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NBS Technical Note 1209

MARKET: A Model for Analyzing the Production, Transmission, and Distribution of Natural Gas

Christoph Witzgall and Patsy B. Saunders

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Abstract

This report describes the MARKET submodel, one of three that combine to form the Gas Analysis Modeling System (GAMS). GAMS was developed for use by the Energy Information Administration of the U.S. Department of Energy. It provides a tool for analyzing the regional effects on the domestic natural gas market of various policies for regulating the price of natural gas at the wellhead. MARKET is concerned with the production of gas reserves and the transmission and distribution of gas to consumers. It solves a network equilibration problem to arrive at estimates of production quantities and prices.

Keywords: demand, deregulation, energy model, equilibration, gas distribution, gas production, gas transmission, natural gas, network, pipeline, policy modeling, simulation, supply

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CHAPTER 1

Introduction

In the Spring of 1981, the Operations Research Division of the National Bureau of Standards (NBS) was contacted by the Department of Energy's Energy Information Administration (EIA) to explore NBS participation in the development of a mathematical model representing the major economic aspects of the natural gas market in the U.S. and their interrelationships. A need for such a model was perceived because of a rising conviction in Congress and the Administration that changes in the regulatory structure of the natural gas market, particularly at the production end of it, were becoming necessary. This regulatory structure is dominated by the Natural Gas Policy Act (NGPA) of 1978.

In the ensuing months, NBS conducted an intensive discussion with EIA staff, in particular Dr. Richard P. O'Neill, about the requirements to be met by such a model, its general structure, and the availability of supporting data. NBS eventually concentrated on marketing aspects, formulating a network equilibrium model and developing a solution procedure for it.

By the Fall of 1981, a first general specification of Gas Analysis Modeling System (GAMS) had evolved, with NBS efforts now focused on the implementation of MARKET, one of three major components of the GAMS system. The other two components are PROLOG and BID. PROLOG, developed at EIA, is concerned with the exploration and development of natural gas reserves in response to expected profitability, capital resources, and the availability of drilling rigs and other equipment. Finding rates applied to levels of exploratory drilling yield natural gas reserves which are offered for sale to pipeline companies. BID, developed by Professor Charles Mylander of the U.S. Naval Academy, simulates the process by which competing pipeline companies bid for the reserves offered by producers. The actual price bid by each pipeline company is based on the estimated production schedule and price of reserves currently dedicated to the pipeline company and the estimated price and quantity of gas that can be marketed over the next several years. Reserves are awarded on the basis of prices. When bid prices exceed ceiling prices, reserves are awarded according to historical market shares modified by bid prices. MARKET, developed at the National Bureau of Standards (NBS), serves three major functions. First, it establishes a consistent set of base year data describing commercial relationships among pipeline companies, distributors, and end-use markets or consumers. Second, it provides information relevant to the BID model by estimating the quantity of gas that could be sold to distributors and end-users during the next several years at various wellhead price levels. Third, given the average wellhead price and maximum production available from each source of reserves awarded to a pipeline company, MARKET estimates the actual quantity and average price of gas sold by simulating the transmission and distribution of gas to end users. The reserves available from each source are then reduced according to the volume of gas sold.

NBS was also faced with providing a realistic representation of the network of supply relationships between pipeline companies and distribution companies, and with establishing bench-marks for burner-tip demand in the base year. It was found that the form EIA-50 contained information from which such a network could be generated for input into the MARKET model. This task turned out to be too extensive to be handled manually. The task of generating the network of supply relationships from form EIA-50 and supplemental data was therefore automated, giving rise to the procedure GENNET, which operates on a stand-alone basis. The first version of GENNET was completed in January 1982, and it was modified repeatedly until Fall 1982.

The MARKET model is conceptually independent of GENNET and will accept any network generated -- manually or by computer -- so that it meets the generic input requirements of MARKET.

Debugging of MARKET started in January 1982, and the first complete runs of GAMS involving the entire network were obtained in Spring 1982. The assistance of Mr. Samuel Cohen of EIA was crucial for this achievement. A period of testing, adaptation and modification was followed by the first set of production runs in October 1982. The results of these runs provided important insight but in their details were not yet fully compatible with several known aspects of the natural gas market, so that further adjustments as well as further specification of legislative scenarios were needed before conclusive production runs could be conducted. At that time, it was decided that broader participation in these additional steps was desirable, and that staff from Brookhaven National Laboratory (BNL), particularly Mr. Mark Minasi, Dr. Steven Wade, and Mr. Bradford Wing should join NBS in efforts of upgrading and maintaining the MARKET model, with Ms. Barbara Mariner-Volpe as coordinator. Definitive production runs were made at the end of April 1983. Their results formed the cornerstone of the EIA publication: The Natural Gas Market through 1990; Part IV: An Analysis of the NGPA and Several Alternatives (DOE-EIA-0366, May 1983).

Subsequently, efforts to upgrade and to include new options were continued by both BNL and NBS. One major new development involved the integration of the GAMS system with the EIA's Integrated Future Forecasting System (IFFS). In August 1984, EIA issued a first set of documentary reports: Model Documentation of the Gas Analysis Modeling System; Volume I: Model Overview (DOE-EIA-0450/1); Volume II: Model Methodology (DOE-EIA-0450/2); Volume III: Software and Data Documentation and User's Guide (DOE-EIA-0450/3).

It is clear from this short history of the GAMS model, that there is no "final" version. At best there are certain "frozen" versions, which represent various stages of development and various specific scenarios that EIA was called upon to analyze at particular points in time. Indeed, GAMS is fairly typical for large modeling efforts of this kind in that it represents a collection of adaptable interrelating submodels rather than a single monolithic package. Nevertheless, the characteristic features and the structural basis of GAMS have remained unchanged to a remarkable degree.

The purpose and the scope of the present report must be seen in this context. That purpose is to outline the major concepts and assumptions of the MARKET model as developed by NBS. For additional details of implementation as well as information about alternative assumptions and particular stages of the model evolution, the reader is referred to an extensive set of Notes at the end of the report.

The document is organized into four chapters and an appendix consisting of a set of notes. Chapter 2 provides the background setting and an overview of the model for the nonspecialist reader. It attempts to convey the nature of the analytic requirements, which GAMS in general and MARKET in particular are designed to address, and to discuss the model structure vis-a-vis these requirements. The subsequent more comprehensive description of MARKET is then split into two parts: Chapter 3 features the key concepts of the model individually, whereas Chapter 4 treats their interrelationships and the procedural techniques employed in the model. Chapter 5 describes the GENNET procedure for generating the representation of the supply network which underlies MARKET.

A letter report, GAMS/MARKET: A Model for Analyzing the Production, Transmission, and Distribution of Natural Gas, was transmitted to EIA in May 1983. The present report relies heavily on the material contained in that letter report which is more detailed and documentation oriented, but does not deal with some of the more recent developments.

CHAPTER 2

Background and Model Overview

In this chapter, we examine the aspects of natural gas commerce which are to be modeled. We then specify requirements for such a model, discuss available data, and provide a brief overview of the MARKET model. We close with an examination of the expectations which surround mathematical models like GAMS.

2.1 The national natural gas industry

Not until the 1930's did the use of natural gas begin on a significant commercial scale. During the two decades following World War II, natural gas proceeded to replace manufactured gas almost entirely as the Nation's gas fuel and to open vast new markets as a residential and commercial heating and cooling agent, as industrial boiler fuel and feed stock, and as a resource for generating electric energy. For a comprehensive as well as entertaining treatise on the development of the natural gas market in our country, we refer to an article by B. Commoner [6].

This development was put into motion by the evolution of an extensive and intricate system of gas pipelines. The majority of the large pipelines originate in the area encompassed by Texas, Lousiana and their neighboring States. They service distant major population and industrial centers such as New England, the Upper Midwest, and California. A newer development is the influx of Canadian Gas into the Pacific States and the Great Lakes Region. A trans-Canadian pipeline making Alaskan gas available to the lower 48 states is still on the planning boards. Beyond this, the construction of new pipeline mileage has apparently peaked, and only few major pipeline extensions are anticipated.

The pipelines are operated by pipeline companies (see Table 2.1). Typically, these companies buy their gas from gas-producing companies on the basis of long term price-binding contractual agreements. These represent agreements by individual producers to offer their whole production for sale to one particular pipeline company, respectively, usually for the entire production periods of the facilities in question. The agreements also stipulate how sales prices are to be set and recalculated over time.

The pipeline company then sells and transmits the gas to distribution companies, which sell and distribute the gas locally to end-users. The latter are generally divided into four end-use sectors, residential, commercial, industrial and electric utilities, with different rates charged according to sector. Consumption data are usually reported broken down by these sectors.

To denote the major stations through which gas passes on its way to the end-user, the terms wellhead, pipegate, citygate and burnertip are frequently employed. The gas enters the pipegate, the start of the pipeline proper, after it has been gathered from the wellhead and processed to remove liquids and impurities. A considerable amount of plant and lease fuel, typically around 5-8%, is needed to power gathering and processing facilities, and is consumed on the spot by various parties involved in the production process. The citygate is the point at which the gas becomes the property of the distribution company, and the burnertip is the point of actual consumption (see Figure 2.1). On their journey from pipegate to citygate, shipments will suffer transmission losses, mainly due to the use of parts of these shipments as pipeline fuel, that is, gas to power compressor stations. During distribution, gas will be lost by leakage or be otherwise unaccounted for.

Volume of natural gas is usually measured at 14.73 psia and 60°F. A frequently used unit is the "Mcf" (= 1000 cubic feet). Energy content of delivered natural gas varies between 950 and 1250 Btu (= British thermal unit) per cubic foot with 1020 Btu adopted frequently as a nominal value. The abbreviations "BBtu" and "Quad" are used for billions and quadrillions of Btu, respectively. In this report, we use the terms volume and quantity interchangeably for shipments of gas, regardless of whether these shipments are measured by volume or energy content.

Both pipeline and distribution companies are considered public utilities, that is, they are permitted to recover all costs, but are not permitted to profit beyond an agreed upon return on the securities issued by them. Posted rates, or tariffs, are therefore subject to review and approval by public agencies. Prices charged by interstate pipeline companies are monitored by the Federal Energy Regulatory Commission (FERC), and those of intrastate pipelines and distribution companies by the Public Utility Commissions in their respective States.

From the regulatory point of view, there is an important distinction between the interstate and the intrastate market for natural gas. The interstate market is formed by pipeline companies which engage in the transmission and selling of natural gas across state lines, and also by those producers whose gas reserves are contractually dedicated for sale to such interstate pipelines. The intrastate market is then defined by exclusion as those production and transmission facilities which are not part of the interstate market.

The above description of the natural gas industry is, of course, oversimplified. First of all, not all gas transmitted by a pipeline is owned by that pipeline: there are many transactions in which a pipeline company transmits gas owned by some other party. The tariffs for such transmission services are again posted and subject to approval by public agencies.

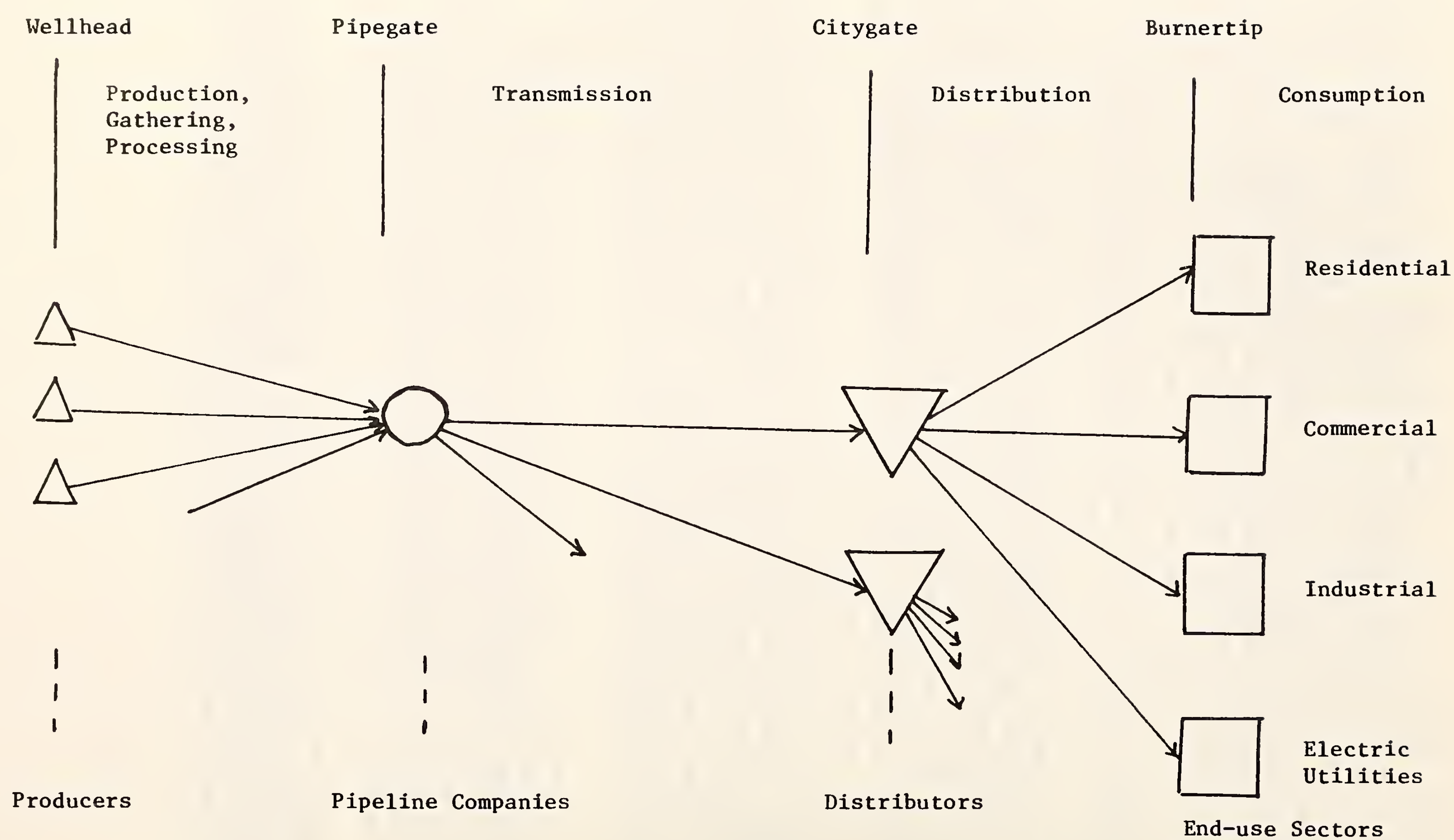


Figure 2.1: Schematic Representation of the Flow of Natural Gas

TABLE 2.1 Eleven Major Gas Pipeline Companies and Their 1980 Sales and Supply Patterns
Source: Form FERC-2, Gas Account - Natural Gas, pp. 518-519

	Net Receipts (Billions of Cubic Feet)			Net Deliveries (Billions of Cubic Feet)			
	Produced and Purchased	Withdrawn from Storage	Total	Sales	Company Use, Losses	Put into Storage	Total
El Paso	1307	2	1309	1181	128	-0-	1309
Tenneco	1178	70	1248	1130	70	48	1248
Columbia	1110	76	1186	1080	13	93	1186
Natural Gas Pipeline of America	1018	90	1108	947	44	117	1108
United Gas Pipeline	1049	71	1120	1022	24	74	1120
Texas Eastern	963	64	1027	935	41	51	1027
Transco	942	16	958	898	45	15	958
Michigan Wisconsin	697	130	827	675	28	124	827
Panhandle Eastern	733	31	764	666	59	39	764
Texas Gas	638	55	693	635	20	38	693
Southern Natural	621	44	665	597	21	47	665

The distinction between pipeline companies and distribution companies is not as clear-cut as one might wish. A typical distribution company (see Table 2.3) like Washington Gas Light may have transmission facilities crossing state lines, and therefore could be considered legally an interstate pipeline. Some distributors like Pacific Gas and Electric may own transmission facilities comparable in size to those of major pipeline companies and may be the main suppliers of other sizeable distributors. On the other hand, pipeline companies may sell directly to end-users in the industrial as well as in the residential sectors. Sales of this kind to major industrial customers are typically nonjurisdictional, i.e., subject to less stringent tariff control by the FERC. The same distribution company may furthermore sell - at different rates - in more than one State, Washington Gas Light being again a prime example.

Distribution companies are, in general, concerned with local distribution. Their numbers of customers are typically large, and most customers are end-users. Pipeline companies transmit large quantities of gas over long distances. They gather gas from many production facilities, channel it into large single pipelines, and sell to a relatively small number of customers, mostly for resale rather than end-use. Distributors are state regulated; interstate pipelines are federally regulated. Distribution companies tend to be older corporate units than pipeline companies, going back to the days of coal gas: in some cases the old wooden pipes are still in use. Frequently, a distribution company supplies both gas and electricity, whereas pipeline companies deal typically with only one energy source, namely natural gas. Classification becomes difficult for companies like Mountain Fuel and Kansas-Nebraska. These are relatively young companies serving large sparsely populated areas which often spread over state lines. While distributing directly to residential as well as industrial end-users, they operate large transmission facilities and withdraw gas from dedicated reserves. These companies thus have the characteristics both of distributors and of medium sized interstate pipeline companies.

Last but not least, there is a large degree of <u>vertical integration</u> of corporations across production, transmission and distribution. Many pipeline companies and even some distributors own gas reserves directly or via subsidiaries. Many distribution companies are subsidiaries of a pipeline company. For example, the distribution companies Columbia of Ohio, Columbia of West Virginia, and Columbia of Pennsylvania are wholly owned subsidiaries of the Columbia Gas Pipeline Company. On the other hand, Washington Gas Light, a distributor, owns gas reserves in Wyoming.

A significant portion of the natural gas withdrawn consists of <u>direct sales by producers</u> to end-users; or it is <u>producer-used</u>, that is, it will be directly utilized other than as plant and lease fuel by its producer, usually a large industrial facility, without involving any second party. In the latter case, there are no actual sales involved, although prices may be formally reported for tax purposes.

TABLE 2.2: Forty Major Gas Distribution Companies and Their 1978 Sales and Supply Patterns
Source: Vol. I National Gas Rate Design Study [2]

	Company, Location	Sales, Trillion Btu Total	Sales, Trillion Btu Residential	Thous. Resid. Customers	Major Suppliers
1	Southern California Gas Los Angeles, CA	725.4	309.1	3393	72% El Paso
2	Pacific Gas & Electric San Francisco, CA	659.5	229.0	2532	37% El Paso, Canadian imports
3	Northern Illinois Gas Evanston, IL	522.8	217.5	1255	75% Natural Gas Pipeline, 14% Midwestern, 8% Northern
4	Lone Star Gas Dallas, TX	500.3	101.5	1028	intrastate supplied
5	Michigan Consolidated Gas Detroit, MI	458.2	174.1	946	73% Michigan-Wisconsin, 7% Panhandle Eastern
6	East Ohio Gas Cleveland, OH	382.9	179.0	905	(subsidiary of Consolidated Natural Gas Co.)
7	Columbia Gas of Ohio Columbus, OH	348.4	157.9	961	(subsidiary of Columbia Gas Transmission Co.)
8	Consumers Power Flint, MI	346.4	171.9	963	59% Trunkline
9	The Peoples Gas, Light & Coke Chicago, IL	334.8	180.1	850	90% Natural Gas Pipeline, 10% Midwestern
10	Oklahoma Natural Gas Tulsa, OK	268.9	59.5	501	intrastate supplied

Table 2.2 (Continued)

Company, Location	Sales, Trillion Btu Total	Residential	Thous. Resid. Customers	Major Suppliers
11 The Gas Service Kansas City, MO	246.7	122.4	765	97% Cities Service, 3% Panhandle Eastern
12 Northern Indiana Public Service Hammond, IN	232.1	74.0	456	55% Natural Gas Pipeline, 30% Midwestern, 11% Panhandle Eastern
13 Atlanta Gas Light Atlanta, GA	220.0	78.4	679	88% Southern Natural, 11% Transco
14 Entex, Inc. Houston, TX	203.4	88.7	1051	intrastate supplied
15 Peoples Natural Gas (Northern) Council Bluffs, IA	201.8	36.6	234	(Division of Northern Natural Gas Pipeline Co.)
16 Public Service of Colorado Denver, CO	180.5	70.8	557	92% Colorado Interstate
17 Public Service Electric & Gas Newark, NJ	177.0	101.3	1151	52% Transco, 31% Texas Eastern, 6% Tenneco
18 Southern Union Gas Austin, TX	160.4	45.0	511	intrastate supplied
19 Pioneer Natural Gas Amarillo, TX	176.3	26.4	224	intrastate supplied
20 Minnesota Gas Minneapolis, MN	149.8	74.2	468	96% Northern Natural

Table 2.2 (Continued)

Company, Location	Sales, Trillion Btu Total	Residential	Thous. Resid. Customers	Major Suppliers
21 Arkansas-Louisiana Gas Shreveport, LA	147.9	69.9	606	(is an interstate pipeline company)
22 Laclede Gas St. Louis, MO	137.7	74.2	507	100% Mississippi River
23 Wisconsin Gas Milwaukee, WI	132.2	50.2	356	93% Michigan Wisconsin, 6% Natural Gas Pipeline
24 Mountain Fuel Supply Salt Lake City, Utah	131.0	48.7	331	(is an interstate pipeline company.)
25 Columbia Gas of Pennsylvania Aliquippa,PA	124.8	48.2	298	(subsidiary of Columbia)
26 The Peoples Natural Gas Pittsburgh, PA	124.3	53.2	287	(subsidiary of Consolidated)
27 Cincinnati Gas & Electric Cincinnati, OH	110.7	51.5	325	94% Columbia
28 Washington Gas Light Washington, D.C.	110.4	62.1	497	86% Columbia, 14% Transco
29 Illinois Power Decatur, IL	103.5	47.6	336	31% Mississippi River, 30% Natural Gas Pipeline,
30 Brooklyn Union Gas Brooklyn Borough, NY	96.7	77.7	1029	68% Transco, 17% Texas Eastern, 8% Tenneco

Table 2.2 (Continued)

Company, Location	Sales, Trillion Btu Total	Sales, Trillion Btu Residential	Thous. Resid. Customers	Major Suppliers
31 Alabama Gas Corp. Birmingham, AL	96.2	34.6	319	92% Southern Natural
32 Niagara Mohawk Power Syracuse, NY	93.8	54.6	383	100% Consolidated
33 Indiana Gas Lafayette, IN	93.9	42.8	261	65% Panhandle Eastern, 23% Texas Gas Transmission
34 Baltimore Gas & Electric Baltimore, MD	84.5	40.6	473	100% Columbia
35 Northwest Natural Gas Portland, OR	83.4	17.5	190	100% Northwest Pipeline
36 Kansas-Nebraska Natural Gas Phillipsburg, KS	82.5	19.0	146	(is an interstate pipeline company.)
37 Equitable Gas Pittsburgh, PA	82.0	42.4	239	(is an interstate pipeline company)
38 Iowa-Illinois Gas & Electric Cedar Rapids, IA	77.7	29.6	195	93% Natural Gas Pipeline, 7% Northern
39 Consolidated Edison Manhattan Borough, NY	72.5	38.4	956	64% Transco, 22% Texas Eastern, 13% Tenneco
40 Washington Natural Gas Seattle, WA	68.5	21.4	205	100% Northwest Pipeline

2.2 Characteristic features of the natural gas market

For our purposes, the salient feature of the natural gas market is the relationship between the pipeline company as buyer and the gas producer as seller. As was mentioned above, this relationship is based on long range contractual agreements which dedicate the production from specified reserves to a particular pipeline company. This commitment of an individual producer to a particular pipeline company is due to the need for a physical hook-up between the wellhead and the pipegate. The pipeline company thus acts as a monopsony: it is the only available buyer from all those gas reserves to which it has access. In this situation, the contractual agreements serve a dual purpose: they set price levels or price formulas over the anticipated period of production, and they protect the producer by establishing production levels which the pipeline must absorb. These contract clauses commonly take the form of take-or-pay provisions. In their strictest form these provisions stipulate that the buyer is required to pay for a certain percentage of the available production regardless of whether he actually withdraws this amount. A similar contractual rigidity and price levels tied to world oil prices govern most import agreements.

Since increased demand causes increased production of gas from expensive sources, one might expect a market characterized by "diseconomy of scale", that is, unit prices rising with increasing demand. Due to take-or-pay provisions, however, average wellhead prices tend to fall rather than rise with increasing demand. Therefore, and because of fixed tariff requirements (see Section 2.3.2), the natural gas market is dominated by economy of scale effects.

Another important characteristic of the natural gas market is its seasonal pattern. Gas demand in the residential and the commercial sectors is considerably higher in the heating season, approximately October through March, than during the remainder of the year. On the other hand, for physical and financial reasons, gas production proceeds at an essentially even pace. This leads to production in excess of demand during the nonheating season. Vast underground storage facilities are then used to store excess gas for consumption during the heating season. Underground storage facilities may be owned or leased by distribution companies as well as by pipeline companies.

The need for storage can be reduced by smoothing demand. This is accomplished, particularly in Southwestern States, by electric utility companies using gas as generator fuel during the summer months to supply additional electricity needed for air conditioning. Alternatively, customers able to use fuels that can be stored locally, such as oil or coal, are induced by reduced rates to use gas mainly during periods of excess availability. If not enough gas is stored during the summer, then shortages might be caused, for instance, by unexpectedly inclement weather conditions. In this case, certain industrial customers may be curtailed, meaning that residential and commercial market sectors are given priority for the available gas.

2.3 Federal regulation of natural gas commerce

Federal regulation of the natural gas industry began with the passage of the Natural Gas Act of 1938 (NGA, Public Law 75-688). It addressed the interstate market only, spelling out the rules for monitoring tariffs, providing the foundation for what was subsequently interpreted as the authority of the FERC to establish ceiling prices at the wellhead (Phillips decision 1954) and to require proof of sufficiency of the reserves available to a pipeline company in order to meet anticipated end-user demand for a specified number of years. Over the succeeding four decades, the NGA was followed by numerous laws and regulations affecting all aspects of the natural gas industry. The most comprehensive of these laws is the Natural Gas Policy Act of 1978 (NGPA, Public law 95-621), which evolved after more than eighteen months of Congressional debate.

