed the total amount supplied at that point. The constraints also ensure that the quantity flowing from the supply point has been properly split between the peak and off-peak period during any one year. The peak supply constraint states that, for any supply type and any supply level, a specified portion (Appendix F, Table F30) of the annual supply flow must be used to supply peak demands. Similarly, the off-peak supply constraint states that a specified portion of the annual supply flow must be used to supply off-peak demands. The latter constraint is defined slightly differently for onshore and offshore dry gas production: the supply quantity supplied to the off-peak networks must be less than or equal to a specified portion of the total annual dry gas production level. The constraints are as follows.

For each supply point:

> (flow from the supply point to a peak period firm service network transshipment node) + (flow from the supply point to a peak period interruptible service network transshipment node) = (peak share of total supply) * (total annual quantity supplied from the supply curve)

For each onshore and offshore supply point:

> (flow from the supply point to an off-peak period firm service network transshipment node) + (flow from the supply point to an off-peak period interruptible service network transshipment node) ≤ (off-peak share of total supply) * (total annual quantity supplied from the supply curve)

For each supply point excluding onshore and offshore supplies:

> (flow from the supply point to an off-peak period firm service network transshipment node) + (flow from the supply point to an off-peak period interruptible service network transshipment node) = (off-peak share of total supply) * (total annual quantity supplied from the supply curve)

A constraint (referred to as the alpha constraint) was originally designed to prevent backstop prices from translating back through the network from the demand points when backstop supply was required. It has since been determined to be unnecessary and will be removed from the model in a subsequent version. The alpha constraint states that the total interruptible flows from a node to the end-use demand points must be less than or equal to total noncore end-use demands. The right hand side is represented as: alpha times total noncore end-use demands. Note that the alpha constraint in the current model has been deactivated by permanently setting the alpha factor to 1.0. The general form of the alpha constraint is presented below.

> (flow out of the transshipment node to peak period noncore demand points in all lower 48 regions) + (flow out of the transshipment node to off-peak period noncore demand points in all lower 48 regions) - losses ≤ (alpha factor) * ((total quantity consumed at the peak period noncore lower 48 demand point) + (total quantity consumed at the off-peak period noncore lower 48 demand point))

Capacity expansion and flow constraints are defined for each interregional arc in the overall network. These constraints ensure that pipeline capacity is built, as necessary, to satisfy only core peak period demand, and that the total flows along the interregional arcs are less than or equal to the available capacities (base[55] plus added capacity). Within these constraints, seasonal maximum arc utilization rates are used to capture the variation in load patterns

[55]Recall from previous sections that capacity expansion levels are being determined for year t+n; therefore, the base capacity refers to the capacity existing at the end of the year t+n-1.

and operational limitations throughout the season. Constraints have been established for firm service peak period flows, total peak period flows, and total off-peak period flows for each interregional arc in the network. In general, maximum seasonal pipeline utilizations are set equal to the fraction of the year represented by the season times an assumed maximum utilization rate for the type of service represented (Appendix F, Table F34) times a factor representing the percentage of the pipe reserved to account for the potential of abnormal weather (Appendix F, Table F40).

It is the firm service peak period capacity constraint that ensures that no pipeline capacity is built beyond what is needed to satisfy peak period core market requirements. It states that total peak firm flow along an arc must **equal** total capacity (base plus added capacity) times a maximum peak firm arc utilization rate. It is the equality requirement that does not allow new capacity to be built unless peak core demands require additional quantities to flow along the specific arc(s). The peak total (firm and interruptible) period capacity constraint has been established as an **inequality** constraint to ensure that the flows to satisfy noncore peak period requirements are **less than or equal to** the remaining peak season effective capacity (i.e., total capacity times the maximum peak season utilization rate) once the core market requirements have been met. In addition, an off-peak period capacity constraint (also as an inequality constraint) has been developed to ensure that the total off-peak season flows on the arc are less than or equal to the off-peak season effective capacity (i.e., total capacity times the maximum off-peak season utilization rate). The resulting constraints are given below for each interregional arc.

For each peak firm service interregional arc:

(flow along the arc to satisfy core market peak period requirements) = (level of base capacity used + level of pipeline capacity expansion) * (peak period interregional arc maximum utilization rate for firm service)

For each peak firm and interruptible service interregional arc:

(flow along the arc to satisfy noncore peak period requirements) + (flow along the arc to satisfy core market peak period requirements) ≤ (base capacity + level of pipeline capacity expansion) * (peak period interregional arc maximum utilization rate)

For each off-peak firm and interruptible service interregional arc:

(flow along the arc to satisfy noncore off-peak period requirements) + (flow along the arc to satisfy core market off-peak period requirements) ≤ (base capacity + level of pipeline capacity expansion) * (off-peak period interregional arc maximum utilization rate)

Storage expansion and flow constraints are defined for each node in the lower 48-State portion of the network. These constraints ensure that storage capacity is built, as necessary, to satisfy peak period core market requirements and that the flows from storage are less than or equal to the total available storage capacity (base[56] plus added capacity). Constraints have been established for firm service peak period flows and total peak period flows from storage locations at each node. Storage utilization rates (Appendix F, Table F31) have been used to define the maximum storage levels used for peak firm service and total peak storage. The peak firm service constraint has been established as an equality constraint to ensure that no storage capacity is built beyond what is needed to satisfy peak period core market requirements. The total peak constraint has been established as an inequality constraint to ensure that the flows to satisfy noncore requirements are less than or equal to the effective storage capacity remaining after the core market requirements have been met. The resulting constraints are given below.

For each storage point:

(flow from the storage point to the peak period firm service network transshipment node) = ((level of base storage capacity used) + (storage capacity expansion)) * (peak period maximum storage utilization rate for firm service)

[56]Recall from previous sections that storage capacity expansion levels represent working gas capacities and are being determined for year t+n; therefore, the base storage refers to the working gas storage capacity existing at the end of the year t+n-1.

For each storage point:

> (flow from the storage point to the peak period interruptible service network transshipment node) + (flow from the storage point to satisfy core market requirements) ≤ ((base storage capacity) + (storage capacity expansion)) * (peak period maximum storage utilization rate for total peak service)

Similar to the AFM, minimum flows have been defined for the CEM firm service networks (in the form of lower bounds on the flow variables). These minimum flows are defined to be a fraction of the resulting firm flows in the Annual Flow Module in the current model year plus an estimated utilization of the new capacity added between the current model year (t) and the beginning of the CEM forecast year (t+n). As in the Annual Flow Module, this fraction is exogenously specified (Appendix F, Table F32) and is intended to represent the level of flexibility core customers exhibit in changing their selected routes for transporting natural gas from year-to-year, even if relative costs would indicate a change would be prudent (e.g., flexibility would be lessened due to the existence of long-term contracts). Finally, maximum utilization rates are used to split the minimum firm flow into peak and off-peak minimum firm flows, as described below.

For each interregional arc on the peak firm service network:

> peak firm flow ≥ (minimum flow fraction) * (estimated firm flow) * (peak period share of firm flow)

For each interregional arc on the off-peak firm service network:

> off-peak firm flow ≥ (minimum flow fraction) * (estimated firm flow) * (off-peak period share of firm flow)

Additional constraints are represented as lower and/or upper bounds on the flow variables. These include lower bounds set for flows along all arcs (and networks) with bidirectional flows,[57] as well as upper and lower bounds set on all flows into (off-peak firm and interruptible) and out of (peak firm and interruptible) storage. Finally, a number of bound constraints are needed to completely describe the step functions for the supply, capacity expansion, and storage expansion curves. These bounds serve to define the lengths of each of the steps on the curves.

Thus, the linear program solves for the level and location of storage and pipeline capacity expansion, as well as the associated peak and off-peak flows. Note that the amount of capacity expansion is a continuous function. Although, for a given pipeline company, capacity may be added only through discrete projects, the arcs in the CEM represent aggregates of pipeline companies. Taken together these companies can add capacity in virtually any desired quantity through combinations of additional compressor capacity, looping, or other means.

Mathematical Specification of the Linear Programming Formulation

This section presents the set of equations which establishes the linear programming formulation for the CEM. This set is comprised of an objective function, flow constraints, and bounds on model variables.

[57]Minimum flows for bidirectional arcs in the CEM are set by multiplying the corresponding minimum flows established in the Annual Flow Module by assumed peak shares (Appendix F, Table F38).

$$\begin{aligned}\underset{x,ysup,ycap,ystr,qzz}{\text{minimize}} \; & \sum_{i,j} TAR^{F}_{i,j} * (x^{PF}_{i,j} + x^{OF}_{i,j}) + \sum_{i,j} TAR^{I}_{i,j} * (x^{PI}_{i,j} + x^{OI}_{i,j}) + \sum_{s,i} TAR^{P}_{s,i} * (x^{PF}_{s,i} + x^{PI}_{s,i}) \\ & + \sum_{s,i} TAR^{O}_{s,i} * (x^{OF}_{s,i} + x^{OI}_{s,i}) + \sum_{i,d} TAR^{PF}_{i,d} * x^{PF}_{i,d} + \sum_{i,d} TAR^{PI}_{i,d} * x^{PI}_{i,d} + \sum_{i,d} TAR^{OF}_{i,d} * x^{OF}_{i,d} \\ & + \sum_{i,d} TAR^{OI}_{i,d} * x^{OI}_{i,d} + \sum_{s,i} \sum_{k=1}^{c} PSUP_{s,i,k} * ysup_{s,i,k} + \sum_{i,j} \sum_{k=0}^{c} PCAP_{i,j,k} * ycap_{i,j,k} \\ & + \sum_{st,i} \sum_{k=0}^{c} PSTR_{st,i,k} * ystr_{st,i,k} + \sum_{i,d} PZZ^{PI}_{i,d} * qzz^{PI}_{i,d} + \sum_{i,d} PZZ^{OI}_{i,d} * qzz^{OI}_{i,d}\end{aligned} \tag{49}$$

where,

the subscripted indices are:

i,j, and m	=	transshipment node
d	=	demand type
s	=	supply type
st	=	storage
k	=	step on the curve
c	=	number of steps on the curve
i,j	=	arc connecting transshipment nodes i and j
i,d	=	arc from transshipment node i to demand point d
s,i	=	arc from supply point s to transshipment node i
st,i	=	arc from transshipment node i to storage point st
i,st	=	arc from transshipment node i to storage point st

the superscripted indices are:

P	=	peak period
O	=	off-peak period
F	=	firm
I	=	interruptible

the parameters are:

TAR	=	tariff (pipeline usage from node to node, gathering charge from supply point to node, or distributor charge from node to end-use point), (dollars per Mcf)
EFF	=	efficiencies (fraction)
U	=	maximum allowable utilization of an arc in the season (fraction)
UP	=	maximum percentage of supply available for demand type (fraction)
UST	=	maximum percentage of storage available to demand type (fraction)
QDEM0	=	quantity demanded (Bcf)
ESTFLOW	=	flow from Annual Flow Module in year t, plus estimated utilization of capacity added after year t through year t+n (Bcf)
SHR	=	period share of total flow (fraction)
MINBIFLO	=	minimum flow for bidirectional arcs (Bcf)
MNSTR	=	minimum flow allowed into or out of storage for specified network (Bcf)
MXSTR	=	maximum flow allowed into or out of storage for specified network (Bcf)
ALPHA	=	factor used to bind the alpha constraint (fraction)
DMD	=	total demand for a demand type (Bcf)
PCTMFLO	=	percent minimum flow requirement (fraction)
PSUP	=	prices on the supply steps (dollars per Mcf)
PCAP	=	prices on the pipeline capacity steps (dollars per Mcf)

PSTR = prices on the storage capacity steps (dollars per Mcf)
PZZ = price of backstop supply (dollars per Mcf)
LSUP = lower bound on supply step (Bcf)
USUP = size of supply step (Bcf)
UCAP = size of pipeline capacity step (Bcf)
USTR = size of storage capacity step (Bcf)

the variables are:

$x_{i,j}$ = flow from i to j (Bcf)
$ysup_{s,i,k}$ = for supply point (s,i), the amount of supply step k taken (Bcf)
$ycap_{i,j,k}$ = for arc i,j, the amount of pipeline capacity step k built (Bcf)
$ycap_{i,j,0}$ = for arc i,j, the amount of base pipeline capacity taken (Bcf)
$ystr_{st,i,k}$ = for storage point (st,i), the amount of storage capacity step k built (Bcf)
$ystr_{st,i,0}$ = for storage point (st,i), the amount of base capacity taken (Bcf)
$qzz_{i,d}$ = amount of backstop supply used for demand point (i,d), (Bcf)

Mass Balance Constraints at Each Transshipment Node (m):

$$\sum_{\substack{i \\ i \neq m}} x^{PF}_{i,m} * EFF^{P}_{i,m} + \sum_{s} x^{PF}_{s,m} * EFF^{P}_{s,m} + \sum_{st} x^{PF}_{st,m} = \sum_{d} x^{PF}_{m,d} + \sum_{\substack{i \\ i \neq m}} x^{PF}_{m,i} \tag{50}$$

$$\sum_{\substack{i \\ i \neq m}} x^{PI}_{i,m} * EFF^{P}_{i,m} + \sum_{s} x^{PI}_{s,m} * EFF^{P}_{s,m} + \sum_{st} x^{PI}_{st,m} = \sum_{d} x^{PI}_{m,d} + \sum_{\substack{i \\ i \neq m}} x^{PI}_{m,i} \tag{51}$$

$$\sum_{\substack{i \\ i \neq m}} x^{OF}_{i,m} * EFF^{O}_{i,m} + \sum_{s} x^{OF}_{s,m} * EFF^{O}_{s,m} = \sum_{st} x^{OF}_{m,st} + \sum_{d} x^{OF}_{m,d} + \sum_{\substack{i \\ i \neq m}} x^{OF}_{m,i} \tag{52}$$

$$\sum_{\substack{i \\ i \neq m}} x^{OI}_{i,m} * EFF^{O}_{i,m} + \sum_{s} x^{OI}_{s,m} * EFF^{O}_{s,m} = \sum_{st} x^{OI}_{m,st} + \sum_{d} x^{OI}_{m,d} + \sum_{\substack{i \\ i \neq m}} x^{OI}_{m,i} \tag{53}$$

Mass Balance Constraints at Each Storage Point (st,i):

$$(x^{OF}_{i,st} + x^{OI}_{i,st}) * EFF^{O}_{i,st} = x^{PF}_{st,i} + x^{PI}_{st,i} \tag{54}$$

Mass Balance Constraints for Demand Points (i,d):

$$x^{PF}_{i,d} * EFF^{P}_{i,d} = QDEM0^{PF}_{i,d} \tag{55}$$

$$x^{PI}_{i,d} * EFF^{P}_{i,d} + qzz^{PI}_{i,d} = QDEM0^{PI}_{i,d} \tag{56}$$

$$x^{OF}_{i,d} * EFF^{O}_{i,d} = QDEM0^{OF}_{i,d} \tag{57}$$

$$x^{OI}_{i,d} * EFF^{O}_{i,d} + qzz^{OI}_{i,d} = QDEM0^{OI}_{i,d} \tag{58}$$

Supply Utilization Constraints at Each Supply Point (s,i):

$$x^{PF}_{s,i} + x^{PI}_{s,i} = \sum_{k=1}^{c} ysup_{s,i,k} * UP^{P}_{s,i} \tag{59}$$

For onshore and offshore supply types only,

$$x_{s,i}^{OF} + x_{s,i}^{OI} \leq \sum_{k=1}^{c} ysup_{s,i,k} * UP_{s,i}^{O} \tag{60}$$

For all supply types other than onshore and offshore,

$$x_{s,i}^{OF} + x_{s,i}^{OI} = \sum_{k=1}^{c} ysup_{s,i,k} * UP_{s,i}^{O} \tag{61}$$

Alpha Constraint:[58]

$$\sum_{i,d} (x_{i,d}^{PI} + x_{i,d}^{OI}) \leq ALPHA * \sum_{i,d}(\frac{DMD_{i,d}^{PI}}{EFF_{i,d}^{P}} + \frac{DMD_{i,d}^{OI}}{EFF_{i,d}^{O}}) \tag{62}$$

Pipeline Capacity Constraints for Each Arc (i,j):

$$x_{i,j}^{PF} = U_{i,j}^{PF} * (ycap_{i,j,0} + \sum_{k=1}^{c} ycap_{i,j,k}) \tag{63}$$

$$x_{i,j}^{PI} + x_{i,j}^{PF} \leq U_{i,j}^{P} * (ycap_{i,j,0} + \sum_{k=1}^{c} ycap_{i,j,k}) \tag{64}$$

$$x_{i,j}^{OF} + x_{i,j}^{OI} \leq U_{i,j}^{O} * (ycap_{i,j,0} + \sum_{k=1}^{c} ycap_{i,j,k}) \tag{65}$$

Storage Capacity Constraint for Each Region (st,i):

$$x_{st,i}^{PF} = UST_{st,i}^{PF} * (ystr_{st,i,0} + \sum_{k=1}^{c} ystr_{st,i,k}) \tag{66}$$

$$x_{st,i}^{PI} + x_{st,i}^{PF} \leq UST_{st,i}^{P} * (ystr_{st,i,0} + \sum_{k=1}^{c} ystr_{st,i,k}) \tag{67}$$

Minimum Bounds on Peak and Off-peak Firm Flows for each Arc (i,j):

$$x_{i,j}^{PF} \geq PCTMFLO_{i,j}^{F} * ESTFLOW_{i,j}^{F} * SHR_{i,j}^{PF} \tag{68}$$

$$x_{i,j}^{OF} \geq PCTMFLO_{i,j}^{F} * ESTFLOW_{i,j}^{F} * SHR_{i,j}^{OF} \tag{69}$$

Other bound constraints set minimum flows along bidirectional arcs, as well as minimum and maximum flows into and out of storage:

$x_{i,j}^{xx} \geq MINBIFLO$	for each bidirectional flow arc (i,j), and each network (xx = PF, PI, OF, OI)
$MNSTR_{st,i}^{xx} \leq x_{st,i}^{xx} \leq MXSTR_{st,i}^{xx}$	for each flow (xx = PF, PI, OF, OI) into and out of storage (st,i)

[58]The ALPHA factor was set to 1.0 in the *Annual Energy Outlook 1995.*

The following bound constraints also are defined for the steps on the supply, capacity expansion, and storage expansion curves:

$LSUP_{s,i,k}$	$\leq ysup_{s,i,k}$	$\leq USUP_{s,i,k}$	for each supply point (s,i), and k=1,2,...,n.
0	$\leq ycap_{i,j,k}$	$\leq UCAP_{i,j,k}$	for each arc i,j, and k=0,1,2,...,n.
0	$\leq ystr_{st,i,k}$	$\leq USTR_{st,i,k}$	for each storage point (st,i), and k=0,1,2,...,n.

For the most part LSUP is zero, except on the first step of the supply curve where a minimum supply level may be defined.

Thus, the above equations and bounds mathematically specify the linear program objective function and the key model constraints. A commercial software package[59] designed to solve linear programming problems is utilized to modify and solve the linear program matrix, and to access the resulting solution.

Implementation of the Linear Program Within the CEM

The CEM linear program solves for the level and location of pipeline and storage capacity expansion, as well as the corresponding peak and off-peak flows associated with firm and interruptible service. To provide this information, the linear program matrix is solved in two phases—the first establishes the pipeline and storage expansion levels, and the second establishes the final flows.

In the first phase of the CEM, the linear program is defined according to the equations above, and solved. From this solution, pipeline and storage capacity expansions and peak firm flows are established. However, base capacity on some pipeline arcs may not be fully utilized because of insufficient peak core demand requirements. Likewise, some base storage capacity may not be fully utilized due to peak core demand requirements. This underutilization, in turn, restricts the amount of off-peak and interruptible flows that can occur along the underutilized arcs, and into/out of underutilized storage facilities. This occurrence is dictated by the pipeline and storage capacity constraints. The second phase serves to remove this connection between peak firm flows and other flows, while still maintaining the peak firm flow levels resulting in the first phase.

In the second phase, the peak period capacity constraints (equations 66 and 69) must be represented such that interruptible volumes can flow along the unused capacity. To accomplish this, pipeline and storage capacities ($ycap_{i,j}$ and $ystr_{st,i}$) are held constant and set equal to the solution levels (YCAP and YSTR) from the first CEM phase (base utilization plus added capacity). This is represented with the changes in the equation from 'ycap' to 'YCAP' and from 'ystr' to 'YSTR.' Also, a constant term is added to the constraint that identifies the unused base capacity which may be used for interruptible flows only. The corresponding equations are presented below.

Pipeline Capacity Constraint for Peak Period Flows on Arc (i,j):

$$x_{i,j}^{PI} + x_{i,j}^{PF} \leq U_{i,j}^{P} * (YCAP0_{i,j} + \sum_{k=1}^{c} YCAP_{i,j,k}) + U_{i,j}^{P} * (QCAP0_{i,j} - YCAP0_{i,j}) \quad (70)$$

Storage Capacity Constraint for Peak Period Flows in Each Region (st,i):

$$x_{st,i}^{PI} + x_{st,i}^{PF} \leq UST_{st,i}^{P} * (YSTR0_{st,i} + \sum_{k=1}^{c} YSTR_{st,i,k}) + UST_{i,j}^{P} * (QSTR0_{st,i} - YSTR0_{st,i}) \quad (71)$$

[59] All of the linear programming problems within the NEMS will be solved using the Optimization and Modeling Library (OML), a product of Ketron Management Science, a Division of Bionetics Corporation.

where,

$x_{i,j}$	=	flow from i to j (Bcf)
U	=	maximum allowable utilization of an arc in the season (fraction)
QCAP0	=	base pipeline capacity (capacity level existing at the end of year t+n-1) (Bcf)
YCAP	=	actual pipeline capacity added (Bcf)
YCAP0	=	base pipeline capacity utilized (Bcf)
$x_{st,i}$	=	flow from storage (st) to node (i) (Bcf)
UST	=	maximum percentage of storage available (fraction)
QSTR0	=	base storage capacity (capacity level existing at the end of year t+n-1), (Bcf)
YSTR	=	actual storage capacity added (Bcf)
YSTR0	=	base storage capacity utilized (Bcf)

With the completion of the second phase, the CEM has generated pipeline and storage capacity expansion results, as well as seasonal flows corresponding to core and noncore markets. The capacities are used directly in the Annual Flow Module, while the flows are used to generate annual pipeline capacity utilization factors for use in the Annual Flow Module. The procedure to generate annual capacity utilization factors is presented in the next section.

Processing of CEM Results

The primary purpose of the CEM is to provide the Annual Flow Module and Pipeline Tariff Module each year with a forecast of physical pipeline capacity and working gas storage capacity for forecast year t+n, to determine maximum pipeline capacity utilizations corresponding to annual firm and total interregional flows (to be used in the maximum annual flow constraints within the Annual Flow Module), and to determine firm and interruptible net storage withdrawals (to be used in the node mass balance constraints within the Annual Flow Module). Capacity expansion results are used to determine the forecasted capacity levels; firm and total flows are used to determine pipeline utilizations; and, seasonal firm and interruptible flows into and out of storage are used to calculate firm and interruptible net storage withdrawals. These calculations are presented below.

Pipeline and storage capacity expansion levels for forecast year t+n are generated by solving the CEM linear program, and are used to determine forecasted capacities. Physical pipeline capacity along the interregional arc from transshipment node i to node j is calculated as the base capacity (including planned expansions -- Appendix F, Table F42) plus the corresponding level of expansion in year t+n.

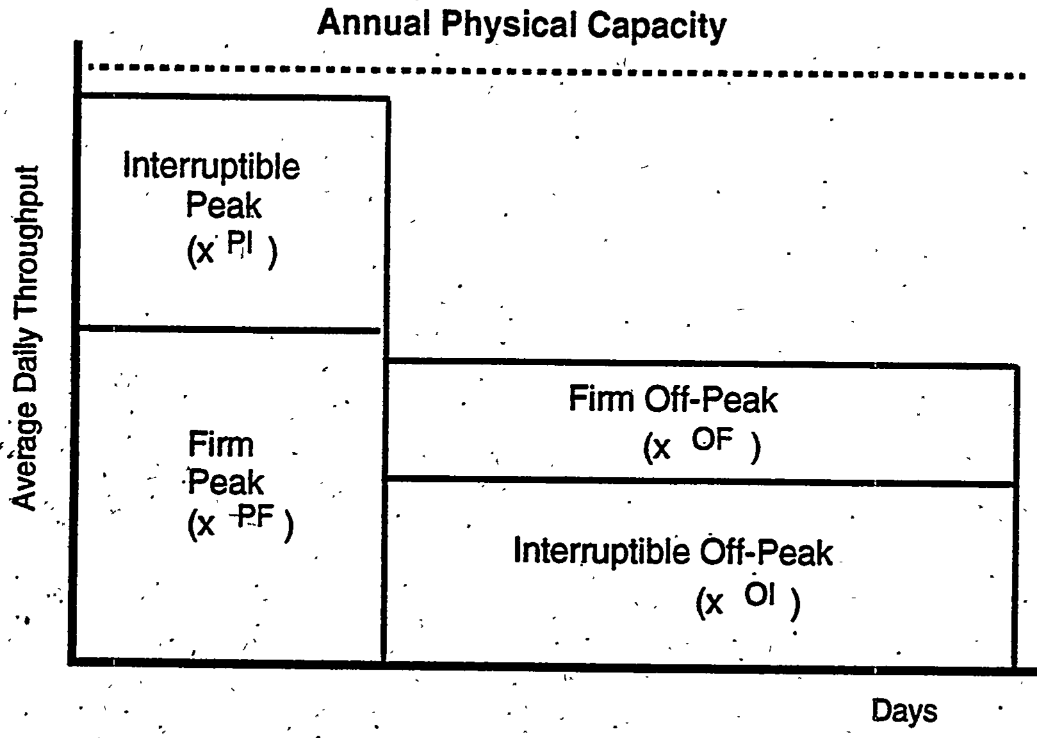
$$PhyCap_{i,j} = QCAP0_{i,j} + \sum_{k=1}^{n} ycap_{i,j,k} \tag{72}$$

Likewise, regional working gas storage for year t+n is calculated as base working gas (including planned expansions -- Appendix F, Table F33) plus the corresponding level of expansion in year t+n.

$$StrCap_{st,i} = QSTR0_{st,i} + \sum_{k=1}^{n} ystr_{st,i,k} \tag{73}$$

Since loads on a pipeline tend to be variable throughout a year (with full utilization more prevalent during the peak season and lower utilization during the off-peak season), the purpose of the maximum annual flow constraints in the Annual Flow Module is to better represent seasonal flows on an annual basis. This is accomplished by using the seasonal flow patterns resulting in the CEM and translating them into annual pipeline utilizations. The CEM calculates both firm and total annual pipeline utilizations to be used within the maximum annual flow constraints for both firm and total flows in the Annual Flow Module. A graphical depiction of the load curve that represents seasonal flows is presented in Figure 7-4.

Figure 7-4. Example of a Seasonal Flow Pattern Along an Arc



Firm annual utilizations are a function of peak firm flows, off-peak firm flows, and peak firm utilization rates. Peak firm utilization rates (Appendix F, Table F34) define the maximum portion of total physical annual capacity available to the peak firm service network along a specific arc, and are used in conjunction with other utilizations to establish arc-specific load duration curves represented in the CEM. Assuming that the resulting peak firm flow reflects full utilization of the capacity available to the core market during the peak season, an equivalent maximum annual capacity available to the core market can be calculated by dividing the peak firm flow by the peak firm utilization. Next, dividing the total firm flow (peak and off-peak) by this maximum annual firm capacity produces maximum firm annual utilizations used by the Annual Flow Module. The following equations result.

For the core market, along each arc i,j:

$AUTILZ_{i,j}^{F}$ = ((the flow along the arc to satisfy peak period core market requirements) + (the flow along the arc to satisfy off-peak period core market requirements)) / (equivalent annual firm capacity)

given, equivalent annual firm capacity = (the flow along the arc to satisfy peak period core market requirements) / (peak firm utilization rate)

$$AUTILZ^F_{i,j} = \frac{(x^{PF}_{i,j} + x^{OF}_{i,j})}{ECAP^F_{i,j}}$$

$$ECAP^F_{i,j} = \frac{x^{PF}_{i,j}}{UTILZ^{PF}_{i,j}} \qquad (74)$$

where,

$AUTILZ_{i,j}{}^F$	=	annual firm capacity utilization rate along arc i,j (fraction)
$x_{i,j}{}^{PF}$	=	peak firm flow along arc i,j (Bcf)
$x_{i,j}{}^{OF}$	=	off-peak firm flow along arc i,j (Bcf)
$ECAP_{i,j}{}^F$	=	equivalent capacity available to core market along arc i,j (Bcf)
$UTILZ_{i,j}{}^{PF}$	=	peak firm capacity utilization rate along arc i,j (fraction)

Likewise, total capacity utilization rates are a function of peak firm flows, off-peak firm flows, peak interruptible flows, off-peak interruptible flows, and peak utilization rates. Peak utilization rates (Appendix F, Table F34) define the maximum portion of total physical annual capacity available in the peak period along a specific arc, and are used in conjunction with other utilizations to establish arc-specific load duration curves represented in the CEM. Assuming that the resulting peak flows reflect full utilization of the capacity available during the peak season, an equivalent maximum annual capacity available to the natural gas market can be calculated by dividing the total peak flow by the peak utilization. Next, dividing the total flow (peak and off-peak, firm and interruptible) by this maximum annual capacity produces maximum annual total utilizations used by the Annual Flow Module. The following equations result.

For the total natural gas market, along each arc i,j:

$AUTILZ_{i,j}{}^T$ = ((the flow along the arc to satisfy peak period core market requirements) + (the flow along the arc to satisfy off-peak period core market requirements) + (the flow along the arc to satisfy peak period noncore requirements) + (the flow along the arc to satisfy off-peak period noncore requirements)) / (equivalent total annual capacity)

given, equivalent total annual capacity = ((the flow along the arc to satisfy peak period core market requirements) + (the flow along the arc to satisfy peak period noncore requirements) / (peak utilization rate)

$$AUTILZ^T_{i,j} = \frac{(x^{PF}_{i,j} + x^{OF}_{i,j} + x^{PI}_{i,j} + x^{OI}_{i,j})}{ECAP^T_{i,j}}$$

$$ECAP^T_{i,j} = \frac{(x^{PF}_{i,j} + x^{PI}_{i,j})}{UTILZ^P_{i,j}} \qquad (75)$$

where,

$AUTILZ_{i,j}{}^T$	=	total annual capacity utilization rate along arc i,j (fraction)
$x_{i,j}{}^{PF}$	=	peak firm flow along arc i,j (Bcf)
$x_{i,j}{}^{OF}$	=	off-peak firm flow along arc i,j (Bcf)
$x_{i,j}{}^{PI}$	=	peak interruptible flow along arc i,j (Bcf)
$x_{i,j}{}^{OI}$	=	off-peak interruptible flow along arc i,j (Bcf)
$ECAP_{i,j}{}^T$	=	equivalent total annual capacity available to the natural gas market along arc i,j (Bcf)
$UTILZ_{i,j}{}^P$	=	peak capacity utilization rate along arc i,j (fraction)

Contingencies have been written into the code to ensure that the total utilization remains greater than the firm, and that the total utilization is above a minimum threshold utilization.

Finally, net storage withdrawals are determined by subtracting off-peak flows going into storage from peak flows going out of storage. This is done at each node for each class of customer (i.e., firm or interruptible). Thus, an annual representation of the seasonal flow patterns established by the CEM is generated for use by the Annual Flow Module. This is defined by the following equations:

$$NETSTR_i^F = x_{st,i}^{PF} - x_{st,i}^{OF} \tag{76}$$

$$NETSTR_i^I = x_{st,i}^{PI} - x_{st,i}^{OI} \tag{77}$$

where,

$NETSTR_i^F$	=	net storage at node i for firm market (Bcf)
$NETSTR_i^I$	=	net storage at node i for interruptible market (Bcf)
$x_{st,i}^{PF}$	=	peak firm flow out of storage at node i (Bcf)
$x_{st,i}^{OF}$	=	off-peak firm flow into storage at node i (Bcf)
$x_{st,i}^{PI}$	=	peak interruptible flow out of storage at node i (Bcf)
$x_{st,i}^{OI}$	=	off-peak interruptible flow into storage at node i (Bcf)

8. Pipeline Tariff Module Solution Methodology

This Chapter discusses the solution methodology for the Pipeline Tariff Module (PTM) of the Natural Gas Transmission and Distribution Model (NGTDM). In this Module, for fully regulated services, the rates developed by the methodology are used as actual costs for transportation and storage services. Where interruptible services are more loosely regulated or where markets are deemed competitive, the methodology computes maximum and minimum rates for service. The minimum rate is used as a lower bound on the price of services. The actual price charged for these more loosely regulated services or the "market clearing price" is determined by the Annual Flow Module. Under current regulatory policy, the maximum price computed by the methodology (the 100-percent load factor rate) will act as a cap on the market clearing price. This "price cap" will not be enforced if deregulation of service is assumed or if Federal Energy Regulatory Commission provides for alternative pricing/cost recovery mechanisms.

The PTM tariff calculation is divided into two phases: a base-year initialization phase and a forecast year update phase. These two phases include the following steps: (1) determine the total cost of service, (2) classify line items of the cost of service as fixed and variable costs, (3) allocate fixed and variable costs to rate component (reservation and usage fee, [volumetric charge]) based on the rate design, (4) aggregate costs to the network arc/network node, (5) for transportation services, allocate costs to type of service (firm and interruptible),[60] and (6) compute arc-specific (node-specific) rates. For the base-year phase, the cost of service is developed from the financial data base while for the forecast year update phase the costs are estimated using a set of econometric equations. These steps are used to determine (1) transportation rates for the Annual Flow Module, (2) storage rates for the Annual Flow Module, (3) transportation rates for the Capacity Expansion Module to determine pipeline capacity expansion, and (4) storage rates for the Capacity Expansion Module to determine storage capacity expansion. A general overview of the methodology for deriving rates is presented in the box on the next page, while the PTM system diagram is presented in Figure 8-1.

Base-Year Initialization Phase

The purpose of the base-year initialization phase is to provide, for the base year of the NEMS forecast horizon, an initial set of NGTDM network-level transportation and storage revenue requirements and tariffs. The base-year information is developed from existing pipeline company transportation and storage data. The base-year initialization process draws heavily on two data bases developed by the Office of Oil and Gas, EIA. These data represent the existing physical pipeline and storage system. The physical system is at a more disaggregate level than the NGTDM network. The first data base provides detailed company-level financial, cost, and rate base parameters. This financial data base contains information on capital structure, rate-base, and revenue requirements by major line item of the cost of service for the base year of the model. The second data base covers the physical attributes of the natural gas pipelines, including contract demand and pipeline layout. The physical pipeline layout data are used, along with the contract data, to derive the allocation and billing determinants. These determinants subsequently are used to compute unit rates for transportation services along each arc (and for storage services at each node) of the NGTDM network.

This section discusses three separate processes that occur during the base-year initialization phase: (1) the computation of the cost of service and rates for services, (2) the construction of capacity expansion cost/tariff curves, and (3) manipulations required to pass the rates to the Annual Flow Module and curves to the Capacity Expansion Module.

The computation of base-year cost of service and rates for services involves six distinct procedures as outlined in the box below. Each of these procedures is discussed in detail below.

[60]This step is not carried out for storage service because no distinction is made between firm and interruptible storage services.

PTM Methodology for Deriving Rates

For Each Company

- Derive the Total Cost of Service (COS)
  - Base Year - Read COS Line Items from Data Base
  - Forecast Year
    - Include Costs for Capacity Expansion
    - Estimate COS Line Items from Forecasting Equations
- Classify Line Items as Fixed and Variable Costs
- Allocate Costs to Rate Component Based on Rate Design

For Each Node and Arc

- Aggregate Costs to Network Arcs and Nodes
- Allocate Costs to Services
  - Derive Allocation Determinants
  - Derive Costs by Type of Service
- Compute Rates for Services
  - Derive Billing Determinants
  - Derive Unit Fees

In order to facilitate capacity expansion decisions in the Capacity Expansion Module, the PTM constructs cost/tariff curves which relate incremental pipeline or storage facility capacity expansion to corresponding rates. These curves are developed from historically based estimates of capital and revenue requirements for capacity expansion projects using the computational procedures for determining base-year cost of service and rates.

Prior to passing the rates to the Annual Flow Module and Capacity Expansion Module, the PTM rates must be adjusted to maintain consistency among the three modules. PTM rates are calculated in nominal dollars and then converted to real dollars for use in the Annual Flow Module and Capacity Expansion Module.

Computation of Rates

An overview of the processing of costs in the PTM ratemaking procedure is illustrated in Figure 8-2. In the base-year initialization phase of the PTM, rates are computed using the six-step process outlined above. The first three steps are performed for the transportation and storage functions at the company level: (1) derivation of the total cost of service, (2) classifying line item costs as fixed and variable costs, and (3) allocation of fixed and variable costs to rate components based on rate design. The fourth step is to transform the costs from the company level to the network (arc and node) level. Allocation of costs to services (Step 5) and computation of rates (Step 6) are carried out at the arc level for transportation and the node level for storage. Step 5 is only executed for the transportation function because there is only one type of storage service represented in the PTM.

The equations apply, in general, to both transportation and storage functions. However, not all variables used in an equation are defined for both functions. For example, costs associated specifically with transportation services, such

Figure 8-1. Pipeline Tariff Module System Diagram

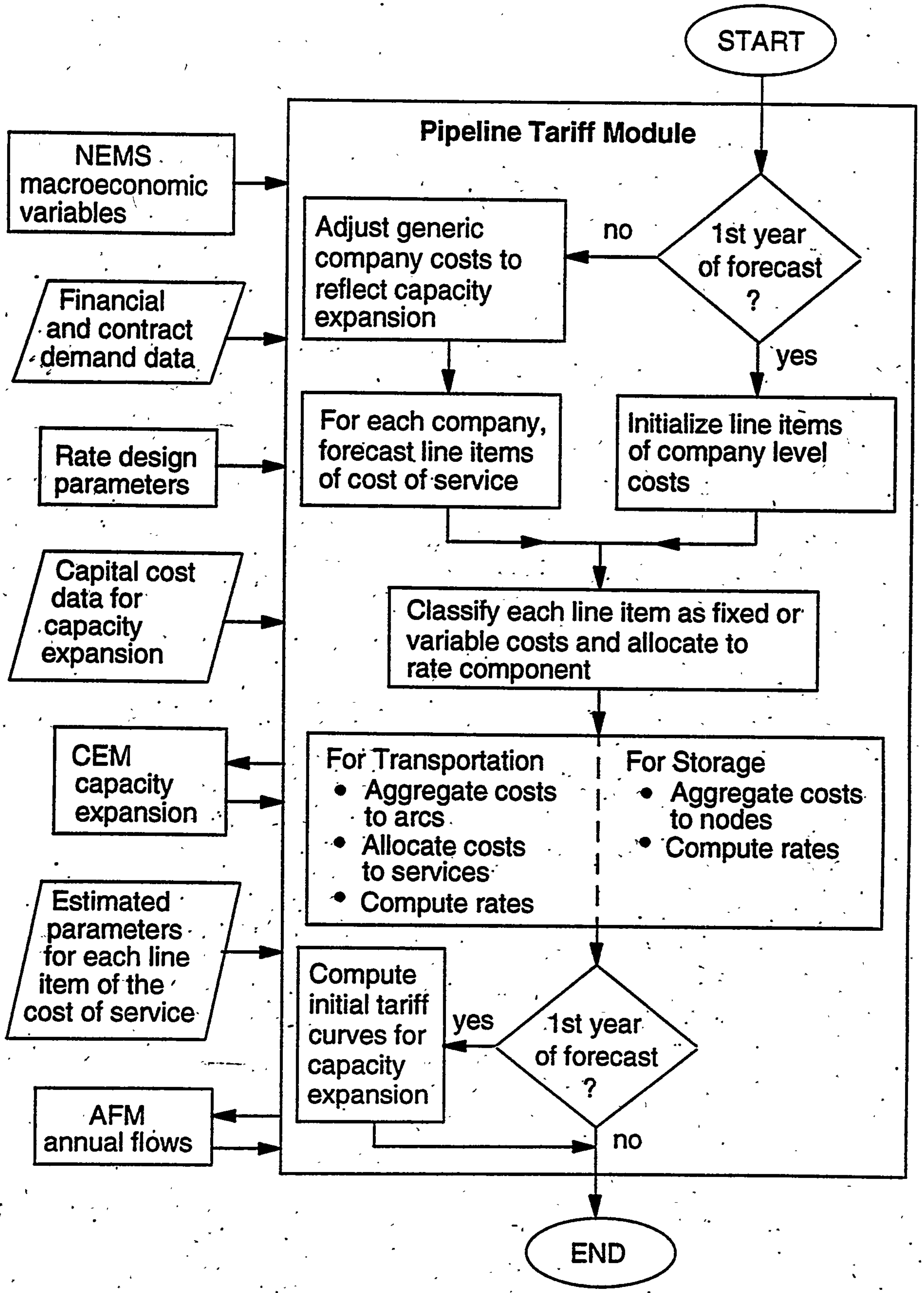
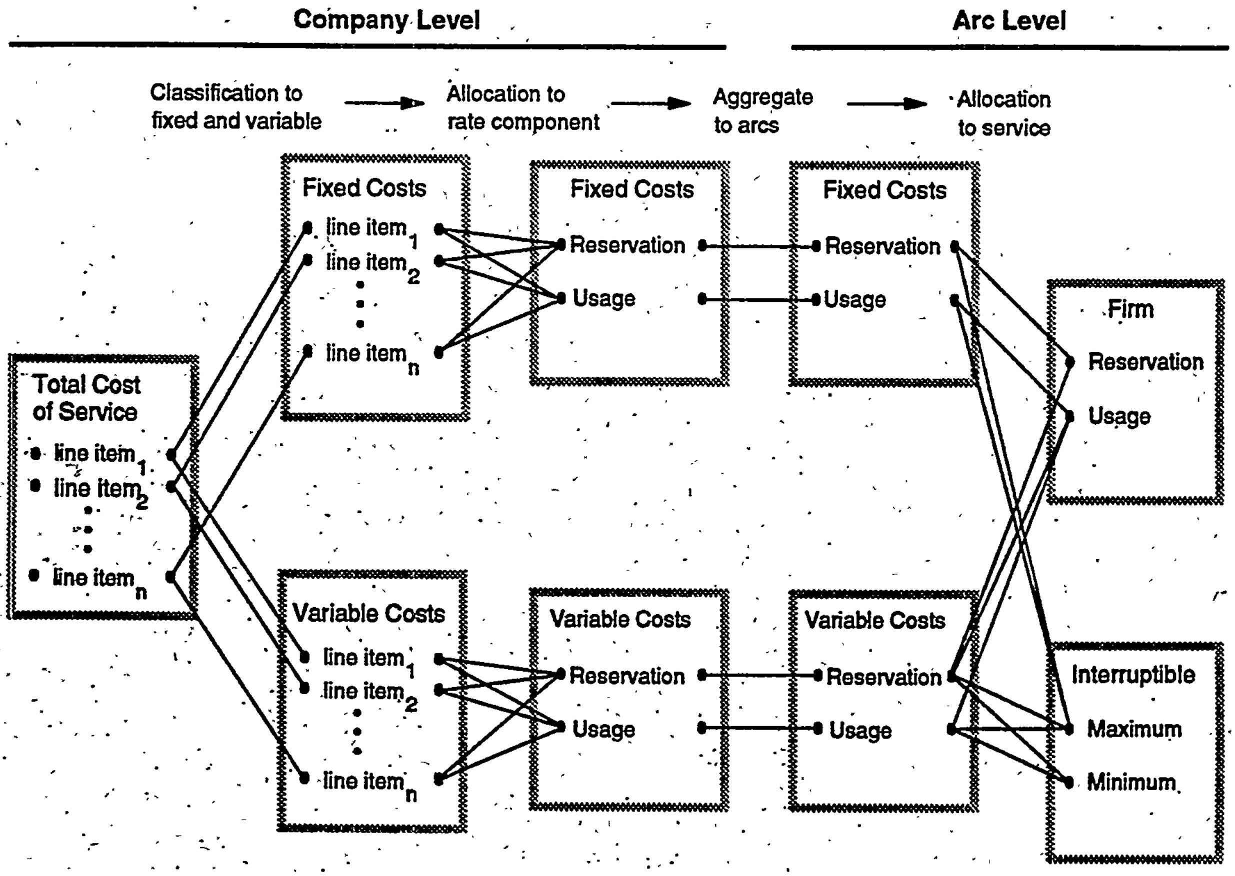


Figure 8-2. Processing Transportation Service Costs in the Ratemaking Process



as compressor station labor costs are set to zero when the equation is used to determine storage-related costs.

Step 1: Derivation of the Total Cost-of-Service

The total cost-of-service for a pipeline company is computed as the revenue requirement minus any revenue credits. The total revenue requirement (TRR) consists of a just and reasonable return on the rate base plus normal operating expenses. Revenue credits reflect revenues generated by nonjurisdictional services and one time costs that are outside of the scope of the PTM. Therefore, the total cost of service is computed as follows:

$$TCOS = TRR - REVC \tag{78}$$

$$TRR = TRRB + TNOE \tag{79}$$

where,

TCOS	=	total cost-of-service (dollars[61])
TRR	=	total revenue requirement (dollars)
TNOE	=	total normal operating expenses (dollars)
REVC	=	revenue credits to cost-of-service (dollars) (Appendix E, Table E5)
TRRB	=	total return on rate base (dollars)

[61]All costs discussed in this chapter are in nominal dollars, unless explicitly stated otherwise.

Derivations of return on rate base, total normal operating expenses, and revenue credits are presented in the following subsections.

Return. In order to compute the return portion of the cost-of-service, the determination of capital structure and rate base is necessary. Capital structure is important because it determines the cost of capital to the pipeline company. The weighted average cost of capital is applied to the rate base to determine the return component of the cost-of-service, as follows:

$$TRRB = WAROR * APRB \tag{80}$$

where,

TRRB = total return on rate base [before taxes, (dollars)]
WAROR = weighted-average before-tax return on capital (fraction)
APRB = adjusted pipeline rate base (dollars)

In addition, for reporting purposes, the return on rate base is broken out into the three components as shown below.

$$PFEN = (PFES/TOTCAP) * PFER * APRB \tag{81}$$

$$CMEN = (CMES/TOTCAP) * CMER * APRB \tag{82}$$

$$LTDN = (LTDS/TOTCAP) * LTDR * APRB \tag{83}$$

where,

PFEN = total return on preferred stock (dollars)
PFES = value of preferred stock (dollars)
TOTCAP = total capitalization (dollars)
PFER = coupon rate for preferred stock (fraction)
APRB = adjusted pipeline rate base (dollars)
CMEN = total return on common stock equity (dollars)
CMES = value of common stock equity (dollars)
CMER = common equity rate of return (fraction)
LTDN = total return on long-term debt (dollars)
LTDS = value of long-term debt (dollars)
LTDR = long-term debt rate (fraction)

The cost of capital (WAROR) is computed as the value-weighted average cost of capital for preferred stock, common stock equity, and long-term debt, as follows:

$$WAROR = (PFES*PFER + CMES*CMER + LTDS*LTDR)/TOTCAP \tag{84}$$

$$TOTCAP = PFES + CMES + LTDS \tag{85}$$

where,

WAROR = weighted-average before-tax return on capital (fraction)
PFES = value of preferred stock (dollars)
PFER = preferred stock rate (fraction)
CMES = value of common stock equity (dollars)
CMER = common equity rate of return (fraction)
LTDS = value of long-term debt (dollars)
LTDR = long-term debt rate (fraction)
TOTCAP = total capitalization (dollars)

The total rate base is computed as the sum of net plant in service, cash working capital, other working capital and transition expense balance minus accumulated deferred income taxes. That is,

$$APRB = NIS + CWC + OWC + TPEB - ADIT \tag{86}$$

where,

APRB = adjusted pipeline rate base (dollars)
NIS = net capital cost of plant in service (dollars)
CWC = cash working capital (dollars)
OWC = other working capital (dollars)
TPEB = transition expense balance (dollars)[62]
ADIT = accumulated deferred income taxes (dollars)

The net plant in service is the original capital cost plant in service minus the accumulated depreciation.

$$NIS = GPIS - ADDA \tag{87}$$

where,

NIS = net capital cost of plant in service (dollars)
GPIS = original capital cost of plant in service [gross plant in service (dollars)]
ADDA = accumulated depreciation, depletion, and amortization (dollars)

Total Normal Operating Expenses. Total normal operating expense line items include depreciation, taxes, administrative and general expenses, customer expenses, and operation and maintenance expenses. In the PTM, taxes are disaggregated further into Federal, State, and other taxes and tax credits to permit tax policy analysis. Operation and maintenance expenses also are disaggregated into several categories to enhance accuracy in forecasting expenses by function.

$$TNOE = DDA + TOTAX + TAG + TCE + TOM \tag{88}$$

where,

TNOE = total normal operating expenses (dollars)
DDA = depreciation, depletion, and amortization costs (dollars)
TOTAX = total Federal and State income tax liability (dollars)
TAG = total administrative and general expense (dollars)
TCE = total customer expense (dollars)[63]
TOM = total operations and maintenance expense (dollars)

Depreciation, depletion, and amortization costs, administrative and general expense, and customer expense are available directly from the financial data base.

Total taxes are computed as the sum of Federal and State income taxes and other taxes, less tax credits, as follows:

$$TOTAX = FSIT + OTTAX - FSITC \tag{89}$$

[62]The transition expense balance is the remaining balance of approved but yet to be recovered transition costs associated with restructuring gas supply contracts for Order 636.

[63]Customer expense includes direct payroll distributions of salaries and wages associated with the following services: customer accounts, customer service, information, and sales.

$$FSIT = FIT + SIT \tag{90}$$

where,

TOTAX = total Federal and State income tax liability (dollars)
FSIT = Federal and State income tax (dollars)
OTTAX = all other taxes assessed by Federal, State, or local governments except income taxes (dollars)
FSITC = Federal and State investment tax credits (dollars)
FIT = Federal income tax (dollars)
SIT = State income tax (dollars)

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:

$$ATP = APRB*(PFER*PFES + CMER*CMES)/TOTCAP \tag{91}$$

where,

ATP = after-tax profits (dollars)
APRB = adjusted pipeline rate base (dollars)
TOTCAP = total capitalization (dollars)
PFER = preferred stock rate (fraction)
PFES = value of preferred stock (dollars)
CMER = common equity rate of return (fraction)
CMES = value of common stock equity (dollars)

and the Federal income taxes are

$$FIT = (FRATE*ATP / 1.- FRATE) \tag{92}$$

where,

FIT = Federal income tax (dollars)
FRATE = Federal income tax rate (fraction) (Appendix F, Table F47)
ATP = after-tax profits (dollars)

State income taxes are computed by multiplying the sum of taxable returns 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 are computed as follows:

$$SIT = SRATE * (FIT + ATP) \tag{93}$$

where,

SIT = State income tax (dollars)
SRATE = average State income tax rate (fraction) (Appendix F, Table F47)
FIT = Federal income tax (dollars)
ATP = after-tax profits (dollars)

Total operations and maintenance expense consists of three major categories: supervision and engineering expenses, compressor station expenses, and other operations and maintenance expenses.[64] Compressor station expenses are disaggregated further into two categories: compressor station operating and maintenance labor expenses and compressor station operating and maintenance nonlabor expenses. That is, total operating and maintenance expense (TOM) equals

$$TOM = SEOM + CSOML + CSOMN + OTOM \tag{94}$$

where,

- TOM = total operations and maintenance expense (dollars)
- SEOM = supervision and engineering expense (dollars)
- CSOML = compressor station operating and maintenance labor expense (dollars)
- CSOMN = compressor station operating and maintenance nonlabor expense (dollars)
- OTOM = other operations and maintenance expense (dollars)

Revenue Credits. The revenue requirement is reduced (increased) by various revenue credits (expenses) to determine the total cost-of-service. These credits may relate to one-time expenditures that are outside the scope of the other cost categories.

After the determination of the total cost of service, each line item is classified as a fixed or variable cost as described in Step 2.

Step 2: Classification of Cost of Service Line Items as Fixed and Variable Costs

The PTM classifies each line item of the cost of service (computed in Step 1) as a fixed and variable cost. 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 R_i to fixed and variable cost is determined as follows:

$$R_{i,f} = ALL_f * R_i/100 \tag{95}$$

$$R_{i,v} = ALL_v * R_i/100 \tag{96}$$

where,

- $R_{i,f}$ = fixed cost portion of line item R_i (million dollars).
- ALL_f = percentage of line item R_i representing fixed cost
- R_i = total cost of line item i (million dollars)
- $R_{i,v}$ = variable cost portion of line item R_i (million dollars)
- ALL_v = percentage of line item R_i representing variable cost
- i = line item index
- 100 = $ALL_f + ALL_v$

An example of this procedure is illustrated in Table 8-1.

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.

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[64]Some expenses in this category apply only to transportation costs. Consequently, compressor-related and similar expenses will not be calculated for storage facilities.

Table 8-1. Illustration of Fixed and Variable Cost Classification

Cost of Service Line Item	Total	Allocation Factors (percent) Fixed Cost	Variable Cost	Cost Component 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
Tax Credits	1,000	100	0	1,000	0
Administrative & General	50,000	90	10	45,000	5,000
Customer	2,000	100	0	2,000	0
Operations & Maintenance					
Supervision & Engineering	7,000	100	0	7,000	0
Compression Station/Labor	5,000	100	0	5,000	0
Compression Station/Nonlabor	1,000	20	80	200	800
Other O & M	40,000	80	20	32,000	8,000
Revenue Requirement	225,000			211,200	13,800
Revenue Credits	25,000	100	0	25,000	0
Total Cost-of-Service	200,000			186,200	13,800

The rate design to be used within the PTM is specified by input parameters, which can be modified by the user to reflect changes in rate design over time. The PTM 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 the 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. For storage service the rate components are aggregated into one volumetric charge that is based on the amount of working gas capacity.[65]

The actual reservation and usage fees that pipelines are allowed to charge are regulated by the Federal Energy Regulatory Commission. 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, the more fixed costs are allocated to usage fees, the more costs are recovered based on throughput. Thus high load factor customers pay a larger share of system costs. Allocating a larger share of fixed costs to reservation fees, however, leads to low load factor customers bearing a larger share of system costs.

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 8-2. The PTM 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 the network arc, the composite rate design at the arc-level is the volumetric-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. In this option, the user will have the capability to specify the initial and final rate designs and the forecast year in which the rate design changes. Currently, the first option is used in PTM (Appendix F, Table F48).

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 8-3a and 8-3b and is generalized in the equations below.

The classification of transportation line item costs $R_{i,f}$ and $R_{i,v}$ to reservation and usage cost is determined as follows:

$$R_{i,f,r} = ALL_{f,r} * R_{i,f}/100 \tag{97}$$

$$R_{i,f,u} = ALL_{f,u} * R_{i,f}/100 \tag{98}$$

$$R_{i,v,r} = ALL_{v,r} * R_{i,v}/100 \tag{99}$$

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

where,

R = line item cost (dollars)
ALL = percentage of reservation or usage line item R representing fixed or variable cost (Appendix F, Table F13)
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

[65]This simplified representation of one volumetric charge related to the working gas capacity is designed to include all the costs that in actual practice are recovered through reservation, inventory, injection, and withdrawal charges.

Table 8-2. 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 = 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 fixed and variable costs allocated to reservation and usage components of the rates.

After ratemaking Steps 1, 2 and 3 are completed for each company, company-level costs are transformed to arc-level (node-level) rates for transportation (storage) services. This process, carried out for each arc and node in the NGTDM network, is accomplished in ratemaking Steps 4, 5 and 6 as presented below.

Step 4: Aggregation of Classified Cost of Service to Network Arcs and Nodes

As discussed above, for transportation services the PTM develops fixed and variable costs and allocates them to reservation and usage rate components at the pipeline company level. The PTM apportions these components to distinct segments of a pipeline path based on the share of the mileage-based capacity reservations on the segment. These pipeline path segments represent the portions of the physical pipeline system that fall within the transshipment nodes that define a network arc. The costs associated with each segment are mapped to the network arc by

Table 8-3a. Illustration of Allocation of Fixed Costs to Rate Components

Cost of Service Line Item	Total	Allocation Factors (percent) Reservation	Allocation Factors (percent) Usage	Cost Assigned to Rate Component Reservation	Cost Assigned to Rate Component Usage
Total Return					
Preferred Stock	1,000	0	100	0	1,000
Common Stock	30,000	0	100	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
Tax Credits	1,000	100	0	1,000	0
Administrative & General	45,000	100	0	45,000	0
Customer	2,000	100	0	2,000	0
Operations & Maintenance					
Supervision & Engineering	7,000	100	0	7,000	0
Compression Station/Labor	5,000	100	0	5,000	0
Compression Station/Nonlabor	200	100	0	200	0
Other O & M	32,000	100	0	32,000	0
Revenue Requirement	211,200			150,200	61,000
Revenue Credits	25,000	100	0	25,000	0
Total Cost-of-Service	186,200			125,200	61,000

Table 8-3b. Illustration of Allocation of Variable Costs to Rate Components

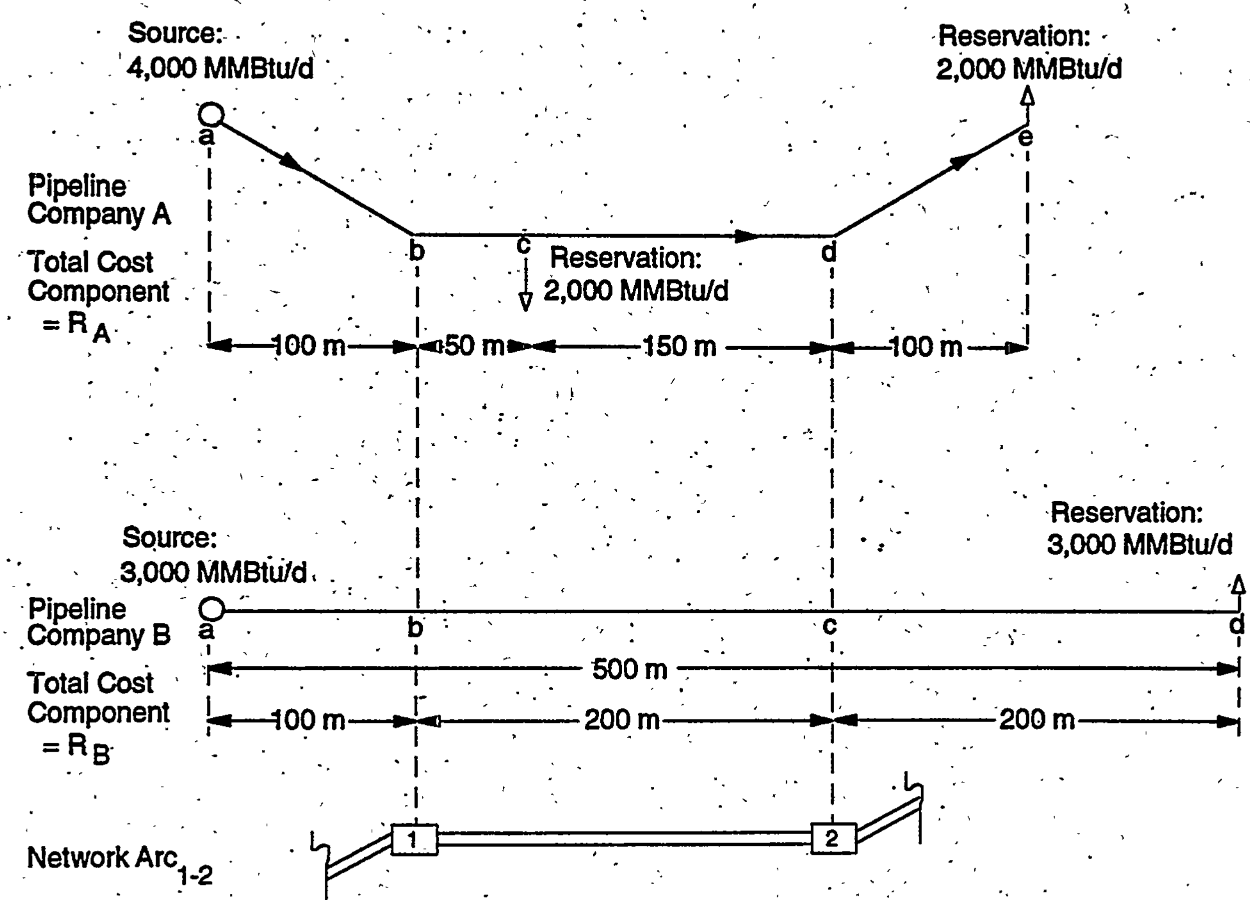
Cost of Service Line Item	Total	Allocation Factors (percent) Reservation	Allocation Factors (percent) Usage	Cost Assigned to Rate Component Reservation	Cost Assigned to Rate Component Usage
Total Return					
Preferred Stock	0	0	100	0	0
Common Stock	0	0	100	0	0
Long-Term Debt	0	0	100	0	0
Normal Operating 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
Tax Credits	0	0	100	0	0
Administrative & General	5,000	0	100	0	5,000
Customer	0	0	100	0	0
Operations & Maintenance					
Supervision & Engineering	0	0	100	0	0
Compression Station/Labor	0	0	100	0	0
Compression Station/Nonlabor	800	0	100	0	800
Other O & M	8,000	0	100	0	8,000
Revenue Requirement	13,800			0	13,800
Revenue Credits	0	0	100	0	0
Total Cost-of-Service	13,800			0	13,800

aggregating the cost information across all pipeline segments identified with an arc.[66] The capacity reservation shares used to apportion costs to pipeline segments are derived exogenously from the capacity reserved and distances associated with each segment and the capacity reserved and distances for the complete pipeline path (Appendix F, Table F14). The shares do not change throughout the forecast.

This procedure is illustrated for two hypothetical pipeline companies (Figure 8-3). In the example, it is assumed that the total costs to be distributed to distinct pipeline segments are R_A and R_B for Company A and Company B, respectively. Notice that Company A is defined by network a, b, c, d, e in the upper portion of Figure 8-3 and Company B is defined by network a, b, c, d in the middle half of the figure. Company A receives 4000 MMBtu/day at point a, discharges 2000 MMBtu/day at point c and ships the remaining 2000 MMBtu/day to point e. Company B ships 3,000 MMBtu along its entire route, from point a to point c. It is assumed further that segment b-d of Company A's pipeline path and segment b-c of Company B's pipeline path are to be mapped into the network arc defined by the transshipment nodes 1-2 at the bottom of Figure 8-3. Note that company A's segment b-d actually is composed of two segments: segment b-c and segment c-d.

The mileage-based capacity reservation (V) is determined as the capacity reserved in each pipeline segment multiplied by the length of the pipeline segment. For Company A the reservation on segment b-c is the quantity (4000*50) MMBtu-miles and the reservation on segment c-d is the quantity (2000*150) MMBtu-miles per day. For

Figure 8-3. Example of Apportioning Pipeline Costs to Network Arcs



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[66]In the forecast years, arc-level costs include costs associated with generic companies representing pipeline capacity added subsequent to the base year. Generic companies are discussed in the section describing the forecast year updating process.

company B, the reservation on segment b-c is the quantity (3000*200) MMBtu-miles per day. The total reservation along the pipeline path for company A is the sum of the reservations on each segment, or 1,100,000 MMBtu-miles per day.[67]

Once the reservations on the segments are determined, the pipeline costs are apportioned to each segment as follows. The share of cost (R_A) allocated to Company A's pipeline segment b-c is determined as the cost multiplied by the ratio of the reservations on segment b-c to the reservations on the total pipeline path, expressed as follows:

$$R_A^{b-c} = R_A * V_A^{b-c} / V_A^T \tag{101}$$

where,

R_A^{b-c} = portion of R_A allocated to Company A segment b-c
R_A = total component cost for Company A (dollars)
V_A^{b-c} = reservations on Company A segment b-c
V_A^T = total reservation on Company A pipeline path

In this example, V_A^{b-c} equals 200,000 MMBtu-miles per day and V_A^T equals 1,100,000 MMBtu-miles per day.

Similarly, the allocation of costs to Company A's segment c-d [$R_A^{c-d} = R_A*(3/11)$] and to Company B's segment b-c [$R_B^{b-c} = R_B*(6/15)$] are obtained. Finally, the costs are aggregated to the network arc by summing all distinct costs for Company A's segment b-c and segment c-d and Company B's segment b-c.

$$R_{1-2} = R_A^{b-c} + R_A^{c-d} + R_B^{b-c} \tag{102}$$

where,

R_{1-2} = total costs allocated to arc 1-2
R_A^{b-c} = portion of R_A allocated to Company A segment b-c
R_A^{c-d} = portion of R_A allocated to Company A segment c-d
R_B^{b-c} = portion of R_B allocated to Company B segment b-c

Through this procedure, company-level fixed and variable costs are assigned to arcs on the NGTDM network and for each arc these costs have been assigned to a rate component. Thus the following variables are defined:

FCR_a = fixed costs assigned to the reservation component of the rate
VCR_a = variable costs assigned to the reservation component of the rate
FCU_a = fixed costs assigned to the usage component of the rate
VCU_a = variable costs assigned to the usage component of the rate
a = arc

Apportioning storage costs to network nodes is a more straightforward process because the costs are simply assigned to the nodes as a function of the share of storage capacity located in each region. Through the procedure provided in the following equations company-level fixed and variable costs are shared out and aggregated to nodes on the NGTDM network.

[67]Derived based on capacity reservations on arc a-b equal to (4000*100) MMBtu-miles per day, plus capacity reservations on arc b-c of (4000*50) MMBtu-miles per day, plus capacity reservations on arc c-d of (2000*150) MMBtu-miles per day and capacity reservations (2000*100) MMBtu-miles per day on arc d-e.

$$FCS_n = FCS_n + (NS_{p,n} * SF_p) \tag{103}$$

$$VCS_n = VCS_n + (NS_{p,n} * SV_p) \tag{104}$$

where,

VCS_n = variable costs of storage cost (million dollars)
FCS_n = fixed costs of storage (million dollars)
$NS_{p,n}$ = share of company p gas storage capacity located at the node n [Appendix F, Table F18 (fraction)]
SF_p = company p fixed costs for storage service (million dollars)
SV_p = company p variable costs for storage service (million dollars)
p = pipeline company index
n = node index

Step 5: Allocation of Arc-Level Transportation Costs to Services

The arc-level fixed and variable costs are allocated to firm and interruptible transportation services. In allocating these costs, a portion of the fixed costs are assigned to noncore customers. Historically, rate designs have placed some of the recovery of fixed costs at risk by assigning the recovery of these costs to noncore customers. Should the revenues obtained from interruptible service be less than those anticipated in the ratemaking process, the pipeline company would not recover all of its fixed costs. Variable costs are allocated based on total annual throughput for each type of service. The development of the allocation determinants is discussed next.

Allocation Determinants for Fixed Costs. The allocation determinants for fixed costs are based, in part, on the firm capacity reservations and annual interruptible transportation volumes along an arc. The procedure for obtaining arc-level reservations and flows in the base year is comparable to the process described above for aggregating segment costs to an arc.[68] The allocation determinants for fixed costs are defined as follows. The fixed cost allocation determinant for firm service is defined as the annualized peak-day reservations for firm service divided by the sum of the annualized peak-day firm reservations and an adjusted annual throughput volume for interruptible service. In equation form, this allocation determinant (FADFS) is defined as follows:

$$FADFS_a = (PRESV_a*365/(PRESV_a*365 + ISERV_a*RADJ_a*(1 + IEXPCT_a/100))) \tag{105}$$

where,

$FADFS_a$ = allocation determinant for fixed costs recovered from firm service (ratio)
$PRESV_a$ = peak-day reservations for firm transportation service (Bcf per day) [Appendix F, Table F17]
$ISERV_a$ = annual throughput volume for interruptible transportation service (Bcf per year)
$IEXPCT_a$ = expected annual rate of growth in interruptible transportation [Appendix F, Table F35 (percent, currently set to 0)]
$RADJ_a$ = adjustment factor for discounting [Appendix F, Table F35 (ratio, currently set to 1.0)]
a = arc

The interruptible throughput volume is adjusted in the above equation for two reasons. First, the interruptible volumes are adjusted to reflect anticipated changes in interruptible transportation volumes using the user-specified IEXPCT parameter. Second, the volume is adjusted downward via the RADJ factor to reflect anticipated discounting of interruptible transportation services. This adjustment factor (RADJ) reflects the degree of discounting that took place in the prior forecast year and is defined as follows:

[68] In subsequent years, flow volumes are input to the PTM at the arc-level.

$$RADJ_a = AFM\_PTAR\_I_a^{t-1} \,/\, PMAX_a^{t-1} \tag{106}$$

where,

t = current year index
$RADJ_a$ = adjustment factor for discounting [Appendix F, Table F35 (ratio)]
$AFM\_PTAR\_I_a^{t-1}$ = average interruptible service rate in year t-1 [Appendix F, Table F15 (dollars per Mcf)]
$PMAX_a^{t-1}$ = maximum interruptible service rate in year t-1 (dollars per Mcf)
a = arc

Similarly, the allocation determinant for fixed costs assigned to interruptible service (FADIS) is defined as

$$FADIS_a = \frac{ISERV_a * RADJ_a * (1+IEXPCT_a/100)}{PRESV_a * 365 + ISERV_a * RADJ_a * (1+IEXPCT_a/100)} \tag{107}$$

where,

$FADIS_a$ = allocation determinant for fixed costs assigned to interruptible service [1-$FADFS_a$ (ratio)]
$ISERV_a$ = annual throughput volume for interruptible transportation service (Bcf per year)
$RADJ_a$ = adjustment factor for discounting [Appendix F, Table F35 (ratio)]
$IEXPCT_a$ = expected rate of growth in interruptible transportation [Appendix F, Table F35 (percent)]
$PRESV_a$ = peak-day reservations for firm transportation service (Mcf per day) [Appendix F, Table F17]
a = arc

Allocation Determinants for Variable Costs. The allocation determinants for variable costs are based on the annual firm and interruptible service volumes on the arc. The allocation determinant that assigns variable costs to firm service (VADFS) is defined as the annual throughput volume for firm transportation on the arc (FSERV) divided by the total annual throughput volume for firm and interruptible service on the arc, as follows:

$$VADFS_a = FSERV_a/(FSERV_a + ISERV_a) \tag{108}$$

where,

$VADFS_a$ = allocation determinant for variable costs assigned to firm service (ratio)
$FSERV_a$ = annual throughput volume for firm transportation service (Bcf per year)
$ISERV_a$ = annual throughput volume for interruptible transportation (Bcf per year)
a = arc

The allocation determinant that assigns variable costs to interruptible services (VADIS) is defined as the annual throughput volume for interruptible service divided by the total annual throughput volume for firm and interruptible service, as follows:

$$VADIS_a = ISERV_a/(FSERV_a + ISERV_a) \tag{109}$$

where,

$VADIS_a$ = allocation determinant for variable costs assigned to interruptible service (ratio)
$ISERV_a$ = annual throughput volume for interruptible transportation service in (Bcf per year)
$FSERV_a$ = annual throughput volume for firm transportation (Bcf per year)
a = arc

The determinants are applied to costs previously allocated to rate components (in Step 4) to derive the costs allocated to the firm transportation rate components. Similarly allocation determinants are applied to obtain the costs allocated to interruptible transportation. These procedures are outlined in equation form below.

Derivation of Fixed and Variable Costs Allocated to the Reservation Fee for Firm Transportation. Costs allocated to the firm transportation reservation fees consist of the firm transportation portion of the fixed and variable costs assigned to the reservation fee. This cost is derived by applying the allocation determinants as follows:

$$RCFS_a = (FADFS_a * FCR_a) + (VADFS_a * VCR_a) \tag{110}$$

where,

$RCFS_a$ = reservation costs assigned to core customers (million dollars per year)
$FADFS_a$ = allocation determinant for fixed costs recovered from firm service (ratio)
FCR_a = fixed costs assigned to the reservation component of the rate (million dollars per year)
$VADFS_a$ = allocation determinant for variable costs recovered from firm service (ratio)
VCR_a = variable costs assigned to the reservation component of the rate (million dollars per year)
a = arc

Derivation of Fixed and Variable Costs Allocated to the Usage Fee for Firm Transportation. Costs allocated to the firm transportation usage fees consists of the firm transportation portion of the fixed and variable costs assigned to the usage fee. This cost is derived by applying the allocation determinants as follows:

$$UCFS_a = (FADFS_a * FCU_a) + (VADFS_a * VCU_a) \tag{111}$$

where,

$UCFS_a$ = usage costs assigned to core customers (million dollars per year)
$FADFS_a$ = allocation determinant for fixed costs recovered from firm service (ratio)
FCU_a = fixed costs assigned to the usage component of the rate (million dollars per year)
$VADFS_a$ = allocation determinant for variable costs recovered from firm service (ratio)
VCU_a = variable costs assigned to the usage component of the rate (million dollars per year)
a = arc

Derivation of Fixed and Variable Costs Allocated to Interruptible Transportation. Costs allocated to interruptible transportation service consist of a portion of the fixed and variable costs assigned to the reservation and usage rate components. This cost is derived by applying the allocation determinants as follows:

$$CIS_a = (FADIS_a * (FCU_a + FCR_a)) + (VADIS_a * (VCU_a + VCR_a)) \tag{112}$$

where,

CIS_a = costs assigned to noncore customers (million dollars per year)
$FADIS_a$ = allocation determinant for fixed costs recovered from interruptible service (ratio)
FCU_a = fixed costs assigned to the usage component of the rate (million dollars per year)
FCR_a = fixed costs assigned to the reservation component of the rate (million dollars per year)
$VADIS_a$ = allocation determinant for variable costs recovered from interruptible service (ratio)
VCU_a = variable costs assigned to the usage component of the rate (million dollars per year)
VCR_a = variable costs assigned to the reservation component of the rate (million dollars per year)
a = arc

The costs allocated to interruptible transportation service are not used to derive the maximum and minimum rates that may be charged for interruptible service. These costs are presented here to account fully for all costs that make up the total cost of service and to facilitate the discussion of the derivation of the costs allocated to firm transportation service. The computation of rates for firm and interruptible service is presented in Step 6.