2.3.1 The NGPA

A main purpose of the NGPA was to facilitate the decontrol of natural gas prices at the wellhead in a manner which would not disrupt existing markets. In particular, the NGPA was intended to provide a price structure which would gradually escalate some wellhead prices to parity with crude oil prices, and thereby provide a smooth transition to a limited decontrol in 1985. Here parity is obviously understood in terms of Btu content. The lawmakers were particularly concerned with the possibility of a sudden large increase in gas prices should a gap exist between crude oil prices and natural gas prices at the time of decontrol. Such a price "fly-up" may conceivably occur under such circumstances in spite of long range contractual agreements between producers and pipelines because of the existence of pricing clauses or "favored nation" clauses in such agreements, or because of legal ("force majeure") and commercial pressure for renegotiations.

The price escalation factors specified in the NGPA were based on the assumption that the 1985 crude oil price would amount to about $15 per barrel. The crude oil price, however, has risen much faster and, as a result, the NGPA has not been sufficient to narrow the gap between oil and gas prices effectively.

In order to formulate its decontrol scheme, the NGPA defines several categories of natural gas depending on their mode of production. These NGPA-categories are referred to by their corresponding section numbers in the NGPA: 102-109. Roughly speaking, category 102 ("new gas") refers to wells drilled after 1977 and sufficiently distant (2.5 miles) from, or sufficiently deeper (1,000 feet) than a previously established reservoir, but not below 15,000 feet. Category 103 ("not so new gas") contains wells drilled after 1977, but not well enough separated from previously established reservoirs. Category 104 ("old interstate gas") encompasses all reserves dedicated to interstate commerce prior to 1978. Categories 105 and 106 refer to "old intrastate gas", the difference between the two being whether the gas is produced under an original or renegotiated ("rolled over") contract.

Category 107 ("high cost") gas includes new wells which are very deep (below 15,000 feet). Category 108 ("stripper wells") is made up of slowly producing wells mainly found in Appalachia, and Category 109 covers all the remaining types of gas. Categories other than 104,105,106 will contain reserves that have not yet been contractually committed to a specific buyer. Eventually such reserves will enter either the interstate or the intrastate market.

Under the NGPA most new gas (category 102) is scheduled for deregulation by 1985, as are parts of categories 103, 105 and 106. The remaining portion of category 103 is to be deregulated by 1987. The very cheap old gas in category 104 is not considered for deregulation and its price is not permitted to rise faster than inflation.

The NGPA also contains incremental pricing provisions, namely mechanisms for pipeline companies to pass on certain price increases at the wellhead without requiring a rate hearing by the FERC. These provisions contain special clauses protecting the residential and commercial markets by requiring industrial "boilers" to absorb, within specified limits, a comparatively larger portion of such price increases. Full NGPA ceiling prices were originally denied to production from reserves owned directly, i.e. not via subsidiary, by an interstate pipeline company. In such cases, the FERC maintained the old NGA position that prices at the wellhead were to be calculated on a cost-of-service basis. That position was overturned by the U.S. Court of Appeals for the 5th Circuit (Mid-Lousiana 1981). The Mid-Lousiana decision's biggest impact is on the El Paso Natural Gas Company, which obtains about 15% of its production from directly owned reserves.

2.3.2 Rate determination

The rate schedules under which transmission and distribution companies collect their revenues differ widely in their structures. Interstate transmission tariffs are monitored by the FERC and follow schemes whose salient features are a monthly so called demand charge, which is "fixed", that is, it has to be paid regardless of the quantity purchased, and a so called commodity charge, which is "variable", that is, a per unit cost. The demand charge for each customer is calculated from a posted demand rate by multiplying it with maximum expected peak demand, for instance, in terms of largest daily delivery during the year. Such a maximum expected peak demand is stated by the customer, and it limits the peak delivery to which the customer is entitled under this rate schedule. In addition, a rate schedule may stipulate minimum sales, seasonal surcharges, and so on. Pipeline companies covering large distances may distinguish up to seven, but more usually two or three, different rate zones. Besides so called "general service schedules", pipeline companies offer separate rate schedules for various special purposes and for direct sales to end-users.

The rate schedules of distribution companies reflect the differences in guidelines issued by public utility commissions in different states. Furthermore, separate rate schedules have to be provided for the individual end-use sectors. For a discussion of distributor rate schedules see [2].

All methods for determining the actual tariff numbers within a rate schedule are, regardless of all other differences, based on the same principle, namely recovery of expenses. Typically, a rate base is determined for the year in question. This rate base consists essentially of the cost of total plant (at purchase prices) plus working capital for the year minus accumulated depreciation and minus accumulated deferred income taxes. The costs of capitalization of the rate base and of dividends to stockholders determine the required return for the year. This required return together with the cost of purchased gas, operating and maintainance expenses, depreciation expenses and taxes constitutes the total cost of service, which is to be compensated by tariffs. The cost of service is divided into a "fixed" part and a "variable" part, the latter consisting of the unit cost of purchased gas and a portion of the operating and maintainance expenses. In the case of interstate gas pipeline companies, the FERC limits what fraction of the fixed cost of service can be recovered through (fixed) demand charges. The most recent decision (United Formula, 1973) sets a limit of 25% for all interstate gas pipeline companies. Thus at least 75% of the fixed costs of service, together with all variable costs of service, must be recovered through (variable) commodity charges.

The presence of fixed charges generates an immediate economy of scale at the citygate and at the burnertip. A less immediate but stronger economy of scale effect is due to the relative constancy of the rate base and therefore of the fixed costs of service: if sales decrease then tariffs must increase to recover this fixed cost of service. These effects reinforce the economy of scale effects that result from take-or-pay provision at the wellhead.

2.4 Model purpose and scope

In view of the persistent gap between gas and oil prices, important questions arise about the prospect, size and timing of price "fly-up" caused by deregulation of natural gas production prices as stipulated in the NGPA. At the heart of these questions is the need to understand the consequences of different deregulation options in order to analyze the potential effects on all parties. Specifically, the analyst wants to consider deregulation measures of the following form: (i) some NGPA categories originally not slated for deregulation will now be subject to deregulation; (ii) the deregulation date of a particular NGPA category will be changed; (iii) the escalation of price limits for particular NGPA categories will be accelerated or retarded.

The following questions will have to be addressed: What would be the regional price and consumption figures for natural gas at the burnertip during the 1980's under various category-specific deregulation assumptions? How would the reserve position and category mix change for major pipeline companies, and what impact would this change have on the supply situation for the particular regions served by these companies? In this section, we will address the question of what general structural specifications a mathematical model like the GAMS model would have to meet in order to aid in analysing such questions.

The immediate impact of the changes caused by deregulation measures is on the wellhead prices which are paid by the pipeline companies to their producers. Individual pipelines will be affected differently, because their reserves contain different proportions of NGPA categories. These reserve differences translate into price and consumption impacts at the burnertip, which differ by region and end-use sector. Furthermore, the exploration patterns will change with the economic attractiveness of the various production categories, and one might expect pronounced regional differences in what categories of gas are considered worth exploring for. This is because the market position of the individual pipelines which are supplied by a particular production region may vary from production region to production region.

These considerations indicate the "resolution", i.e., the degree of detail, needed in the model and in the supporting data. In particular, the following requirements should be met:

(A) The major conduits of supply represented by the major pipelines and pipeline aggregates, as well as the major distributors and distributor aggregates along with their supply relationships, must be identifiable items within the model.

(B) All consumption must be traceable through the system from wellhead to burnertip. By this we mean that, at each way-station, the incoming quantity is accounted for in terms of outgoing quantities and predicted transmission and distribution losses. The available reserves have to be reduced by the amounts of gas withdrawn from these reserves.

(C) Funds payed for incoming and received for outgoing gas transactions must be balanced, taking tariffs into account, so that effects of price changes at the wellhead on prices at the burnertip can be predicted. This balance is a bookkeeping balance it does not preclude profits or losses.

(D) The reserves of a pipeline need to be distinguished according to their NGPA category as well as other information -- historical, physical and contractual -- necessary to establish reserve-production ratios and to formulate the wellhead price changes due to deregulation.

(E) Demand elasticities must be available, for instance through exogenous specifications, by user sector for each distribution point that is represented in the model and for each study year.

(F) Tariffs for pipeline companies and distributors should be modeled in such a fashion that effects of economy of scale resulting from fixed costs and nearly constant rate bases can be observed.

The requirements (A) through (F) are necessary to establish a causal relationship between selective price changes at the wellhead and subsequent changes in consumption at the burnertip. The requirements (A) and (D) are also necessary to provide a framework for the modeling of the acquisition, by individual pipelines or pipeline aggregates, of newly discovered reserves. (B) and (C) are needed to establish tight arithmetic connections between volumes and prices at the wellhead on one side and at the burnertip on the other.

2.5 Data sources

The GAMS model has been designed and implemented to meet the requirements outlined in the previous section. The question then arises whether the necessary data are available for its support. We proceed to describe the major data sources at hand.

First, all interstate gas pipeline companies are required to report their annual sales to each client by volume and price. These data are part of Form FERC-2, which is a comprehensive annual report of all transactions of a pipeline company. Form FERC-2 has recently become available in computer readable form.

Next, all sellers of natural gas for end-use, that is, all distribution companies, but also some pipelines and producers, have to respond to Form EIA-50. This form, intended for assessing alternative fuel demand due to natural gas curtailments, asks for monthly sales broken down by end-use sectors, the number of customers in each end-use sector, a list of suppliers by name together with the annual quantity they supplied, and a list by name of their major nonresidential customers. The information is compiled annually in computer readable form and covers the period from April 1 until March 31. Mandatory since 1980, production and consumption data are collected on a calendar year basis by Form EIA-176. This form also reports "amounts unaccounted for", that is, gas lost for various reasons by companies selling for end-use. In addition, Form EIA-176 contains information about producer-used gas, which is not available from Form EIA-50.

All domestic operators of oil and gas wells report their estimated oil and gas reserves annually on Form EIA-23. Similarly, the interstate pipeline companies report on the status of their dedicated reserves and of commitments by other pipeline companies on Form FERC-15, the natural gas companies' annual report on gas supply.

Detailed figures about the purchases of interstate pipelines from gas well operators, covering both volumes and prices as well as indicating NGPA categories, are available in the form of Purchased Gas Adjustment (PGA) filings. These are required to be filed by interstate pipeline companies, under the incremental pricing provisions of the NGPA, whenever a company applies for an adjustment of its posted gas prices in response to price increases at the wellhead.

The tariffs posted by the major interstate gas pipeline companies are listed semiannually by H. Zinder and Associates in their Summary of Rate Schedules of Natural Gas Pipeline Companies [4]. More detailed information on these tariffs can be extracted from rate hearing depositions with the FERC. Every year, the American Gas Association (AGA) publishes an extensive and valuable summary of statistics, mainly at the state level, called GAS FACTS [1]. Also, the EIA provides annually a comprehensive statistical overview of natural gas commerce in the United States based on Form EIA-176. Its publication, the Natural Gas Annual (NGA) (DOE-EIA-0131), covers the production, interstate movements, storage, and consumption of natural gas. An excellent guide to data collections by the Federal Government available in 1980 and a concise discussion of the underlying issues are provided by the EIA report, A Review of Requirements for Natural Gas Data (DOE-EIA-0624), of December 1980.

While the available information is copious on volumes, it is rather sparse on prices, especially burnertip prices other than state averages. Additional difficulties are due to the fact that many of the above data sources are restricted to interstate commerce. Nevertheless, a data base supporting the GAMS model has been assembled successfully.

It should be noted that this data base refers essentially to a single year, the "base year" 1980. This is because key data sources have been available only recently in a form that is useful to the model. Indeed, several months are usually needed to compile and edit the data collections of the previous year, and post 1980 data were therefore not available during the design phase of the model. Nor were earlier data representative, since 1980 was the first year reflecting the full impact of the the NGPA.

This poses a peculiar challenge to the modeler: instead of being able to extrapolate past temporal trends, he has to rely essentially on "snap-shot" information about a single base year and to create future temporal trends from it. This is achieved by referring to given time-dependent demand curves for individual regional end-use sectors during the forecast period. Such demand curves indicate the annual quantity of natural gas consumed at a particular market and in a particular year as a function of the average annual unit price. Using models outside the GAMS system and without NBS assistance, EIA has been able to create the basic information from which such individual demand curves can be derived. The parameters of these demand curves are the main temporal inputs available.

2.6 Overview of the MARKET model

The GAMS model explores the impact of policy decisions on natural gas cost and consumption by year, end-use sector, and demand region as well as on the discovery, acquisition and production patterns of the natural gas reserves. The GAMS system consists mainly of three models called PROLOG, BID and MARKET (see Figure 2.4). PROLOG models the exploration and development of reserves.

BID awards the resulting reserve additions to individual pipeline companies on the basis of a simulated bidding process and it informs MARKET accordingly. Once a reserve belonging to a particular gas producing company has been awarded -- or rather dedicated -- to a particular pipeline company, it is assumed that gas from this reserve may be sold to this pipeline company only and that any request by the pipeline company within the production capability of the producer will be met at prices agreed upon at the outset. This does not mean, that these prices will not change (in constant dollars) on

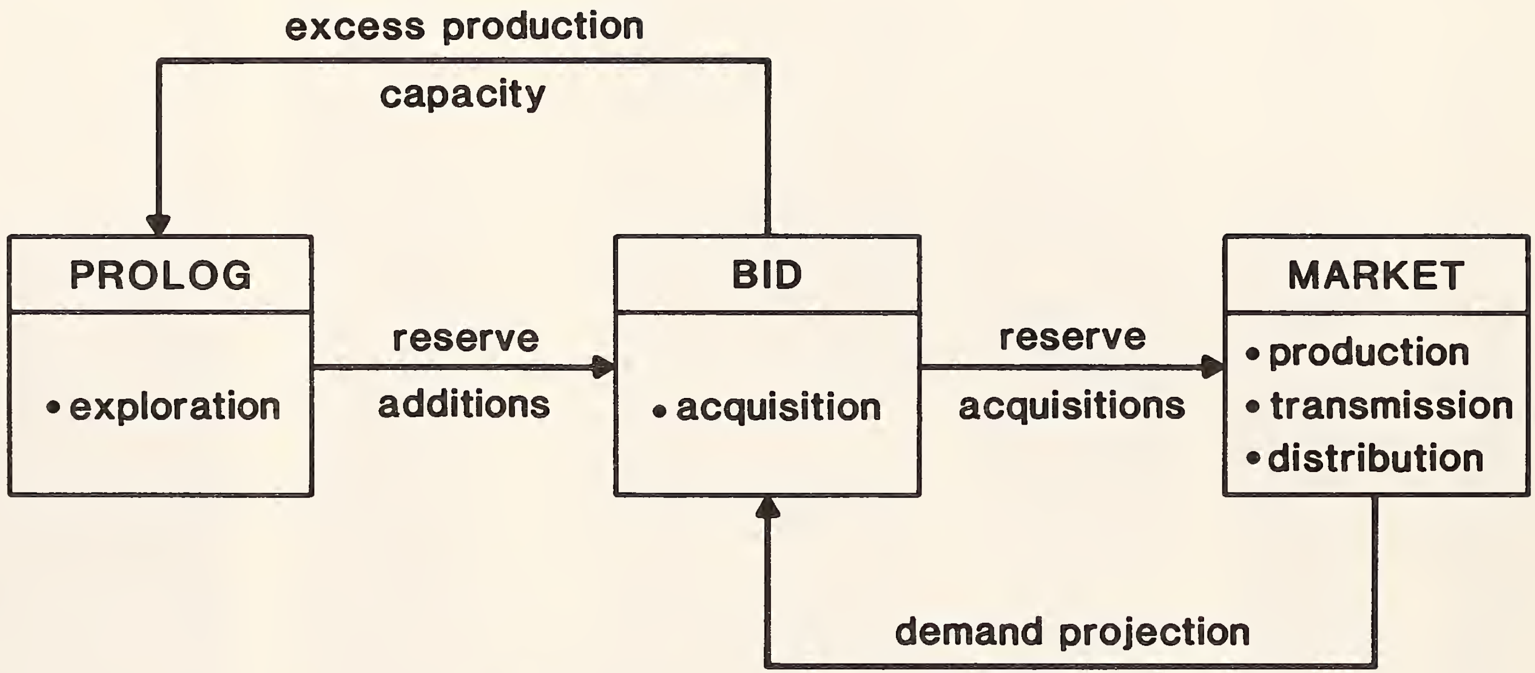


Figure 2.4: Schematic overview of the GAMS model

a yearly basis, but rather that price changes are also agreed upon in advance, possibly conditional to the occurrence of certain events. Price renegotiations can be specified in GAMS as part of a deregulation scenario. It should be noted that GAMS is the first model to represent the entire national gas market in a way designed to distinguish the process of committing gas reserves from the process of purchasing gas at the wellhead.

The main task of the MARKET model is to determine annual consumption volumes and their prices by region (both "Census" and "DOE") and end-use sector (see Figure 2.5). It does so by economic equilibration based on a comprehensive <u>network of national supply patterns</u>, encompassing all significant pipeline companies and distributors. This network is generated by a stand-alone computer program called GENNET. GENNET extracts most of the information for this task, including the connectivities which determine the structure of the network, from Form EIA-50.

In the first modeled year, the base year, MARKET establishes a baseline of volumes, prices, and related quantities. For subsequent years, it generally equilibrates between demand at the burnertip and supply at the pipegate, taking into account transmission and distribution losses (including compressor fuel), add-on tariffs (that is, charges for transmission and distribution expenses), and storage. There is a specific <u>supply curve</u> for each "pipeline system" and a specific <u>demand curve</u> for each "market". Pipeline systems represent either a single major pipeline company or a combination of smaller ones. Markets typically consist of all customers of a distributor that are in the same end-use sector.

The demand curves are essentially exogenous input. They indicate how much gas a market is potentially able to absorb at any given average price during the year in question. Some of the parameters of the demand curve reflect the market performance during the previous year. Prices of alternative fuels, in particular residual ("Number 6") fuel oil, are used to provide cut-off prices for various markets, that is, gas prices above which gas is replaced by an alternative energy source, and below which gas would be the preferred fuel.

A supply curve indicates the annual average unit price as a function of the annual purchase from reserves dedicated to a particular pipeline system. It is determined, as outlined below, from the full amounts that could be produced from each of the individual "reserve blocks", their take-or-pay ratios and their posted wellhead prices. The full amounts that could, but do not have to, be produced in a particular year are calculated from "production profiles", which essentially express possible production rates as a function of the maturity of the reserves in question. Production profiles for the base year are an EIA developed input. For subsequent years, reserve additions with specified production profiles are generated within GAMS by PROLOG.

The way in which the annual production is spread over the available reserves determines the average wellhead price: the more that is taken from cheaper reserves instead of expensive ones, the lower the price. The withdrawal strategy thus determines the supply curve. Once the actual annual purchase at the pipegate has been calculated by MARKET, either in the process of establishing the base year flow or in the process of equilibration, then this amount is actually withdrawn according to the above strategy. The amounts remaining in each individual reserve are recorded for reference by other components of GAMS.

When using MARKET, the analyst can choose from two alternative withdrawal strategies. The "minimum cost-take" strategy minimizes the average purchase price after having satisfied the take-or-pay provisions. Under the "rateable take" strategy, the take-or-pay provisions are again satisfied first, and then a fixed percentage of the remaining deliverable gas in each reserve block is withdrawn.

What happens in the model if there is not enough demand to pass the take-or-pay thresholds? Under both of the above options, a fixed percentage of the take-or-pay minimum in each reserve block is withdrawn and the price is determined accordingly. That is, if a shortfall occurs in the model, the theoretically ensuing penalties are not fully assessed. This is done because for the purpose of equilibration only those wellhead costs that can be passed through to the consumer at the burnertip should be considered. In the absence of meaningful precedents for large defaults, the position was taken that there are regulatory obstacles to passing significant take-or-pay penalties on to the end-user. It was also assumed that the impact of large take-or-pay penalties would be blunted by individual renegotiation.

The burnertip price is determined by adding tariff increments for transmission and distribution to the wellhead price after making allowances for plant and lease fuel. Transmission and distribution (add-on) tariffs are modeled separately. For transmission tariffs, base year averages are determined from rate hearing depositions at the FERC. These base year transmission tariffs, which consist of demand rates (fixed) and commodity charges (variable), may be escalated by a constant factor in each subsequent year. For distributors, general relationships between the quantities of sales and the number of customers on one side, and rate bases on the other, were empirically developed for this project by J.-M. Guldmann of Ohio State University [3]. These relationships are used for estimating distribution tariffs.

The burnertip prices determine - via the demand curves -the amount to be produced while, on the other hand, this amount determines the well-head price which in turn determines the burnertip price. It is this kind of circular definition that is resolved by the equilibration process, which is discussed extensively in Chapters 3 and 4.

The solution of this large equilibration problem is made possible by a decomposition scheme in which MARKET selects a "primary" supplier for each distribution company so that each distributor is nominally associated with a single pipeline system. The equilibration process then matches each individual supply curve against a well defined set of associated demand

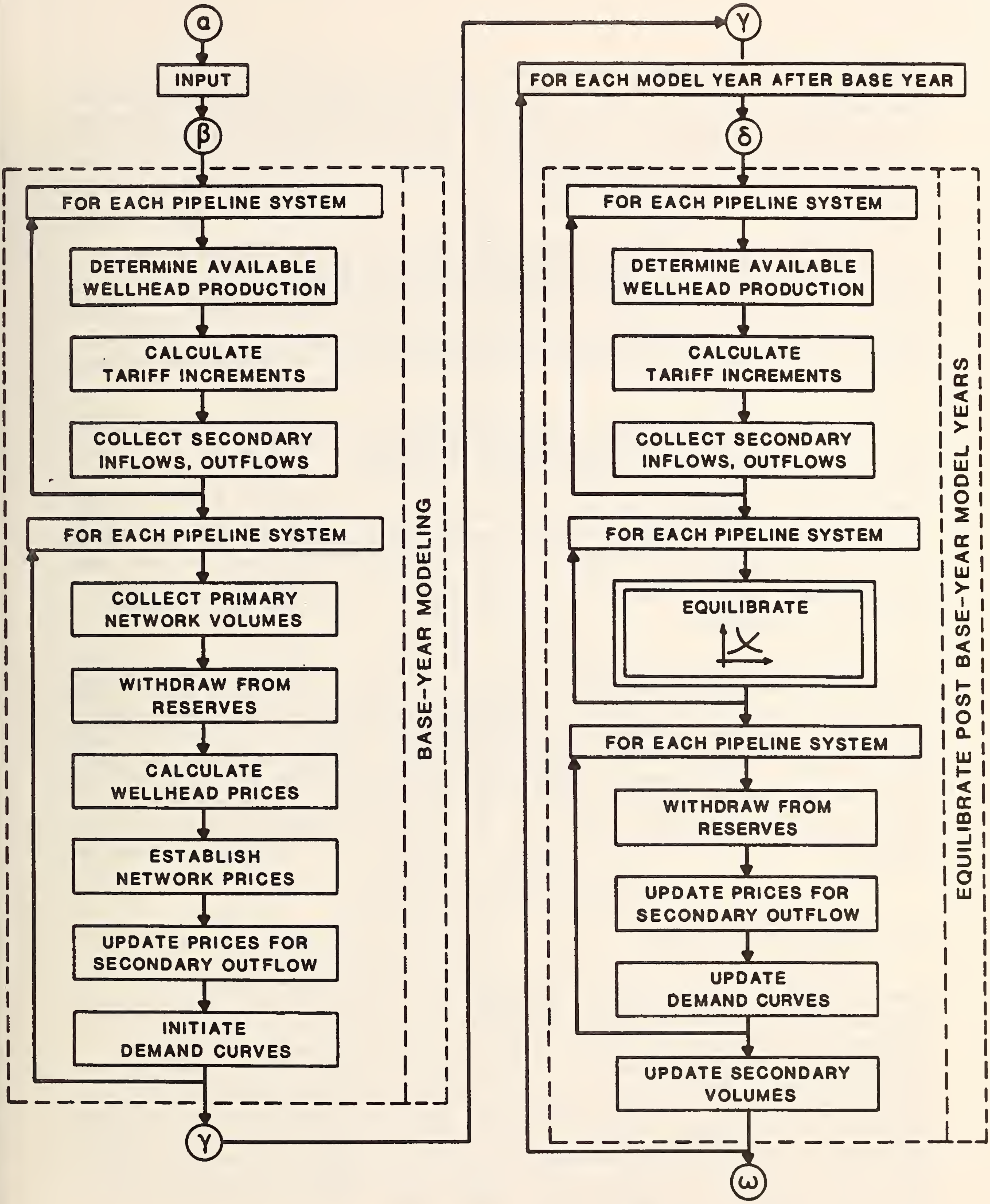


Figure 2.5: Schematic flowchart of the MARKET model

curves. Some sales, particularly those between the resulting subnetworks, are considered "secondary" and serve as boundary conditions for the equilibration. The secondary volumes and prices are updated in a separate process at the end of the model year based on the arbitrary assumption of equal cost shares among suppliers of an individual distributor. By this we mean that, in the presence of several suppliers to a distributor, the ratios of their sales values remain constant from one year to the next.

To some extent, incoming secondary quantities may be thought of as take-or-pay obligations, and indeed there are many examples where the secondary supplier does supply a distributor on a take-or-pay basis. The reason, however, for honoring secondary transactions first is fundamentally that their estimates have been completed at previous time step in the model process, and that the equilibration is designed to proceed under fixed side conditions.

At the end of each model year, the MARKET model develops estimates which enable it to respond to repeated queries by BID about how much gas a particular pipeline company will be able to absorb in a given future year at a given price. Here "future" means after the year for which the model has just completed its forecast. The BID model utilizes the responses to these queries for developing the bidding posture of the pipeline company in question. These demand projections can be thought of as a "model within a model" in that they try to represent processes invoked by actual pipeline companies when they estimate their sales potential (see Figure 2.6) for various "price tracks" covering future years.

The MARKET model is designed around the present framework of natural gas commerce: a distributor supplies captive end-users and buys from one or more pipeline companies and possibly from other distributors; a pipeline company buys from other pipeline companies but mainly from committed producers. The MARKET model ignores vertical integration. Most deregulation scenarios can be modeled within this framework, except the scenario in which all pipeline companies are transformed into common carriers. While working within the above framework, the MARKET model does not attempt to address the effects of deregulation on the financial position of corporations involved in natural gas commerce.

2.7 Model sensitivities

To which quantities and assumptions is the MARKET model sensitive? Numerical model results clearly depend on the structure of the supply network, the available reserves and their categories in the base year, burnertip consumption and prices in the base year, the specified demand elasticities, parameters for tariff estimation, the bidding procedures in BID, drilling equipment data in PROLOG, just to name a few. The assumed level and price of Canadian imports may critically affect the quantity of gas used by electrical utilities in California, and so on. Those model conclusions, however, which are based on comparing several GAMS runs with each other, will depend on many such quantities only in a minor way as long as the general structure of the natural gas market is reasonably well represented. This point will be discussed further in the next section.

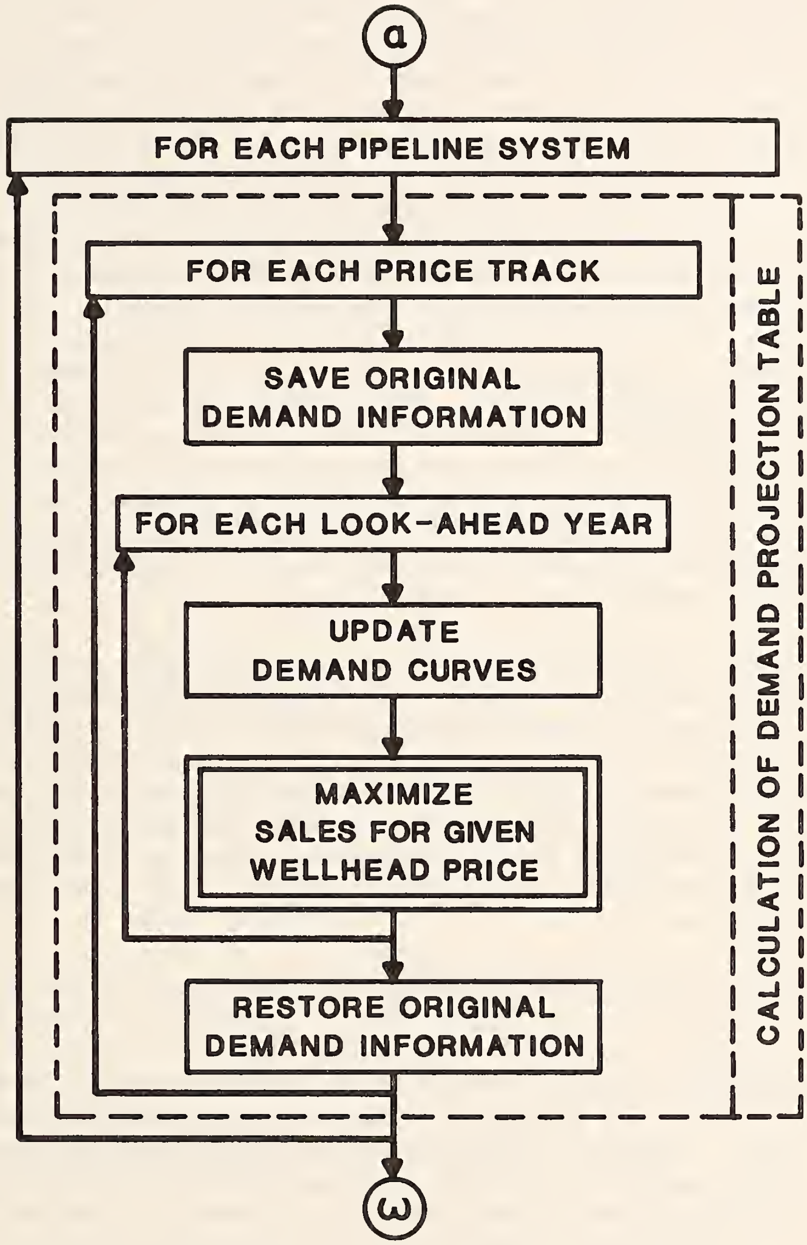


Figure 2.6. Schematic Flowchart of the demand projection portion of the MARKET model

The question of sensitivity really aims at the possibility of more disconcerting phenomena: are there parameters to which the model is sensitive in an unstable fashion so that small changes in such input parameters lead to large swings in output responses. Among the input items which may indeed cause such an instability in MARKET are discontinuous demand curves. By this we mean demand curves which specify a large demand at prices up to a particular cut-off price and, say, zero demand for any price that exceeds, however minimally, the cut-off price (see Section 3.6.3). Such discontinuities or cliffs in a demand curve may cause unstable behavior, provided some modeled burnertip prices end up close to a cut-off price. It is obvious that in such a case a very small change in any one of a multitude of model parameters may cause the burnertip price to increase just enough to push the demand "over the cliff", that is, cause a previously hefty demand to suddenly disappear. Similarly, a small parameter change somewhere in the model may trigger a price decrease which is small but sufficient to activate a hitherto latent demand.

This potential instability does not invalidate the MARKET model. On the contrary, it may be germane to actual market behavior and may thus provide valuable insight. Also, the instability need not always be realized, since the results are often sufficiently far away from cliffs that small parameter changes will have only commensurate effects. The purpose of a particular analysis should determine the extent to which the analyst chooses to build potential instabilities into his demand curves. It also helps if the instabilities are dispersed over a large network.

In many models, instability is caused by oscillatory behavior. Again, this may be a bona fide representation of real phenomena. In fact, determining whether oscillatory behavior develops, and its amplitude, may be a main purpose of a model. However, when or where a peak occurs in an oscillatory process tends to be sensitive to small changes in input parameters and assumptions. In designing the MARKET model, the authors have attempted to avoid oscillatory behavior as much as possible. However, oscillatory effects may be caused by a combination of cliffs in demand curves and tariff responses to past demand levels.

A third kind of sensitivity is caused by what may be called switches. In this case, small changes in the first year of a multiple year model may result in a different setting of a switch and accordingly set the model on different time paths leading to a large discrepancy of results in later years. Such a switch mechanism in a model may again represent the reality of the situation to be modeled (e.g., bandwagon effects), but unrecognized switch situations may jeopardize model results. MARKET does not contain intentional switches. An undesirable switch situation may arise for excessively large, so called, "lag exponents" in the demand specifications, and is discussed in a note to Section 3.6.

2.8 What can a mathematical model achieve?

The mathematical models we are talking about make statements about the future development of an extremely complex system, in the present instance, the natural gas industry in the United States. The description of such a system typically requires a large data base, and involves a huge amount of calculation in which these data are transformed and related to each other in order to derive certain indicative quantities. In this enterprise, the computer is a necessary ally, so much so that mathematical models often are identified with particular collections of computer programs whose output is considered as the result of the model.

The claim that future behavior of a complex system can be predicted in this fashion needs examination. What a model can do is to single out certain perceived trends, propose mathematical relationships between them, and determine the consequences of these assumptions. These consequences should indeed be valid estimates of future behavior provided the postulated trends continue intact over the forecast period, and the assumptions representing the modeler's perceptions of those trends and their relationships were essentially correct. The first condition cannot be verified: unexpected developments cannot be ruled out. At best, a model can predict what might happen assuming that some selected present trends and relationships continue or be subject to anticipated changes. This is not a problem. Indeed such information is extremely valuable to any decision maker. Actuarial models of mortality, for instance, are indispensable to various industries in spite of the realization that the detailed results of these models often have been invalidated by the occurrence of catastrophes. The problem is rather that of verifying the remaining condition, namely, that the assumptions which govern the underlying trends and their interrelationships were perceived and represented correctly. This is a formidable task under the best of circumstances, and may well not be practical as an a priori exercise. In such situations, the analyst must rely on skill and intuition to assess the assumptions on which the mathematical model is based and to detect discrepancies in the model output. Model assumptions can be further tested by sensitivity analyses and through experimentation with modified assumptions. For mature models, the experience of past model applications might provide guidance in interpreting more recent model results.

An important class of model assumptions represent idealizations, that is, conceptually compelling relationships which would hold exactly were it not for minor and less clear-cut effects militating against them. The physicists' model of free fall is a case in point. Here the effects of air resistance, air currents and the changing distance from Earth are ignored. It is important to explore idealized behavior. Even if an idealization turns out to be untenable, the actual behavior of a system is often best understood in terms of deviation from idealized behavior. Accepted patterns of idealization support the analyst's understanding of a model and provide a vantage point for the comparison of different models. The MARKET model is built on several idealizations. The concept of economic equilibrium is a major one of these.

This concept represents an idealization because the time-lags involved in arriving at an equilibrium are ignored. Most cost optimizations are idealizations because in real life cost minimization may not be the only decision criterion, and even if it were, cost minimization decisions in the real world may have to be based on information that is less complete than the model assumes. Ignoring effects arising from vertical integration within the natural gas industry constitutes yet another idealization.

Not all model assumptions are idealizations. Many represent undisputed facts. Others express the modeler's intuitive selection of a process intended to exhibit the same qualitative behavior as some particular feature in the real world. Such assumptions are often called exogenous assumptions and carry with them an element of arbitrariness. An example of such an essentially arbitrary exogenous assumption is the equal cost shares assumption for alternate suppliers in MARKET. Other exogenous assumptions are scenario specifications, e.g., the development of world oil prices. These assumptions, mostly about quantities rather than relationships, specify the hypothetical situations to be analyzed by the model.

Certain assumptions are simplifications adopted to facilitate the solution of a problem. Their justification is the expectation that the errors which are introduced by these simplifications are sufficiently small. A typical simplification is the decomposition in MARKET of the base network of supply patterns into subnetworks served by single "primary" suppliers, with supplies between different such subnetworks considered "secondary" and estimated in a less detailed fashion. Like most large models, GAMS resorts to judgmental assumptions where the modeler's information is limited with respect to some minor aspect of the model, or where certain model quantities have to be arbitrarily constrained to lie within the perceived limits of model validity. Judgemental assumptions are a priori perceived as having only inconsequential effects on the results of the model; otherwise they would be classified as exogenous assumptions. Simplifications and judgmental assumptions may act as indicators for areas for further research and model improvement.

Some judgemental assumptions in MARKET are prompted by a particular set of model data and may have to be changed if the model were to switch to a different data set. Several model runs are usually needed to stabilize model performance and to detect internal data inconsistencies. This holds in particular for the large network of gas supply patterns representing, for the purposes of the model, the entire national gas industry. While this network is automatically generated offline by GENNET, this is done with the expectation of subsequent adjustments by the analyst. It would have been possible to automate most of those adjustments, but to do so would not have been an effective use of available resources at the time.

Based on the scope and extent of the underlying exogenous and judgmental assumptions, the use of a mathematical model in an analysis needs to be qualified. Unlike for the classical statistical models, confidence statements concerning the forecasts of policy evaluation models such as GAMS usually cannot be given. Concerning the value in using such models, the position taken is that a model "forecast" represents one among several plausible developments, differing in their underlying assumptions, for which the impact of hypothetical trend-breaking events such as deregulation is to be assessed. It is expected that the size and the direction of the impact can be gauged differentially with a higher degree of confidence than that accorded to the model forecast itself. Experience with mathematical models by and large tends to support this expectation. It can also be verified to some extent by examining the impacts of trend breaking events on alternative plausible forecasts, that is, forecasts based on different exogenous assumptions specifying model relationships.

It would be a mistake to ignore some important benefits which accrue from the process of modeling in itself. This process cannot help but increase understanding of the subject area by forcing a systematic investigation of and experimentation with the assumptions upon which present understanding is based. This may lead to increased insight through reevaluation of these assumptions. A further benefit lies in the implicit data analysis performed by a model. This analysis may pinpoint inconsistencies and errors in data sets as well as semantic differences among separate data sources. If a model is executed at regular time intervals, then the analyst can develop his intuitive judgment of the relationships between the model results and the real world. In this case, the model acts as a powerful "indicator" of trends and events. A mathematical model may be the only way to do justice to a complex and substantive data base.

CHAPTER 3

Conceptual Description of the MARKET Model

In this chapter, we describe the major building blocks of the MARKET model: the network structure, supply at the wellhead, demand at the burnertip, tariffs and storage. In the next chapter, we will discuss the model processes which are based on these building blocks.

The description of the model will consist, for the most part, of introducing the major variables of the model and of stating in terms of these variables the assumptions with which we attempt to reflect aspects of the real world. The latter have been outlined in Chapter 2. Statements about model variables usually represent model assumptions rather than factual statements, and are therefore not always expressly identified as assumptions.

3.1 The general setting of the GAMS model

The purpose of the GAMS model is to explore the impact of alternative policy decisions on (i) natural gas cost and consumption by year, end-use sector and demand region; ii) depletion of existing reserves; iii) exploration and acquisition of new reserves.

The GAMS model is a recursive simulation model with econometric and linear programming components. The model "simulates" in that it creates a fairly detailed facsimile of the natural gas industry, and in that it is built largely on cause-and-effect relationships among the components of the industry. The degree of explicitness necessary to address the major questions facing the analyst was discussed in the previous chapter. The simulation is "recursive", because it begins with a baseline of historical data and modeled quantities for the base year, and derives new values for these quantities for the next year by referring to the values in the base year. The quantities modeled for each subsequent year are calculated analogously using those of the previous year.

All internal financial statements are in constant dollars, that is, base year dollars. For most recent scenarios, the base year has been 1980, while all model years covered the period 1980-1990. Certain demand estimation procedures, however, extend beyond the model years to a horizon year, say, 1995 (Note 1). Some model values refer to the year prior to the base year.

In the absence of a specific convincing policy-relevant alternative hypothesis, the judgemental assumption is made that there are no major changes in weather conditions, or more precisely, that in all years up to the horizon the weather conditions will be equivalent to those during the base year.

The natural gas industry conducts its operation under the influence of multiple state and federal regulations. This tends to limit the effect of particular corporate structures on its mode of operation. Intricacies of corporate structures are beyond the scope of the model. Consequently, GAMS ignores vertical integration, that is, it assumes producers, pipeline companies and distributors to be separate corporate units, each independently pursuing its own corporate interests.

In what follows, pipeline systems are the model elements which buy and transport natural gas, selling it subsequently to client distribution companies. Reserve blocks, representing the producer function, are aggregates of reserves which are treated as units by the GAMS model. The reserves in the same reserve block are of a single NGPA category and share other properties of a physical, contractual or historical nature.

3.2 The Role of the MARKET model in GAMS

As pointed out before, GAMS consists of three models: PROLOG, representing exploration, discovery and development of reserves; BID, representing commitment of these reserves to pipeline systems; and MARKET, representing production, transmission, distribution and consumption of natural gas. The GAMS driver calls these models in the above sequence once for each model year. The results of the BID model impact the MARKET model directly and vice versa, whereas there is no such direct impact on PROLOG. In some cases, we will therefore refer to an interaction with BID, instead of using the more correct but less informative term "interaction with the GAMS driver".

There are two instances of interaction between BID and MARKET. In the first instance, information for each reserve block, including newly acquired ones about its current level of production capability, take-or-pay provisions and price of gas is transmitted from BID to MARKET at the beginning of each model year. During the model year, MARKET then equilibrates supplies and demands to determine the amount consumed at the burnertip and the amount which has to be produced in order to support this consumption. This annual production is allocated to specific reserve blocks, and the quantities of gas contained in these reserve blocks are accordingly reduced. The quantities remaining in each particular reserve block are reported back to BID at the end of the model year. Thus BID is kept apprised of how much gas each pipeline system can draw upon in the future. All reserve information has been adjusted prior to being passed to MARKET to reflect processing and the removal of plant and lease fuel.

In the second instance of interaction, BID queries MARKET repeatedly on how much gas a pipeline system would be able to absorb, and would correspondingly purchase at the pipegate from dedicated reserves, in a given future year for a specified average purchase price at the pipegate. Here the term "future" is used in terms of the model: the "present" year is the latest year for which the MARKET model has completed its forecast; the future years are those years which follow, up to the horizon. BID uses the above information when it models the bidding for new reserves.

These marketability estimates required by BID are derived by applying an abbreviated version of that part of MARKET which is invoked annually to execute the regular forecasts. Each year, MARKET constructs a demand projection table, whose rows correspond to a specified number of consecutive future years (the look-ahead period), whose columns correspond to price tracks, and whose values are the maximum amounts of gas which might be purchased from dedicated reserves at each given price in each given year by the pipeline system for which the table is being set up. The prices increase from left to right in each row. The values in each individual row are sample points for a projected pipegate demand curve which is typically monotonically nonincreasing. The values in individual columns, however, need not change monotonically over the future years (Note 2).

The queries from BID are handled as a table look-up procedure, with interpolation for in-between prices and default conventions for prices which fall outside the grid (Note 3). However, BID tailors the grid prices to each individual pipeline system in such a fashion that most look-up prices can be expected to lie inside the grid. The recursive nature of MARKET requires that each year can be analyzed only after the previous years have been analyzed. The same is true for the abbreviated version of MARKET which is used to estimate maximum purchases for future years. The demand projection table is therefore constructed column by column, each application of the abbreviated MARKET procedure building on the results from the previously modeled year.

The main reason for abbreviating the demand projection portion of MARKET is that the projections for future years are carried out separately for individual pipeline systems and, therefore, cannot model the actions and reactions of other pipeline systems. To some extent, this may be thought of as reflecting the fact that, in real life, the leadership of a pipeline company must plan and bid on the basis of limited information about the plans of other pipeline companies.

Because of the abbreviated modeling and because of the maximum sales assumptions during previous years, the values in the demand projection table are speculative: it is not guaranteed that, when the actual modeling process reaches the year of the projection, the modeled pipegate prices and quantities lie precisely on the projected pipegate demand curve. This of course is not an inconsistency of the model, because the "actual" future-year values depend on decisions yet to be made (i.e. simulated) by BID.

3.3 The base network of supply patterns

MARKET requires a representation of the national natural gas transmission and distribution system by a collection of networks. These networks are a major input into the model. Networks generated by the GENNET program in separate runs have been used in production runs. The most prominent network in this collection is the base network. It represents all significant sales relationships between pipeline and distribution companies, but does not cover sales to end users. Essentially, the base network represents each company by a node, and links two nodes by an arc whenever one of the corresponding companies supplies the other. In general, an arc has an origin node and a destination node which differs from the origin node. Some arcs, however, may have only a destination node. In this fashion, a formal network or "graph" is defined. These formal networks represent relationships between their nodes, but do not necessarily correspond to physical layouts.

Pipeline companies transport not only their own gas, but also -- for a fee -- gas that belongs to other companies. Since gas from various sources cannot be distinguished once it enters the pipeline, this amounts to a swap of gas shipments. Transactions of this kind are not distinguished in the base network. The latter represents sales regardless of whose pipelines were used for the actual delivery. This design decision is based on the observation that pipeline companies treat transportation fees paid to other companies as a general operating cost to be compensated through generally posted tariffs. Thus a distributor who receives direct delivery through the pipeline operated by the supplier and another distributor delivery to whom requires the transportation services of an additional pipeline company will be charged the same tariffs, other things like rate zones being equal.

In what follows, a formal definition of the base network will be followed by a brief discussion of its generation principle and its associated model quantities. Whenever possible the name used in the model's computer code for a model quantity is provided in parentheses along with this quantity when it is first mentioned.

3.3.1. Definition of the base network

The base network is a network representation of sales and does not attempt to portray the physical network of pipelines. The gas sold by a particular pipeline company to a distributor need not be physically delivered using facilities of this pipeline company: it may well be transported by some other pipeline to its destination. The model also does not consider capacity limitations for transmission. Figures 3.1 and 3.2 illustrate the distinction between the network of physical pipelines and the network of sales.

In Figure 3.1, we picture two distinct pipeline companies. Pipeline company P_1 sells to four distribution companies: D_1, D_2, D_3, D_4. However, its physical facilities are disconnected: one piece serves D_1, D_2, D_4, while a separate piece connects D_3 to pipeline company P_2. The latter sells to distribution companies D_4 and D_5. It does not sell to distributor D_3, but agrees to provide transportation between the two separate facilities owned by P_1. The existing sales relationships are schematically characterized by Figure 3.2, with distributor D_4 being supplied by both pipelines.

Accordingly, the base network contains two kinds of nodes, pipeline nodes or P-nodes and distributor nodes or D-nodes. Each D-node must be supplied by at least one node. D-nodes may not supply P-nodes. However, P-nodes may supply other P-nodes and D-nodes may supply other D-nodes.

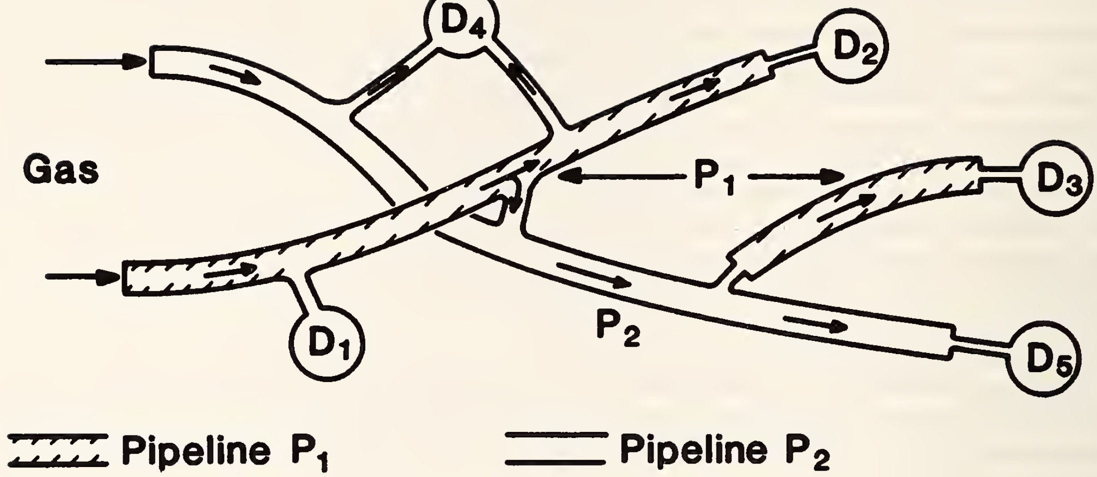


Figure 3.1: Physical layout of pipelines

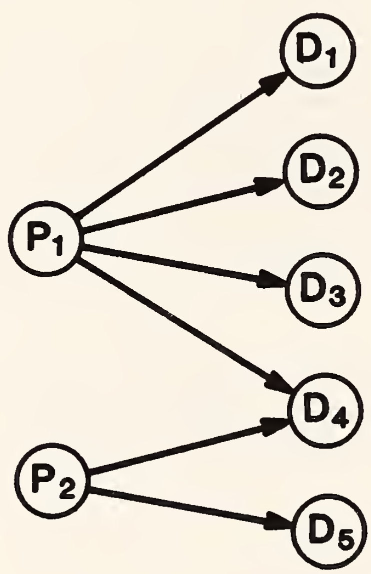


Figure 3.2: Network of sales patterns for Figure 3.1

In the present network, groups of actual pipeline companies are combined into single pipeline systems. This aggregation is accomplished by representing each actual pipeline company in such a pipeline system by a P-node and connecting them to a single artifically introduced P-node (Figure 3.3). The latter will serve as what will be later defined as a "root node" (Note 4).

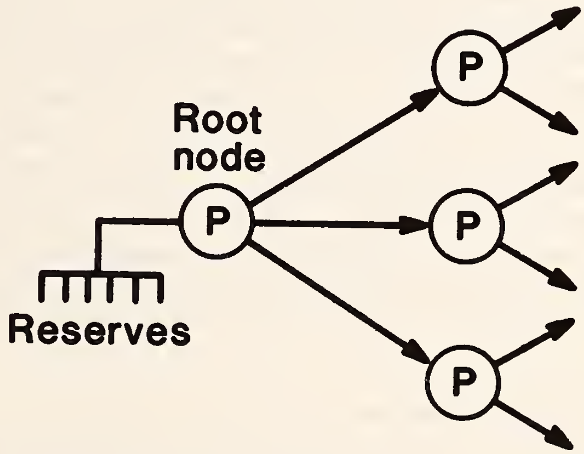


Figure 3.3: Rooted pipeline cluster

3.3.2. Structure of the base network

We turn to the question of determining the existing supply patterns. In recent applications, this information was obtained from Form EIA-50. On that form, companies report their monthly burnertip sales according to end-use sectors, but not their sales for resale. In addition, the above companies report their suppliers, and it is this information which defines the sales patterns. NBS has developed GENNET, a stand alone computer program that automatically generates a base network from Form EIA-50 computerized files (Note 5). This procedure is described in Chapter 5. At this point, we describe a few features of GENNET which are helpful to the general understanding of the structure of the base network.

A number of mostly small suppliers listed on Form EIA-50 belong to the intrastate market, and are accounted for as follows: if a supplier is not found on an analyst-supplied list of interstate pipeline companies, then these supplies are associated with the state in which delivery is taken, and are considered as originating from a model-generated "intrastate pipeline company", which is characterized by an exogenously selected cluster of states. Such a model-generated intrastate pipeline company can contain small interstate pipeline companies as well as actual intrastate pipeline companies, and should therefore not be confused with the latter. The model generated intrastate pipeline companies are represented in the network by P-nodes just like the interstate pipeline companies, and they are treated like the latter throughout the model.