Step 6: Computation of Rates

Firm Transportation Service. Arc-level reservation and usage fees for firm service are determined by dividing the costs corresponding to each rate component by the appropriate billing determinants. Thus, the reservation fee is determined as the reservation costs recovered from firm service ($RCFS_a$) divided by the annualized reservations for firm transportation service. That is,

$$RFEE_a = RCFS_a/(PRESV_a*365) \tag{113}$$

where,

$RFEE_a$ = reservation fee for firm service in dollars per Mcf of capacity reserved
$RCFS_a$ = reservation costs assigned to core customers (million dollars per year)
$PRESV_a$ = peak-day reservations for firm transportation service (Bcf per day) [Appendix F, Table F17]
a = arc

The NGTDM pipeline network uses tariffs in the form of dollars per Mcf of throughput. Therefore, the reservation fee component of the NGTDM pipeline tariff is derived by dividing the reservation costs assigned to firm service ($RCFS_a$) by the annual firm transportation service throughput. That is,

$$PTAR\_REV\_F_a = RCFS_a/FSERV_a \tag{114}$$

where,

$PTAR\_REV\_F_a$ = reservation fee component of the firm service pipeline tariff (dollars per Mcf of throughput)
$RCFS_a$ = reservation costs assigned to core customers (million dollars per year)
$FSERV_a$ = annual throughput volume for firm transportation (Bcf per year)
a = arc

Similarly, the usage fee is determined as the usage costs recovered from core customers ($UCFS_a$) divided by the annual throughput volume for firm service, as follows:

$$UFEE_a = UCFS_a/FSERV_a \tag{115}$$

where,

$UFEE_a$ = usage fee for firm service (dollars per Mcf)
$UCFS_a$ = usage costs assigned to core customers (million dollars per year)
$FSERV_a$ = annual throughput volume for firm transportation (Bcf per year)
a = arc

The total firm pipeline tariff is the sum of the reservation and usage components as shown below:

$$PTAR\_F_a = PTAR\_REV\_F_a + UFEE_a \tag{116}$$

where,

$PTAR\_F_a$ = pipeline tariff for firm service sent to the Annual Flow Module (dollars per Mcf)
$PTAR\_REV\_F_a$ = reservation fee component of the firm service pipeline tariff (dollars per Mcf of throughput)
$UFEE_a$ = usage fee for firm service (dollars per Mcf)
a = arc

To account for regulatory oversight and to assist in stabilizing the tariffs, a check is performed each year to limit the annual increase in the firm tariff components to a user specified escalation rate. This limit is imposed as shown in the following equations:

$$RFEE_{a,t} = MIN\ (RFEE_{a,t},\ \ PREV\_REV\_F_a * (1+MAXESC)) \tag{117}$$

where,

RFEE = reservation fee for firm service (dollars per Mcf)
PREV_REV_F = reservation fee for firm service in the previous year (dollars per Mcf)
MAXESC = maximum allowable annual escalation rate for tariffs [Appendix F, Table F35 (fraction)]
a = arc
t = forecast year

and

$$UFEE_{a,t} = MIN\ (UFEE_{a,t},\ \ PREV\_COM\_F_a * (1+MAXESC)) \tag{118}$$

where,

UFEE = usage fee for firm service (dollars per Mcf)
PREV_REV_F = usage fee for firm service in the previous year (dollars per Mcf)
MAXESC = maximum allowable annual escalation rate for tariffs [Appendix F, Table F35 (fraction)]
a = arc
t = forecast year

Various accounting mechanisms have been built into the tariff computation procedures to account specifically for Order 636 transition costs. These mechanisms are implemented in the base year (and subsequent years) and therefore they are presented in this section of the Chapter.[69]

Balances in purchase gas adjustment accounts (otherwise known as Account 191) are collected on a per unit basis of firm throughput. The costs are assumed to be collected over a multi-year period. The Account 191 surcharge is computed as follows:

$$PTAR\_191\_F_a = (ANUM191_a/FSERV_a)/A191YRS \tag{119}$$

where,

$PTAR\_191\_F_a$ = firm tariff surcharge for Account 191 transition costs (dollars per Mcf)
ANUM191 = Account 191 transition costs assigned to arc a (million dollars)
$FSERV_a$ = annual throughput volume for firm transportation (Bcf per year)
A191YRS = number of years Account 191 costs are assumed to be collected (Appendix F, Table F24)
a = arc

Tariff surcharges to collect gas supply realignment costs (GSR costs) are computed in a similar manner, however, flexibility is provided to assign a portion of the costs to core customers and a portion of the costs to noncore customers as follows:

$$PTAR\_GSR\_F_a = [(AGSRCOSTS_a*SHARE\_GSR\_F)\ /\ FSERV_a]\ /\ GSRYRS \tag{120}$$

where,

$PTAR\_GSR\_F_a$ = firm tariff surcharge for GSR transition costs (dollars per Mcf)
$AGSRCOSTS_a$ = GSR transition costs assigned to arc a (million dollars)
SHARE_GSR_F = fraction of GSR transition costs assigned to firm service (Appendix F, Table F24)
$FSERV_a$ = annual throughput volume for firm transportation (Bcf per year)

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[69]The magnitude of Order 636 transition costs; the years during which they are collected and the share of costs assigned to different classes of service are data driven. See Table F24 in Appendix F for the default assumptions.

$$GSRYRS = \text{number of years GSR costs are assumed to be collected (Appendix F, Table F24)}$$
$$a = \text{arc}$$

The total firm tariff sent to the Annual Flow Module network is the sum of the firm tariff and any Order 636 surcharges. The total tariff is computed as shown below.

$$PTAR\_F_a = PTAR\_F_a + PTAR\_191\_F_a + PTAR\_GSR\_F_a \tag{121}$$

where,

$PTAR\_F_a$ = total tariff for firm service passed to the Annual Flow Module (dollars per Mcf)
$PTAR\_191\_F_a$ = firm tariff surcharge for Account 191 transition costs (dollars per Mcf)
$PTAR\_GSR\_F_a$ = firm tariff surcharge for GSR transition costs (dollars per Mcf)
a = arc

This firm tariff is then checked against a maximum firm tariff (Appendix F, Table F45) to prevent the tariff from becoming unrealistically high due to low utilization along the arc.

Interruptible Transportation Service. The actual interruptible transportation rates are determined within the linear programming solution procedure, but are bounded by regulated maximum and minimum rates provided by the PTM. The arc-level maximum and minimum rates for interruptible transportation service are derived from variable costs, reservation and usage fees for firm service, and a load factor permitted by FERC for interruptible service (LFAC) (currently set equal to 100 percent). The maximum tariff (MAX_a) is computed as the sum of the reservation fee (divided by the load factor) and the usage fee. That is,

$$MAX_a = RFEE_a/LFAC + UFEE_a \tag{122}$$

where,

MAX_a = maximum rate for interruptible service (dollars per Mcf)
$RFEE_a$ = reservation fee for firm service (dollars per Mcf)
$LFAC$ = load factor for deriving the maximum interruptible rate [Appendix F, Table F35 (ratio)]
$UFEE_a$ = usage fee for firm service in (dollars per Mcf)
a = arc

The minimum tariff (MIN_a) is computed as the sum of all variable costs associated with the arc ($VSUM_a$) divided by the total annual firm and interruptible throughput volume, as follows:

$$MIN_a = VSUM_a/(FSERV_a + ISERV_a) \tag{123}$$

$$VSUM_a = VCR_a + VCU_a \tag{124}$$

where,

MIN_a = minimum rate for interruptible service (dollars per Mcf)
$VSUM_a$ = total variable costs for firm and interruptible service (million dollars)
$FSERV_a$ = annual throughput volume for firm transportation (Bcf)
$ISERV_a$ = annual throughput volume for interruptible transportation service (Bcf)
VCR_a = variable costs assigned to the reservation component of the rate (million dollars)
VCU_a = variable costs assigned to the usage component of the rate (million dollars)
a = arc

Similar to the firm pipeline tariffs, the regulated maximum interruptible tariff is limited to increase at a rate no greater than a user specified escalation rate as shown in the equation below.

$$MAX_{a,t} = MIN(MAX_{a,t}, MAX_{a,t-1} * (1+MAXESC)) \qquad (125)$$

where,

MAX_a = maximum rate for interruptible service (dollars per Mcf)
MAXESC = maximum allowable annual escalation rate for tariffs [Appendix F, Table F35 (fraction)]
a = arc
t = forecast year

Interruptible transportation rates may also include some surcharge attributable to Order 636 transition costs. Gas supply realignment costs are partially collected through a surcharge on interruptible rates. The computation of this surcharge is shown below.

$$PTAR\_GSR\_I_a = [(AGSRCOSTS_a * SHARE\_GSR\_I) \,/\, ISERV_a] \,/\, GSRYRS \qquad (126)$$

where,

$PTAR\_GSR\_I_a$ = interruptible tariff surcharge for GSR transition costs (dollars per Mcf)
$AGSRCOSTS_a$ = GSR transition costs assigned to arc a (million dollars)
SHARE_GSR_I = fraction of GSR transition costs assigned to interruptible service (SHARE_GSR_I = 1.0-SHARE_GSR_F)
$ISERV_a$ = annual throughput volume for interruptible transportation (Bcf per year)
GSRYRS = number of years GSR costs are assumed to be collected (Appendix F, Table F24)
a = arc

Finally, an interruptible tariff is computed to be used as the cost of moving interruptible gas along each arc in the Annual Flow Module network. The value for this tariff is set as a function of user specified parameters. The tariff may be set to either the minimum or maximum tariff (MIN_a or MAX_a) plus the Order 636 surcharges (if applicable) or it may be set to some value in the range bounded by MIN_a and MAX_a. Should this latter option be chosen, the parameter MAXDISC_I represents a discount off the maximum rate that noncore customers will receive. The computation of this rate is shown below.

$$PTAR\_I_a = MAX_a * MAXDISC\_I \qquad (127)$$

where,

$PTAR\_I_a$ = total tariff for interruptible transportation service passed to the Annual Flow Module (dollars per Mcf)
MAX_a = maximum rate for interruptible service (dollars per Mcf)
MAXDISC_I = user specified maximum allowable discount for interruptible transportation service [Appendix F, Table F35 (fraction)]

This interruptible tariff is then checked against a maximum interruptible tariff (Appendix F, Table F45) to prevent the tariff from becoming unrealistically high due to low utilization along the arc.

Storage Service. Storage facilities are defined in the NGTDM network at regional nodes. In the base-year initialization phase, storage facility costs, capacities, inventories, and other data for existing companies are allocated to regional NGTDM network nodes using storage facility data in FERC and EIA data series.[70] An interstate pipeline company's total reported storage cost is allocated to NGTDM region nodes according to the regional

[70]FERC Form 2 provides total storage costs for interstate pipeline companies with storage facilities. Form EIA-191 provides injections, withdrawals, inventories, and base and working gas capacity by field/reservoir for storage facilities owned by all storage companies. The Form EIA-191 filings include information that allows facilities to be designated as owned by interstate pipeline and other firms.

distribution of natural gas storage capacity in the company's own storage facilities, as reported on Form EIA-191.[71] Because storage costs are related to base gas storage capacity, the cost allocation is based on the company's regional share of base gas storage capacity relative to its total base gas storage capacity. Regional interstate pipeline company-level costs are aggregated to the corresponding NGTDM region node (Equations 103 and 104).

The regional storage costs for interstate pipeline companies are converted to per-unit-capacity costs by dividing the aggregate regional cost by the aggregate regional base gas storage capacity. The interstate pipeline per-unit storage capacity cost obtained for each region is applied to the noninterstate (intrastate and third party owners) regional storage capacity to obtain their estimated storage costs. These costs are added to the NGTDM region aggregate interstate pipeline company costs (FCS and VCS) to obtain the total storage facility costs (FCST and VCST) at the region node.

Next, the node-level storage tariff is computed as the sum of fixed and variable total costs divided by the working gas capacity, as shown below.

$$STAR_n = VSUM_n/WGCTT_n \tag{128}$$

$STAR_n$ = storage tariff (dollars per Mcf)
$VSUM_n$ = total storage costs (million dollars)
$WGCTT_n$ = working gas capacity, jurisdictional and non-jurisdictional (Bcf)
n = node

The total cost of storage is defined as the sum of all fixed and variable total storage costs as shown below:

$$VSUM_n = VCST_n + FCST_n \tag{129}$$

where,

$VSUM_n$ = total storage cost (million dollars)
$VCST_n$ = variable storage costs (million dollars)
$FCST_n$ = fixed storage cost (million dollars)
n = node

To account for regulatory oversight and to assist in stabilizing the tariffs, a check is performed each year to limit the annual increase in the storage tariff to a user specified escalation rate. This limit is imposed as shown in the following equation.

$$STAR_n = MIN(STAR_{n,t}, STAR_{n,t-1} * (1 + MAXESCO)) \tag{130}$$

where,

$STAR_{n,t}$ = storage tariff (dollars per Mcf)
MAXESC = maximum allowable annual escalation rate for tariffs [Appendix F, Table F35 (fraction)]
n = node
t = forecast year

This method of computing storage tariffs does not conform strictly to industry practices; rather it conforms to the representation of storage in other modules of the NGTDM.

[71]To distribute costs regionally, it is assumed that reported costs represent only costs associated with storage facilities owned by the company and do not include costs of storing gas in other facilities.

Construction of Capacity Expansion Cost (Pipeline/Storage) Tariff Curves

As part of the base-year initialization process, the PTM constructs cost (or pipeline/storage tariff) curves for the Capacity Expansion Module. The primary criterion in determining when and where physical pipelines and storage facilities will need to be expanded is the need of customers purchasing firm service to receive gas on future peak days. A secondary criterion is that the costs associated with pipeline and storage expansion are kept to a minimum. In general, pipeline companies and LDC's recognize that the high costs incurred in adding pipeline and storage capacity may lead to increased per-unit charges to customers purchasing firm service, which in the short-term may lead to slight decreases in consumption levels. In the long-term, increased delivery costs may lead to much more significant demand shifts when end-use capital purchasing decisions are affected.

To facilitate the cost minimization process in the Capacity Expansion Module, separate cost/tariff curves for incremental pipeline capacity expansion and storage expansion projects are developed for the incremental pipeline and storage services by the PTM and input to the Capacity Expansion Module. These cost/tariff curves relate incremental capacity expansion by arc (region) to corresponding pipeline (storage) tariffs.

The cost/tariff curves are constructed through a process comparable to the base-year initialization procedure described earlier. The PTM has an exogenous data input file of pipeline and storage capacity cost curves that relate capital cost to corresponding capacity expansion. Pipeline and storage capital cost data are developed from the incremental costs required to add an additional increment of capacity along a network arc or to a storage node in the NGTDM. These incremental costs reflect the capital costs associated with adding compressors, looping,[72] and other means of expanding pipeline capacity, or the capital costs associated with adding new or expanding existing natural gas storage fields. The PTM also obtains from an exogenous data base the operating costs, depreciation schedules, and other components of revenue requirements associated with pipeline or storage expansion. The exogenous data are defined by region and are based on historic industry averages.

Construction of the pipeline capacity (storage) tariff cost curves is comparable to the process in which base-year transportation (storage) tariffs are developed. However, instead of using the existing pipeline company data bases, the components of revenue requirements for the capacity expansion cost curves are obtained from a separate exogenous data base containing the capital and revenue requirements for capacity expansion projects. Using these data, together with the base-line initialization equations discussed below, the PTM develops the reservation fee associated with each level of capacity expansion provided by the Capacity Expansion Module. The pipeline capacity (storage) expansion tariff curves are constructed in the base year and are used by the Capacity Expansion Module in all subsequent forecast years.[73]

Passing Rates to the Annual Flow Module and Curves to Capacity Expansion Module

As discussed in Chapter 5, the PTM passes the following items to the Annual Flow Module: (1) reservation costs assigned to core customers, (2) usage fees for firm transportation service, (3) minimum transportation rate for interruptible service, (4) maximum transportation rate for interruptible service, and (5) rates for storage service. All PTM data elements passed to the Annual Flow Module must be converted to real dollars using the GDP deflators from the NEMS macroeconomic model. Similarly, when passing the capacity expansion cost tariff curves to the Capacity Expansion Module, the rates must be converted to real dollars.

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[72]Looping is the construction of a pipeline parallel to an existing line to increase the capacity of the system.

[73]The pipeline tariff is in dollars per MMBtu-mile and the storage tariff, including injection and inventory costs, is in dollars per MMBtu of working gas capacity.

Forecast Year Update Phase

The purpose of the forecast year update phase is to project, for each subsequent year of the forecast period, the line items of the cost-of-service discussed above that are used to develop rates. In each remaining year of the simulation, the PTM forecasts the pipeline company-level parameters required to determine the cost of capital, rate-base, operation and maintenance expense, and taxes. Additionally, arc-specific billing determinants are projected for the forecast year. These parameters are used to calculate the arc-specific (node-specific) rates using the procedure described in the base-year initialization phase. The forecasting relationships are discussed in detail below.

The PTM also accounts for revenues and volumetric flows for new capacity in the forecast year by assigning these parameters to arc- or region-specific generic pipeline or storage companies. These parameters are forecast at the arc-level in subsequent years. Generic pipeline and storage companies are discussed in more detail below.

After all the line items of the cost-of-service are forecasted, the PTM proceeds to: (1) classify line items of the cost of service as fixed and variable costs, (2) allocate fixed and variable costs to rate component (reservation and usage fee, volumetric charge) based on the rate design, (3) aggregate costs to the network arc/network node, (4) for transportation services, allocate costs to type of service (firm and interruptible), and (5) compute arc-specific (node-specific) rates.

Generic Pipeline and Storage Companies for Capacity Expansion

The Capacity Expansion Module projects pipeline capacity expansion at the arc level and storage expansion at the regional level, as opposed to determining expansion for individual companies. The PTM creates arc-specific generic pipeline companies and regional, node-specific, generic storage facilities to incorporate the effects of capacity expansion on an arc or node. Thus, the PTM tracks costs attributable to capacity added during the forecast period separately from the costs attributable to facilities in service in the base year. The PTM uses an exogenous data base to obtain the capital costs which correspond to the level of capacity expansion provided by the Capacity Expansion Module in the forecast year.[74] The exogenous data base contains costs in real dollars. These costs must be converted to nominal dollars in the forecast year using the GDP deflators provided by the NEMS macroeconomic model. Other line items of the cost-of-service for the generic companies are derived from historical industry averages and are provided by an exogenous data base. These costs too must be converted to nominal dollars and also must be scaled to reflect the size of expansion determined by the Capacity Expansion Module.

The new capacity expansion expenditures allowed in the rate-base within the forecast year is derived for each arc and node from the amount of incremental capacity additions determined by the Capacity Expansion Module as shown below.

$$NCAE = \sum_{s=2}^{S}(CAPCST_{a,s} - CAPCST_{a,s-1}) * (EXPAND_{a,s} / AVAIL_{a,s}) \qquad (131)$$

$$NCAE = \sum_{s=2}^{S}(CAPCST_{n,s} - CAPCST_{n,s-1}) * (EXPAND_{n,s} / AVAIL_{n,s}) \qquad (132)$$

where,

NCAE = new capacity expansion expenditures allowed in the rate base within the forecast year (dollars)
CAPCST = total capital cost to expand capacity (dollars)

[74]Capital requirements for new storage capacity expansion are determined from the incremental base gas capacity expansion and the wellhead price in the forecast year which is used as cushion gas to maintain adequate pressures.

EXPAND	=	amount of incremental capacity added by the Capacity Expansion Module (Bcf)
AVAIL	=	maximum amount of capacity expansion available (Bcf)
a	=	arc
n	=	node
s	=	index for type of expansion, 1 = existing capacity, 2 = compression, 3 = looping, 4,5,6 = new pipe

The total capital cost to expand capacity at each arc is derived below.

$$CAPCST_{a,s} = CAPCST_{a,s-1} + (ARCCC_{a,s} * ((ARCEX_{a,s} - ARCEX_{a,s-1}) * 1{,}000{,}000) * MILES_a)/365 \qquad (133)$$

where,

CAPCST	=	total capital cost to expand capacity (dollars)
ARCCC	=	capital cost per unit of expansion (dollars-day per Mcf-mile)
ARCEX	=	allowable expansion size for an arc (Bcf)
MILES	=	length of transportation arc in miles [Appendix F, Table F17]
a	=	arc
s	=	index for type of expansion, 1 = existing capacity, 2 = compression, 3 = looping, 4,5,6 = new pipe

An upper bound limiting the amount of additional capacity that can be achieved through adding compression, looping, and adding new pipe is defined for each arc as a function of the base year arc capacity. The bounds are defined as follows:

$$ARCEX_{a,s} = PCAP\_MAX_a * ARCFAC_{a,s} \qquad (134)$$

where,

ARCEX	=	maximum allowable capacity expansion (Bcf)
PCAP_MAX	=	base year design capacity (Bcf)
ARCFAC	=	arc capacity expansion factor [Appendix F, Table F16 (fraction)]
a	=	arc
s	=	expansion step

Unit capital costs for expanding capacity are adjusted to reflect regional differences in costs, as shown below.

$$ARCCC_{a,s} = CCOST_{a,s} * (1 + CSTFAC_{a,s}) \qquad (135)$$

where,

ARCCC	=	capital cost per unit of expansion (dollars-day per Mcf-mile)
CCOST	=	capital cost to expand 1 unit of pipeline capacity [Appendix F, Table F16 (dollars-day per Mcf-mile)]
CSTFAC	=	factor to accommodate regional difference in cost [Appendix F, Table F16 (fraction)]
a	=	arc
s	=	expansion step

Similar to pipeline capacity expansion, capital costs for expanding storage at each node is derived below.

$$CAPCST_{n,s} = CAPCST_{n,s-1} + (NODECC_{a,s} * (NODEEX_{n,s} - NODEEX_{a,s-1} * 1{,}000{,}000) \qquad (136)$$

where,

$CAPCST$ = total capital cost to expand capacity (dollars)
$NODECC$ = capital cost per unit of expansion (dollars per Mcf)
$NODEEX$ = allowable expansion size for a node (Bcf)
n = node
s = expansion step

An upper bound limiting the amount of additional storage capacity that can be added at each node is defined as a function of the base year node capacity. The bounds are defined as follows:

$$NODEEX_{n,s} = (WGCT_n + WGCNT_n) * NODFAC_{n,s} \tag{137}$$

where,

$NODEEX$ = maximum allowable capacity expansion at a given storage node (Bcf)
$WGCT$ = jurisdictional working gas capacity in the base year (Bcf)
$WGCNT$ = nonjurisdictional working gas capacity in the base year (Bcf)
$NODFAC$ = node capacity expansion factor [Appendix F, Table F16 (fraction)]
n = node
s = expansion step

For pipeline capacity expansion, the peak day reservations are set equal to the daily capacity (the capacity provided by the Capacity Expansion Module divided by 365 days per year). The annual flow through the pipeline is calculated as the capacity multiplied by a utilization factor provided by the Capacity Expansion Module or assumed exogenously. For storage capacity expansion, the amount of gas withdrawn is set equal to the working gas capacity.

After the generic pipeline company transportation and storage volumes and cost-of-service are determined, the generic company is treated within the PTM as an additional arc-specific pipeline company and/or regional node-specific storage facility. Cost-of-service for the aggregate of all prior years' capacity expansion projects is projected to the forecast year according to the subsequent year's forecasting procedure discussed below. Company-level cost-of-service for the new incremental capacity in the forecast year are determined according to the base-year initialization procedure discussed above and added to the projected cost-of-service of the aggregate prior years' capacity.

Forecasting Cost-of-Service[75]

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 new construction 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. Thus, 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 which, 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 factor cost changes (e.g., wage rates), the extent or complexity of service provided to each customer, and the efficiency of the technology level employed in providing the service.

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

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 factor cost changes 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 PTM (e.g., annual throughput, etc.) which 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/storage facility costs, accounting algorithms, exogenous assumptions, and inputs from other NEMS modules. These forecasting algorithms may be classified into three distinct projected pipeline cost areas, as follows:

- The projection of existing and incremental rate base and capital costs
- The projection of capital-related components of the revenue requirement
- The projection of operations and maintenance expenses of the revenue requirements.

The empirically derived forecasting algorithms discussed below are determined for each pipeline company.

Projection of Rate Base and Cost of Capital

The approach for projecting rate base and capital costs is summarized in Table 8-4. Long-run marginal capital costs of pipeline companies are reflected in changes in the rate base. Once projected, the rate base is translated into capital-related components of the revenue requirements based on projections of the cost of capital, capitalization, and algorithms for depreciation and tax effects.

Rate-Base Components. The projected rate base in year t is computed as in the base year. That is, the rate base in year t is the net plant in service in year t plus working capital and transition expenses in year t.

$$PRB_t = GPIS_t - ADDA_{t-1} + CWC_t + OWC_t \tag{138}$$

where,

PRB = pipeline rate base before adjustment in dollars
GPIS = original capital cost of plant in service (gross plant in service) in dollars
ADDA = accumulated depletion, depreciation, and amortization in dollars
CWC = cash working capital in dollars
OWC = other working capital in dollars
t = forecast year

The variables of the rate-base equation are forecast by the following set of equations. First, gross plant in service in the forecast year is determined by the prior year's gross plant in service, new capacity expansion (as determined by the Capacity Expansion Module), current capital additions to existing plants for replacement and refurbishment, and cost associated with new facilities for complying with Order 636. Gross plant in service is forecast as follows:

$$GPIS_t = \begin{cases} GPIS_{t-1} + BLAE_t + PNEWFAC_t & \text{(existing pipe)} \\ GPIS_{t-1} + NCAE_t & \text{(generic pipe)} \end{cases} \tag{139}$$

where,

GPIS = original capital cost of plant in service (gross plant in service) in dollars
NCAE = new capacity expansion expenditures allowed in rate base within the forecast year in dollars
BLAE = capital expenditures associated with base year capacity (refurbishment/replacement expenditures) in dollars
PNEWFAC = cost of new facilities required to comply with Order 636 (nominal dollars)[76]

[76]New facilities transition cost will be added into original capital cost of plant in service, on individual pipeline basis. See Table F24 in Appendix F for default assumptions on costs and depreciation schedules.

Table 8-4. Approach to Projection of Rate Base and Capital Costs

Projection Component	Approach
1. Rate Base	
a. Gross plant in service	
I. Capacity expansion costs for generic pipeline/storage	Provided by the Capacity Expansion Module
II. Replacement/refurbishment costs for existing pipeline/storage	Accounting algorithm or user defined options
b. Accumulated Depreciation, Depletion & Amortization	Existing Pipelines: empirically estimated Generic Pipelines: accounting algorithm
c. Cash and other working capital	Empirically estimated
d. Transition expenses	Accounting algorithm with exogenous specification for recovery/absorption
e. Accumulated deferred income taxes	Existing Pipelines: empirically estimated Generic Pipelines: accounting algorithm.
f. Depreciation, depletion, and amortization	Existing Pipelines: empirically estimated Generic Pipelines: accounting algorithm
2. Cost of Capital	
a. Long-term debt rate	Base year average rate, adjusted using projected bond yields
b. Preferred equity rate	Base year rate (fixed)
c. Common equity return	Incorporate changes in dividend/bond yields
3. Capital Structure	Held constant at base year values

Capital expenditures associated with base year capacity (refurbishment on existing pipeline/storage) are obtained by using three available options (BLAESWT = 0, 1, 2). The first option (used in *AEO95*) sets capital expenditures for pipeline refurbishment/replacement to zero. The second option sets refurbishment to be a proportion of the annual depreciation expense. The proportion is a function of the age of the plant. Option three allows the user to exogenously define total annual capital expenditures for refurbishment for the whole pipeline industry. The industry-wide expense is distributed to individual companies as a function of the gas plant in service. These options are defined as follows:

<u>option 1</u> (BLAESWT=0):

$$BLAE_t = 0 \tag{140}$$

<u>option 2</u> (BLAESWT=1):

$$BLAE_t = DDA_t * ADDA_t \ / \ GPIS_{t-1} \tag{141}$$

where,

BLAE = capital expenditures associated with base year capacity (refurbishment/ replacement expenditures) in dollars
DDA = depreciation, depletion and amortization costs in dollars
ADDA = accumulated depreciation, depletion, and amortization in dollars
GPIS = original capital cost of plant in service (gross plant in service) in dollars
t = forecast year

<u>option 3</u> (BLAESWT=2):

$$BLAE_t = BLAETOT * (GPIS_{t-1} \ / \ INDUSTRYGPIS_{t-1}) \tag{142}$$

where,

BLAE = capital expenditures associated with base year capacity (refurbishment/ replacement expenditures) in dollars
BLAETOT = user-defined total capital expenditure for refurbishment/replacement for the pipeline industry in dollars
GPIS = original capital cost of plant in service (gross plant in service) in dollars
INDUSTRYGPIS = total capital cost of plant in service (gross plant in service) for pipeline industry in dollars
t = forecast year

Accumulated depreciation, depletion, and amortization is given by:

$$ADDA_t = ADDA_{t-1} + DDA_t \tag{143}$$

where,

ADDA = accumulated depreciation, depletion, and amortization in dollars
DDA = depreciation, depletion, and amortization costs in dollars

A regression equation is used to define the annual depreciation, depletion, and amortization for existing pipelines, while an accounting algorithm is used for generic pipelines. For existing pipelines, this expense is forecast as follows:

$$DDA_t = (1-\rho)*\beta_0 + \beta_1*NETPLT_t + \beta_2*DEPSHR_t + \rho*DDA_{t-1} - \rho*(\beta_1*NETPLT_{t-1} + \beta_2*DEPSHR_{t-1}) \quad (144)$$

where,

DDA = depreciation, depletion, and amortization costs in dollars
β_0,β_1,β_2 = coefficients estimated based on an empirical study (Appendix G, Table G4)
ρ = estimated auto-correlation coefficients (Appendix G, Table G4)
NETPLT = net capital cost of plant in service (dollars)
DEPSHR = ratio of accumulated depreciation, depletion, and amortization expenses to gross plant in service (a proxy for pipeline age)

The net plant in service and the proxy for pipeline age are defined as follows:

$$NETPLT_t = GPIS_{t-1} - ADDA_{t-1}$$
$$DEPSHR_t = ADDA_{t-1} / GPIS_{t-1} \quad (145)$$

where,

GPIS = original capital cost of plant in service (gross plant in service) in dollars
ADDA = accumulated depreciation, depletion, and amortization in dollars

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

$$DDA_t = \sum_{s=1991}^{t} (NCAE_s / 30) \quad (146)$$

where,

DDA_t = depreciation, depletion, and amortization costs in dollars
$NCAE_s$ = new capacity expenditures occurring in year s (in dollars)
s = the year new expansion occurred
30 = 30 years of plant life
t = forecast year

Cash working capital is set equal to zero, because historically it has been at or near zero. Thus,

$$CWC_t = 0 \quad (147)$$

where,

CWC = cash working capital in dollars

Other working capital consists of material and supplies, gas held in storage, and other components that vary by company. Other working capital is calculated as a function of gross plant in service, as follows:

$$OWC_t = GPIS_t^{\beta 0} * GPIS_{t-1}^{-\rho*\beta 0} * \exp[\beta 1 * (MC\_PGDP_t - \rho*MC\_PGDP_{t-1})] * \exp[\beta 2 * (TYEAR - \rho*(TYEAR-1.0))] * OWC_{t-1}^{\rho} * CONST \quad (148)$$

where,

OWC = other working capital in dollars
GPIS = original capital cost of plant in service (gross plant in service) in dollars
$\beta 0$ = estimated coefficient on gross plant in service

ρ = estimated auto correlation coefficient
$\beta 1$ = estimated coefficient on price level
MC_PGDP_t = implicit GDP price deflator (from the Macroeconomic Activity Model)
$\beta 2$ = estimated coefficient on time trend
TYEAR = year in Julian units (i.e., 1995)
CONST = estimated constant term
t = forecast year
[Note: See Table G4 in Appendix G for derivation of coefficients and regression statistics]

The rate base is adjusted for accumulated deferred income taxes and other expenses as follows:

$$APRB_t = PRB_t - ADIT_t + TPEB \qquad (149)$$

where,

APRB = adjusted pipeline rate base in dollars
PRB = pipeline rate base before adjustment in dollars
ADIT = accumulated deferred income taxes in dollars
TPEB = transition expense balance in dollars
t = forecast year

Accumulated deferred income taxes depends on income tax regulations in effect, differences in tax and book depreciation, and the time vintage of past construction. The relationship established for the existing pipeline is different from the relationship for generic pipeline. The accumulated deferred income taxes for existing pipeline/storage is derived as follows:

$$ADIT_t = \beta_0 + \beta_1 * ADIT_{t-1} + \beta_2 * NETPLT_t \qquad (150)$$

where,

$\beta_0, \beta_1, \beta_2$ = coefficients estimated based on empirical study (Appendix G, Table G4)
ADIT = accumulated deferred income taxes in dollars
NETPLT = difference between original capital cost of plant in service and accumulated depreciation in previous period (net plant in service) in dollars
t = forecast year

Accumulated deferred income taxes for generic companies is calculated using an accounting algorithm. It is assumed that for rate making purposes, straight line depreciation (SLD) is used. However, for tax purposes, modified accelerated cost recovery system (MACRS) with a 15 1/2 year schedule is used. ADIT is derived from the difference between two depreciation schedules and the tax rate. Selecting the formula used to calculate ADIT depends on the difference between two depreciation schedules and the book value of the asset (calculated using the MACRS depreciation schedule). The formulae are as follows:

$$ADIT_t = \begin{cases} ADIT_{t-1} + (DEPRMACRS_t - DEPRSL_t) * FRATE & \text{if } DEPRMACRS > DEPRSL \\ ADIT_{t-1} & \text{if } DEPRMACRS < DEPRSL \text{ and } BOOKVL > 0 \\ ADIT_{t-1} - DEPRSL_t * FRATE & \text{if } BOOKVL = 0 \end{cases} \qquad (151)$$

where,

ADIT = accumulated deferred income taxes in dollars
DEPRMACRS = annual depreciation expense using MACRS
DEPRSL = annual depreciation expense using 30 year straight line schedule

FRATE = federal tax rate (Appendix G, Table G4)
BOOKVL = book value of plant, which is calculated using straight line depreciation schedule
t = forecast year

and,

$$DEPRMACRS_t = \sum_{s=1991}^{t} NCAE_s * MACRS\_RATE_{t-s+1}$$

$$DEPRSL_t = \sum_{s=1991}^{t} NCAE_s / 30 \tag{152}$$

where,

NCAE = new capacity expansion expenditures occurring in year s (in dollars)
MACRS_RATE = rate of depreciation by MACRS schedule (Appendix G, Table G4)
s = the year new expansion occurred
t = forecast year

Cost of Capital. The capital-related components of the revenue requirement depend upon the size of the rate base and the cost of capital to the pipeline company. In turn, the company cost of capital depends upon the rates of return on debt and equity and the amounts of debt and equity in the overall capitalization.

Company cost of capital consists of long-term debt, preferred stock, and common equity. The rate of return variables for debt and equity will be related to forecast macroeconomic variables. For example, it is assumed that the long-term debt rate for existing pipe will vary as a function of a delta off of the long-term debt rate and the yield on AA utility bonds provided by the Macroeconomic Activity Model, as follows:

$$LTDR_t = MC\_RMPUAANS_t / 100.0 + LTDR_b - MC\_RMPUAANS_b / 100.0 \tag{153}$$

where,

LTDR = long-term debt rate [Appendix E, Table E5 (fraction)]
MC_RMPUAANS = AA utility bond index rate provided by the Macroeconomic Activity Model (percentage)
b = base year
t = forecast year

The coupon rate for preferred stock is assumed constant at the base-year coupon rate for existing pipelines. Thus,

$$PFER_t = PFER_b \tag{154}$$

where,

PFER = coupon rate for preferred stock [Appendix E, Table E5 (fraction)]
b = base year
t = forecast year

The rate of return on common equity for existing pipelines is considered to be a function of the long-term debt rate and the difference between the long-term debt rate and the approved rate of return on common equity in the base year.

$$CMER_t = LTDR_t + CMER_b - LTDR_b \tag{155}$$

where,

CMER	=	common equity rate of return [Appendix E, Table E5 (fraction)]
LTDR	=	long-term debt rate [Appendix E, Table E5 (fraction)]
b	=	base year
t	=	forecast year

For existing companies, the values of common stock, preferred stock and long term debt are assumed to be constant in real dollars; therefore, in nominal dollars these are increased by the inflation rate for the forecast period:

$$\begin{aligned} PFES_t &= PFES_{t-1} * GDPINFL_t \\ CMES_t &= CMES_{t-1} * GDPINFL_t \\ LTD_t &= LTD_{t-1} * GDPINFL_t \end{aligned} \tag{156}$$

where,

PFES	=	value of preferred stock in nominal dollars
CMES	=	value of common equity in nominal dollars
LTD	=	long-term debt in nominal dollars
GDPINFL	=	implicit GDP price inflator relative to previous year (from the Macroeconomic Activity Model)
t	=	forecast year

For generic companies, the long-term debt rate (GLTDR), coupon rate for preferred stock (GPFER), and common equity rate of return (GCMER) are assumed to be constant over the forecast period (Appendix F, Table F46). Likewise, the capital structure for generic pipeline are also assumed constant. The three components of capital structure (GPFESTR, GCEMSTR, and GLTDSTR) are defined as the average 1990 capital structure of the pipeline directly represented in the PTM (Appendix E, Table E4), and are used, along with the adjusted pipeline rate base, to determine the values of preferred stock, common stock, and long term debt:

$$\begin{aligned} PFES_t &= GPFESTR_t * APRB_t \\ CMES_t &= GCMESTR_t * APRB_t \\ LTD_t &= GLTDSTR_t * APRB_t \end{aligned} \tag{157}$$

where,

PFES	=	value of preferred stock in nominal dollars
CMES	=	value of common equity in nominal dollars
LTD	=	long-term debt in nominal dollars
GPFESTR	=	average historical ratio of preferred stock to total capital used as capital structure for generic pipeline (constant over forecast period)
GCMESTR	=	average historical ratio of common stock to total capital used as capital structure for generic pipeline (constant over forecast period)
GLTDSTR	=	average historical ratio of long term debt to total capital used as capital structure for generic pipeline (constant over forecast period)
APRB	=	adjusted pipeline rate base (dollars)
t	=	forecast year

Capital structure is the percent of total capitalization represented by each of the three capital components: long-term debt costs, preferred equity, and common equity. The proportions of total capitalization due to common stock, preferred stock, and long-term debt is considered fixed at the base-year values throughout the forecast. Assuming that the fractions of total capitalization remain the same over the forecast horizon,[77] the weighted average cost of capital in the forecast year is given by:

$$WAROR_t = [(PFER_t * PFES_t) + (CMER_t * CMES_t) + (LTDR_t * LTDS_t)] \; / \; TOTCAP_t \tag{158}$$

where,

WAROR = weighted-average before-tax rate of return on capital (fraction)
PFER = coupon rate for preferred stock (fraction)
PFES = value of preferred stock (dollars)
CMER = common equity rate of return (fraction)
CMES = value of common stock (dollars)
LTDR = long-term debt rate (fraction)
LTDS = value of long-term debt (dollars)
TOTCAP = sum of the value of long-term debt, preferred stock, and common stock equity [Equation 85 (dollars)]
t = forecast year

Projection of Capital-Related Components of the Revenue Requirements

The approach to the projection of capital-related components of the revenue requirements is summarized in Table 8-5. Given the rate-base and capitalization projections discussed above, the components of revenue requirements are relatively straightforward to project. The capital-related components of the revenue requirements include total return; Federal and State tax credits; Federal and State income taxes; other taxes; and depreciation, depletion, and amortization costs. These cost components are projected as follows:

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

$$TRRB_t = WAROR_t * APRB_t \tag{159}$$

where,

TRRB = total return on rate base (before taxes) in dollars
WAROR = weighted-average before-tax rate of return on capital (fraction)
APRB = adjusted pipeline rate base in dollars
t = forecast year

The return on rate base for existing companies is broken out into the three components as shown below:

$$PFEN_t = (PFES_t / TOTCAP_t) * PFER_t * APRB_t \tag{160}$$

$$CMEN_t = (CMES_t / TOTCAP_t) * CMER_t * APRB_t \tag{161}$$

$$LTDN_t = (LTDS_t / TOTCAP_t) * LTDR_t * APRB_t \tag{162}$$

where,

PFEN = total return on preferred stock (dollars)
PFES = value of preferred stock (dollars)
TOTCAP = total capitalization (dollars)
PFER = coupon rate for preferred stock (fraction)
APRB = adjusted pipeline rate base (dollars)

[77]Changes in capital structure could be treated later as an enhancement to the PTM. This would involve consideration of, among other factors, sources and uses of funds, dividend payout policies, and regulatory caps on how much common equity is permitted in determining rates. It is not clear that this enhancement would offer large benefits to the forecast.

Table 8-5. Approach to Projection of Revenue Requirements: Capital-Related Costs and Taxes

Projection Component	Approach
1. Rate Base-related Components	
a. Total return	Direct calculation from projected rate base and rates of return
b. Federal/State tax credits	Held constant in real terms at base year values
c. Federal/State income taxes	Accounting algorithms based on tax rates
2. Other Taxes	Held constant in real terms at base year values

CMEN = total return on common stock equity (dollars)
CMES = value of common stock equity (dollars)
CMER = common equity rate of return (fraction)
LTDN = total return on long-term debt (dollars)
LTDS = value of long-term debt (dollars)
LTDR = long-term debt rate (fraction)
t = forecast year

For generic companies the capital structure is assumed to be constant over the forecast period. Therefore, the return on rate base for generic companies (new expansion portion of pipeline/storage) is defined using a simpler format:

$$PFEN_t = (GPFESTR) * PFER_t * APRB_t \tag{163}$$

$$CMEN_t = (GCEMSTR) * CEMR_t * APRB_t \tag{164}$$

$$LTDN_T = (GLTDSTR) * LTDR_t * APRB_t \tag{165}$$

where,

PFEN = total return on preferred stock (dollars)
CMEN = total return on common stock equity (dollars)
LTDN = total return on long-term debt (dollars)
GPFESTR = average historical ratio of preferred stock to total capital used as capital structure for generic pipeline (constant over forecast period)
GCMESTR = average historical ratio of common stock to total capital used as capital structure for generic pipeline (constant over forecast period)
GLTDSTR = average historical ratio of long term debt to total capital used as capital structure for generic pipeline (constant over forecast period)
PFER = coupon rate for preferred stock (fraction)
CMER = common equity rate of return (fraction)
LTDR = long-term debt rate (fraction)
APRB = adjusted pipeline rate base (dollars)
t = forecast year

Total taxes consists of Federal income taxes, State income taxes, and other taxes at average rates, minus tax credits for Federal and State income taxes. Federal income taxes and State income taxes are calculated in the same manner as in the base year (Equations 89-93) using average tax rates. The equation for total taxes is as follows:

$$TOTAX_t = FSIT_t + OTTAX_t - FSITC_t \tag{166}$$

where,

TOTAX = total Federal and State income tax liability (dollars)
FSIT = Federal and State income tax (dollars)
FSITC = Federal and State investment tax credits (dollars)
OTTAX = all other taxes assessed by Federal, State, or local governments except income taxes (dollars)
t = forecast year

Federal income tax credits are assumed to remain constant in real terms at the base year level throughout the forecast and therefore they are adjusted for inflation. Other taxes relate to 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 are determined as a function of the previous year's level times the inflation rate from the previous year.

$$OTTAX_t = OTTAX_{t-1} * (MC\_PGDP_t \,/\, MC\_PGDP_{t-1}) \tag{167}$$

where,

OTTAX = all other taxes assessed by Federal, State, or local governments except income taxes (dollars)
MC_PGDP = implicit GDP price deflator (from the Macroeconomic Activity Model)
t = forecast year

Projection of Normal Operating Expenses and Revenue Credits

The remaining projected components of the revenue requirements are normal operating expenses and revenue credits. Normal operating expenses are further disaggregated into depreciation, depletion, and amortization expenses, total taxes (previously estimated above), administrative and general expense, customer expenses, and total operations and maintenance expenses. The approach to the projection of these line items is summarized in Table 8-6. The projected costs are based on long-run marginal cost relationships in the pipeline industry which relate cost incurrence to external measures of industry size or activity and which relate unit costs to measurable changes in factor costs, the level and nature of the service, and technology. In some cases costs are assumed to be held constant because of limited resources available to develop data and develop the empirical estimates.

The total cost of service for a forecast year is as follows:

$$TCOS_t = TRRB_t + TNOE_t - REVC_t \tag{168}$$

where,

TCOS = total cost-of-service (dollars)
TRRB = total return on rate base [before taxes (dollars)]
TNOE = total normal operating expenses (dollars)
REVC = revenue credits to cost-of-service (dollars)
t = forecast year

Revenue credits to cost-of-service is determined as a function of the previous year's level times the inflation rate from the previous year, as follows:

Table 8-6. Approach to Projection of Revenue Credits and Normal Operating Expenses

Projection Component	Approach
1. Revenue Credits to Cost of Service	Held constant at base-year value adjusted for inflation
2. Depreciation, Depletion, and Amortization	Empirically estimated
3. Administrative & General • salaries, pension benefits, regulatory expenses, and other expenses	Empirically estimated
4. Customer Expense	Held constant at base-year value adjusted for inflation
5. Total Operating and Maintenance Expense	Empirically estimated

$$REVC_t = REVC_{t-1} * (MC\_PGDP_t / MC\_PGDP_{t-1}) \tag{169}$$

where,

REVC = revenue credits to cost-of-service (dollars)
MC_PGDP = implicit GDP price deflator (from the Macroeconomic Activity Model)
t = forecast year

The revenue requirement consists of a just and reasonable return on the rate base plus normal operating expenses.

$$TRR_t = TRRB_t + TNOE_t \tag{170}$$

where,

TRR = total revenue requirement (dollars)
TRRB = total return on rate base [before taxes (dollars)]
TNOE = total normal operating expenses (dollars)
t = forecast year

The total normal operating expenses costs consist of the following components:

$$TNOE_t = DDA_t + TOTAX_t + TAG_t + TCE_t + TOM_t \tag{171}$$

where,

TNOE = total normal operating expenses (dollars)
TOTAX = total Federal and State income tax liability (dollars)

DDA = depreciation, depletion, and amortization costs (dollars)
TAG = total administrative and general expense (dollars)
TCE = total customer expense (dollars)
TOM = total operating and maintenance expense (dollars)
t = forecast year

A regression equation is used to define the annual depreciation, depletion, and amortization for existing pipelines, while an accounting algorithm is used for generic pipelines. For existing pipelines, this expense is forecast as follows:

$$DDA_t = (1-\rho)*\beta_0 + \beta_1*NETPLT_t + \beta_2*DEPSHR_t + \rho*DDA_{t-1} - \rho*(\beta_1*NETPLT_{t-1} + \beta_2*DEPSHR_{t-1}) \quad (172)$$

where,

DDA = depreciation, depletion, and amortization costs in dollars
$\beta_0, \beta_1, \beta_2$ = coefficients estimated based on an empirical study (Appendix G, Table G4)
ρ = estimated auto-correlation coefficients (Appendix G, Table G4)
NETPLT = net capital cost of plant in service (dollars)
DEPSHR = ratio of accumulated depreciation, depletion, and amortization expenses to gross plant in service (a proxy for pipeline age)

The net plant in service and the proxy for pipeline age are defined as follows:

$$NETPLT_t = GPIS_{t-1} - ADDA_{t-1}$$
$$DEPSHR_t = ADDA_{t-1} / GPIS_{t-1} \quad (173)$$

where,

GPIS = original capital cost of plant in service (gross plant in service) in dollars
ADDA = accumulated depreciation, depletion, and amortization in dollars

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

$$DDA_t = \sum_{s=1991}^{t} (NCAE_s / 30) \quad (174)$$

where,

DDA_t = depreciation, depletion, and amortization costs in dollars
$NCAE_s$ = new capacity expansion expenditures occurring in year s (in dollars)
s = the year new expansion occurred
30 = 30 years of plant life
t = forecast year

Total administrative and general costs are determined as a function of gross plant in service and average annual wage rate[78]:

where,

[78]Note that the second WAGE term in the TAG equation was inadvertently coded as $WAGE_t$ for the *AEO95*, but should have been coded as a lagged term $WAGE_{t-1}$ (in accordance with the final estimated econometric equations presented in Appendix G, Table G4). Once the correction was made, results from both equations were compared and determined to be very close due to the small difference between $WAGE_t$ and $WAGE_{t-1}$. Subsequent versions of the PTM will have the proper TAG equation.

$$TAG_t = e^{(1-\rho)*\beta_0} * GPIS_{t-1}^{\beta_1} * e^{\beta_2 * year} * WAGE_t^{\beta_3} * TAG_{t-1}^{\rho} * GPIS_{t-2}^{-\rho*\beta_1} * e^{-\rho*\beta_2*(year-1)} * WAGE_t^{-\rho*\beta_3} \tag{175}$$

TAG = total administrative and general costs in real dollar
$\beta_0,\beta_1,\beta_2,\beta_3$ = coefficients estimated based on an empirical study (Appendix G, Table G4)
ρ = estimated auto-correlation coefficients (Appendix G, Table G4)
$YEAR$ = year in Julian units (i.e.1990)
$GPIS$ = original capital cost of plant in service (Gross Plant In Service) in dollar
$WAGE$ = average annual salary paid in natural gas transmission industry, which is adjusted by real labor index (Appendix G, Table G4)
t = forecast year

Then, the total administrative and general costs are converted to nominal dollar to be consistent with the convention in this module.

$$TAG_t = TAG_t * MC\_PGDP_t \tag{176}$$

where,

MC_PGDP = implicit GDP price deflator (from the Macroeconomic Activity Model)
t = forecast year

For projection purposes, total customer expense is a function of last year's level times the inflation rate from the previous year.

$$TCE_t = TCE_{t-1} * (MC\_PGDP_t \,/\, MC\_PGDP_{t-1}) \tag{177}$$

where,

TCE = total customer expense (dollars)
MC_PGDP = implicit GDP price deflator (from the Macroeconomic Activity Model)
t = forecast year

Total operating and maintenance expenses are estimated separately for existing pipeline and generic pipeline, as follows.

Existing pipeline[79]:

$$TOM_t = e^{(1-\rho)*\beta_0} * MILE_{i,t}^{\beta_1} * WAGE_t^{\beta_2} * PEQUIP_t^{\beta_3} * TYEAR^{\beta_4} * TOM_{t-1}^{\rho} * MILE_{i,t-1}^{-\rho*\beta_1} * WAGE_t^{-\rho*\beta_2} * PEQUIP_{t-1}^{-\rho*\beta_3} * (TYEAR-1)^{-\rho*\beta_4} \tag{178}$$

Generic pipeline:

$$TOM_t = e^{(1-\rho)*\alpha_0} * GPIS_{t-1}^{\alpha_1} * PEQUIP_t^{\alpha_2} * e^{\alpha_3 * DEPSHR_t} * TOM_{t-1}^{\rho} * GPIS_{t-2}^{-\rho*\alpha_1} * PEQUIP_{t-1}^{-\rho*\alpha_2} * e^{-\rho*\alpha_3*DEPSHR_{t-1}} \tag{179}$$

where,

TOM = total operating and maintenance expense in real dollars
$\beta_0,\beta_1,\beta_2,\beta_3,\beta_4$ = coefficients estimated for existing pipeline (Appendix G, Table G4)

[79]Note that the second WAGE term in the TOM equation for existing pipeline was inadvertently coded as $WAGE_t$ for the *AEO95*, but should have been coded as a lagged term $WAGE_{t-1}$ (in accordance with the final estimated econometric equations presented in Appendix G, Table G4). Also, the YEAR terms should have been coded as exp(ß$_4$*YEAR) and exp(ρ*ß$_4$*(YEAR-1)) as presented in Appendix G, Table G4. Once these corrections were made, results from both equations were compared and determined to be very close. Subsequent versions of the PTM will have the proper TOM equation for existing pipeline.

$\alpha_0,\alpha_1,\alpha_2,\alpha_3$ = coefficients estimated for generic pipeline (Appendix G, Table G4)
ρ = estimated auto-correlation coefficients (Appendix G, Table G4)
$MILE_i$ = mile of pipeline for i^{th} company, which is a proxy for the firm's physical capital
WAGE = average annual salary paid in natural gas transmission industry, which is adjusted by real labor index (Appendix G, Table G4)
PEQUIP = price index of compressor station equipment
GPIS = original capital cost of plant in service [gross plant in service (dollars)]
DEPSHR = ratio of accumulated depreciation, depletion, and amortization to gross plant in service
TYEAR = year in Julian units (i.e., 1995)
t = forecast year

Then, total operating and maintenance expenses are converted to nominal dollars to be consistent with the convention in this module.

$$TOM_t = TOM_t * MC\_PGDP_t \tag{180}$$

where,

MC_PGDP_t = implicit GDP price deflator (from the Macroeconomic Activity Model)
t = forecast year

Computation of Rates for Forecast Years

Rates for the forecast years are computed using the procedures for the base-year initialization phase discussed above. These procedures include the following steps: (1) classify line items of the cost of service as fixed and variable costs, (2) allocate fixed and variable costs to rate component (reservation and usage fee, volumetric charge) based on the rate design, (3) aggregate costs to the network arc/network node, (4) for transportation services allocate costs to type of service (firm and interruptible), and (5) compute arc-specific (node-specific) rates. Estimation of pipeline costs for forecast years was presented in the previous section. Adjustment of the billing determinants in each year of the forecast is discussed below.

The method used to forecast billing determinants is consistent with (1) the assumptions used in the scenario definition, (2) the capacity factor/load factor assumptions, and (3) the incremental new capacity derived from the capacity expansion algorithm. Base-year peak-day billing determinants will not change throughout the forecast period for capacity in place in the base year. Rather, changes in billing determinants from capacity additions will be captured through arc-specific generic pipeline companies. Forecast pipeline and storage capacity requirements are determined by the Capacity Expansion Module. Incremental annual pipeline capacity and storage requirements and capital cost requirements by arc provided by the Capacity Expansion Module are assigned to arc-specific generic pipeline companies and storage facilities. Arc-specific adjustments to billing determinants are modeled through the addition to base-year volumes of incremental annual and peak service volumes for each generic pipeline company. Annual volume billing determinants will change based on throughput solved for in the Annual Flow Module in the previous year with an adjustment to include an estimate of throughput on incremental expansion in the current year assuming a load factor provided by the Capacity Expansion Module.

Billing determinants are determined, at the arc-level, by peak-day design delivery requirements, annual firm transportation volumes, annual interruptible transportation volumes, and the arc distances between regional nodes. Since regional growth in pipeline capacity is aggregated to the arc-level, arc distance between regional nodes remains constant throughout the forecast period. Consequently, changes in billing determinants are effected solely through changes in peak-day design and annual natural gas flows through each network arc during the forecast period.

9. Model Assumptions, Inputs, and Outputs

This last chapter summarizes the model and data assumptions used by the Natural Gas Transmission and Distribution Model (NGTDM) solution methodology and also presents the data inputs to and the outputs from the NGTDM.

Assumptions

This section presents a brief summary of the assumptions used within the Natural Gas Transmission and Distribution Model (NGTDM). Generally, there are two types of data assumptions that affect the NGTDM solutions. The first type can be derived based on historical data (past event), 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. Information on the performance testing of the NGTDM through variation in key inputs to the model is provided in Volume II of this document (the Model Developer's Report, January 3, 1995), which discusses the model performance and results of sensitivity testing. All model input assumptions, both those derived from known sources and those derived through analyst judgment, are provided in Appendix F.

The assumptions summarized in this section are referred to in Chapters 3 - 8. They are used in NGTDM equations as their 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. These assumptions are summarized below.

Market Service Classification

Nonelectric sector natural gas customers are classified as either core or noncore customers, with core customers transporting their gas under firm (or near firm) transportation agreements and noncore customers transporting their gas under interruptible or short-term capacity release transportation agreements. The residential, commercial, and transportation (vehicles using compressed natural gas) sectors are assumed to be core customers. Industrial end users fall into both categories, with industrial boilers and refineries assumed to be noncore and all other industrial users assumed to be core.

Electric generator natural gas customers are classified as either (1) core, (2) noncore, priced competitive with distillate fuel oil, or (3) noncore, priced competitive with residual fuel oil. The classification is based on the type of electric generation boiler. The electric generation units defining each of the three customer classes modeled are as follows: (1) core — gas steam units or gas combined cycle units, (2) noncore priced competitive-with-distillate — dual-fired turbine units or gas turbine units, (3) noncore priced competitive-with-residual — dual-fired steam plants (consuming both natural gas and residual fuel oil).

Demand

The shares for disaggregating nonelectric Census Division demands to NGTDM regions are held constant throughout the forecast period and are set equal to the average historical levels from 1985 to 1990 (Table F6).

The Alaskan natural gas consumption for residential, commercial, and industrial sectors (Equations 13, 14, 15) is defined as a function of the exogenously specified number of customers and the landed costs of crude oil in the current and previous forecast years (Tables E18, G1, G2). The Alaskan gas consumption is disaggregated into South and North Alaska in order to compute the natural gas production forecasts in these regions (Equations 16, 17). The value of gas consumption in South Alaska as a percent of total Alaskan gas consumption is based on average historical data (Table F10). Similarly, the Alaskan lease fuel, plant fuel, and pipeline fuel consumption levels are calculated as historically based percentages of total dry production in Alaska (Table F7). To compute natural gas prices by end-use sector for Alaska, fixed markups derived from historical data (Table F8) are added to the average Alaskan natural gas wellhead price over the North and South regions (Equation 18). Historically based percentages and markups are held constant throughout the forecast period.

The lease fuel consumption in each NGTDM region is computed as an historically derived percentage of dry gas production in each NGTDM/OGSM region (Table F2). These percentages are held constant throughout the forecast period.

Pipeline fuel use is derived by NGTDM region using the efficiencies associated with each arc in the NGTDM network and exogenously specified shares, used to allocate fuel use along an interregional arc to its associated regions based on the relative pipeline mileage in a given region (Table F39). These shares are held constant through the forecast period. The NGTDM estimates ambient emissions from the pipeline fuel consumption. These emissions are a function of pipeline fuel use and emissions coefficients (Equation 36). An average emission coefficient vector was derived for each emission type represented in NEMS, using coefficients for different types of compressors and the 1990 national composition of compressor capacity (e.g., 23 percent reciprocating engine and 77 percent gas turbines). Emission control technologies currently used in compressors and the national composition of the compressor capacity are assumed not to change over the forecast period. Thus, the emission factors are kept constant throughout the forecast period (Table F25).

In the Capacity Expansion Module, peak and off-peak consumption levels are calculated as exogenously specified percentages of expected annual consumption levels. These exogenous peak and off-peak shares (Tables F3 and F4 for consumption, Table F30 for exports) by market type and sector are estimated based on historical monthly natural gas consumption and are held constant throughout the forecast period.

Pricing of Services

Firm 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. The test for determining whether or not to build new capacity is done based on incremental rates, however. Core market transmission and distribution services remain subject to cost of service, rate of return regulation. Noncore transmission services are competitively priced with the price floor equal to the variable cost of delivering natural gas (generally compressor station fuel plus a few cents).

End-use prices for residential, commercial, and core industrial customers are derived by adding markups to the regional hub price of natural gas associated with core service. Parameters such as efficiencies for compressor stations fuel use (Table F19), a minimum markup, and benchmark factors (Table F29) are incorporated in the calculation of the markups. These markups (Equations 38, 41, 42, and 45) include the cost of service provided by intraregional interstate pipelines, intrastate pipelines, and local distributors. The intrastate tariffs are accounted for endogenously through historical model benchmarking. The distribution tariffs for the nonelectric sectors are based on historical data (Table F21), and are assumed to decline at a rate of 1 percent per year throughout the forecast. This compares to an average 1.2 percent per year decline observed in the commercial sector distributor markup since 1984 (the first year EIA collected such data). Since 1986, the residential and commercial distributor margins have declined at an average annual rate of 1.9 and 2.9 percent, respectively.

Similarly, prices for natural gas service to the core segment of the electric generation sector are derived by adding a markup to the regional hub price of core market natural gas supplies. The markups for electric generators are endogenously derived based on historical end-use prices and are modified over the forecast period as a function of user-specified parameters. The base markup to electric generators (excluding the intraregional interstate markup) is the average of the 1992 and 1993 markup to gas steam and gas combined-cycle units. This markup is derived as the difference between the NGTDM regional hub price for core natural gas supplies (minus the intraregional interstate tariff) and an historically based regional electric generators' price for gas steam units and gas combined-cycle units. During the forecast period, the base markup is linearly reduced so that, by 1999, the markup is 50 percent of the average of the base value and a minimum markup. (The minimum markup from the regional hub to the power plant is $0.04 (1993 dollars per thousand cubic feet)). The reduction is to capture the threat of bypass, which creates a downward trend in the markups. Beyond 1999, the markup is held constant.

End-use prices for industrial noncore customers are computed by adding a markup to the natural gas supply price for the noncore service customers at the regional market hub. These regional markups (Equation 47) are endogenously derived as the difference between estimated historical 1993 end-use prices (Table E8) and the NGTDM regional noncore hub price (passed by the Annual Flow Module solution matrix). The industrial noncore markups are held constant throughout the forecast period.

For electric generation noncore customers, natural gas is priced competitively with the associated alternative fuel oil (residual or distillate fuel oil) and is marketed to dual-fired electric generating units (units that burn gas or residual fuel oil) or gas turbines and dual-fired turbines (units that burn gas or distillate fuel oil). In this sector, two types of markups are derived: (1) competitive-with-residual fuel oil markup (Equation 48), which is based on the value of service to the sector as determined by the competing residual fuel oil price, and (2) competitive-with distillate fuel oil markup, which is based on the value of service to the sector as determined by the alternative distillate fuel oil price. Both markups are determined as the difference between the product of a discount factor (Table F23) multiplied by the price of the alternative fuel oil to electric generators in the region and the noncore natural gas price at the regional hub. These markups are constrained by maximum and minimum values. For competitive-with-distillate fuel oil service, the maximum value is the electric generator core sector markup minus a user specified discount. The minimum value is the greater of either the competitive-with-residual fuel oil markup or a user-specified minimum threshold markup.

For compressed natural gas used as a vehicle fuel (VNG), there are two pricing methodologies (developed in the DTM) available for deriving end-use prices. The first methodology, the historical markup method, uses a markup (Equation 41) derived from historical prices (Table E8). The second methodology, the full cost price method, develops a markup (Equation 42) for VNG using an algorithm that takes into account cost components of supplying and dispensing VNG (Table F27), Federal and State taxes (Table F27), and the price of motor gasoline to commercial customers. To assure the competitiveness of VNG relative to motor gasoline, the full cost markup is checked against a maximum markup which would result in a VNG price equal to the commercial motor gasoline price times an assumed discount factor (Table F27). The DTM transitions from the historical markup to the full cost markup in a user specified forecast year. This transition is intended to capture the evolution in the market from government/industry sponsored demonstration programs to large scale commercial use. In the version of the NGTDM used for the AEO95, a linear phase in from the first to the second method begins in 1994 and continues through 2005, after which the VNG price is assumed to reflect fully all components of the retail price.

Pipeline Tariffs and Regulation

In the computation of natural gas pipeline transportation and storage rates, the Pipeline Tariff Module uses a set of data assumptions based on historical data or expert judgment. These include the following:

- Factors (Table F13) to allocate each company's line item costs into the fixed and variable cost components of the reservation and usage fees (Equations 97 to 100)

- Capacity reservation shares (Table F14, assumed constant throughout the forecast) used to allocate costs to portions of the physical pipeline system

- Share of a pipeline company's storage capacity located in a region (Table F18), used to allocate fixed and variable costs to network nodes (Equations 103, 104)

- Load factor and maximum allowable annual escalation rate for tariffs (Table F35) and FERC Order 636 transition cost parameters (Table F24) needed for the derivation of pipeline tariffs for firm and interruptible transportation services (Equations 120 and 127) and storage tariffs (Equation 130)

- Capacity expansion cost parameters (Table F16) and pipe mileage (Table F17) used to derive total capital costs to expand pipeline capacity (Equation 133) and storage capacity (Equation 136), respectively.

All interstate pipeline companies are assumed to have completed the switch from modified fixed variable (MFV) to straight fixed variable (SFV) rate design by January 1994 to comply with Federal Energy Regulatory Commission Order 636 rate design changes. Approved transition costs are assumed to be consistent with FERC's revised cost estimate as published by the General Accounting Office in "Natural Gas: Costs, Benefits, and Concerns Related to FERC Order 636, Final Report," November 1993 (Table F24). It is assumed that the Gas Supply Realignment costs are recovered over a 5-year period beginning in 1994. Furthermore, it is assumed that 90 percent of these costs are assigned to firm transportation markets and 10 percent are assigned to interruptible markets as stipulated in Order 636. Purchase Gas Adjustment Account Balance (Account 191) costs are assumed to be collected over a 2-year period, also beginning in 1994. These costs will be paid only by core customers.

With full implementation of FERC Order 636 and the increasing array of unbundled services being offered by pipelines, it is assumed that segmentation of the natural gas market will continue and ultimately lead to prices reflecting the marginal costs of providing service to diverse groups of end users. The methodology employed in solving for the market equilibrium within the natural gas market assumes that marginal costs are the basis for determining market clearing prices throughout the forecast period. The NGTDM uses the market clearing prices in developing the supply and end-use prices paid by noncore customers. The weighted average cost of gas is used in deriving the cost of natural gas supplies delivered to core market customers.

Pipeline Capacity and Utilization

The Annual Flow Module linear program formulation has been developed to minimize a supply and transportation cost objective function (Equation 23) subject to the following constraints: capacity utilization constraints (Equations 24-25), mass balance constraints (Equations 26-29), and bounds on model flow variables (Equations 31-35). The capacity utilization constraints for the firm market and total market along each interregional arc set the limits on the flows for the firm market and total market, respectively. These utilization levels represent the maximum fraction of the physical capacity on the pipeline that is expected to be used on an annual basis. A small portion (Table F41) of this capacity is assumed to be reserved in the event of severe weather. The minimum bounds on flows along transshipment arcs in the firm and interruptible networks (Equations 31-35) are set as percentages (Table F32) of flows in the previous forecast year. In the first forecast year, minimum flows are set as a percentage of historically derived flows for 1990 (Table F20). These minimum flows help to generate some continuity in flows patterns from year to year. The model methodology assumes that pipeline and storage capacities are available 2 years from the decision to add new capacity.

In the CEM, it is assumed that pipelines and local distribution companies build and subscribe to a portfolio of pipeline and storage capacity to serve a colder-than-normal winter consumption levels. This is represented by building 5 to 15 percent more pipeline capacity than is necessary to support normal winter loads (with lower percentages on arcs supplying areas with warmer winters). Within the CEM, consumption is represented for peak and off-peak periods based on historically based sectoral splits, held constant throughout the forecast period.

The model only represents natural gas that is injected into storage in the off-peak period to be withdrawn during the peak period. Annual net storage withdrawals equal zero in all years of the forecast. The Capacity Expansion Module is constrained by an assumed maximum level of incremental storage capacity that can be built in each NGTDM region (Table F26).

Several data assumptions are embedded in the mathematical specification of the linear program in the Capacity Expansion Module. The minimum constraints on the arcs from each supply point during both the peak and off peak periods (Table F30) ensure that the production rates in a period do not exceed a plausible level. The formulation ensures that pipeline capacity is built primarily to satisfy firm peak demand. Exogenously specified seasonal maximum pipeline utilization rates (Table F34) are used to capture the variation in load patterns within a period.

The storage expansion and flow are bounded above by the maximum storage levels determined from the assumed storage utilization rates (Table F31).

The Capacity Expansion Module provides the Annual Flow Module and Pipeline Tariff Module with a forecast of working gas storage capacity, physical pipeline capacity, and maximum annual pipeline capacity utilization rates. The total available pipeline capacity in a given forecast year is calculated as last year's value plus planned expansions (Table F42) and any additional expansion determined to be required within the model. Assumed maximum seasonal utilization rates (Table F34) are used together with peak and off-peak flows within firm and interruptible markets to calculate the firm and total annual pipeline capacity utilization rates in the Capacity Expansion Module. The existing regional working gas capacity [including planned storage expansions (Table F33)] is added to the determined level of storage expansion to obtain the regional working gas storage capacity level.

Supply

The supply curves for domestic dry gas production (Equation 12) incorporate assumed values of short-term price elasticity of supply (Table F37) depending on the selected functional form. In addition, these supply curves are limited by minimum and maximum levels, calculated as a factor (Table F11) times the reserves times the expected production-to-reserves ratio.

Imports from Mexico and Canada at each border crossing point are represented as follows: (1) Mexican imports are assumed constant and provided by the Oil and Gas Supply Model; (2) Canadian imports are largely determined from Canadian pipeline capacities (provided by the Oil and Gas Supply Model) and exogenously defined maximum seasonal utilizations (Table F34). Total gas imports from Canada (Equation 4) exclude the amount of gas that travels into the United States and then back into Canada (Table F9). Liquefied natural gas imports are provided by the Oil and Gas Supply Model.

Associated-dissolved gas production is calculated for each OGSM region (Equation 7), as primarily a function of the level of crude oil production provided by the Petroleum Market Model and an historical average ratio of associated-dissolved gas-to-oil production (Table F49). The calculated levels are held constant (i.e., are not a function of the natural gas price in the current forecast year) in both the Annual Flow Module and the Capacity Expansion Module. Using assumed shares of the related OGSM region's associated-dissolved gas production within an NGTDM/OGSM region (Table F5), these regional gas production levels are disaggregated into the NGTDM/OGSM regions. Synthetic production of natural gas from coal (provided by the Coal Market Model) is also represented as a constant supply within the Annual Flow Module and the Capacity Expansion Module. However, synthetic gas production from liquid hydrocarbons in Illinois (Equation 2), which is defined within exogenously specified minimum and maximum production levels (Table F1), is represented as a function (Table G3) of the firm service market natural gas price in the East North Central Census Division. Synthetic gas production from liquid hydrocarbons in Hawaii is held constant throughout the forecast period at an assumed average historical production level (Table F1). Finally, other supplemental supplies (Table F12) are held constant throughout the forecast in the Annual Flow Module and the Capacity Expansion Module.

The supply representation in the Capacity Expansion Module employs a number of parameters (Table F30) to split the annual production designated as constant into peak and off-peak levels and to develop bounds on the seasonal levels of production designated as price responsive.

Model Inputs

The NGTDM is a comprehensive framework which simulates the United States' natural gas transmission and distribution industry as regulated by the Federal Energy Regulatory Commission for the pipeline transportation services across States (at the interstate level) and by State Public Utility Commissions for the local distribution services within States (at the intrastate level). The natural gas pipeline network (including storage) ties the suppliers to the end-users of natural gas, and captures the interactions among these institutions that ultimately determine market clearing prices and quantities consumed in the United States' natural gas market. The NGTDM inputs are grouped into six categories: supply inputs, pipeline financial and regulatory inputs, pipeline capacity and utilization inputs, storage inputs, end-use pricing inputs, and demand inputs. Short input data descriptions and cross-references to Appendix tables that provide more detail on the sources and transformation of the input data are provided below.

Supply Inputs

Supply curve parameters (Tables E2, E9, E10, E11, E12, E13, F12, F37, F44, F49 and G3)[80]
Historical production levels for supplemental natural gas supplies (Table E1)
Historical import levels and prices (Tables E3, E14, E15, and F9)
Alaskan Natural Gas Transportation System parameters (Table F7)
Regional supply shares for associated-dissolved gas and supplemental supplies (Tables F5, F12)
Minimum and maximum production-to-reserves ratios (Table F11)
Seasonal supply shares (Table F30)
Seasonal wellhead price differentials (Table F43)
Maximum and minimum synthetic natural gas production and historical data (Tables E16, F1, and G3)

Pipeline Financial and Regulatory Inputs

Rate design specification (Table F13)
Pipeline rate base, cost, and volume parameters (Tables E4, E5, and F15)
Revenue requirement forecasting equation parameters (Table G4)
Order 636 transition cost parameters (Table F24)
Rate of return set for generic pipeline companies (F46)
Federal and State income tax rates (F47)
Parameters for interstate pipeline transportation rates (Tables F35 and F45)

Pipeline Capacity and Utilization Inputs

Seasonal transmission service utilization rates and minimum flows (Tables F32, F34, and F38)
Existing pipeline capacity and planned capacity additions (Tables E6 and F42)
Costs of new construction (Table F16)
Pipeline fuel usage parameters (Tables E7, F19, and F39)
Factors related to planning for abnormal weather (Tables F40 and F41)
Distance and capacity commitments by network arc (Table F17)
Emissions factors (Tables F25)
Company volume shares by arc (Table F14)

Storage Inputs

Existing storage capacity and planned additions (Table F33)
Seasonal utilization parameters (Table F31)
Share of company storage capacity by region (Table F18)
Costs of storage additions (Table F16)
Maximum storage capacity potential by region (Table F26)

[80]Table whose numbering begins with the letters E, F, and G can be found in the Appendices E, F, and G, respectively.

End-Use Pricing Inputs

Discount factors for pricing natural gas to noncore electric generation customers (Tables F23 and F29)
State and Federal taxes, costs to dispense, and other compressed natural gas pricing parameters (Table F27)
Distributor markups for core nonelectric sector customers (Table F21)
Historical end-use prices (Tables E8 and E17)

Demand Inputs

Subregion gas consumption shares for Census Divisions 5, 8 and 9 (Table F6)
Seasonal consumption shares (Tables F3 and F4)
Historical export quantities and prices (Table E15)
Alaskan supply and demand parameters (Tables E18, F7, F8, F10, and G1)
Lease and plant fuel consumption parameters (Tables E7 and F2)
Short-term demand elasticities (Table F36)

Model Outputs

Once a set of solution values are determined within the NGTDM, those values required by other models of NEMS are passed accordingly. In addition, the NGTDM model results are presented in a series of internal and external reports, as outlined below.

Outputs to NEMS Models

The NGTDM passes its model solution values to different NEMS models as follows:

- Pipeline fuel consumption and lease and plant fuel consumption by Census Division (to NEMS PROPER)
- Natural gas wellhead prices by Oil and Gas Supply Model region (to NEMS REPORTS)
- Core and noncore natural gas prices by sector and Census Division (to NEMS PROPER)
- Dry natural gas production and supplemental gas supplies by Oil and Gas Supply Model region (NEMS REPORTS)
- Core and noncore (competitive with distillate and residual fuel oil) natural gas prices to electric generators by NGTDM/Electricity Market Model region (to Electricity Market Model)
- Dry natural gas production by Petroleum Administration for Defense Districts region (to Petroleum Market Model)
- Nonassociated dry natural gas production by NGTDM/Oil and Gas Supply Model region (to Oil and Gas Supply Model)
- Canadian natural gas wellhead price and production (to Oil and Gas Supply Model)
- Natural gas imports and prices by border crossing (to Oil and Gas Supply Model)
- Synthetic natural gas from coal supply price by NGTDM/Oil and Gas Supply Model region (to Coal Market Model)

- Capital expenditures for pipeline and storage expansion (Macro-Economic Model).