Direct sales of natural gas by pipeline companies to end-users are also reported on Form EIA-50, as are direct sales by producers to end-users. The latter sales are treated as direct sales by one of the model-generated intrastate pipeline companies. In order to maintain a model convention that all end-users are supplied from D-nodes, the GENNET program includes artificial D-nodes in the base network, attaching them to P-nodes to play the role of intermediary distribution companies selling whatever is actually sold directly by the pipeline companies in question.

In any given State, direct sales by pipeline companies to end-users, if present, typically follow one of two patterns: (i) the pipeline company sells to one or a few large industrial customers or electric utilities; (ii) the pipeline company functions as a distribution company serving substantial numbers of residential and commercial customers in the given State. In both cases, GENNET introduces artificial intermediary D-nodes into the base network. In the first case, the D-node is marked as a direct sales D-node (or "pseudo" D-node in Section 5.1) in the network generated by GENNET, and MARKET will treat these special D-nodes differently during tariff and price calculations (see Sections 3.7 and 4.1.2). In the second case, however, the artificially generated D-nodes ("generic" D-nodes in Section 5.1) are not distinguished from the genuine ones and are treated like the latter throughout the MARKET model.

There are other occasions in which GENNET creates D-nodes that do not correspond exactly to distribution companies listed in Form EIA-50 compilations. For instance, a multi-state distribution company will be broken down into its state components, each represented by a separate D-node. Also, in a later version of GENNET, the analyst has the option of aggregating all those distributors within a State whose sales fall below a specified threshold on a statewide basis and representing them by a single D-node. None of these artifically generated D-nodes are specifically identified as such and are consequently treated by MARKET as if they were genuine.

Included in the base network are some arcs without origin node, which we call outer arcs, and whose destinations are typically P-nodes. Their purpose is to accommodate imports and Alaskan gas (Note 6) by providing the analyst with a mechanism for specifying individual exogenous prices and volumes on a year by year basis for those outer arcs he chooses to activate. To aid the analyst, GENNET prints a directory of the outer arcs it has set up.

3.3.3 Quantities associated with the base network

Almost every arc of the base network represents a transaction that occurred during the base year and is expected to occur again during the model years. We call such arcs proper arcs. Exceptions are: (i) arcs which have been added to connect P-nodes for the purpose of pipeline system representation, such as arcs emanating from the root node in a rooted cluster; (ii) outer arcs, i.e., import and Alaskan arcs. In fact, none of the P-to-P arcs are proper in the current network, although more advanced versions of the network may have proper P-to-P arcs representing stable sales between pipeline companies. Such sales are currently handled by reallocating some of the dedicated reserves.

With each proper arc, GENNET associates an annual transaction quantity or flow (QUANA) and its corresponding unit sales price (PRCEA) averaged over the base-year. These volumes are inputs for the base year, along with the base network specifications, and are updated annually by the model. Arcs which are not proper will not have flows or prices associated with them as inputs, since they do not correspond to transactions listed on Form EIA-50. GENNET also associates with each arc a transmission loss (RTMLA) estimate. These loss rates are either inputs or, optionally, calculated on the basis of transportation mileage (Note 7). Once entered or calculated, they remain unchanged.

Due to transmission loss, the transaction quantity at the origin of an arc is necessarily greater than that at the destination. If not otherwise stated, flow specifications are understood to apply at the destination throughout the model.

For each node of the base network we input a storage capacity (QSTOW) and an associated annual storage loss (RSTLW) estimate. Both are held constant in the model. Storage capacity refers to large underground storage facilities, not the short term storage devices used mainly by distribution companies.

This storage capacity does not represent the capacity of storage owned and operated by the company in question, but rather the capacity typically available for storage of the company's own gas, regardless of whether the facilities are owned or leased. See Sections 3.8 and 4.4 for further information on how the MARKET model handles storage.

The only geographical information in the base network concerns distributors: it identifies a home State (XLOCW) for each D-node. As was mentioned before in this section, distribution companies that sell in more than one state are split into one component for each state and each of these components is represented by a D-node, provided this component distributor is large enough to meet the size criteria of GENNET (see Chapter 5).

Finally, a tariff indicator (UTILA) has been attached by GENNET to an arc. Its purpose is to indicate whether a tariff for this arc is to be specified directly. If the indicator is positive, it will point to a tariff scheme consisting of a demand rate (PDEMU) and a commodity mark-up (PCOMU). The meaning of these quantities will be explained in Section 3.7. Along with the tariff scheme, a mileage estimate (GDSTU) is provided to MARKET to be used optionally for calculating the transmission loss along the arc in question (Note 7). If the tariff indicator is zero, then there are no tariffs and mileage estimates, and if it is negative it indicates a direct sales D-node. For these cases, tariffs are not provided directly but are determined in MARKET as described in Sections 3.7 and 4.13.

3.4 Primary supplies and pipeline systems

The distributors are now partitioned into groups associated with distinct pipeline systems. To this end, for each D-node and some P-nodes, respectively, a single arc terminating at this node is selected as a node's primary arc or predecessor arc. The origins of the predecessor arcs are called predecessor nodes. Conversely, there are successor nodes.

In the case of D-nodes, we select as the incoming primary arc the one that delivers the largest supply in the base year. The designation will remain unchanged during later model years, even though the model does not assure that these primary supplies remain dominant. Since every D-node is supplied from at least one node in the base network (see Section 3.3.1), each D-node has a (unique) predecessor.

In the case of P-nodes, predecessor arcs are selected so as to indicate that these nodes represent portions of a pipeline or a pipeline system. For instance, in rooted pipeline clusters such as the one illustrated in Figure 3.3, the arcs connecting the root node on the left with the P-nodes on the right would be predecessor arcs of the latter. The predecessor arcs of P-nodes are typically not proper arcs and have therefore no volumes of gas associated with them at the outset. The choice of the predecessors of P-nodes is therefore not based on dominance of supplies.

Nodes without predecessors are necessarily P-nodes and are called <u>root nodes</u>. All arcs in the base network which are not primary arcs are called <u>secondary</u>.

The methodology of the MARKET model is based on the assumption that the transactions designated as primary transactions in the MARKET model cover a major portion of the natural gas market. The MARKET model is considerably less detailed in its estimation of secondary transactions than of primary transactions. The basic assumption of primary dominance is well satisfied considering the current base network as a whole: including imports, secondary transactions of the P-D and D-D kind between different pipeline systems account for less than 15% of total volume (<u>Note 8</u>). However, there are a few locations in the base network at which the effect of secondary transactions is relatively more pronounced than in the network as a whole. In Section 4.1.1 we will describe some measures that can be taken to mitigate potential adverse effects of local secondary dominance. See Section 6.4 for a discussion of the issues concerning the division of base network arcs into primary and secondary ones.

3.4.1 <u>Pipeline systems and system networks</u>

Consider the predecessor of a particular node, then the predecessor of the predecessor, and so on. This repeated selection of predecessors must either terminate at a root node or go on forever in a cycle. In the latter case, we consider the predecessor assignment faulty. The network generator GENNET provides a noncyclic predecessor assignment (See Chapter 5).

The term "<u>pipeline system</u>" can now be completely defined. In the base network, each node is either a root node or the successor, direct or indirect, of a single root node. Each root node then defines a unique system of P-nodes and D-nodes, all of which are connected by a sequence of primary arcs to this particular root node. This is what we call a "pipeline system". In the model, it will act like a single pipeline company serving a set of client distributors as their main supplier.

Between one and six <u>market nodes</u> or <u>M-nodes</u> are attached to each D-node. Each of these markets consists of all customers of this particular distributor which meet one of the following criteria:

Residential
Commercial
Utilities without residual fuel oil capability
Industrial without residual fuel oil capability
Utilities with residual fuel oil capability (switching subsector)
Industrial with residual fuel oil capability (switching subsector)

In other words, the two end-use sectors "industrial" and "utilities" are further subdivided into <u>end-use subsectors</u> by their ability to switch to residual ("Number 6") fuel oil as their alternate energy source. This ability renders these markets particularly sensitive to price increases, which is one reason why they are treated separately. Other reasons are differences in curtailment priority and consumption patterns (<u>Note 9</u>).

With each pipeline system, we now associate a system network consisting of P-nodes and D-nodes connected by primary arcs with additional M-nodes attached to the distributors. In each system network, each node but the root node has a unique predecessor whereas the root has none. A graph with this property is known as a "rooted tree" provided it is connected, as is the case here. Each node in the base network appears in precisely one system network. The predecessors of M-nodes are D-nodes, the predecessors of D-nodes are either D-nodes or P-nodes, and, if they exist, the predecessors of P-nodes are P-nodes. Each P-node must have at least one primary successor that is not a direct sales D-node. This latter property is needed for price level calculations described in Section 4.1.2.

Figure 3.4 illustrates the relationship between two system networks and a base network. Here the rooted cluster method (Figure 3.3) was used to represent pipeline systems of more than one pipeline company. Solid lines indicate arcs in the system networks. Heavy lines indicate arcs in the base network, the broken ones refering to secondary arcs. P_1 and P_4 are the root nodes. All arcs in the base network are proper (recall this term's definition in Section 3.3.3) except the outer arc terminating at P_2 and the two arcs originating at P_1. The latter two arcs are not proper if P_1, P_2 and P_3 form a rooted cluster with P_1 an artificially introduced root node. P-to-P secondary arcs like the one from P_4 to P_2 are a feature of a more advanced network design. In the current network, such arcs are not present.

As in the base network, the system network connectivities are input to the model. This input has to be compatible with the base network and the predecessor assignment for the latter. The network generator GENNET automatically generates the system networks along with the base network in a compatible fashion. Currently there are 17 pipeline systems, of which five represent commerce which is predominantly intrastate.

The distinction between primary and secondary supply transactions, and the resulting concept of a pipeline system, is a major design concept of the model. It brings about a dramatic simplification of the model solution by permitting most model processess to be carried out for one pipeline system at a time, with secondary information being updated only once every model year (Note 10).

3.4.2. Consumption patterns at M-nodes

For each D-node, the MARKET model requires customer and monthly consumption figures by end-use sector in the base-year. These quantities are part of the system network data, which are a major input currently generated by GENNET. More recent versions of MARKET provide a benchmarking capability which adjusts these input data in order to ensure compatibility with NGA data in the base year (Note 11).

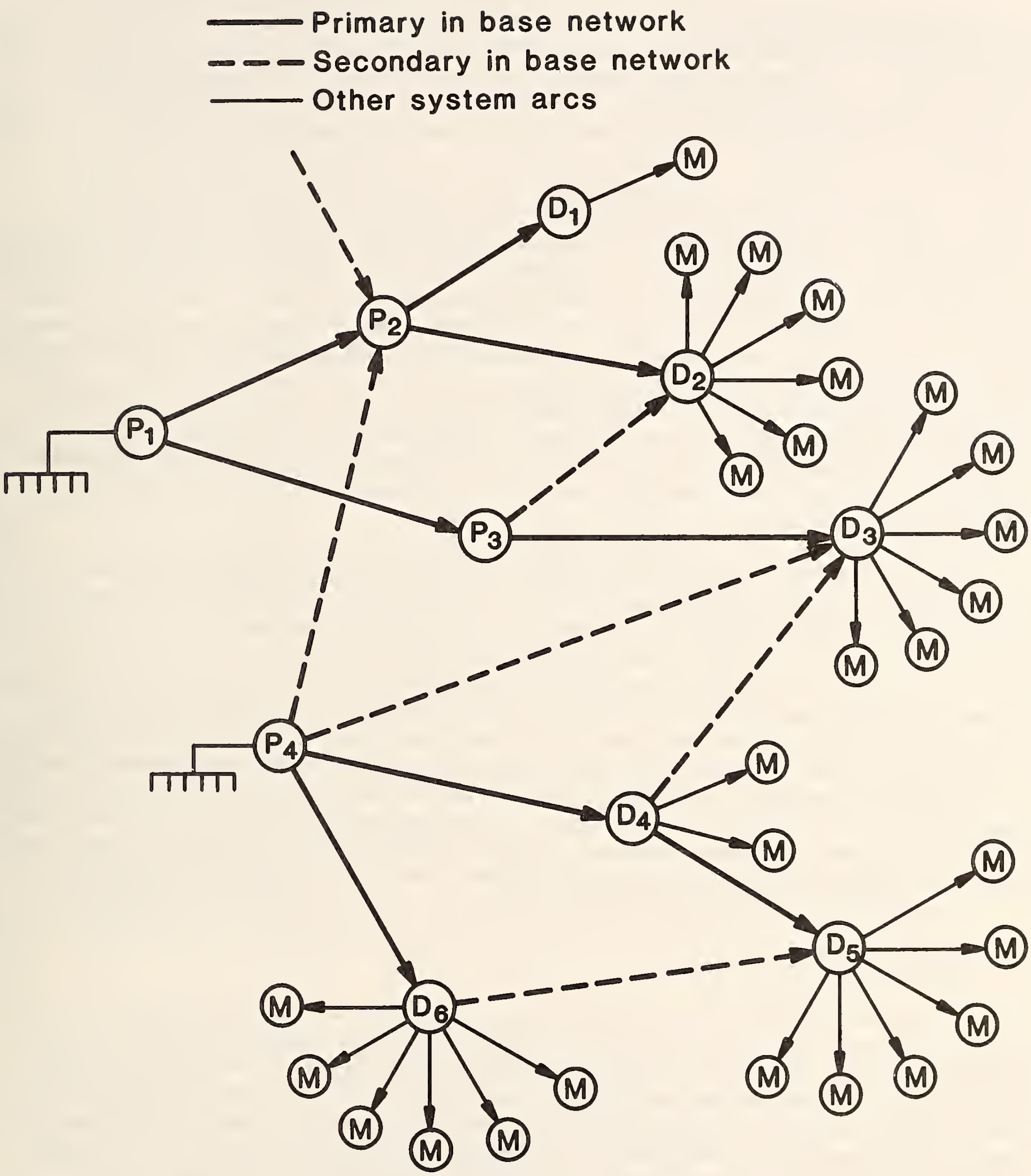


Figure 3.4: Schematic example of a gas supply network, consisting of a base network (heavy lines) supplemented by the market nodes.

For each M-node, there is a known base year consumption (QBASV) and a base year customer count (ZBASV). These quantities are part of the pipeline system specifications that are prepared by GENNET and are taken directly from Form EIA-50. The same source yields, for each M-node, a heating factor (RHTGV) and a loadfactor (RLODV). These were derived from the Form EIA-50 monthly consumption data. The heating factors are used to represent seasonality of demand. They are defined as the ratios of heating season (October through March) consumption to total annual consumption at each M-node. The estimates for loadfactors are used by the model for tariff calculations. They represent the ratio of peak day consumption to average daily consumption over the year. "Monthly" loadfactors obtained by dividing the peak month consumption by the average monthly consumption over the year are read into GENNET and transmitted to MARKET, which then transforms these monthly loadfactors into "daily" loadfactors by multiplication with an analyst provided loadfactor transformation ratio. AGA, acting on an inquiry by NBS, has reported in a private communication results of a data analysis which support the assumption that a loadfactor transformation ratio of 1.5 represents a reasonable approximation to the relationship between "monthly" and "daily" loadfactors, and this value is consequently used in MARKET (Notes 12, 13).

With each M-node, the model associates distribution losses measured between the citygate and the burnertip. These include compressor fuel, company usage, leakage and otherwise unaccounted for losses. At present, there is no input mechanism for these distribution losses. The model will estimate corresponding loss factors very roughly in the course of establishing system flows for the base year (see Section 4.1.1). For system nodes other than M-nodes and with the exception of the root node, the transmission loss on the primary inflow has already been determined, namely for the corresponding arc in the base network (Section 3.3.3). This loss quantity can therefore be transferred from the base network to the system network (Note 14). When there is no need to be specific, we will refer to both transmission and distribution losses as system transmission losses (RTMLV) or just transmission losses.

3.5 Supply at the pipegate

At the beginning of each model year, starting with the base year, the BID model presents MARKET with a list of reserve blocks. These include reserves available at the start of the modeling process as well as - after the base year - newly discovered and acquired reserves provided by PROLOG and BID. For each of these reserve blocks, BID specifies the pipeline system the reserve block is dedicated to, the amount of remaining reserves (QRRSK), the unit reserve price (PSUPK), the take-or-pay percentage (RTOPK), as well as productivity information. The take-or-pay percentage is the percentage of the full annual production capability from a reserve block for which the pipeline system will have to pay regardless of whether delivery is taken of that amount. We assume for the purposes of the model that all take-or-pay provisions are in this simplified form.

After MARKET has determined the amount to be withdrawn from each reserve block, it makes the corresponding updates in the list of reserve blocks and hands the updated list back to BID. MARKET also reports to BID, for each individual pipeline system, the total remaining reserves prior to this year's production. This and the above described exchange of information between MARKET and BID constitute the first instance of interaction between MARKET and BID as mentioned in Section 3.2.

For the base year, GAMS derives its reserve estimates mainly from Form EIA-23 data (Notes 15,30). EIA has sampled contracts between pipeline companies and gas producers to estimate take-or-pay percentages for these initial reserves.

3.5.1 Production profiles and supply curves

The model has to determine the potential annual production capability of each reserve block for a current model year or, in other words, how much can be maximally produced from a specific reserve block over the course of the year. This amount is a fraction of the total reserves contained in the block, and arises from the latter by division with a potential reserve-production ratio. This reserve-production ratio is not constant but changes over the productive period of the reserve block. For this reason, the BID model specifies - and passes on to MARKET - a (potential) production profile rather than a fixed reserve-production ratio to describe the production capability of a reserve block at its present state of development.

In general, one can distinguish three separate production phases. The development phase begins with the start of production and is characterized by rising productivity due to additional extraction equipment. The constant phase is reached when productivity is limited mainly by capacity of the gathering system. The decline phase sets in when the reserve nears exhaustion and gas pressure drops to the point where withdrawal rates fall below the limit set by the gathering system. GAMS assumes that the (full marginal) production rate increases linearly during the development phase, remains constant during the constant phase, and decreases exponentially during the decline phase. This results in a production profile of the form shown in Figure 3.5.

The production profile expresses the production rate as a function of time. This functional relationship, however, is only valid if production proceeds at full potential. If this is not the case, then gas pressure, for instance, may not drop as fast as implied by the production profile. In order to describe the effects of curtailing production, the model assumes that the production rate depends only on the amount previously produced. More precisely, given the amount previously produced, the model determines the time at which this amount could have been produced without any curtailments of production. We call this point in time the production time as opposed to real time. The integral over the profile function between the production time and the production time plus one year then represents the production capability of the reserve block during the year in question (see Figure 3.5). This calculation is repeated each year.

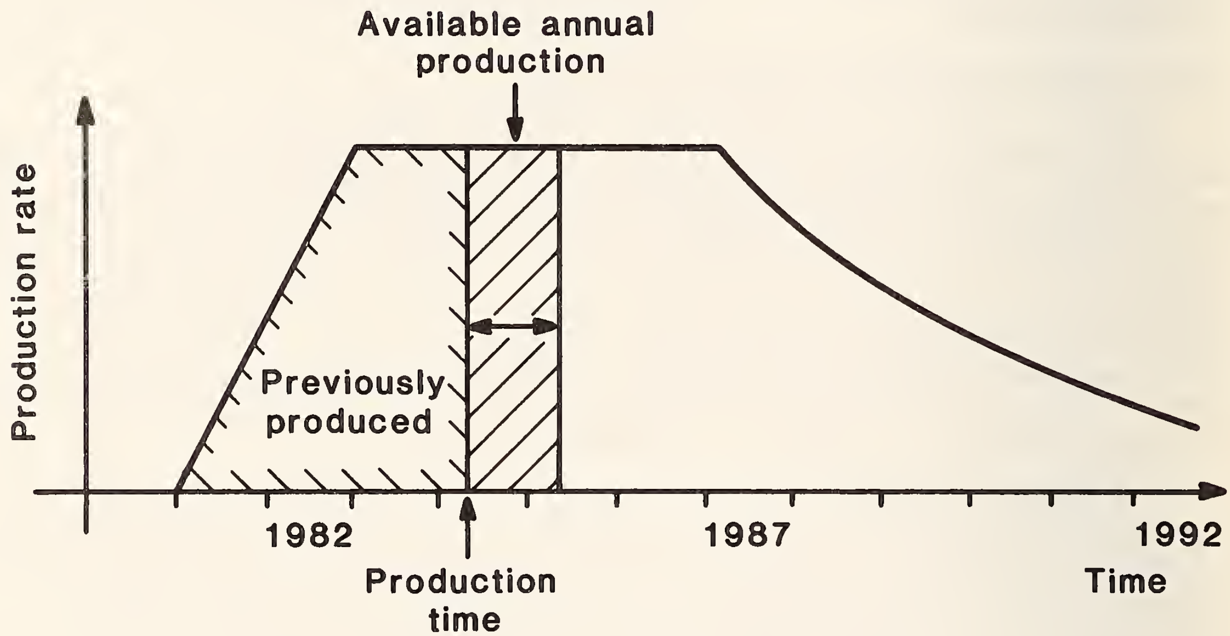


Figure 3.5: Schematic production profile

Once the potential production quantities are known for the reserve blocks of a pipeline system, a supply curve can be determined for the pipeline system. Essentially, this supply curve relates the annual production quantity from all reserve blocks dedicated to the pipeline system to an annual average unit price. To determine a price for the amount to be withdrawn, a withdrawal strategy has to be specified. As was mentioned before, the MARKET model gives the analyst a choice between two EIA-specified withdrawal strategies: minimum cost-take and rateable take. These options are not selectively applied: once a withdrawal strategy has been selected, it is applied every time during the model run.

As its name implies, the minimum cost-take strategy minimizes the supply price. First gas is withdrawn from each reserve block up to its take-or-pay threshold. After all take-or-pay provisions have thus been satisfied, the left-over demand is then allocated starting with the cheapest reserve block and proceeding in order of increasing prices. The gas currently available in each reserve block is used up before proceeding to the next reserve block until withdrawal is complete. The total amount to be withdrawn thus determines the individual amounts to be withdrawn from each reserve block, and thereby the average unit price for the total. In the case of take-or-pay shortfall, that is, if the total amount to be withdrawn is insufficient to cover all take-or-pay obligations, the withdrawal price is set arbitrarily to the average price of the total minimum take-or-pay production. In this case, the same percentage of the take-or-pay limit is withdrawn from each reserve block. Conceptually, this amounts to creating a single reserve block combining the take-or-pay portions from all reserve blocks. Figure 3.6 illustrates the form of supply curves that result from adopting this withdrawal strategy. Note, that this supply curve is in terms of average prices per unit of production. A supply curve in terms of marginal prices would take the form of a step function and thus would not be continuous. For a detailed discussion of the mathematical form of the supply curve under the minimum cost-take option see Note 16.

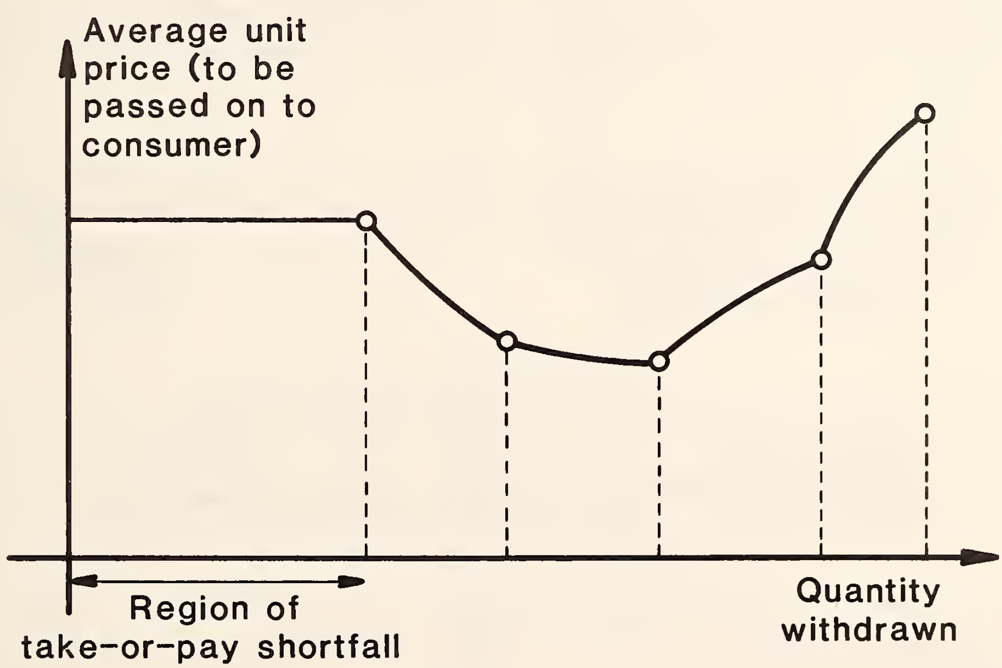


Figure 3.6: Schematic supply curve for minimum cost-take

The rateable take strategy proceeds in the same fashion up to the take-or-pay threshold. Thereafter, however, it withdraws at the same rate from all remaining sources (Note 17). For instance, if the remaining demand were half of the remaining supply, then one half of each of its remaining deliverability would be withdrawn from each reserve block. The price then becomes the average price of the remaining available supplies after take-or-pay provisions have been satisfied. The supply curve is thus equal to the supply curve which would result from two conceptual reserve blocks (See Figure 3.7). For the rateable take strategy to work, it is important that expensive reserves have high take-or-pay ratios compared to the less expensive ones; otherwise, prices will be cheaper if take-or-pay provisions are violated.