Internal Reports

The NGTDM produces reports designed to assist in the detailed analysis of gas market results. These reports include the following information:

- Average natural gas wellhead price by NGTDM region
- Natural gas hub price at each transshipment node, by type of service
- Natural gas distributor markups by end-use sector, type of service, and NGTDM region
- Matrices of data describing interregional transmission between NGTDM regions
  - Flows of natural gas by type of service
  - Maximum physical pipeline capacity
  - Maximum annual pipeline capacity utilization
  - Realized annual pipeline capacity utilization.
- Peak period and off-peak period expected natural gas consumption levels by region and sector used in the Capacity Expansion Module
- Expected natural gas supply volumes as implied in the Capacity Expansion Module results, by Oil and Gas Supply Model region.
- Pipeline capacity expansion by arc
- Storage capacity expansion by region.

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 wellhead prices and production levels by NGTDM region (and the average for the lower 48 United States)
- Natural gas end-use prices, margins, and revenues
- Natural gas import and export volumes and import prices
- Natural gas supply activity and prices by NGTDM region
- Pipeline fuel consumption by NGTDM region (and for the United States)
- Emissions of carbon dioxide, carbon monoxide, carbon, and methane emitted from the combustion of natural gas at pipeline compressor stations 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 pipeline capacity utilization (entering and exiting a region) by NGTDM region and Census Division

- Natural gas transmission and distribution revenues, activity levels, and unit costs

- Natural gas underground storage and pipeline capacity by NGTDM region

- Unaccounted for natural gas[81]

[81]Unaccounted for natural gas is a balancing item between the amount of natural gas consumed and the amount supplied.

Appendix A

NGTDM Model Abstract

NGTDM Model Abstract

Model Name: Natural Gas Transmission and Distribution Model

Acronym: NGTDM

Title: Natural Gas Transmission and Distribution Model

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: Integrated Analysis and Forecasting
- Division: Energy Supply and Conversion
- Branch: Oil and Gas Analysis, EI-823
- Model Contact: Jim Diemer
- Telephone: (202) 586-6126

Documentation: Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, December 1993).

Previous Documentation: None

Reviews Conducted:

- 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

- Paul R. Carpenter, PhD, Incentives Research, Inc., "Review of the *Component Design Report Pipeline Tariff Module (PTM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*," Boston, MA, April 30, 1993

- Paul R. Carpenter, PhD, Incentives Research, Inc., "Review of the *Component Design Report Distributor Tariff Module (DTM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*," Boston, MA, April 30, 1993.

- 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.

Archive Tapes: NEMS94—(Part of the National Energy Modeling System archive package as archived for the *Annual Energy Outlook 1994*, DOE/EIA-0383(94)).

NEMS95—(Part of the National Energy Modeling System archive package as archived for the *Annual Energy Outlook 1995*, DOE/EIA-0383(95)).

Energy System Covered: 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 9 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 independently

- Time Unit/Frequency: Annually through 2010

- Product(s): Natural gas

- Economic Sector(s): Residential, commercial, industrial, electric generators and transportation

Data Input Sources: (Non-DOE)

- National Oceanographic and Atmospheric Administration (NOAA)
  — Heating degree data

- *The Potential for Natural Gas in the United States* (National Petroleum Council, December, 1992)
  — Pipeline capacity expansion cost estimates

- *Gas Facts* (American Gas Association)
  — Historical industrial firm and interruptible gas prices

- Federal Offshore Statistics 1990, OCS Report, MMS91/0068
  — Offshore gas production and market values

- Canadian Petroleum Association Statistical Summary
  — Canadian natural gas wellhead price and production

- Alaska Department of Natural Resources
  — State of Alaska historical and projected oil and gas consumption.

- Information Resources, Inc., "Octane Week"

— State vehicle natural gas (VNG) taxes

Data Input Sources: (DOE) **Forms and Publications:**

- EIA-23, "Annual Survey of Domestic Oil and Gas Reserves"
  — Annual estimate of gas reserves by type and State

- EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition"
  — Annual natural gas sources of supply, consumption, and flows on the interstate pipeline network

- EIA-860, "Annual Electric Generator Report"
  — Electric generators plant type and code information, used in the classification of power plants as core or noncore customers. Data from this report are also used in the derivation of historical prices and markups for firm/interruptible service.

- EIA-767, "Steam-Electric Plant Operation and Design Report"
  — Electric generators plant type and boiler information, by month, used in the classification of power plants as core or noncore customers. Data from this report are also used in the derivation of historical prices and markups for firm/interruptible service

- EIA-759, "Monthly Power Plant Report"
  — Natural gas consumption by plant code and month, used in the classification of power plants as core or noncore customers. Data from this report are also used in the derivation of historical prices and markups for firm/interruptible service

- Rate case filings under Section 4 of the Natural Gas Policy Act, as submitted to FERC by each pipeline company
  — Contract demand data and cost allocation by pipeline company

- *Annual Energy Review*, DOE/EIA-0384
  — Gross domestic product and implicit price deflator

- FERC Form 2, "Annual Report of Major Natural Gas Companies"
  — Financial statistics of major interstate natural gas pipelines
  — Annual purchases/sales by pipeline (volume and price)

- FERC-567, "Annual Flow Diagram"
  — Pipeline capacity and flow information

- Federal Energy Regulatory Commission (FERC)
  — FERC Order 636 transition costs

- EIA-191, "Underground Gas Storage Report"
  — Base gas and working gas storage capacity and monthly storage injection and withdrawal levels by region and pipeline company

- EIA-846, "Manufacturing Energy Consumption Survey"
  — Base year average annual core industrial markups for local transportation service

- *Capacity and Service on the Interstate Natural Gas Pipeline System 1990*, DOE/EIA-0556
  — Pipeline capacity and capacity reservations by customer.

- *Natural Gas Monthly*, DOE/EIA-0130
  — Base year historical quantity and price data

Models and other:

- National Energy Modeling System (NEMS)
  — Domestic supply, imports, and demand representations are provided as inputs to the NGTDM from other NEMS modules.

- Interstate Natural Gas Pipeline Data System (PIPENET)
  — Inter-regional pipeline capacity
  — Contract demand data.

General Output Descriptions:

- Average natural gas end-use prices and consumptions levels by sector and region
- Average natural gas supply prices and production levels by region
- Compressor station emissions of C, CO, CO_2, CH_4, and VOC reported as carbon by region
- Pipeline fuel consumption by region
- Pipeline capacity additions and utilization levels by region
- Capital investment in pipeline construction.

Related Models: NEMS (part of)

Part of Another Model: Yes, the National Energy Modeling System (NEMS).

Model Features:

- Model Structure: Modular; consisting of four major components: the Annual Flow Module (AFM), the Capacity Expansion Module (CEM), the Pipeline Tariff Module (PTM), and the Distributor Tariff Module (DTM)

  — AFM Integrating module 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.

  — CEM Develops pipeline and storage facilities capacity and capacity expansion plans, and establishes effective maximum utilization rates for each pipeline route based on a seasonal analysis of supply and demand capability

  — PTM Develops firm/interruptible tariffs for transportation and storage services provided by interstate pipeline companies

- — DTM Develops markups for distribution services provided by LDC's and intrastate pipeline companies.

- Modeling Technique:

  - — AFM Linear program
  - — CEM Linear program
  - — PTM Accounting algorithm
  - — DTM Empirical process based on historical data and competing fuel prices.

- Special Features:

  - — Represents interregional flows of gas and pipeline capacity constraints
  - — Represents regional supplies
  - — Represents different types of transmission service (firm and interruptible)
  - — Calculates emissions associated with pipeline fuel use
  - — Determines the amount and the location of pipeline and storage facility capacity expansion on a regional basis
  - — Captures the economic tradeoffs between pipeline capacity additions and increases in regional storage capability
  - — Provides a peak/off-peak, or seasonal analysis capability in the area of capacity expansion
  - — Quantifies capital investment in capacity expansion
  - — Distinguishes end-use customers by type (core and noncore).

Model Interfaces: NEMS

Computing Environment:

- Hardware Used: IBM 3090
- Operating System: MVS
- Language/Software Used: FORTRAN, Ver. 2.05
- Memory Requirement 8328K
- Storage Requirement: 19 Tracks for input data storage; 37 tracks for code storage; and 51 tracks for compiled code storage
- Estimated Run Time: 4.4 CPU minutes

- Special Features: NGTDM uses a proprietary software package, Optimization and Modeling Library (OML) distributed by the Ketron Management Science Division of the Bionetics Corporation. This is a specially designed linear programming interface that is callable from FORTRAN.

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: November 1994.

Appendix B

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Appendix C

NEMS Model Documentation Reports

NEMS Model Documentation Reports

- The National Energy Modeling System is documented in a series of 15 model documentation reports, available early in 1994 by contacting the National Energy Information Center, 202/586-8800.

Energy Information Administration, *National Energy Modeling System Integrating Module Documentation Report*, DOE/EIA-M057 (Washington, DC, December 1993).

Energy Information Administration, *Model Documentation Report: Macroeconomic Activity Module of the National Energy Modeling System*, forthcoming.

Energy Information Administration, *Documentation of the D.R.I. Model of the U.S. Economy*, forthcoming.

Energy Information Administration, *National Energy Modeling System International Energy Model Documentation Report*, forthcoming.

Energy Information Administration, *World Oil Refining, Logistics, and Demand Model Documentation Report*, forthcoming.

Energy Information Administration, *Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System*, forthcoming.

Energy Information Administration, *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*, forthcoming.

Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*, forthcoming.

Energy Information Administration, *Model Documentation Report: Transportation Sector Demand Module of the National Energy Modeling System*, forthcoming.

Energy Information Administration, *Documentation of the Electricity Market Module*, forthcoming.

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Energy Information Administration, *EIA Model Documentation: Petroleum Market Module of the National Energy Modeling System*, forthcoming.

Energy Information Administration, *Model Documentation: Coal Market Module*, forthcoming.

Energy Information Administration, *Model Documentation Report: Renewable Fuels Module*, forthcoming.

Appendix D

Alternative Modeling Approaches

Alternative Modeling Approaches

During the design phase of the NGTDM, a survey was conducted of models and modeling approaches being used throughout the industry to analyze and forecast natural gas transmission and distribution activities. These approaches, along with other general modeling approaches, were considered as possible candidates for the NGTDM design. This appendix provides an overview of the methods and modeling techniques considered. First, the modeling techniques employed in several different natural gas transmission and distribution models are reviewed. Second, modeling approaches used in models not specifically designed for natural gas transmission and distribution, but which could be applied to this area, are discussed. Finally, conclusions based on the research and comparisons between other models and the methodology selected for the NGTDM are presented.

Other Natural Gas Transmission and Distribution Models

The natural gas transmission and distribution industry is a segment of the complex natural gas production/delivery/demand system, and therefore is usually modeled as part of a larger, overall modeling system. Because the market structure of the transmission and distribution industry is rapidly evolving, most representations developed in the past are no longer adequate. Several of the models reviewed have detailed supply and demand representations, with fairly simple mechanisms for linking the two. Others have incorporated mechanisms for dealing with such issues as capacity expansion and the unbundling of transportation services, but none offers a comprehensive modeling treatment of the transmission and distribution industry as a whole. Additionally, none of the models reviewed addresses the issue of the environmental impacts associated with the transmission and distribution of natural gas. It was ultimately decided that there were no models in existence that could be used either intact or as a base to begin with and modify for the development of the NGTDM. Although it would have been very difficult to develop a model that addresses all of the regulatory issues and complexities of the industry, the design of the NGTDM considered desirable features of all the modeling approaches reviewed, and the resultant model provides a more comprehensive analysis tool than any other models available. This section provides an overview of the other natural gas models that were considered.

Gas Analysis Modeling System (GAMS)[82]

EIA's previous model of the natural gas market is the Gas Analysis Modeling System (GAMS), a computer-based partial equilibrium model used to analyze the U.S. natural gas production/delivery/demand system. GAMS produces annual forecasts through 2010 of natural gas production, consumption, and prices. GAMS interacts with a separate supply component which represents the various available sources of natural gas supplies and separate demand components that represent natural gas consumption by end-use sector and Federal region. GAMS consists of a mechanism for representing the costs and losses associated with the transmission and distribution of natural gas and an iterative equilibration process that solves the entire system to determine the wellhead and end-use prices at which an overall supply/demand balance can be achieved. Although the model can be run in a stand-alone mode, it is primarily used as the natural gas module within the Intermediate Future Forecasting System (IFFS),[83] a modeling system representing the supply and demand response within all the primary U.S. energy markets. The GAMS demand representation is provided through IFFS by the Demand Modeling System (DEMS), for the non- electric generators demand sectors, and by the Electricity Market Model (EMM) for the electric generators sector. The representation of onshore Lower-48 natural gas production is provided through direct linkage with the Production

[82]For complete documentation of GAMS, see Energy Information Administration, *Documentation of the Gas Analysis Modeling System*, DOE/EIA-M044(92) (Washington, DC, December 1991).

[83]For more information on IFFS, see Energy Information Administration. *Documentation of the Integrating Module of the Intermediate Future Forecasting System*, DOE/EIA-M023(91) (Washington, DC, May 1991).

of Onshore Lower-48 Oil and Gas Model (PROLOG).[84] Supply estimates for other sources of gas are either set exogenously or determined endogenously via additional supply submodules.

GAMS was developed in 1982 and 1983 when the complex system of price ceilings in effect under the Natural Gas Policy Act (NGPA) of 1978 covered both interstate and intrastate wellhead purchases of natural gas. The categorization of gas under the NGPA and the contractual nature of the natural gas market that existed at the time were primary factors in the early structure of the model. The laws and regulations concerning the natural gas market have changed rapidly in support of deregulation and increased competitiveness (for a detailed discussion on industry background, see Appendix C). The GAMS model has subsequently undergone a number of methodological changes, to represent the active spot market, the deregulation of wellhead gas prices, and the increase in competitive pressures throughout the industry.

In the original version of GAMS, a detailed pipeline network consisting of 17 pipeline systems was used to reconcile supply and demand in the market equilibration process. This network represented sales of gas from the wellhead, through pipelines, to distributors, and to end-users. Physical movement of gas through the system was not tracked, and pipeline capacities were not accounted for. Reserves were dedicated to the individual pipeline systems and drawn down, as produced, through an elaborate accounting mechanism that tracked gas by NGPA category and contract terms and conditions. The sales structure allowed for analysis of alternative wellhead contract pricing schemes and their effect on the natural gas market. In order to represent both the increased spot market activity and the growing competition within the marketplace, GAMS was subsequently modified to include a pool of spot or decontrolled gas available to all pipelines. Reserves were no longer treated as dedicated to individual pipelines. GAMS was also revised to reflect changes in producer contracts, with contracts treated as respondent to market conditions and new contracts excluding take-or-pay[85] restrictions.

As a result of increased competition and the unbundling of pipeline sales and transportation services, the cost-of-service representation of bundled rates originally used to represent tariffs within GAMS was no longer representative of the market. The tariff component in GAMS was replaced with a simple mechanism that calculates end-use prices by adding exogenously determined regional transmission and end-use distribution costs (which are fixed throughout the forecast) to the national average wellhead price. Competition was represented by allowing these costs to be discounted in the industrial and electric generators sectors. As pricing distinctions responsive to market conditions between different levels of transmission and distribution service developed, the different levels of service were represented by expanding the level of electric generators sector detail. The electricity market module (EMM) provides demand curves to GAMS in the form of step functions defined by a set of price/quantity pairs. The steps on the curves simulate the effect of large-scale fuel switching and changes in the plant dispatching order by electric utilities. To model the price variation associated with different levels of service, these demand curves were redefined to represent three categories of electric generator plant types as follows: (1) core customers assumed to purchase firm service and pay the highest rates, (2) noncore customers assumed to purchase interruptible service and pay lower rates, and (3) customers with fuel switching capabilities sometimes offered discounted rates based on competing fuel prices. In contrast to the detailed electric generators demand representation, each regional demand curve provided to GAMS by DEMS for the non- electric generators sectors is defined simply by a unique reference price/quantity pair and an associated elasticity.

Transmission/distribution losses and pipeline fuel use are taken into account within GAMS during the supply/demand equilibration process by applying factors based on historical data to total throughput. The equilibrating process includes the following steps: (1) estimating a national wellhead price (the initial estimate is the previous year's solution price, and subsequent estimates are based on the previous iteration's price), (2) adding appropriate markups (representing transmission and distribution tariffs) to arrive at regional/sectoral end-use prices, (3) evaluating end-use consumption levels at these prices using the appropriate demand curves, (4) summing these consumption levels and adding losses to arrive at the amount which would be demanded at the wellhead given the estimated wellhead price, and (5) comparing this aggregate consumption (plus losses) to the level (provided by PROLOG) that would be supplied given the estimated wellhead price. If the calculated consumption is not within a specified tolerance of the

[84]For more information on PROLOG, see Energy Information Administration, "Model Methodology and Data Description of the Production of Onshore Lower-48 Oil and Gas Model." DOE/EIA-M034(91) (Washington, DC, April 1991).

[85]Take-or-pay contract restrictions required a pipeline to pay for the specified quantity of gas whether or not it could be resold.

corresponding supply level, a new wellhead price is estimated and the process is repeated until convergence is achieved.

Data Resources, Inc. (DRI)[86]

The DRI natural gas market analysis is done in conjunction with an overall analysis of the entire U.S. energy sector. The principal models used are short-term natural gas spot price and demand models, a longer term U.S. and regional energy model (which has detailed sectoral demand submodels), and a U.S. oil and gas drilling/production model. Annual forecasts through 2010 are provided for 11 regions based on Census regions and subdivisions of Census regions.

The DRI modeling system uses an iterative process (based on achieving a wellhead price/residual fuel oil price ratio that is deemed to reflect accurately free-market supply/demand influences) which determines average regional wellhead gas acquisition prices and then applies region- and sector-specific markups to arrive at end-use prices. Average natural gas prices are projected for U.S. domestic wellhead gas (based on spot, contract, and regulation-influenced gas prices) and for Canadian and LNG imports. These prices are then combined into regional "acquisition" prices, based on the varying volume weights of each gas source in the region. Region- and sector-specific markups are then applied to each region's average acquisition cost to arrive at each sector's end-use price for the region. The markups are intended to capture the transmission, distribution, and other delivery costs for each sector in each region. The markups are based on historical EIA data. Thus interstate pipeline transmission rates are not separately and specifically estimated, but rather, are rolled in with local distribution and other charges into the overall retail markups. Growth in price markups is assumed to increase at the rate of inflation, as determined by the GNP deflator. Pipeline capacity constraints and capacity expansion issues are not addressed in the model.

Wharton Econometric Forecasting Associates (WEFA)[87]

WEFA models the transmission/distribution of natural gas by means of a supply/transportation model within its Natural Gas Modeling System. The North American natural gas market is defined as a collection of many markets (16 hubs) which trade gas both intra-regionally (within hubs) and inter-regionally (between hubs). Markets may be defined geographically, by type of transaction (spot or contract), by quality of service (interruptible or firm), and by season (heating or nonheating). The model is implemented as a spreadsheet that determines the production and consumption in each market and the volume of gas transported between markets and between seasons (storage), using a heuristic algorithm to solve iteratively for a set of prices across regions, seasons, and time periods that achieves a market balance. Annual forecasts are provided through 2020 for natural gas production and wellhead prices in 13 domestic supply basins, and for flows, capacity utilization, transportation costs, and required capacity expansion along the arcs connecting the 16 hubs.

Three key assumptions are made as follows:

- Producers maximize profits and consumers minimize costs, subject to demand requirements and capacity constraints

- Pipeline transportation and storage rates are a function of regulation, and capacity expansion only takes place if it is economic (i.e., if the marginal cost of expansion is less than the marginal price that consumers are willing to pay for the additional gas)

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[86]The most current documentation on DRI's model was written in 1984 and is out of date. A brief report entitled "Natural Gas Forecasting Methodology" provided by Margaret Rhodes of DRI was used for a more accurate description of their current methodology.

[87]The WEFA model is used for internal forecasts only, and thus full documentation does not exist. Information on their current methodology was obtained from a brief methodology description in the *WEFA Natural Gas Service Long-Term Forecast* (Bala Cynwyd, PA, Winter 1992) and from telephone conversations with Morris Greenberg of WEFA.

- Prices are permitted to adjust freely to clear all markets simultaneously.

Initial estimates of regional, end-use gas requirements are determined from econometric models for the non- electric generators sectors and from regional load dispatch models for the electric generators sector. The demand is then assigned to the different supply regions based on initial market shares. Initial estimates of regional/sectoral prices are also used. Actual prices are then determined, and the relevant demands adjusted via price elasticities for subsequent iterations. Transportation tariffs are initialized assuming a load factor of 85 percent, but may be discounted if the actual utilization is less.

Consumption is disaggregated into heating and nonheating seasons, and further disaggregated by users with and without fuel switching capability. Consumers have the flexibility of selecting alternative supply sources. Gas can be transported from regions linked by the pipeline network or withdrawn from storage, both subject to available capacity. Any gas withdrawn from storage during a heating season is replaced during the following nonheating season. Consumers adjust supply sources to minimize costs, given the price of gas in the source region and the transportation (or storage) rate, including fuel and loss. Transportation rates are determined assuming competitive conditions, and rates on routes with excess capacity can be discounted down to variable costs. Alternatively, if pipeline capacity on a given route is constrained, rates may be adjusted upward in the solution process to the point where they exceed the regulated transportation ceiling rate in order to clear the market. In this case, if the marginal value of the expansion, as measured by current and future price differentials and utilization rates, exceeds its marginal cost, capacity is expanded. If such expansion does not occur, transportation-constrained sources will lose market share to unconstrained routes.

Throughout the solution process, prices are adjusted to reduce excesses of supply or demand in any or all regions/seasons/time periods. The process is repeated iteratively until market-clearing prices are determined. Convergence is achieved when the following conditions are met:

- Excess supply/demand is zero in each market
- The delivered cost of gas to each region is the same for every active route
- Pipeline capacity utilization is less than or equal to 100 percent on every route
- The marginal value of transportation on each route is less than or equal to the marginal cost of expansion.

American Gas Association (AGA)[88]

Natural gas modeling at the American Gas Association is done within the framework of the American Gas Association's Total Energy Resource Analysis model (A.G.A.-TERA). The TERA modeling system provides annual projections through 2010 of natural gas production, consumption, and prices, with projections for the residential, commercial, industrial, and electric generators end-use sectors provided for the nine Census Regions. The approach is a heuristic one that simulates the market and does not assume optimization of either policy or market behavior. The equilibration process involves the interaction of three components: (1) a set of drilling models, (2) a demand/marketplace model, and (3) a deliverability model. The drilling models and the demand/marketplace model provide inputs for the deliverability model, but there is not an automated feedback loop from the deliverability model to the drilling and demand/marketplace models. Analyst intervention is often necessary to equilibrate the market via adjustments in the trial wellhead prices.

The models treat the natural gas transmission and distribution segment of the industry very simply. Flows are not explicitly represented, and capacity constraint/expansion issues are not treated. The prices of natural gas to

[88] *Introduction to the A.G.A-TERA Energy Modeling System*, American Gas Association (Arlington, VA, 1991), provides a very general overview of the overall model; phone conversations with Leon Tucker of the A.G.A. provided specifics on the handling of transmission and distribution.

consumers are calculated as linear functions of the wellhead price via ordinary least squares regression in order to reflect the combination of supply-related costs and transmission and delivery-related costs.

Gas Research Institute (GRI) Energy Overview Model (EOM)[89]

In producing its yearly Baseline Energy Forecast, the Gas Research Institute (GRI) uses a model known as the Energy Overview Model (EOM). The transmission and distribution segment of the natural gas industry is represented by a separate model, the National Pipeline/Flowing Gas Model developed by Energy and Environmental Analysis, Incorporated (EEA). The EEA model is a simulation model that represents the U.S. pipeline system by means of 12 composite pipeline groups, which are aggregates of actual pipeline systems chosen to represent the major differences in gas supply areas serving the 10 Federal regions. The network has recently been expanded to include the entire North American gas market (including both Canada and Mexico). Each pipeline group has its own inventory of gas reserves, access to one or more of 15 supply regions (as represented in the GRI Hydrocarbon Supply Model), and an individual cost of service estimate for pipeline operations. The EEA model is integrated with the EOM, and thus flows are considered in the market equilibration process. Nonlinear optimization is used to minimize costs subject to supply and demand constraints.

The pipeline model simulates pipelines in their role as both merchants and transporters of gas. Transportation services are provided to distributors and end-users under a mix of rates based on the quality of service. Rates are based on cost-of-service with the flexibility for rate discounting caused by market pressures. An accounting system tracks both committed gas supplies under long-term contracts with pipelines and uncommitted supplies being marketed by producers and sold on the spot market. Associated with committed supplies are detailed contract terms and conditions.

The model represents the distribution of supply from the city gate to end-users by means of an aggregate local distribution company (LDC) in each demand region. Revenue requirement accounts are maintained for each LDC to set distribution margins by end-use sector, with margins and burnertip gas prices differing by demand region. LDCs themselves offer end-users both sales service and transportation of gas purchased on the spot market.

Seasonal transmission charges for each pipeline group and distribution charges for the LDC in each Federal region are estimated by the model based on cost-of-service estimates. The charges are then allocated to the services provided by the distributor or pipeline. Market pressures and regulatory structures determine the extent to which those charges recover gas transmission and distribution costs. A cost-of-service algorithm estimates year-to-year changes in the overall nongas costs of pipeline operations so as to take into account the response of the costs to changes in system throughput, compression costs (which change with volume and cost of gas), rate base, and the cost of capital. After determining the cost of service for each pipeline group, the model allocates these costs between the sales and transportation services offered to customers based on the mix of each pipeline's merchant and transport services. After allocating costs, the model pipelines establish a structure of differential rates for the various classes of service. The transmission margin included in pipeline resale rates is assigned on a fully allocated basis, meaning that the costs allocated to this service will be fully recovered in providing the service. Pipelines also maintain separate firm and interruptible rates applicable to transportation. Competitive forces and market pressures may prevent pipelines from fully recovering costs for interruptible service. The model allows margins on transportation to distributors to be reduced below full cost recovery to represent the potential discounting pressures on pipeline supplies caused by interpipeline competition. Costs not recovered due to discounting are reported.

The EEA model has recently been updated to include a detailed representation of capacity expansion in support of an ongoing National Petroleum Council (NPC) study.[90] The model takes into account both planned expansion and other future expansion. An input data file describes planned projects for the next 5 years, including their construction costs. For projects beyond the 5-year time horizon, the same data file contains "generic" projects that can be

[89] *Guide to the Hydrocarbon Supply Model, 1990 Update*, Energy and Environmental Analysis, Inc. (Arlington, VA, October 1990) and conversations with EEA and GRI staff.

[90] The enhanced treatment of capacity expansion in the EEA Pipeline/Flowing Gas Model has not as yet been documented. The above information was provided through conversations with Robert Crawford of EEA.

undertaken if it is economic to do so. Data for these generic projects include cost estimates on a dollars per thousand cubic feet/mile (where mileage figure represents miles that the gas is actually moved). Cost data are determined by using a cost algorithm that reflects today's capacity addition costs. Three sets of cost algorithms are employed: one for the Lower 48 States, one for Canada, and one for frontier areas where expansion is costly. Regional differences in construction costs are not captured. Costs are determined for three types of possible expansion: compression only, looping and compression combined, and construction of new pipe. Potential future projects are set up throughout the system as though they were real ones. Thus the model sees what is analogous to a supply curve for capacity additions at each node. The steps on the "supply" curve are analogous to the amount of each of the three types of expansion possible at that point in the system. The data allow for expansion everywhere in the system, with those areas deemed most likely to have more expansion activity provided higher bounds on the amount of expansion possible.

In solving for capacity expansion, the model begins each forecast year with an estimate of new capacity that would be needed to meet the demands for that year. Each potential new pipeline link has a supply source with an associated volume and price elasticity, and a demand at its destination. The model takes into account how much the supply price would be raised at the source due to the added volume, and how much the demand would be depressed as a result of the associated higher prices. Capacity to be added is controlled by the criteria that any added capacity must be able to operate at a minimum of an 80-percent load factor. New links compete against alternate supply sources and each other—capacity will not be added if there is a cheaper alternative for meeting demand. New costs are compared against the cost of adding capacity. The cost of the added capacity must be less than the price differential on competing links, and the throughput high enough (at least 80 percent) in order for capacity to be added.

Storage is considered to be a supply source during the winter months and a demand source during the summer months. Storage expansion is not endogenously determined. Offline scenarios are run to determine how much storage capacity would increase, and storage is fixed within any given model run. The offline analysis to determine storage expansion is an iterative process in which estimates of expected increases in storage are made, the model is run and results analyzed, estimates are revised and the model rerun until analyst judgment indicates a satisfactory estimate of future storage expansion.

Decision Focus, Inc. (DFI) North American Regional Gas Model (NARG)[91,92]

Decision Focus, Inc. has developed a multiregion Samuelson spatial equilibrium model used by the Gas Research Institute (GRI) for sensitivity analyses. This model is referred to as the GRI North American Regional Natural Gas Supply-Demand Model.

The model represents approximately 150 distinct gas supply sources in the United States and Canada. Fifteen demand regions are represented, 3 in Canada and 12 in the United States (based on disaggregations of the census regions), with distinctions within each demand region between core and noncore markets.[93] In the United States, all of the residential and commercial and half of the industrial demand are assumed to be core, while the balance of the industrial and all of the electric generators demand are assumed to be noncore.

The model's representation of the North American pipeline system includes:

- A comprehensive pipeline network consisting of current and potential future pipeline links from supply regions to demand regions

[91]Dale M. Nesbitt *et. al.*, "Analysis of GRI North American Regional Gas Supply-Demand Model", in *North American Natural Gas Markets: Selected Technical Studies, Energy Modeling Forum (EMF) Report 9*, Volume III, pp. 185-234 (Stanford University, April 1989)

[92]Dale M. Nesbitt *et. al.* (DFI), "Appendices for the GRI North American Regional Natural Gas Supply-Demand Model," prepared for Gerald Pine (GRI), February 1990.

[93]The core service customer is guaranteed service (i.e., is assumed to purchase firm service) and generally pays the highest rate for natural gas. The noncore customers consume gas under a less certain and/or less continuous basis (i.e., an interruptible basis) and typically are offered a lower rate than the core customers.

- Tariffs and losses for each pipeline link.

The degree of pipeline detail is consistent with the degree of supply and demand detail elsewhere in the model. In particular, while the model could have been designed to enumerate and distinguish every individual pipeline in the United States, its developers instead sought commonalities among supply regions, pipelines, and demand regions that would allow aggregation. Rather than representing individual pipelines, the model instead represents pipeline corridors from its supply regions to its demand regions. These corridors are explicitly defined by the characterization of the model's supply and demand regions, and by the configuration of the U.S. and Canadian pipeline systems that exist today. Each of the existing pipeline corridors represented in the model begins in a given supply region, extends perhaps through intermediate supply and demand regions, and terminates in a demand region. The network of existing pipeline corridors interconnects all currently producing regions with all currently consuming regions.

The model also enumerates all prospective future pipelines that might be built in the next 50 years. These pipelines connect new producing regions (or subregions) with various demand regions, and connect Canada and Mexico to the United States. They are truly prospective in the sense that they will be built only if they become economic (i.e., only if supplies at the upstream end, marked up to account for the cost of the new pipelines, constitute the most competitive source at the downstream end). In the model, looping is considered as an option for all existing capacity, as well as for the existing links of the new corridors.

The linkage between Canada and the United States is potentially very important. The model therefore distinguishes the pipelines in Canada that directly or indirectly lead to the Lower 48 United States. The model also includes two prospective Canadian export routes to the United States. One of these routes runs from North Alaska through Alberta and ultimately to the United States, and represents the upstream leg of the Alaska Natural Gas Transportation System. The other runs from Northern Canada (MacKenzie and Beaufort Sea), through Alberta, and ultimately to the United States, and represents the pipeline that will have to be built in order to exploit Canadian Arctic gas (the Polar project and prospective expansions).

The current version of the model contains corridor capacity estimates prepared by Benjamin Schlesinger and Associates (BSA, under contract to the California Energy Commission). BSA also provided appropriate corridor transmission costs, which represent the embedded cost of each pipeline and specifically account for discounting behavior on the part of pipeline owners. Pipeline capacities and cost structures for all Canadian pipelines are based on data from the National Energy Board of Canada.

Several generic types of pipeline capacity expansion are explicitly represented (for each pipeline link) within the model:

- Expansion of capacity of a given pipeline by such actions as looping or increasing pressure
- Expansion of capacity along a given corridor by adding a new pipeline
- Addition of an entirely new pipeline corridor.

For each pipeline link, the model assumes that the embedded cost of the capacity currently in place will affect the rates for quantities of gas transported that do not exceed the current known capacity. In order to transport more gas than the current capacity of the corridor, it is necessary to augment the capacity through looping or pressure increases. Such augmentation is possible (at a cost) and is usually bounded by an upper constraint (i.e., looping and pressure increases can each add only a limited quantity of additional capacity). In order to exceed the capacity of an existing, fully looped, maximum pressure pipeline link, it is necessary to add new pipeline capacity. At the incremental cost of securing appropriate rights of way and building such a pipeline, it is possible to expand the capacity of that corridor virtually without bound.

The model thus requires current transportation cost information, capacity expansion costs through augmentation, and new capacity addition costs. For the current version of the model, such data (for every existing and prospective future corridor) were provided by BSA under contract to the California Energy Commission.

Stanford University North American Gas Trade Model (GTM)[94]

The North American Gas Trade Model (GTM) developed at Stanford University in conjunction with the Stanford University International Energy Project is an interregional natural gas trade partial equilibrium model which computes, for 2 single time periods (1990 and 2000), market clearing prices and a possible pattern of trade flows between 11 supply and 14 demand regions in the United States, Mexico, and Canada. Demands within the United States are provided for each of four consuming sectors (residential, commercial, industrial, and electric generators). Key inputs to the model include:

- The regional distribution of gas supplies and demands at alternate price levels
- Transportation charges
- Pipeline capacity constraints
- Canadian and Mexican export quantity limits.

In some regions, prices are free to move so as to equilibrate supplies and demands, while in others there may be disequilibria associated with controls over prices and/or quantities traded. The objective of the solution process is to maximize the sums of producers' and consumers' surpluses, or, alternatively, maximize the sum of consumers' benefits minus the costs of production and transportation. With the exception of the nonlinearity of the objective function, the GTM is a straightforward transportation model. The model is solved using MINOS, a nonlinear programming computer package.

Economic policy and technical constraints are handled as upper or lower bounds on objective function variables. For example, pipeline capacity limits are represented as upper bounds on the transportation variables, and take-or-pay contract limits are represented as lower bounds. The user can specify limits on certain demands or export volumes, which allows the simulation of export and price controls. Taxes or subsidies on individual supplies or demands can be similarly represented by constraints on individual supply and demand variables. Each of these conditions is represented as an upper or lower bound on an individual variable.

The objective function contains linear cost coefficients related to the transportation variables. Supply and demand variables enter in a separable nonlinear form. A market equilibrium is computed by maximizing the objective function subject to supply and demand constraints and upper and lower bounds on individual variables. If supply and demand are unconstrained, the shadow prices will be the marginal costs of production or the price consumers are willing to pay. This information can aid the analyst in making decisions (e.g., whether to expand production or increase capacity).

Massachusetts Institute of Technology (MIT) Center for Energy Policy Research[95]

The Center for Energy Policy Research Energy Laboratory at MIT has developed a North American natural gas trade model as part of a project on international gas issues. The primary purpose of the model is to estimate the costs and benefits to Canada and Canadian firms of alternative gas production and export programs. While it is an interregional trade equilibrium model similar in concept to the Gas Trade Model (GTM) described above, it has been formulated as a linear, rather than a nonlinear, programming problem. The model solves for exports to the United States and investment and production in each Canadian supply area, reporting additional information including marginal costs of production, export prices, marginal export revenues, capital rental charges, resource depletion costs, etc. The model includes nine different pools of Canadian reserves and three gas markets within the United States: West Coast, Middle West, and North East.

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[94]Mark A. Beltramo, Alan S. Manne, and John P. Weyant, "A North American Gas Trade Model (GTM)." *Energy Journal*, July 1986, pp. 15-32.

[95]Charles Blitzer, "A North American Natural Gas Model: Part I," *Final Report on Canadian-U.S. Natural Gas Trade*, (Cambridge, MA: MIT Center for Energy Policy Research October 1985).

Constraints involve supply/demand balances, production-reserve relationships, production-investment relationships, export delivery patterns, pipeline capacity constraints, and export revenues. Demand functions are represented by piece-wise linear approximations. Pipeline capacity is input exogenously. Investment in capacity expansion, although incorporated in annual capital costs, is not, however, endogenously determined. Pipeline operating costs are handled as linear functions of export volumes based on operating cost coefficients.

The model can be solved using any one of three objective functions:

- Maximize net benefits to Canada as a whole

- Maximize the sum of net benefits to Canada and to U.S. importers of Canadian gas

- Simulate competitive profit maximizing behavior among Canadian producers, inclusive of royalties.

The second objective function seeks to determine the perfectly competitive solution, in effect maximizing net benefits to Canada (producers' surplus) and net benefits to the United States (consumers' surplus).

Energy Information Administration Gasnet Model[96]

The Gasnet model is an optimization model, developed by EIA in the late 1970's to forecast short-term seasonal patterns of natural gas distribution given predetermined projections of both supply and demand for natural gas. Although no longer in use within EIA, the Gasnet model was reviewed in doing background research for development of the NGTDM as it explicitly represents a pipeline network, using a series of constrained optimization techniques to simulate the transmission pattern within the natural gas industry. Gasnet provides summary tables listing quarterly estimates of natural gas supply by State and consumption and excess demand by State for the residential, commercial, industrial, and electric generators sectors.

On the demand side, 48 States, the District of Columbia, Mexico, and 5 Canadian provinces are represented. On the supply side, there are 45 producing areas located in the 26 producing U.S. States and 4 Canadian provinces. Four of the producing States are divided into substate regions. Five major interstate pipeline activities are represented in the model: (1) selling gas to end-users, (2) receiving produced gas, (3) injecting or withdrawing gas from storage, (4) exchanging gas with other pipeline companies, and (5) transmitting their own gas volume to other States. Within the model, various nodes are interconnected by arcs. Each node is associated with one or more of the five major activities described above.

The model connects the demand regions and supply areas to estimate the sectoral effects of natural gas shortages. The model represents each pipeline by a system of interconnected nodes allowing the calculation of interstate flows along a pipeline system. A separate module, the Historical Apportionment Model (HAM), computes the distribution of the forecasted gas production through the network on the basis of the historical relative flows (i.e., the pattern determined from the base year data). The HAM model solution provides a base case for the final phase of the modeling process: the linear program. The linear program minimizes the deviations of gas from the desired storage goals, the sum of excess demands and supplies by consuming sector in each State, and the costs of operation for the transmission of gas throughout the entire network, subject to the following constraints:

- Mass balance at each node

- Regional gas production equation for each region

- Balance of supply and demand over all States and demand sectors.

[96]Energy Information Administration, *Gasnet: Methodology Description* (Washington, DC, August 1978)

Solution Methods for Solving Network Flows

In developing the methodology for the NGTDM, a number of modeling techniques were evaluated other than those employed in natural gas models. In particular, specific mathematical formulations and solution techniques, such as linear programming (LP), mixed integer programming (MIP), special ordered sets (SOS), and nonlinear programming were considered.[97] In addition to the specific natural gas models discussed above, the following models were reviewed because they employ techniques that were considered for use in the NGTDM.

Energy Information Administration Project Independence Evaluation System (PIES)[98]

The PIES model, developed in the mid-1970's, was EIA's first large scale energy forecasting model. The PIES framework consists of three major components: a demand model, a supply network, and an equilibrating mechanism.

The PIES supply network is composed of production, conversion, and transportation activities. They are linked by means of a distribution network that represents the movement of raw materials or products. The major economic assumption implicit in the PIES structure is that market equilibrium conditions govern the purchase prices and quantities of fuels so that the sum of consumers' and producers' surplus is maximized across all regions and all energy industry sectors, subject to the constrained market conditions introduced by government regulation.

The following assumptions are made: (1) subject to regulatory constraints, participants in the economy act in their own self-interest, (2) consumers are rational and maximize their benefits, and (3) producers maximize profits. A linear programming formulation is used, incorporating step-like approximations to the supply and demand curves.

Stanford Research Institute SRI-GULF Energy Model[99]

The Stanford Research Institute's SRI-Gulf Energy Model is a highly-detailed regional, dynamic model of the supply and demand for energy in the United States. It was developed in 1973 to analyze synthetic fuels strategy for the Gulf Oil Corporation and has subsequently been extended and widely used in other energy analyses. It employs a generalized equilibrium modeling methodology which represents a synthesis of several modeling techniques. The conceptual framework of generalized equilibrium modeling emphasizes: (1) the need to focus modeling efforts on decisions and (2) the coordinated decomposition of complex decision problems using iterative methods. A decision problem is first conceptualized, and then decomposed to define the basic decision and physical processes that must be included in the modeling process. The overall model is then implemented using the following three basic elements of generalized equilibrium modeling: (1) *processes* describing the fundamental submodels, (2) a *network* describing the interactions among the processes, and (3) an *algorithm* for determining the numerical values of the variables in the model.

In the SRI-GULF model, 17 end-use demands are modeled for each of the 9 U.S. Census Divisions through 2025. Approximately 2700 processes are represented, with processes that describe end-use demands for energy and primary resource supply linked by a network of other processes describing market behavior, conversion, and transportation. The algorithm used to solve the model finds the set of variables (primarily prices and quantities) that satisfy the physical and behavioral relations embodied in the processes and the linkages among the variables as defined by the network.

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[97]For further information on formulations, see "An Evaluation of Problem Formulations and Mathematical Programming Software for the Gas Market Model of NEMS," Science Applications International Corporation (McLean, VA. April 1992).

[98]*The Integrating Model of the Project Independence Evaluation System, Volume I - Executive Summary*, Logistics Management Institute (Washington, DC, April 1979).

[99]*Generalized Equilibrium Modeling: The Methodology of the SRI-Gulf Energy Model*, Decision Focus, Incorporated (Palo Alto, CA, May 1977).

Although the model involves hundreds of distinct processes, each can be implemented as one of a few basic processes which consist of: (1) simple conversion processes, (2) allocation processes, (3) primary resource processes, (4) end-use demand processes, (5) transportation processes, (6) complex conversion processes, and (7) secondary industry processes. The main process of interest in the SRI-Gulf model is the allocation process, which allocates the demand for a fuel among the competing sources of supply. The allocation process used in the model is a dynamic process that responds continuously to changes in price. The sharing method is represented in terms of simple market share curves and simple market penetration (behavioral lag) curves that reflect lags or time delays in responding to price changes. This is preferable to an allocation process that responds sharply to small differences in prices (as would be the case if demand were allocated entirely to the lowest price source), as the latter tends to overstate the market response to prices.

Conclusions

This section consists of two subsections. The first compares the NGTDM with EIA's former modeling system, GAMS, as one of the main goals of the design of the NGTDM was to address the weaknesses of the GAMS in modeling the current natural gas industry and provide EIA with a more effective modeling tool. The second section compares the NGTDM with the other modeling approaches considered, detailing which aspects of each approach were included and why each particular model or approach was, or was not, adopted for the NGTDM.

Comparison of Capabilities of GAMS to the NGTDM

GAMS has a number of limitations that precluded its use within the NEMS. The NGTDM was designed to address these limitations. As indicated in the Model Quality Audit review of GAMS performed for the Office of Statistical Standards,[100] one of the major limitations of GAMS was that it does not take into account significant regional differences in both supply availability and pricing. When GAMS was first modified to explicitly treat deregulated gas, a simple structure was included to represent a single national pool of deregulated gas. This national representation of deregulated gas means that GAMS does not fully account for regional supply distinctions on the overall market. The NGTDM represents both supply availability and price levels for all supply sources by region.

Another drawback to GAMS is that it does not include a representation of the physical flow of gas, and thus can not be used to analyze pipeline capacity issues. The assumption was made during the initial development of the model that sufficient capacity would exist to satisfy demand, and therefore neither capacity constraints nor future capacity expansion issues were considered. In reality, there are significant differences across regions in capacity utilization, with very heavy utilization occurring in certain sections of the country (specifically the West and Northeast).[101] One of the key determinants of how pipelines will price services in the future will be how intensely their systems are utilized. To represent this, a treatment of both capacity constraints and capacity expansion (pipeline and storage) decisions is necessary. These issues are addressed by a separate Capacity Expansion Module within the NGTDM. Flows are accounted for in the Annual Flow Module (AFM) by incorporating an aggregate representation of the natural gas transmission and distribution network. This allows a more comprehensive analysis of the results of supply and demand shifts on capacities and flow patterns, as well as a more representative analysis of the pricing of natural gas transmission and distribution services.

Also key to the pricing of natural gas transmission and distribution services is the representation of tariffs. While the GAMS representation of tariffs via markups based on fixed historical levels reflects both transmission and local distribution costs, the representation is simplistic and can not be easily adapted to reflect future market conditions. While pipelines and distributors formerly could be assumed to price strictly on the basis of their average cost of service, they are now offering a full range of services under competitive and market-based pricing arrangements. Although not totally deregulated, they have considerable pricing flexibility. The GAMS structure does not reflect

[100]Carpenter, Paul R., "Review of the Gas Analysis Modeling System," Incentives Research Inc. (Boston, MA, August, 1991). (Also contained in Appendix B of the GAMS Model Quality Audit.)

[101]Carpenter, Paul R., "Review of the Gas Analysis Modeling System," Incentives Research Inc.

this, and thus does not permit regulatory analysis of pricing issues. Tariffs in the NGTDM are endogenously determined along different segments of the physical pipeline system, with separate modules to model tariffs for pipeline and distributor services. The NGTDM also represents differences in pricing various classes of service more adequately than GAMS. GAMS applies the class-of-service pricing distinction only to the electric generators sector. Many industrial sector and large commercial sector users are also taking advantage of the lower prices associated with interruptible service, which is available to all customers. The NGTDM has the capability of distinguishing customers by type of service in all end-use sectors. Cost-based, average pricing is applied to core customers (firm service) within each sector and market-based, marginal pricing is applied to noncore customers (interruptible service).

There are two final areas not addressed in GAMS. The first is that of environmental impacts, which has become an area of considerable importance as a result of the Clean Air Act Amendments (CAAA) of 1990. The NGTDM tracks emissions of criteria pollutants associated with the transmission and distribution of natural gas. The second is that of energy related investment. Energy-related investments in areas such as the capacity expansion of natural gas pipelines are quantified in the NGTDM.Key features of the natural gas models reviewed are summarized below in Table D-1. While some of the models, such as WEFA and GRI, do address most of the issues that were of concern in the development of the NGTDM, others, such as the DRI and AGA models, employ a very simplistic

Table D-1. Natural Gas Models Reviewed

Model Feature	DRI	WEFA	AGA	GRI	DFI	GTM	MIT	Gasnet	GAMS	NGTDM
Flows represented	no	yes	no	yes	yes	yes	yes	yes	no	yes
Endogenous tariffs	no	yes	no	yes	no	no	no	no	no	yes
Capacity constraints	no	yes	no	yes	yes	yes	yes	no	no	yes
Capacity expansion	no	yes	no	yes	yes	no	yes	no	no	yes
Core/noncore markets	no	yes	no	yes	yes	no	no	no	no	yes
Seasonal	no	yes	no	yes	no	no	no	yes	no	no
Spot and contract gas	yes	yes	no	yes	no	no	no	no	yes	no
Environmental issues	no	no	no	no	no	no	no	no	no	yes

representation of the transmission and distribution segment of the industry. In the DRI and AGA models, flows are not explicitly represented, end-use prices are determined via fixed markups, and capacity constraints and capacity expansion decisions are not represented. These models were thus not suitable to address the requirements of NEMS.

Comparison of Capabilities of Other Models to the NGTDM

The WEFA and GRI/EEA models address several of the issues which are represented in the NGTDM. Like the NGTDM, these models track flows, take into account capacity constraints and capacity expansion decisions, and have endogenous determination of tariffs. Both models also have structures not represented within the NGTDM, as well as some general drawbacks in comparison to the NGTDM. The WEFA model is implemented as a spreadsheet, and is therefore not directly compatible with the NEMS system. While tariffs are endogenously determined, the methodology is a simple one which does not allow the type of regulatory analysis required by NEMS. While the GRI/EEA model has a more sophisticated determination of tariffs, all pricing is based on cost-of-service, and marginal pricing, which the NGTDM allows for, is the direction in which the industry is going. Capacity and capacity expansion issues are considered to be of great importance, and thus are treated in more detail in the NGTDM than in the GRI/EEA model.

Two features of the WEFA and GRI/EEA models not directly incorporated into the NGTDM are seasonal pricing and the distinction between wellhead spot and contract gas. A detailed treatment of contract pricing provisions for system supply is no longer necessary, since total deregulation of the wellhead market occurred in 1993. In addition, given the resulting competitive nature of the market at the wellhead, it is expected that the majority of new supply contracts will contain clauses tieing the contract price to the going price on the spot market, resulting in these prices moving in tandem over time. If the relative difference between the spot and contract gas price is determined to be significant, this distinction can be readily incorporated within the NGTDM. Seasonal pricing is an important issue for future consideration within NEMS, but is beyond the scope of the current design.

The basic structure of the GTM and MIT models is similar to the design of the NGTDM. Both are interregional trade equilibrium models which, like the NGTDM, are formulated as optimization problems that maximize the sum of producers' and consumers' surpluses subject to supply, demand, regulatory, and technological constraints. There are, however, a number of significant enhancements that are provided in the NGTDM. The GTM focuses on long-term market equilibria rather than on mid-term institutional and regulatory issues, which are important for NEMS to address. Like many of the other models, the GTM does not incorporate an endogenous determination of tariffs or capacity expansion decisions. While the structure of the MIT model is similar to that of the NGTDM, it is basically a Canadian model without the U.S. market detail required of NEMS.

Because of the number of supply regions and pipeline corridors, the representation of the transmission and distribution network incorporated in the DFI model is the most detailed of any of the models reviewed. Given that the solution time required to solve a system of this level of detail does not fall within the NEMS guidelines and that tariffs are determined based on exogenously determined values, the structure was not considered to be suitable for NEMS.

Since the Gasnet model was developed during a time period when the gas market was very different from the current market, it has a structure that could not be easily modified to address the issues relevant to NEMS. It does, however, provide a good example of the general technique of applying network optimization to natural gas transmission and distribution, which is the method that is used in the NGTDM to model the noncore transportation segment of the market.

Of the nonnatural gas models reviewed, PIES was most relevant to the design of the NGTDM. The PIES solution methodology, in fact, forms the basis for the linear programming approach used as the solution methodology in the NGTDM. The allocation process used in the SRI-GULF model was seriously considered to be used as the basis for an heuristic approach to modeling cost-of-service pricing in the core market within the NGTDM. This approach was subsequently abandoned due to added operational and convergence complexity that would be introduced by the use of separate modeling approaches for core and noncore markets.

Appendix E

Historical Data Inputs

Table E1

Data: Historical production levels for synthetic natural gas from liquid hydrocarbons and from coal, and other supplement supplies, to overwrite reported values in an unpublished table.

Author: Joe Benneche, EI-823.

Sources: Natural Gas Annual (1990-1992), DOE/EIA-0131, Table 15.
Natural Gas Monthly (June 1994), DOE/EIA-0130(94/06).

Derivation: The historical production levels for 1990 through 1992 were taken from the Natural Gas Annual. Synthetic gas production from coal is distinguished from synthetic gas production from liquid hydrocarbons, in the State level data, by the location of the associated plants. (Synthetic gas production from coal only occurs in South Dakota at present.) For 1993, the total supplemental gas production was taken from the Natural Gas Monthly. The 1993 values for the individual components were estimated by scaling their 1992 levels upward to sum to the 1993 total.

Notes: None.

Units: Billion cubic feet.

File: HISDATA

Variables: OGPRSUP3 - Production quantities for three supply types: 1) synthetic natural gas from liquid hydrocarbons, 2) synthetic natural gas from coal, and 3) other supplemental supplies.

Year	OGPRSUP3(1)	OGPRSUP3(2)	OGPRSUP3(3)
1990	10.932	53.114	56.358
1991	9.574	52.557	50.601
1992	10.732	58.496	48.691
1993	11.558	63.001	52.441

Table E2

Data: Average natural gas wellhead price in 1989 by NGTDM/OGSM region.

Author: Chetha Phang, EI-823, September 1993.

Sources: *Natural Gas Annual (1990)*, DOE/EIA-0131(90).
Federal Offshore Statistics 1990, OCS report, MMS91/0068.
U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216.
Annual Energy Review 1992, Appendix C.

Derivation: Wellhead prices for offshore regions were derived from the *Federal Offshore Statistics* report. Wellhead prices for the east and west New Mexico substate regions were assigned the average New Mexico price. The onshore regions in Texas and Louisiana were assigned wellhead prices that when averaged with their associated offshore prices (using quantity weights), would result in the average State level wellhead price reported in the *Natural Gas Annual*. The quantity (production) weights for these calculations were taken from the *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves* report. Quantity-weighted average wellhead prices by the NGTDM/OGSM regions were calculated from these data and converted into 1987 dollars using an implicit GDP price deflator.

Notes: The final wellhead price for the NGTDM/OGSM onshore region 1 is set to the onshore region 2's price, and the offshore region 1's price is set to the NGTDM/OGSM region 6's price.

Units: 1987 dollars per thousand cubic feet.

File: INITDAT

Variables: WPRLAGON Average natural gas wellhead price for NGTDM/OGSM onshore regions.
WPRLAGOF Average natural gas wellhead price for NGTDM/OGSM offshore regions (1- Atlantic, 2- Gulf of Mexico, 3-Pacific).

NGTDM/OGSM	1	2	3	4	5	6	7	8	9
WPRLAGON	2.19	2.19	2.61	1.33	1.59	2.78	1.95	2.19	1.52
NGTDM/OGSM	10	11	12	13	14	15	16	17	
WPRLAGON	1.41	1.31	1.24	1.29	1.89	1.44	1.44	2.08	

Offshore Region	1	2	3
WPRLAGOF	2.78	1.71	2.49

Mapping Between NGTDM, OGSM, and NGTDM/OGSM Onshore Regions

NGTDM Region	OGSM Region	NGTDM/OGSM Region
1	1	1
2	1	2
3	1	3
4	3	4
4	5	5
5	1	6
6	1	7
6	2	8
7	2	9
7	3	10
7	4	11
8	5	12
9	6	13
10	2	14
11	4	15
11	5	16
12	6	17

Table E3

Data: Canadian import prices in 1990 by border crossing point, average Canadian wellhead price in 1989, Canadian import pipeline capacity expansion in 1990.

Author: Chetha Phang, EI-823, October 1993.

Source: *Natural Gas Annual* 1990/1991, DOE/EIA-0131.
Canadian Petroleum Association Statistical Summary.
The Potential for Natural Gas in the United States, National Petroleum Council, December 1992.

Derivation: The 1990 Canadian import prices for the 6 border crossing points represented in the NGTDM were derived from reported State level import prices in the *Natural Gas Annual.*

The average Canadian wellhead price in 1989 was obtained from the *Canadian Petroleum Association Statistical Summary*.

The Canadian import pipeline capacity expansion data for 1990, by border crossing point, were derived from the *National Petroleum Council* report.

Notes: These initial values were used in the NGTDM, but they do not affect the solution results.

Units: For gas prices: 1987 dollars per thousand cubic feet.
For capacity expansion: Billion cubic feet.

File: INITDAT

Variables: CN_BRDPRC90 Canadian border prices in 1990.
CN_WELPRC89 Canadian wellhead price in 1989 (1.19)
CN_NEWCAP90 Canadian capacity expansion for 1990.

Transshipment Node at Canadian Border	13	14	15	16	17	18
CN_BRDPRC90	2.69	2.51	1.51	1.68	1.73	1.34
CN_NEWCAP90	0.0	21.9	0.0	28.9	43.1	0.0

Table E4

Data: Pipeline company financial data at company level and by arc.

Author: Pum Kim, Science Applications International Corporation.

Source: Form FERC-2, *Statistics of Interstate Natural Gas Pipeline Companies*, DOE/EIA-0145 (90).

Derivation: The company level financial data is compiled by using 1980-1990 FERC-2 data for interstate pipelines. The arc level financial data is compiled by using 1990 FERC-2 data.

The calculations are based on the following key rate base and capital structure parameters; details can be obtained from the numerous comments, notes and explanations included in the program itself:

- Gross Plant
- Net Plant
- Gross Plant Allocation Factors
- Net Plant Allocation Factors
- Salary Allocation Factors
- Functionalized Rate Base and Return Components
- Functionalized Customer Clearing Expenses
- Functionalized O&M Expenses
- Functionalized Depreciation and DDA
- Functionalized Working Capital

Three flat output files are created for selected pipelines, the last containing base year (1990) data for subsequent use in the PTM.

Notes: None.

Unit: 1990$.

File: FORM2, By company--PTARIFF, By arc.

Variables:

DDA	Depreciation, depletion, and amortization costs.
OTTAX	All other taxes assessed by Federal, State, or local governments except income taxes.
TAG	Total administrative and general expense.
TCE	Total customer expense.
SEOM	Supervision and engineering expense.
CSOML	Compressor station operating and maintenance labor expense.
CSOMN	Compressor station operating and maintenance non-labor expense.
OTOM	Other operations and maintenance expense.
CWC	Cash working capital.
OWC	Other working capital.
ADIT	Accumulated deferred income taxes.
GPIS	Original capital cost of plant in service (gross plant in service).
ADDA	Accumulated depreciation, depletion, and amortization.
PFES	Value of common stock for pipeline and storage
CMES	Value of preferred stock for pipeline and storage
LTD	Value of long term stock for pipeline and storage.

Table E5

Data: Revenue credits and rates of return by pipeline company.

Author: Pum Kim, Science Applications International Corporation.

Source: Pipeline rate cases filed by FERC (revenue credits) (exhibit I). Pipeline rate case settlements, as reported by FERC OPPR (rates of return).

Derivation: Revenue credit is derived from the most recent rate case as submitted by each pipeline company. Transition cost is based on the recommendation from FERC using amortization schedule. Rates of return from pipeline rate case settlements, as reported by FERC OPPR.

Notes: None.

Units: 1987 dollars or percentage.

File: PTARIFF

Variables:

REVC		Revenue credits to cost-of-service (1-transportation, 2-storage).
PCMER		Rate of return, common stock equity in fraction.
PPFER		Rate of return, preferred stock in fraction.
PLTDR		Rate of return, long term debt in fraction.
DCMER		= PCMER - PLTDR.
DLTDR		= PLTDR - AA bond rating (from MC_RMPUAANS in MACOUT common block).

Table E6

Data: Interregional and intraregional pipeline capacity in 1990.

Author: Pum Kim, Science Applications International Corporation.

Source: Key Point Data, FORM FERC-567 DATA, *Annual Flow Diagram*, (90).

Derivation: The data were derived using interstate pipeline capacity between States. If two States were in different regions, then these values were accumulated to calculate the total pipeline capacity along the associated arc. If two States were in the same region, then these data were accumulated to calculate the total intra-regional pipeline capacity in the associated region.

Notes: None.

Unit: Billion cubic feet per year.

File: CAPACTY

Variables: PCAP_MAX Physical interstate pipeline capacity along an arc or within a region.

From	To	PCAP_MAX	From	To	PCAP_MAX	From	To	PCAP_MAX
1	1	1487	8	4	2710	9	8	441
2	1	1800	16	4	2060	11	8	478
13	1	156	2	5	530	17	8	2785
1	2	1800	3	5	2425	8	9	1461
2	2	10742	5	5	13566	9	9	2023
3	2	2344	6	5	7444	18	9	618
5	2	6223	5	6	120	6	10	1131
14	2	410	6	6	35751	7	11	3553
2	3	411	7	6	19735	8	11	433
3	3	16101	4	7	904	11	11	4342
4	3	8548	6	7	34	9	12	1130
5	3	1493	7	7	22989	11	12	3613
6	3	9751	8	7	200	3	15	998
3	4	633	11	7	907	7	19	444
4	4	17167	4	8	1058	11	20	25
7	4	9462	8	8	1277			

Table E7

Data: Historical pipeline fuel consumption and lease and plant fuel consumption by Census Division. These historical data are used to overwrite model results for the reporting of these consumption categories.

Author: Chetha Phang and Joe Benneche, EI-823.

Source: *Natural Gas Annual* (1990-1992), DOE/EIA-0131.
Natural Gas Monthly (June 1994), DOE/EIA-0130(6/94).

Derivation: The numbers for historical values for 1990, 1991, and 1992 were taken from data published in the *Natural Gas Annual*. The 1993 national totals were taken from the *Natural Gas Monthly*. Within the NGTDM these values are disaggregated to produce regional numbers based on the implied 1992 regional shares.

Notes: None.

Units: Billion cubic feet.

File: HISDATA

Variables:
QGPTR — Pipeline fuel consumption by Census Division (national total in 1993, 607.0 Bcf).
QLPIN — Lease and plant fuel consumption by Census Division (national total in 1993, 1205.0 Bcf)

	QGPTR			QLPIN		
Census Division	1990	1991	1992	1990	1991	1992
1	1.872	2.235	2.796	0.0	0.0	0.0
2	41.752	42.057	47.991	6.871	4.575	4.346
3	52.841	48.723	51.307	14.367	11.218	8.836
4	72.487	60.168	60.419	48.037	56.621	52.689
5	37.572	37.646	46.996	11.837	11.822	13.884
6	96.590	86.865	84.142	20.361	15.688	20.663
7	196.455	169.007	168.671	771.540	582.531	613.372
8	124.339	119.585	97.881	146.699	119.308	130.017
9	35.908	35.019	27.508	216.680	327.505	327.012

Table E8

Data: Historical natural gas prices to nonelectric end-use demand sectors. These data are presented for each sector by core and noncore classes and as an average over the two classes for each Census Division. In addition, the data are provided for each sector, by core and noncore classes, for each NGTDM region. These data are used to overwrite the model results that are reported and are passed to the demand model of NEMS in the historical years. They are also used as a basis for benchmarking the NGTDM model to historical prices.

Author: Chetha Phang and Jim Diemer, EI-823.

Source: *Natural Gas Annual* (1990-1992), DOE/EIA-0131, Tables 31, 44-94.
Manufacturing Energy Consumption Survey: Consumption of Energy 1991, (prereleased tables).
Annual Energy Review 1992, DOE/EIA-0384(92), Appendix C for GDP implicit price deflators.

Derivation: In the NGTDM, the residential, commercial, and transportation sectors are assumed to be entirely core customers. Therefore, the average end-use prices for these sectors were assigned to both the core and the noncore classes. The natural gas prices for the residential, commercial, and transportation sectors were derived from Census Division and State level data from the *Natural Gas Annual*, and converted into 1987 dollars.

Core and noncore industrial end-use prices in 1991 were derived using data published from the *Manufacturing Energy Consumption Survey* for the four Census Regions. For 1991 all of the Census Divisions within a Census Region were assigned the same price, for both the core and noncore classes. Similar prices for 1990 and 1992 were derived by adjusting the 1991 values by the difference in the 1991 regional wellhead price and the regional wellhead price in the associated year.

Notes: In the model, these historical data are initially assigned to the variables listed below and are subsequently assigned to similarly named variables in the model that do not contain the leading letter "H".

Units: 1987 dollars per thousand cubic feet.

File: HISDATA

Variables:

HPGFRS	Residential, core natural gas prices by Census Division.
HPGFCM	Commercial, core natural gas prices by Census Division
HPGFTR	Transportation, core natural gas prices by Census Division
HPGFIN	Industrial, core natural gas prices by Census Division
HPGIRS	Residential, noncore natural gas prices by Census Division.
HPGICM	Commercial, noncore natural gas prices by Census Division
HPGITR	Transportation, noncore natural gas prices by Census Division
HPGIIN	Industrial, noncore natural gas prices by Census Division
HPGFRSGR	Residential, core natural gas prices by NGTDM region.
HPGFCMGR	Commercial, core natural gas prices by NGTDM region
HPGFINGR	Industrial, core natural gas prices by NGTDM region
HPGFTRGR	Transportation, core natural gas prices by NGTDM region
HPNGRS	Residential, average natural gas prices by Census Division.
HPNGCM	Commercial, average natural gas prices by Census Division
HPNGTR	Transportation, average natural gas prices by Census Division
HPNGIN	Industrial, average natural gas prices by Census Division

Table E9

Data: Historical natural gas wellhead prices by OGSM region. These historical data are used to overwrite model results in the historical period before they are passed to the OGSM and are reported.

Author: Chetha Phang and Joe Benneche, EI-823.

Source: *Natural Gas Annual* (1990-1992), DOE/EIA-0131.
Federal Offshore Statistics (1990-1992), OCS report, MMS(90-92)/0068.
U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves (1990-1992), DOE/EIA-0216.
Annual Energy Review 1992, DOE/EIA-0384(92), Appendix C for GDP implicit price deflators.
Natural Gas Monthly (June 1994), DOE/EIA-0130(6/94).

Derivation: Wellhead prices for offshore regions were derived from the *Federal Offshore Statistics* report. Wellhead prices for the east and west New Mexico substate regions were assigned the average New Mexico price. The onshore regions in Texas and Louisiana were assigned wellhead prices that when averaged with their associated offshore prices (using quantity weights), would result in the average State level wellhead price reported in the *Natural Gas Annual*. The quantity (production) weights for these calculations were taken from the *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves* report. Quantity-weighted average wellhead prices by the NGTDM/OGSM regions were calculated from these data and converted into 1987 dollars using an implicit GDP price deflators. The wellhead gas prices for the Alaska regions (10- offshore North, 11- onshore North, 12- South) were set to the State average wellhead prices from the *Natural Gas Annual*, after being converted to 1987 dollars. The 1993 national average natural gas wellhead price from the *Natural Gas Monthly* and the 1992 historical regional natural gas wellhead prices are used by the model to approximate regional 1993 prices.

Notes: A placeholder price was assigned to the Atlantic offshore region.

Units: 1987 dollars per thousand cubic feet.

File: HISDATA

Variables: MNUMOR — OGSM region (1 to 6 is for OGSM onshore regions, 7 to 9 is for offshore regions, 10 to 12 for Alaska regions, 13 is for the average lower 48 States).
OGWPRNG — Natural gas wellhead price by OGSM region (1993 lower 48 State average natural gas wellhead price set to 1.63 1987$/Mcf).

OGSM Region	OGWPRNG(1990)	OGWPRNG(1991)	OGWPRNG(1992)
1	2.37	2.15	2.03
2	1.47	1.38	1.48
3	1.41	1.26	1.41
4	1.41	1.30	1.46
5	1.27	1.09	1.16
6	2.01	2.02	1.86
7	2.75	2.15	2.03
8	1.63	1.47	1.43
9	2.46	2.44	2.25
10	1.22	1.26	1.17
11	1.22	1.26	1.17
12	1.22	1.26	1.17

Table E10

Data: Historical dry natural gas production by OGSM region. These historical data are used to overwrite the model results in these years before they are passed to the OGSM and are reported.

Author: Chetha Phang and Joe Benneche, EI-823.

Source: *Natural Gas Annual* (1990-1992), DOE/EIA-0131.
U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves (1990-1992), DOE/EIA-0216.
Historical and Projected Oil and Gas Consumption, Alaska Department of Natural Resources, Division of Oil and Gas, February 1993, Table 4.
Natural Gas Monthly (June 1994), DOE/EIA-0130(6/94).

Derivation: Dry gas production by State/substate were aggregated into the OGSM regional level (for 6 onshore regions and 3 offshore regions). The State level data were taken from the *Natural Gas Annual*. When substate level data were required, the State level data was disaggregated based on data from the *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves* report.

The production numbers for the Alaska regions (10- offshore North, 11- onshore North, 12- South) were computed using the total dry production from the *Natural Gas Annual* and the Alaska North/South split based on production numbers from the Alaska Department of Natural Resources.

For 1993, State level dry gas production values from the *Natural Gas Monthly* are used (along with 1992 substate splits) to derive regional 1993 dry gas production levels within the NGTDM for 1993.

Notes: None.

Units: Billion cubic feet.

File: HISDATA

Variables:

MNUMOR	OGSM region (1 to 6 is for onshore regions, 7 to 9 is for offshore regions, 10 to 12 is for Alaska regions).
OGPRDNG	Dry natural gas production by OGSM region.

	OGPRDNG		
MNUMOR	1990	1991	1992
1	780.9	793.1	769.9
2	4381.0	4427.7	4529.2
3	3382.9	3282.8	3252.4
4	1639.7	1642.2	1783.2
5	1660.2	1808.6	2104.8
6	301.7	313.6	296.3
7	0.0	0.0	0.0
8	5230.5	4964.6	4632.1
9	51.4	55.8	59.6
10	0.0	0.0	0.0
11	193.0	225.2	226.4
12	188.4	184.2	185.2

Table E11

Data: Historical dry gas production by Petroleum Administration for Defense District (PADD) region. These historical data are used to overwrite the model results in these years before they are passed to the Petroleum Market Model (PMM).

Author: Chetha Phang and Joe Benneche, EI-823.

Source: *Natural Gas Annual* (1990-1992), DOE/EIA-0131.
Natural Gas Monthly (June 1994), DOE/EIA-0130(6/94).

Derivation: The dry gas production by State from the *Natural Gas Annual* were aggregated into PADD region for each historical year. For 1993, the State level data was taken from the *Natural Gas Monthly* and the aggregation is performed within the NGTDM.

The PADD regions are defined as follows:

PADD I: Maine, Massachusetts, New Hampshire, Rhode Island, Vermont, District of Columbia, Delaware, Maryland, New Jersey, New York, Pennsylvania, Florida, Georgia, North Carolina, South Carolina, Virginia, and West Virginia.

PADD II: Indiana, Illinois, Kentucky, Tennessee, Michigan, Ohio, Minnesota, Wisconsin, North Dakota, South Dakota, Oklahoma, Kansas, Missouri, Nebraska, and Iowa.

PADD III: New Mexico, Texas, Louisiana, Arkansas, Mississippi, and Alabama.

PADD IV: Montana, Idaho, Wyoming, Utah, and Colorado.

PADD V: Washington, Oregon, California, Nevada, Arizona, Alaska, and Hawaii

Notes: None.

Units: Billion cubic feet.

File: HISDATA

Variables: MNUMPR PADD region (1 to 5).
PRNG_PADD Dry gas production by PADD.

	PRNG_PADD		
MNUMPR	1990	1991	1991
1	389.672	381.668	363.003
2	3148.031	3101.842	2990.510
3	12420.686	12237.727	12389.679
4	1114.590	1196.566	1328.492
5	736.695	779.999	768.221

Table E12

Data: Historical nonassociated dry natural gas production by NGTDM/OGSM region. These historical data are used to overwrite the model results in these years before they are passed to the OGSM.

Author: Chetha Phang and Joe Benneche, EI-823.

Source: *Natural Gas Annual* (1990-1992), DOE/EIA-0131.
U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216.
Natural Gas Monthly (June 1994), DOE/EIA-0130(6/94)

Derivation: The nonassociated and associated-dissolved fractions of total production and the substate level data published in the *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves* report are used to generate nonassociated dry natural gas production at the necessary substate level, consistent with the State level dry natural gas production data published in the *Natural Gas Annual*. These data are aggregated to the NGTDM/OGSM regions. For 1993 State level dry gas production from the *Natural Gas Monthly* are disaggregated based on the necessary 1992 data to derive similar values for 1993 within the NGTDM.

Notes: None.

Units: Billion cubic feet.

File: HISDATA

Variables:
NSUPSUB NGTDM/OGSM onshore region (1 to 17).
NOCSREG NGTDM/OGSM offshore region (1 to 3).
OGPRDNGON Nonassociated dry natural gas production by NGTDM/OGSM onshore region.
OGPRDNGOF Nonassociated dry natural gas production by NGTDM/OGSM offshore region.

	OGPRDNGON		
NSUPSUB	1990	1991	1992
1	0.0	0.0	0.0
2	199.2	171.6	161.5
3	183.0	217.9	217.5
4	535.6	507.6	598.6
5	10.0	11.0	1.5
6	175.9	186.5	176.1
7	72.3	75.8	79.1
8	210.7	258.5	429.2
9	3702.9	3689.1	3576.6
10	2480.9	2405.5	2344.2
11	773.3	762.3	758.5
12	858.0	935.8	1068.1
13	2.8	2.7	2.6
14	0.0	0.0	0.0
15	270.7	240.1	292.0
16	482.9	551.1	714.2
17	117.5	139.4	133.5

	OGPRDNGOF		
NOCSREG	1990	1991	1992
1	0.0	0.0	0.0
2	4632.5	4393.0	4091.0
3	17.8	17.6	15.4

Table E13

Data: Historical natural gas wellhead prices by NGTDM/OGSM region. These data are used to overwrite final model results for report writing and to assign values to the variable referred to as P0, used in defining the supply curves within the NGTDM over the historical period.

Author: Chetha Phang, EI-823, November 1993.

Source: *Natural Gas Annual* (1990-1992), DOE/EIA-0131.
Federal Offshore Statistics (1990-1992), OCS report, MMS91/0068.
U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216.
Annual Energy Review 1992, DOE/EIA-0384(92), Appendix C for GDP implicit price deflators.
Natural Gas Monthly (June 1994), DOE/EIA-0130(6/94).

Derivation: Wellhead prices for offshore regions were derived from the *Federal Offshore Statistics* report. Wellhead prices for the east and west New Mexico substate regions were assigned the average New Mexico price. The onshore regions in Texas and Louisiana were assigned wellhead prices that when averaged with their associated offshore prices (using quantity weights), would result in the average State level wellhead price reported in the *Natural Gas Annual*. The quantity (production) weights for these calculations were taken from the *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves* report. Quantity-weighted average wellhead prices by the NGTDM/OGSM regions were calculated from these data and converted into 1987 dollars using an implicit GDP price deflator.

To derive 1993 regional wellhead prices in the NGTDM, the 1992 NGTDM/OGSM regional prices are equally scaled so that the quantity-weighted average natural gas price equals the national average published in the *Natural Gas Monthly* for 1993 (1.63 1987$/Mcf).

Notes: The final wellhead price for the NGTDM/OGSM onshore region 1 is set to the onshore region 2's price, and the offshore region 1's price is set to the NGTDM/OGSM region 6's price.

Units: 1987 dollars per thousand cubic feet.

File: HISDATA

Variables:

NSUPSUB	NGTDM/OGSM onshore region (1 to 17).
NOCSREG	NGTDM/OGSM offshore region (1 to 3).
HWPRLAGON	Natural gas wellhead price by NGTDM/OGSM onshore regions.
HWPRLAGOF	Natural gas wellhead price by NGTDM/OGSM offshore regions.

	HWPRLAGON		
NSUPSUB	1990	1991	1992
1	2.06	1.86	1.65
2	2.06	1.86	1.65
3	2.45	2.21	2.11
4	1.38	1.16	1.27
5	1.58	1.41	1.62
6	2.75	2.45	2.37
7	1.96	1.72	1.59
8	2.06	1.75	1.79
9	1.39	1.35	1.45
10	1.41	1.40	1.45
11	1.31	1.33	1.50
12	1.16	1.03	1.05
13	1.23	1.21	1.07
14	1.99	2.09	2.07
15	1.49	1.19	1.35
16	1.49	1.19	1.35
17	2.02	2.03	1.87
	HWPRLAGOF		
1	2.75	2.45	2.03
2	1.63	1.47	1.43
3	2.46	2.44	2.25

Table E14

Data: Historical Canadian natural gas wellhead price and production. These historical data are used to overwrite model results in these years before they are passed to the OGSM and are reported.

Author: Chetha Phang, EI-823, November 1993.

Source: *Canadian Petroleum Association.*

Derivation: The Canadian dry natural gas production and wellhead price were obtained from the source listed above. The Canadian wellhead price was converted into GDP 1987 U.S. dollars per Mcf.

Notes: None.

Units: For price: 1987 dollars per thousand cubic feet.
For volumes: Billion cubic feet.

File: HISDATA

Variables: OGCNPPRD Canadian natural gas wellhead price.
OGCNQPRD Canadian dry natural gas production.

	1990	1991	1992	1993
OGCNPPRD	1.17	0.99	0.93	1.03
OGCNQPRD	3766.48	3909.66	4224.00	5041.24

Table E15

Data: Historical natural gas import and export levels and prices, at NGTDM border crossings and liquefied natural gas (LNG) terminals. These data are used to overwrite model results before they are sent to the OGSM and are reported.

Author: Chetha Phang, EI-823.

Source: *Natural Gas Annual* (1990-1992), DOE/EIA-0131.
Natural Gas Monthly (June 1994), DOE/EIA-0130(6/94).

Derivation: Natural gas import and export levels were aggregated from State level data published in the *Natural Gas Annual*. The import and export price data were either directly extracted from the same publication for a particular State or represent quantity-weighted averages over the appropriate State level data.

To generate 1993 import and export data, the 1992 values were scaled to equal total natural gas import and export levels or quantity-weighted average import and export prices for Canada, Mexico, and LNG imports and exports, as published in the *Natural Gas Monthly*.

Notes: For 1990 the natural gas import price bordering Washington State was not published. As a placeholder, the 1991 value plus 6 cents was used.

Units: For price: 1987 dollars per thousand cubic feet.
For volumes: Billion cubic feet.

File: HISDATA

Variables:

MNUMBX	U.S. border crossing index (1=VT, NH, ME; 2=NY; 3=OH, MI, WI; 4=MN, ND; 5=ID, MT; 6=WA; 7=TX; 8=AZ, NM; 9=CA; 10= Japan; 11= Everett, MA; 12= Cove Point, MD; 13= Elba Island, GA; 14= Lake Charles, LA; 15= Total Canada; 16= Total Mexico; 17= Total LNG; 18= Total U.S.).
OGQNGIMP	Natural gas imports by border crossing.
OGPNGIMP	Natural gas import price by border crossing.
OGPNGEXP	Natural gas export price by border crossing.

YEAR	MNUMBX	CATEGORY/ENTRY	OGQNGIMP	OGPNGIMP	OGQNGEXP	OGPNGEXP
1990	1		14.512	2.69	0.000	0.00
1990	2		98.217	2.50	0.000	0.00
1990	3		0.000	0.00	17.284	2.39
1990	4		308.581	1.68	0.000	0.00
1990	5		858.313	1.63	0.075	1.49
1990	6		168.441	1.39	0.000	0.00
1990	7		0.000	0.00	13.983	1.61
1990	8		0.000	0.00	1.676	2.14
1990	9		0.000	0.00	0.000	0.00
1990	10	JAPAN	0.000	0.00	52.546	3.17
1990	11	EVERETT, MA	53.443	2.47	0.000	0.00
1990	12	COVE POINT, MD	0.000	0.00	0.000	0.00
1990	13	ELBA ISLAND, GA	0.000	0.00	0.000	0.00
1990	14	LAKE CHARLES, LA	30.750	1.66	0.000	0.00
1990	15	TOTAL, CANADA	1448.064	1.68	17.359	2.38
1990	16	TOTAL, MEXICO	0.000	0.00	15.659	1.66
1990	17	TOTAL, LNG	84.193	2.18	52.546	3.17
1990	18	TOTAL, US	1532.257	1.71	85.564	2.74
1991	1		15.796	2.38	0.000	0.00
1991	2		188.233	2.23	0.000	0.00
1991	3		1.151	1.44	14.751	1.62
1991	4		378.492	1.46	0.000	0.00
1991	5		890.430	1.47	0.041	1.46
1991	6		235.614	1.28	0.000	0.00
1991	7		0.000	0.00	58.851	1.49
1991	8		0.000	0.00	1.597	1.88
1991	9		0.000	0.00	0.000	0.00
1991	10	JAPAN	0.000	0.00	54.005	3.15
1991	11	EVERETT, MA	30.312	2.61	0.000	0.00
1991	12	COVE POINT, MD	0.000	0.00	0.000	0.00
1991	13	ELBA ISLAND, GA	0.000	0.00	0.000	0.00
1991	14	LAKE CHARLES, LA	33.284	1.44	0.000	0.00
1991	15	TOTAL, CA	1709.716	1.53	14.792	1.62
1991	16	TOTAL, ME	0.000	0.00	60.448	1.50
1991	17	TOTAL, LNG	63.596	2.00	54.005	3.15
1991	18	TOTAL, US	1773.312	1.55	129.245	2.20

YEAR	MNUMBX	CATEGORY/ENTRY	OGQNGIMP	OGPNGIMP	OGQNGEXP	OGPNGEXP
1992	1		17.248	2.37	0.000	0.00
1992	2		435.470	2.05	0.000	0.00
1992	3		38.568	1.32	67.763	1.51
1992	4		369.137	1.44	0.000	0.00
1992	5		963.487	1.39	0.014	1.37
1992	6		270.477	1.22	0.000	0.00
1992	7		0.000	0.00	93.408	1.59
1992	8		0.000	0.00	2.565	1.17
1992	9		0.000	0.00	0.000	0.00
1992	10	JAPAN	0.000	0.00	52.532	2.84
1992	11	EVERETT, MA	30.479	2.38	0.000	0.00
1992	12	COVE POINT, MD	0.000	0.00	0.000	0.00
1992	13	ELBA ISLAND, GA	0.000	0.00	0.000	0.00
1992	14	LAKE CHARLES, LA	12.637	1.43	0.000	0.00
1992	15	TOTAL, CANADA	2094.387	1.52	67.777	1.51
1992	16	TOTAL, MEXICO	0.000	0.00	95.973	1.58
1992	17	TOTAL, LNG	43.116	2.10	52.532	2.84
1992	18	TOTAL, US	2137.503	1.53	216.282	2.86

1993 Inport/Export Data	Canada	Mexico	Liquefied Natural Gas
Import Volumes	2193.678	1.728	81.682
Export Volumes	49.491	36.824	55.952
Import Prices	1.63	1.55	1.71
Export Prices	1.66	1.67	2.64

Table E16

Data: The price charged for synthetic natural gas produced from coal (currently only occurring and expected to occur at the Great Plains Coal Gasification Plant in North Dakota). These historical data are used to overwrite model results before they are passed to the Coal Model of the NEMS.

Author: Chetha Phang, EI-823, November 1993.

Source: *Natural Gas Annual* (1990-1992), DOE/EIA-0131.
Annual Energy Review 1992, DOE/EIA-0384(92), Appendix C for GDP implicit price deflators.

Derivation: The average natural gas wellhead price in a State is assumed as a proxy for the price of synthetic gas produced from coal in the same State. These historical prices were taken from the *Natural Gas Annual* and converted into 1987 dollars. Since the only coal gasification plant is in North Dakota (NGTDM region 5) only one regional price is assigned in the NGTDM for this category and all of the other regions are set to zero. For 1993, the 1992 historical wellhead price for North Dakota was assumed.

Notes: None.

Units: 1987 dollars per thousand cubic feet.

File: HISDATA

Variables: CLSYNGWP Price of synthetic natural gas from coal by NGTDM/OGSM region.

		CLSYNGWP		
SUBREG	NGTDM - OGSM Region	1990	1991	1992
5	04 - 05	1.58	1.42	1.63

Table E17

Data: Input data and parameters for deriving electric generation natural gas prices for core, competitive with distillate fuel, and competitive with residual fuel oil service classes for 1990, 1991, and 1992 by NGTDM/EMM region. These historical data are used to overwrite model results for natural gas prices sent to the Electricity Market Module, to benchmark the NGTDM core electric generation natural gas prices, and for deriving parameters for setting noncore prices.

Author: Joe Benneche, EI-823.

Source: *Natural Gas Annual* (1990-1992), DOE/EIA-0131.
Baseline Projection Databook Volume 2, Gas Research Institute, 1994.

Derivation: Historical natural gas prices for the three categories of electric generation customers are derived within the NGTDM so that the quantity-weighted average price in each NGTDM/EMM region matches the values published in the Natural Gas Annual for the years 1990 through 1992 (HPGTELGR). These prices were derived based on assumed relationships between these three categories. First, for each NGTDM/EMM region the fraction of the price of natural gas to electric generators competitive with distillate divided by the natural gas price to electric generators competitive with residual fuel oil is assumed to be 1.3 (HRAT2ELGR). Second, for each NGTDM/EMM region the fraction of the price of natural gas to core electric generation customers divided by noncore electric generation customers (competitive with distillate and competitive with residual fuel oil) is assumed at a regionally specific value. These ratios were based on the relationship between comparable variables (NGPECOSR and NGPEIFCF) in the Gas Research Institute's publication (pages 608 and 610).

Units: Fraction or 1987 dollars per thousand cubic feet.

File: HISDATA

Variables:

HPGTELGR	Average natural gas price to electric generators by NGTDM/EMM region.
HRAT1ELGR	Assumed ratio (fraction) of core natural gas price to electric generators to noncore natural gas price to electric generators (competitive with distillate and residual fuel combined)
HRAT2ELGR	Assumed ratio (fraction) of natural gas price to electric generators competitive with distillate fuel oil to those competitive with residual fuel oil (1.3).
(used to calculate)	
HPGFELGR	Electric generation core natural gas price by NGTDM/EMM region (assigned to PGFELGR).
HPGIELGR	Electric generation competitive with distillate fuel natural gas price by NGTDM/EMM region (assigned to PGIELGR).
HPGCELGR	Electric generation competitive with residual fuel oil natural gas price by NGTDM/EMM region (assigned to PGCELGR).

Regions NGTDM/ EMM	1990		1991		1992	
	HPGTELGR	HRAT1ELGR	HPGTELGR	HRAT1ELGR	HPGTELGR	HRAT1ELGR
1	2.23	1.947	1.90	1.947	2.20	1.802
2	2.01	1.574	1.74	1.471	1.86	1.816
3	2.17	1.574	1.95	1.471	2.05	1.816
4	0.89	2.145	1.12	1.512	1.07	1.439
5	2.45	2.145	1.90	1.512	1.89	1.439
6	1.98	1.785	1.72	2.042	1.86	1.000
7	1.54	1.785	1.37	2.042	1.60	1.000
8	4.53	1.595	3.08	1.396	2.92	1.389
9	2.31	1.595	2.06	1.396	2.21	1.389
10	2.15	1.595	1.60	1.396	2.08	1.389
11	2.69	1.843	2.25	2.006	2.29	1.749
12	1.64	1.843	1.38	2.006	1.55	1.749
13	1.92	1.495	1.72	1.816	1.86	1.383
14	1.97	1.495	1.78	1.816	1.93	1.383
15	1.88	1.802	1.52	1.894	1.58	1.699
16	1.91	1.802	1.83	1.894	1.79	1.699
17	1.84	1.884	1.38	2.079	1.93	1.322
18	2.26	1.595	1.84	1.396	1.90	1.389
19	1.95	1.496	1.60	1.150	1.78	1.728
20	2.77	1.297	2.50	1.294	2.32	1.422
21	1.40	1.884	0.98	2.079	0.98	1.322

Table E18

Data: Natural gas wellhead price in Alaska and landed cost of crude oil in 1989. Used when calculating Alaskan consumption and wellhead prices in model "forecast" year 1990.

Author: Chetha Phang, EI-823, October 1993.

Source: *Annual Energy Review* 1991, DOE/EIA-0384, Table 71 and Appendix C.
Natural Gas Annual 1991, DOE/EIA-0131, Table 45.

Derivation: The real world oil price for 1989 was read directly from the *Annual Energy Review* (AER) 1991, Table 71. The real wellhead gas price for Alaska in 1989 was obtained by dividing the current wellhead gas price of $1.36 (*Natural Gas Annual* 1991, Table 45) by the GDP implicit price deflator of 1.084 (AER 1991, Appendix C).

Notes: None.

Units: For oil price: 1987 dollars per barrel.
For gas price: 1987 dollars per thousand cubic feet.

File: INITDAT

Variables:

WOP89	Imported crude oil refiner acquisition cost in 1989 (16.68 1987$/barrel).
WPR89	Natural gas wellhead price in Alaska in 1989 (1.25 1987$/Mcf).

Appendix F

Assumptions Data

Table F1

Data: Assumed minimum level, and 1989 level, of synthetic gas production from liquid hydrocarbons in Illinois. Assumed forecast level of synthetic gas production from liquid hydrocarbons in Hawaii.

Author: Joe Benneche, EI-823.

Source: *Natural Gas Annual 1992*, DOE/EIA-0131(91), Table 57.

Derivation: The assumed minimum synthetic gas production level in Illinois is set at the 1991 level, the minimum of the observed production levels from 1987 through 1992. The maximum synthetic gas production level in Illinois is set at 50 percent above the level in the previous forecast year. For 1990 (the first model year), the variable SNG89 holds the value for the previous forecast year.

For the forecast, the assumed level of synthetic gas production from liquid hydrocarbons in Hawaii is set at the average of the observed levels from 1988 through 1992.

Notes: None.

Units: Billion cubic feet.

File: INITDAT

Variables:

SNGMIN	Assumed minimum level of synthetic natural gas production from liquid hydrocarbons in Illinois.
SNGHI	Assumed level of synthetic natural gas production from liquid hydrocarbons in Hawaii.
SNG89	Synthetic natural gas production from liquid hydrocarbons in Illinois in 1989.

SNG89	SNGMIN	SNGHI
9.477	6.849	2.780

Table F2

Data: Consumption of "lease fuel" (gas used in well, field, and lease operations) as a percentage of dry gas production by NGTDM/OGSM region.

Author: Chetha Phang, EI-823, September 1993.

Sources: *Natural Gas Annual* (1985-1990), DOE/EIA-0131.
U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves (1985-1990), DOE/EIA-0216.

Derivation: For each year, the lease fuel consumption (by State) and the dry gas production (by State/substate) are aggregated to the NGTDM/OGSM region level. Lease fuel consumption for the necessary subregions within Texas and New Mexico are derived by assuming that the ratio of lease consumption to dry gas production is constant throughout the State. For each NGTDM/OGSM region from 1985 to 1990, the lease fuel consumption as a percent of dry production is computed as the lease fuel consumption divided by dry gas production in the region. Finally, the average lease percentage is computed over the specified time period. For region 1, where there is no dry gas production, the percentage was set to the region 2 value.

Notes: None.

Units: Fraction.

File: INITDAT

Variable: PCTLSE_SUPL Lease fuel consumption as a percent of dry gas production by NGTDM/OGSM region

NGTDM/OGSM	1	2	3	4	5	6	7	8	9
PCTLSE_SUPL	0.030	0.030	0.032	0.030	0.040	0.031	0.030	0.046	0.032
NGTDM/OGSM	10	11	12	13	14	15	16	17	
PCTLSE_SUPL	0.031	0.034	0.046	0.025	0.040	0.033	0.033	0.038	

Table F3

Data: Peak and off-peak period gas consumption shares (fraction), by market type (core, noncore), and NGTDM region for the residential, commercial, and industrial sectors.

Author: Chetha Phang, EI-823, September 1993.

Sources: Heating Degree Day data base from The National Oceanographic and Atmospheric Administration. *Natural Gas Monthly* 1985-1990, DOE/EIA-0130.
Data created using PIPEJCL.PEAKOFF.RCIUSHR.D0615931

Derivation: For the residential and commercial sectors, the monthly gas consumption by State and year were first adjusted to reflect estimated normal heating degree day consumption levels. The normal heating degree day was computed as the average of the heating degree days over 30 years from 1961 to 1990 by State and month. The method of Ordinary Least Squares (OLS) was used to estimate these adjusted gas consumption levels, which were approximated by linear equations of the difference between the actual and normal heating degree day by State, month, and year. Next, these State consumption levels were aggregated to NGTDM region by year and peak and off-peak period. (The peak period is defined to include December, January, February, and March of a given year.) To compute peak and off-peak gas consumption shares for each of these sectors, the peak and off-peak gas levels were divided by the annual gas consumption in each NGTDM region and year (1985 to 1990). Finally, the average consumption shares were computed over 1985 to 1990 for each NGTDM region.

For the industrial sector, no heating degree day adjustment was done to the gas consumption. For each NGTDM region and year, the monthly core gas consumption was computed as the annual total industrial gas consumption times the industrial core share of the annual total (an approximation from preliminary data) times the percent of industrial system sales in each month of the year. The monthly noncore gas consumption was computed as the monthly gas consumption minus the monthly core gas consumption in each NGTDM region. Finally, the peak versus off-peak splits were computed as the peak (or off-peak) volume divided by the annual volume, for both core and noncore industrial consumption.

Notes: None.

Units: Share (fraction).

File: FSHARES

Variables:

NON_POSHR_F Peak and off-peak gas consumption shares by NGTDM region for the core residential, commercial, and industrial sectors.

NON_POSHR_I Peak and off-peak gas consumption shares by NGTDM region for the noncore residential, commercial, and industrial sectors.

Peak and Off-Peak Gas Consumption Shares for the Residential, Commercial, and Industrial Sectors, by NGTDM Region and by Market Type

NGTDM Region	1	2	3	4	5	6	7	8	9	10	11	12
Residential C—Peak	0.596	0.607	0.626	0.648	0.641	0.646	0.628	0.593	0.586	0.555	0.629	0.527
Residential C—Off-Peak	0.404	0.393	0.374	0.352	0.359	0.354	0.372	0.407	0.414	0.445	0.371	0.473
Residential N—Peak	0.596	0.607	0.626	0.648	0.641	0.646	0.628	0.593	0.586	0.555	0.629	0.527
Residential N—Off-Peak	0.404	0.393	0.374	0.352	0.359	0.354	0.372	0.407	0.414	0.445	0.371	0.473
Commercial C—Peak	0.535	0.563	0.618	0.576	0.558	0.590	0.522	0.563	0.524	0.406	0.519	0.423
Commercial C—Off-Peak	0.465	0.437	0.382	0.424	0.442	0.410	0.478	0.437	0.476	0.594	0.481	0.577
Commercial N—Peak	0.535	0.563	0.618	0.576	0.558	0.590	0.522	0.563	0.524	0.406	0.519	0.423
Commercial N—Off-Peak	0.465	0.437	0.382	0.424	0.442	0.410	0.478	0.437	0.476	0.594	0.481	0.577
Industrial C—Peak	0.317	0.461	0.509	0.441	0.406	0.386	0.341	0.387	0.391	0.374	0.388	0.365
Industrial C—Off-Peak	0.683	0.539	0.491	0.559	0.594	0.614	0.659	0.613	0.609	0.626	0.612	0.635
Industrial N—Peak	0.295	0.142	0.144	0.220	0.263	0.321	0.299	0.357	0.314	0.327	0.287	0.226
Industrial N—Off-Peak	0.705	0.858	0.856	0.780	0.737	0.679	0.701	0.643	0.686	0.673	0.713	0.774

C = Core; N = Noncore.
Note = For the industrial sector, the shares for 1990 are computed.

Table F4

Data: Peak and off-peak period electric generation consumption shares, by market type (core, competitive with distillate, competitive with residual fuel oil) for each NGTDM/EMM region.

Author: Chetha Phang, EI-823, September 1993.

Sources: *Natural Gas Monthly* 1985-1990, DOE/EIA-0130.
Form EIA-860, Form EIA-767, Form EIA 759.
Data created using PIPEJCL.PEAKOFF.RCIUSHR.D0615931.

Derivation: For each year, the monthly gas consumption by electric generators by State and plant type were first aggregated into NGTDM/EMM regions for each of the three market types represented in the NGTDM. Specifically, the following definitions were used for classifying the market types from different plant types:

- core market is for gas steam and gas combined cycle turbines
- Competitive with residual fuel oil market is for dual fired steam turbines
- Competitive with distillate fuel oil market is for gas turbines and dual fired turbines

These monthly gas consumption levels were then adjusted to match the monthly electric utility consumption published in the *Natural Gas Monthly*. [All the electric utility consumption in West Virginia was assumed to be competitive with distillate.] The adjusted monthly consumption levels were then aggregated into peak and off-peak period by market type.

For each market type in each NGTDM/EMM region the peak and off-peak shares were computed as a fraction of the total electric utility consumption for each type and region. The shares used in the model represent an average over the years 1988 through 1990.

Notes: None.

Units: Share (fraction).

File: FSHARES

Variables:

UTIL_POSHR_F	Electric generation core market peak and off-peak period gas consumption shares by NGTDM/EMM region.
UTIL_POSHR_I	Electric generation competitive with distillate fuel market peak and off-peak gas consumption shares by NGTDM/EMM region.
UTIL_POSHR_C	Electric generation competitive with residual fuel oil peak and off-peak gas consumption shares by NGTDM/EMM region.

Electric Generation Peak and Off-peak Gas Consumption Shares by NGTDM/EMM Region and Market Type

NGTDM/EMM Region	Core/Peak	Core/ Off-Peak	Competitive w/Distillate Peak	Competitive w/Distillate Off-Peak	Competitive w/Residual Peak	Competitive w/Residual Off-Peak
1	0.047	0.953	0.072	0.928	0.043	0.957
2	0.228	0.772	0.203	0.797	0.124	0.876
3	0.358	0.642	0.203	0.797	0.154	0.846
4	0.351	0.649	0.183	0.817	0.450	0.550
5	0.217	0.783	0.265	0.735	0.214	0.786
6	0.003	0.997	0.199	0.801	0.148	0.852
7	0.186	0.814	0.177	0.823	0.164	0.836
8	0.333	0.667	0.452	0.548	0.333	0.667
9	0.333	0.667	0.143	0.857	0.112	0.888
10	0.135	0.865	0.072	0.928	0.015	0.985
11	0.000	1.000	0.365	0.635	0.333	0.667
12	0.135	0.865	0.272	0.728	0.126	0.874
13	0.224	0.776	0.296	0.704	0.273	0.727
14	0.264	0.736	0.313	0.687	0.250	0.750
15	0.195	0.805	0.306	0.694	0.172	0.828
16	0.229	0.771	0.601	0.399	0.323	0.677
17	0.232	0.768	0.414	0.586	0.000	0.000
18	0.236	0.764	0.250	0.750	0.267	0.733
19	0.241	0.759	0.198	0.802	0.216	0.784
20	0.314	0.686	0.257	0.743	0.256	0.744

Table F5

Data: Share of associated-dissolved gas production in an OGSM region, that was produced in each associated NGTDM/OGSM region.

Author: Chetha Phang, EI-823, September 1993.

Source: *Natural Gas Annual* (1988-1991), DOE/EIA-0131.
U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves (1988-1991), DOE/EIA-0216.

Derivation: The *Natural Gas Annual* provides total natural gas production for each State, whereas the "Reserves Report" provides more disaggregated numbers (i.e., some substate values and associated-dissolved versus nonassociated). Comparable values differ between the two sources and the Natural Gas Annual is considered to be more accurate. Therefore, the required disaggregated values from the "Reserves Report" are scaled to match the those reported in the *Natural Gas Annual.*

The NGTDM/OGSM regional splits for associated-dissolved gas production are computed by dividing the associated-dissolved gas production in each NGTDM/OGSM region by the associated-dissolved gas production in its corresponding OGSM region. The values used in the model represent the average over the years 1988 through 1991. For each OGSM region these shares sum to 1.

Units: Fraction.

File: INITDAT

Variable: SHR_AD17 Share of associated-dissolved gas production in an OGSM region, that is produced in each associated NGTDM/OGSM region.

NGTDM/ OGSM	1	2	3	4	5	6	7	8	9
OGSM	1	1	1	3	5	1	1	2	2
SHR_AD17	0.0000	0.0182	0.8838	0.0522	0.1192	0.0768	0.0212	0.0249	0.9633
NGTDM/ OGSM	10	11	12	13	14	15	16	17	
OGSM	3	4	5	6	2	4	5	6	
SHR_AD17	0.9478	0.7649	0.8395	0.0000	0.0118	0.2351	0.0413	1.000	

Table F6

Data: Share of nonelectric gas consumption in a Census Division that is in an associated NGTDM region by sector (residential, commercial, industrial, and transportation).

Author: Chetha Phang, EI-823, September 1993.

Sources: *Natural Gas Monthly* (1985-1990), DOE/EIA-0130.
Natural Gas Annual 1991, DOE/EIA-0131(91).
Data created using PIPEJCL.DEMSHR.BYNGTDM.D0422931.

Derivation: For the residential, commercial, and industrial sectors, the monthly natural gas consumption levels by State from the *Natural Gas Monthly* are aggregated to derive annual NGTDM regional consumption levels and annual Census Division consumption levels. For each year from 1985 to 1990 and for each NGTDM region, the regional consumption share of its associated Census Division was computed by dividing the NGTDM regional gas consumption level by its corresponding Census Division consumption level. Finally, an average share for each NGTDM region was computed over the years 1985 to 1990 for use in the model.

For the transportation sector, the NGTDM regional gas consumption shares are computed based on the 1991 gas consumption data from the *Natural Gas Annual (1991)*.

Notes: None.

Units: Share (fraction).

File: INITDAT

Variable: NG_CENSHR Share of nonelectric gas consumption in a Census Division that is in an associated NGTDM region, by sector

Portion of Consumption in each Census Region in each NGTDM Region, for the Nonelectric Sectors.

NGTDM Region	1	2	3	4	5	6	7	8	9	10	11	12
Census Division					5			8	9	5	8	9
Residential	1.000	1.000	1.000	1.000	0.961	1.000	1.000	0.775	0.105	0.039	0.225	0.895
Commercial	1.000	1.000	1.000	1.000	0.850	1.000	1.000	0.709	0.188	0.150	0.291	0.812
Industrial	1.000	1.000	1.000	1.000	0.868	1,000	1.000	0.813	0.184	0.132	0.187	0.816
Transportation	1.000	1.000	1.000	1.000	0.437	1.000	1.000	0.539	0.787	0.563	0.461	0.213

Note: Transportation sector shares are based on 1991 consumption levels from the *Natural Gas Annual 1991*.

Table F7

Data: Lease fuel, plant fuel, and pipeline fuel consumption as a percentage of dry gas production in North and South Alaska, as well as assumed values for future production associated with the Alaskan Natural Gas Transportation System (ANGTS).

Author: Chetha Phang, EI-823, September 1993.

Source: *Natural Gas Annual* (1987-1991), DOE/EIA-0131.

Derivation: The total Alaskan lease fuel, plant fuel, and pipeline fuel consumption levels as a percentage of Alaskan dry gas production (averaged over the years 1987 through 1991) were applied in the model for both North and South Alaska and for the production associated with ANGTS, with one exception. For the pipeline fuel consumption associated with the ANGTS, the percentage of dry production was assumed to be 7.5 percent.

Notes: None.

Units: Fraction.

File: INITDAT

Variables:

AK_PCTPLT Alaskan plant fuel consumption as a percent of dry production for the categories: North, South, and ANGTS.

AK_PCTPIP Alaskan pipeline fuel consumption as a percent of dry production for the categories: North, South, and ANGTS.

AK_PCTLSE Alaskan lease fuel consumption as a percent of dry production for the categories: North, South, and ANGTS.

Supporting Data on Alaska	1987	1988	1989	1990	1991
Lease fuel consumption (MMcf)	112,404	151,280	189,702	166,155	187,106
Plant fuel consumption (MMcf)	4,278	2,390	2,537	27,720	36,088
Pipeline fuel consumption (MMcf)	2,109	1,961	1,876	1,708	2,597
Dry gas production (MMcf)	340,247	355,398	373,797	381,431	409,381
Plant fuel as a percent of production (fraction)	0.0126	0.0067	0.0068	0.0726	0.0882
Pipeline fuel as a percent of production (fraction)	0.0062	0.0055	0.0050	0.0045	0.0063
Lease fuel as a percent of production (fraction)	0.3303	0.4257	0.5075	0.4356	0.4570

Assumed Percentages (presented as fractions) of Dry Gas Production for Lease, Plant, and Pipeline Fuel Consumption for the Alaskan Production Categories: North, South, and ANGTS.

	North	South	ANGTS
AK_PCTPLT	0.0882	0.0882	0.0882
AK_PCTPIP	0.0055	0.0055	0.0750
AK_PCTLSE	0.4312	0.4312	0.4312

Table F8

Data: Alaskan wellhead to end-use gas price markups for the residential, commercial, and electric generation sectors and the Alaskan wellhead to lower 48 States border price differential.

Author: Chetha Phang, EI-823, September 1993.

Sources: *Natural Gas Annual* 1986, 1988, 1991, DOE/EIA-0131.
Annual Energy Review 1991 (Table 69, Appendix C).

Derivation: The end-use natural gas price markups for the residential and commercial sectors in Alaska were computed by taking the average over five years (1987 through 1991) of the differences between the end-use gas price (to the associated sector) and the average wellhead price. For the electric generation sector, the markup was calculated as the average of the differences between the price to electric generators and the average wellhead price from 1986 to 1990.

The difference between the average Alaskan natural gas wellhead price and the price at the first delivery-point in the lower 48 States by way of a future Alaskan Natural Gas Transportation System was assumed to be $1.00 (1987$/Mcf).

Notes: The industrial markup is not computed here since the NGTDM model uses an estimated regression equation for industrial gas price, specified as a linear function of total landed costs of crude oil imports. This equation is described in Table G1.

Units: 1987 dollars per thousand cubic feet.

File: INITDAT

Variables:

AK_RM	Alaskan residential natural gas price markup from the Alaskan wellhead.
AK_CM	Alaskan commercial natural gas price markup from the Alaskan wellhead.
AK_EM	Alaskan electric generation natural gas price markup from the Alaskan wellhead.
ANGTS_TAR	Alaskan wellhead to lower 48 States border price differential.

AK_RM	AK_CM	AK_EM	ANGTS_TAR
2.183	1.236	0.219	1.00

Table F9

Data: Canadian gas production volume crossing the U.S. border and flowing back into Canada, which is not part of import/export trade.

Author: Joe Benneche, EI-823.

Source: *Natural Gas Annual* (1990-1992), DOE/EIA-0131.

Derivation: The Canadian natural gas that crosses the U.S. border in Minnesota and ultimately flows back to Canada (by way of Michigan and Montana) is set in the model to 356.401 billion cubic feet in 1990 and to 362.861 billion cubic feet in 1991. For 1992 and beyond, it is set to 486.163 billion cubic feet (the 1992 historical level). This volume is calculated as the amount flowing into Minnesota from Canada minus the imports into Minnesota. The percentage of this gas which flows back into Canada through Michigan is set in the model (specified as a fraction) to 95.4 percent in 1990, 95.5 percent in 1991 and to 97 percent for 1992 and beyond.

Notes: None.

Units: Billion cubic feet and fraction.

File: INITDAT

Variables:

CANFLO_IN	Canadian gas volume crossing the U.S. border in Minnesota which is not imported, but ultimately flows back to Canada.
CANFLO_SHR	Percentage of Canadian gas volume crossing back into Canada at the U.S. border in Michigan (as opposed to Montana).

Table F10

Data: Percent of Alaskan consumption in South Alaska by sector.

Author: Chetha Phang, EI-823, October 1993.

Source: *State of Alaska Historical and Projected Oil and Gas Consumption*, Alaska Department of Natural Resources, February 1993.

Derivation: The percent of Alaskan consumption in South Alaska by sector was computed based on the reported sectoral consumption levels for 1991 for total and Southern Alaska in the referenced publication.

Notes: The sector number is defined as follows: 1- Residential, 2- Commercial, 3- Industrial, 4- Transportation, 5- Electric Utilities.

Units: Fraction.

File: INITDAT

Variables: AK_PCTSOUTH — Percent of Alaskan consumption in South Alaska.

Sector	1	2	3	4	5
AK_PCTSOUTH	0.965	1.000	0.792	1.000	0.981

Table F11

Data: Multiplicative factor (applied to expected production-to-reserve ratio) for setting maximum and minimum onshore and offshore nonassociated natural gas production.

Author: Joe Benneche, EI-823.

Source: Analyst judgement.

Derivation: In order to constrain the Annual Flow Module and Capacity Expansion Module to realistic production levels in all regions, assumed maximum and minimum production levels were defined as a percent above or below the expected production (i.e., reserves times expected production-to-reserves ratio). The maximum was set at 20 percent above the expected production and the minimum was set at 10 percent below.

Units: Fraction.

File: INITDAT

Variables: PARM_MAXPR Ratio of maximum production to expected production (set at 1.2).
PARM_MINPR Ratio of minimum production to expected production (set at 0.9).

Table F12

Data: Exogenous forecast of other supplemental supplies, specified as a national level with associated regional shares.

Author: Joe Benneche, EI-823.

Source: *Natural Gas Annual 1992*, DOE/EIA-0131(92), Table 15.

Derivation: Other supplemental supplies are defined as total supplemental gas supplies minus synthetic natural gas, as defined in the Natural Gas Annual (NGA), Table 15. The national historical levels for the years 1990, 1991, and 1992 were taken from the NGA. The 1993 total supplemental gas supplies was taken from the Natural Gas Monthly, June 1994 (DOE/EIA-0130(94/6) and the 1994 and 1995 totals were taken from the Short-Term Energy Outlook, 3rd Quarter (DOE/EIA-0202 (94/3Q). Other supplemental supplies for these years were derived by subtracting assumed values for synthetic natural gas in these years. Synthetic gas from coal was assumed at the 1992 level of 58.496 Bcf. Synthetic gas production levels from liquid hydrocarbons for Hawaii and Illinois were assumed at the average from 1988 through 1992 (2.78 Bcf) and the average from 1990 through 1992 (7.66 Bcf), respectively.

The regional shares (for deriving NGTDM regional values from the national level) for other supplemental supplies were computed as the average over 1990 through 1992 of the ratio of the production of other supplemental supplies in a region to the national production level. The production levels in NGTDM regions 10, 11, and 12 are zero and were therefore not included in the variable dimensions.

Notes: None.

Units: Fraction for shares; Billion cubic feet for volumes.

File: INITDAT

Variables: OSUP_RSHR Other supplemental supplies regional shares.
OSUP_TOT Other supplemental supplies forecast value.

NGTDM Region	1	2	3	4	5	6	7	8	9
OSUP_RSHR	0.010	0.274	0.383	0.039	0.094	0.004	0.007	0.186	0.003

Forecast Year	1990	1991	1992	1993	1994	1995	1996-2015
OSUP_TOT	56.356	50.603	48.690	58.062	58.062	65.062	58.062

Table F13

Data: Allocation factors for Straight Fixed Variable (SFV) and Modified Fixed Variable (MFV).

Author: Pum Kim, Science Applications International Corporation.

Source: Analyst judgement based on full rate case filing under Section 4 of the Natural Gas Act, as submitted to FERC by each pipeline company.

Derivation: Assumptions were made based on industry expertise and actual allocation factors as submitted to FERC. Based on these factors, an analyst derived line item allocation factors for MFV and SFV. Line item costs as filed in the rate cases were mapped into FERC Form 2 cost categories. Allocation factors submitted in the rate cases were weighted by the respective costs to derive cost weighted average allocation factors.

Notes: None.

Unit: Percentage.

File: ALLOCAT

Variables:

ARF	Allocation factor of fixed costs (transportation).
AFR	Allocation factor of fixed costs to reservation (transportation).
AVR	Allocation factor of variable costs to reservation (transportation).
ASF	Allocation factor of fixed costs (storage).
ARV	= 1 - ARF, Allocation factor of variable costs (transportation).
AFU	= 1 - AFR, Allocation factor of fixed costs to usage (transportation).
AVU	= 1 - AVR, Allocation factor of variable costs to usage (transportation).
ASV	= 1 - ASF, Allocation factor of variable costs (storage).

Table F14

Data: For each pipeline company, the gas it transports through each of the interstate pipeline arcs represented in the NGTDM divided by the gas it transports in total.

Author: Pum Kim, Science Applications International Corporation.

Source: Production Data, FORM EIA-176 DATA, *Natural Gas Annual*, DOE/EIA-0131(90).
Key Point Data, FORM FERC-567 DATA, *Annual Flow Diagram*, (90).
Contract Demand Data, Rate Cases as submitted to FERC by each pipeline company (90).
Map State Data, Pipeline System Map as created by each pipeline company (90).

Derivation: The following procedures were performed for each pipeline company:

- Determine all production points.
- Determine all contract demand points.
- Determine all possible paths from production point to contract demand point.
- Derive what percentage of the gas will flow from a production point to the demand point for each pipeline company.

Notes: None.

Unit: Fraction.

File: PTARIFF

Variables:

PID	Pipeline company ID.
PNAME	Pipeline company name.
PS	Fraction of gas a pipeline company provides to an arc.

Table F15

Data: Average interruptible pipeline service rates in 1989.

Author: Pum Kim, Science Applications International Corporation.

Source: Form FERC-2, *Annual Report of Major Natural Gas Companies*, 1990. Assumptions based on industry expertise and actual allocation factors as submitted to FERC.

Derivation: Process for deriving average annual interruptible pipeline transportation rates:

1. Process Form FERC-2 data using allocation factors as submitted to FERC.
2. Calculate total revenues into peak demand (D1) charge, annual demand (D2) charge, and commodity charges.
3. Retrieve total revenues (D1, D2, commodity) from step 2.
4. Let interruptible contract demand equal 10 percent of firm c firm contract demand volume.
5. Accumulate total contract demand volume by State.
6. Calculate annual firm volumes for demand charges.
7. Calculate annual interruptible service rate.

Notes: The 1989 interruptible rate is set to zero for all arcs not listed below.

Unit: 1987 dollars per thousand cubic feet.

File: PTARIFF

Variables: AFM_PTAR_I Average interruptible service rates in 1989 for transporting natural gas between transhipment nodes within the NGTDM.

From	To	AFM_PTAR_I	From	To	AFM_PTAR_I	From	To	AFM_PTAR_I
1	1	0.003	8	4	0.070	8	8	0.070
1	2	0.014	16	4	0.002	9	8	0.070
2	2	0.066	3	5	0.003	11	8	0.070
3	2	0.024	5	5	0.070	17	8	0.002
5	2	0.031	6	5	0.038	8	9	0.022
14	2	0.008	5	6	0.011	9	9	0.070
2	3	0.053	6	6	0.015	18	9	0.070
3	3	0.018	7	6	0.028	6	10	0.026
4	3	0.067	4	7	0.038	10	10	0.022
5	3	0.059	6	7	0.070	7	11	0.070
6	3	0.023	7	7	0.063	8	11	0.070
3	4	0.020	8	7	0.043	11	11	0.070
4	4	0.070	11	7	0.037	11	12	0.070
7	4	0.070	4	8	0.070			

Table F16

Data: Initial pipeline expansion cost curve by arc. Capital Costs for Each Arc - Expansion cost. Capital Costs for Each Storage Region

Author: Pum Kim, Science Applications International Corporation.

Source: Nation Petroleum Council (NPC) national average cost for expansion of $1.25 for compression, $1.40 for looping, and $1.80 for new pipe.
Evaluation of U.S. Natural Gas Storage Operations prepared by Pace Consultants for Gas Research Institute, GRI-92/0467.

Derivation: Use regional cost for expansion to derive an average for each region. Apply regional differential to the national average to derive cost at the arc level. Based on planned storage expansion, calculate average price of expansion by storage expansion region.

Notes: None.

Unit: CCOST ($-day/Mcf-mile).
NODECC ($/Mcf).

File: PTARIFF

Variables:

CCOST	Cost to expand 1 unit (Mcf-mile) of pipeline.
ARCFAC	Maximum pipeline capacity expansion factor, by arc.
CSTFAC	(1.0 + CSTFAC) is multiplied to CCOST derive capital cost at each arc. This is used to increase or decrease capital cost based on the region of the country.

Table F17

Data: Average distance of each arc and average contract demand at each receiving end of an arc.

Author: Pum Kim, Science Applications International Corporation.

Source: Production Data, FORM EIA-176 DATA, *Natural Gas Annual*, DOE/EIA-0131(90).
Key Point Data, FORM FERC-567 DATA, *Annual Flow Diagram*, (1990).
Contract Demand Data, Rate Cases as submitted to FERC by each pipeline company (1990).
Map State Data, Pipeline System Map as created by each pipeline company (1990).

Derivation: Milage Calculation Based on contract demand and Production Data.

All of these files were derived from the same source as "shares data":

Calculate distance of a pipeline system.
Find distance from origin to border crossing into another State.
Find distance from origin to contract demand point within same State.
Find distance from border crossing point to border crossing point in another State.
Find distance from border crossing point to contract demand point in another State. Since there may be more than one contract demand points, contract demand weighted mileage will consolidate contract demand points into one distance. within a State.
Associate each contract demand point to nearest border crossing point in each State.
Calculate contract demand weighted mileage for each State.
Get production volume and coordinates for each State.
Get contract demand values (annual and daily) for a given State.
Get all possible production source for each contract demand point in a State..
If more than one supply point exists for a contract demand point, calculate supply weighted miles for the pipeline from the supply origination point(s) to contract demand end point(s) (this is the contract demand weighted mileage calculated earlier).

Notes: None.

Unit: Distance (miles); contract demand (Bcf/day).

File: PTARIFF

Variables:

MILES	Length of an arc.
CONDEM	Peak day reservation firm contract demand, base year. (assigned to variable PRESV in the base year)

Table F18

Data: Base gas storage capacity share by region for each pipeline company.

Author: Pum Kim, Science Applications International Corporation.

Source: Form EIA-191, *Underground Gas Storage Report.*

Derivation: Each pipeline company's storage capacity within a region was divided by the pipeline company's total storage capacity in all regions.

Notes: None.

Unit: Fraction.

File: PTARIFF

Variables: N — Storage region.
NS — Share of company storage in the region.

Pipeline Company	N	NS	Pipeline Company	N	NS
ARKLA ENERGY RESOURCES	4	0.041	QUESTAR PIPELINE CO	8	1.000
	7	0.959	NATL FUEL GAS SUPPLY CORP	2	1.000
WILLIAMS NATURAL GAS CO	4	0.623	NAT GAS PIPELINE CO OF AMER	3	0.369
	7	0.377		4	0.248
COLORADO INTERSTATE GAS CO	4	0.343		7	0.382
	8	0.657	NORTHERN NATURAL GAS CO	4	1.000
COLUMBIA GAS TRANSMISSION	2	0.076	NORTHWEST NATURAL GAS CO	9	1.000
	3	0.519	PANHANDLE EASTERN PIPELINE CO	3	0.849
	5	0.404		7	0.151
CNG TRANSMISSION CORP	2	0.741	SOUTHERN NATURAL GAS CO	6	1.000
	5	0.259	TEXAS EASTERN TRANS CORP	5	1.000
EL PASO NATURAL GAS CO	11	1.000	TEXAS GAS TRANS CORP	3	0.047
K N ENERGY INC	4	0.928		6	0.953
	8	0.072	TRANSCONTINENTAL GAS PIPELINE	6	0.030
ANR PIPELINE CO	3	1.000		7	0.970
MISSISSIPPI RIVER TRANS CORP	3	0.051	TRUNKLINE GAS CO	7	1.000
	7	0.949	UNITED GAS PIPELINE CO	6	0.038
WILLISTON BASIN INTERSTATE PL	8	1.000		7	0.962

Table F19

Data: Efficiencies along network arcs. The percentage of gas leaving point "a" which is consumed as pipeline fuel while moving the gas to point "b."

Authors: Pum Kim and Lauren Busch, Science Applications International Corporation.

Source: Production Data, FORM EIA-176 DATA, *Natural Gas Annual*, DOE/EIA-0131(90).
Key Point Data, FORM FERC-567 DATA, *Annual Flow Diagram*, (90).
Contract Demand Data, Rate Cases as submitted to FERC by each pipeline company (90).
Map State Data, Pipeline System Map as created by each pipeline company (90).
Natural Gas Annual 1992 pipeline fuel consumption by state.

Derivation: For each arc, total mileage of gas transmission was derived based on production, contract demand, and key point. Initial efficiency rates were calculated and then adjusted to insure that the 1990 regional pipeline fuel consumption levels would result when they were applied to the 1990 inter/intraregional flows and disaggregated into regions using mileage splits from Table F39. Initial efficiencies were calculated as:

efficiency = 1.0 - (((miles gas travels in an arc / 100.0 miles) * 0.5) / 100.0)

Notes: None.

Unit: Fraction.

File: INITDAT

Variables:

NEFF_PIPE	Efficiency along distribution arc to nonelectric sectors (assumed at 1.0)
UEFF_PIPE	Efficiency along distribution arc to electric generators (assumed at 1.0)
SEFF_PIPE	Efficiency along gathering arc from supply source to transhipment node
MEXEFF	Efficiency along arc from Mexican border to export node (set at 1.0)
CANEFF	Efficiency along arc from Canadian border to export node (set at 1.0)
AEFF_PIPE_SCALE93	Multiplicative scaling factor to calibrate AEFF_PIPE to reflect 1993 national historical pipeline fuel consumption (set to 0.884)
AEFF_PIPE	Efficiency along interstate pipeline arcs (shown below).

Arc	AEFF_PIPE	Arc	AEFF_PIPE	Arc	AEFF_PIPE	Arc	AEFF_PIPE
2 > 1	0.983	4 > 4	0.997	11 > 7	0.985	8 > 12	0.945
13 > 1	0.995	7 > 4	0.972	19 > 7	0.995	9 > 12	0.987
1 > 2	0.983	8 > 4	0.990	4 > 8	0.995	11 > 12	0.948
2 > 2	0.987	16 > 4	0.995	8 > 8	0.979	12 > 12	0.989
3 > 2	0.980	2 > 5	0.974	9 > 8	0.995	21 > 12	0.988
5 > 2	0.995	3 > 5	0.995	11 > 8	0.975	1 > 13	0.995
14 > 2	0.992	6 > 5	0.976	17 > 8	0.995	2 > 14	0.995
2 > 3	0.990	5 > 6	0.995	8 > 9	0.980	3 > 15	0.995
3 > 3	0.999	6 > 6	0.996	18 > 9	0.986	4 > 16	0.995
4 > 3	0.974	7 > 6	0.968	6 > 10	0.988	8 > 17	0.995
5 > 3	0.995	4 > 7	0.980	7 > 11	0.960	9 > 18	0.986
6 > 3	0.975	6 > 7	0.995	8 > 11	0.970	7 > 19	0.995
15 > 3	0.980	7 > 7	0.992	11 > 11	0.945	11 > 20	0.995
3 > 4	0.995	8 > 7	0.995	20 > 11	0.995	12 > 21	0.995

Table F20

Data: Inter/intraregional flow of natural gas in 1990 by firm and interruptible service markets.

Authors: Pum Kim, Science Applications International Corporation and Joe Benneche, EI-823.

Source: Production Data, FORM EIA-176 DATA, *Natural Gas Annual*, DOE/EIA-0131(90).
Key Point Data, FORM FERC-567 DATA, *Annual Flow Diagram*, (90).
Contract Demand Data, Rate Cases as submitted to FERC by each pipeline company (90).
Map State Data, Pipeline System Map as created by each pipeline company (90).
Annual interstate flow of gas *Natural Gas Annual 1990*, DOE/EIA-0131(90), Vol I, Table 9.

Derivation: Rough estimates of firm service flows were derived primarily based on contract demand data. Interruptible flows were approximated to be twenty percent of firm service flows. These rough estimates were scaled so that there sum would equal the annual inter/intraregional flow of gas reported in the *Natural Gas Annual 1990*. Subsequently significant adjustments have been made to these numbers to avoid linear program solution infeasibilities as historical firm consumption levels have been modified within other NEMS models.

Notes: In the future, a more thorough analysis will be performed to derive better estimates of the firm and interruptible market interstate flows.

Unit: Billion cubic feet

File: CAPACITY

Variables: AFLOW_F Inter/intraregional flow of gas under firm service market (in 1990)
AFLOW_I Inter/intraregional flow of gas under interruptible service market (in 1990)

Arc	AFLOW_F	AFLOW_I	Arc	AFLOW_F	AFLOW_I	Arc	AFLOW_F	AFLOW_I
1 > 1	193	39	8 > 4	513	102	9 > 8	8	1
2 > 1	294	59	16 > 4	553	112	11 > 8	68	13
13 > 1	13	2	2 > 5	72	15	17 > 8	716	142
2 > 2	1397	249	3 > 5	606	121	8 > 9	424	85
3 > 2	444	89	5 > 5	1764	353	9 > 9	263	53
5 > 2	1421	284	6 > 5	1460	627	18 > 9	115	53
14 > 2	81	17	5 > 6	8	2	6 > 10	266	53
2 > 3	6	1	6 > 6	4649	930	7 > 11	460	151
3 > 3	2094	419	7 > 6	4200	1149	8 > 11	143	28
4 > 3	1460	626	4 > 7	10	2	11 > 11	565	113
5 > 3	211	42	7 > 7	2989	598	9 > 12	190	186
6 > 3	1565	671	8 > 7	44	9	11 > 12	718	524
3 > 4	26	5	11 > 7	36	7	3 > 15	291	58
4 > 4	2232	446	4 > 8	85	17	7 > 19	12	2
7 > 4	1160	292	8 > 8	166	33	11 > 20	2	1

(Note: Any arc not listed above was assigned a flow level of 0.0)

Table F21

Data: Distributor markups for nonelectric core service customers.

Author: Joe Benneche and Jim Diemer, EI-823.

Source: *Natural Gas Annual* (1990-1992), DOE/EIA-0131.
Unpublished Form EIA-176 data as aggregated by Roy Cass of the Office of Oil and Gas.
Manufacturing Energy Consumption Survey: Consumption of Energy 1991, (prereleased tables).

Derivation: The distributor markups for the residential and commercial sectors in each NGTDM region were set at the average regional end-use price minus the average regional citygate price in 1992. Citygate prices for NGTDM regions that are subsets of Census Divisions were provided by the Office of Oil and Gas.

The distributor markups for the industrial sector in each NGTDM region were similarly calculated, but represent an average over the years 1990 through 1992. In this case, the citygate prices for the NGTDM regions that are subsets of Census Divisions were set at the average associated citygate price for the Census Division. Core industrial end-use prices in 1991 were derived using data published from the *Manufacturing Energy Consumption Survey*. The 1990 and 1992 core industrial end-use prices were derived by adjusting the 1991 values by the difference in the 1991 regional wellhead price and the regional wellhead price in the associated year.

Unit: 1987 dollars per thousand cubic feet.

File: DTARIFF

Variables: DISTO

NGTDM Region	Residential	Commercial	Industrial
1	3.72	2.23	0.15
2	3.27	2.11	0.38
3	1.69	1.24	0.00
4	1.71	1.00	0.09
5	2.87	1.76	0.00
6	2.18	1.59	0.00
7	2.25	1.17	0.17
8	1.64	1.07	0.41
9	2.79	1.90	0.33
10	5.35	1.96	0.00
11	3.01	1.63	0.41
12	2.69	2.01	0.33

Table F22

Data: Storage efficiencies (i.e., fraction of natural gas injected that can be withdrawn at a later date)

Author: Joe Benneche, EI-823

Sources: Analyst Judgement

Derivation: Efficiency temporarily set to 1.0.

Notes: In actuality, loses occur in the storage process. This number will be researched and revised in the future.

Units: Fraction

File: INITDAT

Variables: EFF_STR Storage efficiency

Table F23

Data: Assumed pricing parameters for the noncore electric generation sector.

Author: Joe Benneche, EI-823.

Source: Derived estimates of electric generation natural gas prices for the competitive with residual fuel oil categories for 1990 and 1991.
Purchase prices to electric utilities for residual fuel oil by Census Division in 1990 and 1991 were taken from a database used in the Petroleum Market Model.

Derivation: The Census Division level prices for residual fuel oil were assumed for each NGTDM/EMM region contained within a Census Division. NGRATMAX was calculated as the competitive with residual fuel natural gas price divided by the residual fuel price, averaged over 1990 and 1991. For NGTDM/EMM regions 2, 3, 13, 14, and 20 the resulting values were adjusted. The similar variable (UDPD1) setting the assumed relationship for the competitive with distillate natural gas price to the distillate fuel price was assumed at 0.80 for all but the 21st NGTDM/EMM region.

Unit: Fraction.

File: DTARIFF

Variables:
NGRATMAX Assumed relationship between natural gas price to electric utilities, in the competitive with residual fuel oil category, to the residual fuel oil price
UDPD1 Assumed relationship between natural gas price to electric utilities, in the competitive with distillate fuel oil category, to the distillate fuel oil price

NGTDM/EMM Region	Residual Fuel Oil (NGRATMAX)	Distillate Fuel Oil (UDPD1)
1	0.87	0.80
2	0.92	0.80
3	0.92	0.80
4	0.39	0.80
5	0.65	0.80
6	1.06	0.80
7	0.91	0.80
8	1.03	0.80
9	0.90	0.80
10	0.59	0.80
11	1.01	0.80
12	0.75	0.80
13	0.92	0.80
14	0.92	0.80
15	0.47	0.80
16	0.55	0.80
17	0.30	0.80
18	0.81	0.80
19	0.43	0.80
20	0.92	0.84

Table F24

Data: FERC Order 636 transition costs by pipeline company and other transition cost parameters.

Author: Jim Diemer, EI-823.

Source: Federal Energy Regulatory Commission (Memo from Elizabeth Moler to Representative John Dingell, "Response to Chairman Dingell's Questions Regarding Various Aspects of Order 636, March 16, 1993) and General Accounting Office (*Natural Gas: Costs, Benefits, and Concerns Related to FERC's Order 636*, Washington, DC, GAO/RCED-94-11, November 1993).

Derivation: Transition costs consist of gas supply realignment (GSR) costs and purchase gas adjustment (PGA or account 191) costs. Transition cost data was extracted from the Restructuring Filings the pipeline companies provided to the Federal Energy Regulatory Commission (FERC) to comply with Order 636. In some cases, FERC staff and GAO staff have revised the pipeline submissions to be more in line with what they believe will ultimately be approved by the Commission. EIA did not manipulate the data in any way. It assumes that these costs will be fully recovered. In Order 636 and in subsequent hearings, FERC has indicated that the gas supply realignment costs are to be recovered over a 4 year period and the purchase gas adjustment balance account would be recovered over a 1 year period beginning with the 1993/1994 heating season. EIA assumes that it will take slightly longer to recover the costs because of small number of transition costs actually approved by October 1, 1993. Therefore, it is assumed that the PGA balances will be recovered over 2 years and the GSR costs will be recovered over 5 years beginning in 1994. Additionally, it is assumed that interruptible customers will be responsible for paying 10 percent of the GSR costs.

Notes: The data need to be updated as the actual transition costs are approved. The collection schedule may need to be revised based on the experienced gained as the industry begins operating under the Order in November 1993.

Unit: Millions of 1993 dollars.

File: PTARIFF (ANUM191, AGSRCOSTS, and PNEWFAC) and RDESIGN (A191YRS, GSRYRS, SHARE_GSR_F, and NEWCOSR_PER)

Variables:

A191YRS	Number of years Account 191 costs are assumed to be collected
ANUM191	Transition costs associated with Account 191
AGSRCOSTS	Transition costs associated with GSR charges
SHARE_GSR_F	Fraction of GSR transition costs assigned to firm service customers
GSRYRS	Number of years GSR costs are assumed to be collected
NEWCOST_PER	Depreciation period for new facilities required for compliance with Order 636
PNEWFAC	Transition costs associated with new facilities required to comply with Order 636
PSTRANDED	Cost related to pipeline company physical assets for bundled services that are no longer needed in an unbundled environment. For compliance with Order 636.

Order 636 Transition Costs (1993 Dollars)

Interstate Pipeline Company	Purchase Gas Adjustment Account Balance	Gas Supply Realignment	Total
Algonquin Gas Transmission Co.	0	0	0
ANR Pipeline Company	0	235,000,000	235,000,000
Arkla, Inc.	100,000	30,000,000	30,100,000
Colorado Interstate Gas Co.	0	6,000,000	6,000,000
CNG Transmission Corp.	80,000,000	34,000,000	114,000,000
Columbia Gas Transmission Corp.	175,000,000	0	175,000,000
Columbia Gulf Transmission Corp.	0	0	0
East Tennessee Natural Gas Co.	0	0	0
El Paso Natural Gas Co.	0	0	0
Florida Gas Transmission Co.	0	54,000,000	54,000,000
Great Lakes Gas Transmission Co.	0	0	0
Kern River Gas Transmission Co.	0	0	0
K-N Energy, Inc.	0	250,000,000	250,000,000
Midwestern Gas Transmission Co.	0	0	0
Mississippi River Transmission Corp.	0	25,000,000	25,000,000
National Fuel Gas Supply Corp.	0	0	0
Natural Gas Pipeline Company of America	0	550,000,000	550,000,000
Northern Border Pipeline Company	0	0	0
Northern Natural Gas Co.	0	0	0
Northwest Pipeline Corp.	50,000	19,936	69,936
Pacific Gas Transmission Co.	0	0	0
Panhandle Eastern Pipe Line Co.	20,000,000	50,000,000	70,000,000
Questar Pipeline Co.	0	0	0
Southern Natural Gas Co.	0	476,000,000	476,000,000
Tennessee Gas Pipeline Co.	123,600,000	442,000,000	565,600,000
TETCO	84,883,975	559,000,000	643,883,975
Texas Gas Transmission Corp.	0	175,000,000	175,000,000
Trailblazer Pipeline Co.	0	0	0

Interstate Pipeline Company	Purchase Gas Adjustment Account Balance	Gas Supply Realignment	Total
Transcontinental Gas P. L. Corp.	0	0	0
Transwestern Pipeline Co.	14,400,000	16,500,000	30,900,000
Trunkline Gas Company	15,000,000	10,000,000	25,000,000
United Gas Pipe Line Co.	6,900,000	21,000,000	27,900,000
Williams Natural Gas Company	18,000,000	30,000,000	48,000,000
Williston Basin Interstate Gas Co.	0	20,000,000	20,000,000
Wyoming Interstate Natural Gas Co.	0	0	0
Other Pipeline Companies	5,134,857	230,440,000	235,574,857
Total Industry Costs	543,068,832	3,213,959,936	3,757,028,768

Source: "Costs, Benefits, and Concerns Related to FERC's Order 636," General Accounting Office, Washington, DC, November 1993.

Table F25

Data: Emissions factors for natural gas pipeline compressors.

Author: Chetha Phang, EI-823.

Source: Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors", Fourth Edition, AP-42, September, 1985, p. 3.2-2.
Emissions of Greenhouse Gases in the United States 1985-1990, DOE/EIA-0573, September 1992.

Derivation: An average emission coefficient vector was derived for each emission type represented in NEMS, using coefficients for different types of compressors and the 1990 national composition of compressor capacity (i.e., 23 percent reciprocating engine and 77 percent gas turbines). Emissions factors for the production of carbon monoxide, sulfur oxides, and nitrogen oxides for the two engine types were taken from the Environmental Protection Agency publication and weighted on these percentages to obtain an average emissions rate for all engine types. The methane emissions rate was assigned as 90 percent of the hydrocarbon emissions rate, also sighted in this publication, and the remaining 10 percent was attributed to the volatile organic compounds category.

The total carbon emissions level for 1990 was taken from the EIA publication. The emissions rate for carbon dioxide was derived algebraically. The contribution of the other emissions compounds containing carbon to this total carbon emissions level was determined by multiplying the pipeline fuel consumption level in 1990 by the emissions factor for the compound and by the percent of its molecular weight attributable to carbon. The remainder was assumed to come from carbon dioxide emissions and was derived accordingly, using the relative molecular weight of carbon in carbon dioxide.

Unit: Thousand pounds of emissions per billion cubic feet of pipeline fuel consumed.

File: INITDAT

Variables: EMISRAT Thousand pounds of emissions per billion cubic feet of pipeline fuel consumed per emission type.

Total Carbon (C)	32,681.8
Carbon Monoxide (CO)	191.0
Carbon Dioxide (CO2)	118,728.2
Sulfur Oxides (SOX)	0.6
Nitrogen Oxides (NOX)	1013.0
Volatile Organic Compounds (VOC)	34.0
Methane (CH4)	250.0
Particulates	0.0

Table F26

Data: Storage expansion factors and associated costs.

Author: Phyllis Martin, EI-823.

Source: Analyst judgment.

Derivation: Based on maps of the United States indicating salt cavern creations and depleted wells within each region.

Notes: Factors act as multipliers of existing storage capacity to arrive at potential incremental capacity through 2010, up to a maximum potential level.

Unit: Multipliers and 1987$/Mcf

File: P.TARIFF

Variables:
NODFAC Potential incremental additional storage capacity expansion, defined as a multiple of the currently existing storage capacity.
NODECC Unitized cost to expand at the corresponding storage level.

NGTDM Region	Expansion Level	NODFAC	NODECC
1	--	--	--
2	1	0.33	3.00
	2	2.00	5.20
3	1	1.00	3.13
	2	2.00	4.00
4	1	1.00	4.00
5	1	0.50	4.00
6	1	2.00	4.00
	2	5.00	8.23
7	1	1.00	3.52
	2	2.00	4.00
8	1	0.25	3.00
	2	0.75	4.00
9	1	1.00	4.24
10	--	--	--
11	1	0.33	4.24
12	1	0.25	4.00

Table F27

Data: Transportation (compressed natural gas vehicle) sector pricing parameters.

Author: Joe Benneche, EI-823.

Source: State taxes from *The Clean Fuels Report*, April 1993.
Federal tax from *Octane Week*, Volume VIII, Number 13, August 9, 1993.
The other parameters are based on expert judgment.

Derivation: An average state tax for each NGTDM region was derived by averaging the reported state taxes in each region, weighted on the number of commercial sector customers in each state. States which will be charging an annual flat fee were not considered. The federal tax rate for compressed natural gas is quoted at $0.4854 (1993$/Mcf) in the source. This figure was converted into 1987 dollars by dividing by 1.235.

The maximum price of compressed natural gas is set relative to the price of gasoline to commercial customers (in equivalent units), and is assumed in the model to be 0.90 for all regions.

The cost of dispensing compressed natural gas at a retail station was partially based on an uncitable study that estimated the markup required to cover the incremental costs of installing compressed natural gas dispensing equipment in an existing conventional gasoline outlet plus the monthly costs of the outlet prior to the installation of the new equipment.

Notes: See Chapter 6 for more details on how compressed natural gas for vehicles is priced.

Unit: Fraction or 1987 dollars per thousand cubic feet.

File: DTARIFF

Variables:

STAX	Approximate average state tax for compressed natural gas consumed in vehicles in each NGTDM region starting in 1994. [Originally this value is assigned to the variable TSD2]
FTAX	Federal tax for compressed natural gas consumed in vehicles starting in 1994 ($0.395 1987$/Mcf). [Originally this value is assigned to the variable TFD2]
PERCDISC	Assumed ratio of the compressed natural gas maximum price to the commercial motor gasoline price (in equivalent units). [Originally this value is assigned to the variable TPD1]
RETAIL_COST	Cost of dispensing compressed natural gas for vehicles at a retail outlet (set at $0.30 1987$/Mcf).

NGTDM Region	1	2	3	4	5	6	7	8	9	10	11	12
STAX	1.359	0.736	0.681	1.164	1.086	1.015	0.916	0.991	1.316	1.051	0.514	1.051
PERCDISC	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9

Table F28

Data:	Share of Canadian and Mexican exports transported via the firm service network.	
Author:	Joe Benneche, EI-823	
Sources:	None.	
Derivation:	These shares were not based on real data, but were set based on model conveniences. This will likely be modified in the future.	
Notes:	None.	
Units:	Fraction	
File:	INITDAT	
Variables:	CANFRMITR_SHR	Share of exports to Canada transported via the firm service market (assumed at 0.0)
	MEXFRMITR_SHR	Share of exports to Mexico transported via the firm service market (assumed at 1.0)

Table F29

Data:	Pricing parameters for core electric generators.	
Author:	Jim Diemer, EI-823.	
Source:	Analyst judgment.	
Notes:	The core markup consists of a minimum markup (URFLOOR) and a benchmark factor. The benchmark factors are linearly phased down to URFLOOR + (UBENCH * UBENPER) beginning in the first year of the forecast for UBENYRD years thereafter.	
Unit:	UBENPER	fraction
	UBENYRD	number of years
	URFLOOR	1987 dollars per Mcf
File:	DTARIFF	
Variables:	TILT	Reserved for later use, currently set to zero (also UTILT1,UTILT2Y,UTILT2)
	UBENPER	The amount (fraction) the benchmark factors are reduced over the period UBENYRD, [UBENPER set equal to 0.50]
	UBENYRD	The length of the period (years) the benchmark factors are reduced by UBENPER, [UBENYRD set equal to 6]
	URFLOOR	The minimum mark-up for distributor services for core electric generators (dollars per Mcf), [URFLOOR set equal to $0.03 in all NGTDM regions]

Table F30

Data: Peak and off-peak parameters for natural gas production and exports, and Canadian gas that passes through the United States and back to Canada.

Author: Joe Benneche, EI-823.

Source: *Natural Gas Imports and Exports*, (for the four quarters of 1990), prepared by the Office of Fuels Programs, Office of Fossil Energy, DOE.
Natural Gas Monthly, DOE/EIA-0130(92/11).
Analyst judgement. Historically based shares were derived using monthly data for 1990.

Derivation: The derivation of values for SUP_PKSHR are described below. These values were also assigned to variable SUP_PUTILZ. SUP_OUTILZ was set equal to 1 - SUP_PUTILZ.

Domestic onshore and offshore production

State level 1990 monthly natural gas production from the *Natural Gas Monthly* were summed into the relevant NGTDM/OGSM regions. (Necessary state splits and onshore/offshore splits were based on annual data from FORM EIA-23.) These monthly data were used to derive peak period production shares for each onshore NGTDM/OGSM region and each offshore region.

Canadian and liquefied natural gas imports

Monthly imports of natural gas in 1990 for each of the NGTDM entry points were calculated by summing the imports into the relevant cities as reported in *Natural Gas Imports and Exports*. These monthly data were used to derive peak period shares for each NGTDM entry point with imports in 1990. Entry points with no current flows were assigned either the average Canadian or the liquefied natural gas import peak period share, as appropriate (34 and 41 percent respectively).

Categories of supplies (or exports) with assumed peak period splits (not based on history):

- natural gas exports (EXP_PSHR, assumed 50 percent flow in peak period, all borders)
- synthetic natural gas from liquids (assumed 33 percent supplied in peak period)
- other supplemental supplies (assumed 33 percent supplied in peak period)
- Mexican imports (assumed 34 percent flow in peak period, based on peak period supply in NGTDM region 7)
- Alaskan Natural Gas Transmission System (assumed 35 percent flow in peak period, based on peak period imports into NGTDM region 9)
- Canadian natural gas flowing through the United States to Canadian markets (CANFLO_PFSHR, assumed 70 percent flow in peak period)

Notes: In future years, a more thorough analysis will be made of seasonal supply trends over recent years to improve on these data, and to potentially offer insight into how seasonal supply availability might shift over time in the future.

Units: Fraction.

File: CEMDATA

Variables:	SUP_PUTILZ	Maximum share of "variable" supply sources available during the peak period by supply type and by NGTDM or NGTDM/OGSM region.
	SUP_OUTILZ	Maximum share of "variable" supply sources available during the off-peak period by supply type and by NGTDM or NGTDM/OGSM region
	SUP_PKSHR	Share of annual "fixed" supply sources available during the peak period by supply type and by NGTDM or NGTDM/OGSM region
	EXP_PSHR	Share of annual exports in peak period by border crossing
	CANFLO_PFSHR	Share of Canadian gas flowing through the United States to Canadian markets which travels during the peak period

[Note: A "variable" supply source is defined as one that is allowed to change in response to a change in the natural gas price within the CEM, unlike a "fixed" supply source. The three "variable" supply sources in the CEM are onshore and offshore production and synthetic natural gas production from liquid hydrocarbons.]

Table F31

Data: Annual and seasonal utilization factors for underground storage.

Author: Joe Benneche, EI-823.

Source: Analyst judgment.

Notes: Storage capacity is defined within the NGTDM as working gas capacity, (i.e., the volume of gas which is available for delivery). The current model does not represent gas which is injected and withdrawn in the same period. The model only represents that gas which is injected in the off-peak period to be withdrawn in the peak period. The limit imposed on this quantity in the model, on an annual basis, equals the working gas capacity times the maximum annual utilization factor (STR_UTIL, set to 1.0 for all regions). In addition the storage use by the firm service customers in all regions is limited to 85 percent of the working gas capacity, to insure that interruptible service customers have some access to storage.

Unit: Fraction.

File: CEMDATA

Variables:

STR_UTIL	Maximum annual storage utilization (set to 1.0 for all NGTDM regions)
STR_FUTILZ	Maximum utilization of storage by firm service customers (set to 0.85 for all NGTDM regions)

Table F32

Data: Share of the previous forecast year's firm and interruptible flow along an interregional arc which is used to set the minimum firm and interruptible service flows for the current forecast year.

Author: Joe Benneche, EI-823.

Source: Analyst judgment.

Derivation: These parameters are meant to reflect the inertia in the system due to such factors as long term commitments (e.g., contracts) and are a prime candidate for sensitivity testing. All of the minimum interruptible service flow constraints in the linear program are set to the previous year's flow times 0.20. Initially, all of the minimum firm service flow constraints in the linear program were set to the previous year's flow times 0.80. However various test runs indicated a need to adjust this factor for some of the more downstream arcs in the network as follows: 2->1 = 0.70, 8->12 0.60, 9->12 = 0.45, 11->12 = 0.60, and 6->10 = 0.10.

Units: Fraction.

File: INITDAT

Variables: APCT_MINF Factor to define minimum interregional firm service flow
APCT_MINI Factor to define minimum interregional interruptible service flow

Table F33

Data: Existing and planned storage capacity by NGTDM region.

Author: Phyllis Martin, EI-823.

Source: EIA Form-191 "Underground Gas Storage Report" for existing capacity.
Various natural gas industry publications for announced capacity addition projects.
Consultation with an industry expert.

Derivation: Existing capacity was compiled from summations of Form-191 data by region. Capacity additions were compiled from announced storage expansion projects.

Units: Million cubic feet.

File: CAPACTY

Variables:

BGSCT	Base gas capacity-jurisdictional by region
BGSCNT	Base gas capacity-nonjurisdictional by region
BASET	Base gas capacity-total by region
WGCT	Working gas capacity-jurisdictional by region
WGCNT	Working gas capacity-nonjurisdictional by region
WORKT	Working gas capacity-total by region
PNEW_STRX	Annual planned storage capacity additions by region

NGTDM Region	2	3	4	5	6	7	8	9	11	12
BGSCT	419376	522691	313939	348750	131736	407212	155629	3291	15000	0
BGSCNT	47197	828460	64882	37179	22703	333555	74873	21300	5204	243945
BASET	466573	1351151	378821	385929	154439	740767	230502	24591	20204	243945
WGCT	268885	551097	278474	175244	143340	358623	381859	6500	53600	0
WGCNT	82477	754266	44237	26430	31011	446954	88204	12800	20796	228163
WORKT	351362	1305363	322711	204674	174351	805577	470063	19300	74396	228163
PNEW_STRX										
1991	6200	3000	0	0	0	10000	0	0	0	0
1992	0	7200	15900	0	3000	42700	30000	0	0	0
1993	0	45000	0	0	6500	41000	0	0	0	0
1994	11000	0	0	0	4700	0	5300	0	0	0
1995	0	3900	0	0	8700	0	0	0	0	0

Table F34

Data: Maximum seasonal interregional pipeline utilizations for peak and off-peak periods and for firm service in the peak period from transhipment node to transhipment node.

Author: Joe Benneche, EI-823.

Source: Analyst judgment.

Derivation: For most arcs the maximum peak firm, total peak, and total off-peak utilizations were set at 0.80, 0.99, and 0.75, respectively. The arc going into Florida (NGTDM region 10) was treated specially due to the fact that the national off-peak period is really a peak period in Florida. To best facilitate the representation of Mexican imports in the linear program, the associated arcs have been assigned a maximum utilization of 1.00 for peak firm, total peak, and total off-peak.

Notes: Future work will be done on deriving better representations for these utilizations based on available data.

Units: Fraction.

File: CEMDATA

Variables:

ARC_PUTILZ	Maximum utilization during the peak period between transhipment nodes
ARC_PFUTILZ	Maximum utilization for firm service in the peak period between transhipment nodes
ARC_OUTILZ	Maximum utilization during the off-peak period between transhipment nodes

Table F35

Data: User specified parameters for deriving interstate pipeline transportation rates.

Author: Jim Diemer, EI-823.

Source: Analyst judgment.

Notes: RADJ is used only in the first year of the model runs. In subsequent years, it is updated based on model results.

Unit: Fraction.

File: RDESIGN

Variables:

RADJ	An estimate of the ratio of the average interruptible transportation rate to the maximum approved interruptible transportation rate in 1990
IEXPT	The assumed average annual growth rate for the volume of interruptible gas moved on the interstate pipeline network
MAXESC	The assumed maximum annual escalation rate for pipeline tariffs
LFAC	Load factor for deriving the maximum interruptible transportation rate
MAXDISC_I	User-specific fraction defining the interruptible transportation rate as a fraction of the maximum interruptible rate

Table F36

Data: Short-term nonelectric demand elasticities by sector.