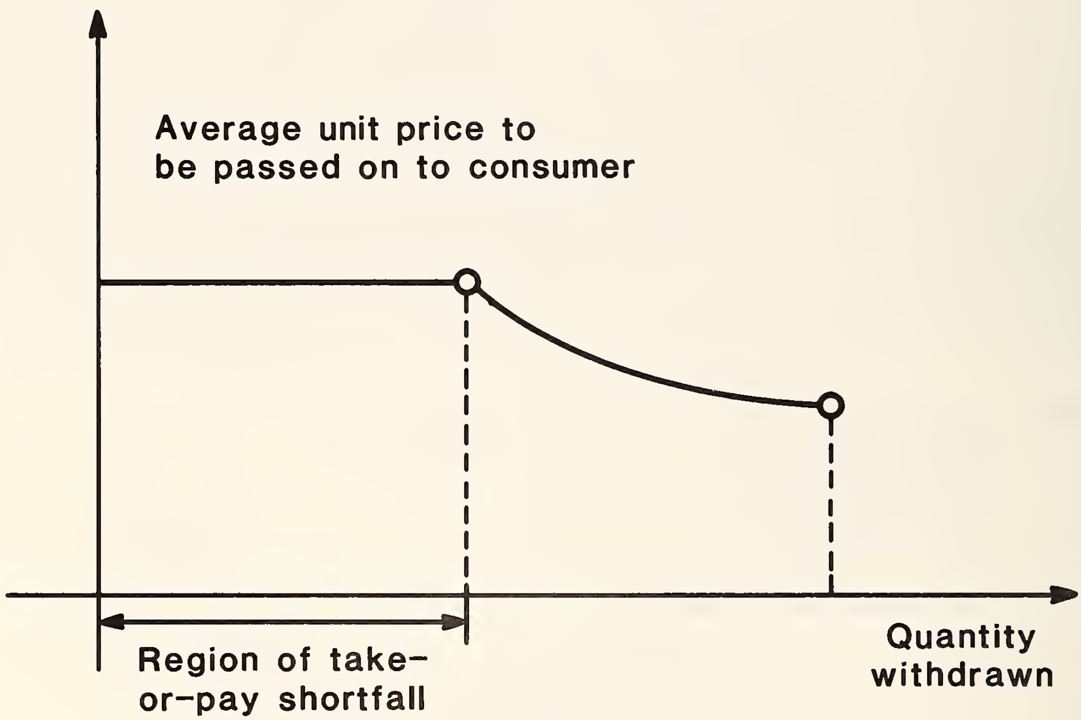


Figure 3.7: Schematic supply curve for rateable take

In justification of the arbitrary price used in case of a take-or-pay shortfall, we present the following arguments. We are in effect considering only that portion of the supply price at the pipegate which can be expected to affect the price at the burnertip. When the formally calculated supply price rises steeply because of take-or-pay shortfall -- it rises to infinity as the purchased quantity approaches zero -- then it becomes doubtful whether this price will be allowed to be passed on to the consumer, although there appear to have been too few precedents for a regulatory policy to emerge. We also expect that contract renegotiations would ensue if large take-or-pay shortfalls were inevitable.

3.5.2 Analysis of production profiles

A production profile of the kind described above is determined by five profile parameters:

T_1 = start of production (TLINK)
T_2 = start of constant phase (TCONK)
T_3 = start of decline phase (TDCLK)
q_{max} = maximum production rate (QRTEK)
Q_{res} = total original reserves (QORSK).

In addition, we introduce as a sixth profile parameter the reserve-production ratio during the phase of exponential decline

T_e = decline phase reserve-production ratio [years]

This parameter indicates how long it would take from the beginning of the decline phase to exhaust the resources of the reserve block if production were to be sustained at the maximum production rate q_{max} (Figure 3.8). Thus T_e can

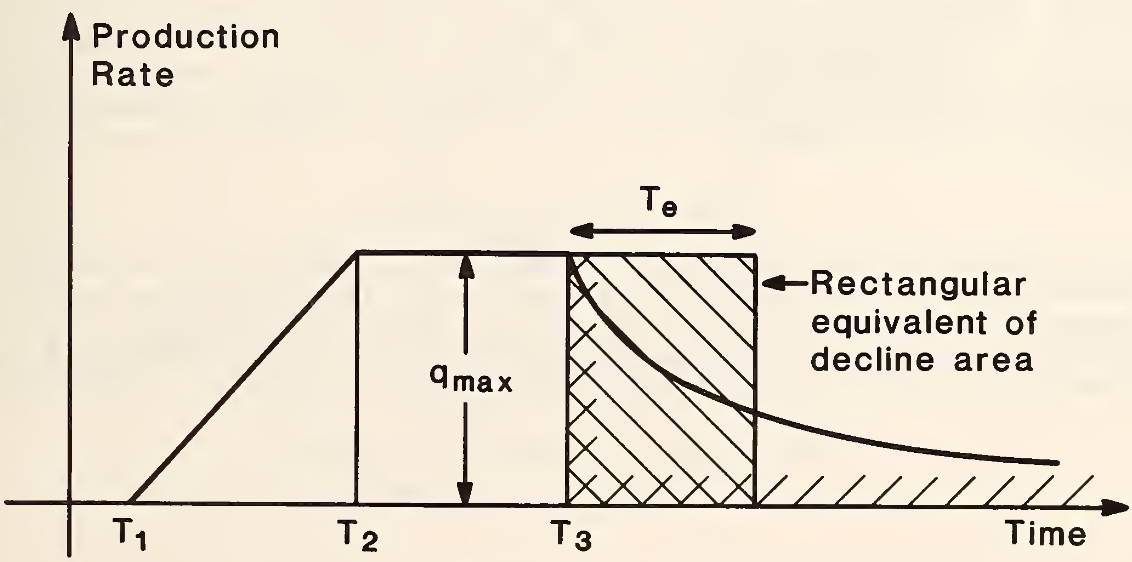


Figure 3.8: Role of profile parameters

be calculated from the quantity of reserves available during the decline phase. This amount, in turn, is found by subtracting the production during the previous two phases

$$q_{max} \cdot \left(\frac{T_2-T_1}{2}\right) \quad , \quad q_{max} \cdot (T_3-T_2),$$

from the total original reserves Q_{res}. The parameter T_e is recalculated in each model year in this fashion. Using T_e, the profile function q(T) can be expressed in the form

$$\frac{q(T)}{q_{max}} = \begin{cases} 0 & \text{for } T \leq T_1 \\ \dfrac{T-T_1}{T_2-T_1} & \text{for } T_1 \leq T \leq T_2 \\ 1 & \text{for } T_2 \leq T \leq T_3 \\ \exp\left(\dfrac{T_3-T}{T_e}\right) & \text{for } T_3 \leq T . \end{cases}$$

The main computational task that faces MARKET concerning the modeling of supplies is to calculate the full production capability Q_{full} of the reserve block during a given year. This calculation requires determining the point in time T_{prod} such that full production up to this time would have yielded the historical production Q_{hist} from the time the reserve block has been activated. More precisely, Q_{hist} is the amount withdrawn from the reserve block in the course of modeling up to the present model year, and it is calculated as the difference between the originally available reserve Q_{res} and the remaining reserves Q_{rem}:

$$Q_{hist} = Q_{res} - Q_{rem}.$$

Both the original and the remaining reserves are provided by BID as part of the reserve block information. This determines the state of development of the reserve block and consequently the present production capability. In order to determine T_{prod} we express the full production prior to a given time as a function of that time (see Figure 3.9)

$$Q(T) = \int_{-\infty}^{T} q(t)dt \ ,$$

where

$$Q_{res} = \int_{-\infty}^{+\infty} q(t)dt \ ,$$

and then find the inverse T(Q) of the above function in order to determine the production time

$$T_{prod} = T(Q_{hist}).$$

The latter then yields the full production capability for the current year (see Figure 3.9):

$$Q_{full} = Q(T_{prod} + 1) - Q(T_{prod}).$$

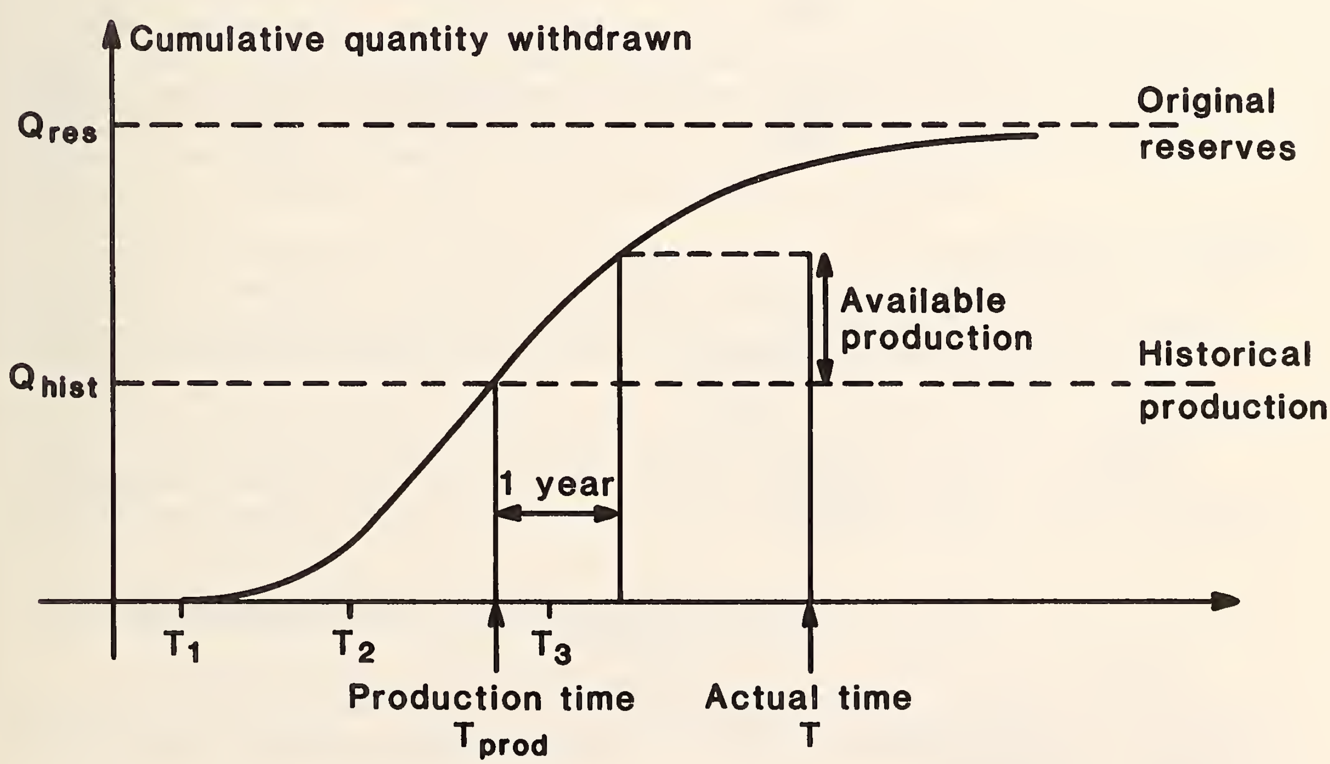


Figure 3.9: Cumulative production from a reserve block as a function of time: Q = Q(T)

In what follows, we will provide formulas for these calculations. Let

$$Q(T_2) = \int_{-\infty}^{T_2} q(t)dt = q_{max} \cdot \frac{T_2-T_1}{2}$$

$$Q(T_3) = \int_{-\infty}^{T_3} q(t)dt = Q(T_2) + q_{max} \cdot (T_3-T_2) = q_{max} \cdot T_3 - \frac{T_1+T_2}{2}$$

be the quantities produced up to the breakpoints T_2 and T_3, respectively. The reader confirms readily that

$$\frac{Q(T)}{q_{max}} = \begin{cases} 0 & \text{for } T < T_1 \\[2ex] \dfrac{(T-T_1)^2}{2(T_2-T_1)} & \text{for } T_1 < T < T_2 \\[2ex] \dfrac{Q(T_2)}{q_{max}} + (T-T_2) = T - \dfrac{T_1+T_2}{2} & \text{for } T_2 < T < T_3 \\[2ex] \dfrac{Q(T_3)}{q_{max}} + T_e \cdot \left(1 - \exp\left(\dfrac{T_3-T}{T_e}\right)\right) & \text{for } T_3 < T, \end{cases}$$

and that consequently

$$T(Q) = \begin{cases} T_1 + \sqrt{\dfrac{2(T_2-T_1)Q}{q_{max}}} & \text{for } 0 < Q < Q(T_2) \\[2ex] T_2 + \dfrac{Q-Q(T_2)}{q_{max}} & \text{for } Q(T_2) < Q < Q(T_3) \\[2ex] T_3 - T_e \cdot \log\left(1 - \dfrac{Q-Q(T_3)}{q_{max} \cdot T_e}\right) & \text{for } Q(T_3) < Q < Q_{res}. \end{cases}$$

These are the formulas used by MARKET for the calculation of the annual production capability.

Note that the above formulas remain valid if $T_1 = T_2$, $T_2 = T_3$, or both. In these cases the profiles will assume the shapes indicated in Figure 3.10 (Note 18).

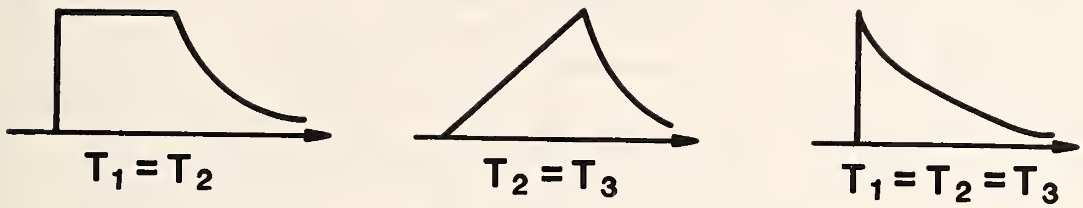


Figure 3.10: Special cases of production profiles

3.6 Demand at the burnertip

The MARKET model establishes for each M-node an individual local demand curve. The reader may recall that each M-node is associated with a unique end-use sector and a unique distributor. Each M-node represents the total market of this distributor in that end-use sector or subsector (see Section 3.4.1). The demand curves are based -- as are the supply curves (see Section 3.5.1) --, on average rather than marginal prices (Note 19).

Demand information is analyst supplied and in essence exogenous to MARKET. However, the analyst is required to supply demand curves only for each of 10 DOE-specified demand regions see (Figure 3.11). From these regional demand curves -- one for each end-use sector and each model year --, the local demand curves are generated automatically. The MARKET model also has the capability to generate future demand curves if the analyst so desires. This capability is based on the input of regional reference volumes (QRRSIY, ORCMIY, ORINIY, ORUTIY) and regional reference prices (PRRSIY, PRCMIY, PRINIY, PRUTIY) for each end-use sector starting with the year preceding the base year, and ending with the horizon year.

3.6.1 Illustrating local demand curve generation

In what follows, methods for generating and updating local demand curves are illustrated using a particular kind of demand curves as an example. To this end, consider local demand curves of the form (Note 20)

$$q = q_{ref} \left(\frac{p}{p_{ref}}\right)^{\beta} .$$

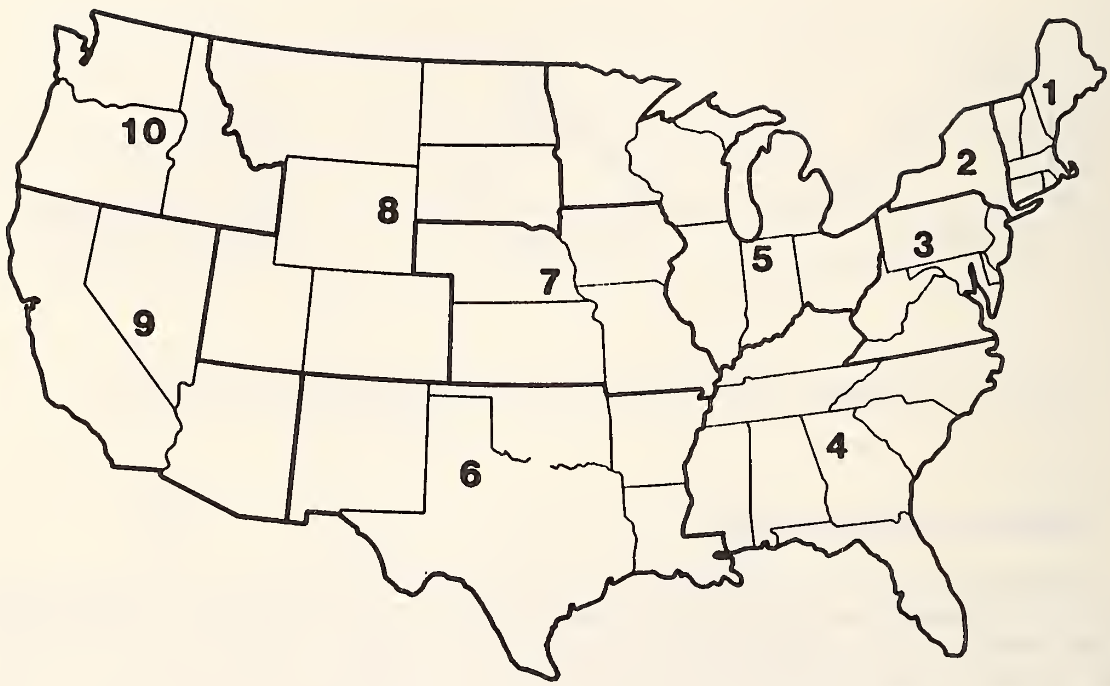


Figure 3.11: DOE demand regions

These are curves of constant (negative) elasticity

$$\beta = \frac{p}{q} \cdot \frac{dq}{dp} = \text{constant.}$$

The remaining two parameters, the <u>local reference volume</u> q_{ref} (QTRFV) and the <u>local reference price</u> p_{ref} (PTRFV) determine the general level of demand at the particular location (= M-node) by fixing a point, namely (p_{ref}, q_{ref}), through which the demand curve must pass. Indeed, for $p = p_{ref}$,

$$q = q_{ref}\left(\frac{p_{ref}}{p_{ref}}\right)^{\beta} = q_{ref} \cdot 1^{\beta} = q_{ref} \ .$$

These local curves can be interpreted as arising from a regional demand curve of the same form,

$$Q = Q_{ref}\left(\frac{P}{P_{ref}}\right)^{\beta} ,$$

by proper scaling. Here Q_{ref} and P_{ref} denote the regional reference volumes and prices for the given year and end-use sector. The scaling works as follows. For the base year, MARKET determines the consumption volume and the average burnertip price at each M-node. This volume and this price become the local reference volume and local reference price for each local demand curve, respectively. Then the home state of the M-node is determined and its demand region is deduced from this. The elasticity β of the regional demand curve is then used for the local demand curve, which is completely determined in this fashion. Note that multiplying the regional demand curve by the constant factor

$$\frac{q_{ref}}{Q_{ref}}\left(\frac{p_{ref}}{P_{ref}}\right)^{\beta}$$

will indeed produce the local demand curve in question.

The rationale behind this scheme of generation by scaling is that the geographic, social, and behavioral factors which determine elasticity or, more generally, the shape of the demand curve are sufficiently constant for the purposes of the model throughout each demand region. Thus only the level of demand is at issue locally.

Demand curves for subsequent years can be generated directly from the sequence of regional reference volumes and prices together with regional elasticity information (<u>Note 21</u>).

MARKET specifies local reference volumes and prices because they permit specification of demand levels not just for the special demand functions described above, but also in the case of more general demand functions.

3.6.2 The regional demand compatibility condition

The question arises: If the average burnertip price and the total consumption are calculated for all M-nodes of a given end-use sector in a given region, does this total price-quantity pair determine a point on the regional supply curve? If the answer is affirmative, then the regional demand compatibility (RDC) condition is satisfied.

In the base year, the local volumes and prices are known, and the RDC condition requires only that the observed base year volumes sum to the regional reference volume and that the average price correspondingly agree with the regional reference price.

In subsequent model years, if equilibration is employed, the actual prices and volumes as determined by the model at M-nodes will differ from the corresponding local reference prices and volumes. It can be shown that even for simple demand curves of constant elasticity, the RDC condition may no longer hold, even if all local reference volumes and prices are compatible with the regional reference volumes and prices (see Note 22 for an example).

In more recent versions, various demand iteration schemes have been implemented in which the RDC condition is enforced as much as possible. Clearly, it cannot be enforced in the case of a regional shortage because in this case the actual deliveries will fall below the demand as indicated by the regional demand curve.

Now let

$$\Phi(P)$$

be the regional demand curve for source end-use sector in a given year, and

$$\phi_i^{(o)}(p),\ i=1,\ldots,n\ ,$$

a set of corresponding initial local demand curves. Then the equilibration is carried out, resulting in local price-quantity pairs

$$p_i,\ q_i = \phi_i^{(o)}(p)\ .$$

Thus

$$Q = \sum q_i, \quad P = \sum p_i q_i / Q$$

are the resulting regional quantities and prices. If

$$Q = \Phi(P)\ ,$$

then the RDC condition is satisfied. If not, the local demand curves are rescaled:

$$\phi_i^{(1)}(p) = \frac{\Phi(P)}{Q} \cdot \phi_i^{(o)}(p)\ ,\ i = 1,\ldots,n\ .$$

This scale factor has been chosen so that the rescaled local demand curves satisfy the RDC condition for the local prices p_i which were determined in the previous demand iteration. Indeed the scaling does not affect the regional average price as the scale factor cancels:

$$\frac{\sum \phi_i^{(1)}(p_i)\cdot p_i}{\sum \phi_i^{(1)}(p_i)} = \frac{\sum \phi_i^{(o)}(p_i)\cdot p_i}{\sum \phi_i^{(o)}(p_i)} = P .$$

Furthermore,

$$\sum \phi_i^{(1)}(p_i) = \frac{\Phi(P)}{Q} \sum \phi_i^{(o)}(p_i) = \frac{\Phi(P)}{Q} \cdot Q = \Phi(P).$$

Unfortunately, there is no reason to expect that the scaled demand curves would have equilibrated at the same local prices p_i as the initial ones. To completely enforce the RDC condition, it is therefore necessary to reequilibrate with the scaled demand curves and, if necessary, to repeat the process of scaling.

Note that the result of this iteration process depends on the choice of the initial local demand curves. Demand iteration will yield different results when started with different sets of local demand curves, even if the regional demand curve is the same in both cases, and the local demand curves are sealed replicas of this regional demand curve. Therefore it is important to select the initial local demand curves with care. The regional references and prices provide a vehicle for intial demand estimation. Denoting by ω and π the ratios of this year's regional reference volumes and prices to last year's regional reference volumes and prices, respectively, one might define initial local demand curves

$$\psi_i^{(o)}(p) = i = 1,\ldots,n$$

with the help of those used in the previous model year:

$$\psi_i^{(o)}(p) = \phi_i^{(o)}(\frac{p}{\pi}).$$

In the case of the special demand functions discussed in (3.6.1), this amounts to simply multiplying the local reference volumes and prices by ω and π, respectively. This suggests an alternative way of generating initial local demand functions: i) multiply the local reference volumes of the previous year first by the final scaling factors resulting from demand iteration and then by π to derive new reference volumes; ii) multiply the local reference prices of the previous year by π to derive new reference prices; iii) for each M-node, scale the regional demand curve so that it passes through the point defined by the new local reference volume and price.

3.6.3 Cut-off prices

For each supply curve, a cut-off price (PCUTV) is calculated from state prices for alternative fuels. It indicates the price above which an alternative fuel would be preferred over gas, and demand is assumed zero if the actual price rises above this cut-off price. Only the cut-off price derived from the price of residual fuel oil will be low enough to influence model calculations appreciably; this cut-off price is used for those industrial and utilities end-use subsectors which can switch to residual fuel oil (recall Section 3.4.1). For details concerning the handling of cut-off prices and related issues, consult Note 23.

3.7 Tariffs

Pipeline and distribution companies post tariffs to recover the costs of purchasing natural gas well as the expenses incurred in handling it. For the purposes of this report, we use the term tariff for the additional charges beyond the costs of purchasing gas. The reason for considering such mark-up or add-on tariffs rather than the posted tariffs is that, during the process of equilibration, the posted tariffs are assumed to vary in response to changes in the tentative pipegate purchase prices whereas mark-up tariffs are assumed to remain unchanged during that process. We distinguish transmission tariffs levied by pipeline companies and distribution tariffs levied by distribution companies. Storage tariffs will be considered in Section 3.8 . Schematically, we have:

burnertip price = citygate price level + distribution tariff mark-up,

city gate price = pipegate price level + transmission tariff mark-up.

As already indicated, tariff mark-ups are determined prior to equilibration, which then establishes the burnertip (and city gate) prices and therefore, in a sense, the posted tariffs. For the difference between city gate prices and city gate price levels see Section 4.1.2.

The model represents tariffs at each system node with the help of two tariff parameters: a fixed hook-up or demand charge (CFIXV) and a per unit commodity mark-up (PVARV). For the commercial entity represented by a system node, the demand charge represents an annual cost of doing business with the commercial entity represented by the predecessor of this node. The demand charge must be paid regardless of the volume purchased. If the system node is an M-node, the demand charge is understood to be the total of the annual hook-up charges for all customers in the particular market that corresponds to the M-node. For each system node, the commodity mark-up, when added to the unit price at the predecessor node, will yield the full "commodity charge", that is, the purchase price per unit of primary supplies at the system node.

The above tariff scheme represents a considerable simplification, especially of distribution tariff schemes, which in reality tend to be more complex and to involve more than two parameters. It amounts to the approximation, by a rising straight line, of a fairly involved functional relationship between the volume purchased by a market and the dollar cost of mark-ups beyond the supply price to the distributor (see Figure 3.12).