Author: Joe Benneche, EI-823.

Source: Analyst judgment.

Derivation: Only the industrial sector elasticities have an appreciable impact on limiting the number of iterations of the NEMS system. These elasticities were set to values that seemed to help the NEMS convergence effort.

Notes: These elasticities do not need to be accurate. Their only purpose is to speed convergence of the NEMS system. Theoretically, the closer they are to the implied elasticities in the represented NEMS demand model, the sooner the NEMS will converge.

Unit: Not applicable.

File: INITDAT

Variables:

NONU_ELAS_F Demand elasticity for nonelectric, core service customers (currently set to 0 for all sectors)

NONU_ELAS_I Demand elasticity for nonelectric, noncore customers (currently set to -0.1 for all sectors, except for the industrial sector which is set to -0.5)

Table F37

Data: Nonassociated natural gas supply curve parameters.

Author: Joe Benneche, EIA-823.

Source: Analyst judgment.

Notes: A more thorough description of the variables represented in this table is provided in Chapter 3. These are likely candidates for variables to vary for sensitivity testing of the NGTDM.

Unit: Not applicable.

File: INITDAT

Variables:

TYP_SUPCRV	Selected supply curve option
PARM_SUPCRV2	Parameters for defining supply curves under option 2 ($PARM\_SUPCRV2_1$ = 0.50, $PARM\_SUPCRV2_2$ = 2.00)
PARM_SUPCRV3	Parameters for defining supply curves under option 3 ($PARM\_SUPCRV3_1$ = 0.03, $PARM\_SUPCRV3_2$ = 4.00)

Table F38

Data: Fraction of annual firm and interruptible service flow along bidirectional arcs during the peak period.

Author: Joe Benneche, EI-823.

Source: Analyst judgment.

Derivation: Historically the flow along the bidirectional arcs in the NGTDM network represent approximately 3 percent of the interregional flows. Currently there are no data to support the derivation of these shares and they have a negligible impact on the model results. Therefore, their values were selected somewhat arbitrarily.

Units: Fraction.

File: INITDAT

Variables:

BIARC_PFSHR	Fraction of annual firm service bidirectional flow during the peak period (currently set at 0.50)
BIARC_PISHR	Fraction of annual interruptible service bidirectional flow during the peak period (currently set at 0.25)

Table F39

Data: Percent of interregional pipeline capacity represented by an arc which is in the region where the arc begins (i.e., the "source" region), based on approximations of the relative miles of pipe represented in each of the associated regions.

Author: Jim Diemer, EI-823.

Source: Analyst judgment and PennWell Map of *Natural Gas Pipelines of the United States and Canada*, 1992.

Derivation: The mileage splits were approximated by measuring distances between major regional market centers and the location of the region boundary relative to those market centers.

Units: Fraction.

File: INITDAT

Variables: NG_ARCSIZE Percent of an arc's pipeline capacity in the "source" region.

Arc	NG_ARCSIZE	Arc	NG_ARCSIZE	Arc	NG_ARCSIZE	Arc	NG_ARCSIZE
2 > 1	0.70	8 > 4	0.33	4 > 8	0.75	11 > 12	1.00
13 > 1	0.00	16 > 4	0.00	9 > 8	0.25	21 > 12	0.00
3 > 2	0.33	2 > 5	1.00	11 > 8	0.50	1 > 13	1.00
5 > 2	0.75	3 > 5	0.25	17 > 8	0.00	2 > 14	1.00
14 > 2	0.00	6 > 5	0.50	8 > 9	0.20	3 > 15	1.00
2 > 3	0.50	5 > 6	0.20	18 > 9	0.00	4 > 16	1.00
4 > 3	0.75	7 > 6	0.77	6 > 10	0.25	8 > 17	1.00
5 > 3	0.25	4 > 7	0.50	7 > 11	0.10	9 > 18	1.00
6 > 3	0.50	6 > 7	0.23	8 > 11	0.50	7 > 19	1.00
15 > 3	0.00	8 > 7	0.90	20 > 11	0.00	11 > 20	1.00
3 > 4	0.90	11 > 7	0.80	8 > 12	0.90	12 > 21	1.00
7 > 4	0.50	19 > 7	0.00	9 > 12	1.00		

Table F40

Data: Weather factors used by the Capacity Expansion Module

Author: Jim Diemer, EI-823.

Source: Analyst judgment.

Derivation: The "weather factors used by the Capacity Expansion Module" represent the reserve margins used by local distribution companies in planning their pipeline capacity reservation levels for firm service. These data are used by the Capacity Expansion Module to set aside a portion of the pipeline capacity that is reserved for abnormal weather contingency plans and therefore is not available for use by firm service customers for the normal weather conditions assumed in the forecast. Currently all of the arcs in the network originating from nodes 5 through 11 are assumed to reserve 5 percent of their firm service capacity to carry gas in the event of abnormal weather. All other arcs are assumed to reserve 15 percent.

Notes: In reality these factors vary slightly across the country depending on the range of temperatures in the areas being served. Future versions of the NGTDM may include factors which reflect these differences.

Units: Fraction.

File: AFMDATA

Variables: WTHRFAC Weather factors used by the Capacity Expansion Module

Table F41

Data: Weather factors used by the Annual Flow Module

Author: Joe Benneche, EI-823.

Source: Analyst judgment.

Derivation: It is assumed that holders of firm pipeline capacity will release up to 1 - WTHR_XCAP of their reserved capacity, thereby retaining a fraction (WTHR_XCAP) of their reserved pipeline capacity as a safety margin in case the weather should turn colder, resulting in a surge in firm service demand. Currently all active arcs are assigned a 1 percent safety margin.

Units: Fraction.

File: AFMDATA

Variables: WTHR_XCAP Weather factors used by the Annual Flow Module

Table F42

Data: Planned pipeline capacity additions along arcs by year.

Author: Jim Diemer, EI-823.

Source: Industry expert and FERC NGA Section 7(c) Filings "Application for Certificate of Public Convenience and Necessity" and various natural gas industry new sources.

Derivation: Compilation of announced proposed expansion projects.

Units: Million cubic feet per day.

File: CAPACTY

Variables: PNEW_CAP Annual planned pipeline capacity additions along arcs

Table F43

Data: Factor for establishing a seasonal differential for the domestic wellhead price.

Author: Joe Benneche, EI-823.

Source: *Natural Gas Monthly*, DOE/EIA-0130, Table 4.

Derivation: The national quantity-weighted average peak and off-peak period wellhead prices were derived for 1990 and 1991 based on monthly data. The basic equation used for assigning values to the variables (PKPRCFAC and OPPRCFAC) was:

factor = (average period price / average annual price) - 1

This factor was calculated for the peak and off-peak periods for 1990 and 1991. The values provided below represent the average over these two years.

Notes: Regional monthly data were not readily available when these numbers were derived. This factor will most likely vary significantly by region. In addition, the trends on seasonal wellhead prices have been substantially different in the most recent years. Therefore, some further research into assigning seasonal price differentials in the model is warranted.

Unit: Fraction.

File: (defined in local DATA statement in SUBROUTINE CEMLPSNY)

Variables:

PKPRCFAC Factor for differentiating the peak period wellhead price from the average annual wellhead price (PKPRCFAC set equal to 0.169)

OPPRCFAC Factor for differentiating the off-peak period wellhead price from the average annual wellhead price (OPPRCFAC set equal to -0.094)

Table F44

Data: Multiplicative wellhead price benchmark factor applied to supply curves.

Author: Joe Benneche, EI-823.

Sources: *Short-Term Energy Outlook* (3rd Quarter 1994), DOE/EIA-0202(94/3!).

Derivation: Multiplicative factors were determined through a trail-and-error process by running the NEMS a few times with candidate multipliers to arrive at one for 1994 and one for 1995 that would result in national wellhead prices that match those published in the *Short-Term Energy Outlook*, (3rd Quarter). The factor for 1995 was used throughout the forecast period. Multiplicative factors were not determined for the historical period, although this will be done in the future.

Notes: Although the model allows for regional specific multiplicative benchmark factors, all regions were assigned the same value.

Units: None.

File: INITDAT

Variables:

PSHIFTON — A multiplicative factor used to shift the onshore supply curve along the price axis in order to benchmark national average wellhead prices to the *Short-Term Energy Outlook*.

PSHIFTOFF — A multiplicative factor used to shift the offshore supply curve along the price axis in order to benchmark national average wellhead prices to the *Short-Term Energy Outlook*.

Years	1990-1993	1994	1995	1996-2010
PSHIFTON (all regions)	1.00	0.95	0.98	0.98
PSHIFTOF (all regions)	1.00	0.95	0.98	0.98

Table F45

Data: Maximum limit set for arc-level firm and interruptible tariffs

Author: Jim Diemer

Sources: Analyst judgement.

Derivation: Maximum limit on firm tariff is set to \$.50/mcf (in 1987\$); maximum limit on interruptible tariff is set to 1/3 of maximum limit for firm tariff, \$.18/mcf (in 1987\$).

Notes: None.

Units: 1987 dollars per thousand cubic feet.

File: RDESIGN

Variables: LIMITFIRM
LIMITINT

Table F46

Data: Rates of return set for generic pipeline companies

Author: Kevin Forbes

Sources: Analyst judgement.

Derivation: GPFER and GCMER are the weighted averages of 1990 weights; GLTDR is only an approximation. Values are derived from FERC FORM2 data: GPFER = 0.0211, GCMER = 0.1243, and GLTDR = 0.1000.

Notes: The coupon rate for preferred stock is unrealistically low. This is probably attributed to some companies listing the par value of the preferred stock. The coupon rate for preferred stock needs to be revised.

Units: Fraction.

File: RDESIGN

Variables:

GPFER	Coupon rate for preferred stock for a generic company.
GCMER	Common equity rate of return for a generic company.
GLTDR	Long term debt rate for a generic company.

Table F47

Data: Maximum rate applicable for Federal and State corporate income taxes

Author: Jim Diemer, EI-823

Sources: Federal tax code and FERC FORM2 data

Derivation: Maximum rate applicable for Federal corporate income taxes was derived from the tax code and is set to 34%. The maximum rate applicable for State corporate income taxes varies from State to State. The State rate is set to 5% to reflect the average rate derived from data reported on FERC Form 2.

Notes: None.

Units: Fraction.

File: RDESIGN

Variables:

FRATE	Federal income tax rate
SRATE	State income tax rate

Table F48

Data:	Rate design matrix
Author:	Jim Diemer
Sources:	Federal Energy Regulatory Commission Restructuring Filings and Section 4 Rate Case Filings
Derivation:	Modified Fixed Variable rate design method is used for all pipeline from 1990 to 1993 in PTM. Straight Fixed Variable rate design method is used for all pipeline from 1994 to 2010 in PTM.
Notes:	None.
Units:	None.
File:	RDESIGN
Variables:	MATRIX Rate design specification for each pipeline for each year.

Table F49

Data: Ratio of associated-dissolved gas production to oil production.

Author: Joe Benneche, EI-823.

Sources: *Natural Gas Annual* (1987-1992), DOE/EIA-0131
U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves (1987-1992), DOE/EIA-0216

Derivation: For each OGSM region, the associated-dissolved gas production was divided by the oil production and an average was taken over the years 1987 through 1992.

Notes: Table 5 contains background information on how associated-dissolved gas production by OGSM region was generated.

Units: Fraction.

File: Fortran DATA Statement in SUBROUTINE NGTDM_PRE

Variables: ADG_TO_OIL Average associated-dissolved gas production to oil production ratio.

OGSM Region	Onshore						Offshore		
	1	2	3	4	5	6	1	2	3
ADG_TO_OIL	2.1781	1.3718	1.8364	1.2214	1.2516	0.5959	0.0000	1.8360	0.5912

Appendix G

Derived Data

Table G1

Data: Parameter estimates for the Alaskan natural gas consumption equations for the residential, commercial, and industrial sectors. Parameter estimates for the Alaskan average natural gas wellhead and industrial price equations.

Author: Chetha Phang, EI-823, September 1993.

Source: *Natural Gas Annual* 1986, 1988, 1991, DOE/EIA-0131.
Annual Energy Review 1991 (Table 69, Appendix C).
Data created using PIPEJCL.ALASKA.DEMAND1.D0512931
and PIPEJCL.ALASKA.DEMAND2.D0507931.

Derivation: The method of Ordinary Least Squares (OLS) was used to estimate the parameters of the Alaskan natural gas consumption equation for each sector (except for electric generation), the industrial sector natural gas price equation, and the average wellhead price equation. These equations are defined as follows:

Residential Natural Gas Consumption

$$\ln YR_t = AK\_C(1) + AK\_C(2)*\ln OP_{t-1} + AK\_C(3)*\ln RN_t$$

Durbin-Watson = 2.079, R-Squared = 0.9477, N = 11

Variables:	AK_C(1)	AK_C(2)	AK_C(3)
Estimated Value:	5.587	0.03195	0.8958
t-statistic:	(8.54)	(0.60)	(7.23)

Commercial Natural Gas Consumption

$$\ln YC_t = AK\_D(1) + AK\_D(2)*\ln OP_{t-1} + AK\_D(3)*\ln CN_t$$

Durbin-Watson = 1.673, R-Squared = 0.430, N = 12

Variables:	AK_D(1)	AK_D(2)	AK_D(3)
Estimated Value:	7.90	0.255	0.5437
t-statistic	(9.506)	(2.06)	(2.603)

Industrial Natural Gas Consumption

$$YI_t = AK\_E(1) + AK\_E(2) * OP_t + AK\_E(3) * T$$

Durbin-Watson = 1.755, R-Squared = 0.3529, N = 23

Variables:	AK_E(1)	AK_E(2)	AK_E(3)
Estimated Value:	7708.4	339.65	2981.55
t-statistic:	(0.466)	(0.879)	(3.188)

Average Natural Gas Wellhead Price

$$WP_t = AK\_F(1) + AK\_F(2) * WP_{t-1} + AK\_F(3) * PD_t$$

Durbin-Watson = 1.707, R-Squared = 0.7392, N = 22

Variables:	AK_F(1)	AK_F(2)	AK_F(3)
Estimated Value:	0.093	0.4703	0.00141
t-statistic:	(0.89)	(2.56)	(2.89)

Industrial Natural Gas Price

$$IP_t = AK\_G(1) + AK\_G(2) * OP_t$$

Durbin-Watson = 2.149, R-Squared = 0.288, N = 12

Variables:	AK_G(1)	AK_G(2)
Estimated Value:	1.0191	0.00645
t-statistic:	(9.997)	(2.009)

where,

- ln = natural logarithm operator
- N = number of observations
- RN_t = residential consumers (thousands) at current year. (AK_RN), See Table G2
- CN_t = commercial consumers (thousands) at current year. (AK_CN), See Table G2
- OP_t = total landed costs of crude oil imports (1987$/barrel) at current year. (WOPCUR)
- YR_t = natural gas consumption (Bcf)
- YR_t = residential gas consumption (MMcf) at current year. (QALK_NONU_F(1))
- YC_t = commercial gas consumption (MMcf) at current year. (QALK_NONU_F(2))
- YI_t = industrial gas consumption (MMcf) at current year. (QALK_NONU_F(3))
- OP_{t-1} = total landed costs of crude oil imports lagged one year. (WOPLAG)
- T = time trend variable having value 1, 2, 3,..., 23 starting from 1969 to 1991. In 2015, the T variable will take on the value of 47. (CNTYR+21)
- PD_t = dry gas production (Bcf) at current year. (AK_PROD)
- WP_t = average wellhead price (1987$/Mcf) at current year. (WPRCUR)
- WP_{t-1} = average wellhead price (1987$/Mcf) lagged one year. (WPRLAG)
- IP_t = industrial gas price (1987$/Mcf). (PALK_NONU_F(3))

Notes: 1. Variables displayed in parentheses are used in the source code.)
2. Starting values for lagged oil and gas prices are presented in Table E18.

File: INITDAT

VARIABLES:

AK_C	Parameters for Alaskan residential natural gas consumption.
AK_D	Parameters for Alaskan commercial natural gas consumption.
AK_E	Parameters for Alaskan industrial natural gas consumption.
AK_F	Parameters for average Alaskan natural gas wellhead price.
AK_G	Parameters for Alaskan industrial natural gas price.

Table G2

Data: Exogenous forecast of the number of residential and commercial customers in Alaska

Author: Joe Benneche, EI-823

Source: *Natural Gas Annual* (1985-1992), DOE/EIA-0131.

Derivation: Assumed growth rates for the number of residential and commercial customers were applied starting in 1993 to generate a forecast. The growth rates for the number of residential (1.02081) and commercial (1.02573) customers were set to the average annual growth from 1985 through 1992. (Note: The year 1985 was selected based on a visual inspection of the data back to 1969.) Data before 1993 represent historical numbers.

Notes: None.

Units: Thousands of customers.

File: INITDAT

Variables: AK_RN Number of residential natural gas customers (thousands) in Alaska
AK_CN Number of commercial natural gas customers (thousands) in Alaska

Year	AK_RN	AK_CN	Year	AK_RN	AK_CN
1990	70.808	11.921	2003	93.152	16.138
1991	72.565	12.071	2004	95.091	16.553
1992	74.268	12.204	2005	97.069	16.979
1993	75.813	12.518	2006	99.089	17.416
1994	77.391	12.840	2007	101.151	17.864
1995	79.002	13.170	2008	103.256	18.324
1996	80.646	13.509	2009	105.405	18.795
1997	82.324	13.857	2010	107.598	19.279
1998	84.037	14.213	2011	109.837	19.775
1999	85.786	14.579	2012	112.123	20.283
2000	87.571	14.954	2013	114.456	20.805
2001	89.393	15.339	2014	116.838	21.341
2002	91.253	15.733	2015	119.269	21.890

Table G3

Data: Parameter estimates of the regression equation for the projection of Illinois synthetic natural gas production from liquid hydrocarbons.

Author: Chetha Phang, EI-823, September 1993.

Source: *Natural Gas Annual* 1985, DOE/EIA-0131, Table 11.
Natural Gas Annual 1986, 1987, DOE/EIA-0131, Table 12.
Natural Gas Annual 1988, 1989, 1990, Table 15.
Annual Energy Review 1991 (Tables 71, 81, Appendix C).
Data created using PIPEJCL.SNGLQDS.PRDPROJ.D0420931.

Derivation: The method of Ordinary Least Squares (OLS) was used to estimate the parameters of the Illinois synthetic gas production from liquid hydrocarbons equation, which is assumed to be a log-linear function of East North Central regional gas price. This production function is expressed as follows:

$$\ln SNG_t = a1 + (a2 * \ln ENCGPR_t)$$

where,

ln =	natural logarithm
SNG_t =	synthetic natural gas production from liquid hydrocarbons in Illinois in year t (Bcf)
$ENCGPR_t$ =	East North Central regional gas price (1987\$/Mcf) in year t
a1, a2 =	parameters to be estimated

The OLS regression results based on the given data (1981-1991) showed an evidence of positive serial correlation in the data with Durbin-Watson d = 1.125. Using the Generalized Difference Equations to correct for the positive serial correlation between the disturbance terms, the second stage regression results were obtained as follows:

$$\ln SNG_t = -0.5161 + 2.81803 * \ln ENCGPR_t$$
t-statistic = (0.98) (6.46)
Durbin-Watson = 1.599, R-Squared = 0.8224, N = 11.

The above production equation can be written as:

$$SNG_t = SNGA1 * ENCGPR_t^{SNGA2} \text{ or,}$$
$$SNG_t = 0.5968 * ENCGPR_t^{2.81803}$$

where, SNG_t and $ENCGPR_t$ are defined in the source code as VAL and VALUE, respectively.

Units: Not applicable (no units).

File: INITDAT

Variables:

SNGA1	Intercept coefficient for the Illinois synthetic gas production function.
SNGA2	Slope coefficient for the Illinois synthetic gas production function.

Table G4

Data: Coefficients for PTM forecasting equations. Total working capital; total administrative and general expense; accumulated deferred income taxes; depreciation, depletion, and amortization expenses; and total operations and maintenance expense.

Author: Science Applications International Corporation

Source: Form FERC-2: Data collected for 1980 - 1991.

Derivation: Estimations are done by using accounting algorithm or forecast software. Forecasts are based on a series of Fortran-based econometric equations which have been estimated using the Total Statistical Package (TSP) software. Equations are estimated for each pipeline company or generic pipeline: total working capital; total operations and maintenance expense; total administrative and general expense; depreciation, depletion, and amortization expenses; and accumulated income taxes. These equations are defined as follows:

(1) Total Working Capital

$$OWC_t = GPIS_t^{\beta 0} * GPIS_{t-1}^{-\rho * \beta 0} * \exp[\beta 1 * (MC\_PGDP_t - \rho * MC\_PGDP_{t-1})]$$
$$* \exp[\beta 2 * (TYEAR - \rho * (TYEAR-1.0))] * OWC_{t-1}^{\rho} * OWC\_CONST$$

where,

(a) existing pipeline

β0, β1, β2	= (1.92244, 1.99710, -0.170208)
ρ	= 0.602771
OWC_CONST	= (1-ρ) * EXP(C+FDj)
FDj	= firm dummy variable which is equal to 1, if j = i, or equal to 0, otherwise. (value of FDj see Table G4.1)
t-statistic	= See Table G4.1
DW	= 1.65411
R-Squared	= 0.985791

(b) generic pipeline

β0, β1, β2	= (1.76412, 1.94711, -0.159168)
ρ	= 0
OWC_CONST	= 294.161
t-statistic	= 3.12307, 26.9230, 1.70727, -3.31806
DW	= 1.93182
R-Squared	= 0.952241

(2) Total Administrative and General Expense

$$TAG_{i,t} = e^{(1-\rho)*\beta_0} * GPIS_{t-1}^{\beta_1} * e^{\beta_2*year} * WAGE_t^{\beta_3} *$$
$$TAG_{t-1}^{\rho} * GPIS_{t-2}^{-\rho*\beta_1} * e^{-\rho*\beta_2*(year-1)} * WAGE_{t-1}^{-\rho*\beta_3}$$

and,

$$WAGE = AVG\_WAGE * \left(\frac{MC\_ECIWSPNS_t / MC\_ECIWSPNS_b}{MC\_PGDP_t / MC\_PGDP_b}\right)$$

where,

FDj	=	firm dummy variable which is equal to 1, if j = i, or equal to 0, otherwise. (value of FDj see Table G4.2)
AVG_WAGE	=	37225.64 (in 1987$)
i	=	pipeline
b	=	1990 (base year)

(a) existing pipeline

β0,β1,β2,β3	=	(FDj, 0.735401, -0.532295E-4, 1.00293)
ρ	=	0.296068

All statistics are applied to Log-linear regression function (LN_TAG):

t-statistic	=	See Table G4.2a
DW	=	1.77879
R-Squared	=	0.9999

(b) generic pipeline

β0,β1,β2,β3	=	(-4.12803, 0.868975, -.05988E-4, 0.351339)
ρ	=	0.68177

All statistics are applied to Log-linear regression function (LN_TAG):

t-statistic	=	See Table G4.2b
DW	=	1.85921
R-Squared	=	0.956792

(3) Accumulated Deferred Income Tax

(a) existing pipeline

$$ADIT_{i,t} = \beta_0 + \beta_1 * ADIT_{t-1} + \beta_2 * NETPLT_t$$

where,

β0,β1,β2	= (FDj + POST86, 0.72988, 0.064099)
FDj	= firm dummy variable which is equal to 1, if j = i, or equal to 0, otherwise. (value of FDj see Table G4.3)
POST86	= 0.129514E+7
i	= pipeline
t-statistic	= See Table G4.3
DW	= 1.85921
R-Squared	= 0.956792

(b) generic pipeline

Accumulated deferred income taxes for generic companies is calculated using an accounting algorithm. Straight Line Depreciation (SDL) is used for rate making purposes, while Modified Accelerated Cost Recovery System (MACRS) with a 15½ year schedule is used for tax purposes. The amount of depreciation using the MACRS and SDL schedules are derived as follows:

$$DEPRMACRS_t = \sum_{s=2}^{s=t} NCAE_s * MACRS\_RATE_{t-s+1}$$

$$DEPRSL_t = \sum_{s=2}^{s=t} NCAE_s/30$$

where,

MACRS_RATE	= (5.00, 9.50, 8.55, 7.70, 6.93, 6.23, 5.90, 5.90, 5.91, 5.90, 5.91, 5.90, 5.91, 5.90, 5.91, 2.95)
FRATE	= 35 %

(4) Total Depreciation, Depletion, and Amortization

(a) existing pipeline

$$DDA_{i,t} = (1-\rho)*\beta_0 + \beta_1*NETPLT_t + \beta_2*DEPSHR_t + \rho*DDA_{t-1} - \rho*(\beta_1*NETPLT_{t-1} + \beta_2*DEPSHR_{t-1})$$

where,

β0,β1,β2	= (FDj, β1,β2)
	= (FDj, 0.037362, -0.315983E7)
FDj	= firm dummy variable which is equal to 1, if j = i, or equal to 0, otherwise. (value of FDj see Table G4.4)
ρ	= 0.151232
i	= pipeline
t-statistic	= See Table G4.3
DW	= 1.77499
R-Squared	= 0.9634

(b) generic pipeline

A regression equation is not used for the generic pipeline; instead, an accounting algorithm is used (presented in Chapter 8).

(5) Total Operations and Maintenance Expense

(a) existing pipeline

$$TOM_{i,t} = e^{(1-\rho)*\beta_0} * MILE_{i,t}^{\beta_1} * WAGE_t^{\beta_2} * PEQUIP_t^{\beta_3} * e^{\beta_4*YEAR} *$$
$$TOM_{t-1}^{\rho} * MILE_{i,t-1}^{-\rho*\beta_1} * WAGE_{t-1}^{-\rho*\beta_2} * PEQUIP_{t-1}^{-\rho*\beta_3} * e^{-\rho*\beta_4*(YEAR-1)}$$

where,

β0,β1,β2,β3,β4	=	(FDj, β1, β2, β3, β4)
	=	(FDj, 0.342875, 0.387606, 0.588657, -0.256796E-4)
FDj	=	firm dummy variable which is equal to 1, if j = i, or equal to 0, otherwise. (value of FDj see Table G4.5)
ρ	=	0.391207
i	=	pipeline
WAGE	=	(see TAG)

All statistics are applied to Log-linear regression function (LN_TOM):

t-statistic	=	See Table G4.5a
DW	=	1.6777
R-Squared	=	0.9998

(b) Generic Pipeline

$$TOM_{i,t} = e^{(1-\rho)*\alpha_0} * GPIS_{t-1}^{\alpha_1} * PEQUIP_t^{\alpha_2} * e^{\alpha_3*DEPSHR_t} *$$
$$TOM_{t-1}^{\rho} * GPIS_{t-2}^{-\rho*\alpha_1} * PEQUIP_{t-1}^{-\rho*\alpha_2} * e^{-\rho*\alpha_3*DEPSHR_{t-1}}$$

where

α0,α1,α2,α3	=	(-11.1327, 0.874303, 2.15763, 0.575590)
ρ	=	0.904554
WAGE	=	(see TAG)
PEQUIP	=	106.495

All statistics are applied to Log-linear regression function (LN_TOM):

t-statistic	=	See Table G4.5b
DW	=	2.11985
R-Squared	=	0.9969

Variables:

OWC	=	other working capital in dollars
GPIS	=	original capital cost of plant in service (gross plant in service) in dollars
MC_PGDP_t	=	implicit GDP price deflator for year t (from the Macroeconomic Activity Model)
TYEAR	=	year in Julian units (i.e., 1995)
OWC_CONST	=	estimated constant term
TAG	=	total administrative and general costs in real dollar
WAGE	=	salary paid in natural gas transmission industry, which is adjusted by real labor index
AVG_WAGE	=	average annual salary paid in natural gas transmission industry
MC_ECIWSPNS	=	price index of labor (from Macroeconomic Activity Model)
ADIT	=	accumulated deferred income taxes in dollars
NETPLT	=	difference between original capital cost of plant in service and accumulated depreciation in previous period (net plant in service) in dollar
FRATE	=	federal tax rate
MACRS_RATE	=	rate of depreciation by MACRS schedule
DDA	=	depreciation, depletion, and amortization costs (dollars)
DEPSHR	=	percentage of depreciation, derived from dividing accumulated depreciation by gross plant in service in previous period
TOM	=	total operating and maintenance expense in real dollars
$MILE_i$	=	mile of pipeline of i^{th} company, which is a proxy for the firm's physical capital
PEQUIP	=	price index of compressor station equipment.
FDj	=	firm dummy variable which is equal to 1 if j=i, 0 otherwise (i=pipeline).
YEAR	=	year in Julian units (i.e., 1995)

Notes: None.

Units:

OWC	=	nominal dollar
GPIS	=	nominal dollar
TAG	=	nominal dollar
WAGE	=	nominal dollar
ADIT	=	nominal dollar
NETPLT	=	nominal dollar
DDA	=	nominal dollar
TOM	=	nominal dollar
AVG_WAGE	=	1987 real dollar
MC_PGDP_t	=	index
MC_ECIWSPNS	=	index
PEQUIP	=	index
FRATE	=	fraction
MACRS_RATE	=	fraction
DEPSHR	=	fraction
$MILE_i$	=	mile
TYEAR	=	Julian units (i.e., 1995)
YEAR	=	Julian units

Reference: Refer to "Documentation of the Pipeline Tariff Model Econometric Equation" by Science Applications International Corporation, April 30, 1993.

File: PTARIFF

Table G4.1. Summary Statistics for the Total Working Capital Equation with Dummy Variables

Coefficient	Estimated Value	Standard Error	t-statistic
C	312.686	86.8191	3.60157
LN_GPIS	1.92244	.069013	27.8560
GDP_INDX	1.99710	1.11522	1.79077
YEAR	-.170208	.044260	-3.84567
FD330	1.06750	.233223	4.57715
FD840	1.02271	.232931	4.39060
FD930	.957291	.231520	4.13481
FD1005	-.665842	.253675	-2.62479
FD1010	-1.14718	.248872	-4.60952
FD1075	-.317635	.234846	-1.35253
FD1450	1.54210	.241970	6.37310
FD1470	.970518E-02	.249324	.038926
FD1705	.350049	.234705	1.49144
FD1913	.257109	.235866	1.09006
FD2520	1.79581	.233402	7.69406
FD3240	.115678	.245968	.470296
FD3320	-.599203	.260134	-2.30344
FD3360	.737649	.235027	3.13856
FD3382	.396329	.230722	1.71778
FD3410	1.57254	.266284	5.90550
FD3450	1.02331	.253706	4.03345
FD3540	2.00584	.234659	8.54791
FD3620	-.955885	.266306	-3.58942
FD3775	-1.67645	.267098	-6.27652
FD3800	-1.79113	.257699	-6.95045
FD3835	.123892	.235964	.525046
FD4098	.764999	.267453	2.86031
FD4135	1.23531	.231506	5.33598
FD4160	.379134	.244188	1.55263
FD4875	-.037315	.230755	-.161708
FD5340	-.094529	.250759	-.376972
FD5715	.214417	.230721	.929338
FD5902	-.876017	.285765	-3.06552
FD6090	-1.58252	.277425	-5.70432
FD6210	.020513	.242916	.084444
FD6410	-1.14827	.246102	-4.66584
FD6420	-1.01856	.280325	-3.63351
FD6425	.357665	.236251	1.51392
FD6450	-.286970	.258668	-1.10941
FD6480	1.22267	.251145	4.86838
FD6630	-.589305	.241943	-2.43572
FD7000	.823061	.248338	3.31427
FD7010	1.89759	.334460	5.6736

Table G4.2a. **Total Administrative and General Expense Equation for Existing Pipeline with Dummy Variables**

Coefficient	Estimated Value	Standard Error	t-statistic
β1	.735401	.014597	50.3806
β2	-.532295E-04	.841012E-05	-6.32922
β2	1.00293	.062162	16.1342
FD50	-8.32601	.663543	-12.5478
FD330	-8.28496	.669439	-12.3760
FD840	-8.10217	.665637	-12.1720
FD930	-8.29780	.666119	-12.4569
FD1005	-8.06064	.670649	-12.0192
FD1010	-8.99644	.669862	-13.4303
FD1075	-8.30440	.667187	-12.4469
FD1450	-8.45605	.660527	-12.8020
FD1470	-7.81714	.671893	-11.6345
FD1705	-8.17991	.667485	-12.2548
FD1913	-8.97032	.668156	-13.4255
FD2050	-9.88618	.665980	-14.8446
FD2520	-8.11535	.666245	-12.1807
FD3240	-8.03321	.664505	-12.0890
FD3320	-8.10176	.671329	-12.0682
FD3360	-8.45617	.665292	-12.7105
FD3382	-8.72908	.671533	-12.9987
FD3410	-8.42774	.661734	-12.7358
FD3450	-8.47500	.662160	-12.7990
FD3540	-8.15116	.661535	-12.3216
FD3620	-7.60459	.689486	-11.0294
FD3775	-9.67062	.670523	-14.4225
FD3800	-7.99579	.675908	-11.8297
FD3835	-8.28506	.669162	-12.3812
FD4098	-10.7344	.659691	-16.2718
FD4135	-8.55915	.669733	-12.7799
FD4160	-8.20972	.671983	-12.2171
FD4875	-8.93700	.679667	-13.1491
FD5340	-8.13496	.672273	-12.1007
FD5715	-9.73727	.665231	-14.6374
FD5902	-8.08158	.674050	-11.9896
FD6090	-8.14258	.674760	-12.0674
FD6210	-8.09727	.668095	-12.1199
FD6410	-10.8687	.672342	-16.1654
FD6420	-8.06411	.673277	-11.9774
FD6425	-8.27496	.672619	-12.3026
FD6450	-8.74262	.674288	-12.9657
FD6480	-10.0812	.676944	-14.8922
FD6630	-7.78317	.669021	-11.6337
FD7000	-10.5163	.663408	-15.8519

Table G4.2b. **Total Administrative and General Expense Equation for Generic Pipeline**

Coefficient	Estimated Value	Standard Error	t-statistic
β_0	-4.12803	2.34214	-1.76250
β_1	0.868975	0.012919	67.2608
β_2	-0.5988E-4	0.13176E-4	-4.54454
β_3	0.351339	0.223428	1.57249

Table G4.3. Summary Statistics for Accumulated Deferred Income Tax Equation with Dummy Variables

Coefficient	Estimated Value	Standard Error	t-statistic
β1	.729880	.034326	21.2633
β2	.064099	.010285	6.23223
POST86	.129514E+07	597315.	2.16827
FD50	-.585536E+07	.421084E+07	-1.39054
FD330	.103331E+08	.432398E+07	2.38973
FD840	-.150482E+07	.398517E+07	-.377605
FD930	-.127081E+08	.577500E+07	-2.20054
FD1005	.792681E+08	.478025E+08	1.65824
FD1010	.500322E+07	.399926E+07	1.25104
FD1075	.866611E+07	.423324E+07	2.04716
FD1450	-.170162E+07	.138914E+07	-1.22495
FD1470	.288398E+08	.147628E+08	1.95354
FD1705	-261066.	.430122E+07	-.060696
FD1913	.107255E+07	.392570E+07	.273212
FD2050	-331096.	.252541E+07	-.131106
FD2520	100804.	.149690E+07	.067342
FD3240	-.386891E+07	.265839E+07	-1.45536
FD3320	.246935E+07	.143454E+08	.172135
FD3360	-655528.	.289783E+07	-.226214
FD3382	.134276E+07	.257215E+07	.522039
FD3410	-415096.	.279459E+07	-.148536
FD3450	746529.	.175377E+07	.425670
FD3540	-.253967E+07	.225567E+07	-1.12590
FD3620	-.155808E+07	.187475E+08	-.083108
FD3775	.229058E+08	.130580E+08	1.75416
FD3800	.376959E+08	.384250E+08	.981025
FD3835	.891349E+07	.766289E+07	1.16320
FD4098	-666686.	.131096E+07	-.508549
FD4135	-.790190E+07	.292055E+07	-2.70562
FD4160	.188337E+08	.957605E+07	1.96675
FD4875	.157189E+07	.105719E+08	.148685
FD5340	.115389E+07	.746511E+07	.154571
FD5715	766982.	.163080E+07	.470309
FD5902	.383549E+08	.382716E+08	1.00218
FD6090	.526591E+08	.443985E+08	1.18606
FD6210	-.139606E+07	.738119E+07	-.189137
FD6410	.222869E+07	.592477E+07	.376165
FD6420	.530083E+08	.214303E+08	2.47352
FD6425	-.166049E+07	.683077E+07	-.243089
FD6450	.257150E+08	.150151E+08	1.71262
FD6480	-555813.	569203.	-.976475
FD6630	-.244766E+08	.231915E+08	-1.05541
FD7000	-.156129E+07	.439756E+07	-.355035

Table G4.4. Summary Statistics for Depreciation, Depletion, and Amortization Equation with Dummy Variables

Coefficient	Estimated Value	Standard Error	t-statistic
β1	.037362	.215921E-02	17.3036
β2	-.315983E+07	.118222E+07	-2.67278
FD50	.524613E+07	835848.	6.27641
FD330	.172594E+07	.105781E+07	1.63161
FD840	.699559E+07	.100105E+07	6.98822
FD930	.563834E+07	.134644E+07	4.18759
FD1005	.971449E+07	.245244E+07	3.96115
FD1010	.363580E+08	.307654E+07	11.8178
FD1075	.920971E+07	.116537E+07	7.90282
FD1450	.242638E+07	785470.	3.08908
FD1470	.130872E+08	.161691E+07	8.09396
FD1705	.142000E+08	.125675E+07	11.2990
FD1913	.923499E+07	.130261E+07	7.08962
FD2050	.170989E+08	.253646E+07	6.74126
FD2520	.384055E+07	759960.	5.05362
FD3240	.584337E+07	.141660E+07	4.12492
FD3320	.307323E+08	.606948E+07	5.06341
FD3360	.380696E+07	.104426E+07	3.64560
FD3382	.637875E+07	881543.	7.23589
FD3410	.233743E+07	619300.	3.77430
FD3450	.231227E+07	634010.	3.64705
FD3540	.314533E+07	595989.	5.27751
FD3620	.369447E+08	.878650E+07	4.20471
FD3775	-.595437E+07	.114663E+08	-.519293
FD3800	.279146E+08	.498743E+07	5.59699
FD3835	.912853E+07	.202461E+07	4.50877
FD4098	.118440E+07	463369.	2.55605
FD4135	.155105E+08	.413476E+07	3.75123
FD4160	.122954E+08	.177809E+07	6.91496
FD4875	.789833E+07	.326112E+07	2.42197
FD5340	.282235E+08	.192597E+07	14.6542
FD5715	.897115E+07	.105040E+07	8.54073
FD5902	.817257E+08	.100491E+08	8.13266
FD6090	.455475E+08	.437448E+07	10.4121
FD6210	.176696E+08	.157079E+07	11.2489
FD6410	.266977E+07	.242852E+07	1.09934
FD6420	.620667E+08	.391804E+07	15.8413
FD6425	.111083E+08	.291027E+07	3.81694
FD6450	.202480E+08	.152389E+07	13.2870
FD6480	.496049E+07	839117.	5.91156
FD6630	.175537E+08	.288080E+07	6.09335
FD7000	.217175E+07	.209350E+07	1.03737

Table G4.5a. Summary Statistics for Total Operations and Maintenance Expense Equation with Dummy Variables

Coefficient	Estimated Value	Standard Error	t-statistic
β1	.342875	.078797	4.35138
β2	.387606	.168281	2.30333
β3	.588657	.200972	2.92905
β4	-.256796E-04	.935084E-05	-2.74623
FD50	6.79653	2.19762	3.09268
FD330	6.97665	2.23171	3.12614
FD840	7.11083	2.22728	3.19261
FD930	7.22983	2.21703	3.26104
FD1005	8.10685	2.24016	3.61886
FD1010	7.65299	2.22076	3.44611
FD1075	7.57392	2.21943	3.41255
FD1450	6.48876	2.20089	2.94825
FD1470	8.21841	2.24074	3.66772
FD1705	7.29399	2.22241	3.28202
FD1913	7.85283	2.21265	3.54906
FD2050	8.35659	2.17778	3.83720
FD2520	6.03473	2.23717	2.69749
FD3240	6.32501	2.21033	2.86157
FD3320	8.10859	2.23577	3.62676
FD3360	6.85725	2.19262	3.12743
FD3382	6.56682	2.20947	2.97213
FD3410	6.20674	2.21499	2.80215
FD3450	6.74434	2.20391	3.06018
FD3540	6.84241	2.20220	3.10708
FD3620	8.11329	2.23964	3.62259
FD3775	6.01943	2.19387	2.74375
FD3800	8.04531	2.25343	3.57026
FD3835	7.09010	2.22286	3.18963
FD4098	4.71036	2.16982	2.17086
FD4135	6.91779	2.19686	3.14894
FD4160	8.19826	2.23198	3.67308
FD4875	6.68537	2.19490	3.04586
FD5340	7.73552	2.23298	3.46421
FD5715	7.02103	2.18317	3.21599
FD5902	8.34731	2.24784	3.71348
FD6090	8.84093	2.24302	3.94153
FD6210	7.84311	2.22737	3.52124
FD6410	4.70828	2.18881	2.15107
FD6420	8.33229	2.23914	3.72120
FD6425	7.70595	2.22735	3.45969
FD6450	7.65582	2.22080	3.44733
FD6480	6.00379	2.16242	2.77642
FD6630	7.60412	2.23424	3.40345
FD7000	4.93881	2.18333	2.26206

Table G4.5b. **Total Operations and Maintenance Expense Equation for generic pipeline**

Coefficient	Estimated Value	Standard Error	t-statistic
α_0	-11.1327	1.95251	-5.70176
α_1	0.874303	0.043239	20.2201
α_2	2.15763	0.332584	6.50702
α_3	0.575590	0.209663	2.74531

Appendix H

Variable Cross Reference Table

Variable Cross Reference Table

The linear program (LP) formulation of the Annual Flow Module (AFM) is presented in matrix form in Figure H-1. The rows represent the objective function, variable bounds, and problem constraints, and the columns are the variables to be solved. Each row (constraint) and column (variable) have been given a unique name which also are defined in Figure H-1. The row and column names are used in the code to identify where changes are to be made in the working matrix during each model iteration or model year. Since the variables defined in the AFM LP equations are being referenced differently within 1) the mathematical equations presented in Chapter 5, 2) the LP matrix (referenced above), and 3) the code, a cross reference table (Table H-1) has been generated for these variables.

Similarly, Figure H-2 presents the LP matrix representation of the Capacity Expansion Module (CEM) formulation, as well as definitions of the abbreviations and names used. Again, the columns represent the variables, and the rows represent the objective function, variable bounds, and problem constraints corresponding to the model equations defined in Chapter 7. Table H-2 presents a cross reference of the names used within 1) the mathematical equations presented in Chapter 7, 2) the LP matrix (referenced above), and 3) the code to reference the variables in the model equations.

Note that in both figures, two coefficients are defined for a single variable in the mass balance constraints. This is a shortcut means of representing the coefficient associated with the same flow variable that is needed within two mass balance constraints. For example, when the arc represents flow into a node, the coefficient is the arc efficiency variable; however, when the arc represents flow going out of a node, the flow should not be reduced by efficiency, thus the coefficient is one.

The Distributor Tariff Module (DTM) and Pipeline Tariff Module (PTM) are represented by economic and regression equations (see Chapters 6 and 8 for details). Table H-3 presents cross references of model equation variables defined in this document and in the code for the PTM. The DTM equation variables in the document match those in the code.

Figure H-1. LP Matrix Definition for the Annual Flow Module (AFM)

		XFN**N**	XIN**N**	XFS++N**	XIS++N**	XFN**?@@	XIN**?@@	XFQ**?@@	XIQ**?@@	SS++N**#	F**B?@@	F**P?@@#	F**N?@@#	I**B?@@	I**P?@@#	I**N?@@#		RHS
AFMOBJ		TARF	TARI	TARF	TARI	TARF	TARI	PZZF	PZZI	PSUP	-PDEMF	-PDEMF	+PDEMF	-PDEMI	-PDEMI	+PDEMI		
AFMBND	U									USUP	UDEMF	UDEMF	UDEMF	UDEMI	UDEMI	UDEMI		
	L	MINFF	MINFI	MINSF	MINSI					0	UDEMF	0	0	UDEMI	0	0		
CPN**N**		1	1														<=	QCAPO(i,j)*UTILZT(i,j)*(1-PCTW)
CPF**N**		1															<=	QCAPO(i,j)*UTILZF(i,j)*(1-PCTW)
MFN**		EFF,-1		EFF		-1											=	-1*NETSTR_F
MIN**			EFF,-1		EFF		-1										=	-1*NETSTR_I
MF**?@@						EFF		1			-1	-1	1				=	0
MI**?@@							EFF		1					-1	-1	1	=	0
MS++N**				-1	-1					1							=	0

Legend: ** = nodes (01-21), ++ = OGSM region (01-06), ? = sector code (R,C,I,T,U),
@@ = CENSUS (01-09) or NERC region (01-13), # = step number on curve (1-9)

Figure H-1. LP Matrix Definition for the Annual Flow Module (AFM) (Continued)

Columns

X F N * * N * *	=	Firm flow from node to node
X I N * * N * *	=	Interruptible flow from node to node
X F S + + N * *	=	Firm flow from supply to node
X I S + + N * *	=	Interruptible flow from supply to node
X F N * * ? @ @	=	Firm flow to end-use sector
X I N * * ? @ @	=	Interruptible flow to end-use sector
X F Q * * ? @ @	=	Firm flow from backstop supply to end-use sector
X I Q * * ? @ @	=	Interruptible flow from backstop to end-use sector
S S + + N * * #	=	Steps on regional supply curve
F * * B ? @ @	=	Base step on core demand curve
F * * P ? @ @ #	=	Positive steps on core demand curve
F * * N ? @ @ #	=	Negative steps on core demand curve
I * * B ? @ @	=	Base step on noncore demand curve
I * * P ? @ @ #	=	Positive steps on noncore demand curve
I * * N ? @ @ #	=	Negative steps on noncore demand curve
R H S	=	Right hand side of constraint equations

Rows

A F M O B J	=	AFM Objective Function
A F M B N D	=	AFM Variable Bounds
C P N * * N * *	=	Pipeline capacity limit--Total flow
C P F * * N * *	=	Pipeline capacity limit--Firm flow
M F N * *	=	Regional mass balance--Firm network
M I N * *	=	Regional mass balance--Interruptible network
M F * * ? @ @	=	End-use mass balance--Firm network
M I * * ? @ @	=	End-use mass balance--Interruptible network
M S + + N * *	=	Supply subregion mass balance

Legend: ** = nodes (01-21), ++ = OGSM region (01-06), ? = sector code (R,C,I,T,U),
@@ = CENSUS (01-09) or NERC region (01-13), # = step number on curve (1-9)

Figure H-1. LP Matrix Definition for the Annual Flow Module (AFM) (Continued)

Coefficients, Right Hand Sides (RHS), and Bounds

EFF	=	Regional pipeline efficiency
TARF	=	Supply, distributor, pipeline tariffs--Firm network
TARI	=	Supply, distributor, pipeline tariffs--Intrp. network
PZZF	=	Alt. fuel price for backstop supply--Firm network
PZZI	=	Alt. fuel price for backstop supply--Intrp. network
PSUP	=	Prices on supply curve steps (87$/mcf)
USUP	=	Quantities on supply curve steps (BCF)
PDEMF	=	Prices on demand curve steps (87$/mcf)--core (Firm service)
PDEMI	=	Prices on demand curve steps (87$/mcf)--noncore (Interruptible service)
UDEMF	=	Quantities on demand curve steps (BCF)--core (Firm service)
UDEMI	=	Quantities on demand curve steps (BCF)--noncore (Interruptible service)
MINFF	=	Minimum flow along interregional arc--firm
MINFI	=	Minimum flow along interregional arc--interruptible
MINSF	=	Minimum flow from supply to node--firm network
MINSI	=	Minimum flow from supply to node--interruptible network
QCAP0	=	Physical pipeline capacity (BCF) for year t
UTILZT	=	Pipeline utilization--Total flow
UTILZF	=	Pipeline utilization--Firm flow
PCTW	=	Weather factor percent
NETSTR_F	=	Net firm storage withdrawals
NETSTR_I	=	Net interruptible storage withdrawals

Table H-1. Cross Reference of AFM Variables Between Documentation, LP, and Code

Documentation	AFM LP Variable	Code Variable
Objective Function Variables:		
$x^F_{s,i}$	XFS++N**	AFLOW_F(s,i)
$x^I_{s,i}$	XIS++N**	AFLOW_I(s,i)
$x^F_{i,j}$	XFN**N**	AFLOW_F(i,j)
$x^I_{i,j}$	XIN**N**	AFLOW_I(i,j)
$x^F_{i,d}$	XFN**?@@	AFLOW_F(i,d)
$x^I_{i,d}$	XIN**?@@	AFLOW_I(i,d)
$qzz^F_{i,d}$	XFQ**?@@	F_BKSTOP
$qzz^I_{i,d}$	XIQ**?@@	I_BKSTOP
$ysup_{s,i,\pm k}$	SS++N**#	SUP_QTY(s,i,sr)
$QDEM0^F_{i,d}$ & $ydem^F_{i,d,\pm k}$	F**BU@@ F**PU@@# F**NU@@#	UTIL_QTY_F(i,sr)
	F**B?@@ F**P?@@# F**N?@@#	NONU_QTY_F(d,i,sr) (where d = ? = r,c,i,t)
$QDEM0^I_{i,d}$ & $ydem^I_{i,d,\pm k}$	I**BU@@ I**PU@@# I**NU@@#	UTIL_QTY_I(i,sr)
	I**B?@@ I**P?@@# I**N?@@#	NONU_QTY_I(d,i,sr) (where d = ? = r,c,i,t)
Variable Bounds:		
	UDEMF(BASE FIRM)	BASE_QTY, EXPQTY
	UDEMI(BASE INT)	BASE_QTY, EXPQTY
$UDEM^F_{i,d,+k}$	UDEMF(POS FIRM)	DQDEL(ns) from DQUANT(ns), DELQ
$UDEM^F_{i,d,-k}$	UDEMF(NEG FIRM)	DQDEL(ns) from DQUANT(ns), DELQ
$UDEM^I_{i,d,+k}$	UDEMI(POS INT)	DQDEL(ns) from DQUANT(ns), DELQ
$UDEM^I_{i,d,-k}$	UDEMI(NEG INT)	DQDEL(ns) from DQUANT(ns), DELQ
$USUP_{s,i,k}$	USUP	SQDEL(ns) from SQUANT(ns)
$MINF^F_{i,j}$	MINFF	ACAP_MIN
$MINF^I_{i,j}$	MINFI	ACAP_MIN
!!!!	MINSF	MINSUPF
!!!!	MINSI	MINSUPI

Table H-1. Cross Reference of AFM Variables Between Documentation, LP, and Code (Continued)

Documentation	AFM LP Variable	Code Variable
Objective Function Coefficients		
	PDEMF(BASE FIRM)	BASE_PR, EXPPR
	PDEMI(BASE INT)	BASE_PR, EXPPR
$PDEM^F_{i,d,+k}$	PDEMF(POS FIRM)	DPRICE(ns)
$PDEM^F_{i,d,-k}$	PDEMF(NEG FIRM)	DPRICE(ns)
$PDEM^I_{i,d,k}$	PDEMI(POS INT)	DPRICE(ns)
$PDEM^I_{i,d,-k}$	PDEMI(NEG INT)	DPRICE(ns)
$PSUP_{s,i,\pm k}$	PSUP	SPRICE(ns)
$PZZ^F_{i,d}$	PZZF	NG_BKSTOP_PR
$PZZ^I_{i,d}$	PZZI	NG_BKSTOP_PR
$TAR^F_{s,i}$	TARF(S->N)	STAR_F(s,i)
$TAR^I_{s,i}$	TARI(S->N)	STAR_I(s,i)
$TAR^F_{i,j}$	TARF(N->N)	PTAR_F(i,j)
$TAR^I_{i,j}$	TARI(N->N)	PTAR_I(i,j)
$TAR^F_{i,d}$	TARF(N->D)	UTIL_DTAR_F(i,d) NONU_DTAR_F(i,d) CANTAR_F(i,d) MEXTAR_F(i,d)
$TAR^I_{i,d}$	TARI(N->D)	UTIL_DTAR_I(i,d) NONU_DTAR_I(i,d) CANTAR_I(i,d) MEXTAR_I(i,d)
Capacity Constraints:		
equation: 24 $PCAPMAX_{i,j}$ $AUTILZ^T_{i,j}$ $WTHRXCAP_{i,j}$	rowname: CPN**N** QCAP0(i,j) UTILZT(i,j) PCTW	rowname: CPN**N** PCAP_MAX(i,j,p) AUTILZ_T(i,j,p) WTHR_XCAP(i,j)
equation: 25 $PCAPMAX_{i,j}$ $AUTILZ^F_{i,j}$ $WTHRXCAP_{i,j}$	rowname: CPF**N** QCAP0(i,j) UTILZF(i,j) PCTW	rowname: CPF**N** PCAP_MAX(i,j,p) AUTILZ_F(i,j,p) WTHR_XCAP(i,j)

Table H-1. Cross Reference of AFM Variables Between Documentation, LP, and Code (Continued)

Documentation	AFM LP Variable	Code Variable
Mass Balance Constraints at Transshipment Nodes:		
equation: 26 $QSTR^{F}_{ST}$	**rowname: MFN**** NETSTR_F	**rowname: MFN**** NETSTR_F(i,p)
equation: 27 $QSTR^{I}_{ST}$	**rowname: MIN**** NETSTR_I	**rowname: MIN**** NETSTR_I(i,p)
Coefficients: $EFF_{i,m}$ $EFF_{s,m}$	 EFF(N->N) EFF(S->N)	 AEFF_PIPE(i,m) SEFF_PIPE(s,sr)
Mass Balance Constraints at Demand Points:		
equation: 28 $QDEM0^{F}_{i,d}$	**rowname: MF**?@@** F**B?@@	**rowname: MF**?@@** UTIL_QTY_F, NONU_QTY_F
equation: 29 $QDEM0^{I}_{i,d}$	**rowname: MI**?@@** I**B?@@	**rowname: MI**?@@** UTIL_QTY_I, NONU_QTY_I
coefficients: $EFF_{i,d}$	 EFF(N->D)	 UEFF_PIPE(i,d) NEFF_PIPE(i,d) CANEFF(i) MEXEFF(i)
Mass Balance Constraint at Supply Points:		
equation: 30	**rowname: MS++N****	**rowname: MS++N****

i,j,m= transhipment nodes, s= source, d = demand node, sr= subregion, p= forecast year, ST=storage, k,ns= steps on supply curve, sr= subregion.

Figure H-2. LP Matrix Definition for the Capacity Expansion Module (CEM)

		PFN**N**	PIN**N**	OFN**N**	OIN**N**	PFS++N**	PIS++N**	OFS++N**	OIS++N**	PFN**?@@	PIN**?@@	OFN**?@@	OIN**?@@	PIQ**?@@	OIQ**?@@
CEMOBJ		TARF	TARI	TARF	TARI	TARF	TARP	TARO	TARO	TARPF	TARFI	TAROF	TAROI	PZZFI	PZZOI
CEMBND	U														
	L	MINPF		MINOF											
MPFN**		EP,-1				EP				-1					
MPIN**			EP,-1				EP				-1				
MOFN**				EO,-1				EO				-1			
MOIN**					EO,-1				EO				-1		
MSTN**															
MPF**?@@										EP					
MPI**?@@											EP			1	
MOF**?@@												EO			
MOI**?@@													EO		1
CPF**N**		1													
CPI**N**		1	1												
CON**N**				1	1										
CPFSTN**															
CPISTN**															
SPS++N**						1	1								
SOS++N**								1	1						
XXITOT											1		1		
TPBKSTOF														1	
TOBKSTOF															1

Legend: ** = nodes (01-21), ++ = OGSM region (01-06), ? = sector code (R,C,I,T,U), @@ = CENSUS (01-09) or NERC region (01-13), # = step number on curve (0-9)

Figure H-2. LP Matrix Definition for the Capacity Expansion Module (CEM) (Continued)

		FFSTN**	PISTN**	OFSTN**	OISTN**	SS--N**#	STK***	CN**N**#		RHS	
CEMOBJ						PSUP	PSTR	PCAP			
CEMBND	U	PFSTU	PISTU	OFSTU	OISTU	USUP	USTR	UCAP			
	L	PFSTL	PISTL	OFSTL	OISTL	0	0	0			
MPFN**		1							=	0	
MPIN**			1						=	0	
MOFN**				-1					=	0	
MOIN**					-1				=	0	
MSTN**		-1	-1	EOSTR	EOSTR				=	0	
MPF**?@@									=	QDEMOPF(i,d)	
MPI**?@@									=	QDEMOPI(i,d)	
MOF**?@@									=	QDEMOOF(i,d)	
MOI**?@@									=	QDEMOOI(i,d)	
CPF**N**								-UPF(i,j)	=	0	
CPI**N**								-UP(i,j)	<=	0	(CEM loop 1)
									<=	QCAP0 - YCAP0	(CEM loop 2)
CON**N**								-UO(i,j)	<=	0	
CPFSTN**		1					-UPFSTR		=	0	
CPISTN**		1	1				-UPSTR		<=	0	(CEM loop 1)
									<=	QSTR0 - YSTR0	(CEM loop 2)
SPS++N**						-UPP(s,i)			=	0	
SOS++N**						-UPO(s,i)			<=	0	(STYP=1,2)
									=	0	(STYP=3,8)
XXITOT									<=	ALPHA * (PIDMD/EFF + OIDMD/EFF: for (i,j)	
TPBKSTOP											
TOBKSTOP											

Legend: ** = nodes (01-21), ++ = OGSM region (01-06), ? = sector code (R,C,I,T,U),
@@ = CENSUS (01-09) or NERC region (01-13), # = step number on curve (0-9)

Figure H-2. LP Matrix Definition for the Capacity Expansion Module (CEM) (Continued)

Columns

P F N * * N * *	=	Peak Firm flow from node to node
P I N * * N * *	=	Peak Interruptible flow from node to node
O F N * * N * *	=	Off-Peak Firm flow from node to node
O I N * * N * *	=	Off-Peak Interruptible flow from node to node
P F S + + N * *	=	Peak Firm flow from supply to node
P I S + + N * *	=	Peak Interruptible flow from supply to node
O F S + + N * *	=	Off-Peak Firm flow from supply to node
O I S + + N * *	=	Off-Peak Interruptible flow from supply to node
P F N * * ? @ @	=	Peak Firm flow to end-use sector
P I N * * ? @ @	=	Peak Interruptible flow to end-use sector
O F N * * ? @ @	=	Off-Peak Firm flow to end-use sector
O I N * * ? @ @	=	Off-Peak Interruptible flow to end-use sector
P I Q * * ? @ @	=	Peak Interruptible flow from backstop supply to end-use sector
O I Q * * ? @ @	=	Off-Peak Interruptible flow from backstop supply to end-use sector
P F S T N * *	=	Peak Firm flow from storage
P I S T N * *	=	Peak Interruptible flow from storage
O F S T N * *	=	Off-Peak Firm flow from into storage
O I S T N * *	=	Off-Peak Interruptible flow from into storage
S S & & N * * #	=	Steps on regional supply curve
S T N * * #	=	Steps on storage capacity expansion curve
C C * * N * * #	=	Steps on pipeline capacity expansion curve
R H S	=	Right hand side of constraint equations

Rows

C E M O B J	=	CEM Objective Function
C E M B N D	=	CEM Variable Bounds
M P F N * *	=	Regional mass balance--Peak Firm network
M P I N * *	=	Regional mass balance--Peak Interruptible network
M O F N * *	=	Regional mass balance--Off-Peak Firm network
M O I N * *	=	Regional mass balance--Off-Peak Interruptible network
M S T N * *	=	Regional mass balance--Storage points
M P F * * ? @ @	=	End-use mass balance--Peak Firm network
M P I * * ? @ @	=	End-use mass balance--Peak Interruptible network
M O F * * ? @ @	=	End-use mass balance--Off-Peak Firm network
M O I * * ? @ @	=	End-use mass balance--Off-Peak Interruptible network
C P F * * N * *	=	Pipeline capacity limit--Peak Firm flow
C P I * * N * *	=	Pipeline capacity limit--Total Peak flow
C O N * * N * *	=	Pipeline capacity limit--Total Off-Peak flow
C P F S T N * *	=	Regional storage capacity limit--Peak Firm flow
C P I S T N * *	=	Regional storage capacity limit--Total Peak flow
S P S + + N * *	=	Region supply limits for total Peak flows
S O S + + N * *	=	Region supply limits for total Off-Peak flows
X X I T O T	=	Alpha constraint to stop backflow of bkstop prices
T P B K S T O P	=	Backstop used--Total Peak
T O B K S T O P	=	Backstop used--Total Off-Peak

Legend: ** = nodes 01-21, ++ = OGSM region 01-06, ? = sector code,
@@ = CENSUS or NERC region, 01-13, # = step number on curve

Figure H-2. LP Matrix Definition for the Capacity Expansion Module (CEM) (Continued)

Coefficients, Right Hand Side (RHS), and Bounds

TARF	=	Interregional pipeline tariffs--Firm networks
TARI	=	Interregional pipeline tariffs--Intrp. networks
TARP	=	Supply gathering charges--Peak networks
TARO	=	Supply gathering charges--Off-Peak networks
TARPF	=	Distributor tariffs--Peak Firm network
TARPI	=	Distributor tariffs--Peak Intrp. network
TAROF	=	Distributor tariffs--Off-Peak Firm network
TAROI	=	Distributor tariffs--Off-Peak Intrp. network
PZZPI	=	Alt. fuel price for backstop supply--Peak Intrp. network
PZZOI	=	Alt. fuel price for backstop supply--Off-Peak Intrp. network
PSUP	=	Prices on supply curve steps (87$/mcf)
USUP	=	Quantities on supply curve steps (BCF)
PSTR	=	Prices on storage capacity curve steps (87$/mcf)
USTR	=	Quantities on storage capacity curve steps (BCF)
PCAP	=	Prices on pipeline capacity curve steps ($/mcf)
UCAP	=	Quantities on pipeline capacity curve step (BCF)
MINPF	=	Minimum interregional flow--Peak Firm
MINOF	=	Minimum interregional flow--Off-Peak Firm
PFSTU	=	Maximum flow from storage to Peak Firm network
PFSTL	=	Minimum flow from storage to Peak Firm network
PISTU	=	Maximum flow from storage to Peak Intrp. network
PISTL	=	Minimum flow from storage to Peak Intrp. network
OFSTU	=	Maximum flow from storage to Off-Peak Firm network
OFSTL	=	Minimum flow from storage to Off-Peak Firm network
OISTU	=	Maximum flow from storage to Off-Peak Intrp. network
OISTL	=	Minimum flow from storage to Off-Peak Intrp. network
EP	=	Regional pipeline efficiency--Peak networks
EO	=	Regional pipeline efficiency--Off-Peak networks
EOSTR	=	Regional storage efficiency
UPF	=	Utilization factor for Peak Firm flows (i.e., .33 * .95)
UP	=	Utilization factor for total Peak flows (i.e., .33 * .99)
UO	=	Utilization factor for total Off-Peak flows (i.e., .67 * .80)
UPFSTR	=	Utilization factor for Peak Firm storage flows
UPSTR	=	Utilization factor for total Peak storage flows
UPP	=	Maximum % supply available for Peak flows (i.e., .33 * .99)
UPO	=	Maximum % supply available for Off-Peak flows (i.e., .33 * .85)
QDEM0PF	=	Peak core (Firm service) demands (BCF) for year t+n+h or t+n
QDEM0PI	=	Peak noncore (Interruptible service) demands (BCF) for year t+n+h or t+n
QDEM0OF	=	Off-Peak core (Firm service) demands (BCF) for year t+n+h or t+n
QDEM0OI	=	Off-Peak noncore (Interruptible service) demands (BCF) for year t+n+h or t+n
QSTR0	=	Existing + Planned storage capacity (BCF) for year t+n
YSTR0	=	Utilized capacity (BCF) in alpha loop 1
ALPHA	=	curtailment fraction (percentage)
PIDMD	=	Total Peak noncore (Interruptible service) demand (BCF)
OIDMD	=	Total Off-Peak noncore (Interruptible service) demand (BCF)

Table H-2. Cross Reference of CEM Variables Between Documentation, LP, and Code		
Documentation	**CEM LP variable**	**Code variable**
Objective Function Variables:		
$x^{PF}_{s,i}$	PFS++N**	PF_FLOW(s.i) & PFAK & PFFLOW
$x^{PI}s,i$	PIS++N**	PI_FLOW(s,i) & PIFLOW
$x^{OF}_{s,i}$	OFS++N**	OF_FLOW(s,i) & OFAK & OFFLOW
$x^{OI}_{s,i}$	OIS++N**	OI_FLOW(s,i) & OIFLOW
$x^{PF}_{i,j}$	PFN**N**	PF_FLOW(i,j) & PF
$x^{PI}_{i,j}$	PIN**N**	PI_FLOW(i,j)
$x^{OF}_{i,j}$	OFN**N**	OF_FLOW(i,j) & OF
$x^{OI}_{i,j}$	OIN**N**	OI_FLOW(i,j)
$x^{PF}_{i,d}$	PFN**?@@	PF_FLOW(i,d)
$x^{PI}_{i,d}$	PIN**?@@	PI_FLOW(i,d)
$x^{OF}_{i,d}$	OFN**?@@	OF_FLOW(i,d)
$x^{OI}_{i,d}$	OIN**?@@	OI_FLOW(i,d)
$qzz^{PI}_{i,d}$	PIQ**?@@	BKSTOP
$qzz^{OI}_{i,d}$	OIQ**?@@	BKSTOP
$x^{PF}_{st,i}$	PFSTN**	PFSTR
$x^{PI}_{st,i}$	PISTN**	PISTR
$x^{OF}_{st,i}$	OFSTN**	OFSTR
$x^{OI}_{st,i}$	OISTN**	OISTR
$ysup_{s,i,k}$	SS++N**#	SQUANT(ns)
QSTRO & $ystr_{st,i,k}$	STN**#	QSTR
QCAPO & $ycap_{i,j,k}$	CN**N**#	QCAP
Variable Bounds:		
$USUP_{s,i,k}$	USUP	SQDEL(ns) from SQUANT(ns)
$USTR_{st,i,k}$	USTR	QSTRCURV(i) & CEM_QSTR(i,nst)
$UCAP_{i,j,k}$	UCAP	QCAPCURV(i) & CEM_QCAP(i,nc)
$MXSTR^{xx}_{st,i}$ (xx=PF,PI,OF,OI)	PFSTU, PISTU, OFSTU, OISTU	$PFSTRBND_{i,2}$, $PISTRBND_{i,2}$, $OFSTRBND_{i,2}$, $OISTRBND_{i,2}$
$MNSTR^{xx}_{st,i}$ (xx=PF,PI,OF,OI)	PFSTL. PISTL. OFSTL. OISTL	$PFSTRBND_{i,1}$, $PISTRBND_{i,1}$, $OFSTRBND_{i,1}$, $OISTRBND_{i,1}$
$PCTMFLO^{F}_{i,j} * ESTFLOW^{F}_{i,j} * SHR^{PF}_{i,j}$ $PCTMFLO^{F}_{i,j} * ESTFLOW^{F}_{i,j} * SHR^{OF}_{i,j}$ MINBIFLO	MINPF MINOF	MINXPF MINXOF MINBIOF.MINBIOI.MINBIPF, MINBIPI

Table H-2. Cross Reference of CEM Variables Between Documentation, LP, and Code (Continued)		
Documentation	**CEM LP variable**	**Code variable**
Objective Function Coefficients:		
$TAR^{P}_{s,j}$	TARP	TARP(styp,j,s)
$TAR^{O}_{s,j}$	TARO	TARO(styp,j,s)
$TAR^{F}_{i,j}$	TARF	PTAR_COM_F(i,j)
$TAR^{I}_{i,j}$	TARI	PTAR_I(i,j)
$TAR^{PF}_{i,d}$ & $TAR^{OF}_{i,d}$	TARPF & TAROF	NONU_DTAR_F(i,d), UTIL_DTAR_F(i,d)
$TAR^{PI}_{i,d}$ & $TAR^{OI}_{i,d}$	TARPI & TAROI	NONU_DTAR_I(i,d), UTIL_DTAR_I(i,d)
$PSUP_{s,j,k}$	PSUP	SUP_PR(styp,j,s)
$PSTR_{st,i,k}$	PSTR	PSTRCURV(i) & PSTR & CEM_PSTR(i,nst)
$PCAP_{i,j,k}$	PCAP	PCAPCURV(i) & CEM_PCAP(i,nc)
$PZZ^{PI}_{i,d}$	PZZPI	NG_BKSTOP_PR
$PZZ^{OI}_{i,d}$	PZZOI	NG_BKSTOP_PR
Mass Balance Constraints at Transshipment nodes:		
equation: 50	**rowname: MPFN****	**rowname: MPFN****
equation: 51	**rowname: MPIN****	**rowname: MPIN****
equation: 52	**rowname: MOFN****	**rowname: MOFN****
equation: 53	**rowname: MOIN****	**rowname: MOIN****
coefficients: $EFF^{P}_{i,j}$ $EFF^{P}_{s,j}$ $EFF^{O}_{i,j}$ $EFF^{O}_{s,j}$	 EP EP EO EO	 AEFF_PIPE(i,j) SEFF_PIPE(s,j) AEFF_PIPE(i,j) SEFF_PIPE(s,j)
Mass Balance Constraint at storage:		
equation: 54	**rowname: MSTN****	**rowname: MSTN****
coefficients: $EFF^{O}_{i,st}$	 EOSTR	 EFF_STR
Mass Balance Constraints at End-use nodes		
equation: 55 $QDEM0^{PF}_{i,d}$	**rowname: MPF**?@@** $QDEM0PF_{i,d}$	**rowname: MPF**?@@** QDEMOPF(i,d) & QDEMOPFU(i)
equation: 56 $QDEM0^{PI}_{i,d}$	**rowname: MPI**?@@** $QDEM0PI_{i,d}$	**rowname: MPI**?@@** QDEMOPI(i.d) & QDEMOPIU(i)
equation: 57 $QDEM0^{OF}_{i,d}$	**rowname: MOF**?@@** $QDEM0OF_{i,d}$	**rowname: MOF**?@@** QDEMOOF(i,d) & QDEMOOFU(i)
equation: 58 $QDEM0^{OI}_{i,d}$	**rowname: MOI**?@@** $QDEM0OI_{i,d}$	**rowname: MOI**?@@** QDEMOOI(i.d) & QDEMOOIU(i)
coefficients: $EFF^{P}_{i,d}$ $EFF^{O}_{i,d}$	 EO EP	 NEFF_PIPE(i.d) & UEFF_PIPE(i,d) NEFF_PIPE(i,d) & UEFF_PIPE(i,d)
Pipeline Capacity Constraints;		
equation: 63	**rowname: CPF**N****	**rowname: CPF**N****

Table H-2. Cross Reference of CEM Variables Between Documentation, LP, and Code (Continued)		
Documentation	**CEM LP variable**	**Code variable**
equation: 64 (CEM loop 2) right hand side	**rowname: CPI**N**** (CEM loop 2) QCAP0-YCAP0	**rowname: CPI**N**** (CEM loop 2) PCAP & QCAP0(i,j)-YCAP(i,j,1)
equation: 65	**rowname: CON**N****	**rowname: CON**N****
coefficients: $U^{PF}_{i,j}$ $U^{P}_{i,j}$ $U^{O}_{i,j}$	**CON**N**** UPF UP UO	**PCAP** UPF from ARC_PFUTILZ(i,j) UP from ARC_PUTILZ(i,j) UO from ARC_OUTILZ(i,j)
Storage Capacity Constraints:		
equation: 66	**rowname: CPFSTN****	**rowname: CPFSTN****
equation: 67 (CEM loop 2) right hand side	**rowname: CPISTN**** (CEM loop 2) QSTR0-YSTR0	**rowname: CPISTN**** (CEM loop 2) QSTR0(st)-YSTR(st,1)
coefficients: $UST^{PF}_{st,i}$ $UST^{P}_{st,i}$	 UPFSTR UPSTR	 STR_FUTILZ STR_UTILZ(st)
Supply constraints:		
equation: 59	**rowname: SPS++N****	**rowname: SPS++N****
euqations: 60,61	**rowname: SOS++N****	**rowname: SOS++N****
Rowname/RHS: $UP^{P}_{s,i}$ $UP^{O}_{s,i}$	 UPP UPO	 UPP using SUP_PUTILZ(styp,j,s) or SUP_PKSHR(styp,j,s) UPO using SUP_OUTILZ(styp,j,s) or SUP_PKSHR(styp,j,s)
Alpha Constraint:		
equation: 62 ALPHA $DMD^{PI}_{i,d}$, $DMD^{OI}_{i,d}$ $EFF^{P}_{i,d}$, $EFF^{O}_{i,d}$	**rowname: XXITOT** ALPHA PIDMD, OIDMD EFF, EFF	**rowname: XXITOT** ALPHA TOTDMD using PIDMDTOT, OIDMDTOT
Backstop Variables:		
ALPHA * $SUM_{i,d}$ {$DMD^{PI}_{i,d/EFFPi,d}$ + $DMD^{OI}_{i,d}/EFF^{O}_{i,d}$}	XXITOT	ALPHA * (PIDMDTOT(d) + OIDMDTOT(d))
	TPBKSTOP	BKSTOP(d)
	TOBKSTOP	BKSTOP(d)
Post_processing results:		
$PhyCap_{i,j}$		PNEW_CAP(i,j)
$StrCap_{st,i}$		PNEW_STR(i)
$ECAP^{F}_{i,j}$		REC
$UTILZ^{PF}_{i,j}$		PEAKPCNT * ARC_PFUTILZ(i,j)
$ECAP^{T}_{i,j}$		REC
$UTILZ^{P}_{i,j}$		PEAKPCNT * ARC_PUTILZ(i,j)

i,j = nodes, s = source, d = demand node, nc = steps on pipe cap curve, nst = steps on storage curve, styp = source type, st = storage node
yr = year, bnd = lower/upper bound.

Table H-3. Cross Reference of PTM Variables Between Documentation, and Code		
Documentation	Code Variable	Equation #
$R_{i,f}$	RF	95, 97, 98
$R_{i,v}$	RV	96, 99, 100
ALL_f	ARF(rd,i)	95
ALL_v	ARV(rd,i)	96
R_i	COST(1,i)	95, 96
$R_{i,f,r}$	RFR(i)	97
$R_{i,f,u}$	RFU(i)	98
$R_{i,v,r}$	RVR(i)	99
$R_{i,v,u}$	RVU(i)	100
$ALL_{f,r}$	AFR(rd,i)	97
$ALL_{f,u}$	AFU(rd,i)	98
$ALL_{v,r}$	AVR(rd,i)	99
$ALL_{v,u}$	AVU(rd,i)	100
R_A^{b-c}	Not used	101
R_A	RFR(18)	101
V_A^{b-c} / V_A^T	PS(P,AF,AT)	101
R_{1-2}	FCR,VCR,FCU,VCU	102
$PMAX_s^{t-1}$	MAX(AF,AT)	106
$INDUSTRYGPIS_{t-1}$	PLTOGPIS1	142
$GPIS_{t-1}$	PGPIS	139, 141, 142, 148, 175, 179
$GPIS_{t-2}$	PPGPIS	175, 179
YEAR	1989+CURIYR	175
TYEAR	1989+CURIYR	178
β0	OWC_BETA0	148
β1	OWC_BETA1	148
β2	OWC_BETA2	148
ρ	OWC_RHO	148

Table H-3. Cross Reference of PTM Variables Between Documentation, and Code (continued)

Documentation	Code Variable	Equation #
β0	TAG_FD	175 (existing pipeline)
β1	TAG_TEMP(1,1)	175 (existing pipeline)
β2	TAG_TEMP(1,2)	175 (existing pipeline)
β3	TAG_TEMP(1,3)	175 (existing pipeline)
ρ	TAG_RHO_E	175 (existing pipeline)
β0	(1-TAG_RHO_G)*TAG_TEMP(2,1)	175 (existing pipeline)
β1	TAG_TEMP(2,2)	175 (generic pipeline)
β2	TAG_TEMP(2,4)	175 (generic pipeline)
β3	TAG_TEMP(2,3)	175 (generic pipeline)
ρ	TAG_RHO_G	175 (generic pipeline)
$WAGE_t$	TAG_SALARY	175
$WAGE_{t-1}$	P_TAG_SALARY	175
β0	ADIT_TEMP(1,3)+ADIT_FD	150
β1	ADIT_ADIT = ADIT_TEMP(1,1)	150
β2	ADIT_NETPLT = ADIT_TEMP(1,2)	150
β0	DDA_FD	144, 172
β1	DDA_NETPLT	144, 172
β2	DDA_DEPSHR	144, 172
ρ	DDA_RHO_E	144, 172
DDA_t	DDASL, DDA(P,T,CT)	146, 174
β0	TOM_FD	178
β1	TOM_TEMP(1,1)	178
β2	TOM_TEMP(1,2)	178
β3	TOM_TEMP(1,3)	178
β4	TOM_TEMP(1,4)	178
ρ	TOM_RHO_E	178
$WAGE_t$	TOM_SALARY	178
$WAGE_{t-1}$	P_TOM_SALARY	178
MILE	MILE_FD	178

Table H-3. Cross Reference of PTM Variables Between Documentation, and Code (continued)

Documentation	Code Variable	Equation #
$\alpha0$	TOM_TEMP(2,1)	179
$\alpha1$	TOM_TEMP(2,2)	179
$\alpha2$	TOM_TEMP(2,3)	179
$\alpha3$	TOM_TEMP(2,4)	179
ρ	TOM_RHO_G	179
PEQUIP	TOM_PP	178, 179
T - Pipeline type, t - year, rd - rate design index, i - node		

Appendix I

Model Equations

Model Equations

This appendix presents the mapping of the equation (by equation number) in the documentation with the subroutine in the NGTDM code where the equation is used or referenced.

Chapter 3 Equations	
EQ. #	**SUBROUTINE**
1 (Firm) (Interr.)	NGTDM_CRVNONUFX* NGTDM_CRVNONUIX*
2	NGSYN_LIQH*
3-6	NGCAN_IMP*
7 (onshore & offshore)	NGTDM_PRE
8-12 (onshore) (offshore)	NGPRD_L48* NGPRD_OCS*
13-19	NGTDM_DMDALK
* Function	

Chapter 5 Equations	
EQ. #	**SUBROUTINE**
20-22	Not applicable
23	NGTDM_LPSI,NGTDM_LPEI,NGTDM_EFFLP, NGTDM_TARPI,NGTDM_TARDI,NGTDM_SUPCI, NGTDM_UTILCI,NGTDM_NONUCI,NGTDM_EXCI
24-27	NGTDM_CAPI
28-29	NGTDM_UTILCI,NGTDM_NONUCI,NGTDM_EFFLP,NGTDM_LPEI
30	NGTDM_SUPCI
31,34-35	NGTDM_CAPI
32-33	NGAFM_SUPMIN
36	PROPEROUT

Chapter 6 Equations	
EQ. #	SUBROUTINE
37	NGTDM_POSTNONU
38	NGTDM_DTM
39,41	NGTDM_HISOVR
40,42-44	NGTDM_POSTNONU
45	NGTDM_DTM
46-47	NGTDM_HISOVR
48	NGTDM_POSTUTIL

Chapter 7 Equations	
EQ. #	SUBROUTINE
49	CEMLPSNY, CEMLPNE, CEMCANIMP, CEMFLOWNN, CEMSUPCI, CEMSCAP, CEMBACK, CEMPCAP, NGCEM_ADJSTR, NGCEM_ADJCAP
50-53	CEMLPST,CEMLPNN,CEMLPSNB
54	CEMLPST
55-58	CEMLPNE,CEMDMD
59	CEMLPSUP,CEMCANSUP,CEMSUPCI
60	CEMLPSUP,CEMSUPCI
61	CEMLPSUP,CEMCANSUP,CEMSUPCI
62	UPDTRHS
63	CEMLPCAP,CEMCANIMP,CEMDMD,CEMPCAP
64	RESET_RHS,CEMLPCAP,CEMCANIMP,CEMDMD,CEMPCAP
65	CEMLPCAP,CEMCANIMP,CEMDMD,CEMPCAP
66-67	CEMLPST_UTIL,CEMSCAP,RESET_RHS
68-69	CEMCANIMP,CEMFLOWNN
70-71	RESETMATRIX
72-73	GETSOLUTION1
74-75	NGCEM_AFMUTILZ
76-77	GETSOLUTION2

Chapter 8 Equations	
EQ #	SUBROUTINE
78-94	PTMA_CALCULATE_COST
95-100	PTMJ_TRNS_COST_OF_SERVICE
101-102	PTM4_BASE_YEAR_PIPELINE
103-104	PTM4_BASE_YEAR_PIPELINE, PTM6_FORECAST_PIPELINE
105-130	PTMD_ALLOCATE_ARC_LEVEL_COST
131-132	PTM9_EXPAND_GENERIC
133-137	PTM2_BASE_YEAR_INITIALIZATION
138	PTMA_CALCULATE_COST
139	PTMA_CALCULATE_COST, PTM7_FORECAST_COST
140-145	PTM7_FORECAST_COST
146	PTM9_EXPAND_GENERIC
147-148	PTM7_FORECAST_COST
149	PTMA_CALCULATE_COST
150-151	PTM7_FORECAST_COST
152	PTM7_FORECAST_COST, PTM9_EXPAND_GENERIC
153-166	PTMA_CALCULATE_COST
167	PTM7_FORECAST_COST
168	PTMA_CALCULATE_COST
169	PTM7_FORECAST_COST
170-171	PTMA_CALCULATE_COST
172-173	PTM7_FORECAST_COST
174	PTM9_EXPAND_GENERIC
175-180	PTM7_FORECAST_COST

Appendix J

Model Variable Definition List

Parameters Defined for the NGTDM			
Variable	**Include**	**Value**	**Definition**
CEMN	NGTDMLOC	2	Number of years ahead for cap expan.
CEMNS	NGTDMLOC	6	Number of steps on cap expansion curves
FHISYR	NGTDMLOC	1990	First historical year
IBASYR	NGTDMOUT	1990	First year in simulation
IENDYR	NGTDMOUT	MNUMYR+IBASYR-1	Last year in simulation
JARC	NGTDMLOC	5	Max # of arcs into node
JSUP	NGTDMLOC	4	Max # of supply sources into node
JTOTSUP	NGTDMLOC	NSUPTYP*NGTDM*JSUP	Max # of total supply connections
JTREE	NGTDMLOC	6	Max # of branches on level of tree
JUTIL	NGTDMLOC	4	Max # of dmd reg. Per node
LHISYR	NGTDMLOC	1993	Last historical year
MAX_CT	NGTDMPTM	2	Max num of cost types 1 = transportation cost 2 = storage cost
MAX_DESIGN	NGTDMPTM	3	Maximum number of rated design types
MAX_EXPANSION	NGTDMPTM	CEMNS	Maximum number of expansions
MAX_ITEM	NGTDMPTM	18	Maximum number of cost line items
MAX_PIPE	NGTDMPTM	80	Maximum number of pipeline companies
MAX_PT	NGTDMPTM	4	Max num of cost types 1 = individual pipeline 2 = scaled cost data 3 = 1990 hist by arc 4 = generic company data by arc
MAX_STEPS	NGTDMPTM	CEMNS	Maximum number of steps
MNFNGSS	OGSMOUT	4	IM/EX Region 1 = Canada 2 = Mexico 3 = LNG 4 = Net Imports

Parameters Defined for the NGTDM

Variable	Include	Value	Definition
MNOGDTP	OGSMOUT	4	Drilling regions 1 = Lower 48 States--Onshore 2 = Lower 48 States--Offshore 3 = Alaska 4 = US
MNOGRGN	OGSMOUT	10	OGSM reporting regions 1 = East Coast 2 = Gulf Coast 3 = Mid-Continental 4 = Perm Basin 5 = Rocky Mountains 6 = West Coast 7 = Gulf 8 = Pacific 9 = Atlantic 10 = Lower 48 States
MNUMP	MPBLK	91	# of NEMS price variables
MPSIZE	MPBLK	MNUMP*MNUMCR*MNUMYR	Size of price array
NAFMIO	OMLBUF	100,000	Size of workspace for AFM matrix
NALKREG	NGTDMOUT	3	# of Alaska supply regions
NCAN	NGTDMOUT	6	# of boarder crossings into Canada
NCEMIO	OMLBUF	130,000	Size of workspace for CEM matrix
NDSTEP	NGTDMLOC	4	Number of steps on half of dmd curve
NEMMREG	NGTDMOUT	13	# of EMM electric generators dmd regions
NEMMSUB	NGTDMOUT	20	# of NGTDM/EMM subregions
NGTDM	NGTDMLOC	21	Number of NGTDM nodes
NLNG	NGTDMOUT	4	# of potential sup LNG sources
NMEX	NGTDMOUT	3	# of boarder crossings into Mexico
NNCEN	NGTDMOUT	9	# of Census divisions
NNGREG	NGTDMOUT	12	# of NGTDM regions (excluding boarder crossings)
NOCSREG	NGTDMOUT	3	# of off-shore supply regions

Parameters Defined for the NGTDM

Variable	Include	Value	Definition
NONUSEC	NGTDMLOC	4	Number of non- electric generators sectors
NPREG	NGTDMOUT	NSUPREG+NOCSREG	# of OGSM regs (6-on,3-off)
NSDOMREG	NGTDMLOC	NOCSREG+NSUPREG	# of offshore and OGSM supply regions
NSSTEP	NGTDMLOC	9	Number of steps on supply curve
NSUPREG	NGTDMOUT	6	# of OGSM supply regions
NSUPSUB	NGTDMOUT	17	# of NGTDM/OGSM subregions
NSUPTYP	NGTDMLOC	8	Number of supply types
NTREE	NGTDMLOC	8	Number of levels on tree
NUMSTR	NGTDMCEM	10	Number of nodes with storage

Variable Definition List for NGTDM Global Variables Grouped by Fortran INCLUDE Statement

INCLUDE (CAPEXP)

Variable	Common Name	Characteristics	Definitions
CAPENT	CAPEXP	Dimen: MNUMYR Units: 87$	Capital expenditures for capacity expansion in the NGTDM

INCLUDE (COALOUT)

Variable	Common Name	Characteristics	Definitions
CLSYNGQN	COALOUT	Dimen: 17,MNUMYR Units: Tril. BTU	Coal Syn NG quantity

INCLUDE (CONVFACT)

Variable	Common Name	Characteristics	Definitions
CFNGC	CONVFACT	Dimen: --- Units: MMBtu/mcf	Natural Gas. Consum/Prod conversion factor: 1.031 MMBtu/mcf
CFNGN	CONVFACT	Dimen: --- Units: MMBtu/mcf	Natural Gas. Nonutil conversion factor: 1.030 MMBtu/mcf
CFNGU	CONVFACT	Dimen: --- Units: MMBtu/mcf	Natural Gas. Util conversion factor: 1.034 MMBtu/mcf

INCLUDE (EMABLK)

Variable	Common Name	Characteristics	Definitions
JGCELGR	EMABLK	Dimen: MNUMYR Units: 87$/MMBtu	Elec Util. carbon tax for emissions from NG

INCLUDE (EMISSION)			
Variable	**Common Name**	**Characteristics**	**Definitions**
EMNT	EMISSION	Dimen: MNUMCR,MNPOLLUT,MNUMYR Units: 1000 metric tons	NGTDM Emissions by Region

INCLUDE (EMMOUT/UGOILOUT)			
Variable	**Common Name**	**Characteristics**	**Definition**
QRLELGR	UGOILOUT	Dimen: 21,MNUMYR Format: real*4	LS Resid. use in D_F plants
QRHELGR	UGOILOUT	Dimen: 21,MNUMYR Format: real*4	HS Resid. use in D_F plants
GSHRMIN	UGOILOUT	Dimen: 21,MNUMYR Format: real*4	Min. gas use in D_F plants
GRATMIN	UGOILOUT	Dimen: 21,MNUMYR Format: real*4	G/O price ratio at minimum
GSHRMAX	UGOILOUT	Dimen: 21,MNUMYR Format: real*4	Max. gas use in D_F plants
GRATMAX	UGOILOUT	Dimen: 21,MNUMYR Format: real*4	G/O price ratio at maximum
GSHRPAR	UGOILOUT	Dimen: 21,MNUMYR Format: real*4	Parity gas use in D_F plants
GRATPAR	UGOILOUT	Dimen: 21,MNUMYR Format: real*4	G/O price ratio at par

INCLUDE (INTOUT)

Variable	Common Name	Characteristics	Definitions
IT_WOP	INTOUT	Dimen: MNUMYR,2 Units: 87S/BBL	World oil price

INCLUDE (MACOUT)

Variable	Common Name	Characteristics	Definitions
MC_ECIWSPNS	MACOUT	Dimen: MNUMYR Units: ---	Employment cost index-pvt wage&salary
MC_PGDP	MACOUT	Dimen: MNUMYR Units: ---	Implicit GDP price deflator
MC_RMPUAANS	MACOUT	Dimen: MNUMYR Units: ---	Yield on AA utility bonds
MC_WPI	MACOUT	Dimen: MNUMYR Units: ---	Producer Price Index (82=1.0)

INCLUDE (MXPBLK)

Variable	Common Name	Characteristics	Definitions
XIT_WOP	MXPBLK	Dimen: MNXYR,2 Units: 87S/BBL	Expected world oil price
XOGWPRNG	MXPBLK	Dimen: MNUMOR,MNXYR Units: 87S/mcf	Expected NG wellhead price

INCLUDE (MXQBLK)

Variable	Common Name	Characteristics	Definitions
XQGFCM	MXQBLK	Dimen: MNUMCR,MNXYR Units: Tril. BTU	Expected demands for NG by firm commercial sector
XQGFEL	MXQBLK	Dimen: MNUMCR,MNXYR Units: Tril. BTU	Expected demands for NG by firm electric generation sector
XQGFIN	MXQBLK	Dimen: MNUMCR,MNXYR Units: Tril. BTU	Expected demands for NG by firm industrial sector
XQGFRS	MXQBLK	Dimen: MNUMCR,MNXYR Units: Tril. BTU	Expected demands for NG by firm residential sector
XQGFTR	MXQBLK	Dimen: MNUMCR,MNXYR Units: Tril. BTU	Expected demands for NG by firm transportation sector
XQGICM	MXQBLK	Dimen: MNUMCR,MNXYR Units: Tril. BTU	Expected demands for NG by interruptible commercial sector
XQGIEL	MXQBLK	Dimen: MNUMCR,MNXYR Units: Tril. BTU	Expected demands for NG by interruptible electric generation sector
XQGIIN	MXQBLK	Dimen: MNUMCR,MNXYR Units: Tril. BTU	Expected demands for NG by interruptible industrial sector
XQGIRS	MXQBLK	Dimen: MNUMCR,MNXYR Units: Tril. BTU	Expected demands for NG by interruptible residential sector
XQGITR	MXQBLK	Dimen: MNUMCR,MNXYR Units: Tril. BTU	Expected demands for NG by interruptible transportation sector
XQNGELCN	MXQBLK	Dimen: 21,MNXYR Units: Tril. BTU	Expected demands for NG by competitive electric generation sector (NGTDM/EMM subregions)
XQNGELFN	MXQBLK	Dimen: 21,MNXYR Units: Tril. BTU	Expected demands for NG by firm electric generation sector (NGTDM/EMM subregions)
XQNGELIN	MXQBLK	Dimen: 21,MNXYR Units: Tril. BTU	Expected demands for NG by interruptible electric generation sector (NGTDM/EMM subregions)

INCLUDE (NCNTRL)

Variable	Common Name	Characteristics	Definitions
BASEYR	NCNTRL	Dimen: — Units: —	Base year in NEMS (e.g., 1990)
CURITR	NCNTRL	Dimen: — Units: —	Current iteration in NEMS (e.g., 1,2,3...)
CURIYR	NCNTRL	Dimen: — Units: —	Current year in NEMS (e.g., 1,2,3,...)
ENDYR	NCNTRL	Dimen: — Units: —	Last model year currently available in NEMS (i.e., 2010)
EXE	NCNTRL	Dimen: — Units: —	On/off flag for the EMM
FCRL	NCNTRL	Dimen: — Units: —	Switch indicating if NEMS has converged for a year
IRELAX	NCNTRL	Dimen: — Units: —	Switch to run relaxation routine in MAIN
LASTYR	NCNTRL	Dimen: — Units: —	Last year the model has been defined by user to run (e.g., 2000 or 2010 or ...)
MAXITR	NCNTRL	Dimen: — Units: —	Maximum iterations defined by user
NCRL	NCNTRL	Dimen: — Units: —	Switch indicating the report writing loop within NEMS
PRTDBGG	NCNTRL	Dimen: — Units: —	On/off flag for NGTDM trace reports

INCLUDE (NGCEMRPT)			
Variable	**Common Name**	**Characteristics**	**Definition**
BKSTOP	CEMRPT	Dimen: NNGREG Units: Bcf	Total backstop supply from LP soln
OPSUP	CEMRPT	Dimen: NSUPTYP,NGTDM,4 Units: Bcf	Off-peak supply from LP soln
PFSTN	CEMRPT	Dimen: NUMSTR Units: Bcf	Peak firm storage usage from LP soln
PKSTN	CEMRPT	Dimen: NUMSTR Units: Bcf	Total peak storage usage from LP soln
PKSUP	CEMRPT	Dimen: NSUPTYP,NGTDM,4 Units: Bcf	Peak supply from LP soln

INCLUDE (NGGLOBAL)			
Variable	**Common Name**	**Characteristics**	**Definitions**
NGDBGCNTL	TRACERPT	Dimen: 4,20 Units: —	NGTDM trace frquency switch
NGDBGITR	TRACERPT	Dimen: 4,20 Units: —	Report for current iteration
NGDBGRPT	TRACERPT	Dimen: 4,20 Units: —	NGTDM trace report switch

INCLUDE (NGRPT)

Variable	Common Name	Characteristics	Definitions
AEU_PR	NGRPT	Dimen: 12,3,MNUMYR Units: ---	Average regoinal end use price
AEU_TOT	NGRPT	Dimen: 3,MNUMYR Units: ---	Average end use price -- firm/interruptible total
AMH_PR	NGRPT	Dimen: 12,3,MNUMYR Units: ---	Average market hub price
AMH_TOT	NGRPT	Dimen: 3,MNUMYR Units: ---	Average market hub price total
AVG_CONS_CF	NGRPT	Dimen: MNUMYR Units: ---	Average consumption cost --Firm w/intraregional
AVG_CONS_CI	NGRPT	Dimen: MNUMYR Units: ---	Average consumption cost --Interruptible w/intraregional
AVG_TRAN_CF	NGRPT	Dimen: MNUMYR Units: ---	Average transportation cost--firm
AVG_TRAN_CI	NGRPT	Dimen: MNUMYR Units: ---	Average transportation cost--interruptible
CAP_CEN	NGRPT	Dimen: 11,4,MNUMYR Units: ---	Capacity entering node census division
CAP_CEX	NGRPT	Dimen: 11,4,MNUMYR Units: ---	Capacity exiting node census division
CAP_NEN	NGRPT	Dimen: 14,4,MNUMYR Units: ---	Capacity entering node (NGTDM)
CAP_NEX	NGRPT	Dimen: 14,4,MNUMYR Units: ---	Capacity exiting node (NGTDM)
CONS	NGRPT	Dimen: 12,3,MNUMYR Units: ---	Regional consumption
CONS_TOT	NGRPT	Dimen: 3,MNUMYR Units: ---	Total consumption for all regions
DIST_NONU_F	NGRPT	Dimen: MNUMYR Units: ---	Firm distribution for non utility
DIST_NONU_I	NGRPT	Dimen: MNUMYR Units: ---	Interruptible distribution for non utility
DIST_REV	NGRPT	Dimen: 3,3,MNUMYR Units: ---	Total US distribution

INCLUDE (NGRPT)

Variable	Common Name	Characteristics	Definitions
DIST_UTIL_F	NGRPT	Dimen: MNUMYR Units: ---	Firm distribution--utility
DIST_UTIL_I	NGRPT	Dimen: MNUMYR Units: ---	Interruptible distribution--utility
DOMSUP	NGRPT	Dimen: 12,MNUMYR Units: ---	Domestic Supply--by region--(bcf)
DOMSUP_TOT	NGRPT	Dimen: MNUMYR Units: ---	Domestic Supply--national--(bcf)
END_USE_AL	NGRPT	Dimen: 2,4,MNUMYR Units: ---	Enduse consumption activity level
INTER_MOVE_AL	NGRPT	Dimen: 3,MNUMYR Units: ---	Interstate movement activity level
INTER_T_REV	NGRPT	Dimen: 3,4,MNUMYR Units: ---	Firm interstate transmission
NETIMP	NGRPT	Dimen: 12,MNUMYR Units: ---	Net imports--regional--(bcf)
NETIMP_TOT	NGRPT	Dimen: MNUMYR Units: ---	Net imports--regional--(bcf)

INCLUDE (NGTABLE)			
Variable	**Common Name**	**Characteristics**	**Definitions**
DIST_NET_NF	FDISTVARS	Dimen: --- Units: ---	Firm net distribution, nonutility
DIST_NET_NI	FDISTVARS	Dimen: --- Units: ---	Interruptible net distribution, nonutility
DIST_NET_UF	FDISTVARS	Dimen: --- Units: ---	Firm net distribution, utility
DIST_NET_UI	FDISTVARS	Dimen: --- Units: ---	Interruptible net distribution, utility
EXPORT_F	FENDUSE	Dimen: --- Units: ---	Firm exports
EXPORT_I	FENDUSE	Dimen: --- Units: ---	Interuptible exports
EXT_ARCMAP	FEXTMAP	Dimen: NGTDM,6 Units: ---	Inverse of NG ARC_MAP
EXT_ARCNUM	FEXTMAP	Dimen: NGTDM Units: ---	Number of exit arcs from node
LEVEL_F	FALVARS	Dimen: --- Units: ---	Firm level of interstate movements
LEVEL_I	FALVARS	Dimen: --- Units: ---	Interruptible level of interstate movements
NONU_QTY_TF	FENDUSE	Dimen: --- Units: ---	Total firm nonutility--all regions and sectors
NONU_QTY_TI	FENDUSE	Dimen: --- Units: ---	Total interruptible nonutility--all regions and sectors
RENT_NF	FINTVARS	Dimen: --- Units: ---	Negative firm rent
RENT_NI	FINTVARS	Dimen: --- Units: ---	Negative interruptible rent
RENT_PF	FINTVARS	Dimen: --- Units: ---	Postive firm rent
RENT_PI	FINTVARS	Dimen: --- Units: ---	Postive interruptible rent
TOTAL_F	FINTVARS	Dimen: --- Units: ---	Total firm revenue

INCLUDE (NGTABLE)			
Variable	**Common Name**	**Characteristics**	**Definitions**
TOTAL_I	FINTVARS	Dimen: --- Units: ---	Total interruptible revenue
UTIL_QTY_TF	FENDUSE	Dimen: --- Units: ---	Total firm utility--all regions and sectors
UTIL_QTY_TI	FENDUSE	Dimen: --- Units: ---	Total interruptible utility--all regions and sectors

INCLUDE (NGTDMCEM)

Variable	Common Name	Characteristics	Definition
ARC_OUTILZ	CEMDAT	Dimen: 21,21 Units: fraction	Max off-PK utilization of total cap available during off-PK period
ARC_PFUTILZ	CEMDAT	Dimen: NGTDM,NGTDM Units: fraction	Max PK firm utilization of total cap available during PK period
ARC_PUTILZ	CEMDAT	Dimen: 21,21 Units: fraction	Max PK utilization of total cap available during PK period
B	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
C	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
C1--not used	PRDCAPDAT	Dimen: NPREG Units: ---	Estimated parameters for productive capacity equations
C2--not used	PRDCAPDAT	Dimen: NPREG Units: ---	Estimated parameters for productive capacity equations
C3--not used	PRDCAPDAT	Dimen: NPREG Units: ---	Estimated parameters for productive capacity equations
C4--not used	PRDCAPDAT	Dimen: NPREG Units: ---	Estimated parameters for productive capacity equations
C5--not used	PRDCAPDAT	Dimen: NPREG Units: ---	Estimated parameters for productive capacity equations
CANFLO_PFSHR	CEMDMDS	Dimen: --- Units: fraction	PK share of firm imports from Can.
E	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
EC	LPNAME3	Dimen: --- Format: char*2	Double letters, used to define LP variables
EM	LPNAME3	Dimen: --- Format: char*2	Double letters, used to define LP variables
EXP_PSHR	CEMEXP	Dimen: 9 Units: fraction	Peak share of annual exports
EXPMAP	CEMMAP	Dimen: 2,9 Units: ---	ID's 9 export border-crossing arcs by NGTDM source and dest nodes (1=source, 2=dest)

INCLUDE (NGTDMCEM)			
Variable	**Common Name**	**Characteristics**	**Definition**
F	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
HALPHA	ALPHADATA	Dimen: --- Units: fraction	A tracking of the high alpha value last used (real*8)
LALPHA	ALPHADATA	Dimen: --- Units: fraction	A tracking of the low alpha value last used (real*8)
LASTALPHA	ALPHADATA	Dimen: --- Units: fraction	A tracking of the alpha value last used (real*8)
M	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
N	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
NONU_POSHR_F	CEMDAT	Dimen: 2,4,NNGREG Units: fraction	PK, off-PK split of core (firm) nonutil dmd
NONU_POSHR_I	CEMDAT	Dimen: 2,4,NNGREG Units: fraction	PK, off-PK split of noncore (interrup.) nonutil dmd
O	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
OBJCEM	LPCEM	Dimen: --- Format: char*8	Objective function name for use by OML
OF_FLOW	CEMFLOW	Dimen: 21,21 Units: Bcf	Resulting off-PK firm flow along network arcs
OFSTRBND	STRBND	Dimen: NNGREG,2 Units: Bcf	Bound on OF flow into storage (1=lower, 2=upper)
OI	LPNAME3	Dimen: --- Format: char*2	Double letters, used to define LP variables
OI_FLOW	CEMFLOW	Dimen: 21,21 Units: Bcf	Resulting off-PK interrup. flow along network arcs
OISTRBND	STRBND	Dimen: NNGREG,2 Units: Bcf	Bound on OI flow into storage (1=lower, 2=upper)
OPPCNT	CEMDAT	Dimen: --- Units: fraction	Off-PK period as percent of year
P	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables

INCLUDE (NGTDMCEM)

Variable	Common Name	Characteristics	Definition
PCTMIN_OF--not used	CEMDMDS	Dimen: -- Units: --	== not used ==
PCTMIN_PF--not used	CEMDMDS	Dimen: -- Units: --	== not used ==
PEAKPCNT	CEMDAT	Dimen: -- Units: fraction	PK period as percent of year
PF_FLOW	CEMFLOW	Dimen: 21,21 Units: Bcf	Resulting PK firm flow along network arcs
PFSTRBND	STRBND	Dimen: NNGREG,2 Units: Bcf	Bound on PF flow out of storage (1=lower, 2=upper)
PI	LPNAME3	Dimen: -- Format: char*2	Double letters, used to define LP variables
PI_FLOW	CEMFLOW	Dimen: 21,21 Units: Bcf	Resulting PK interrup. flow along network arcs
PISTRBND	STRBND	Dimen: NNGREG,2 Units: Bcf	Bound on PI flow out of storage (1=lower, 2=upper)
PRDCAP89--not used	PRDCAPDAT	Dimen: NPREG Units: --	Hist 1989 prod cap by OGSM
PRDCAP90--not used	PRDCAPDAT	Dimen: NPREG Units: --	Hist 1990 prod cap by OGSM
PRDCAP91--not used	PRDCAPDAT	Dimen: NPREG Units: --	Hist 1991 prod cap by OGSM
Q	LPNAME3	Dimen: -- Format: char*1	Single letter, used to define LP variables
QCAP0	RESET	Dimen: NGTDM,NGTDM Units: Bcf	Base capacity on cap expansion curve
QDEMOOF	CEMDMDS	Dimen: 4,21 Units: Bcf	Off-PK core (firm service) nonutil dmd in forecast yr CEMN or (CEMN + CEMH).
QDEMOOFU	CEMDMDS	Dimen: NEMMSUB Units: Bcf	Off-PK core (firm service) util dmd in forecast yr CEMN
QDEMOOI	CEMDMDS	Dimen: 4,21 Units: Bcf	Off-PK noncore (interup. service) nonutil dmd in forecast yr CEMN or (CEMN + CEMH)

INCLUDE (NGTDMCEM)			
Variable	**Common Name**	**Characteristics**	**Definition**
QDEMOOIU	CEMDMDS	Dimen: NEMMSUB Units: Bcf	Off-PK noncore util dmd in forecast yr CEMN
QDEMOPF	CEMDMDS	Dimen: 4,21 Units: Bcf	PK core nonutil dmd in forecast yr CEMN or (CEMN + CEMH)
QDEMOPFU	CEMDMDS	Dimen: NEMMSUB Units: Bcf	PK core (firm service) util dmd in forecast yr CEMN
QDEMOPI	CEMDMDS	Dimen: 4,21 Units: Bcf	PK noncore (interrup. service) nonutil dmd in forecast yr CEMN or (CEMN + CEMH)
QDEMOPIU	CEMDMDS	Dimen: NEMMSUB Units: Bcf	PK noncore (interrup. service) util dmd in forecast yr CEMN
QFNONU_MAXGROW	MXGRW	Dimen: --- Units: ---	Max annual average growth used in estimating expected nonutility firm demand in the CEM
QSTR0	CEMDAT	Dimen: NUMSTR Units: Bcf	Base capacity on storage expansion curve
R	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
S	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
STOR_NODES	STORAG	Dimen: 11 Units: ---	mapping of storage locations into NGTDM nodes 1-12
STR_FUTILZ	STORAG2	Dimen: NUMSTR Units: fraction	1 - storage losses for PK firm network
STR_UTILZ	STORAG2	Dimen: NUMSTR Units: fraction	1 - storage losses for PK interrup. network
SUP_OUTILZ	CEMDAT	dimen: NSUPTYP,NGTDM,4 Units: fraction	Portion of total supply allocated to off-PK network
SUP_PKSHR	CEMSUP	Dimen: 8,NGTDM,4 Units: fraction	Peak share of annual supply
SUP_PUTILZ	CEMDAT	Dimen: NSUPTYP,NGTDM,4 Units: fraction	Portion of total supply allocated to PK network
T	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables

INCLUDE (NGTDMCEM)			
Variable	**Common Name**	**Characteristics**	**Definition**
TARO	CEMDAT	Dimen: NSUPTYP,NGTDM,4 Units: 87$/mcf	Tariff along supply arc for off-PK firm and off-PK interrupt. networks
TARP	CEMDAT	Dimen: NSUPTYP,NGTDM,4 Units: 87$/mcf	Tariff along supply arc for PK firm and PK interrupt. networks
TOTDMD	CEMDMDS	Dimen: --- Units: Bcf	Total noncore (interrup.service) dmd used in alpha loop (real*8)
U	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
UTIL_POSHR_C	CEMDAT	Dimen: 2,NEMMSUB Units: fraction	PK, off-PK split of competitive util dmd
UTIL_POSHR_F	CEMDAT	Dimen: 2,NEMMSUB Units: fraction	PK, off-PK split of core (firm service) util dmd
UTIL_POSHR_I	CEMDAT	Dimen: 2,NEMMSUB Units: fraction	PK, off-PK split of noncore (interrup. service)util dmd
WTHRFAC	CEMDAT	Dimen: NGTDM,NGTDM Units: fraction	Weather factor--percent of capacity normally not used for normal weather scenarios
X	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
YCAP	RESET	Dimen: NGTDM,NGTDM,CEMNS Units: Bcf	Step results on cap expansion curve in 1st alpha loop
YSTR	CEMDAT	Dimen: NUMSTR,CEMNS Units: Bcf	Step results on storage expansion curve in 1st alpha loop

INCLUDE (NGTDMLOC)			
Variable	**Common Name**	**Characteristics**	**Definition**
BIARC_PFSHR	MINFLOW	Dimen: --- Units: fraction	PK/Off-PK share of firm Bi-flow
ADGPRD89	NGADGPRD1	Dimen: nsdomreg	1989 Ad gas prod onshore & offshore
ADGPRDON	NGADGPRD1	Dimen: NSUPSUB Units: Bcf	AD gas production onshore
AEFF_PIPE	LPCAP1	Dimen: NGTDM,NGTDM Units: fraction	Eff along pipeline arc
AFLOW_F	PTARAFM	Dimen: NGTDM,NGTDM Units: Bcf	Resulting firm NG flow
AFLOW_I	PTARAFM	Dimen: NGTDM,NGTDM Units: Bcf	Resulting interrup. NG flow
AFM_PTAR_I	AFMVARX	Dimen: NGTDM,NGTDM Units: 87$/mcf	Realized pipe tariff for noncore (interrup. service)market
ANEW_CAP	FFCAP	Dimen: NGTDM,NGTDM Units: Bcf	New annual capacity
ARC_CYCLE	FARCS	Dimen: 25,2 Units: ---	Node pairs identifying Bi-flow arcs
ARG0	LPARG	Dimen: --- Units: ---	Real*8 variable used to pass info to LP via OML
ARG1	LPARG	Dimen: --- Units: ---	Real*8 variable used to pass info to LP via OML
ARG2	LPARG	Dimen: --- Units: ---	Real*8 variable used to pass info to LP via OML
AUTILZ_F	LPCAP1	Dimen: NGTDM,NGTDM,CEMN Units: fraction	Capacity utilization limit for firm
AUTILZ_T	LPCAP1	Dimen: NGTDM,NGTDM,CEMN Units: fraction	Capacity utilization limit for firm + interrup.
BENCHF	LPDTAR1	Dimen: NONUSEC,NNGREG Units: 87$/mcf	Benchmarking adj for nonutilities
BGSCNT	PFRCEM	Dimen: NNGREG Units: Bcf	Non-jurisdictional BGSCT
BGSCT	PFRCEM	Dimen: NNGREG Units: Bcf	Base gas storage capacity at node

INCLUDE (NGTDMLOC)

Variable	Common Name	Characteristics	Definition
BIARC_PISHR	MINFLOW	Dimen: -- Units: fraction	PK/Off-PK share of interrup. Bi-flow
CAN_NODEIN	CANFLOW	Dimen: -- Units: --	Canadian node where 'Can flow-thru' gas flows in
CAN_NODEOUT	CANFLOW	Dimen: 2 Units: --	Canadian nodes where 'Can flow-thru' gas flows out
CANEFF	EXPNEW	Dimen: NCAN Units: fraction	Eff along arcs to Canadian nodes
CANFLO_IN	CANFLOW	Dimen: -- Units: Bcf	'Can flow-thru' gas flowing into US
CANFLO_OUT	CANFLOW	Dimen: 2 Units: Bcf	'Can flow-thru' gas flowing out of US thru nodes 15 & 17
CANFLO_SHR	CANFLOW	Dimen: -- Units: --	'Can flow-thru' share going out node 15
CEM_PCAP	PTARCEM	Dimen: NGTDM,NGTDM,CEMNS Units: 87$/mcf	Price on each step of pipeline capacity expansion curves
CEM_PCAPEST	PTARCEM1	Dimen: NGTDM,NGTDM,CEMN Units: $/mcf	Est price on pipeline cap expansion curve for use by PTM
CEM_PSTR	PTARCEM	Dimen: NNGREG,CEMNS Units: Bcf	Quantity on each step of storage expansion curves
CEM_PSTREST	PTARCEM1	Dimen: NNGREG,CEMN Units: $/mcf	Est price on storage expansion curve for use by PTM
CEM_QCAP	PTARCEM	Dimen: NGTDM,NGTDM,CEMNS Units: Bcf	Quantity on each step of pipeline capacity expansion curves
CEM_QSTR	PTARCEM	Dimen: NNGREG,CEMNS Units: 87$/mcf	Price on each step of storage expansion curves
CEMH	CEMEXP01	Dimen: -- Format: integer*4	Year demand data after capital expansion year
CEMYR	NGMAPS	Dimen: -- Units: --	Used to determine array position (1,CEMN) of current year CEM expansion results
CHAR0	CHARS	Dimen: -- Format: char*1	Single character for 0
CN_TOL	NGPRDCRV	Dimen: --- Format: real*4	Allowed tolerance for CN_SHRDIF

INCLUDE (NGTDMLOC)

Variable	Common Name	Characteristics	Definition
CONST_SUP	LPMAPS	Dimen: NSUPTYP Units: ---	Indicator for constant supply by supply type
CP	LPNAME2	Dimen: --- Format: char*2	Double letter, used to create LP var & row names
D	LPNAME2	Dimen: --- Format: char*1	Single blank. used to create LP var & row names
DD	LPNAME2	Dimen: --- Format: char*2	Double blank, used to create LP var & row names
DELFLG	CEMEXP03	Dimen: --- Format: logical	Flag indicating use of pt incr on str expan crv
DELFLG_CAP	CEMEXP03	Dimen: --- Format: logical	Flag indicating use of pr incr on cap expan crv
DELPR_CAP	CEMEX02	Dimen: --- Format: Real*4	Price incr on steps 2+ on cap expan crv
DELPR_STR	CEMEX02	Dimen: --- Format: Real*4	Price nicr on steps 2+ on str expan crv
DMDFLAG_I	LPDTAR1	Dimen: nngreg Format: logical	Flag to check constant demand- noncore (interruptible service) industrial
DMDPR_I	LPDTAR1	Dimen: nngreg	Dtar lower bound-noncore (inter. service) ind
DTAR_CHK	LPDTAR1	Dimen: nngreg	1991 Dtar for firm transp
EFF_STR	LPCAP1	Dimen: --- Units: fraction	Storage eff (1-loss)
EHISYR	NGMAPS	Dimen: --- Format: integer*4	End year for historical overwrites Must be >= FHISYR and <= LHISYR
EMMSUB	NGMAPS	Dimen: NNGREG,NEMMREG Units: ---	NGTDM/EMM subreg. given NGTDM & EMM reg
EMMSUB_EL	NGMAPS	Dimen: NEMMSUB Units: ---	EMM reg mapped into NGTDM/EMM subreg
EMMSUB_NG	NGMAPS	Dimen: NEMMSUB Units: ---	NGTDM reg mapped into NGTDM/EMM subreg
EPHASE	LPDTAR1	Format: integer*4	End phase year

INCLUDE (NGTDMLOC)

Variable	Common Name	Characteristics	Definition
EXAFM	MODUL	Dimen: --- Format: logical	Not used: Flag to indicate that the AFM module is turned on
EXCEM	MODUL	Dimen: --- Format: logical	Not used: Flag to indicate that the CEM module is turned on
EXPTM	MODUL	Dimen: --- Format: logical	Not used: Flag to indicate that the PTM module is turned on
FTAX	LPDTAR1	Dimen: ----	Federal tax
IYRSWT	NGMAPS	Dimen: 40 Units: ---	Used to determine (1,CEMN) array position corresponding to current year CEM expansion results
LAGPR_NF	MODUL	Dimen: NONUSEC,NGTDM Format: real*4	Used to store firm non-utility price from last iteration/year($87mcf)
LAGPR_NI	MODUL	Dimen: NONUSEC,NGTDM Format: real*4	Used to store interruptible non-utility price from last iteration/year($87mcf)
LAGPR_UF	MODUL	Dimen: NONUSEC,NGTDM Format: real*4	Used to store firm utility price from last iteration/year ($87mcf)
LAGPR_UI	MODUL	Dimen: NONUSEC,NGTDM Format: real*4	Used to store interruptible utility price from last iteration/year ($87mcf)
LAST_TIME	TIMING	Dimen: ----	Timing variable for NGTDM code
LPRC_MAX		Units: ---- Format: integer*4	Maximum number of lagged price adjusted levels
LPRC_SBADJ	NGPRDCRV	Dimen: lprc_max	Phased portion of base mult.
LPRC_SBASE	NGPRDCRV	Dimen: lprc_max	Base multiplier of lag price
LPRC_SYEAR	NGPRDCRV	Dimen: lprc_max	Year of lag price adjst level
MD	LPNAME2	Dimen: --- Format: char*2	Double letter, used to create LP var & row names
MINBIOF	MINFLOW	Dimen: 25 Units: Bcf	Min Bi-flow for CEM Off-PK firm
MINBIOI	MINFLOW	Dimen: 25 Units: Bcf	Min Bi-flow for CEM Off-PK interrup.
MINBIPF	MINFLOW	Dimen: 25 Units: Bcf	Min Bi-flow for CEM PK firm

INCLUDE (NGTDMLOC)			
Variable	**Common Name**	**Characteristics**	**Definition**
MINBIPI	MINFLOW	Dimen: 25 Units: Bcf	Min Bi-flow for PK interrup.
MN	LPNAME2	Dimen: --- Format: char*2	Double letter, used to create LP var & row names
MODYR	NGMAPS	Dimen: --- Units: ---	Current model year (i.e., 1990)
MS	LPNAME2	Dimen: --- Format: char*2	Double letter, used to create LP var & row names
NARC_CYCLE	FARCS	Dimen: --- Units: ---	Number of arcs defined as bidirectional flows
NEFF_PIPE	FSEC1	Dimen: NONUSEC,NGTDM Units: fraction	Eff along arc to nonutil sector
NETSTR_F	LPCAP1	Dimen: NNGREG,CEMN Units: Bcf	Net withdrawals from storage--firm
NETSTR_I	LPCAP1	Dimen: NNGREG,CEMN Units: Bcf	Net withdrawals from storage--interrup.
NEWFLOOR_I	LPDTAR1	Dimen: nngreg	Lower bound on price-noncore (inter. svc.) ind
NG_ARCMAP	LPMAPS	Dimen: NGTDM,JARC Units: ---	Node ID mapped into each NGTDM reg
NG_ARCNUM	LPMAPS	Dimen: NGTDM Units: ---	# of arcs into each NGTDM reg
NG_BKSTOP_PR	EXPNEW	Dimen: --- Units: 87$/mcf	NG sup backstop price
NG_CENMAP	LPMAPS	Dimen: NGTDM Units: ---	CENSUS reg ID mapped into each NGTDM reg
NG_EMMMAP	LPMAPS	Dimen: NGTDM,JUTIL Units: ---	EMM reg ID mapped into each NGTDM reg
NG_EMMSUB	LPMAPS	Dimen: NGTDM Units: ---	# of NGTDM/EMM subreg per NGTDM reg
NG_SUPMAP	LPMAPS	Dimen: NSUPTYP,NGTDM,JSUP Units: ---	OGSM reg ID mapped into each NGTDM reg
NG_SUPSUB	LPMAPS	Dimen: NSUPTYP,NGTDM Units: ---	# of NGTDM/OGSM subreg per NGTDM reg

INCLUDE (NGTDMLOC)			
Variable	**Common Name**	**Characteristics**	**Definition**
NGHIST_FLG	NGMAPS	Dimen: — Units: —	Flag indicating hist overwrite: 0=NO, 1=YES
NGRATMAX	DTARAFM	Dimen: NEMMSUB Units: —	Max NG discount rate off of alternate fuel
NGUNIT	NGTRAC	Dimen: — Units: —	Output unit # for NGTDM writes
NGWRITE	NGTRAC	Dimen: — Units: —	NGTDM trace write level indicator
NONU_DTAR_F	LPDTAR1	Dimen: NONUSEC,NGTDM Units: 87$/mcf	Distributor tar to core (firm service) nonutil sec
NONU_DTAR_I	LPDTAR1	Dimen: NONUSEC,NGTDM Units: 87$/mcf	Distributor tar to noncore (interrup. service) nonutil sec
NONU_ELAS_F	NGDMDCRV	Dimen: — Format: real*4	Core (Firm service) nonutil demand curve elasticities
NONU_ELAS_I	NGDMDCRV	Dimen: NONUSEC Format: real*4	Inter.non-utility demand curve elasticities
NSDOMREG		Units: --- Format: integer*4	# of domestic supply regions
NUM	LPNAME2	Dimen: 9 Format: char*1	Numbers 1-9, used to create LP var & row names
OCSMAP	NGMAPS	Dimen: NOCSREG Units: ---	Mapping of NGTDM/OGSM subreg into off-shore production regions
OILPRD89	NGADGPRD1	Dimen: nsdomreg	1989 oil prod onshore & offshore
PARM_MAXPR	NGPRDCRV	Format: real*4	Params to set max prod. level
PARM_MINPR	NGDMDCRV	Dimen: Format: real*4	Parameter to set minimum production level
PARM_MINSUP	NGPRDCRV	Dimen: 2	Params to set min prod. level
PARM_SUPCRV2	NGPRDCRV	Dimen: 2	Params defining supcrv 2
PARM_SUPCRV3	NGPRDCRV	Dimen: 2	Params defining supcrv 3
PCAP_AFM	PTARAFM	Dimen: NGTDM,NGTDM Units: Bcf	Physical cap along arc in AFM, t-1.

INCLUDE (NGTDMLOC)			
Variable	**Common Name**	**Characteristics**	**Definition**
PCAP_ANGTS	CAPANGTS	Dimen: MNUMYR Format: real*4	Maximu ANGTS capacity along arc 18-9
PCAP_MAX	PTARAFM	Dimen: NGTDM,NGTDM,CEMN Units: Bcf	Maximum physical cap along arc
PCT_XCAP	PTARAFM	Dimen: --- Units: fraction	Percent excess capacity on pipe
PDELMX	LPSTEP2	Dimen: --- Units: 87$/mcf	Max price delta off base price--LP supply and demand curve
PMMMAP_NG	NGMAPS	Dimen: NSUPSUB Units: ---	PADD reg mapped into NGTDM/OGSM subreg
PNEW_CAP	FFCAP	Dimen: NGTDM,NGTDM Units: Bcf	New physical capacity
PNEW_STR	LPCAP1	Dimen: NNGREG Units: Bcf	New storage added/built
PSHIFTOF	NGPRDCRV	Dimen: NSUPSUB, IBASYR:IENDYT Format: real*4	Shift offshore prodution function on pricce axis.
PSHIFTON	NGPRDCRV	Dimen: NSUPSUB, IBASYR:IENDYT Format: real*4	Shift onshore prodution function on pricce axis
PSSTEP	LPSTEP2	Dimen: NSSTEP Units: ---	Number of steps on LP supply curve
PSTR_MAX	PTARAFM	Dimen: NNGREG,CEMN Units: Bcf	Maximum annual storage available
PTAR_COM_F	PTARAFM	Dimen: NGTDM,NGTDM Units: 87$/mcf	Firm service pipeline commodity charge
PTAR_F	PTARAFM	Dimen: NGTDM,NGTDM Units: 87$/mcf	Interregional pipeline tariffs for firm service
PTAR_I	PTARAFM	Dimen: NGTDM,NGTDM Units: 87$/mcf	Interregional pipeline tariffs for interrup.
PTAR_IMAX	PTMVARX	Dimen: NGTDM,NGTDM Units: 87$/mcf	Max pipe tariff allowed for noncore (interrup. service) market
PTAR_REV_F	PTARAFM	Dimen: NGTDM,NGTDM Units: 87$	Firm service pipeline revenue requirements
Q1	LPNAME2	Dimen: --- Format: char*1	Single letter, used to create LP var & row names

INCLUDE (NGTDMLOC)

Variable	Common Name	Characteristics	Definition
QALK_NONU_F	QPALK1	Dimen: NONUSEC Units: Bcf	Alaska core (firm service) nonutil dmd
QALK_NONU_I	QPALK1	Dimen: NONUSEC Units: Bcf	Alaska noncore (interrup. service) nonutil dmd
REGNUM	LPNAME2	Dimen: NGTDM Format: char*2	NGTDM region num (01-21)
ROWNAM	LPMTRX2	Dimen: --- Format: char*8	LP row name sent to OML
SEC	LPNAME2	Dimen: NONUSEC Format: char*1	Nonutil sec ID (R,C,I,T), used to create LP var & row names
SEFF_PIPE	FOTHER	Dimen: NGTDM,JSUP Units: fraction	Eff along arc from sup
SOLN	LPARG	Dimen: 5 Units: ---	Real*8 Variable to hold info retrieved from LP via OML
STAT	LPMTRX2	Dimen: --- Format: char*2	LP variable status indicator from OML
STAX	LPDTAR1	Dimen: ngtdm	State tax
STPHASE	LPDTAR1	Format: integer*4	Start phasing-firm transp.
SUP_ID	LPNAME2	Dimen: NSUPTYP,9 Format: char*2	NG supply type code
SUP_MAX	FOTHER	Dimen: NSUPTYP,NGTDM,JSUP Units: Bcf	Max supply prod level
SUP_PR	NGXFXI2	Dimen: NSUPTYP,NGTDM,JSUP Units: 87$/mcf	Resulting supply price from LP soln
SUPSUB	NGMAPS	Dimen: NNGREG,NSUPREG Units: ---	NGTDM/OGSM subreg, given NGTDM & OGSM reg
SUPSUB_NG	NGMAPS	Dimen: NSUPSUB Units: ---	NGTDM reg mapped into NGTDM/OGSM subreg
SUPSUB_OG	NGMAPS	Dimen: NSUPSUB Units: ---	OGSM reg mapped into NGTDM/OGSM subreg
SUPWITR	NGMAPS	Format: char*4	Iterations to write out supply curve parameters

INCLUDE (NGTDMLOC)

Variable	Common Name	Characteristics	Definition
SUPWRYR	NGMAPS	Format: integer*4	Year to start writing supply curve parameters
TFLOOR	LPDTAR1	Dimen: ngtdm Format: integer*4	Dtariff lower bound for firm transportation
TPD1	LPDTAR1	Dimen: ngtdm	User specified % discount
TPD2	LPDTAR1	Dimen: ngtdm	Alt user specified % discount
TPD2YR	LPDTAR1	Dimen: ngtdm	Year switch
TYP_SUPCRV	NGPRDCRV	Dimen: ---- Format: integer*4	Supply curve functional form 1-orig est.,2-"gams",3-3 tier
U1	LPNAME2	Dimen: --- Format: char*1	Single letter, used to create LP var & row names
UBENCH	DTARAFM	Dimen: NEMMSUB Units: 87$/mcf	Benchmarking adj for utilities
UDFLOOR	DTARAFM	Dimen: NEMMSUB Units: 87$/mcf	Lower bound on distributor markup
UDPD1	DTARAFM	Dimen: NEMMSUB Units: fraction	Percent discount off alt. fuel price
UDPD2	DTARAFM	Dimen: NEMMSUB Units: ---	Alt. User % discount off alt. fuel price
UDPD2YR	DTARAFM	Dimen: NEMMSUB Units: ---	Year switch for % discount off alt. fuel price
UEFF_PIPE	FSEC1	Dimen: NGTDM,JUTIL Units: fraction	Eff along arc to util sector
UNERR	NGTRAC	Dimen: --- Units: ---	Output unit # for error writes
URNUM	MODUL	Dimen: Format: integer*4	Input file unit number: contains module specific info to be read when NGTDM modul is turned off
UTIL_DTAR_ID	DTARAFM	Dimen: NGTDM,JUTIL Units: 87$/mcf	Competitive distillate price
UTIL_DTAR_IR	DTARAFM	Dimen: NGTDM,JUTIL Units: 87$/mcf	Competitive resid PR

INCLUDE (NGTDMLOC)			
Variable	**Common Name**	**Characteristics**	**Definition**
UTIL_ELAS_F	NGDMDCRV	Dimen: NONUSEC Format:	Firm utility demand curve elasticity
UTIL_ELAS_I	NGDMDCRV	Dimen: NONUSEC Format:	Inter utility demand curve elasticity
UWNUM	MODUL	Dimen: Format: integer*4	Output file unit number: module specific info is written for use when NGTDM module is turned off
VARNAM	LPMTRX2	Dimen: — Format: char*8	LP variable name sent to OML
WGCNT	PFRCEM	Dimen: NNGREG Units: Bcf	Non-jurisdictional WGCT
WGCT	PFRCEM	Dimen: NNGREG Units: Bcf	Working gas capacity at node
WTHR_XCAP	PTARAFM	Dimen: NGTDM,NGTDM Units: fraction	Percent excess capacity on pipe
XSPRNT	LPMTRX2	Dimen: — Format: char*8	LP solution print indicator for OML

INCLUDE (NGTDMOUT)

Variable	Common Name	Characteristics	Definition
CLSYNGWP	NGTDMOUT	Dimen: 17,MNUMYR Units: 87$/MMBtu	Price of synthetic NG from coal
OGPRDNGOF	NGTDMOUT	Dimen: 3,MNUMYR Units: Bcf	NA dry gas prod offshore
OGPRDNGON	NGTDMOUT	Dimen: 17,MNUMYR Units: Bcf	NA dry gas prod onshore
PGCELGR	NGTDMOUT	Dimen: 21,MNUMYR Units: 87$/MMBtu	Util competitive NG price
PGFELGR	NGTDMOUT	Dimen: 21,MNUMYR Units: 87$/MMBtu	Util core (firm service) NG price
PGIELGR	NGTDMOUT	Dimen: 21,MNUMYR Units: 87$/MMBtu	Util noncore (interrupt service) NG price
PRNG_PADD	NGTDMOUT	Dimen: MNUMPR,MNUMYR Units: Bcf	Tot dry gas production (w/ lease & plant)
MNPERCNT	TMPSUP	Dimen: --- Units: fraction	Min % delta off base price for supply curve
SUPMULT	TMPSUP	Dimen: NSSTEP Units: fraction	% off of base supply price
WTPERCNT	TMPSUP	Dimen: --- Units: fraction	Relaxation % on last supply price
Equivalence for FILER used for data storage			
REAL EQ_NTOUT(MNUMYR*(3*21+2*17+3+MNUMPR))			
EQUIVALENCE (EQ_NTOUT,OGPRDNGON)			
Equivalence for MAIN to test convergence on natural gas to util			
REAL MUPRC(21,MNUMYR,3)			
EQUIVALENCE(MUPRC,PGFELGR)			

INCLUDE (NGTDMPTM)			
Variable	Common Name	Characteristics	Definition
A191END	TRANSC	Format: INTEGER	Year to end collecting acct. 191 costs
A191START	TRANSC	Format: INTEGER	Year to start collecting acct. 191 costs
A191YRS	TRANSC	Format: INTEGER	Num. years acct 191 costs are collected
A2P -- not used	CURVE	Dimen: NGTDM,NGTDM Units: ---	Arc to pipeline conversion
ADDA	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Accumulated DDA costs
ADIT	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Accumulated deferred income taxes
ADIT_C	PCOST	Dimen: MAX_PIPE Units: Nominal $	Constant for forecasting equation
ADIT_TEMP	TRANSC	Dimen: 2,9	Temp. var for ADIT equation
AFR	WITHIN	Dimen: MAX_DESIGN,MAX_ITEM Units: fraction	Alloc. of fixed cost to res.
AFU	WITHIN	Dimen: MAX_DESIGN,MAX_ITEM Units: fraction	Alloc. of fixed cost to usage
AGSRCOSTS	TRANSC	Units: MAX_PIPE	GSR costs by arc
ANUM191	TRANSC	Units: MAX_PIPE	191 transition costs by arc
ARC2P	CURVE	Dimen: NGTDM,NGTDM Units: ---	Arc to pipeline conversion
ARCCC	CURVE	Dimen: NGTDM,NGTDM,MAX_STEPS Units: 87$/mcf-mile	Arc capital cost size
ARCEX	CURVE	Dimen: NGTDM,NGTDM,MAX_STEPS Units: Bcf	Arc expansion size
ARCFAC	CURVE	Dimen: NGTDM,NGTDM,MAX_STEPS Units: fraction	Arc capacity expansion factor
ARCUSED	CURVE	Dimen: NGTDM,NGTDM,MAX_STEPS Units: Bcf	New pipeline capacity already added
ARF	WITHIN	Dimen: MAX_DESIGN,MAX_ITEM Units: fraction	Alloc. of fixed cost
ARV	WITHIN	Dimen: MAX_DESIGN,MAX_ITEM Units: fraction	Alloc. of variable cost

INCLUDE (NGTDMPTM)

Variable	Common Name	Characteristics	Definition
ASF	WITHIN	Dimen: MAX_DESIGN,MAX_ITEM Units: fraction	Alloc. of fixed storage cost
ASV	WITHIN	Dimen: MAX_DESIGN,MAX_ITEM Units: fraction	Alloc. of var. storage cost
AVR	WITHIN	Dimen: MAX_DESIGN,MAX_ITEM Units: fraction	Alloc. of var. cost to res.
AVU	WITHIN	Dimen: MAX_DESIGN,MAX_ITEM Units: fraction	Alloc. of var. cost to usage
BASERADJ	TRANSC	Format: real*4	Adj factor for discounting in base year
BG2WG	WITHIN	Dimen: NNGREG Units: fraction	Base gas to working gas ratio (juris)
BG2WGN	WITHIN	Dimen: NNGREG Units: fraction	Base gas to working gas ratio (non-juris)
BLAE	PCOST	Dimen: --- Units: Nominal $	Capital expenditures associated with base year capacity (refurbishment/replacement exp) dollars
CAPCST	PCOST	Dimen: MAX_PIPE, MAX_CT,MAX_STEPS Units: 87$/Bcf	Total capital cost at each arc (historical avg)
CMES	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Value of common stock equity in dollars
CONDEM	READCD	Dimen: NGTDM,NGTDM Units: Bcf	Peak-day res. Firm tran, base year
COST	WITHIN	Dimen: 2,MAX_ITEM Units: Nominal $	Indiv. cost of service
CRATE	PCOST	Dimen: 3 Units: fraction	Rate of return array
CSOML	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Compressor station op and maint labor expense
CSOMN	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Compressor station op and maint nonlabor exp.
CTOT	PCOST	Dimen: 2 Units: Bcf	Total u.S. Capacity

INCLUDE (NGTDMPTM)

Variable	Common Name	Characteristics	Definition
CWC	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Cash working capital
DBGRPT	MISCC	Dimen: — Format: char*15	Debug report flag
DCMER	PCOST	Dimen: MAX_PIPE Units: fraction	Rate of return differential
DDA	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Depreciation, depletion, and amortization costs
DDA_C	PCOST	Dimen: MAX_PIPE Units: Nominal $	Constant for forecasting equation
DDA_TEMP	TRANSC	Dimen: 2,9	Temp. var for DDA equation
DISCNT_I	TRANSC	Format: real*4	Discount inter off maximum
DLTDR	PCOST	Dimen: MAX_PIPE Units: fraction	Rate of return debt (fraction) differential
FCR	WITHIN	Dimen: MAX_STEPS,NGTDM,NGTDM Units: Nominal $	Fixed res. cost
FCS	WITHIN	Dimen: MAX_STEPS,NNGREG Units: Nominal $	Fixed storage cost
FCU	WITHIN	Dimen: MAX_STEPS,NGTDM,NGTDM Units: Nominal $	Fixed usage cost
FRATE	TRANSC	Format: real*4 Units: fraction	Federal income tax rate
FSERV	PFRAFM	Dimen: NGTDM,NGTDM Units: Bcf/yr	Annual throughput volume for firm transportation
FSITC	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Federal and state investment tax credits
GCMER	TRANSC	Format: real*4	CMER for gen. pipe company
GLTDR	TRANSC	Format: real*4	LTDR for gen. pipe company
GPFER	TRANSC	Format: real*4	PFER for gen. pipe company
GPIS	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Gross plant in service
GSREND	TRANSC	Format: INTEGER	Year to end collecting GSR costs

INCLUDE (NGTDMPTM)

Variable	Common Name	Characteristics	Definition
GSRSTART	TRANSC	Format: INTEGER	Year to start collecting GSR costs
GSRYRS	TRANSC	Format: INTEGER	# years GSR costs are collected
IEXPCT	TRANSC	Format: real*4	Expected rate of growth in int. transp. service
ISERV	PFRAFM	Dimen: NGTDM,NGTDM Units: Bcf/yr	Annual throughput volume for interrup. Trans.
KARCEX	TRANSC	Dimen: MAX_STEPS Format: real*4	Arc expansion steps at Kern river (8->12)
KCMER	TRANSC	Format: real*4	CMER for Kern river(8->12)
KLTDR	TRANSC	Format: real*4	LTDR for Kern river (8->12)
LFAC	TRANSC	Format: real*4	Load factor for deriving max int. rate
LIMITFIRM	TRANSC	Format: real*4	Max limit set for firm tariff
LIMITINT	TRANSC	Format: real*4	Max limit set for inter tariff
LTD	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Value of long-term debt in dollars
MATRIX	WITHIN	Dimen: MAX_PIPE,MNUMYR Units: ---	Rate design specification
MAX	PTOAFM	Dimen: NGTDM,NGTDM Units: 87$/mcf	Maximum rate for interruptible service
MAXDISC_I	TRANSC	Format: real*4	Max allowable discount for inter transp. service
MAXESC	TRANSC	Format: real*4	Maximum allowable escalation rate for tariff
MAXPID	MISCN	Dimen: --- Units: ---	Maximum valid pipelines used
MILES	READCD	Dimen: NGTDM,NGTDM Units: miles	Length of an arc
MIN	PTOAFM	Dimen: NGTDM,NGTDM Units: 87$/mcf	Minimum rate for interruptible service
NEWCOST_PER	TRANSC	Format: INTEGER	# years new fac. costs are collected
NEWCOSTEND	TRANSC	Format: INTEGER	Year to end collecting new fac. costs

INCLUDE (NGTDMPTM)

Variable	Common Name	Characteristics	Definition
NEWCOSTSTART	TRANSC	Format: INTEGER	Year to start collecting new fac. costs
NODECC	CURVE	Dimen: NNGREG,MAX_STEPS Units: 87$	Capital cost for node
NODEEX	CURVE	Dimen: NNGREG,MAX_STEPS Units: Bcf	Node expansion size
NODFAC	CURVE	Dimen: NNGREG,MAX_STEPS Units: fraction	Node capacity expansion factor
NODUSED	CURVE	Dimen: NNGREG,MAX_STEPS Units: Bcf	New storage already expanded
NS	FUTURE	Dimen: MAX_PIPE,NNGREG Units: fraction	Node shares
OTOM	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Other operations and maintenance expense
OTTAX	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	All other taxes except income taxes
OWC	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Other working capital
OWC_C	PCOST	Dimen: MAX_PIPE Units: Nominal $	Constant for forecasting equation
OWC_TEMP	TRANSC	Dimen: 2,9	Temp. var for OWC equation
PCOST	NGTDMPTM	Dimen: MAX_PIPE Units: fraction	Rate of return on preferred stock
P2AF -- not used	CURVE	Dimen: MAX_PIPE Units: ---	Pipeline to arc conversion
P2ARCF	CURVE	Dimen: MAX_PIPE Units: ---	Pipeline to arc conversion
P2ARCT	CURVE	Dimen: MAX_PIPE Units: ---	Pipeline to arc to conversion
P2AT -- not used	CURVE	Dimen: MAX_PIPE Units: ---	Pipeline to arc to conversion
PCMER	PCOST	Dimen: MAX_PIPE Units: fraction	Rate of return common stock equity

INCLUDE (NGTDMPTM)

Variable	Common Name	Characteristics	Definition
PFES	PCOST	Dimen: MAX_PIPE, MAX_PT,MAX_CT Units: Nominal $	Value of preferred stock in dollars
PGSRCOSTS	TRANSC	Units: MAX_PIPE Format: REAL*4	GSR costs based on ind. pipe company
PID	MISCN	Dimen: MAX_PIPE Units: ---	Pipeline ID number, 4 digits
PIPEEXP	WITHIN	Dimen: NGTDM,NGTDM Units: Bcf	Pipeline capacity expansion passed from cem
PLTDR	PCOST	Dimen: MAX_PIPE Units: fraction	Rate of return debt
PNAME	MISCC	Dimen: MAX_PIPE Format: char*32	Pipeline name
PNEWFAC	TRANSC	Units: MAX_PIPE	New facilities cost based on ind. pipe company
PNUM191	TRANSC	Units: MAX_PIPE Format: REAL*4	191 transition costs, by pipe company
PFER	PCOST	Dimen: MAX_PIPE Units: fraction	Rate of return preferred stock
PRESV	READCD	Dimen: NGTDM,NGTDM Units: Bcf	Peak-day res. Firm tran, adjusted with CAPEXP
PREV_COM_F	PREVIO	Dimen: NGTDM,NGTDM Units: 87$/mcf	Previous year's commodity charge
PREV_IMAX	PREVIO	Dimen: NGTDM,NGTDM Units: 87$/mcf	Previous year's maximum interrup. Tariff
PREV_REV_F	PREVIO	Dimen: NGTDM,NGTDM Units: 87$/mcf	Previous year's usage charge
PREV_STAR	PREVIO	Dimen: NNGREG Units: 87$/mcf	Previous year's storage tariff
PREVPIPE	WITHIN	Dimen: NGTDM,NGTDM Units: Bcf	Pipeline capacity expansion passed from cem
PREVPSTR	WITHIN	Dimen: NNGREG Units: Bcf.	Storage node expansion (juris+non juris.)
PRTRPT--not used	MISCN	Dimen: --- Units: ---	Print debug routines

INCLUDE (NGTDMPTM)

Variable	Common Name	Characteristics	Definition
PS	FUTURE	Dimen: MAX_PIPE,NGTDM,NGTDM Units: fraction	Pipeline shares
PSTRANDED	TRANSC	Units: MAX_PIPE	Stranded cost based on ind. pipe company
PTAR_191_F	TRANSC	Units: MAX_PIPE	Firm tariff based on 191 cost
PTAR_GSR_F	TRANSC	Units: MAX_PIPE	Firm tariff based on GSR cost
PTAR_GSR_I	TRANSC	Units: MAX_PIPE	Int. tariff based on GSR cost
PTMYR	PFRAFM	Dimen: — Units: —	Like CEMYR--used to determine array position of current year CEM expansion info
REVC	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Revenue credits to cost-of-service
RFEE	PTOAFM	Dimen: NGTDM,NGTDM Units: 87$/mcf	Reservation fee for core (firm service) cust
RFR	WITHIN	Dimen: MAX_ITEM Units: Nominal $	Fixed reservation cost
RFU	WITHIN	Dimen: MAX_ITEM Units: Nominal $	Fixed usage cost
RVR	WITHIN	Dimen: MAX_ITEM Units: Nominal $	Variable reservation cost
RVU	WITHIN	Dimen: MAX_ITEM Units: Nominal $	Variable usage cost
SCALE_F	TRANSC	Format: real*4	Scale for firm
SEOM	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Supervision and engineering expense
SF	WITHIN	Dimen: MAX_ITEM Units: Nominal $	Fixed storage cost
SGCOST--not used	FUTURE	Dimen: NNGREG,MAX_ITEM Units:	Generic pipeline company stor. Line item cost
SHARE_GSR_F	TRANSC	Format: real*4	Fraction of GSR transition cost to firm
SHARE_GSR_I	TRANSC	Format: real*4	Fraction of GSR transition cost to int.