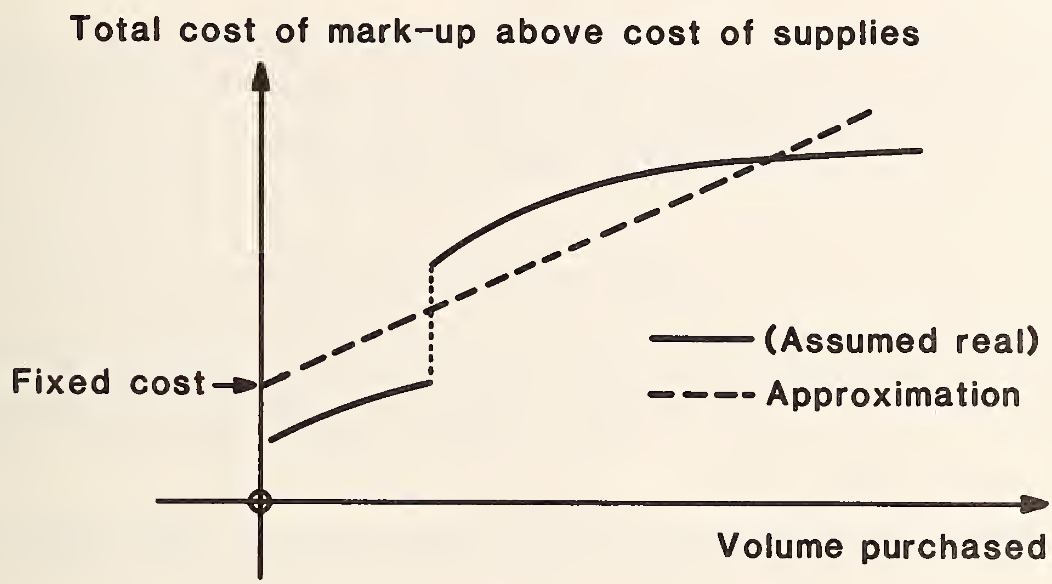


Figure 3.12. Schematic illustration of a prototype mark-up relationship and its approximation by a linear relationship with fixed cost.

The model either derives tariff parameters from <u>direct tariff specifications</u> made for corresponding arcs in the base network--which is the procedure currently used for all transmission tariffs--or it estimates them annually using the <u>distribution tariff module</u>, an NBS-coded subroutine in the MARKET model. This subroutine is based on general relationships between consumption and rate bases. These relationships have been developed empirically for NBS by J.-M. Guldmann [3]. They are outlined in Section 3.7.2. In the case of direct sales D-nodes, tariffs are calculated in the base year as the difference between two node price levels for the D-node itself and the preceeding P-node, and are assumed zero for the successor M-nodes (see Section 4.2.2). In subsequent years, direct sales tariffs are treated as if they were directly specified. Whether direct tariff specification or the distribution tariff module is to be used depends on the value of the tariff indicator which is input via GENNET for each arc of the base network (see Section 3.3.3): positive tariff indicators trigger direct tariff specification, while negative tariff indicators characterize direct sales distributors.

An escalation option permits the analyst to increase both transmission and distribution tariffs annually by a fixed specifiable percentage.

3.7.1 Expected flows and peak day volumes

Whether using direct tariff specification or the distribution tariff module, the derivation of the fixed charges requires the prior estimation of loadfactors and expected flows (QEXPV). The distribution tariff module requires, in addition, an expected customer count (ZEXPV). The loadfactors are derived from Form EIA-50 and are input via GENNET for M-nodes, as explained in Section 3.4.2 . For the remaining nodes they are estimated as weighted averages of loadfactors at succeeding nodes using expected flows as weights. The expected flows and the expected customer counts represent not model forecasts, but rather the expectations of pipeline and distribution companies concerning their upcoming sales. The initialization and subsequent calculation of the expected flows and the expected customer counts are discussed in Sections 4.1 and 4.2.5 . The expected flows and the loadfactors are combined into an estimate of what a pipeline company might expect as a peak day volume (Notes 12,13).

Expected flows and expected customer counts at system nodes associated with specific States are derived by multiplicatively modifying the annual flows and customer counts that were obtained for the previous model year. The model selects the ratio of successive population growth projections as the modification factor for the State in question. P-nodes are not associated with specific States; here a growth factor of 1.1 is assumed for expected flows. Customer counts are not modeled for P-nodes. In the base year, the actual base year figures are utilized in establishing expected flows and customer counts whenever the latter are defined.

In the case of direct tariff specification, a tariff scheme consisting of a demand rate and a commodity mark-up are associated via input with an arc of the base network (see Section 3.3.3). The demand charge then is again the product of the demand rate and the expected peak day volume. The commodity mark-up is transferred directly. For interstate pipeline companies, tariffs are broken down by zones. They have been extracted by NBS from rate hearing depositions at the FERC. These transmission tariffs fluctuate considerably over the course of a year due to new rate hearings, invoking incremental pricing provisions, and adjustment for previous overcharges. Tariff data thus represent estimates of annual averages. For intrastate transactions, demand rates are assumed to be zero and commodity mark-up figures have been estimated using GAS FACTS as follows: In States with substantial intrastate commerce in natural gas, the difference between statewide averages of citygate and wellhead prices is assumed to be representative of the commodity mark-up. In all other States, a volume-weighted average over these particular commodity mark-ups is used.

The distribution tariff module, on the other hand, derives tariffs via rate base modeling. It calculates costs of service and then defrays these costs on the basis of expected flows and expected customer counts by end-use sector via a commodity mark-up, a customer charge and a--using expected peak day volume--a peak-demand charge. The latter two charges are then combined into a single demand charge per end-use sector. Sales to another distributor are treated as industrial sales, unless the tariff pointer calls for direct sales specification.

Direct tariff specification is currently used for transmission tariffs, that is, tariff increments on P-D arcs. Use of the distribution tariff module is restricted to D-M and D-D arcs (Note 24). Provisions exist in MARKET for escalating directly specified tariffs (and tariffs in general) by an annual fixed rate in order to allow for a growth rate of tariffs which exceeds inflation (Note 25).

3.7.2 Outline of the distribution tariff module

A set of equations relating the total annual sales of a distribution company to its tariffs, has been developed by J.-M. Guldmann under contract to NBS and is described in detail in [3]. NBS has selected some of these equations and modified others for its construction of the distribution tariff module. We will now outline this procedure.

The module first calculates for the base year the total purchase (not replacement) values of three categories of plant in service. These categories are: transmission, distribution and general service. Let

B_T = base year purchase value of transmission plant
B_D = base year purchase value of distribution plant
B_G = base year purchase value of general service plant
V_T = present year purchase value of transmission plant
V_D = present year purchase value of transmission plant
V_G = present year purchase value of general service plant.

With

Q_{BASE} = Total sales during the base year,

the following equations have been empirically developed:

$$B_T = 4134520 + .4190155 \cdot Q_{BASE} ,$$

$$B_D = 7.584965 \cdot (Q_{BASE})^{.919708} ,$$

$$B_G = .33520768 \cdot (Q_{BASE})^{.927259} .$$

(The fact that constraints are expressed using seven or eight digits does not indicate that these digits are all significant.) In subsequent model years, these values of plant are updated by estimated additions and replacements. Additions are determined as multiples (addition factors) of the increase Δ in total sales, provided the latter is positive. If there is a drop in sales, there will be no additions. We denote the addition factors by

$$\alpha_T,\ \alpha_D,\ \alpha_G\ .$$

For their calculation, we refer to [3].

Replacements are determined as a fraction of the respective plant values. Their original purchase value is estimated as follows:

$$R_T = 0.00176 \cdot V_T$$

$$R_D = 0.00753 \cdot V_D$$

$$R_G = 0.03624 \cdot V_G\ .$$

Replacements add to the purchase value of the plant because the replaced items are now more expensive than when they were purchased originally. In other words, after subtracting the purchase value, the replacement value has to be added in order to describe the effect of the replacement on plant value. The replacement value is estimated using the Handy-Whitman Index [5] for utility construction under suitable assumptions about the lifetime of the replaced parts. The resulting replacement value multipliers

$$\rho_T,\ \rho_D,\ \rho_G$$

vary by State and are directly input into MARKET. The new plant values are now calculated from the old ones as follows:

$$V_T(\text{new}) = V_T + \alpha_T \cdot \Delta + (\rho_T - 1) \cdot R_T$$

$$V_D(\text{new}) = V_D + \alpha_D \cdot \Delta + (\rho_D - 1) \cdot R_D$$

$$V_G(\text{new}) = V_G + \alpha_G \cdot \Delta + (\rho_G - 1) \cdot R_G\ .$$

A distinction is made between total plant V_{ALUE} and total plant in service,

$$V_T + V_D + V_G$$

The following relationship has been determined:

$$V_{ALUE} = 1.04193 \cdot (V_T + V_D + V_G).$$

In order to arrive at the rate base, one must now calculate the accumulated depreciation and then subtract it from V_{ALUE}. In the base year, accumulated depreciation is estimated in terms of plant in service values:

$$A_{DEP} = .36025 \cdot B_T + .30331 \cdot B_D + .39396 \cdot B_G\ .$$

In subsequent years the accumulated depreciation is updated by adding annual depreciation

$$D_{EP} = 0.03522 \cdot V_T + 0.03059 \cdot V_D + 0.03388 \cdot V_G \quad ,$$

and by subtracting the original purchase value of replaced parts,

$$R_{EP} = R_T + R_D + R_G \quad ,$$

from the accumulated depreciation:

$$A_{DEP}(\text{new}) = A_{DEP} + D_{EP} - R_{EP} \quad .$$

The module also considers, in the above equation, a term for salvage values which we have deleted for clarity of exposition.

The rate base R_{BAS} is now given as follows

$$R_{BAS} = V_{ALUE} - A_{DEP} \quad .$$

The module goes on to estimate operations and maintenance costs C_{OP} and to calculate the revenue requirement R_Q excluding gas purchase costs. The latter are excluded because the purpose of the module is to estimate add-on tariffs that are to be added to the model-determined gas purchase price.

$$R_Q = C_{OP} + D_{EP} + \omega \cdot R_{BAS} \quad .$$

Here ω is an input-specified return percentage.

The remainder of the calculation allocates the revenue requirement to the markets served by the distributor. To this end, the revenue requirement is split into three parts: <u>capacity costs</u>, <u>customer costs</u>, and <u>volumetric costs</u>. The procedure then is to prorate the capacity costs over the attached markets according to their expected peak day volumes, the customer costs according to their numbers of customers, and to use the volumetric costs as commodity mark-ups.

This method essentially guarantees recouping the revenue requirement. However equitable, the method is not quite realistic, in particular for residential end-use. Here the model-generated hook-up charge per customer, consisting of both the share of the capacity costs and the individual customer costs, is too large whereas the commodity mark-up is too small. In general, regulatory agencies tend to require that a major portion of the capacity costs be recouped via commodity mark-ups, a procedure which favors residential customers (in the short run). This may result in over- or undercharging depending on how the actual consumption differs from the expected consumption. For further developments concerning the distribution tariff module see <u>Note 26</u>.

3.8 Storage

Since production of natural gas proceeds at an essentially even pace while consumption differs according to season, large storage facilities are needed. Smaller storage facilities at the citygate serve to stabilize daily fluctuations. These smaller facilities are not represented in the model. The model does, however, provide for the representation of large underground storage facilities which serve to equalize summer and winter demands (see Figure 3.13). In fact, each node of the base network is considered as a potential storage location, the capacity of which is input via GENNET together with an annual storage loss percentage on withdrawal (see Section 3.3.3). The storage losses are envisioned to consist mainly of the pipeline fuel used for transportation to and from the storage facility and also for storage operation (Note 27).

For each year following the base year, the model estimates storage needs on the basis of the seasonal differences of the previous year's consumption pattern. This estimation process is described in detail in Section 4.4 . It will store -- up to the specified storage capacities -- these expected needs during the summer and withdraw them -- subject to storage loss -- during the winter. The underlying assumption is that additions to storage during the summer equal the withdrawals from storage during the winter (compare Figure 3.13).

Shipments to and from storage will be treated as if they were secondary transactions. This requires the specification of values along with volumes. The value of a shipment into storage is determined on the basis of the price level that prevails at the system node in question when the shipment is made. Upon withdrawal from storage, the model levies a storage tariff in the form of a fixed percentage, say 25%, of the shipment's original value. This tariff is intended to cover a variety of costs incurred in connection with storage. If storage is company owned, than the tariff represents investment and operating costs associated with that facility. If storage is leased, it represents a tariff paid to some other company. In both cases, seasonal differences in secondary supply costs, which are not accounted for directly, as well as "loss of opportunity" are considered as storage costs (Note 28).

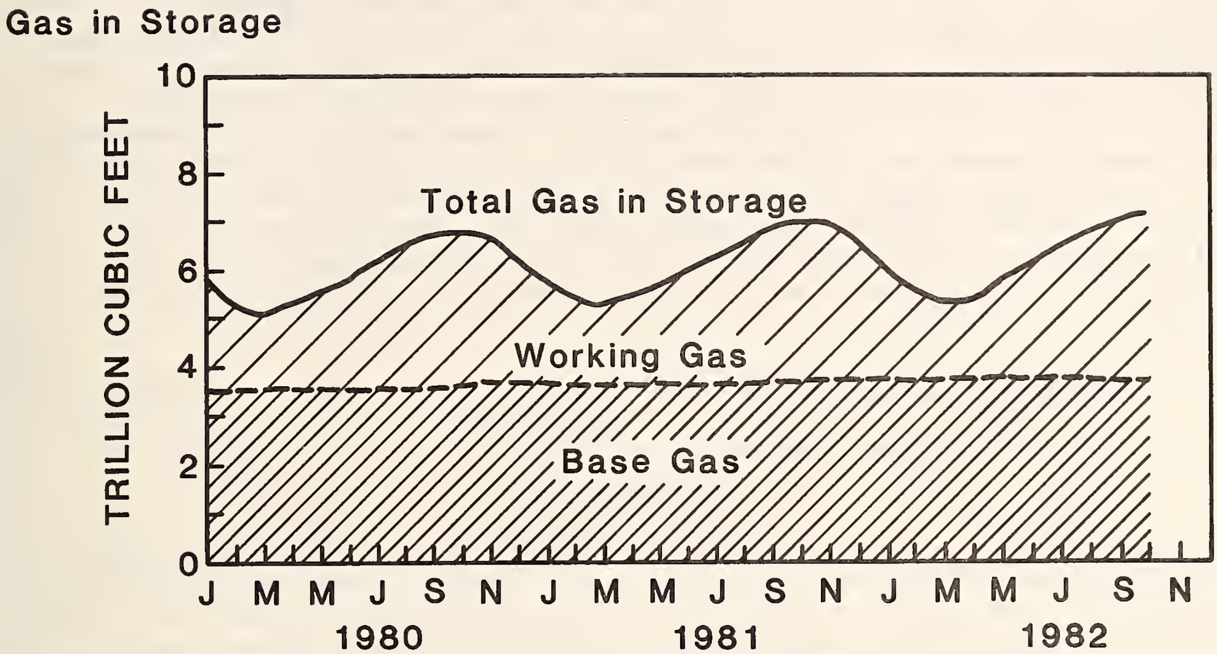


Figure 3.13: Natural Gas in Storage. (Monthly Energy Review, December 82)

3.9 The concept of equilibration

For model years other than the base year (Note 29), the MARKET model uses equilibration of demand and supply curves to determine the volumes produced and consumed by each pipeline system as well as the respective prices at the pipegate and the burnertip.

There are two modes of operation. The MARKET model equilibrates either on an annual or on a semiannual (heating year) basis. A more detailed discussion of these two options is given in the procedural description of the equilibration process in Chapter 4.

In its simplest form, the equilibration process balances a single demand curve against a single supply curve. Our problem is more complex in that it involves many demand curves (one for each M-node), and several supply curves (one for each pipeline system). It can be classified as a network equilibration problem. Fixing secondary volumes and prices simplifies this problem considerably, because this results in partitioning the set of demand curves by pipeline systems so that demand curves which are in the same pipeline system are to be balanced against a common supply curve. One might then consider combining all the demand curves in the pipeline system into a single root demand curve to be balanced against the supply curve at the pipegate. We will explore this general idea in a brief discussion of equilibration in general and the structure of the root demand curve in particular. This discussion will provide a basis for interpreting model procedures.

3.9.1 Definition of equilibrium

Consider an arbitrary demand curve

$$p = D(q) \ , \ 0 \leq q \ ,$$

which indicates the maximum unit price p the "buyer" is willing to pay for quantity q . Thus $p \cdot q = q \cdot D(q)$ would be the cost of the transaction. Note that this definition of a demand curve is different from the one used in Section 3.6 , where quantity was expressed as a function of price rather than the other way around. For a general discussion, we prefer the above definition of demand curve because the maximum acceptable price is always a unique function of the quantity to be purchased, whereas two different quantities may well have the same maximum acceptable price. This also means that the function $D(q)$ need not be monotonic in q . (The function $q \cdot D(q)$, which represents the acceptable dollar cost rather than the acceptable unit price, is however always monotonic.)

Next we consider an arbitrary supply curve

$$p = S(q) \ , \ 0 \leq q \leq q_{max} \ ,$$

which states the minimum unit price p at which the "seller" is willing to sell quantity q . Again $p \cdot q = q \cdot S(q)$ would be the minimum acceptable total return for quantity q . Note that this definition is compatible with the one used in Section 3.5 . Again there is always a functional relationship of the above form. The example of a supply curve in Section 3.5, as illustrated in Figure 3.7, shows that the quantity q may not be expressed uniquely as a function of the minimum acceptable price p .

Suppose now that all points (q,p) with

$$p \leq D(q)$$

represent deals acceptable to the buyer, and that all points with

$$p = S(q)$$

represent deals acceptable to the seller. Finally define an equilibrium point as the point (q_o, p_o) of largest quantity $q_o < q_{max}$ among those points that represent deals with are acceptable to both. Then there are three possible outcomes (see Figure 3.14).

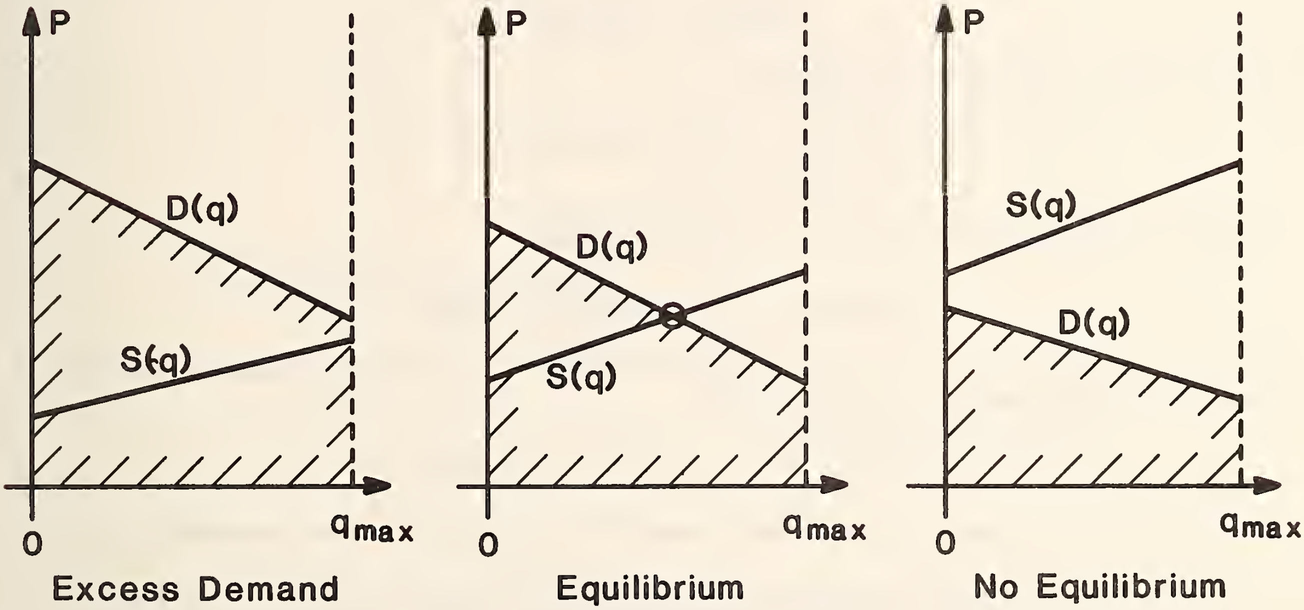


Figure 3.14 Schematic illustration of equilibration

In the first case, the buyer would be willing to pay more in order to get more. This can happen only in a price regulated environment. In the second case, both buyer and seller realize their expectations and an equilibrium ensues. In the third case, there are no acceptable deals.

The reader notices that this schematic description of equilibration is asymmetric: on the one hand, we assume that the set of seller-acceptable price-quantity pairs agrees precisely with the supply curve, whereas on the other hand, the demand curve bounds an entire area of price quantities acceptable to the buyer. This asymmetry indeed holds in our application. It arises because we assume that the producers of natural gas are no longer in a bargaining position. Their bargaining was done in the process of arriving at longterm contractual agreements with the pipeline company. As a result, the price of gas in each reserve block is no longer negotiable and the quantity produced is at the discretion of the pipeline company subject, of course, to availability limitation and take-or-pay provisions. Depending on the choice of the withdrawal strategy, the average unit price of supplies at the pipegate is uniquely determined by the total quantity produced from all dedicated reserves. This means that only price-quantity pairs which lie on the supply curve are acceptable.

To find the equilibrium for a given pair of supply and demand curves, one may proceed as follows: Start with the value q_{max} and check whether

$$D(q_{max}) \geq S(q_{max}) \quad .$$

If so, then $(q_{max}, S(q_{max}))$ is the solution. In particular, if $D(q_{max}) > S(q_{max})$, then the excess demand case prevails. If the above condition fails, that is, if

$$D(q_{max}) < S(q_{max}) \quad ,$$

then choose some small increment

$$\delta = \frac{1}{N} \cdot q_{max}$$

and test successively for k = 1, ..., N whether

$$D(q_{max} - k \cdot \delta) \geq S(q_{max} - k \cdot \delta) \quad .$$

If this condition is satisfied for some integer k, then two values $\bar{q}$ and $\bar{q}+\delta$ have been found with

$$D(\bar{q}) \geq S(\bar{q}) \quad , \quad D(\bar{q}+\delta) < S(\bar{q}+\delta) \quad .$$

The supply and demand curves must therefore intersect at some argument q_o, $\bar{q} \leq q_o < \bar{q}+\delta$, and thus determine an equilibrium point (q_o,p_o). This point can be found, for instance, by consecutive bipartition. The absence of an equilibrium is expected if

$$D(q_{max} - k \cdot \delta) > S(q_{max} - k \cdot \delta)$$

for all k=1, ..., N . Because this test is finite, it does not entirely rule out the existence of an intersection of the two curves and therefore of an equilibrium. However, it renders it highly unlikely. If an equilibrium should indeed exist in spite of the above evidence to the contrary, it would represent a highly unstable situation which would not provide the basis for safe conclusions. Similarly, if an intersection (q_o,p_o) is found by the above procedure, then we expect it to be the "rightmost" intersection, that is, the one that maximizes q_o . That is how the equilibrium is defined. Again there is no formal assurance that an intersection further to the right has not fallen "between the cracks". If so, however, we feel again that such an intersection would have provided an unstable equilibrium.

3.9.2 Transformation and combination of demand curves

In this section, we will illustrate the construction of the root demand curve by means of a simple example. Consider two market nodes, 1 and 2, fed from root node 0. Two fixed charges C_1 and C_2 are associated with the deliveries to nodes 1 and 2, respectively. For simplicity, we assume that there is no commodity mark-up or transmission loss associated with either delivery. With each market node i, i=1,2, we associate a demand curve D_i (Figure 3.15).

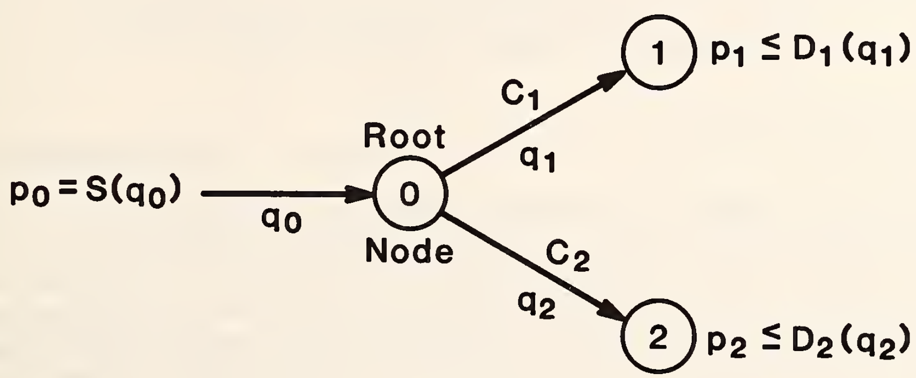


Figure 3.15: Example of network equilibration

We want to transform each market demand curve into the corresponding demand curve at the junction where the delivery arc leaves the root node. More precisely, we want demand curves expressed in terms of the prices which hold prior to the addition of the respective fixed charges. The point (q_i,p_i) represents an acceptable deal, if $p_i < D_i(q_i)$. In order to consummate the deal (q_i,p_i), we must have the deal $(\overline{q_i},\overline{p_i})$ prior to adding fixed charges where

$$q_i = \overline{q_i} \quad \text{(no transmission loss)} \quad ,$$

$$\overline{p_i} = p_i - C_i/q_i \quad \text{(fixed charge)} \quad .$$

The deal $(\overline{q_i},\overline{p_i})$ is therefore acceptable if and only if the resulting deal (q_i,p_i) is acceptable. Thus

$$\bar{p}_i < \bar{D}_i(\bar{q}_i) \quad \Longleftrightarrow \quad p_i < D_i(q_i) \quad ,$$

where $\bar{D}_1$ denotes the desired transformed demand curve. It follows that $\bar{D}_1$ derives from D_1 simply by substitution for both q_i and $\bar{p}_i$:

$$\bar{D}_i(\bar{q}_i) = D_i(\bar{q}_i) - C_i/\ \bar{q}_i \ ,$$

or more precisely (see Figure 3.17),

$$\bar{D}_i(\bar{q}_i) = \max\ \{0, D_i(q_i) - C_i/\ \bar{q}_i\}$$

Even if the original demand curves D_i are monotonic, the new demand curves will in general no longer be monotonic (see Figure 3.16).