INCLUDE (NGTDMPTM)			
Variable	**Common Name**	**Characteristics**	**Definition**
SHISEXP	CURVE	Dimen: NNGREG Units: Bcf	Historical storage expansion
SRATE	TRANSC	Units: fraction Format: real*4	Average state income tax rate
STAR	PTOCEM	Dimen: NNGREG Units: 87$/mcf	Storage Tariffs
STOT	PCOST	Dimen: 20 Units: Nominal $	Total u.S. Storage cost by line item
SV	WITHIN	Dimen: MAX_ITEM Units: Nominal $	Variable storage cost
TAG	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Total administrative and general expense
TAG_C	PCOST	Dimen: MAX_PIPE Units: Nominal $	Constant for forecasting equation
TAG_TEMP	TRANSC	Dimen: 2,9	Temp. var for TAG equation
TCE	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Total customer expense
TGCOST--not used	FUTURE	Dimen: NGTDM,NGTDM,MAX_ITEM Units:	Generic pipeline company trans. Line item cost
THISEXP	CURVE	Dimen: NGTDM,NGTDM Units: Bcf	Historical pipeline expansion
TOM	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Total operations and maintenance expense
TOM_C	PCOST	Dimen: MAX_PIPE Units: Nominal $	Constant for forecasting equation
TOM_TEMP	TRANSC	Dimen: 2,9	Temp. var for TOM equation
TOTAEX	CURVE	Dimen: NGTDM,NGTDM Units: ---	Number of expansions in an arc
TOTARC	CURVE	Dimen: --- Units: ---	Total number of valid pipeline arc
TOTNEX	CURVE	Dimen: NNGREG Units: ---	Number of expansions in a node

INCLUDE (NGTDMPTM)			
Variable	**Common Name**	**Characteristics**	**Definition**
TPEB	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Transition expense balance
TTOT	PCOST	Dimen: 20 Units: Nominal $	Total u.S. Transportation cost by line item
UFEE	PTOAFM	Dimen: NGTDM,NGTDM Units: 87$/mcf	Usage fee for firm service
VCR	WITHIN	Dimen: MAX_STEPS,NGTDM,NGTDM Units: Nominal $	Variable res. cost
VCS	WITHIN	Dimen: MAX_STEPS,NNGREG Units: Nominal $	Variable storage cost
VCU	WITHIN	Dimen: MAX_STEPS,NGTDM,NGTDM Units: Nominal $	Variable usage cost
WGCNTEXP	WITHIN	Dimen: NNGREG Units: Bcf	Storage node expansion (non-juris)
WGCTEXP	WITHIN	Dimen: NNGREG Units: Bcf	Storage node expansion (juris)
WGN2WG	WITHIN	Dimen: NNGREG Units: fraction	Working gas (nj) to working gas ration

INCLUDE (NGTDMREP)

Variable	Common Name	Characteristics	Definition
NGPIPCAP	NGTDMREP	Dimen: 2,MNUMYR Units: Bcf	NG pipeline capacity--national
NGSTRCAP	NGTDMREP	Dimen: 24,MNUMYR Units: Bcf	NG undergnd storage capacity
OGIMCAN	NGTDMREP	Dimen: MNUMYR Units: Bcf	Net imports of Can pipe NG
OGIMLNG	NGTDMREP	Dimen: MNUMYR Units: Bcf	Net imports of LNG
OGIMMEX	NGTDMREP	Dimen: MNUMYR Units: Bcf	Net imports of Mex pipe NG
OGIMNGP	NGTDMREP	Dimen: MNUMYR Units: Bcf	Net imports of pipeline NG
OGPRDNG	NGTDMREP	Dimen: MNUMOR,MNUMYR Units: Bcf	Domestic dry NG prod
OGPRSUP	NGTDMREP	Dimen: MNUMYR Units: Bcf	Total supplemental gas (synthetic + other)
OGPRSUP3	NGTDMREP	Dimen: 3,MNUMYR Units: Bcf	Supplemental NG subcategories
OGWPRNG	NGTDMREP	Dimen: MNUMOR,MNUMYR Units: 87$/mcf	NG wellhead price

Equivalence for/FILER used for data storage

```
REAL EQ_NTREP(2*MNUMOR*MNUMYR+34*MNUMYR)
EQUIVALENCE (EQ_NTREP,OGWPRNG)
```

INCLUDE (NGTEMP)			
Variable	**Common Name**	**Characteristics**	**Definitions**
MINRCOV	AFMTEMP	Dimen: --- Units: fraction	Minimum percent coverage of cost
RETAIL_COST	AFMTEMP	Dimen: --- Units: 87$/mcf	Retail cost
STOTL48	AFMTEMP	Dimen: 1990:2010 Units: BCF	Total supply for the lower 48 (non-associate + associated dissolve + lease & plant)

INCLUDE (NXAFMDAT)

Variable	Common Name	Characteristics	Definitions
AK_C	NGAFMDAT1	Dimen: 3 Units: ---	Estimated coeff used to determine AK consump/ prod levels
AK_CM	NGAFMDAT1	Dimen: --- Units: 87$/mcf	Wellhead to end-use markups--commercial sec
AK_CN	NGAFMDAT1	Dimen: IBASYR:IENDYR Units: 1000 people	Number of commercial customers
AK_D	NGAFMDAT1	Dimen: 3 Units: ---	Estimated coeff used to determine AK consump/ prod levels
AK_E	NGAFMDAT1	Dimen: 3 Units: ---	Estimated coeff used to determine AK consump/ prod levels
AK_EM	NGAFMDAT1	Dimen: --- Units: 87$/mcf	Wellhead to end-use markups--electric generators sec
AK_F	NGAFMDAT1	Dimen: 3 Units: ---	Estimated coeff used to determine AK consump/ prod levels
AK_G	NGAFMDAT1	Dimen: 3 Units: ---	Estimated coeff used to determine AK consump/ prod levels
AK_PCTLSE	NGAFMDAT1	Dimen: 3 Units: fraction	Lease fuel/dry prod (S&N&A)
AK_PCTPIP	NGAFMDAT1	Dimen: 3 Units: fraction	Pipe fuel /dry prod (S&N&A)
AK_PCTPLT	NGAFMDAT1	Dimen: 3 Units: fraction	Plant fuel/dry prod (S&N&A)
AK_PCTSOUTH	NGAFMDAT1	Dimen: 5 Units: fraction	Percent of AK demand in South AK
AK_RM	NGAFMDAT1	Dimen: --- Units: 87$/mcf	Wellhead to end-use markups--residential sec
AK_RN	NGAFMDAT1	Dimen: IBASYR:IENDYR Units: 1000 people	Number of residential customers
ANGTS_TAR	NGAFMDAT1	Dimen: --- Units: 87$/mcf	Price markup for gas moved on ANGTS
CANFRMITR_SHR	NGAFMDAT1	Dimen: NCAN Units: fraction	Firm share--Canadian exports
CN_BRDPRC90	NGAFMDAT1	Dimen: NCAN Units: 87$/mcf	Starting border crossing price 1990

INCLUDE (NXAFMDAT)			
Variable	**Common Name**	**Characteristics**	**Definitions**
CN_NEWCAP90	NGAFMDAT1	Dimen: NCAN Units: Bcf	New pipe capacity in 1990
CN_WELPRC89	NGAFMDAT1	Dimen: --- Units: 87$/mcf	Canadian wellhead price in 1989
DEFPRICE	NGAFMDAT1	Dimen: --- Units: 87$/mcf	Default price if qty=0, any sector
EMISRAT	NGAFMDAT1	Dimen: MNPOLLUT Units: 1000 lb/Bcf	Emissions as percent of pipe fuel
MAXPROF	NGAFMDAT1	Dimen: NOCSREG Units: fraction	Maximum P/R ratio for offshore
MAXPRON	NGAFMDAT1	Dimen: NSUPREG Units: fraction	Maximum P/R ratio for onshore
MEXFRMITR_SHR	NGAFMDAT1	Dimen: NMEX Units: fraction	Share of Mexican exports to firm
NG_CENSHR	NGAFMDAT1	Dimen: NONUSEC,NNGREG Units: fraction	Shares to split census to NGTDM
OSUP_HVAL	NGAFMDAT1	Dimen: IBASYR:1991 Units: Bcf	Historical value for other supplemental supplies
OSUP_RSHR	NGAFMDAT1	Dimen: 7 Units: fraction	Shares for setting reg values for other supplemental supplies
OSUP_TOT	NGAFMDAT1	Dimen: IBASYR:IENDYR Units: Bcf	Tot other supplemental supplies--forecast
SHR_AD17	NGAFMDAT1	Dimen: NSUPSUB Units: fraction	AD gas shares (1-17)
SNG89	NGAFMDAT1	Dimen: --- Units: Bcf	SNG prod fr liq in ILL in 1989
SNGA1	NGAFMDAT1	Dimen: --- Units: ---	Estimated parameter--used to determine SNG from liq.
SNGA2	NGAFMDAT1	Dimen: --- Units: ---	Estimated parameter--used to determine SNG from liq.
SNGHI	NGAFMDAT1	Dimen: --- Units: Bcf	SNG prod fr liq in Hawaii
SNGMIN	NGAFMDAT1	Dimen: --- Units: Bcf	Minimum SNG prod fr liq allowed ILL

INCLUDE (NXAFMDAT)			
Variable	**Common Name**	**Characteristics**	**Definitions**
WOP89	NGAFMDAT1	Dimen: --- Units: 87$/BBL	1989 world oil price
WPR89	NGAFMDAT1	Dimen: --- Units: 87$/mcf	1989 AK wellhead price

INCLUDE (NXTDMAFM)			
Variable	**Common Name**	**Characteristics**	**Definition**
ACAP_MIN_F	NGXFXI	Dimen: NGTDM,NGTDM Units: Bcf	Minimum flow along firm arc
ACAP_MIN_I	NGXFXI	Dimen: NGTDM,NGTDM Units: Bcf	Minimum flow along interrup arc
AD_FR_OIL	NGPERCENT	Dimen: 9,4 Units: ---	PARM1,PARM2,PARM3 in AD eq: ADG=PARM1*(OILPRD**PARM2) *(ADGLAG**PARM3)
ADGPRDOF	NGADGPRD	Dimen: NOCSREG Units: Bcf	AD gas production--offshore
AFM_TOL--not used	FMISC	Dimen: --- Units: ---	Supply tolerance for AFM conv check
APCT_MINF	NGXFXI	Dimen: NGTDM,NGTDM Units: fraction	Min flow as % of last yr along firm arc
APCT_MINI	NGXFXI	Dimen: NGTDM,NGTDM Units: fraction	Min flow as % of last yr along interrup arc
ASTORE	LPCAP	Dimen: NNGREG Units: Bcf-annual	Annual storage vol used
AXMAX --not used	NGMAXIT	Dimen: --- Units: ---	Max. # Of iterations for afm conv.
B1	LPNAME	Dimen: --- Format: char*1	Single letters, used to define LP matrix var
CANTAR_F	AFMNEW	Dimen: NCAN Units: 87$/mcf	Tar along firm arcs to Can nodes
CANTAR_I	AFMNEW	Dimen: NCAN Units: 87$/mcf	Tar along interrup arcs to Can nodes
CONST_DMD	LPDMD	Dimen: --- Units: ---	Indicator defining const dmd scenario
CONST_EXP	AFMNEW	Dimen: --- Units: ---	Indicator for constant exports
DDD	LPNAME	Dimen: --- Format: char*3	Three blanks, used to define LP matrix var
DDDD	LPNAME	Dimen: --- Format: char*4	Four blanks, used to define LP matrix var
DIST_TAR	AFMNEW	Dimen: --- Units: ---	Indicator for changing dist tar coeff

INCLUDE (NXTDMAFM)			
Variable	**Common Name**	**Characteristics**	**Definition**
DMD_TOL--not used	FMISC	Dimen: --- Units: ---	Dmd tolerance for conv check on tree
DXMAX--not used	NGMAXIT	Dimen: --- Units: ---	Max. # Of iterations for adjusting shares
E1	LPNAME	Dimen: --- Format: char*1	Single letters, used to define LP matrix var
F_BKSTOP	FNODE	Dimen: --- Units: Bcf	Tot backstop results for firm
F1	LPNAME	Dimen: --- Format: char*1	Single letters, used to define LP matrix var
FXMAX--not used	NGMAXIT	Dimen: --- Units: ---	Max. # Of iterations for firm conv.
HWPRLAGOF	NHLAGPRC	Dimen: NOCSREG,HISYR Units: 87$/Mcf	Wellhead price last year, offshore
HWPRLAGON	NHLAGPRC	Dimen: NSUPSUB,HISYR Units: 87$/Mcf	Wellhead price last year, onshore
I_BKSTOP	FNODE	Dimen: --- Units: Bcf	Tot backstop results for interrup.
I1	LPNAME	Dimen: --- Format: char*1	Single letters, used to define LP matrix var
ILAG	WELLPR	Dimen: --- Units: ---	# of lag years to estimate LNG
MEXEFF	AFMNEW	Dimen: NMEX Units: fraction	Eff along arcs to Mex nodes
MEXTAR_F	AFMNEW	Dimen: NMEX Units: 87$/mcf	Tar along firm arcs to Mex nodes
MEXTAR_I	AFMNEW	Dimen: NMEX Units: 87$/mcf	Tar along interrup arcs to Mex nodes
MF	LPNAME	Dimen: --- Format: char*2	Double letters, used to define LP matrix var
MI	LPNAME	Dimen: --- Format: char*2	Double letters, used to define LP matrix var.
MINXF	NGXCES	Dimen: NGTDM,NGTDM Units: Bcf	Minimum excess for firm capacity

INCLUDE (NXTDMAFM)			
Variable	**Common Name**	**Characteristics**	**Definition**
MINXI	NGXCES	Dimen: NGTDM,NGTDM Units: Bcf	Minimum excess for interrup. Cap.
MU--not used	FMISC	Dimen: --- Units: ---	Parameters used to reallocate shares
N1	LPNAME	Dimen: --- Format: char*1	Single letters, used to define LP matrix var
NBRNCH--not used	FTREE	Dimen: NTREE Units: --	# of branches at each tree level
NG_ARCSIZE	LPCAP	Dimen: NGTDM,NGTDM Units: fraction	Arc split between NGTDM regions--used to determine pipeline fuel
NG_AVGPR_F	FNODE	Dimen: NGTDM Units: 87$/mcf	Avg price at firm node
NG_AVGPR_I	FNODE	Dimen: NGTDM Units: 87$/mcf	Avg price at interrup. node
NG_MAGPR_F	MAGPR	Dimen: NGTDM Units: ---	Marginal node price, Firm ($87mcf)
NG_MAGPR_I	MAGPR	Dimen: NGTDM Units: ---	Marginal node price, Interruptible ($87mcf)
NODE_DMD	FNODE	Dimen: NGTDM Units: Bcf	Total core (firm service) demand at node
NONU_PR_F	FSEC	Dimen: NONUSEC,NGTDM Units: 87$/mcf	Resulting nonutil firm service price
NONU_PR_I	NGXFXI	Dimen: NONUSEC,NGTDM Units: 87$/mcf	Resulting interrup service nonutil price
NONU_QTY_F	FSEC	Dimen: NONUSEC,NGTDM Units: Bcf	Resulting nonutil core (firm service) dmd
NONU_QTY_I	NGXFXI	Dimen: NONUSEC,NGTDM Units: Bcf	Resulting noncore (interrup. service) nonutil qty
OBJAFM	LPMTRX	Dimen: --- Format: char*8	LP OBJ function name used by OML
P1	LPNAME	Dimen: --- Format: char*1	Single letters, used to define LP matrix var
PALK_NONU_F	QPALK	Dimen: NONUSEC Units: 87$/mcf	Alaska firm service nonutil price

INCLUDE (NXTDMAFM)			
Variable	**Common Name**	**Characteristics**	**Definition**
PALK_NONU_I	QPALK	Dimen: NONUSEC Units: 87$/mcf	Alaska interrup service nonutil price
PALK_UTIL_C	QPALK	Dimen: --- Units: 87$/mcf	Alaska competitive util price
PALK_UTIL_F	QPALK	Dimen: --- Units: 87$/mcf	Alaska firm service util price
PALK_UTIL_I	QPALK	Dimen: --- Units: 87$/mcf	Alaska interrup service util price
PBAS_NONU_F	PQBASE	Dimen: NONUSEC,NNGREG Units: 87$/mcf	Base nonutil firm service price
PBAS_NONU_I	PQBASE	Dimen: NONUSEC,NNGREG Units: 87$/mcf	Base nonutil interuptible service price
PBAS_UTIL_F	PQBASE	Dimen: NEMMSUB Units: 87$/mcf	Base util firm service price
PBAS_UTIL_I	PQBASE	Dimen: NEMMSUB Units: 87$/mcf	Base util inter price
PCT_MINF--not used	NGXFXI	Dimen: --- Units: ---	OLD-- Minimum firm flow as % of last yr
PCT_MINI--not used	NGXFXI	Dimen: --- Units: ---	OLD-- Minimum interrup. Flow as % of last yr
PCTLSE_SUPL	NGPERCENT	Dimen: NSUPSUB Units: ratio	Lease consumption/dry gas prod
PDSTEP	LPSTEP	Dimen: NDSTEP Units: ---	# steps on half of LP demand curve
PIPE_TAR	AFMNEW	Dimen: --- Units: ---	Indicator for changing pipe tar coeff
PNEW_STRX	LPCAP	Dimen: NNGREG,MNUMYR Units: Bcf/yr	New storage capacity additions
PQ_PNG	NGTOTRPT	Dimen: 9 Units: 87$	P*Q by census, used to calc PNG**
PR_TOL--not used	FMISC	Dimen: --- Units: ---	Pr tolerance for conv check on tree
Q_PNG	NGTOTRPT	Dimen: 9 Units: Bcf	Q by census, used to calc PNG**

INCLUDE (NXTDMAFM)			
Variable	**Common Name**	**Characteristics**	**Definition**
QALK_LAP	QPALK	Dimen: — Units: Bcf	Alaska lease & plant
QALK_PIP	QPALK	Dimen: — Units: Bcf	Alaska pipeline fuel
QALK_UTIL_C	QPALK	Dimen: — Units: Bcf	Alaska competitive util dmd
QALK_UTIL_F	QPALK	Dimen: — Units: Bcf	Alaska core (firm service) util dmd
QALK_UTIL_I	QPALK	Dimen: — Units: Bcf	Alaska noncore (interruptible service) util dmd
QBAS_NONU_F	PQBASE	Dimen: NONUSEC,NNGREG Units: Bcf	Base nonutil core (firm service) consumption
QBAS_NONU_I	PQBASE	Dimen: NONUSEC,NNGREG Units: Bcf	Base nonutil noncore (interruptible consumption)
QBAS_UTIL_F	PQBASE	Dimen: NEMMSUB Units: Bcf	Base util core (firm service) consumption
QBAS_UTIL_I	PQBASE	Dimen: NEMMSUB Units: Bcf	Base util noncore (interruptible consumption)
QGCBCF	NGHISTEL	Dimen: NEMMSUB+1,MNUMYR Units: Bcf	Hist comp util dmds
QGFBCF	NGHISTEL	Dimen: NEMMSUB+1,MNUMYR Units: Bcf	Hist core (firm service) util dmds
QGIBCF	NGHISTEL	Dimen: NEMMSUB+1,MNUMYR Units: Bcf	Hist noncore (intrp service) util dmds
QGTBCF	NG_HISTEL	Dimen: NEMMSUB+1, FHISYR:LHISYR Units: Bcf	Historical total utiity demands
REGTREE--not used	FTREE	Dimen: NTREE,JTREE Units: —	Node ID's mapped into each branch
S1	LPNAME	Dimen: — Format: char*1	Single letters, used to define LP matrix var
SIGMA--not used	FMISC	Dimen: — Units: —	Parameters used to reallocate shares
STAR_F	AFMNEW	Dimen: NGTDM,JSUP Units: 87$/mcf	Tar along firm arc from supply

INCLUDE (NXTDMAFM)			
Variable	**Common Name**	**Characteristics**	**Definition**
STAR_I	AFMNEW	Dimen: NGTDM,JSUP Units: 87$/mcf	Tar along interrup arc from supply
SUP_QTY	NGXFXI	Dimen: NSUPTYP,NGTDM,JSUP Units: Bcf	Resulting total sup qty
SUP_QTY_F	NGXFXI	Dimen: NSUPTYP,NGTDM,JSUP Units: Bcf	Resulting sup qty for firm service
SUP_QTY_I	NGXFXI	Dimen: NSUPTYP,NGTDM,JSUP Units: Bcf	Resulting sup qty for interrup
SYNCOALNG	NGCOAL	Dimen: NSUPSUB Units: Bcf	SNG from coal
UTIL_DTAR_F	LPDTAR	Dimen: NGTDM,JUTIL Units: 87$/mcf	Distributor tar to core (firm) util sector
UTIL_DTAR_I	LPDTAR	Dimen: NGTDM,JUTIL Units: 87$/mcf	Distributor tar to noncore (interrup), util sector
UTIL_PR_F	FSEC	Dimen: NGTDM,JUTIL Units: 87$/mcf	Resulting util core (firm) price
UTIL_PR_I	NGXFXI	Dimen: NGTDM,JUTIL Units: 87$/mcf	Resulting noncore (interrup) util price
UTIL_QTY_F	FSEC	Dimen: NGTDM,JUTIL Units: Bcf	Resulting util core (firm service) dmd
UTIL_QTY_I	NGXFXI	Dimen: NGTDM,JUTIL Units: Bcf	Resulting noncore (interrup) util qty
WPRCLAGOF (Not used)	WELLPR	Dimen: NSUPSUB Units: $/mcf	Lagged offshore wellhead price
WPRCLAGON (Not used)	WELLPR	Dimen: NSUPSUB Units: $/mcf	Lagged onshore wellhead price--NGTDM/OGSM subreg
WPRLAGOF	NGLAGPRC	Dimen: NOCSREG Units: 87$/mcf	Offshore wellhead price --last year
WPRLAGON	NGLAGPRC	Dimen: NSUPSUB Units: 87$/mcf	Onshore wellhead price --last year
X1	LPNAME	Dimen: --- Format: char*1	Single letters, used to define LP matrix var
XSPRNTA	LPMTRX	Dimen: --- Format: char*8	AFM soln print indicator used by OML

INCLUDE (NXPTM94)

Variable	Common Name	Characteristics	Definitions
ADIT90	FORECAST94	Dimen: --- Units: ---	Used in forecast equation adit.
ADITSWT	GENERICADIT	Dimen: --- Units: ---	Adit. generator switch
AVG_WAGE	FORECAST94	Dimen: --- Units: ---	Average Salary
BLAEEFFC	PTMSWITCH	Dimen: --- Units: ---	Year BLAE start to be added
BLAEREPT	PTMINDUSTRY	Dimen: --- Units: ---	Report switch for BLAE
BLAESWT	PTMSWITCH	Dimen: --- Units: ---	Switch for BLAE
BLAETOT	PTMSWITCH	Dimen: --- Units: ---	Industry total BLAE
BOOKVL	GENERICADIT	Dimen: --- Units: ---	Book value
DDA_RHO_E	FORECAST94	Dimen: --- Units: ---	RHO in forecast equation DDA for existing pipe line
DEPRMACRS	GENERICADIT	Dimen: --- Units: ---	Double rate DDA
DEPRSL	GENERICADIT	Dimen: --- Units: ---	Straight line DDA
DEPSHR	FORECAST94	Dimen: --- Units: ---	Used in forecast of DDA
DEPSHR90	FORECAST94	Dimen: --- Units: ---	Used in forecast of DDA
DEPSHR91	FORECAST94	Dimen: --- Units: ---	Used in forecast of DDA
GCMESTR	FORECAST94	Dimen: --- Units: ---	Ratio of common stock to to total inv. on arc
GLTDSTR	FORECAST94	Dimen: --- Units: ---	Ration of debt to total inv. on arc

INCLUDE (NXPTM94)			
Variable	**Common Name**	**Characteristics**	**Definitions**
GPFESTR	FORECAST94	Dimen: — Units: —	Ratio of preferred stock to total inv. on arc
GPIS89	FORECAST94	Dimen: — Units: —	Histoical GPIS for existing pipe line
INDYCOST	DATA STATEMENT	Dimen: — Units: —	Number of industry cost variables to be printed
INVSTP	GENERICADIT	Dimen: — Units: —	New expansion at year=YR
MACRS_RATE	FORECAST94	Dimen: — Units: —	Depreciation schedule MCRS to ADIT and DDA
MILE_FD	FORECAST94	Dimen: — Units: —	Miles of existing pipeline
NCAEREPT	PTMINDUSTRY	Dimen: — Units: —	NCAE value
NETPLT	FORECAST94	Dimen: — Units: —	Net plant in service
NETPLT90	FORECAST94	Dimen: — Units: —	1990 net plant in service data
NETPLT91	FORECAST94	Dimen: — Units: —	1991 net plant in service data
NEWFACREPT	PTMINDUSTRY	Dimen: — Units: —	NEWFAC value
P_TAG_SALARY	FORECAST94	Dimen: — Units: —	Previous year salary used in TAG equation
PDEPSHR	FORECAST94	Dimen: — Units: —	Previous year depreciation share
PEQUIP	FORECAST94	Dimen: — Units: —	Price index of equipment
PGPISREPT	PTMINDUSTRY	Dimen: — Units: —	Previous year GPIS value
PLCMPCOST	PTMCMPCOST	Dimen: — Units: —	Cost components by existing pipeline company
PLGCMPCOST	PTMCMPCOST	Dimen: — Units: —	Cost components by generic pipeline company

INCLUDE (NXPTM94)			
Variable	Common Name	Characteristics	Definitions
PLTOCOSTS	PTMINDUSTRY	Dimen: — Units: —	Total PL industry cost (21 yr)
PLTOGPIS1	PTMSWITCH2	Dimen: — Units: —	Total GPIS of existing pipeline industry
PLTOGPIS2	PTMSWITCH2	Dimen: — Units: —	Total GPIS of both existing and generic pipeline industry
PNETPLT	FORECAST94	Dimen: — Units: —	Net Plant for previous year
PPGPIS	FORECAST94	Dimen: — Units: —	Used in TOM of gegeric pipeline
SGCMPCOST	PTMCMPCOST	Dimen: — Units: —	Cost components by existing pipeline region
SGGCMPCOST	PTMCMPCOST	Dimen: — Units: —	Cost components by generic pipeline region
SGTOCOSTS	PTMINDUSTRY	Dimen: — Units: —	Total STG industry cost (21 yr)
TAG_RHO_E	FORECAST94	Dimen: — Units: —	RHO in forecast TAG for existing pipeline
TAG_RHO_G	FORECAST94	Dimen: — Units: —	RHO in forecast TAG for generic pipeline
TOM_RHO_E	FORECAST94	Dimen: — Units: —	RHO used in TOM equation of existing pipeline
TOM_RHO_G	FORECAST94	Dimen: — Units: —	Rho used in TOM equation of generic pipeline
TOMEFFC	PTMSWITCH	Dimen: — Units: —	Year BLAE rate to be added (tomswt=1)
TOMINC1	PTMSWITCH	Dimen: — Units: —	Total incremental TOM for existing pipeline industry
TOMINC2	PTMSWITCH	Dimen: — Units: —	Total incremental TOM for existing and generic pipeline
TOMSWT	PTMSWITCH	Dimen: — Units: —	Switch for incremental TOM

INCLUDE (OGSMOUT)*			
Variable	**Common Name**	**Characteristics**	**Definition**
OGCNBLOSS	OGSMOUT	Dimen: Format: real	Gas lost in transit to border
OGCNCAP	OGSMOUT	Dimen: 6,MNUMYR Format: real	Canadian capacities at border crossing
OGCNCON	OGSMOUT	Dimen: 2,mnumyr Format: real Units: Bcf	Canada gas consumption
OGCNDMLOSS	OGSMOUT	Dimen: --- Format: real	Gas lost from wellhead to Canada demand
OGCNEXLOSS	OGSMOUT	Dimen: --- Format: real	Gas lost from U.S. export to Canada demand
OGCNFLW	OGSMOUT	Dimen: 6 Format: real	Initial flow rates at border crossing
OGCNMARKUP	OGSMOUT	Dimen: 6 Format: real	Transportation markup at border
OGCNMARKUP	OGSMOUT	Dimen: 6 Format: real	Transportation markup at border
OGCNPARM1	OGSMOUT	Dimen: --- Format: real	(alpha) actual gas allocation factor
OGCNPARM2	OGSMOUT	Dimen: --- Format: real	Responsiveness of flow to diff. in border prices
OGCNPPRD	OGSMOUT	Dimen: 2,MNUMYR Format: real	Canadian price of oil and gas
OGCNQPRD	OGSMOUT	Dimen: 2,MNUMYR Format: real	Candian prodictin of oil and gas
OGELSNGOF	OGSMOUT	Dimen: 3, MNUMYR Format: real	Non-associated dry gas production function parameter for offshore
OGELSNGON	OGSMOUT	Dimen: 3,MNUMYR Format: real	Non-associated dry gas production function parameter for onshore
OGNGTSMX	OGSMOUT	Dimen: Format: real	Max known flow in current year
OGPNGIMP	OGSMOUT	Dimen: MNUMBX,MNUMYR Format: real	NG import price by border

INCLUDE (OGSMOUT)*			
Variable	Common Name	Characteristics	Definition
OGPRRCAN	OGSMOUT	Dimen: 2,MNUMYR Format: real	Temp. var for ADIT equation
OGPRRNGOF	OGSMOUT	Dimen: 3,MNUMYR Format: real	Non-associated dry gas p/r ratio offshore
OGPRRNGON	OGSMOUT	Dimen: 3,MNUMYR Format: real	Non-associated dry gas p/r ratio onshore
OGQANGTS	OGSMOUT	Dimen: MNUMYR Format: real	Gas flow at U.S. border from ANGTS
OGQLNMAX	OGSMOUT	Dimen: 4,MNUMYR Format: real	Maximum forseeable LNG regas flow
OGQNGEXP	OGSMOUT	Dimen: MNUMBX,MNUMYR Format: real	NG exports by border crossing
OGQNGGIMP	OGSMOUT	Dimen: MNUMBX,MNUMYR Format: real	NG imports by border crossing
OGQNGSAKMX	OGSMOUT	Dimen: MNUMYR Format: real	Maximum production limit of South Alaska
OGRESCAN	OGSMOUT	Dimen: 2,MNUMYR Format: real	End-of-year reserves
OGRESNGOF	OGSMOUT	Dimen: 3,MNUMYR Format: real	Non-associated dry gas reserves, offshore
OGRESNGON	OGSMOUT	Dimen: 17,MNUMYR Format: real	Non-associated dry gas reserves, onshore
OGTAXPREM	OGSMOUT	Dimen: 2,MNUMYR Format: real	Tax or credit applied at the wellhead (=0 in AEO95)

*This common block contains other variables that are not used in NGTDM.

INCLUDE (OMLBUF)

Variable	Common Name	Characteristics	Definitions
AFMIO	OMLDYN	Dimen: NAFMIO Units: ---	Memory required by AFM LP model
CEMIO	OMLDYN	Dimen: NCEMIO Units: ---	Memory required by CEM LP model

INCLUDE (PMMOUT)*

Variable	Common Name	Characteristics	Definition
DCRDWHP	PMMOUT	Dimen: MNUMOR,MNUMYR Format: real	Dom crude wellhead price
PCTPLT_PADD	PMMOUT	Dimen: MNUMPR,MNUMYR Format: real	Gas plant fuel consumed/total
RFQTDCRD	PMMOUT	Dimen: MNUMOR+2,MNUMYR Format: real	Total domestic crude (incl. EOR)

*This common block contains other variables that are not used in NGTDM.

INCLUDE (MPBLK)*			
Variable	Common Name	Characteristics	Definition
PCLIN	MPBLK	Dimen: NBYNCR,MNUMYR Format: real	Coal, industrial
PDSEL	MPBLK	Dimen: MNUMCR,MNUMYR Format: real	Distillate, electricity (includes petroleum coke)
PDSIN	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	Distillate, industrial
PGCFM	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	Natural gas, core commercial
PGFEL	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	Natural gas, core electrical
PGFIN	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	Natural gas, core industrial
PGFRS	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	Natural gas, core residential
PGFTR	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	Natural gas, core transportation
PGICM	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	Natural gas, noncore commercial
PGIEL	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	Natural gas, noncore electrical
PGIIN	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	Natural gas, noncore industrial
PGIRS	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	Natural gas, noncore residential
PGITR	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	Natural gas, noncore transportation
PLGIN	MPBLK	Dimen: MNUMCR,MNUMYR Format: real	Liquid petroleum gases, industrial
PMGCM	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	Motor Gasoline, commercial
PNGCM	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	Natural gas, commercial

INCLUDE (MPBLK)*			
Variable	**Common Name**	**Characteristics**	**Definition**
PNGEL	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	Natural gas, electrical
PNGIN	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	Natural gas, industrial
PNGRS	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	Natural gas, residential
PNGTR	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	Natrual gas, transportaion
PRSEL	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	Residual fuel, electrical
PRSIN	MPBLK	Dimen: MNUMCR,MNUMYR Format: real	Residual fuel, industrial

*This common block contains other variables that are not used in NGTDM.

INCLUDE (QBLK)			
Variable	Common Name	Characteristics	Definitions
QGFCM	QBLK	Dimen: MNUMCR,MNUMYR Units: tril. BTU	Natural gas, firm, commercial
QGFEL	QBLK	Dimen: MNUMCR,MNUMYR Units: tril. BTU	Natural gas, firm, electricity
QGFIN	QBLK	Dimen: MNUMCR,MNUMYR Units: tril. BTU	Natural gas, firm, industrial
QGFRS	QBLK	Dimen: MNUMCR,MNUMYR Units: tril. BTU	Natural gas, firm, residential
QGFTR	QBLK	Dimen: MNUMCR,MNUMYR Units: tril. BTU	Natural gas, firm, transportation
QGICM	QBLK	Dimen: MNUMCR,MNUMYR Units: tril. BTU	Natural gas, interruptible, commercial
QGIEL	QBLK	Dimen: MNUMCR,MNUMYR Units: tril. BTU	Natural gas, interruptible, electricity
QGIIN	QBLK	Dimen: MNUMCR,MNUMYR Units: tril. BTU	Natural gas, interruptible, industrial
QGIRS	QBLK	Dimen: MNUMCR,MNUMYR Units: tril. BTU	Natural gas, interruptible, residential
QGITR	QBLK	Dimen: MNUMCR,MNUMYR Units: tril. BTU	Natural gas, interruptible, transportation
QGPTR	QBLK	Dimen: MNUMCR,MNUMYR Units: tril. BTU	Natural gas pipeline
QLPIN	QBLK	Dimen: MNUMCR,MNUMYR Units: tril. BTU	Lease and plant fuel
QNGCM	QBLK	Dimen: MNUMCR,MNUMYR Units: tril. BTU	Natural gas, commercial
QNGEL	QBLK	Dimen: MNUMCR,MNUMYR Units: tril. BTU	Natural gas, electricity
QNGIN	QBLK	Dimen: MNUMCR,MNUMYR Units: tril. BTU	Natural gas, industrial
QNGRS	QBLK	Dimen: MNUMCR,MNUMYR Units: tril. BTU	Natural gas, residential

INCLUDE (QBLK)			
Variable	**Common Name**	**Characteristics**	**Definitions**
QNGTR	QBLK	Dimen: MNUMCR,MNUMYR Units: tril. BTU	Natural gas, transportation
QRHEL	QBLK	Dimen: MNUMCR,MNUMYR Units: ---	Residential fuel, high sulfur, electricity
QRLEL	QBLK	Dimen: MNUMCR,MNUMYR Units: ---	Residential fuel, low sulfur, electricity

INCLUDE (TEMPADAT)

Variable	Common Name	Characteristics	Definitions
APCKITR	PACK_AFM	Dimen: — Units: —	Iteration defined for which a packed file of the AFM LP solution will be generated
APCKSWTCH	PACK_AFM	Dimen: — Units: —	Switch indicating that a packed file of the AFM LP solution will be generated
APCKYR	ACK_AFM	Dimen: — Units: —	Year (e.g., 1,2...) defined for which a packed file of the AFM LP solution will be generated

INCLUDE (TEMPCEM)

Variable	Common Name	Characteristics	Definitions
CPCKSWTCH	PACK_CEM	Dimen: — Units: —	Switch indicating that a packed file of the CEM LP solution will be generated
CPCKYR	PACK_CEM	Dimen: — Units: —	Year (e.g., 1,2...) defined for which a packed file of the CEM LP solution will be generated

Variable Definition List for Local Variables Defined Within the AFM

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
Real Function NGCAN_IMP(IBRDX,BPRC)		
AA,BB,CC (NCAN)	REAL*4	Hold intermediate calculations
BPRC	REAL*4	Input border crossing price (87$/mcf)
CN_BRDPRC (NCAN)	REAL*4	Local border crossing prices (87$/mcf)
CN_DEMAND	REAL*4	Canadian consumption (BCF)
CN_EFFCAP(NCAN)	REAL*4	Effective border pipeline capacity (BCF)
CN_EXPORT	REAL*4	Gas from U.S. to Canada (BCF)
CN_FLOCUR(NCAN)	REAL*4	Border flow for currect internal iteration (BCF)
CN_FLOLAG (NCAN)	REAL*4	Adjusted imports in t-1 (BCF)
CN_FLOSHR (NCAN)	REAL*4	Percent of total Canadian imports at each border crossing
CN_LAGSHR(NCAN)	REAL*4	Border crossing share for previous internal iteration
CN_PARMWELPR	REAL*4	Local Border Price minus transportation markup
CN_PRODUC	REAL*4	Canadian dry gas production (BCF)
CN_SHRCAP(NCAN)	REAL*4	CN_EFFCAP as shares
CN_SHRDIF	REAL*4	Difference in iteration shares for convergence check
CN_WELPRC	REAL*4	Canadian wellhead price (87$/mcf)
CN_WPRCLAG	REAL*4	Wellhead price t-1 (87$/mcf)
DD1 (NCAN),EE	REAL*4	Hold intermediate calc's
EXTGAS	REAL*4	Extra gas transfer to other borders due to maximum capacity met at one border (BCF)
EXTSPC	REAL*4	Extra space available for filling along a border crossing (BCF)
I	INTEGER*4	Counter
IBRDX	INTEGER*4	Input border crossing
ICOUNT	INTEGER*4	Iteration counter as check for nonconvergence when determining Candian border crossing quantities
LAGBD	INTEGER*4	IBRDX last time func called
LAGIT	INTEGER*4	NEMS iter last time called

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
LAGYR	INTEGER*4	Yr last time fúnction called
NGCAN_DEMAND	REAL*4	Canadian dmd function
SUBTOT	REAL*4	Sum of BPRC**PARM2
TCN_EFFCAP	REAL*4	Total effective border pipeline capacity (BCF)
TCN_FLOCUR	REAL*4	Total border flow for current internal iteration (BCF)
TOT_BRDQ	REAL*4	Tot production left for U.S. imports (BCF)
TOT_FLOLAG	REAL*4	Total adjusted imports in t-1 (BCF)
Real Function NGTDM_CRVNONUFX(NGRG,CNRG,NSEC,PRICE)		
CNRG	INTEGER*4	Census region
NGRG	INTEGER*4	NGTDM region
NSEC	INTEGER*4	Non electric generators sector identifier
PO	REAL*4	Base price in curve equation
PRICE	REAL*4	Input price
QO	REAL*4	Base qty in curve equation
Real Function NGTDM_CRVNONUIX(NGRG,CNRG,NSEC,PRICE)		
CNRG	INTEGER*4	Census region
NGRG	INTEGER*4	NGTDM region
NSEC	INTEGER*4	Non- electric generators sector identifier
P0	REAL*4	Base pr in curve eq.
PRICE	REAL*4	Input price
Q0	REAL*4	Base qty (comp) in curve eq.
Real Function NGTDM_CRVUTILF(NGRG,EMRG;PRICE)		
EMRG	INTEGER*4	EMM region
NGRG	INTEGER*4	NGTDM region
PRICE	REAL*4	Input price
Real Function NGTDM_SUPCRV(STYP,NODE_ID,NSREG,INVAL,VALUE)		
INVAL	CHARACTER*1	Type of variable value is (Q or P)

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
NGCAN_IMP	REAL*4	Supply function: import from Can.
NGPRD_L48	REAL*4	Supply function: L48 regions
NGPRD_OCS	REAL*4	Supply function: OCS regions
NGSYN_LIQH	REAL*4	Supply function: gas from liq
NODE_ID	INTEGER*4	NGTDM node identifier
NSREG	INTEGER*4	Supply array position
STYP	INTEGER*4	Supply type identifier
SUPL_ID	INTEGER*4	OGSM region or supply number
VALUE	REAL*4	P or Q for setting Q or P
Subroutine BKSTOP_CHK		
EMMREG,CENREG	INTEGER*4	Region ID's
EXNODE	REAL*4	Export node ID
IRET	INTEGER*4	OML return code
ITYP	INTEGER*4	Supply source type
NGREG,NSREG	INTEGER*4	Region ID's
NSEC	INTEGER*4	Sector ID
Subroutine EMMOUTPUT()		
EFF	REAL*4	Efficiency along arc to EU node
I,J,K	INTEGER*4	Counters
TOT	REAL*4	Temporary total I + C (ELECTRIC GENERATORS)
Subroutine NGAFM_DMDREG3		
I,J,K,YR,REG	INTEGER*4	Counters
NRESID_PR(NGTDM)	REAL*4	Non Region 3 Non-residential gas price(93$/mcf)
NRESID_PR_3(NGTDM)	REAL*4	Region 3 Non-residential gas price(93$/mcf)
NRESID_QTY(NGTDM)	REAL*4	Non Region 3 Non-residential gas quantity(bcf)
NRESID_QTY_3(NGTDM)	REAL*4	Region 3 Non-residential gas quantity(bcf)
RESID_PR(NGTDM)	REAL*4	Non Region 3 residential gas price(93$/mcf)

Local Variables Defined Within The NGAFM		
Variable Name	Format	Definition
RESID_PR_3(NGTDM)	REAL*4	Region 3 residential gas price(93$/mcf)
RESID_QTY_3(NGTDM)	REAL*4	Region 3 residential gas quantity(bcf)
TOT_NQTY(NGTDM)	REAL*4	Total Non-residential quantity(bcf)
TOT_QTY_RES(NGTDM)	REAL*4	Total residential quantity(bcf)
TOTNRESID_PR(NGTDM)	REAL*4	Total Non-residential price(93$/mcf)
TOTRESID_PR(NGTDM)	REAL*4	Total residential price(93$/mcf)
Subroutine NGAFM_FIDMD(TOTDMD_F,TOTDMD_I)		
EXNODE	INTEGER*4	Export node ID
ITYP	INTEGER*4	Supply type index
NEMM	INTEGER*4	NGTDM/EMM subregion counter
NGEXP_CAN,NGEXP_MEX	REAL*4	Canadian and Mexican Import Function
NGREG,NSREG	INTEGER*4	Region ID's
NSEC	INTEGER*4	Sector ID
SQUANT	REAL*4	Maximum available supply quantity(used to subtract constant supply from firm demands)
TOTDMD_F,TOTDMD_I	REAL*4	Total firm and interruptible demands(bcf)
Subroutine NGAFM_INITLP		
(no local variables)		
Subroutine NGAFM_SUPMIN(ITYP,NGREG,NSREG,NSUPID,PCT_FSUP,MINSUP)		
ITYP	INTEGER*4	Supply type counter
MINSUP	REAL*4	Minimum Supply(bcf)
MINSUPF	REAL*4	Minimum firm supply
MINSUPI	REAL*4	Minimum interruptible supply
NGREG,NSREG	INTEGER*4	Region/subregion counters
NSUPID	INTEGER*4	Supply region (1-6)
PCT_FSUP	REAL*4	Percent of Minimum supply that is firm
Subroutine NGFEL		

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
I,J	INTEGER*4	Region counters
TOTPQ	REAL*4	Stores P*Q values for a NGTDM reg
TOTPQ_CEN (9)	REAL*4	Stores P*Q values by Census reg
TOTQ	REAL*4	Stores Q totals for a NGTDM reg
TOTQ_CEN (9)	REAL*4	Stores Q totals by Census reg
Subroutine NGFNONU(NSEC)		
I,J	INTEGER*4	Region counters
NSEC	INTEGER*4	Sector ID counter
TOTPQ_CEN (9)	REAL*4	Stores P*Q values by Census reg
TOTQ_CEN (9)	REAL*4	Stores Q totals by Census reg
Subroutine NGIEL		
I,J,K	INTEGER*4	Region counters
TOTPQ	REAL*4	Stores P*Q values for a NGTDM reg
TOTPQ_CEN (9)	REAL*4	Stores P*Q values by Census reg
TOTQ	REAL*4	Stores Q totals for a NGTDM reg
TOTQ_CEN (9)	REAL*4	Stores Q totals by Census reg
Subroutine NGINONU(NSEC)		
I,J	INTEGER*4	Region counters
NSEC	INTEGER*4	Sector ID counter
TOTPQ_CEN (9)	REAL*4	Stores P*Q values by Census reg
TOTQ_CEN (9)	REAL*4	Stores Q totals by Census reg
Subroutine NGLP_RPT(IUNIT) -- not used		
COLSOL	CHARACTER*8	'ACLUD '/ MF
I	INTEGER*4	Counter
IRET	INTEGER*4	OML return code
IUNIT	INTEGER*4	Unit num for output file
NAME	CHARACTER*8	OML row or col name

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
ROWSOL	CHARACTER*8	/'ASLUP '/ MF
STAT2	CHARACTER*2	OML LP status code
SUPPFL	REAL*4	Base level of supply in Florida
TEFFCAPFL	REAL*4	Unadjusted eff total cap into FL
TFLWFL	REAL*4	Required total flow into FL for base demand
VALUE (5)	REAL*8	OML solution
Subroutine NGOUTAFM		
I	INTEGER*4	Counter
ITYP	INTEGER*4	Supply type
NGREG	INTEGER*4	Region counter
Subroutine NGQRSEL		
DEL	REAL*4	Stores change in comp gas demand
NGREG,EMMREG,CENREG	INTEGER*4	Region counters
KK	INTEGER*4	Region counters
NGTDM_CRVUTILIX	REAL*4	Comp gas function
PRX	REAL*4	Price on vertical
PR_FLAG	INTEGER*4	Flag when price on vertical
QRSELGR	REAL*4	Total resid use portion of GOIL
RHDEL	REAL*4	Change in high sulfur resid portion
RLDEL	REAL*4	Change in low sulfur resid portion
Subroutine NGREPIN		
IO,I,IY	INTEGER*4	Unit #/Counters
Subroutine NGREPOUT		
IO,I,J,IY	INTEGER*4	Unit #/Counters
Subroutine NGSUPCHK		
CANDEM	REAL*4	NG demand in Can
CANSUP	REAL*4	NG supply in Can

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
CONTOT	REAL*4	Total NG consumption in Can
ELSTOT	REAL*4	Est. elasticity for ????
EYR	INTEGER*4	(not used)
I	INTEGER*4	Counter
L48DEM	REAL*4	Lower 48 dmd for NG
L48SUP	REAL*4	Lower 48 supply of NG to Can
NGCAN_DEMAND	REAL*4	Function to set NG consump in Can
OTHDEM	REAL*4	Other NG dmd
OTHSUP	REAL*4	Other NG supplies
PRCITR	REAL*4	?????
PRCLAG	REAL*4	Lagged total avg wellhead price for NG
PRICE	REAL*4	Est. total avg wellhead price for NG
REVTOL	REAL*4	???
SUPTOL	REAL*4	???
SUPTOT	REAL*4	???
Subroutine NGTDM_AFM		
ACTFILE	CHARACTER*8	/'ACTFAFM '/ OML database containing the LP problem
ACTPROB	CHARACTER*8	/'ACTPROB '/ OML LP problem name
AFMBYT	INTEGER*4	Size of AFM LP workspace in bytes
DBUGOPEN	LOGICAL	Flag to open DBUG1 trace file
DECK	CHARACTER*8	/'AFMDECK '/ OML LP deck name
FILE_MGR	INTEGER*4	File manager func in NEMS main
FNAME	CHARACTER*18	Filename for NGDBUG1 AFM LP output
FNAME2	CHARACTER*18	NGDBUG2 output file to store supply curve parameters
I	INTEGER*4	Sector counter
IREG	INTEGER*4	NGTDM/OGSM subregion ID (1-17)
IRET	INTEGER*4	OML return code

Local Variables Defined Within The NGAFM		
Variable Name	Format	Definition
ITYP	INTEGER*4	Supply type counter
MIN_SUP	REAL*4	Minimum supply level (BCF)
NGREG	INTEGER*4	Region counter
NSREG	INTEGER*4	Subregion counter
NSUPID	INTEGER*4	Supply region (1-6)
NUM_INFSWRT	INTEGER*4	Number of times infeasible solutions have been written
OMLNAM	CHARACTER*8	Stores name of OML fucntion containing error
PCT_FSUP	REAL*4	Percent of onshore production going to firm network
PER	REAL*4	Percent production not lease and plant
RTCOD	INTEGER*4	Return code from GOMHOT (subroutine to pack LP solution)
TEMPACT	CHARACTER*8	Temporary storage for ACTFILE name
TOTDMD_F	REAL*4	Total firm demand (BCF)
TOTDMD_I	REAL*4	Total interruptible demand (BCF)
UNITNUM	INTEGER*4	Unit # for NGDBUG1 for writing infeasible AFM LP soln.
Subroutine NGTDM_AVGPRC		
FLOW_F	REAL*4	Firm flow along an arc (BCF)
I,J,K,SRC,DEST,NSREG	INTEGER*4	Counters
SUM_FLOW	REAL*4	Sum of flow going into node (from supply and other node)
Subroutine NGTDM_BKADJ (not used)		
ACAP_MAX	REAL*4	Maximum effective capacity along arc into Florida (BCF)
ACAP_MIN	REAL*4	Minimum capacity along arc into Florida (BCF, not used)
DRGFL	INTEGER*4	Non- electric generators demand region for FL
FDEMFL	REAL*4	Firm demand in Florida (BCF)
FEFFCAPFL	REAL*4	Unadjusted eff firm capacity into Florida
FFLWFL	REAL*4	Required firm flow into Florida for base demand
FRFL	INTEGER*4	NGTDM transhipment node connecting into Florida

Local Variables Defined Within The NGAFM

Variable Name	Format	Definition
I	INTEGER*4	Counter
IDEMFL	REAL*4	Interruptible demand in Florida (BCF)
IRET	INTEGER*4	OML return code
PERFL	REAL*4	Percent of supply used for L&P
SRGFL	INTEGER*4	NGTDM/OGSM region in FL
SUPPFL	INTEGER*4	NGTDM/OGSM region for FL
TEFFCAPFL	REAL*4	Unadjusted eff total capacity into Florida
TFLWFL	REAL*4	Required total flow into Florida for base demand
TOFL	INTEGER*4	Transhipment node in FL
URGFL	INTEGER*4	Electric generators subregion for FL
Subroutine NGTDM_CAPI		
ACAP_MAX	REAL*4	Maximum annual capacity (Bcf)
ACAP_MIN	REAL*4	Minimum annual flow (Bcf)
AK_FLOW	REAL*4	NG flow from Alaska into NGTDM node 18 (BCF)
DEL_AKFLOW	REAL*4	Difference in AK flows between current & previous yr
IRET	INTEGER*4	OML return code
NEWFLOW	REAL*4	Estimated flow from new capacity (Bcf)
NGREG, AN, I	INTEGER*4	Reg/Subreg counters
RHSVAL	REAL*4	RHS value for storage variable
SRC, DEST	INTEGER*4	Node ID's
SRC_AKCAN	LOGICAL	Flag to indicate if CAN border crossing intersects w/AK border crossing
Subroutine NGTDM_DTM		
AFP	REAL*4	Alternate fuel price($87/MCF)
DIST0(3,NNGREG)	REAL*4	Base dt from hist input ($87/MCF)
DIST(3,NNGREG)	REAL*4	($87/MCF)
I,J,K,M	INTEGER*4	Index variable

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
IFLOOR(NNGREG)	REAL*4	Lower bound on markup ($87/MCF)
IPD1(NNGREG)	REAL*4	User specified % discount
IPD2YR(NNGREG)	INTEGER*4	Year switch
IPD2(NNGREG)	REAL*4	Alt user specified % discount
NONU_DTARF_DECL	REAL*4	Decline rate of nonu firm distributor tariffs
PERCDISC	REAL*4	% discount
TFD1	REAL*4	User Federal gasoline tax($87/MMBTU)
TFD2	REAL*4	Alt user adj to Fed gasoline tax($87/MMBTU)
TFD2YR	INTEGER*4	Year switch
TILT	REAL*4	TILT determ. fr user input ($87/MCF)
TILT1(3,NNGREG)	REAL*4	User adj to dt ($87/MCF)
TILT2YR(3,NNGREG)	INTEGER*4	Year switch
TILT2(3,NNGREG)	REAL*4	Alt. user adj to dt($87/MCF)
TST1(NNGREG)	REAL*4	User state gasoline tax($87/MMBTU)
TST2YR(NNGREG)	INTEGER*4	Year switch
TST2(NNGREG)	REAL*4	Alternate state gasoline tax($87/MMBTU)
UBENORG(NEMMSUB)	REAL*4	Elec. gen. bench factors calculated in last historical year
UBENPER	REAL*4	Percent of UBENORG not phased out
UBENYRD	INTEGER*4	Number of years UBENORG phaseout
UINTR	REAL*4	Compet w/resid mkup for util sec($87/MCF)
URFLOOR(NEMMSUB)	REAL*4	Lower bound on markup($87/MCF)
URPD1(NEMMSUB)	REAL*4	User specified % discount
URPD2YR(NEMMSUB)	INTEGER*4	Year switch
URPD2(NEMMSUB)	REAL*4	Alt % discount
UTILT1(NEMMSUB)	REAL*4	User adjustment to dt ($87/MCF)
UTILT2Y(NEMMSUB)	INTEGER*4	Year switch
UTILT2(NEMMSUB)	REAL*4	Alt. user adj to dt($87/MCF)

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
W_COAL(NNGREG)	REAL*4	Ratio for coal
W_DIST(NNGREG)	REAL*4	Ratio (weight) for distillate
W_LPG(NNGREG)	REAL*4	Ratio for liquid petroleum gas
W_RESID(NNGREG)	REAL*4	Ratio for residual
Subroutine NGTDM_EFFLP		
EFF	REAL*4	Efficiency from node to end-use sector (Intraregional eff * Distributor eff)
EMMREG, CENREG	INTEGER*4	EMM or Census reg ID
IRET	INTEGER*4	OML return code
NGREG, NSREG	INTEGER*4	Reg/Subreg counter
NSEC	INTEGER*4	Sector ID
Subroutine NGTDM_ENDPR		
BKYEAR	INTEGER*4	Last year in which backstop occurred
NGREG,NSREG,NSEC	INTEGER*4	Counters
Subroutine NGTDM_EXCI		
DELQ	REAL*4	Length of steps (Qty) on export dmd curve
DPRICE (NDSTEP)	REAL*4	PR on export dmd curve steps
EXNODE	INTEGER*4	Export node ID
EXPQTY, EXPPR	REAL*4	Export Qty & Pr
I	INTEGER*4	Counter
IRET	INTEGER*4	OML return code
ITYP, NGREG, NS, SRC	INTEGER*4	Reg/Subreg/Supply type counters
MINF	REAL*4	Min flow on export arcs
NGEXP_CAN, NGEXP_MEX	REAL*4	Can & Mex export functions
Subroutine NGTDM_FLOWSI		
I, NGREG, NSREG	INTEGER*4	Reg/Subreg counters
IRET	INTEGER*4	OML return code

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
SRC, DEST	INTEGER*4	Source & dest node ID
Subroutine NGTDM_HISOVR		
BETA	REAL*4	Phase Variable 0-1 (not used)
CENREG	INTEGER*4	Census Division ID (1-9)
CH	CHARACTER*1	End of data flag (#)
CN_NGEMMAP (9,4)	INTEGER*4	maps from Census region to NGTDM/EMM subregion
CN_NGEMSUB (9)	INTEGER*4	Number of NGTDM/EMM subreg in Census region
DPR_CHK(NNGREG)	REAL*4	Firm end-use price for transportation sector for last historical yr (87$/mcf)
EFF	REAL*4	Efficiency from node to end-use sector (Intraregional eff * Distributor eff)
EMMREG	INTEGER*4	EMM region counter
FILE_MGR	INTEGER*4	Function which passes unit numbers
FNAME	CHARACTER*18	Input file name
HCLSYNGWP (FHISYR:LHISYR)	REAL*4	Hist SYN from coal gas price
HISBENCHF(NONUSEC,NNGREG,FHISYR:LHISYR)	REAL*4	Firm benchmark factors for historical years (87$/mcf)
HOGCNPPRD(FHISYR:LHISYR)	REAL*4	His Canadian NG production price (87$/mcf)
HOGCNQPRD(FHISYR:LHISYR)	REAL*4	His Canadian NG production quantity (BCF)
HOGPNGEXP (MNUMBX,FHISYR:LHISYR)	REAL*4	Hist gas export prices
HOGPNGIMP (MNUMBX,FHISYR:LHISYR)	REAL*4	Hist gas import prices
HOGPRDNG (MNUMOR,FHISYR:LHISYR)	REAL*4	Hist NG dry gas prod (byOGSM)
HOGPRDNGOF (3,FHISYR:LHISYR)	REAL*4	Hist OFSHR NONASSOC gas prod

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
HOGPRDNGON (NSUPSUB, FHISYR:LHISYR)	REAL*4	Hist ONSHR NONASSOC gas prod
HOGPRSUP (FHISYR:LHISYR)	REAL*4	Hist SYN fr LIQ gas price
HOGPRSUP3(3,FHISYR:LHISYR)	REAL*4	Historicl prices for SNG components from liquids (87$/mcf)
HOGQNGIMP (MNUMBX,FHISYR:LHISYR)	REAL*4	Hist gas import quantities
HOGWPRNG (MNUMOR,FHISYR:LHISYR)	REAL*4	Hist wellhead price
HPGCELGR(NEMMSUBA,FHISYR:LHISYR)	REAL*4	Estimated historical price for NG (nonassociated dissolved) to the competitive electric generation sector (87$/mcf)
HPGFCM (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist comm firm service pr--CEN
HPGFCMGR (NNGREG,FHISYR:LHISYR)	REAL*4	Hist comm firm service pr--NGREG
HPGFELGR (NEMMSUBA, FHISYR:LHISYR)	REAL*4	Est. firm service E.U. price (NA)
HPGFIN (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist inds firm service pr--CEN
HPGFINGR (NNGREG,FHISYR:LHISYR)	REAL*4	Hist inds firm service pr--NGREG
HPGFRS (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist resd firm servic pr--CEN
HPGFRSGR (NNGREG,FHISYR:LHISYR)	REAL*4	Hist resd firm service pr--NGREG
HPGFTR (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist tran firm service pr--CEN
HPGFTRGR (NNGREG,FHISYR:LHISYR)	REAL*4	Hist tran firm service pr--NGREG
HPGICM (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist comm interpt service pr--CEN
HPGIELGR(NEMMSUBA,FHISYR:LHISYR)	REAL*4	Estimated historical price for NG (nonassociated dissolved) to the interruptible electric generation sector (87$/mcf)

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
HPGIIN (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist inds interpt service pr--CEN
HPGIRS (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist resd interpt service pr--CEN
HPGITR (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist tran interpt pr--CEN
HPGTELGR(NEMMSUBA,FHISYR:LHISYR)	REAL*4	Estimated historical price for NG (nonassociated dissolved) to the electric generation sector (87$/mcf)
HPRNG_PADD (MNUMPR,FHISYR:LHISYR)	REAL*4	Hist NG dry gas prod (by PADD)
HPRODTOTOF(3)	REAL*4	Hist total offshore gas prod by offshore sup reg (BCF)
HPRODTOTON(17)	REAL*4	Hist total onshore gas prod by NGTDM/OGSM subregion (BCF)
HQGFCMGR(NNGREG)	REAL*4	Hist comm NG consump by NGTDM reg (BCF)
HQGFCM(MNUMCR)	REAL*4	Hist comm NG consump by CENSUS reg (BCF)
HQGFRSGR(NNGREG)	REAL*4	Hist resd NG consump by NGTDM reg (BCF)
HQGFRS(MNUMCR)	REAL*4	Hist resd NG consump by CENSUS reg (BCF)
HQGPTR (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist pipeline fuel consumption (BCF)
HQGTELGR(NEMMSUBA	REAL*4	Hist elec NG consump to NGTDM/EMM subregion (BCF)
HQLPIN (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist lease & plant consumption (BCF)
HRAT1ELGR(NEMMSUBA,FHISYR:LHISYR)	REAL*4	Assumed electric utility pf/@avg(pi,pc)
HRAT2ELGR(NEMMSUBA,FHISYR:LHISYR)	REAL*4	Assumed electric utility pi/pc
I,J,K	INTEGER*4	Counters
ICEN	INTEGER*4	Census region identifier for state data
ING	INTEGER*4	NGTDM region identifier for state data
INGEM	INTEGER*4	NGTDM/EMM region identifier for state data
INGOG	INTEGER*4	NGTDM/OGSM production region identifier for state data

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
IOG	INTEGER*4	OGSM production region identifier for state data
IPADD	INTEGER*4	PADD region identifier for state production data
NEMMSUBA	INTEGER*4	Num NGTDM/EMM regs (w/AK) NEMMSUBA=NEMMSUB+1 PARAMETER
NGREG	INTEGER*4	NGTDM region counter
NOGWPRNG	REAL*4	Avg lower-48 wellhead price (87$/mcf)
NPRDTOT	REAL*4	National dry gas production (BCF)
NQGPTR	REAL*4	National pipeline fuel consumption (BCF)
NQLPIN	REAL*4	National lease and plant consumption (BCF)
NSREG	INTEGER*4	NGTDM subregion counter
NWPRLAG	REAL*4	Avg l-48 wellhead price for LHISYR-1 (87$/mcf)
PEXP(3)	REAL*4	Hist price exports -- CAN,MEX,LNG (87$/mcf)
PIMP(3)	REAL*4	Hist price imports CAN,MEX,LNG (87$/mcf)
PNA	REAL*4	Nonassociated gas production by state (MMCF)
PTOT	REAL*4	Total gas production by state (MMCF)
QEXP(3)	REAL*4	Hist quantity exports -- CAN,MEX,LNG (MMCF)
QGFEL_LOC (MNUMCR)	REAL*4	Hist Q firm service EU consumption by Census (Bcf)
QGIEL_LOC (MNUMCR)	REAL*4	Hist Q I/C EU consumption by Census (Bcf)
QIMP(3)	REAL*4	Hist quantity imports -- CAN,MEX,LNG (MMCF)
QT	REAL*4	Temp holding array (tot E.U. consumption)
SPCM	REAL*4	State commerical sector price of NG (87$/mcf)
SPEU	REAL*4	State elec generation sector price of NG (87$/mcf)
SPIN	REAL*4	State industrial sector price of NG (not used) (87$/mcf)
SPRS	REAL*4	State residential sector price of NG (87$/mcf)
SQCM	REAL*4	State commerical sector consumption of NG (MMCF)
SQEU	REAL*4	State elec generation sector consumption of NG (MMCF)
SQIN	REAL*4	State industrial sector consumptn of NG, not used (MMCF)

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
SQRS	REAL*4	State residential sector consumption of NG (MMCF)
TMAP (14)	INTEGER*4	Imp/Exp mapping border crossing positions to tot
UNITNUM	INTEGER*4	Unit number passed from file manager
XMAP(XNUM)	INTEGER*4	Map border crossing to supply source (1=Can, 2=Mex, 3=LNG)
YR	INTEGER*4	Historical year
Subroutine NGTDM_IMPORTSI		
CFR,CTO	INTEGER*4	From/to nodes for Can. imports
CNFPRC	REAL*4	Price of firm Can. imports at border xing
CNFSHR	REAL*4	Quantity or shr of firm Can. imports at border xing
CNIPRC	REAL*4	Price of interrup. Can. imports at border xing
CNISHR	REAL*4	Quantity or shr of interrup. Can. imports at border xing
IIMP,NSUPID	INTEGER*4	Region/type ID's
IRET	INTEGER*4	OML return code
ITYP	INTEGER*4	Supply type ID
NGREG,NSREG	INTEGER*4	Region/type ID's
Subroutine NGTDM_LPEI		
EXNODE	INTEGER*4	Import/export node counter
IRET	INTEGER*4	OML return code
ITYP	INTEGER*4	Supply type counter
NGREG	INTEGER*4	Region counter
Subroutine NGTDM_LPSI		
IRET	INTEGER*4	OML return code
NGREG, NSREG	INTEGER*4	Reg/subreg counters
NSUPID, ITYP	INTEGER*4	Supply type counter
Subroutine NGTDM_MAXPT		
DEST, I	INTEGER*4	Reg/Subreg counters

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
IRET	INTEGER*4	OML return code
NEWTAR	REAL*4	Realized TARIFF_I
NGREG, NSREG, SRC	INTEGER*4	Reg/Subreg counters
Subroutine NGTDM_NONUCI(NSEC)		
BASE_PR	REAL*4	Base Pr on Nonutil dmd curve
BASE_QTY	REAL*4	Base Qty on Nonutil dmd curve
DPRICE (NDSTEP)	REAL*4	Pr on Nonutil dmd curve steps
DQDEL (NDSTEP)	REAL*4	Length of step (Qty) on Nonutil dmd curve
DQUANT (NDSTEP)	REAL*4	Qty on Nonutil dmd curve
IRET	INTEGER*4	OML return code
NGREG, CENREG	INTEGER*4	NGTDM & Census reg ID's
NGTDM_CRVNONUFX	REAL*4	Func. to generate firm nonutil demand curve w/ elas
NGTDM_CRVNONUIX	REAL*4	Func. to generate Interrup. nonutil demand curve w/ elas
NS, NSEC	INTEGER*4	Counters
Subroutine NGTDM_NONUSI(NSEC)		
CENREG	INTEGER*4	Census region ID
EFF	REAL*4	Efficiency from node to end-use sector (Intraregional eff * Distributor eff)
IRET	INTEGER*4	OML return code
NSEC, NGREG	INTEGER*4	Sector & reg counters
Subroutine NGTDM_POST		
I,J	INTEGER*4	Counters
LP (NSUPSUB)	REAL*4	Lease and Plant
NSEC	INTEGER*4	Sector ID counter
Subroutine NGTDM_POSTNONU		
ADJ_DTAR_F(4,NNGREG)	REAL*4	Adjusted markup for firmtransportation sector to account for phase-out of subsidies (87$/mcf)

Local Variables Defined Within The NGAFM		
Variable Name	Format	Definition
AFP	REAL*4	Alternative fuel price for firm transportation sector (87$/mcf)
PERCDISC	REAL*4	DTAR Discount for the firm transportation sector as a % of the markup to the alternative fuel price
BETA	REAL*4	Variable used to phase-out firm transportation sector subsidies (0-1)
CENREG	INTEGER*4	Census region ID
DTAR_MAX	REAL*4	Maximum DTAR for firm transportation sector (87$/mcf)
DTAR_MIN	REAL*4	Minimum DTAR for firm transportation sector, adjusted TFLOOR with taxes (87$/mcf) (not used)
EFF	REAL*4	Efficiency from node to end-use sector (Intraregional eff * Distributor eff)
MINPRIND	REAL*4	Min price on IND for constant demand, 87$/mcf (not used)
NDISTAR_F(NONUSEC,NGTDM)	REAL*4	Firm distributor tariffs for nonutil sectors (87$/mcf)
NDISTAR_I(NONUSEC,NGTDM)	REAL*4	Interrup. distributor tariffs (87$/mcf)
NGREG,NSEC	INTEGER*4	Region/Sector counters
NREV_F(NGTDM)	REAL*4	Firm distributor revenues by region (million $)
NREV_I(NGTDM)	REAL*4	Interrup. distributor revenues by region (million $)
TOT_REV_NF	REAL*4	Total firm distributor revenues per sector (million $)
TOT_REV_NI	REAL*4	Total interrup. distributor revenue per sector (million $)
Subroutine NGTDM_POSTUTIL		
EFF	REAL*4	Efficiency from node to end-use sector (Intraregional eff * Distributor eff)
KK,I	INTEGER*4	NGTDM/EMM subregion counters
NGREG,NSREG	INTEGER*4	Region/Subregion counters
PERCDISC	REAL*4	Percent of alternate fuel price used to set price for elec generation sector competitive w/ resid.
AFP	REAL*4	Alternate fuel price used to set price for elec generation sector competitive w/ resid. (87$/mcf)

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
UINTD	REAL*4	(not used)
FLOOR	REAL*4	Minimum distributor tariff, used to set price for elec generation sector competitive w/ distillate (87$/mcf)
POILOLD	REAL*4	Avg. oil price used by EMM (87$/MMBTU)
PR_MIN	REAL*4	Min end-use gas pr for electric generation sector (87$/mcf)
TOT_REV_UF	REAL*4	Total firm revenue over all regions (million $)
TOT_REV_UI	REAL*4	Total interruptible revenue over all regions (million $)
UDISTAR_F(NGTDM,NGTDM)	REAL*4	Firm distributor tariffs for elec generator sector (87$/mcf)
UDISTAR_I(NGTDM,NGTDM)	REAL*4	Interrup. distributor tariffs for elec generator sector (87$/mcf)
UREV_F	REAL*4	Firm revenues by NGTDM region (million $)
UREV_I	REAL*4	Interruptible revenues by NGTDM region (million $)
UTIL_PR_ID	REAL*4	End-use price for elec generation sector competitive w/ distillate (87$/mcf)
UTIL_PR_IR	REAL*4	End-use price for elec generation sector competitive w/ resid (87$/mcf)
Subroutine NGTDM_PRE		
ADGLAG (9)	REAL*4	AD gas production last yr
ADG_TO_OIL(NSDOMREG)	REAL*4	Ratio of AD gas prod to oil prod for 1987-92
EMMREG	INTEGER*4	EMM region ID
HADGPRDOF(NOCSREG,1990:1993)	REAL*4	Hist AD gas prod offshore (87$/mcf)
HADGPRDON(6,1990:1993)	REAL*4	Hist AD gas prod onshore (87$/mcf)
I,J,K	INTEGER*4	Counters
NGREG, NSREG	INTEGER*4	Reg, subregion counters
OILLAG (9)	REAL*4	Oil prod last yr (MMBbl)
PALPHA	REAL*4	Assumed relative gas/oil price impact on AD gas prod
PFACT	REAL*4	Production factor for setting AD gas production

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
PGAS_TO_POIL	REAL*4	Avg hist wellhead price ratio for gas pr/wop for 1987-92
SREG	INTEGER*4	Supply region identifier
TEMP	REAL*4	Temporary holding variable
Subroutine NGTDM_SPLYSI(ITYP).		
IRET	INTEGER*4	OML return code
ITYP, NGREG, NSREG	INTEGER*4	Reg/Subreg/Supply type counters
K	INTEGER*4	Supply subregion ID (1-17,1-3)
NGPRD_L48	REAL*4	Supply curve function for lower 48 onshore production
NGPRD_OCS	REAL*4	Supply curve function for offshore production
NSUPID, NS	INTEGER*4	Supply counters
TEMP(NSSTEP)--not used	REAL*4	Not used
UNIT2	INTEGER*4	Unit number for output info written to NGDBUG2
Subroutine NGTDM_SUPCI(ITYP)		
DELSUP_PR	REAL*4	SUP_PR delta for iterations 1 & 2
IREG	INTEGER*4	NGTDM/OGSM subregion ID
IRET	INTEGER*4	OML return code
ITYP	INTEGER*4	Supply type
K	INTEGER*4	Supply Subregion ID (1-17,1-3).
MINSPR_FLG	LOGICAL	Flag indicating minimum supply price reached
MINSUP	REAL*4	Minimum supply (BCF)
MINSUP_PR(NSUPTYP,NGTDM,JSUP)	REAL*4	Minimum price on supply curve (87$/mcf)
MXFLAG	INTEGER*4	Maximum supply flag
NGPRD_L48	REAL*4	Supply function for onshore supply
NGPRD_OCS	REAL*4	Supply function for offshore supply
NGREG	INTEGER*4	Node ID
NGTDM_SUPCRV	REAL*4	Supply curve function

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
NS	INTEGER*4	Supply curve step number
NSREG	INTEGER*4	Supply array position
NSUPID	INTEGER*4	Supply source ID
OLDSUP_PR (NSUPTYP,NGTDM,JSUP)	REAL*4	Old SUP_PR used to calcWTSUP_PR
PER	REAL*4	Percent production not lease and plant
QMIN	REAL*4	Minimum supply quantity (BCF)
SPRICE (NSSTEP)	REAL*4	Price on supply curve steps (87$/mcf)
SQDEL (NSSTEP)	REAL*4	Length of steps (QTY) on supply curve (BCF)
SQUANT (NSSTEP)	REAL*4	QTY on supply curve (BCF)
UNIT2	INTEGER*4	Unit number for output info written to NGDBUG2
WTSUP_PR	REAL*4	Weighted avg SUP_PR
Subroutine NGTDM_SUPTEST(ITYP,NGREG,NSREG)		
DELSUPPR	REAL*4	(not used)
SUP_MIN	REAL*4	Minimum supply on supply curve (BCF)
TSUPPR	REAL*4	Supply PR as a function of QTY from prod func (87$/mcf)
ITYP,NGREG,NSREG	INTEGER*4	Counters
NGPRD_L48	REAL*4	Onshore NG production function
NGPRD_OCS	REAL*4	Offshore NG production function
OREG	INTEGER*4	OGSM supply region ID
P0,Q0	REAL*4	Wellhead pr (87$/mcf) and prod level (BCF) from OGSM
Subroutine NGTDM_TARDI		
ADJ	REAL*4	DTAR adjustment term resulting from delta between marginal and average firm node prices (87$/mcf)
EMMREG, CENREG, NSEC	INTEGER*4	Emm or Census reg ID, sector ID
IRET	INTEGER*4	OML return code
NGREG, NSREG	INTEGER*4	Reg/Subreg counters
Subroutine NGTDM_TARPI		

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
IRET	INTEGER*4	OML return code
NGREG, AN, I	INTEGER*4	Reg/Subreg counters
SRC, DEST	INTEGER*4	Source & dest nodes
Subroutine NGTDM_UTILCI		
BASE_PR	REAL*4	Base Pr on Util dmd curve
BASE_QTY	REAL*4	Base Qty on Util dmd curve
DPRICE (NDSTEP)	REAL*4	Pr on Util dmd curve steps
DQDEL (NDSTEP)	REAL*4	Length of step (Qty) on Util dmd curve
DQUANT (NDSTEP)	REAL*4	Qty on Util dmd curve
EMMREG, NS	INTEGER*4	Emm reg/subreg counter
IRET	INTEGER*4	OML return code
NGREG, NSREG	INTEGER*4	Reg/subreg counters
NGTDM_CRVUTILF	REAL*4	Coe (Firm service) util curve func.
NGTDM_CRVUTILIX	REAL*4	dmd curve function being tested
PRX	REAL*4	Conv. curve MAX or PARITY price
PR_FLAG	INTEGER*4	Conv. curve MAX/PAR price flag
Subroutine NGTDM_UTILSI		
EFF	REAL*4	Intrareg. * Dist. eff
EMMREG	INTEGER*4	EMM region ID
I	INTEGER*4	(not used)
IRET	INTEGER*4	OML return code
KK	INTEGER*4	NGTDM/EMM subregion counter
LAGPR	REAL*4	Lagged electric generators price
NGREG, NSREG	INTEGER*4	Reg/Subreg counters
PERCDISC,AFP	REAL*4	Dist tariff variables
POILOLD	REAL*4	Oil price used by EMM
PR_MIN	REAL*4	Min gas price from G/O ratio

Local Variables Defined Within The NGAFM		
Variable Name	Format	Definition
UINTD,FLOOR	REAL*4	Dist tariff variables
UTIL_PR_ID	REAL*4	Price of distillate to util (holding)
UTIL_PR_IR	REAL*4	Price of competitive to util (holding)
Subroutine OUTOGSM(OGSM_LP)		
CN_TOTFLO	REAL*4	For tot flow from Canada to U.S.
CN_TOTPRD	REAL*4	For tot Canadian production
CN_TOTREV	REAL*4	For tot Can. producer revenue
I,J,K	INTEGER*4	Counters
INBRD	INTEGER*4	Can. border xing for flow in (16,4)
LP2	REAL*4	Lease & plant for offshore
NGCAN_DEMAND	REAL*4	Canadian dmd function.
OGSM_LP (NSUPSUB)	REAL*4	Lease & plant consumption
PERLP	REAL*4	Total percent lease & plant
SUPREG	INTEGER*4	Supply reg counter
SUP_PQT_OFF (NOCSREG)	REAL*4	P*Q total for offshore prod
SUP_PQT_ON (NSUPREG)	REAL*4	P*Q total for onshore prod
SUP_QTY_TOFF (NOCSREG)	REAL*4	Total AD+NA+LP from offshore prod
SUP_QTY_TON (NSUPSUB)	REAL*4	Total AD+NA+LP from onshore prod
SUP_QT_OFF (NOCSREG)	REAL*4	Qty total for offshore prod
SUP_QT_ON (NSUPREG)	REAL*4	QTY total for onshore prod
TOFF	REAL*4	Offshore L48: AD+NA+LP
TOTPQ	REAL*4	Total P*Q
XSUPPLY	REAL*4	NA + AD, lower 48
Subroutine PIPE_REPORT		
FILE_MGR	INTEGER*4	Function which passes unit number
FNAME	CHARACTER*18	Filename ID
I,J,JJ,KK	INTEGER*4	Counters

Local Variables Defined Within The NGAFM		
Variable Name	Format	Definition
UNITNUM	INTEGER*4	Unit num passed from the file manager
Subroutine PROPEROUT(LP)		
CENREG	INTEGER*4	Census division 1-9
DEST	INTEGER*4	Destination node ID
I,J	INTEGER*4	Counters
LP (NSUPSUB)	REAL*4	
NGREG	INTEGER*4	NGTDM region 1-12
PFC (21)	REAL*4	Pipeline fuel consumption
PIPE	REAL*4	Pipeline fuel variable (temporary)
SRC	INTEGER*4	Source node ID
Subroutine READ_DTM(DIST0, TILT1, TILT2YR, TILT2, UTILT1, UTILT2, W_DIST, W_RESID, W_COAL, W_LPG, IPD1, IPD2YR, IPD2, IFLOOR, URPD1, URPD2YR, URPD2, URFLOOR, TST1, TST2YR, TFD1, TFD2YR, TFD2, UBENPER, UBENYRD, NONU_DTARF_DECL)		
CATG,KEY	INTEGER*4	Input variables used to initiate selected sensitivity runs
DIST0(3,NNGREG)	REAL*4	Base DTAR from hist input ($87/mcf)
FILE_MGR	INTEGER*4	Function to provide file unit number
FNAME	CHARACTER*18	DD name (in JCL on mainframe) of input/output file
IFLOOR(NNGREG)	REAL*4	Lower bound on DTAR markup ($87/mcf)
I,J,K	INTEGER*4	(not used)
IPD1(NNGREG)	REAL*4	User specified % discount (not used)
IPD2(NNGREG)	REAL*4	Alt user specified % discount (not used)
IPD2YR(NNGREG	INTEGER*4	Year switch for % discount (not used)
M,MSEC	INTEGER*4	Counters, indices
NONU_DTARF_DECL	REAL*4	Annual decline rate for firm nonutil dist tariff
RTOVALUE	INTEGER	Function to obtain value of input runtime parameter for sens analysis
TFD1	REAL*4	Federal gasoline users tax ($87/mcf)
TFD2	REAL*4	Alt adj to fed gasoline users tax ($87/mcf)

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
TFD2YR	INTEGER*4	Year to switch federal tax level
TILT1(3,NNGREG)	REAL*4	User adj to DTAR for res, comm, ind sectors ($87/mcf)
TILT2(3,NNGREG)	REAL*4	Alt. user adj to DTAR for res, comm, ind sectors ($87/mcf)
TILT2YR(3,NNGREG	INTEGER*4	Year to switch user adj level to DTAR fcr res, comm, indus
TST1(NNGREG)	REAL*4	State gasoline tax ($87/mcf)
TST2(NNGREG)	REAL*4	Alternate state gasoline tax ($87/mcf)
TST2YR(NNGREG	INTEGER*4	Year to switch state tax level
UBENPER	REAL*4	Percent of original benchmark factor (UBENORG) not phased out
UBENYRD	INTEGER*4	Num years to phase out UBENORG
UNITNUM	INTEGER*4	Unit number for input file
URFLOOR(NEMMSUB)	REAL*4	Lower bound on DTAR markup ($87/mcf)
URPD1(NEMMSUB)	REAL*4	User specified % discount (not used)
URPD2(NEMMSUB)	REAL*4	Alt % discount (not used)
URPD2YR(NEMMSUB	INTEGER*4	Year switch for setting % discount
UTILT1(NEMMSUB)	REAL*4	User adjustment to DTAR for F elec gen sector ($87/mcf)
UTILT2(NEMMSUB)	REAL*4	Alt. user adj to DTAR for F elec gen sector ($87/mcf)
UTILT2Y(NEMMSUB)	INTEGER*4	Year to switch adj to DTAR for F elec gen sector
W_COAL(NNGREG)	REAL*4	Ratio for coal (not used)
W_DIST(NNGREG)	REAL*4	Ratio (weight) for distillate (not used)
W_LPG(NNGREG)	REAL*4	Ratio for liquid petroleum gas (not used)
W_RESID(NNGREG)	REAL*4	Ratio for residual (not used)
Subroutine REPORTOUT		
I,J	INTEGER*4	Counters
IIMP	INTEGER*4	Import ID
NODE	INTEGER*4	Import node number
SUP_TOTAL	REAL*4	Placeholder for totals

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
Subroutine REPORT_GENERATOR		
I,J,K	INTEGER*4	Index variable
TEMP_F(NEMMSUB)	REAL*4	Temporary variable core (firm service) electric generators
TEMP_I(NEMMSUB)	REAL*4	Temporary variable noncore (int. service) electric generators
Subroutine REPORT_LOOP(NONU_DTAR)		
I,J,K	INTEGER*4	Index variables
NONU_DTAR(NONUSEC,NGTDM)	REAL*4	Non- electric generators distributor tar.
Subroutine SETSUPMX		
I,J	INTEGER*4	Indices
K	INTEGER*4	NGTDM/OGSM subregion ID (1-17)
NGAFM_ANGTS	REAL*4	Function to set max ANGTS supply to L48
NGIMP_CANX	REAL*4	Function to set max Can NG imports
NGIMP_LNG	REAL*4	Function to set max LNG NG imports
NGIMP_MEX	REAL*4	Function to set max Mex NG imports
NGPRD_L48X	REAL*4	Function to set max Onshore NG production
NGPRD_OCSX	REAL*4	Function to set max Offshore NG production
NGSUP_OTHR	REAL*4	Function to set max NG prod form other supplemental
NGSYN_LIQX	REAL*4	Function to set max SNG liq prod
STYP	INTEGER*4	Supply type identifier
SUPID	INTEGER*4	Supply counter
WPRLAGOF1(NOCSREG)	REAL*4	Offshore wellhead price 1 years lagged (87$/mcf)
WPRLAGOF2(NOCSREG)	REAL*4	Offshore wellhead price 2 year lagged (87$/mcf)
WPRLAGON1(NSUPSUB)	REAL*4	Onshore wellhead price 1 years lagged (87$/mcf)
WPRLAGON2(NSUPSUB)	REAL*4	Onshore well price 2 year lagged (87$/mcf)
Subroutine TOTAL_L48_PROD		
I	INTEGER*4	Counter

Local Variables Defined Within The NGAFM		
Variable Name	**Format**	**Definition**
EYR	INTEGER*4	End year of model run (i.e., 2000 or 2010)
Subroutine WRITE_SUPCRV		
ITYP	INTEGER*4	Supply type (1-8)
NGOG	INTEGER*4	NGTDM/OGSM subregion ID (onshore and offshore)
REG,SREG	INTEGER*4	Supply region index
STEP(NSSTEP)	REAL*4	Pr or Qty on supply curve steps
UNIT2	INTEGER*4	Unit number for output file NGDBUG2
VAL	CHARACTER*1	Defines if value represents P or Q on supply curve
Subroutine WRITE_SUPCRV2		
ITYP	INTEGER*4	Supply type (1-8)
K,R	INTEGER*4	Supply region ID
MAX_PR	REAL*4	Max price on supply curve (87$/mcf)
MINSUP_PR	REAL*4	Min price on supply curve (87$/mcf)
NGPRD_L48	REAL*4	Supply function for lower 48 onshore supply curve
NGPRD_OCS	REAL*4	Supply function for offshore supply curve
NGREG,NSREG	INTEGER*4	Counters, indices
P0,PA,PB,Q0,QA,QB	INTEGER*4	Prices and quantities on supply curve (87$/mcf and BCF)
PER	REAL*4	Percent production not lease and plant
FIXUP	REAL*4	Fixed supply (BCF)
QMIN	REAL*4	Minimum supply (BCF)
UNIT2	INTEGER*4	Unit number for output file NGDBUG2

Local Variables Defined Within the NGCEM		
Variable Name	**Format**	**Defintion**
Real Function CEMIMP_CAN(SUPID,FOREYR)		
FOREYR	INTEGER*4	Model year array position
SUPID	INTEGER*4	Can supply source (1-6)
Real Function CEMIMP_LNG(ILNG,TSTYR)		
ILNG	INTEGER*4	LNG terminal identifier
TSTYR	INTEGER*4	Test year for LNG imports
Real Function CEMPRD_L48X(IREG)		
IREG	INTEGER*4	NGTDM/OGSM subregions (1-17)
Real Function CEMPRD_L48(INVAL,VALUE,IREG)		
BASE	REAL*4	Intermediate value RES*(P/R)
INVAL	CHARACTER*1	Char. indicating if input is 'P' or 'Q'
IREG	INTEGER*4	NGTDM/OGSM region (1-17)
PER	REAL*4	Percent prod not lease & plant
VALUE	REAL*4	Input price or quantity
Real Function CEMPRD_OCSX(IREG)		
IREG	INTEGER*4	Offshore region (1-3)
Real Function CEMPRD_OCS(INVAL,VALUE,IREG)		
BASE	REAL*4	Intermediate value RES*(P/R)
INVAL	CHARACTER*1	Character indicating if the input is 'P' or 'Q'
IREG	INTEGER*4	Offshore region (1-3)
PER	REAL*4	Percent production not lease and plant
VALUE	REAL*4	Input price or quantity
Real Function NGCEM_ANGTS(TSTYR)		
TSTYR	INTEGER*4	Test year for ANGTS
Real Function NGCEM_PROD(INTYP,INREG.INPRC)		
CEMG	INTEGER*4	Number of foresight yrs in avg PCAP calculation

Local Variables Defined Within the NGCEM		
Variable Name	**Format**	**Defintion**
DELGPR (NPREG, 0:NPCAPYR)	REAL*4	Annual change in fore gas price
GPR(NPREG,0:NPCAPYR)	REAL*4	Forecast gas price
INPRC	REAL*4	Gas price in year T+N
INREG	INTEGER*4	Region number for on- or off-shore
INTYP	INTEGER*4	1-onshore, 2-offshore
I,J	INTEGER*4	Counter
LAGIYR	INTEGER*4	Year the last time func called
NPCAPYR	INTEGER*4	Num yrs prod cap calc after current
ONREG	INTEGER*4	NGTDM/OGSM subreg on-shore 1-17
OPR(NPREG,NPCAPYR)	REAL*4	Foresight oil wellhead price
PRDCAP (NPREG,, 0:NPCAPYR)	REAL*4	Productive capacity by OGSM region
PRDCAPLG1(NPREG)	REAL*4	Prod cap in CURIYR-1 by OGSM region
PRDCAPTOT	REAL*4	Total productive capacity
SREG	INTEGER*4	OGSM reg (1-6 on,7-9 off-shore)
STOT	REAL*4	Cur yr onshore prod in OGSM reg
SUBSHR	REAL*4	Prod in INREG / STOT
TT(NPREG)	REAL*4	TT=3 when EGR tax credit is on
Real Function NGCEM_SUPCRV(STYP,NODE_ID,NSREG,INVAL,VALUE,K)		
INVAL	CHARACTER*1	Variable type for value (Q/P)
K	INTEGER*4	Counter
NGPRD_L48	REAL*4	Lower 48 onshore supply func
NGPRD_OCS	REAL*4	Offshore supply func
NGSYN_LIQH	REAL*4	Supply function: gas from liq
NODE_ID	INTEGER*4	NGTDM node identifier
NSREG	INTEGER*4	Supply array position
STYP	INTEGER*4	Supply type identifier

Local Variables Defined Within the NGCEM		
Variable Name	**Format**	**Defintion**
SUPL_ID	INTEGER*4	OGSM region or supply number
VALU4	REAL*4	Hold R*8 value in R*4 variable
VALUE	REAL*8	P or Q for setting Q or P
Subroutine ALPHA_LOOP		
BKSTOP_FLAG	LOGICAL	Flag for backstop
ERRMSG	CHARACTER*180	Error message
FILE_MGR	INTEGER*4	Function to provide file unit number
FNAME	CHARACTER*18	DD name (in JCL on mainframe) of input/output file
IRET	INTEGER*4	OML return code
NUM_INFWRT	INTEGER*4	Number of infeasibility soln's written to output file
UNITNUM	INTEGER*4	Unit number for output file
Subroutine CEMBACK		
DEST, EMMREG	INTEGER*4	Counters
IRET	INTEGER*4	OML return code
NGREG,NSREG,NSEC,CENREG	INTEGER*4	Counters
Subroutine CEMBKSTOP_CHK(STOP_FLAG)		
EMMREG,CENREG	INTEGER*4	Region ID's
IRET	INTEGER*4	OML return code
NGREG,NSREG	INTEGER*4	Region ID's
NSEC	INTEGER*4	Sector ID
STOP_FLAG	LOGICAL	Backstop flag
Subroutine CEMCANIMP		
AKFLOW	REAL*4	Alaska supply along arc 18 to 9
DEST	INTEGER*4	Destination node ID
FOREYR	INTEGER*4	CEM forecast year
IEXP	INTEGER*4	Export node counter

Local Variables Defined Within the NGCEM		
Variable Name	Format	Defintion
IRET	INTEGER*4	OML return code
NS	INTEGER*4	Step number on capacity curve
NXTYR	INTEGER*4	Mapped YR= current YR +1
OFAK	REAL*4	OffPK firm Alaska imports
OFFLOW	REAL*4	OffPK firm flow--imports
OIFLOW	REAL*4	OffPK intrp flow--imports
PFAK	REAL*4	PK firm Alaska imports
PFFLOW	REAL*4	PK firm flow--import arcs
PIFLOW	REAL*4	PK intrp flow--imports
SRC	INTEGER*4	Source node ID
TOTAK	REAL*4	Total Alaska imports
TOTCAN	REAL*4	Total Canadian imports
UO	REAL*4	Coeff in CON**N**
UP	REAL*4	Coeff in CPIN**N**
UPF	REAL*4	Coeff in CPFN**N**
YRB4	INTEGER*4	IYRSWT for yr before CEM year
Subroutine CEMCANSUP		
IRET	INTEGER*4	OML return code
ITYP,NGREG,NSREG,NS,NSUPID,DEST	INTEGER*4	Counters
UPO	REAL*4	Off-peak supply utilization
UPP	REAL*4	Peak supply utilization
YRB4	INTEGER*4	Array position of year before CEM year
Subroutine CEMDMD		
ARCSRC	INTEGER*4	Source node along border crossing arc
CENREG,EMMREG	INTEGER*4	Counters
EXPT.	REAL*8	Total export into Can at border crossing

Local Variables Defined Within the NGCEM		
Variable Name	**Format**	**Defintion**
FOREYR	INTEGER*4	Forecast year
IARG	INTEGER*4	INTEGER*4
IRET	INTEGER*4	OML return code
I,NS,DEST,SRC	INTEGER*4	Counters
NGEXP_CAN,NGEXP_MEX	REAL*4	Canada and Mexican export function
NGREG,NSREG	INTEGER*4	Counters
OFFLOW	REAL*8	OFFPK-F flow along border crossing arc
OIFLOW	REAL*8	OFFPK-I flow along border crossing arc
PFFLOW	REAL*8	PK-F flow along border crossing arc
PIFLOW	REAL*8	PK-I flow along border crossing arc
UO	REAL*8	Coeff for OFF-PK capacity constraint
UP	REAL*8	Coeff for PK capacity constraint
UPF	REAL*8	Coeff for PK-F capacity constraint
Subroutine CEMFLOWNN		
AFMYR	INTEGER*4	IYRSWT for current AFM year
DEST	INTEGER*4	Destination node ID
FCAP	REAL*4	Effective PCAP based on firm flow
FOREYR	INTEGER*4	CEM forecast year
IRET	INTEGER*4	OML return code
I,J,K	INTEGER*4	Counters
MINXOF	REAL*8	Min flow offpeak, firm
MINXPF	REAL*8	Min flow peak, firm
NEW	REAL*4	PCAP added between AFMYR & CEMYR
OF	REAL*4	Effective off-peak firm flow
PCAP	REAL*4	Min effective PCAP
PF	REAL*4	Effective peak firm flow
SRC	INTEGER*4	Source node ID

Local Variables Defined Within the NGCEM		
Variable Name	Format	Defintion
YRB4	INTEGER*4	IYRSWT for year before CEM year
Subroutine CEMINP		
IO	INTEGER*4	IO unit number
IY	INTEGER*4	Year T + N + H
IYN	INTEGER*4	Year T + N
I,J	INTEGER*4	Counters
Subroutine CEMLPCAP		
IRET	INTEGER*4	OML return code
I,NS,NGREG,NSREG	INTEGER*4	Counters
SRC,DEST	INTEGER*4	Source and destination nodes
UO	REAL*4	Coeff in CON**N** cap constraint
UP	REAL*4	Coeff in CPI**N** cap constraint
UPF	REAL*4	Coeff in CPF**N** cap constraint
Subroutine CEMLPNE		
EFF	REAL*4	Intrareg. eff * Dist. eff
IRET	INTEGER*4	OML return code
NSEC,EMMREG	INTEGER*4	Counters
NGREG,NSREG,CENREG,	INTEGER*4	Counters
Subroutine CEMLPNN		
IRET	INTEGER*4	OML return code
I,J,K	INTEGER*4	Counters
SRC,DEST	INTEGER*4	Source and destination nodes
Subroutine CEMLPSNB		
IRET	INTEGER*4	OML return code
NGREG,NSREG,ITYP	INTEGER*4	Counters
NSUPID	INTEGER*4	Supply ID
Subroutine CEMLPSNY		

Local Variables Defined Within the NGCEM		
Variable Name	**Format**	**Defintion**
IRET	INTEGER*4	OML return code
NGREG,NSREG,ITYP	INTEGER*4	Counters
NSUPID	INTEGER*4	Supply ID
OPPRCFAC	REAL*4	Hist OP avg well prc/annual avg well prc
PKPRCFAC	REAL*4	Hist PK avg well prc/annual avg well prc
Subroutine CEMLPST		
IRET	INTEGER*4	OML return code
I,J	INTEGER*4	Counters
Subroutine CEMLPST_UTIL		
IRET	INTEGER*4	OML return code
I,J,NS	INTEGER*4	Counters
Subroutine CEMLPSUP		
IRET	INTEGER*4	OML return code
ITYP,NGREG,NSREG	INTEGER*4	Counters
NGTDM_SUPCRV	REAL*4	Supply curve function
NS,NSUPID	INTEGER*4	Counters
UPO	REAL*4	Off-peak supply utilization
UPP	REAL*4	Peak supply utilization
Subroutine CEMOUT		
IO	INTEGER*4	IO unit
IY	INTEGER*4	Year
I,J	INTEGER*4	Counters
Subroutine CEMPCAP()		
CATG,KEY	INTEGER*4	Input variables used to initiate selected sensitivity runs
DEST,SRC	INTEGER*4	Destination,source nodes
FOREYR	INTEGER*4	CEM model year
IEXP	INTEGER*4	Export node counter

Local Variables Defined Within the NGCEM		
Variable Name	Format	Defintion
I,NS,IRET	INTEGER*4	Counters
NSREG,NGREG	INTEGER*4	Counters
NXTYR	INTEGER*4	Mapped YR= CURIYR+1
PCAPCURV	REAL*4	Price on CEM cap. curve
QCAPCURV	REAL*4	Quantity on CEM cap. curve
QDEL	REAL*4	Length of step on curve
RTOVALUE	INTEGER	Function to obtain value of input runtime parameter for sens analysis
YRB4	INTEGER*4	Year before forecast year
Subroutine CEMPIPE_REPORT		
FILE_MGR	INTEGER*4	Function to open/close file
FNAME	CHARACTER*18	Filename
FSUP(NSUPTYP,NGTDM,JSUP)	REAL*4	Regional firm supply results
IRET	INTEGER*4	OML return code
ISUP(NSUPTYP,NGTDM,JSUP)	REAL*4	Regional interrupible supply results
ITYP,NSUPID	INTEGER*4	Region/loop ID's
I	INTEGER*4	Counter
NGREG,NSREG	INTEGER*4	Region/loop ID's
UNITNUM	INTEGER*4	File channel
Subroutine CEMREPORT		
I,J	INTEGER*4	Counters
Subroutine CEMREPORTOUT		
I	INTEGER*4	Counter
NGREG	INTEGER*4	Counter
Subroutine CEMSCAP()		
FOREYR	INTEGER*4	CEM forecast year (e.g., 3 or 4 or...)

Local Variables Defined Within the NGCEM		
Variable Name	**Format**	**Defintion**
IRET	INTEGER*4	OML return code
NS,NGREG,I	INTEGER*4	Counters
PSTRCURV(CEMNS)	REAL*4	PR on CEM storage cap curve
QDEL	REAL*4	Length of step on capacity curve
QSTRCURV(CEMNS)	REAL*4	QTY on CEM storage cap curve
YRB4	INTEGER*4	Array position for prior CEM yr (up to parameter CEMN)
Subroutine CEMSUPCI(ITYP)		
DELSUP_PR	REAL*4	Price delta between 1st step and P0 step on supply curve (87$/mcf)
IREG	INTEGER*4	NGTDM/OGSM region ID
IRET	INTEGER*4	OML return code
ITYP	INTEGER*4	Supply type
K	INTEGER*4	Counter
MINSPR_FLG	LOGICAL	Flag indicating min PR reached and DELSUP_PR set
MINSUP	REAL*4	Minimum supply
MINSUP_PR(NSUPTYP,NGTDM,JSUP)	REAL*4	Min PR on supply curve (87$/mcf)
MXFLAG	INTEGER*4	Maximum supply flag
NGCEM_SUPCRV	REAL*4	Function - supply curve
NGPRD_L48	REAL*4	Supply func for onshore production
NGPRD_OCS	REAL*4	Supply func for offshore production
NGREG	INTEGER*4	Node ID
NS	INTEGER*4	Supply curve step number
NSREG	INTEGER*4	Supply array position
NSUPID	INTEGER*4	Supply source ID
PER	REAL*4	Percent production not lease and plant
QMIN	REAL*4	Holds min supply qty (BCF)
SHR	REAL*4	Supply share along network

Local Variables Defined Within the NGCEM		
Variable Name	**Format**	**Defintion**
SPRICE(NSSTEP)	REAL*8	Supply price on curve
SQDEL(NSSTEP)	REAL*8	Delta on curve
SQUANT(NSSTEP)	REAL*8	Supply quantity on curve
SRC,DEST	INTEGER*4	Source and destination nodes
Subroutine GETCAP84		
NS	INTEGER*4	Step on capacity expansion curve
PRICE(CEMNS),QTY(CEMNS)	REAL*4	Price and quantity pairs used to define the cap expansion curve (93$/mcf, BCF)
Subroutine GETDEMANDS		
DEMANDF (NONUSEC,NNGREG)	REAL*4	Converted forecasted demand
DEMANDF_U(NEMMSUB)	REAL*4	Converted forecasted demand
DEMANDI (NONUSEC,NNGREG)	REAL*4	Converted forecasted demand
EFF	REAL*4	Intrareg. EFF * DIST. EFF
FOREYRH	INTEGER*4	Forecast year (T + N + H)
FOREYRN	INTEGER*4	Forecast year (T + N)
I,J,K,NSREG	INTEGER*4	Counters
OIDMDTOT(NNGREG)	REAL*4	OFF-PK noncore (interruptible service) total demands
PIDMDTOT(NNGREG)	REAL*4	PK noncore (interruptible service) total demands
Subroutine GETSOLUTION1		
IRET	INTEGER*4	OML return code
I,NS,NGREG	INTEGER*4	Region/loop ID's
NEWCAP	REAL*8	New capacity
SRC,DEST	INTEGER*4	Region/loop ID's
Subroutine GETSOLUTION2		
I,IRET,NGREG	INTEGER*4	Region/loop ID's
SRC,DEST	INTEGER*4	Region/loop ID's

Local Variables Defined Within the NGCEM		
Variable Name	**Format**	**Defintion**
OFSTR,OISTR	REAL*4	Storage flows
PFSTR,PISTR	REAL*4	Storage flows
Subroutine HORZ		
I	INTEGER*4	Counter
Subroutine MATR_COEFF		
I	INTEGER*4	Counter
Subroutine NGCEM_ADJCAP(SRC,DEST,PCAPCURV,QCAPCURV)		
I	INTEGER*4	Counter
NXTYR	INTEGER*4	Mapped YR= CURRENT YR +1
PCAPCURV	REAL*4	Price on CEM cap. curve
QCAP	REAL*4	Quantity on capacity curve
QCAPCURV(CEMNS)	REAL*4	Quantity on CEM cap. curve
SRC,DEST,NS	INTEGER*4	Counters
STEPFLAG	INTEGER*4	Flag for PCAPMAX < QCAP
SUMPQ	REAL*4	Sum of PRICE * QUANTITY
SUMQ	REAL*4	Sum of quantity
Subroutine NGCEM_ADJSTR(NODEID,PSTRCURV,QSTRCURV)		
I	INTEGER*4	Counter
NODEID,NS	INTEGER*4	Counters
NXTYR	INTEGER*4	Mappec YR= CURRENT YR +1
PSTRCURV(CEMNS)	REAL*4	Price on CEM cap. curve
QSTR	REAL*4	Quantity on storage capacity curve
QSTRCURV(CEMNS)	REAL*4	Quantity on CEM cap. curve
STEPFLAG	INTEGER*4	Flag for PSTRMAX < QSTR
SUMPQ	REAL*4	Sum of PRICE * QUANTITY
SUMQ	REAL*4	Sum of quantity
Subroutine NGCEM_AFMUTILZ(SRC;DEST)		

Local Variables Defined Within the NGCEM		
Variable Name	**Format**	**Defintion**
FOREYR	INTEGER*4	CEM forecast year
F_FLOW,T_FLOW,REC	REAL*4	Temp flows
SRC,DEST	INTEGER*4	Region/loop ID's
OFAK	REAL*4	Off-peak firm ANGTS supply
PFAK	REAL*4	Peak firm ANGTS supply
P_FLOW,O_FLOW	REAL*4	Temp flows
Subroutine NGCEM_PCAPMEX		
FOREYR	INTEGER*4	CEM forecast year (e.g., 3,4,...)
DEST,SRC	INTEGER*4	Destination and source node ID
I	INTEGER*4	Counter
IIMP	INTEGER*4	Import node ID for Mex (7-9)
Subroutine NGCEM_SUPMX		
BASE	REAL*4	Intermediate value RES*(P/R)
CEMIMP_CAN	REAL*4	Function setting Canadian demand
CEMIMP_LNG	REAL*4	Function setting LNG import volumes
CEMPRD_L48X	REAL*4	Function setting maximum onshore supply levels
CEMPRD_OCSX	REAL*4	Function setting maximum offshore supply levels
FOREYR	INTEGER*4	CEM forecast year
ILOC	INTEGER*4	Array location
I,J	INTEGER*4	Indices
NGCEM_ANGTS	REAL*4	Function
NGIMP_MEX	REAL*4	Function
NGSUP_OTHR	REAL*4	Function
NGSYN_LIQX	REAL*4	Function setting maximum levels of synthetic gas from liq
STYP	INTEGER*4	Supply type ID
SUPID	INTEGER*4	Supply source ID
Subroutine NGTDM_CEM2		

Local Variables Defined Within the NGCEM		
Variable Name	**Format**	**Defintion**
ACTFILE/'ACTFCEM '/	CHARACTER*8	OML DB containing LP problem
ACTPROB/'ACTPROB'/	CHARACTER*8	OML LP problem name
ALPHA	REAL*8	Fraction of lower 48 interrup. demand allowed to be met (currently=1)
ALPHA_BEG,ALPHA_END	INTEGER*4	(not used)
CATG,KEY	INTEGER*4	Input variables used to initiate selected sensitivity runs
CEMBYT	INTEGER*4	Size of CEM LP workspace
DECK/'CEMDECK '/	CHARACTER*8	OML LP deck name
ERRMSG	CHARACTER*180	Error message
FILE_MGR	INTEGER*4	File manager function
FNAME	CHARACTER*18	Filename for NGDBUG2 LP output
IRET	INTEGER*4	OML return code
MODEL	INTEGER*4	Size of the CEM LP workspace in bytes
RTCOD	INTEGER*4	Return code from OML subroutine GOMHOT
RTOVALUE	INTEGER	Function to obtain value of input runtime parameter for sens analysis
TEMPACT	CHARACTER*8	Temporary storage for ACTFILE name
UNITNUM	INTEGER*4	Unit number for NGDBUG2 output file
Subroutine NGTDM_DATASET2		
(no local variables)		
Subroutine POST_PROCESS		
I,SRC,DEST	INTEGER*4	Region/loop ID's
MAXUTILZ_T	REAL*4	Max UTILZ_T based on PUTIL,OUTIL
Subroutine READ_CEM_DATA		
FILE_MGR	INTEGER*4	Function to open/close file
FNAME	CHARACTER*18	Filename
I,J,K	INTEGER*4	Counters
UNITNUM	INTEGER*4	Unit number of open file

Local Variables Defined Within the NGCEM		
Variable Name	**Format**	**Defintion**
Subroutine RESETMATRIX		
IRET	INTEGER*4	OML return code
I,NS,NGREG	INTEGER*4	Region/loop ID's
SRC,DEST	INTEGER*4	Region/loop ID's
UP	REAL*8	Peak utilization
USP	REAL*8	Storage utilization
Subroutine RESET_RHS		
IRET	INTEGER*4	OML return code
I,NGREG,SRC,DEST	INTEGER*4	Region/loop ID's
Subroutine SETNO_CHANGE		
(no local variables)		
Subroutine UPDTRHS(ALPHA)		
ALPHA	REAL*8	ALPHA
IRET	INTEGER*4	OML return code
VALUE	REAL*8	Placeholder for OML

Local Variables Defined Within the NGPTM

Variable Name	Format	Definition
Integer Function FINDEX(MINPID, PIPEID)		
FOUND	LOGICAL	Indicates a pipeline ID match within search loop
I	INTEGER*4	Index number
MINPID, PIPEID	INTEGER*4	Passed variables
Integer Function PREVIOUS_RATE_DESIGN(NEW_RD)		
FOUND	LOGICAL	Indicates a pipeline ID match within search loop
I	INTEGER*4	Rate design index
NEW_RD	INTEGER*4	New rate design
READIN(MAX_DESIGN)	INTEGER*4	All rate designs read in
Integer Function RATE_DESIGN(PIPELN, YEAR)		
PIPELN	INTEGER*4	Pipeline ID index
PREVIOUS_RATE_DESIGN	INTEGER*4	Previous rate design used
PREVRD	INTEGER*4	Previous rate design used
RD	INTEGER*4	Index of new rate design to be used
YEAR	INTEGER*4	Year of model run
Subroutine NGTDM_PTM		
AF, AT, E, N, P, II	INTEGER*4	Index variables
CATG,KEY	INTEGER*4	Input variables used to initiate selected sensitivity runs
DYR,CT	INTEGER*4	(not used)
RTOVALUE	INTEGER	Function to obtain value of input runtime parameter for sens analysis
Subroutine PTM0_READ_ALLOCATION(RD)		
FILENO	INTEGER*4	Line item index
FILE_MGR	INTEGER*4	Function to open/close file
FNAME	CHARACTER*18	Filename
I	INTEGER*4	Line item index
IALLO	INTEGER*4	Unit number of file to be read in

Local Variables Defined Within the NGPTM		
Variable Name	Format	Definition
RD	INTEGER*4	Rate design index
Subroutine PTM1_CHECK_TARIFFS		
AF, AT, E, N, P	INTEGER*4	Index variables
Subroutine PTM2_BASE_YEAR_INITIALIZATION		
A	INTEGER*4	Pipeline arc index
ADIT_FD	REAL*4	Dummy variable of existing pipe line used by regression eq.
AF, AT, N, YR, I	INTEGER*4	Index variable
CAPEXP	REAL*4	Capacity expansion size
CCOST	REAL*4	Capital cost to expand 1 unit of pipeline
CSTFAC	REAL*4	Factor to accommodate regional diff. in cost
CT	INTEGER*4	Cost type, 1=transportation, 2=storage
DDA_FD	REAL*4	Dummy variable of existing pipe line used by regression eq
DOLYR,DYR	INTEGER*4	Year dollars represented by input data (1990, etc; 1,2,etc)
E	INTEGER*4	Expansion step on cost curve
EOD	CHARACTER*1	End of data indicator
EOF	INTEGER*4	End of file indicator
EXPFAC	REAL*4	Mult. factor for increasing capacity from base
FACTOR	REAL*4	Factor to inc. or dec. cost due to region
FD(100)	INTEGER*4	(not used)
FILE_MGR	INTEGER*4	Function to open/close file
FINDEX	INTEGER*4	Function to find index of READIN pipe ID
FNAME	CHARACTER*18	Filename
G	INTEGER*4	Generic pipeline index
GEN_ID /9999/	INTEGER	Generic pipeline company beginning index ID
IFORM	INTEGER*4	I/O file unit for FORM2 data file
IPTAR	INTEGER*4	I/O file unit for PTARIFF file
IRDES	INTEGER*4	I/O file unit for RATE DESIGN file

Local Variables Defined Within the NGPTM		
Variable Name	**Format**	**Definition**
MAX_MACRS_YR	INTEGER*4	Number of yr in MACRS depreciation schedule
MINPID	INTEGER*4	Minimum index number to start search from
OWC_FD	REAL*4	Dummy variable of existing pipe line used in regression eq
P	INTEGER*4	Pipeline arc index
PIPEID	INTEGER*4	Pipeline ID number
PIPENM	CHARACTER*32	Pipeline company name
PIPEYR	INTEGER*4	Year of model run
PREVAF	INTEGER*4	Previous arc from index
PREVAT	INTEGER*4	Previous arc to index
PREVID	INTEGER*4	Previously read in ID
PREVN	INTEGER*4	Previous node index
STEP	INTEGER*4	Step number on the capacity expansion curve
T	INTEGER*4	Pipeline type, 1=individual, 2=generic
TAG_FD	REAL*4	Dummy variable of existing pipe line used in regression eq
TEMP	CHARACTER*10	(not used)
TNS	REAL*4	Fraction of total gas given to a CD point
TOM_FD	REAL*4	Dummy variable of existing pipe line used in regression eq
TPFES, TCMES, TLTD	REAL*4	Temporary read variables
Subroutine PTM3_REPORT_BASE_YEAR		
AF,AT,N,P,T,YR	INTEGER*4	Index variable
EOF	INTEGER*4	End of file indicator
FINDEX	INTEGER*4	Function to find index of READIN pipe ID
M	REAL*16	Million (in decimal)
MINPID	INTEGER*4	Minimum index number to start search from
PIPEID	INTEGER*4	Pipeline company ID
PIPENM	CHARACTER*32	Pipeline company name
PREVID	INTEGER*4	Previously read in ID

Local Variables Defined Within the NGPTM		
Variable Name	**Format**	**Definition**
TOTRAT	REAL*4	Total shares for a pipeline
Subroutine PTM4_BASE_YEAR_PIPELINE		
AF, AT, I, P, N, E, RD	INTEGER*4	Index variable
RATE_DESIGN	INTEGER*4	RATE_DESIGN function
Subroutine PTM5_CAPACITY_COST_CURVE		
AF,AT,E,I,N,P,RD	INTEGER*4	Index variable
CAPUNIT	REAL*4	Capital cost based on historical cost
CAP_STEP	REAL*4	Capacity difference between step 1 and 2
CUNIT	REAL*4	Capital cost based on first step on curve
RATE_DESIGN	INTEGER*4	RATE_DESIGN function
Subroutine PTM6_FORECAST_PIPELINE		
AK_FLOW,DEL_AKFLOW	REAL*4	Alaska flow variables in node 18
RATE_DESIGN	INTEGER*4	RATE_DESIGN function
RD,AF,AT,N,P,I	INTEGER*4	Index variable
SRC_AKCAN	LOGICAL	Flag indicating input node for ANGTS (node 18)
Subroutine PTM7_FORECAST_COST(P, T, CT)		
ADIT_ADIT	REAL*4	Est. coef for the accum. deffered inc. tax
ADIT_GPIS	REAL*4	Est. coef for the gross plant in service
ADIT_NETPLT	REAL*4	Coef. for net plant in service in ADIT
CHANGE_WAGE	REAL*4	% chg of wage index to % chg GDP
CHANGE_PEQUIP	REAL*4	% chg of producer price index to % chg GDP
DDA_NETPLT, DDA_DEPSHR	REAL*4	DDA coeff. on NETPLT term; DEPSHR and PDEPSHR terms
GDPINFL	REAL*4	GDP inflator
NEWCOST	REAL*4	New facility cost in nominal dollars
OWC_BETA0	REAL*4	Coef for gross plant in service
OWC_BETA1	REAL*4	Coef for GDP deflator index

Local Variables Defined Within the NGPTM		
Variable Name	Format	Definition
OWC_BETA2	REAL*4	Coef for current model year trend
OWC_CONST	REAL*4	Intercept term
OWC_RHO	REAL*4	RHO value from autoregressive trans.
P, T, PT, CT, I ,YR	INTEGER*4	Index variables
PGPIS	REAL*4	Previous year's GPIS
TAG_SALARY	REAL*4	Salary in TAG eqn for existing pipe line
TOMI1, TOMI2	REAL*4	Total increment of O&M cost, used for sensitivity testing
TOM_SALARY, TOM_PP	REAL*4	Salary, previous salary in TOM eqn
TYEAR	REAL*4	Model year
WAGE_RATIO	REAL*4	Ratio of wage index to ratio of GDP index
Subroutine PTM8_FORECAST_GENERIC		
AF,AT,CT,I,N,P,RD	INTEGER*4	Index variable
CUREXP	REAL*4	Total expansion prior to this forecast year
PREEXP	REAL*4	Total expansion prior to this forecast year
RATE_DESIGN	INTEGER*4	RATE_DESIGN function
Subroutine PTM9_EXPAND_GENERIC(EXPCAP, HISCAP, RD, P, CT)		
AF,AT,CT,P,RD,YR	INTEGER*4	Index variable
AVAIL	REAL*4	Capacity available to be expanded
CAPEXP	REAL*4	Capacity expansion size
EXPAND	REAL*4	Capacity to be expanded after complete exp.
EXPCAP	REAL*4	Capacity to be expanded
HISCAP	REAL*4	Historically existing capacity
NCAE	REAL*4	New cap. exp. expenditures allowed in the
S	INTEGER*4	Step index for capacity cost curve
Subroutine PTMA_CALCULATE_COST(P, T, CT)		
APRB	REAL*4	Adjusted pipeline rate-base
ATP	REAL*4	After-tax profits

Local Variables Defined Within the NGPTM		
Variable Name	**Format**	**Definition**
CMEN	REAL*4	Return on common equity
CMER	REAL*4	Common equity rate of return (fraction)
CT	INTEGER*4	Cost type, 1=transportation, 2=storage
FIT	REAL*4	Federal income tax
FSIT	REAL*4	Federal and state income tax
I	INTEGER*4	Line item index
LTDN	REAL*4	Return on long-term debt
LTDR	REAL*4	Long-term debt rate (fraction)
NIS	REAL*4	Net capital cost of plant in service
P	INTEGER*4	Pipeline index
PFEN	REAL*4	Return on preferred stock
PFER	REAL*4	Preferred stock rate (fraction)
SIT	REAL*4	State income tax
T	INTEGER*4	Pipeline type, 1=individual, 2=generic
TCOS	REAL*4	Total cost-of-service
TNOE	REAL*4	Total normal operating expenses
TOTAX	REAL*4	Total federal and state income tax liability
TOTCAP	REAL*4	Total capitalization
TRR	REAL*4	Total revenue credits to cost-of-service
TRRB	REAL*4	Total return on rate-base (before taxes)
WAROR	REAL*4	Weighted-average before-tax return on capital
Subroutine PTMB_REPORT_LINE_ITEMS(P, RD)		
AF, AT, I, J, N	INTEGER*4	Index variable
LINE_HEADER(11)	CHARACTER*30	Report heading
LINE_SUB(18)	CHARACTER*37	Report subheading
M	REAL*4	Million (decimal value)
P	INTEGER*4	Pipeline ID index

Local Variables Defined Within the NGPTM		
Variable Name	**Format**	**Definition**
RD	INTEGER*4	Rate design index
TRFR, TRVR, TRFU, TRVU, TSF, TSV	REAL*4	Accumulate total.
Subroutine PTMC_REPORT_ARC_COST		
AF, AT, N	INTEGER*4	Index variable
TFCR, TVCR, TFCU, TVCU, TFCS, TVCS	REAL*4	Accumulate total.
Subroutine PTMD_ALLOCATE_ARC_LEVEL_COST(EX)		
AF, AT, N, P, T	INTEGER*4	Index variable
CIS	REAL*4	Costs assigned to noncore (interruptible service) customer
EX	INTEGER*4	Expansion step index
F	REAL*4	Fixed storage cost / working gas capacity
FADFS	REAL*4	Allocation determinant for fixed costs in firm
FADIS	REAL*4	Allocation determinant for fixed costs in interrup.
FCSN	REAL*4	Fixed cost storage rate, non-jurisdictional
FCST	REAL*4	Total fixed cost storage rate
INCR_LIMIT	REAL*4	Maximum tariff increase allowed for a year
RADJ	REAL*4	Adjustment factor for discounting (ratio)
RCFS	REAL*4	Reservation costs assigned to core (firm service) customer
UCFS	REAL*4	Usage costs assigned to core (firm service) customers
V	REAL*4	Variable storage cost / working gas capacity
VADFS	REAL*4	Allocation determinant for var. costs in firm
VADIS	REAL*4	Allocation determinant for var. costs in interrup.
VCSN	REAL*4	Variable cost storage rate, non-jurisdictional
VCST	REAL*4	Total variable cost storage rate
VSUM	REAL*4	Total variable costs for firm and interruptible
WGCTT	REAL*4	Total working gas capacity
Subroutine PTME_REPORT_BASE		

Local Variables Defined Within the NGPTM		
Variable Name	**Format**	**Definition**
AF, AT, E, N, P	INTEGER*4	Index variable
Subroutine PTMF_REPORT_FORECAST		
AF, AT, N	INTEGER*4	Index variable
Subroutine PTMG_REPORT_BOTH		
AF, AT, N, P	INTEGER*4	Index variable
Subroutine PTMH_REPORT_CAPACITY_COST_CURVE		
(no local variables)		
Subroutine PTMI_SCALE_LINE(P, CT, E, EXPCAP, HISCAP)		
AF	INTEGER*4	Convert pipeline index to source node
AT	INTEGER*4	Convert pipeline index to dest. node
CT	INTEGER*4	Cost type (1=transportation, 2=storage)
E	INTEGER*4	Expansion index
EXPCAP	REAL*4	Expansion capacity size
FACTOR	REAL*4	Scaling factor for line item
HISCAP	REAL*4	Historical capacity size
P	INTEGER*4	Pipeline index
Subroutine PTMJ_TRNS_COST_OF_SERVICE(RD)		
I, RD	INTEGER*4	Index variable
RF	REAL*4	Fixed cost
RV	REAL*4	Variable cost
Subroutine PTMK_STORAGE_COST_OF_SERVICE(RD)		
I, RD	INTEGER*4	Index variable
Subroutine PTML_ADJ		
AF, AT, E, N, P	INTEGER*4	Index variable
Subroutine PTMM_ADJSTR(NODEID,PTM_SCAP)		
MAPYR	INTEGER*4	Mapped yr= current yr
NODEID, NS	INTEGER*4	Counters

Local Variables Defined Within the NGPTM		
Variable Name	**Format**	**Definition**
PR_ADJ	REAL*4	Price delta
PTM_SCAP	REAL*4	Tariff
QSTRMAX	REAL*4	Current year max cap
Subroutine PTMN_ADJCAP(SRC,DEST,PTM_PCAP)		
MAPYR	INTEGER*4	Mapped yr= current yr
PR_ADJ	REAL*4	Price delta
PTM_PCAP	REAL*4	Tariff
QCAPMAX	REAL*4	Current year max cap
SRC, DEST, NS	INTEGER*4	Counters
Subroutine PTMO_REPORT_GENERIC_LINE		
AF, AT, CT, P, T	INTEGER*4	Index variable
M	REAL*16	Million (in decimal)
Subroutine PTMP_REPORT_EXPANSION(P,CT,RD,PREEXP,CUREXP, ASKEXP)		
AF,AT,I,J,M,N,T	INTEGER*4	Index variable
ASKEXP	REAL*4	Expansion size asked for
COSTTYPE	CHARACTER*15	Row heading for report
CT	INTEGER*4	Type of cost 1=trans, 2=storage
CUREXP	REAL*4	Avail. exp. size for current forecast year
LINE_HEADER(11)	CHARACTER*30	Line heading for report
LINE_SUB(18)	CHARACTER*37	Line subheading for report
P	INTEGER*4	Pipeline ID index
PREEXP	REAL*4	Expansion size before current expansion
RD	INTEGER*4	Rate design index
TRFR, TRVR, TRFU, TRVU, TSF, TSV	REAL*4	Accumulate total.
Subroutine PTMQ_REPORT_FORECAST_GENERIC ! NOT BEEN CALLED		
(no local variables)		

Local Variables Defined Within the NGPTM		
Variable Name	**Format**	**Definition**
Subroutine PTMR_REPORT_COST_COMPONENTS		
P	INTEGER*4	Counter for arc ID
Subroutine PTMS_REPORT_INDUSTRY_COST		
COSTNAME(40)*32	CHARACTER	Row headers for report
II	INTEGER*4	Year subscript on results (1990, 1991, ...)
NCAECUMM(21,2)	REAL*8	Accumulated new cap add expenditures (NCAE, 93$)
REVREQ(30)	REAL*8	Total revenue requirements (93$)
Subroutine PTMT_REPORT_RATES_ON_ARC		
AF,AT	INTEGER*4	Source and destination nodes along arcs
P	INTEGER*4	Arc index

Local Variables Defined Within the NGTDM		
Variable Name	**Format**	**Definition**
Real Function NGAFM_ANGTS(TSTYR)		
TSTYR	INTEGER*4	Current year of model
Real Function NGCAN_DEMAND(CN_WELPRC)		
CN_WELPRC	REAL*4	Canadian wellhead price
Real Function NGEXP_CAN(ICAN,ID,TSTYR)		
FISHR	REAL*4	Share variable
ICAN	INTEGER*4	Canadian border crossing ID
ID	CHARACTER*1	Indicator for firm (F) or interrupt. (I)
TSTYR	INTEGER*4	Year
Real Function NGEXP_MEX(IMEX,ID,TSTYR)		
FISHR	REAL*4	Local share variable
ID	CHARACTER*1	Indicator for Firm (F) or interrup. (I)
IMEX	INTEGER*4	Mexican border crossing ID
TSTYR	INTEGER*4	Year
Real Function NGIMP_CANX(ICAN,TSTYR)		
ICAN	INTEGER*4	Indicator of Canadian border crossing
TSTYR	INTEGER*4	Year for Canadian imports
Real Function NGIMP_LNG(ILNG,TSTYR)		
ILNG	INTEGER*4	LNG terminal identifier
TSTYR	INTEGER*4	Test year for LNG imports
Real Function NGIMP_MEX(IMEX,TSTYR)		
IMEX	INTEGER*4	mexican border crossing number
TSTYR	INTEGER*4	Year for Mexican imports
Real Function NGPRD_L48X(IREG)		
IREG	INTEGER*4	NGTDM/OGSM region (1-17)
Real Function NGPRD_L48(INVAL,VALUE,IREG)		

Local Variables Defined Within the NGTDM		
Variable Name	**Format**	**Definition**
APBASE	REAL*4	Price at lower end of mid segment on three-tier sup curve (assoc w/ AQBASE) (87$/mcf)
AQBASE	REAL*4	Quantity at lower end of mid segment on three-tier sup curve (assoc. w/ APBASE) (BCF)
BPBASE	REAL*4	Price at upper end of mid segment on three-tier sup curve (assoc w/ BQBASE) (87$/mcf)
BQBASE	REAL*4	Quantity at upper end of mid segment on three-tier sup curve (assoc. w/ BPBASE) (BCF)
CURYR	INTEGER*4	Year represented by supply data
ELAS	REAL*4	Supply curve "elasticity"
FIXSUP	REAL*4	Fixed supply quantity (BCF)
INVAL	CHARACTER*1	Character indicating if the input value is a P or Q
IREG	INTEGER*4	NGTDM/OGSM region (1-17)
LAGREG	INTEGER*4	NGTDM/OGSM reg represented during last call of function
MIN_NA	REAL*4	Minimum production of NA gas (BCF)
PBASE	REAL*4	Reference price point (87$/mcf)
PER	REAL*4	Percent prod not lease & plant
QBASE	REAL*4	Reference quantity point (BCF)
QVAR	REAL*4	Quantity of supply above fixed supply (BCF)
VALUE	REAL*4	Input price or quantity
XPBASE	REAL*4	Price associated w/XQBASE (87$/mcf)
XQBASE	REAL*4	OGSM production est: Reserves*PR ratio (BCF)
Real Function NGPRD_OCSX(IREG)		
BASE	REAL*4	Intermediate value RES*(P/R)
IREG	INTEGER*4	OFFSHORE region (1-3)
Real Function NGPRD_OCS(INVAL,VALUE,IREG)		
APBASE	REAL*4	Price at lower end of mid segment on three-tier sup curve (assoc w/ AQBASE) (87$/mcf)

Local Variables Defined Within the NGTDM		
Variable Name	Format	Definition
AQBASE	REAL*4	Quantity at lower end of mid segment on three-tier sup curve (assoc. w/ APBASE) (BCF)
BPBASE	REAL*4	Price at upper end of mid segment on three-tier sup curve (assoc w/ BQBASE) (87$/mcf)
BQBASE	REAL*4	Quantity at upper end of mid segment on three-tier sup curve (assoc. w/ BPBASE) (BCF)
CURYR	INTEGER*4	Year represented by supply data
ELAS	REAL*4	Supply curve "elasticity"
FIXSUP	REAL*4	Fixed supply quantity (BCF)
INVAL	CHARACTER*1	Character indicating if the input value is a P or Q
IREG	INTEGER*4	NGTDM/OGSM region (1-17)
LAGREG	INTEGER*4	NGTDM/OGSM reg represented during last call of function
MIN_NA	REAL*4	Minimum production of NA gas (BCF)
PBASE	REAL*4	Reference price point (87$/mcf)
PER	REAL*4	Percent prod not lease & plant
QBASE	REAL*4	Reference quantity point (BCF)
QVAR	REAL*4	Quantity of supply above fixed supply (BCF)
VALUE	REAL*4	Input price or quantity
XPBASE	REAL*4	Price associated w/XQBASE (87$/mcf)
XQBASE	REAL*4	OGSM production est: Reserves*PR ratio (BCF)
Real Function NGSUP_OTHR(ISUP)		
ISUP	INTEGER*4	Other supplemental location
Real Function NGSYN_LIQH(INVAL,VALUE)		
INVAL	CHARACTER*1	Character indicating if the input value is a P or Q
LAGIYR	INTEGER*4	Year last time function was called
SNGILL	REAL*4	Temp array to hold ILL prod
SNGLAG	REAL*4	Last forecast year's ILL prod
SNGMAX	REAL*4	Maximum allowed ILL prod level

Local Variables Defined Within the NGTDM		
Variable Name	**Format**	**Definition**
VAL	REAL*4	
VALUE	REAL*4	Input value (price or quantity)
Real Function NGSYN_LIQX()		
NGSYN_LIQH	REAL*4	Functin to set SNG liq prod
Real Function NGTDM_CRVUTILIX(NGRG,EMRG,PRICE,PR_FLAG,PRX)		
EMRG	INTEGER*4	EMM region
KK	INTEGER*4	NGTDM/EMM subregions (1-20,21)
M,B	REAL*4	Slope and intercept
NGRG	INTEGER*4	NGTDM region
POILOLD	REAL*4	Oil price used by EMM
PRICE	REAL*4	Input price
PRX	REAL*4	Price on vertical ($/mcf)
PR_FLAG	INTEGER*4	Flag when price on vertical
QI	REAL*4	Noncore (Interruptible service) util dmd
RAT	REAL*4	Gas to oil price ratio
RATMAX	REAL*4	G/O ratio when gas at max
RATMIN	REAL*4	G/O ratio when gas at min
RATOLD	REAL*4	G/O ratio from prev iteration
RATPAR	REAL*4	G/O ratio at effective price
SHRMAX	REAL*4	Gas quantity at maximum
SHRMIN	REAL*4	Min quantity of gas
SHROLD	REAL*4	Gas quantity from prev iteration
SHRPAR	REAL*4	Gas quantity at parity
Subroutine ACTIVITY_LEVELS		
I,J	INTEGER	Counters, indices
SRC,DEST	INTEGER	Source and destination nodes
IYR	INTEGER	Current year index (1,2,...)

Local Variables Defined Within the NGTDM		
Variable Name	**Format**	**Definition**
Subroutine AVG_COST_CALC		
FTOT_RENT	INTEGER	Total firm rent on pipeline (87$)
ITOT_RENT	INTEGER	Total interruptible rent on pipeline (87$)
IYR	INTEGER	Current year index (1,2,...)
Subroutine CALC_CAP(CNVAR,CAP_TEMP,TREG_FLOW,TREG_PCAP,		
ADD	INTEGER	Capacity additions index (not used)
ARC_FLOW	REAL*4	Total flow along arc (BCF)
ARC_PCAP	REAL*4	Max physical capacity along arc (BCF)
CAP	INTEGER	Physical capacity index
CAP_TEMP	REAL*4	Temp variable defining max physical cap along arc (BCF)
CNVAR(14,4,MNUMYR)	REAL*4	Total physical capacity for NGTDM reg (BCF)
I	INTEGER	Census region
INITCAP	INTEGER	Initial capacity index (not used)
IYR	INTEGER	Current year
IYRSWITCH	INTEGER	Index representing current year (1,2)
SRC,DEST	INTEGER	Source, destination nodes along arc
TREG_FLOW(14)	REAL*4	Total flows along arc for Census regions (BCF)
TREG_PCAP(14)	REAL*4	Total phy cap along arc for Census regions (BCF)
UTIL	INTEGER	Capacity utilization index (not used)
Subroutine CAPACITY_ADDC(CCVAR,CURIYR)		
ADD	INTEGER	Capacity additions index
CAP	INTEGER	Physical capacity index
CCVAR(11,4,MNUMYR)	REAL*4	Capacity variable by Census: phys cap and additions (BCF)
CURIYR	INTEGER	Current year (1,2,...)
I	INTEGER	Census region index
INITCAP	INTEGER	Initial capacity index
UTIL	INTEGER	Capacity utilization index

Local Variables Defined Within the NGTDM

Variable Name	Format	Definition
Subroutine CAPACITY_ADDN(CNVAR,CURIYR)		
ADD	INTEGER	Capacity additions index
CAP	INTEGER	Physical capacity index
CNVAR(14,4,MNUMYR)	REAL*4	Capacity variable by NGTDM reg (BCF)
CURIYR	INTEGER	Current year (1,2,...)
I	INTEGER	NGTDM region index
INITCAP	INTEGER	Initial capacity index
UTIL	INTEGER	Capacity utilization index
Subroutine CAPACITY_CALC_ENTER		
ARC_FLOW	REAL*4	NG flow along arc into region (BCF)
ARC_PCAP	REAL*4	Physical cap along arc into region (BCF)
CAP_TEMP	REAL*4	Stores regional avg cap, additions, utilz entering region
I,J,K,L	INTEGER	Counters, indices
IYR	INTEGER	Current year (1,2,...)
SRC,DEST	INTEGER	Source, destination nodes
TREG_FLOW(14)	REAL*4	Total flow entering region (BCF)
TREG_PCAP(14)	REAL*4	Total physical cap entering region (BCF)
Subroutine CAPACITY_CALC_EXIT		
ARC_FLOW	REAL*4	NG flow along arc out of region (BCF)
ARC_PCAP	REAL*4	Physical cap along arc out of region (BCF)
CAP_TEMP	REAL*4	Stores regional avg cap, additions, utilz exiting region
I,J,K,L	INTEGER	Counters, indices
IYR	INTEGER	Current year (1,2,...)
REG_NUM	INTEGER	Region number (not used)
SRC,DEST	INTEGER	Source, destination nodes
TREG_FLOW(14)	REAL*4	Total flow exiting region (BCF)
TREG_PCAP(14)	REAL*4	Total physical cap exiting region (BCF)

Local Variables Defined Within the NGTDM		
Variable Name	**Format**	**Definition**
Subroutine CENSUS_DIV_CAP(TREG_FLOW,TREG_PCAP,CNVAR,CCVAR)		
CAP	INTEGER	Physical capacity index
CCVAR(11,4,MNUMYR)	REAL*4	Capacity variable by Census: phys cap and additions (BCF)
CDREG_FLOW(11)	REAL*4	Total flows along arc into or out of Census reg (BCF)
CDREG_PCAP(11)	REAL*4	Tot physical cap along arcs into or out of Census reg (BCF)
CNVAR(14,4,MNUMYR)	REAL*4	Capacity variable by NGTDM reg (BCF)
FLOW_8ARC11	REAL*4	Flow for arc between 8 and 11 NGTDM reg (BCF)
FLOW_9ARC12	REAL*4	Flow for arc between 9 and 12 NGTDM reg (BCF)
I,J	INTEGER	Counters, indices
IYR	INTEGER	Current year (1,2,...)
IYRSWITCH	INTEGER	Index representing current year (1,2)
PCAP_8ARC11	REAL*4	Phy cap for arc between 8 and 11 NGTDM reg (BCF)
PCAP_9ARC12	REAL*4	Phy cap for arc between 9 and 12 NGTDM reg (BCF)
TREG_FLOW(14)	REAL*4	Total flow into or out of NGTDM reg (BCF)
TREG_PCAP(14)	REAL*4	Total physical cap into or out of NGTDM reg (BCF)
UTIL	INTEGER	Capacity utilization index
Subroutine CONSUMPTION_CALC		
I,J,K	INTEGER	Region indices
IYR	INTEGER	Current year (1,2,...)
TEMP_NONU_F	REAL*4	Total non-utility firm flows (BCF)
TEMP_NONU_I	REAL*4	Total non-utility interrup. flows (BCF)
TEMP_UTIL_F	REAL*4	Total utility firm flows (BCF)
TEMP_UTIL_I	REAL*4	Total utility interrp. flows (BCF)
Subroutine END_USE_CALC		
EU_COST_F	REAL*4	Firm utility end-use cost by NGTDM reg (87$/mcf)
EU_COST_I	REAL*4	Interr utility end-use cost by NGTDM reg (87$/mcf)
EU_COST_TF	REAL*4	Total firm utility end-use cost for all regions (87$/mcf)

Local Variables Defined Within the NGTDM		
Variable Name	**Format**	**Definition**
EU_COST_TI	REAL*4	Total interr end-use cost for all regions (87$/mcf)
EU_D	REAL*4	Denominator for tot end-use pr all regs--total qty (BCF)
EU_N	REAL*4	Numerator for tot end-use pr all regs--total P*Q (87$)
EU_QTY_F	REAL*4	Firm utility end-use qty by NGTDM reg (BCF)
EU_QTY_I	REAL*4	Interr utility end-use qty by NGTDM reg (BCF)
EU_QTY_TF	REAL*4	Total firm utility end-use qty for all regions (BCF)
EU_QTY_TI	REAL*4	Total interr utility end-use qty for all regions (BCF)
I,J,K	INTEGER	Region indices
IYR	INTEGER	Current year (1,2,...)
TEMP_NCF	REAL*4	Total P*Q for firm nonutility by NGTDM region (87$)
TEMP_NCI	REAL*4	Total P*Q for interr nonutility by NGTDM region (87$)
TEMP_NQF	REAL*4	Total qty for firm nonutility by NGTDM region (BCF)
TEMP_NQI	REAL*4	Total qty for interr nonutility by NGTDM region (BCF)
TEMP_UCF	REAL*4	Total P*Q for firm utility by NGTDM region (87$)
TEMP_UCI	REAL*4	Total P*Q for interr utility by NGTDM region (87$)
TEMP_UQF	REAL*4	Total qty for firm utility by NGTDM region (BCF)
TEMP_UQI	REAL*4	Total qty for interr utility by NGTDM region (BCF)
Subroutine FTAB_REPORT(CURIYR,LASTYR)		
FILE_MGR	INTEGER*4	Function to open/close file
FNAME	CHARACTER*18	Filename
CURIYR,LASTYR	INTEGER	Current year; last year
I,J,K	INTEGER	Region indices
NGREG	INTEGER*4	Region index
Subroutine FTAB_RPT		
(no local varuables)		
Subroutine INVERSE_MAP		
I,J,K	INTEGER	Region indices

Local Variables Defined Within the NGTDM		
Variable Name	**Format**	**Definition**
REG_NUM	INTEGER	Region ID
Subroutine MARKET_HUB_PR_CALC		
AMH_D	REAL*4	Total Qty (consumption) at hub (BCF)
AMH_N	REAL*4	Total P*Q at hub (87$)
I,J,K	INTEGER	Region indices
IYR	INTEGER	Current year (1,2,...)
MH_PQ	REAL*4	Total market hub price * quantity by reg (87$)
MH_QTY	REAL*4	Total market hub qty by reg--firm + interr (BCF)
MH_QTY_TF	REAL*4	Total firm market hub quantity by reg (BCF)
MH_QTY_TI	REAL*4	Total interr market hub quantity by reg (BCF)
TEMP_NQF	REAL*4	Total qty for firm nonutility by NGTDM region (BCF)
TEMP_NQI	REAL*4	Total qty for interr nonutility by NGTDM region (BCF)
TEMP_UQF	REAL*4	Total qty for firm utility by NGTDM region (BCF)
TEMP_UQI	REAL*4	Total qty for interr utility by NGTDM region (BCF)
Subroutine NEXTDATA(UNITNUM)		
CH	CHARACTER*1	Dummy var. READ to find beginning of READ (@)
UNITNUM	INTEGER*4	Unit number passed from the file manager
Subroutine NGMAIN		
CATG,KEY	INTEGER*4	Input variables used to initiate selected sensitivity runs
FILE_MGR	INTEGER*4	Function to open/close file
FNIN,FNOUT	CHARACTER*18	Filename of input and output file used for NGTDM module standalone runs
I,J,K	INTEGER*4	Counters, indices
RTOVALUE	INTEGER	Function to obtain value of input runtime parameter for sens analysis
Subroutine NGPRTINF(MATRIX)		
COLSOL/'ACLUD '/	CHARACTER*8	Defines column info to be obtained from OML solution
I	INTEGER*4	Counter, index

Local Variables Defined Within the NGTDM		
Variable Name	**Format**	**Definition**
IRET	INTEGER*4	OML return code
MATRIX	CHARACTER*3	Defines which LP has infeasibility (AFM or CEM)
ROWSOL/'ASLUP '/	CHARACTER*8	Defines row info to be obtained from OML solution
Subroutine NGSET_EXPCAP(MAPYR,YR)		
IEXP	INTEGER*4	Arc counter
MAPYR	INTEGER*4	Mapped reference year
SRC, DEST	INTEGER*4	Source and dest nodes
YR	INTEGER*4	Reference year
YR4	INTEGER*4	Reference year in 4 digits (e.g., 1990)
Subroutine NGSUPPLY_ACT		
I	INTEGER*4	Export region index
IYR	INTEGER*4	Current year (1,2,...)
L48REG	INTEGER*4	Lower 48 region ID (1-12)
NGREG, NSREG	INTEGER*4	Region/subregion index
QEXP	REAL*4	Export qty (BCF)
STYP	INTEGER*4	Supply type index
Subroutine NGTDM_CEM		
ADDYR	INTEGER*4	Num of years for storage addition data
BASET	REAL*4	Total base gas storage (Bcf)
CAP1	LOGICAL	/.TRUE./ Flag indicating 1st itr. 1st yr
CAPADD	REAL*4	New capacity additions (MMcf/day)
CH	CHARACTER*1	Dummy var. READ to find beginning of READ (@)
FILE_MGR	INTEGER*4	Function to open/close file
FNAME	CHARACTER*18	Filename identifier
I,J,K	INTEGER*4	Counters
IEXP	INTEGER*4	Arc counter
IOSHAT	INTEGER*4	Unit number passed from the file manager

Local Variables Defined Within the NGTDM		
Variable Name	**Format**	**Definition**
NGREG	INTEGER*4	Region
NUMSTRX	INTEGER*4	Number of storage nodes
SRC, DEST	INTEGER*4	Source and dest nodes
WORKT	REAL*4	Total working gas storage (mmcf)
YRB4	INTEGER*4	Array position for previous year
Subroutine NGTDM_DATARED()		
AEFF_PIPE_SCALE93	REAL*4	Scale pipeline eff to match 1993 history
CEND	CHARACTER*1	Dummy var read to find end of data (#)
CH	CHARACTER*1	Dummy var. READ to find beginning of READ (@)
DATA	REAL*4	Used as temp storage for data
FILE_MGR	INTEGER*4	Function to open/close file
FNAME	CHARACTER*18	Filename
I,JJ,KK,LL	INTEGER*4	Counters
UNITNUM	INTEGER*4	Unit number passed from the file manager
Subroutine NGTDM_DATASET		
NGREG,NSREG,NSEC,NSUP, DEST,I	INTEGER*4	Sector/Supply region counters
Subroutine NGTDM_DMDALK(YRCALC)		
AK_CONS_N	REAL*4	Tot end-use consumption in N AK
AK_CONS_S	REAL*4	Tot ene-use consumption in S AK
AK_PCTALL(3)	REAL*4	1-AK_PCTPLT-AK_PCTLSE-AK_PCTPIP
AK_PROD(3)	REAL*4	Prod S,N,ANGTS
AK_WPRC(3)	REAL*4	Well price S,N,ANGTS
ANGTS_ON	LOGICAL	Gas flowing on ANGTS
CNTYR	INTEGER*4	Converted YRCALC where eq 1 for 1990
ELDMD	REAL*4	Util demands in AK
EXPJAP	REAL*4	LNG exports from AK to Japan

Local Variables Defined Within the NGTDM		
Variable Name	**Format**	**Definition**
I	INTEGER*4	Counter
SAK_CONS_DIFF	REAL*4	
SAK_IND	REAL*4	
SAK_OVRMAX	LOGICAL	True if S.AK consump exceeds S.AK production
SAK_PROD_DIFF	REAL*4	
WOPCUR	REAL*4	Current world oil price
WOPLAG	REAL*4	Lagged world oil price
WPRLAG	REAL*4	Lagged AK wellhead price "SOUTH"
YRCALC	INTEGER*4	Year to be calculated (e.g., 1995)
Subroutine NGTDM_DTM2		
CH	CHARACTER*1	Dummy var. READ to find beginning of READ (@)
DTAR1	LOGICAL	/.TRUE./ Flag indicating 1st itr, 1st yr
FILE_MGR	INTEGER*4	Function to open/close file
FNAME	CHARACTER*18	Filename
I,J	INTEGER*4	Counters
UNITNUM	INTEGER*4	Unit number passed from the file manager
Subroutine NGTDM_PTM1		
CH	CHARACTER*1	Dummy var. READ to find beginning of READ (@)
FILE_MGR	INTEGER*4	Function to open/close file
FNAME	CHARACTER*18	Filename
I,J	INTEGER*4	Counters
IOPTM	INTEGER*4	Unit number passed from the file manager
PTAR1	LOGICAL	/.TRUE./ Flag indicating 1st itr, 1st yr
Subroutine NGTDM_SENS2(CATG,KEY,SRC,DEST)		
I,J	INTEGER*4	Counters, indices
CATG,KEY	INTEGER*4	Input variables used to initiate selected sensitivity runs
SRC,DEST	INTEGER*4	Source, destination node ID's

Local Variables Defined Within the NGTDM		
Variable Name	**Format**	**Definition**
Subroutine NGTDM_SENS3(CATG,KEY,IPD1,IPD2)		
CATG,KEY	INTEGER*4	Input variables used to initiate selected sensitivity runs
I	INTEGER*4	Region index
IPD1(NNGREG),IPD2(NNGREG)	REAL*4	Adjusted percent discount; alternate adj percent discount
PERCINCR	REAL*4	Change in percent discount
Subroutine NGTDM_SENS4(CATG,KEY,SRC,NGREG,PCAPCURV)		
CATG,KEY	INTEGER*4	Input variables used to initiate selected sensitivity runs
SRC,NGREG,NS	INTEGER*4	Indices
PCAPCURV(CEMNS)	REAL*4	Price on CEM capacity expansion curve (87$/mcf)
Subroutine NGTDM_SENSITIVITY(CATG,KEY)		
AA_RATE	REAL*4	Change in AA Bond rate
AGSRINC	REAL*4	Change in GSR transition costs for firm service
CAPINCR1,CAPINCR2	REAL*4	Change in cost of new capacity
EFFINCR	REAL*4	Change in pipeline efficiency
ELASINC2	REAL*4	Change in elasticity for supply curve option 2
ELASINC3	REAL*4	Change in elasticity for supply curve option 3
KEY,CATG	INTEGER*4	Input variables used to initiate selected sensitivity runs
I,J,K,YR1,YR2	INTEGER*4	Counters, indices
INDDMD(1996:2010)	REAL*4	Change in industrial dmds
LFAC1	REAL*4	Change in LFAC
MAXFAC	REAL*4	Change in max discount for interrup transportation
MSEGINCR	REAL*4	Change in mid segment on supply curve option 3
RESDMD(1996:2010)	REAL*4	Change in residential dmds
UDMD(1996:2010)	REAL*4	Change in utility dmds
UPF(3)	REAL*4	Change in peak firm share
WTHR(3)	REAL*4	Change in CEM weather factor

Local Variables Defined Within the NGTDM		
Variable Name	**Format**	**Definition**
XCAP(2)	REAL*4	Change in AFM weather factor
Subroutine REV_DISTRIB		
AEFF	REAL*4	Pipeline efficiency
I,J,K	INTEGER	Counters, indices
IYR	INTEGER	Current year (1,2,...)
Subroutine REV_INTER_TRANS		
AEFF	REAL*4	Pipeline efficiency
FMARGIN	REAL*4	Resulting firm tariffs along arcs (87$/mcf)
I,J,K	INTEGER	Counters, indices
IMARGIN	REAL*4	Resulting interrup. tariffs along arcs (87$/mcf)
INTRA_F	REAL*4	Firm interstate transmission revenues (87$)
INTRA_I	REAL*4	Interrup. interstate transmission revenues (87$)
IYR	INTEGER	Current year (1,2,...)
RENT	REAL*4	Positive or neg rent along an arc
SRC,DEST	INTEGER	Source, destination node ID
TEMP_NQF	REAL*4	Total qty for firm nonutility by NGTDM region (BCF)
TEMP_NQI	REAL*4	Total qty for interr nonutility by NGTDM region (BCF)
TEMP_UQF	REAL*4	Total qty for firm utility by NGTDM region (BCF)
TEMP_UQI	REAL*4	Total qty for interr utility by NGTDM region (BCF)
TOTAL_T	REAL*4	Temporary rent variable (87$)
Subroutine WRITE_AFM		
I,J,CYR	INTEGER*4	(not used)
RECD	INTEGER*4	Record number for direct access output file
Subroutine WRITE_CEM		
AUT_F(NGTDM,NGTDM), AUT_T(NGTDM,NGTDM)	REAL*4	Firm and total utilization of pipeline along arc
CAP_MAX(NGTDM,NGTDM)	REAL*4	Physical capacity along arc (BCF)

Local Variables Defined Within the NGTDM		
Variable Name	**Format**	**Definition**
FYR,CYR	INTEGER*4	Forecast year (3,4,..); forecast year index (1,2)
I,J	INTEGER*4	Counters, indices
PCAPEST(NGTDM,NGTDM), PSTREST(NNGREG)	REAL*4	Est price on pipeline/storage capacity curve for PTM (87$/mcf)
RECD	INTEGER*4	Record number for direct access output file
STRMAX(NNGREG)	REAL*4	Maximum storage capacity (BCF)
STR_F(NNGREG),STR_I(NNGREG)	REAL*4	Net firm/interrup flow out of storage (BCF)
Subroutine WRITE_PTM		
CPCAP(NGTDM,NGTDM,CEMNS),CQCAP(NGTDM,NGTDM,CEMNS)	REAL*4	P/Q pairs used to define the pipeline capacity curve
CPSTR(NNGREG,CEMNS),CQSTR(NNGREG,CEMNS)	REAL*4	P/Q pairs used to define the storage capacity curve
I,J,K	INTEGER*4	Counters, indices
RECD	INTEGER*4	Record number for direct access output file

Appendix K

Sensitivity Parameters

Sensitivity Parameters

This Appendix lists the parameters that have been selected as sensitivity variables within the NGTDM. Most of the sensitivity options key off of two NEMS runtime parameters: NGCATG to specify the parameter to be perturbed, and NGKEY to identify which perturbation amount to be used. The remaining sensitivity options are activated through input data files as switches and corresponding quantities. These keys and switches are listed along with the parameter descriptions and their corresponding perturbation activity.

SENSITIVITY PARAMETER LISTING			
Parameter	**Switch**	**Key**	**Activity**
Residential demand	NGCATG = 1	NGKEY = 1	Increase by 0.5% per year 1996-2010
		NGKEY = 2	Decrease by 0.5% per year 1996-2010
Industrial demand	NGCATG = 2	NGKEY = 1	Increase firm demand by 0.5% per year 1996-2010
		NGKEY = 2	Decrease firm demand by 0.5% per year 1996-2010
		NGKEY = 3	Increase interruptible demand by 0.5% per year 1996-2010
		NGKEY = 4	Decrease interruptible demand by 0.5% per year 1996-2010
CEM weather factor	NGCATG = 3	NGKEY = 1	weather factor = 0.20
		NGKEY = 2	weather factor = 0.10
		NGKEY = 3	weather factor = 0.0
AFM weather factor	NGCATG = 4	NGKEY = 1	weather factor = 0.10
		NGKEY = 2	weather factor = 0.0
Peak firm utilization	NGCATG = 5	NGKEY = 1	utilization = 0.70
		NGKEY = 2	utilization = 0.90
		NGKEY = 3	utilization = 0.99
Peak & Offpeak gas consumption shares - residential, commercial, industrial	NGCATG = 6		Peak share = 0.33 Offpeak share=0.67
Cost of new capacity on 8->4	NGCATG = 7		Decrease by $2.00
Steps on capacity expansion curve 8->4	NGCATG = 8		Drop all steps except the most expensive step for new capacity
Pipeline capacity addition cost all arcs	NGCATG = 9	NGKEY = 1	Increase by 20%
		NGKEY = 2	Decrease by 20%

SENSITIVITY PARAMETER LISTING			
Parameter	**Switch**	**Key**	**Activity**
Base capacity all arcs	NGCATG = 10	NGKEY = 1	Base cap = 0
		NGKEY = 2	Base cap = Commodity charge
		NGKEY = 3	Base cap = Reservation charge
AA Utility Bond index rate	NGCATG = 11	NGKEY = 1	Increase by 2%
		NGKEY = 2	Decrease by 2%
Load Factor for maximum interruptible transportation rate - LFAC	NGCATG = 12	NGKEY = 1	Increase by 25%
		NGKEY = 2	Decrease by 25%
Interruptible transportation rate fraction of maximum interruptible rate - MAXDISC_I	NGCATG = 13	NGKEY = 1	Increase by 25%
		NGKEY = 2	Decrease by 25%
LFAC and MAXDISC_I	NGCATG = 14		Increase by 25%
Gas Supply Realignment cost	NGCATG = 15		Double
Pipeline fuel use	NGCATG = 16	NGKEY = 1	Increase by 2%
		NGKEY = 2	Decrease by 2%
	NGCATG = 17		Not used
Supply curve parameters	NGCATG = 18	NGKEY = 1	Increase by 50% elasticity for supply curve type 2
		NGKEY = 2	Decrease by 50% elasticity for supply curve type 2
		NGKEY = 3	Increase by 50% elasticity for supply curve type 3
		NGKEY = 4	Decrease by 50% elasticity for supply curve type 3
		NGKEY = 5	Increase middle segment of supply curve type 3 by 50%
		NGKEY = 6	Decrease middle segment of supply curve type 3 by 50%

SENSITIVITY PARAMETER LISTING			
Parameter	**Switch**	**Key**	**Activity**
Percentage discount off of industrial	NGCATG = 19	NGKEY = 1	Increase by 25%
		NGKEY = 2	Decrease by 25%
Residential demand at node 3	NGCATG = 20	NGKEY = 1	Increase by 0.5% per year 1996-2010
		NGKEY = 2	Decrease by 0.5% per year 1996-2010
Utility demand	NGCATG = 21	NGKEY = 1	Increase by 0.5% per year 1996-2010
		NGKEY = 2	Decrease by 0.5% per year 1996-2010
Increment to TOM (Total Operation and Maintenance Expenditure) in NGPTM	TOMSWT = 0 (set in PTARIFF)		No incremental cost in TOM
	TOMSWT = 1 (set in PTARIFF)	TOMINC1 (set in PTARIFF) and/or TOMINC2 (set in PTARIFF)	incremental cost of existing pipelines-- user specified (i.e., 150000000 $1993) incremental cost of entire industry (both existing and generic pipeline)-- user specified (i.e., 1000000000 $1993)