The next step is to combine the demand curves $\bar{D}_i$, $i = 1,2$ into a single demand curve at the root node. That is to say, we ask for a function D_o such that $p_o < D_o(q_o)$ characterizes all acceptable deals struck upon entering the root node. A deal (q_o, p_o) is acceptable if it gives rise to two acceptable deals leaving the root node at the same price $p_o = \bar{p}_i$, $i = 1,2$. For given $\bar{q}_1$ and $\bar{q}_2$, this implies:

$$p_o < D_o(q_o) \Leftrightarrow q_o = \bar{q}_1 + \bar{q}_2 \wedge p_o < \bar{D}_1(\bar{q}_1) \wedge p_o < \bar{D}_2(\bar{q}_2).$$

$$D_o(q_o) = \max\ \{\bar{D}_1(\bar{q}_1),\ \bar{D}_2(\bar{q}_2)\ |\ q_o = \bar{q}_1 + \bar{q}_2\} \quad .$$

This is clearly not a simple operation, and we will not even try to solve it for our application. We would like to point out, however, that the solution can be obtained readily if there are no fixed demand charges, that is, if $C_1 = C_2 = 0$, and if the original demand functions are monotonic. Then $\bar{D}_i = D_i$, inverse functions D_i^{-1} exist, and the reader verifies readily that

$$D_o^{-1} = D_1^{-1} + D_2^{-1} \quad .$$

This means that the inverses of the demand functions combine essentially in an additive fashion.

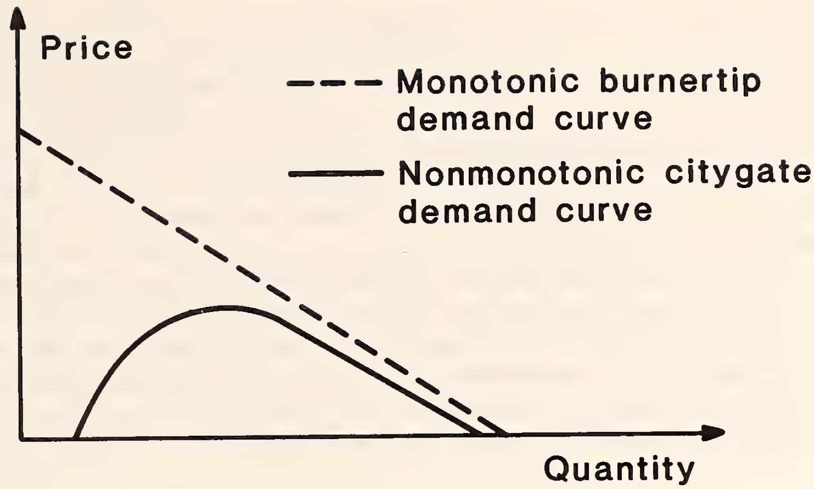


Figure 3.16: Nonmonotonic citygate demand $\overline{D}$ curve derived from monotonic burnertip demand curve D reflecting a demand charge.

In this section, we have described a procedure for constructing a root demand curve which represents the combination of the burnertip demand curves in the system. From a conceptual point of view, it is important to realize that a single demand curve at the pipegate can indeed describe the demand behavior of the entire system. As the above discussion shows, however the actual construction of the root demand curve does not appear practical. We therefore approach the system equilibration problem by means of a series of iterations which are described in Section 4.2. This procedure is conjectured to yield the same result as employing the actual roof demand curve.

CHAPTER 4

Procedural Description of the MARKET Model

Based on the concepts introduced and discussed in Chapter 3, we will now describe the procedures followed by the MARKET model. This description will rely more heavily on detail and stress formal mathematical relationships. We begin with the procedures used to establish the initial set of conditions for the base year. Next we describe in detail the equilibration process which is at the heart of the MARKET model and which has several features that set it apart from conventional equilibration processes. The rest of the chapter addresses the updating of secondary transactions, the determination of storage needs, and the demand projection procedure. We conclude with a summary of MARKET in the form of a brief step-by-step diagram.

4.1 Modeling the base year

Recall that the MARKET model is essentially a simulation model with annual (or semiannual) recursion. In order to initialize these recursions, a baseline of model quantities must be established for the base year. In particular, the base year volumes and price levels are needed to (i) assess the base year withdrawals from reserve blocks; (ii) set reference volumes and prices for the demand curves; (iii) initiate volumes and prices for secondary arcs. Most of these baseline parameters will be direct or only slightly transformed inputs. Other model quantities are calculated. Data from different sources need to be reconciled. At the core of these calculations are the principles of conservation of matter and of balancing monetary accounts. For each system node, the conservation equation,

annual inflow = annual outflow + transmission/distribution/storage losses

must hold, and accounts must balance:

cost of delivered supplies + cost of operation = revenues.

We define the cost of operation to include fixed costs due to depreciation, investment, financing, and dividends, as well as the value of transmission losses of the company represented by the system node. We assume that the cost of operation is precisely compensated by add-on tariffs. This assumption will govern the way sales prices will be calculated from supply prices.

4.1.1 Initial system flows

With each system node of a given pipeline system, we associate in each year a primary supply quantity or system flow (QANNV). In the base year, these volumes are calculated from the volumes consumed annually at M-nodes. As mentioned in Section 3.4.2, these burnertip volumes are a key input generated by GENNET from Form EIA-50. The idea is to propagate these volumes backwards towards the roots, balancing inflows and outflows at each system node and taking into account transmission/distribution losses, secondary inflows and outflows, as well as storage losses.

A data problem, however, arises because distribution losses between the citygate and the burnertip have not been specified. The distinction between transmission and distribution losses, and the data gap associated with the latter, have been discussed at the end of Section 3.3.3. We deal with this data gap by assuming tentatively a fixed distribution loss, say 4%, concerning M-nodes (Note 31).

We will now describe a first round of calculating flows. For the purposes of this description, we will use the term "transmission loss" to cover either transmission loss by a pipeline company or distribution loss by a distribution company. The calculation proceeds from the M-nodes backwards towards the root, considering each system node after the flows into its successor nodes are already known. The following formula expressing flow conservation is used for finding the primary inflow into such a systen node j :

$$Q_j = \sum_{i \varepsilon S(j)} Q_i/r_i + Q_{OUT} - Q_{IN} + (1 - s_j) \cdot Q_{STOR},$$

where

Q_h = primary inflow into system node h metered at h (h = i,j)

r_i = transmission loss factor for system node i (RTMLV) ($r_i < 1.0$)

Q_{IN} = secondary inflow metered at system node j (QTPIV)

Q_{OUT} = secondary outflow metered at system node j (QTPOV)

s_j = storage loss factor for system node j (RSTLV) ($s_j < 1.0$)

Q_{STOR} = amount stored at system node j (QSTOV)

S(j) = set of (direct) successors of system node j .

The transmission loss factor is the factor by which one has to multiply the original value so that a reduction by the specified percentage results, e.g., .96 for a percentage loss of 4%. (The term "transmission yield" might be more logical, but does not emphasize the idea of "loss"). The storage loss factor is defined analogously. It covers losses due to transportation to the storage site, and storage operation. The reader is reminded of the assumption that during the winter everything is withdrawn that was stored in the summer (see Section 3.8). This amount is Q_{STOR} . The term $(1 - s_j) \cdot Q_{STOR}$ represents storage loss (Note 27). See Section 4.4 for the determination of Q_{STOR} .

The total secondary inflow Q_{IN} into a system node, as metered at this node, can be found by direct summation of the corresponding volume information in the base network. The total secondary outflow from a system node, as metered at this node, can be determined similarly, but transmission losses need to be taken into account because the volumes in the base network are defined as buyer-received volumes. Thus

$$Q_{IN} = \sum_{a \varepsilon \overline{B}(w)} q_a \quad ,$$

$$Q_{OUT} = \sum_{a \varepsilon \overline{F}(w)} q_a / r_a \quad ,$$

where

w = label in the base network of system node j

$\overline{B}(w)$ = set of secondary arcs terminating at node w in the base network

$\overline{F}(w)$ = set of secondary arcs originating at node w in the base network

q_a = base year volume for arc a in the base network

r_a = transmission loss factor for arc a in the base network.

During the above calculation it may happen that the secondary inflow at some system node exceeds or almost exceeds the total outflow from this node. In this case, conservation of flow would force the primary inflow to be negative or small compared to the secondary inflow or outflows. This may be due to a data discrepancy, high imports, and so on. The model then arbitrarily boosts the primary flow at this node to a node-specific minimum acceptable flow. And we speak of a market adjustment. The MARKET model then takes the necessary steps to preserve the conservation of flows throughout the system network (Note 32). These steps may include a boost in the distribution loss rates (to not more than 10%) and, if this is not sufficient, an actual increase in consumption at selected market nodes. The majority of distribution loss factors will not be boosted in this fashion, and will remain at the level that had been tentatively set before.

The system flows into D-nodes and into some P-nodes correspond to proper (see Section 3.3.3) primary arcs in the base network, and values for flows on such arcs are input originally along with the base network. These values will be superseded by the corresponding system flows calculated above.

4.1.2 Initial system price levels

With each system node, the model associates the "at cost" prices with respect to sales to primary customers averaged over the current model year. These annual price levels (PANNV) differ from the prices for the primary supplies in that the former have been adjusted to reflect the costs of secondary purchases and storage as well as the proceeds from secondary sales. For system nodes other than the root node, the prices of the primary supplies are calculated from the price level at the predecessor node using the specified demand charges and commodity mark-ups. At the root node, the pipegate price, that is, the average purchase price of dedicated reserves P_0, plays the role of the price level at the predecessor node in the above calculation.

The price levels will be first calculated without taking into account storage, which will be discussed in Section 4.1.3. For nodes i without storage facilities, the price for primary supplies and the at-cost sales price can be expressed as follows:

$$u_i = P_j + M_i + C_i/Q_i \ ,$$

$$P_i = \frac{Q_i \cdot u_i + C_{IN} - C_{OUT}/\theta}{Q_i + Q_{IN} - Q_{OUT}} \ ,$$

where

j = predecessor of system node i

P_h = price level at system node h (h=i,j)

u_i = unit price of primary supplies for system node i

M_i = commodity mark-up (per unit) on primary supplies for system node i

C_i = annual demand charge on primary supplies for system node i

Q_i = quantity of primary supply for system node i

Q_{IN} = secondary supply metered at system node i

Q_{OUT} = secondary sales metered at system node i

C_{IN} = <u>sales value of secondary supplies</u> (CTPIV)

C_{OUT} = <u>sales value of secondary sales</u> (CTPOV)

θ = <u>secondary price mark-up factor</u> (RSCT)

The parameter θ, say 1.25, represents the effect of add-on tariffs on secondary revenues: The difference between the term C_{OUT}/θ and C_{OUT} is the amount retained by the distributor (or pipeline company) i in order to cover expenses. Thus C_{OUT}/θ represents the portion of the revenues that is to be rolled into the calculation of the price level. This is consistent with the method for pricing the secondary sales (see Section 4.3) at a previous modeling step.

In the first of the above two price relationships, the two tariff terms are understood to cover the entire cost of operation associated with this transaction. This includes the value of the transmission/distribution loss. For this reason, the transmission loss factor does not appear explicitly in the price formula.

The second price formula is derived by equating two expressions for the at-cost value of all primary sales from system node i:

$$P_i \cdot (Q_i + Q_{IN} - Q_{OUT}) = Q_i \cdot u_i + C_{IN} - C_{OUT}/\theta \ .$$

Using these price relationships on an annual basis during the base year permits the propagation of price changes at the pipegate to price changes at the burnertip in a deterministic fashion, provided system flows have been specified for the system network. These flows are needed in order to determine the influence of the (fixed) demand charges and of secondary transactions on prices levels.

In the base year, the MARKET model determines a complete set of price levels. There are two sets of data available, each of which can serve as a point of departure from which to calculate price levels. First, there are the base year citygate sales prices associated with proper (see Section 3.3.3) arcs of the base network. These prices can be utilized to calculate the price levels at D-nodes preceded by P-nodes. Second, the price of supplies at the pipegate from dedicated reserves can be determined on the basis of the amount withdrawn -- identified in the model as the primary flow into the root node - and the prices and take-or-pay ratios of the available reserves.

The first option is more attractive, because the citygate prices are given directly whereas the reserve price is deduced from reserve information which unavoidably carries with it a large degree of uncertainty. On the other hand, the price levels will be necessarily calculated from reserve prices in all model years following the base year. Thus not using the analogous method in the base year is likely to cause a discontinuity in price levels between the first two years.

The MARKET first calculates price levels for D-nodes which are preceded by P-nodes. It then calculates, using tariffs, a putative price level for the preceding P-node. Because different D-nodes may have the same predecessor, different price levels may be calculated for the same P-node. This difference is due to the fact that both tariffs and price levels are annual averages and coincide only under ideal conditions. In the absence of such conditions, we average over all price levels at the same P-node using the corresponding sales volumes as weights. In this fashion, we find a particular price level at each P-node which is succeeded by D-nodes. This procedure is based on inverting the above price relationships. First the unit price of the primary supplies for system node i is reconstructed:

$$u_i = \frac{P_i \cdot (Q_i - Q_{IN} - Q_{OUT}) - C_{IN} + C_{OUT}/\theta}{Q_i} \ .$$

Then tariffs are subtracted from the unit price to yield a price level at the predecessor node:

$$P_j = u_i - M_i - C_i/Q_i .$$

These candidate price levels are then averaged, using weights proportional to the volumes, Q_i/r_i, where r_i = transmission loss factor for system node i, over all (direct) successors of the system node other than direct sales D-nodes. At this point, the model uses the fact that each P-node has at least one successor that is not a direct sales D-node (see Section 3.4.1). The volumes Q_i/r_i are primary sales metered at node j, that is, before having incurred transmission loss.

The same averaging procedure can now be used to determine price levels for the remaining P-nodes including the root node. Note that, in this latter case, we no longer average over numbers that by rights should be equal, but are in effect equalizing the supply prices of different pipeline companies in the same system. This is necessary because in subsequent model years these different pipeline companies will incur the same pipegate price.

The resulting pipegate price is now compared with the pipegate price as calculated from the dedicated reserves in order to apprise the analyst of possible price discrepancies which indicate a need for upgrading his reserve information. The transmission tariffs in the pipeline system are then adjusted so that calculating the pipegate price from the citygate prices using the adjusted transmission tariffs would yield the same pipegate price as the one calculated from the reserves. Resulting adjustment factors are retained and applied in subsequent model years. For details of the adjustment process consult Note 33.

The next step is to determine tariffs for direct sales D-nodes. The predecessor of such a node is, by construction, a P-node, and we choose the difference between the price level of the direct sales D-node and the price level of its predecessor as commodity mark-up for the D-node in question. The demand charge is set to be zero. Here we have used the fact that, by definition, direct sales D-nodes do not conduct secondary transactions and that therefore the unit price of primary supplies coincides with the price level. All successor nodes of direct sales D-nodes are M-nodes. The tariffs of these M-nodes are all set to zero.

It is now possible to calculate all price levels in the system network, starting with the reserve price at the pipegate and proceeding to the burnertip. This sets the stage for the next adjustment procedure. Here the tariffs at M-nodes, excluding those arising from direct sales distributors are adjusted so that the state averages of the calculated burnertip prices approximate given state averages by end-use sector. The adjustment factors so determined are kept for the remaining model years. After resetting burnertip price levels to reflect this adustment, the construction of baseline price levels is complete (Note 34).

4.1.3 Adjusting for storage costs.

In the previous section, formulas were derived for the recursive calculation -- both forward and backwards -- of price levels at system nodes. For simplicity of exposition, storage was assumed absent. In this section, we will now discuss a method for adjusting price level formulas in the case that storage is present.

In MARKET, storage costs are represented as arising from storage losses on the one hand and storage tariffs on the other (see Section 3.8). For semiannual price calculations, which are used in the case of semiannual equilibration, the adjustment method is clear (see Section 4.2.3.2): in the summer phase, the price level at node i is determined as if there was no storage. Then the quantity Q_{STOR}, which has been determined beforehand (see Section 4.4), is set aside for storage and priced at the above price level. In the winter phase, Q_{STOR} is adjusted for storage losses and the storage cost is increased by storage tariffs. The entire winter transaction is treated as an additional secondary inflow.

In the case of annual equilibration as well as in the base year, which is modeled on an annual basis, the modeling of storage costs is not as clear-cut. The method presently in MARKET represents the cost of the retrievable gas in storage as follows:

$$C_{STOR} = \alpha \cdot \frac{Q_i \cdot u_i + C_{IN} - C_{OUT}/\theta}{Q_i + Q_{IN} - Q_{OUT}} \cdot Q_{STOR} \cdot$$

Note that the fraction in parentheses represents the price level that would have resulted in the absence of storage. This price level, however, is an annual average, whereas the gas in storage should be priced on the basis of the Summer price level. The factor α is intended to adjust for this price difference. The desired price level can now be calculated:

$$P_i = \frac{Q_i \cdot u_i + C_{IN} - C_{OUT}/\theta - \sigma \cdot C_{STOR}}{Q_i + Q_{IN} - Q_{OUT} - (1 - s_i) \cdot Q_{STOR}} ,$$

Where σ denotes the storage tariff, and s_i the storage loss factor. Altogether, we find:

$$u_i = P_j + M_i + C_i/Q_i ,$$

$$R_{STOR} = Q_{STOR}/(Q_i + Q_{IN} - Q_{OUT}) ,$$

$$P_i = \frac{Q_i \cdot u_i + C_{IN} - C_{OUT}/\theta}{Q_i + Q_{IN} - Q_{OUT}} \cdot \frac{1 + \alpha \cdot \sigma \cdot R_{STOR}}{1 - (1 - s_i) \cdot R_{STOR}} ,$$

where

j = predecessor of system node i

P_h = price level at system node h (h=i,j)

u_i = unit price of primary supplies for system node i

M_i = commodity mark-up (per unit) on primary supplies for system node i

C_i = annual demand charge on primary supplies for system node i

Q_i = quantity of primary supply for system node i

Q_{IN} = secondary supply metered at system node i

Q_{OUT} = secondary sales metered at system node i

C_{IN} = sales value of secondary supplies (CTPIV)

C_{OUT} = sales value of secondary sales (CTPOV)

Q_{STOR} = amount stored at system node i

R_{STOR} = portion of available supplies stored at systems node i

s_i = storage loss factor at system node i

σ = storage tariff (percentage to be added on)

α = seasonal price level adjustment factor.

In Section 4.1.2, the converse formula expressing u_i in terms of P_j was needed. It may be left to the reader to do the same for the above formula.

4.2 Equilibration

In this section, we outline the method for modeling the annual system flows (QANNV) and price levels (PANNV) during the model years following the base year. The method consists of equilibrating supply and demand for each system separately.

The MARKET model gives the analyst a choice between an annual and a semiannual equilibration method. Once the choice is made for a particular run of GAMS, then the equilibrations will be either all annual or all semiannual, depending on this choice.

The main difference between annual and semiannual equilibration lies in the mechanics of propagating prices forward and flows backward. In the case of annual equilibration, the formulas used for this purpose are the ones described for the base year in Sections 4.1.1 and 4.1.2. In the case, of semiannual equilibration, the same equilibration procedure is applied twice, once for the nonheating or summer season (April through September) and once for the heating or winter season (October through March). The results of both equilibrations are then combined into annual figures. The formulas used for price and flow propagations are similar to the ones described in Sections 4.1.1 and 4.1.2. However, secondary volumes and prices are assumed to be equal in both seasons and are consequently halved (Note 35). The annual fixed tariff increments C_i (CFIXV) are also halved. Flows to and from storage are handled as additional secondary outflows and inflows, respectively. The summer price determines the price of stored gas, which is stored in summer and withdrawn in the winter. The price propagation formulas developed in Sections 4.1.2 are thus modified as described in Section 4.2.3.2.

A new concept, "committed flows", is needed in the equilibration phase (see Section 4.2.2). This is because secondary inflows and outflows are treated as fixed side conditions during the equilibration. Care must therefore be taken to assure coverage of the fixed demand due to specified secondary outflows. The handling of committed flows in the annual and semiannual equilibration modes differs again with respect to the secondary inflows and outflows. In the case of semiannual equilibration, secondary volumes and costs are halved with storage treated as a secondary outflow in the summer and a secondary inflow, reduced by storage losses, in the winter. In the case of annual equilibration, the secondary outflows are augumented by the storage losses.

The equilibration is based on a procedure which determines for a given price-quantity pair (PTST,QTST) whether the pipeline system in question can absorb, at the pipegate, the quantity QTST at the pipegate price PTST. More precisely, the question is whether there exists a -- not necessarily unique -- pattern of balanced flows and price levels which arise from QTST and PTST at the root node and terminate at the burnertip with flows that may be consumed at resulting prices according to the respective demand curves. If the answer is "yes", then we call the price-quantity pair feasible.

4.2.1 Bipartition

The equilibration process now consists of two stages. In the first, the objective is to find two points on the supply curve such that one is feasible and the other, with a higher price, is not. To this end, the rightmost point on the supply curve, that is, the point of maximum supply, is examined for feasibility. If this point is feasible, then it will represent the equilibrium point. Typically this represents a shortage situation. If the point of maximum supply is not feasible, then the interval between the committed amount at the pipegate and the maximum supply is divided into a specified number (NINC) of parts, currently ten, and the resulting grid points are examined for feasibility. If some of them are feasible, then the rightmost feasible point, and its infeasible neighbor to the right, bracket the equilibrium point.

During the second stage of the equilibration, the break point between feasibility and infeasibility, that is, between excess of demand and excess of supply, is determined by consecutive bipartition between the above bracketing points. This breakpoint represents an equilibrium with neither excess nor shortage of demand. The bipartition process stops after a fixed, currently number of steps, say ten, or after quantities agree within a specified tolerance, whichever happens first. If none of the above grid points is feasible, then the model declares a failure of the equilibration process. Failure of equilibration for a single pipeline system stops the execution of the model (Note 36).

The concept of equilibration by a search for bracketing points to be followed by a bipartition procedure has been discussed in Section 3.9.1. The difference between the method discussed there and the approach taken here is that here the feasibility check replaces the comparison of the supply and demand curve values.

4.2.2 Committed flows

As was mentioned before, secondary transactions must be honored first. So each pipeline system must make sure that it withdraws enough gas to cover its secondary outflow commitments. The primary flow will therefore consist of two components, a free flow (QITRV) and a committed flow (QCFLV), with the latter determined first and the former subsequently by equilibration. Since there are no secondary transactions at M-nodes, all flow into such nodes is free.

In computing the committed flow (QCFLV) at each nonmarket system node, we balance incoming secondary flows against outgoing ones wherever possible.

In the case of annual equilibration, we use the formula:

$$G_j = \max\{0, \sum_{i\varepsilon S(j)} G_i/r_i + Q_{OUT} - Q_{IN} + Q_{STOR}\cdot(1-s_j)\}.$$

In the case, of semiannual equilibration the following two equations are used according to season:

In the summer:

$$G_j = \max\{0, \sum_{i\varepsilon S(j)} G_i/r_i + \frac{Q_{OUT}}{2} - \frac{Q_{IN}}{2} + Q_{STOR}\} .$$

In the winter:

$$G_j = \max\{0, \sum_{i\varepsilon S(j)} G_i/r_i + \frac{Q_{OUT}}{2} - \frac{Q_{IN}}{2} - s_j\cdot Q_{STOR}\} .$$

Here

G_h = committed flow into system node h (h=i,j)

r_i = transmission loss factor for system node i

s_j = storage loss factor for system node j

Q_{STOR} = amount stored at system node j

Q_{IN} = total secondary inflow metered at system node j

Q_{OUT} = total secondary outflow metered at system node j

S(j) = set of (direct) successors of system node j.

In the formulas pertaining to semiannual equilibration, Q_{OUT} and Q_{IN} are halved because they represent seasonal inflow and outflow.

If the total available supply at the pipegate does not suffice to cover the committed flow, then the execution of the model stops because of insufficient supplies.

We now introduce the quantity G_{IN}. For annual equilibration, we put

$$G_{IN} = \sum_{i \varepsilon S(j)} G_i/r_i + Q_{OUT} + Q_{STOR} \cdot (1-s_i)$$

For semiannual equilibration, there are two seasonally different definitions.

In the summer

$$G_{IN} = \sum_{i \varepsilon S(j)} G_i/r_i + \frac{Q_{OUT}}{2} + Q_{STOR} \cdot$$

In the winter:

$$G_{IN} = \sum_{i \varepsilon S(j)} G_i/r_i + \frac{Q_{OUT}}{2} \cdot$$

This quantity represents the total commitments which have to be covered at node j. There are now two cases. If annually

$$G_{IN} \leq Q_{IN}$$

or semiannually

$$G_{IN} \leq \frac{Q_{IN}}{2} , \; G_{IN} \leq \frac{Q_{IN}}{2} + s_j \cdot Q_{STOR}$$

in the summer and the winter, respectively, then the total secondary inflow covers all committments at system node j. In this case, none of the primary flow into this node needs to be set aside for secondary committments and $G_j = 0$. However, the portion G_{IN} of total secondary inflow must then be earmarked as committed, and only the remaining secondary inflow can contribute to the free flow in the system network. If the total secondary inflow does not cover the committment G_{IN}, then all of this inflow will be earmarked as committed, and the uncovered portion G_j of the committment has to be passed back to the predecessor of node j. Similarly to the primary flow, the secondary flow into node j is thus split into a noncommitted secondary inflow Q_{IN} and the committed secondary inflow (QCOMV).

4.2.3 Feasibility check

The feasibility check would be quite straightforward if fixed charges and secondary inflows and outflows were absent. In such a case, the unit price at the burnertip would depend only on the unit price at the pipegate and not on the system flow. All that would have to be done, therefore, is translate the pipegate price PTST into burnertip prices at the M-nodes by adding commodity mark-ups, consult the corresponding demand curves on how much gas would be consumed at each M-node for these burnertip prices and collect the resulting flows back at the pipegate. If the result exceeded QTST, then the pair (PTST, QTST) would be feasible.

Unfortunately, the feasibility check turns out to be considerably more complicated in the presence of fixed charges or secondary transactions. In this case, the system flow must be modeled concurrently with the price levels, because fixed charges must be spread over, and because secondary transactions need to be rolled in with, the system flow in order to account for their effect on unit prices. This calls for an iterative procedure: establish a tentative flow pattern which adds up to QTST at the pipegate; then translate the given pipegate price PTST into burnertip prices based on the tentative flow pattern; and repeat these two procedures.

More precisely, we proceed as follows: we initiate all price levels in the system network at zero. At each M-node, we find the amount consumed at zero prices by evaluating the corresponding demand curve at zero and then mutiplying the indicated annual demand by either the heating factor or its complement to 1.0, depending on the season. We propagate the resulting flows backwards to the pipegate taking into account secondary transactions and transmission losses.

We then normalize this flow, decreasing or increasing its free portion so that the flow equals QTST at the pipegate and is balanced at intermediate system nodes. This is achieved by multiplying the free flow at each system node by a node specific flow normalization factor (RRHOV). These factors are uniquely determined and their calculation is discussed in Section 4.2.3.1 below. The flow normalization procedure has the following outcomes:

Case I: The generated flow at the pipegate has to be decreased to equal QTST. This indicates a tentative excess of demand at price PTST. It will be shown in Section 4.2.3.1 that, in this case, the flow normalization factors at each system node are less than 1.0. The tentative excess of demand thus spreads to every D-node in the pipeline system. As the flow into the M-nodes, we do not choose the normalized values, but rather make the reduced amount of flow which enters the corresponding D-node available preferentially to residential customers, then to commercial customers, nonswitching utilities, nonswitching industrials, switching utilities, and switching industrials in that order (Note 37). Thus the last end-use subsector in the above order is the first to be tentatively curtailed. (Here, and in the paragraph below, we use the term "tentative" to indicate that these model results are not final because the equilibration has not yet been completed.)

Case II: The generated flow at the pipegate has to be increased to equal QTST. This indicates a tentative excess of supply at price PTST. In this case (see Section 4.2.3.1) the flow normalization factors at each system node are greater than 1.0. The tentative excess of supply thus spreads to every D-node in the pipeline system. Again we do not choose the normalized flow as flow into the M-nodes, but rather pick for each distributor the "last" end-use subsector, that is, the one most likely to be curtailed, to absorb all the tentative excess flow that enters the distributor node.

Case III: The generated flow has exactly the value QTST at the pipegate. In this case, all flow normalization factors equal 1.0, and the normalized flow is identical to the generated flow.

Once a balanced flow with strength QTST is available, the price PTST is carried forward through the system network from the root to the M-nodes, establishing price levels along the way. Tariffs and secondary transactions are taken into account essentially as described in Section 4.1.2. At each M-node, the given demand curve and heating factor yield the consumption according to the season. These volumes consumed then serve as the starting point for a repeat of the flow generation and normalization procedures described above. The price PTST is then carried forward with respect to the latest normalized flow, and so on. Convergence is declared if the latest normalized flow differs from the previous one by, say, less than 1000 BBtu at each system node. It is expected that convergence is bound to occur, but this has not been formally proved.

After the above iteration has converged, then the price-quantity pair (PTST,QTST) is considered feasible if and only if the flow normalization factors have all converged to values less or equal than 1.0 (Cases I and III). If the price-quantity pair (PTST,QTST) has been shown feasible by the above process, then a feasible flow has been actually exhibited. If there is a "final" excess of demand, that is, if the feasibility check indicates that the total available supply and its corresponding average price are a feasible pair and that more would have been purchased if it were available, then the indicated curtailment procedure also becomes final. It is conjectured that if the feasibility check fails, that is, if the above process converges to a flow whose normalization factors are greater than 1.0, then there does not exist a feasible flow. Again there is no formal proof.

In what follows, we describe the formal relationships which underly the above operations.

4.2.3.1 Flow generation and normalization

During flow generation, prior to normalization, the free flow satisfies at each system node j the law of conservation,

$$F_j + \overline{Q}_{IN} = \sum_{i \varepsilon S(j)} F_i / r_i \ ,$$

where

F_h = free flow into system node h (h=i,j)

r_i = transmission loss factor for system node i

$\overline{Q}_{IN}$ = seasonal uncommitted secondary inflow at node j

S(j) = set of (direct) successors of system node j .

The volume $\overline{Q}_{IN}$ is found by subtracting the committed portion from the sum of seasonal secondary inflow and depending on the season withdrawals from storage (see Section 4.2.2). The above equation is used for generating the free flow in the system from burnertip consumption.

The flow normalization factors at system nodes are defined recursively. Denote by ρ_o the flow normalization factor needed to normalize the free portion of the primary flow into the root node. It has to satisfy the relation.

$$\rho_o \cdot F_1 + G_1 = QTST$$

where F_1 and G_1 are the free and the committed flows, respectively, into the root node (= system node number 1). It follows that

$$\rho_o = \frac{QTST - G_1}{F_1} .$$

Suppose system node k is the predecessor of system node j with the added convention that 0 is the predecessor of 1. Because flow conservation has to hold also after normalization, the flow normalization factors ρ_k and ρ_j at nodes k and j, respectively, must satisfy the relation

$$\rho_k \cdot F_j + \overline{Q}_{IN} = \rho_j \cdot \sum_{i \varepsilon S(j)} F_i/r_i .$$

Therefore, and in view of the flow conservation property prior to normalization,

$$\rho_j = \frac{\rho_k \cdot F_j + \overline{Q}_{IN}}{F_j + \overline{Q}_{IN}} .$$

This defines ρ_j recursively for all system nodes j and implies that

$$\rho_j \leq 1.0 \quad \text{if} \quad \rho_o < 1.0 ,$$

$$\rho_j \geq 1.0 \quad \text{if} \quad \rho_o > 1.0 ,$$

$$\rho_j = 1.0 \quad \text{if} \quad \rho_o = 1.0 .$$

The behavior of the flow normalization factors is thus entirely characterized by the relation of the initial flow normalization factor ρ_o to 1.0.

The reader is warned, however, that due to the occurence of negative flows and their subsequent correction, conservation of flow may be violated at some system nodes. We will discuss details concerning negative flows in Section 4.2.4.

4.2.3.2 Determining price levels

It remains to elaborate the price propagation from the root node to the M-nodes. We will discuss only the semiannual case, since for annual equilibration the formulas are the same as in Section 4.1.2 and 4.1.3 In analogy to these Sections, the following equations are used:

$$u_i = P_j + M_i + \frac{1}{2} \cdot C_i/Q_i \quad .$$

In the summer:

$$P_i = \frac{Q_i \cdot u_i + C_{IN}/2 - C_{OUT}/2\theta}{Q_i + Q_{IN}/2 - Q_{OUT}/2}$$

In the winter:

$$P_i = \frac{Q_i \cdot u_i + C_{IN}/2 + (1+\sigma) \cdot C_{STOR} - C_{OUT}/2\theta}{Q_i + Q_{IN}/2 + s_i \cdot Q_{STOR} - Q_{OUT}/2} \quad .$$

Here

j = predecessor of system node i

P_h = price level at system node h (h=i,j)

u_i = unit price of primary supplies for system node i

M_i = commodity mark-up on primary supplies for system node i

C_i = annual demand charge on primary supplies for system node i

Q_i = quantity of primary supply for system node i

s_i = storage loss factor at system node i

Q_{IN} = secondary supply metered at system node i

Q_{OUT} = secondary sales metered at system node i

Q_{STOR} = amount stored at system node i

C_{IN} = sales value of secondary supplies

C_{OUT} = sales value of secondary sales

C_{STOR} = value of quantity stored

σ = storage tariff (percentage to be added on)

θ = secondary price mark-up factor.

Starting with PTST as the predecessor price level for the root node, the price levels at all system nodes can be calculated recursively.

4.2.4 Negative flows and negative prices

In the course of generating flows by backward propagation from the burnertip, enforcing conservation of flow may require that some system flows turn out negative. This will happen if burnertip demand falls to such a low level that the pipeline system is unable to absorb some of the predetermined secondary inflows. In addition to low consumption, the secondary inflow may have increased suddenly on the basis of pronounced price differences between pipeline systems during the previous year (see Section 4.3). In such cases, we arbitrarily adjust the flow to a positive level.

In a general way, the occurrence of <u>negative flows</u> can be considered an indicator of overly high prices for a particular pipeline system and can serve as a valid warning signal that the market is out of order. However, certain system nodes are particularly vulnerable and tend to produce negative flows in situations where drastic actions are not called for (see Section 6.4). This difficulty is ameliorated but not fully corrected by the market adjustments made in the base year. For this reason, the model tolerates--and resets to a small positive quantity--negative flows below a specified tolerance limit. If the size of the negative flow exceeds this limit, then the price-quantity pair (PTST,QTST) will fail the feasibility test. Persistent excessive negative flows may cause failure of the equilibration, and thereby terminate model execution, by negating feasibility for all test points in the first stage of the equilibration. The tolerance limit for negative flows is subject to adjustment from model run to model run depending on the data used and the requirements of the analysis (<u>Note 38</u>).

Setting a negative flow arbitrarily to a positive level during flow generation is to violate the principle of flow conservation. In what follows, we examine some of the consequences of this violation.

Let $D > 0$ be the quantity added to the primary flow at system node j in order to make it positive. Then the conservation of flow equation can be made valid by including this quantity D into it (compare Section 4.2.3.1):

$$F_j + \overline{Q}_{IN} = \sum_{i \varepsilon S(j)} F_i/r_i + D,$$

where

F_h = free flow into system node h (h=i,j)

r_i = transmission loss factor for system node i

$\overline{Q}_{IN}$ = seasonal uncommitted secondary inflow at node j

$S(j)$ = set of (direct) successors of system node j .

Because we want to preserve the property that after each iteration step of the feasibility checking process the flow normalization factors for a pipeline system are either all greater, all less, or all equal to 1.0, we retain the recursion formula for the flow normalization factor ρ_j,

$$\rho_j = \frac{\rho_k \cdot F_j + \overline{Q}_{IN}}{F_j + \overline{Q}_{IN}},$$

even though the assumptions which led to this formula are no longer valid. As a consequence, the normalized flow will also violate the flow conservation principle at system node j:

$$\begin{aligned} \rho_k \cdot F_j + \overline{Q}_{IN} &= \rho_j \cdot (F_j + \overline{Q}_{IN}) \\ &= \rho_j \cdot (\sum F_i/r_i + D) \\ &= \rho_j \cdot \sum F_i/r_i + \rho_j \cdot D \end{aligned}$$

The term $\rho_j \cdot D$ indicates the amount by which the normalized flow violates the law of conservation. In the case that system node j is a D-node, the excess quantity will be automatically allocated to the succeeding M-node of lowest service priority (see Case II in Section 4.2.3), thereby restoring the balance of flows. If the system node j is, however, a P-node then the gap in flow conservation remains. It is very unlikely that such a gap should be present in the final solution to the equilibration problem. In model runs with the current network there were no negative flows into P-nodes, mainly because imports were the only secondary inflows into P-nodes. However, should a small gap remain, then it could be explained on the basis of temporary storage, spot sales, compression equipment failure, etc.

A similar anomaly is the occurrence of negative price levels. Here the predetermined revenue from secondary outflow may exceed the expenses so that a "profit" is made, which should be passed on to succeeding system nodes. In this case, however, the model does not take action other than printing a warning message and resetting the price level to a positive default value, say \$1. Negative prices are a symptom of overly cheap system supplies and are likely to occur mainly during the demand projection process described in Section 4.5.

4.2.5 Post-equilibration wrap-up

In the case of semiannual equilibration, the semiannual volumes and prices must be combined into annual volumes (QANNV) and prices (PAMMV). Reporting purposes aside, the latter are needed to estimate secondary transactions for the subsequent model year, to update customer counts, to update primary flows in the base network, to withdraw from reserves and so on.

The system flows are, of course, just added up for each individual arc:

$$\text{annual flow} = \text{summer flow} + \text{winter flow.}$$

The price levels are averaged using the seasonal primary flows as weights:

$$\text{annual price} = \frac{\text{summer price} \quad \text{summer flow} + \text{winter price} \quad \text{winter flow.}}{\text{summer flow} + \text{winter flow}}$$

This procedure represents an approximation in the presence of secondary transactions (Note 39). The procedure is, however, correct at M-nodes, for which the annual prices are to be reported.

The next step is to update the primary flows in the base network. These flows can be transferred directly from the respective system networks to the corresponding arcs in the base network. In addition, the unit prices for these annual flows have to be reconstituted from the annual price levels. These unit prices will be used for estimating secondary flows (see Section 4.3):

$$u_i = P_j + M_i - C_i/Q_i$$

where

j = predecessor of system node i

u_i = annual unit price of primary flow into system node i

P_j = annual price level at system node j

M_i = commodity mark-up at system node i

C_i = demand charge at system node i

Q_i = annual primary flow into system node i .

This formula works only if system node i is not the root node.

After equilibration, the MARKET model reestimates the customer count (ZCUSV) at each M-node. Let

Z_i = this year's number of customers at M-node i

W_i = last year's number of customers at M-node i

x = the State associated with M-node i

ζ_x = the rate of projected population growth for the year

Q_i = this year's consumption at M-node i

L_i = last year's consumption at M-node i .

If there was no increase in consumption at M-node i, that is, if

$$Q_i \leq L_i,$$

then there will be no change in the number of customers. Also, the model will not change the number of utilities customers under any circumstances. In all other cases, let

$$A_i = W_i \cdot (Q_i/L_i)$$

$$Y_i = \min \{\zeta_x \cdot W_i,\ 1.2 \cdot A_i\} .$$

In terms of these quantities, we define

$$Z_i = \begin{cases} (Y_i + A_i)/2 & \text{for residential and commercial markets} \\ (W_i + Y_i + A_i)/3 & \text{for industrial markets.} \end{cases}$$

These formulas have been chosen arbitrarily to yield a compromise between growth expected on the basis of population projections and growth on the basis of increased consumption volume (Note 40).

4.3 Updating secondary prices and volumes

In this section, the modeling of secondary transactions including the loading and withdrawal from storage will be discussed. While an important part of the MARKET model, secondary transactions will not affect the results of the model as strongly as the primary transactions. Secondary transactions are therefore modeled in a more approximate way than primary transactions. Contrary to their name, secondary transactions have to be known first, that is, before the primary transactions can be calculated, and they provide boundary conditions for these calculations. As soon as the primary transactions have been modeled, they enter into the estimation of secondary transactions for the <u>next</u> model year.

Secondary prices and volumes are associated with arcs in the base network. For the base year, their values have been input and have been taken into account while constructing a baseline of system flows and price levels for the base year.

After the construction of the above baseline, the model proceeds to estimate secondary prices for the next model year. In order to calculate such a price, it first determines the current average price of supplies at the origin node of the secondary arc in question. This price differs from the system price level at this node in that it does not involve the revenues from secondary sales. It does, however, include the prices of secondary supplies at their current level.

The supply price is updated according to the formulas,

$$P_{SUP} = (Q_i \cdot u_i + C_{IN})/(Q_i + Q_{IN})$$

$$P_a = k \cdot (\theta \cdot P_{SUP}/r_a + \overline{P}_a)/2$$

Where

a = secondary are in question

r_a = transmission loss on are a

$\overline{P}_a$ = present price on are a

i = system node at which are a originates

Q_i = primary inflow into system node i

u_i = unit price of primary supplies for system node: (from equilibration)

Q_{IN} = sales value of secondary supplies

P_{SUP} = average price of supplies to system node i

k = secondary price escalation factor

θ = secondary price mark-up factor (RSCT).

The quantity P_{SUP} represents an estimate of the average price of just the supplies. It differs from the price level (PANNV) in that it does not take into account revenues from secondary sales. The prices of secondary sales should then be arrived at by adding a mark-up to the supply price P_{SUP} and taking transmission losses into account. Of course, a secondary sales price has already been established prior to the equilibration and, ideally, this price should be reproduced by the price which is derived from P_{SUP}. However, the two prices will in general not coincide. For this reason, the Market model chooses their average as an upgraded estimate for the secondary sales price in the current model year. In order to estimate the secondary sales-price for the upcoming model year, the upgraded estimate for the current year is multiplied by the secondary price escalation factor k , which so far has always been chosen as 1.1 (Note 41).

For the year immediately following the base year, the volume on secondary arcs is left unchanged from that in the base year. After that year, however, the volume on the secondary arcs is adjusted so as to maintain equal cost shares. By this we mean that the respective sales values, that is, the the amount of money spent for each primary or secondary supply should remain at the same percentage of the total. It is, of course, not possible to maintain equal cost shares in the strict sense, since the primary flow varies while secondary flows are kept fixed. With this understanding we proceed as follows. All secondary sales values are multiplied by the ratio of the primary sales value of the present year to that of the previous year. Since secondary sales prices are already estimated, secondary volumes can be determined by a simple division. Various measures are taken to prevent sudden large changes in the secondary volumes. Such may occur if negative primary flows below the tolerance level were encountered during the previous model year (Note 42). Aside from that, the cost shares of secondary suppliers tend to remain at the same proportions.

Outer arcs, that is, secondary arcs representing imports and Alaskan supplies, are excluded from the above updating procedure. Their quantities and prices are specified each year according to exogenous quantity-price tracks.

In what follows, "present" means "at the end of an annual equilibration" when primary information for the model year is complete. Also available are the most recent transaction volumes and prices for annual primary flows (see Section 4.2.3). For updating secondary volumes with equal market shares in mind, we use the formula

$$Q_a = \frac{\overline{p}_a \cdot Q_b \cdot p_b}{p_a \cdot \overline{Q}_b \cdot \overline{p}_b} \cdot \overline{Q}_a , \quad a \in A(w),$$

where

w = node in the base network

A(w) = set of secondary non-outer arcs into w

b = predecessor arc of w (= primary arc)

$\overline{Q}_a$ = present flow on arc a

$\overline{p}_a$ = present price on arc a

Q_a = subsequent flow on arc a (to be determined)

p_a = subsequent price on arc a (already known)

$\overline{Q}_b$ = previous year's primary flow on arc b (saved)

$\overline{p}_b$ = previous year's primary unit price on arc b (saved)

Q_b = present year's primary flow on arc b

p_b = present year's primary unit price on arc b .

4.4 Estimation of storage requirements

We now describe the method used in MARKET for determining a storage requirement at each individual node of a system network. The understanding is that if this requirement can be satisfied using the storage capacity given for this node, then the indicated quantity will be stored during the summer equilibration. If the storage requirement cannot be satisfied at this node, then the satisfied portion will be added to the storage requirement at the predecessor node, and so on. To initiate this process, the storage requirements at M-nodes need to be specified. These are the quantities T_i necessary to equalize summer and winter deliveries, and are thus given by

$$T_i = (H_i - 1/2)\cdot Q_i$$

where

H_i = heating factor at M-node i

Q_i = previous year's annual flow into M-node i.

These storage requirements (QSDFV local) may be negative, if summer consumption exceeds winter consumption, for instance, at some M-nodes in the utilities sector. The following equations permit these storage requirements to be passed on to preceding system nodes:

$$T_j = \max\{0, \sum_{i\varepsilon S(j)} T_i/r_i - Q_{CAP}\}$$

where

j = predecessor of system node i

T_h = storage requirement at system node h (h=i,j)

r_i = transmission loss factor at system node i

Q_{CAP} = storage capacity at system node j

Q_{STOR} = volume to be stored at system node j

S(j) = set of (direct) successors of system node j .

If $T_j = 0$, that is, if all storage requirements can be satisfied at system node j, then

$$Q_{STOR} = \sum_{i \in S(j)} T_i / r_i$$

and there may be unused storage capacity. If $T_j > 0$, that is, if there is no storage available at system node j or if the storage capacity is insufficient, then

$$Q_{STOR} = Q_{CAP} \cdot$$

In networks, storage capacity is input at zero for all system nodes other than those P-nodes which represent actual pipeline companies. In other words, M-nodes, D-nodes, and those P-nodes which were inserted as root nodes for a rooted cluster of pipeline companies, all have zero storage capacity (see Section 3.8).

4.5 Demand projection

Consider a given model year, called the present year. Model years after the present year are referred to as future years or projection years. After the main modeling task has been completed for the present year, that is, after the annual flows and prices have been determined, the second kind of interaction with BID is initiated. This interaction calls for the generation of a demand projection table with a table grid consisting of pipegate prices and future years. Each column in this grid is a price track for future years following the just completed one up to the horizon year or a specied number of look-ahead years whichever limits the number of years first.

For each of these price tracks, an abbreviated annual modeling procedure is carried out, where each year's modeling builds on the results of the previous year. Secondary information including imports is kept unchanged during this procedure. Tariffs also remain constant except for the optional escalation discussed in Section 3.7.

Demand projection relies mainly on a seasonal flow maximization method, which determines the maximum seasonal absorption at specified pipegate prices for a particular pipeline system. This method differs from that used for equilibration mainly in that it skips the flow normalization step. The tentative flow first generated is again the one resulting from zero burnertip prices. The pipegate price PTST is then carried forward from the pipegate to the burnertip on the basis of this tentative flow. The next flow is based on the consumption generated by the new burnertip prices. This flow then underlies the next price calculation, and so on, until flow and price levels have converged.

In this fashion, flows are generated for the two seasons and are then combined into an estimate of how much gas from its dedicated reserves the pipeline system in question will be able to absorb at the specified pipegate price during the specified year. This value is entered into the demand projection table.

The demand projection process is speculative and appears to be slightly biased toward overstating absorption capabilities. In fact, it models the process of speculation by pipeline companies as to their future sales potential. Keeping the secondary information unchanged affects the various pipeline systems differently. Pipeline systems with dominant secondary outflow will appear to have a captured market and show very little price elasticity (Note 43). Since secondary inflows will maintain the same price in constant dollars, and since gas prices tend to rise faster than inflation, secondary inflows will tend to reduce supply prices for primary customers and will cause demand to rise in addition to reducing demand elasticity to prices at the pipegate.

4.6 Diagram of the MARKET model

In what follows, we list the major steps of MARKET to illustrate the "flow" of its operations. The list cannot be completely specific and the reader is asked to consult the preceding sections as well as the data chapter for details. Also the diagram does not document a specific version, but rather a distillation from all versions which have been used at various times. "Loops" in the model, that is, sequences of operations which are repeatedly executed are indented and bracketed by the lines: "FOR EACH..." and "END OF LOOP".

4.6.1 Input phase

1.1 Enter census projections, price indexes, alternate fuel prices, transmission rate schemes, distance data.

1.2 Enter number of systems, base network (from GENNET): connectivities, quantities, prices, transmission losses, storage capacities, storage losses, States.

1.3 Calculate from distance data those transmission losses which are not entered.

1.4 Enter import and LNG price-volume tracks for specified outer arcs; process Alaska data if present.

1.5 Enter demand curve specifications.

1.6 Enter base year burnertip prices averaged by State and end-use sector.

1.7 Enter system networks (from GENNET): connectivities, consumption, heating factors, loadfactors; transfer certain base network information to system networks; benchmark burnertip volumes if necessary.

1.8 Fetch calendar parameters from GAMS driver: base year, last year of modeling, horizon year.

4.6.2 Base year modeling

2.1 Fetch reserve blocks from BID.

2.2 Imports, LNG, Alaska: set outer arc values exogenously.

FOR EACH system:

2.3 Aggregate secondary inflows and outflows, and their sales costs for each system node.

END OF LOOP

FOR EACH system:

2.4 Calculate available production for each reserve block; report total available production and reserves to BID.

2.5 Determine storage need at each system node.

2.6 Establish system flows and estimate distribution losses; make market adjustments if necessary.

2.7 Allocate pipegate flows to reserve blocks and withdraw indicated amounts; report to BID; determine pipegate price.

2.8 Collect numbers of customers per distributor; estimate flows for year prior to base year.

2.9 Estimate expected flows, transmission load factors and demand charges.

2.10 Model distributor tariffs.

2.11 Calculate pipegate price from citygate prices; reconcile with previous pipegate price by tariff adjustment.

2.12 Price levels for entire system; set tariffs for direct-sales distributors; enter this system's contribution to state volumes and state sales costs by end-use sector into the ledgers of the respective States.

END OF LOOP

2.13 Total volumes and sales costs by end-use sectors and States; calculate average unit prices.

FOR EACH system:

2.14 Control calculated state average prices against those input; calibrate distribution tariffs accordingly; reset burnertip prices.

2.15 Initiate reference volumes and prices for demand curves.

END OF LOOP

FOR EACH system:

2.16 Accumulate state data by end-use sector.

END OF LOOP

2.17 Total state data by end-use sector and calculate average unit price.

4.6.3 Post base year modeling

3.1 Fetch reserve blocks from BID.

3.2 Imports, LNG, Alaska: set outer arcs exogenously.

FOR EACH system:

3.3 Aggregate secondary inflows and outflows and their sales costs for each system node.

END OF LOOP

FOR EACH system:

3.4 Calculate available production for each reserve block; report total available production and reserves to BID.

3.5 Determine storage needs at each system node.

3.6 Estimate expected flows, transmission load factors and demand changes.

3.7 Model distribution tariffs.

3.8 Update reference volumes and prices for demand curves; determine cut-off prices.

3.9 Equilibrate (annual equilibration option)

3.9.1 Determine committed supply QCFL and committed flows

IF maximal supply QMAX does not cover committed supply QCFL:

3.9.2 Terminate: "INSUFFICIENT SUPPLIES TO COVER COMMITMENT"

3.9.3 Determine supply price PMAX from supply curve

IF (QMAX,PMAX) is feasible:

3.9.4 Equilibrium at maximum supply QMAX

ELSE

FOR EACH I=1,...,NINC WHILE (QTST,PTST) not feasible:

3.9.5 QTST = QMAX-I*(QMAX-QCFL)/NINC

3.9.6 Determine supply price PTST from supply curve

IF (QTST,PTST) is feasible:

3.9.7 Bipartition between feasible and infeasible volumes to find equilibration value QEQU.

IF no feasible (QTST,PTST) is found:

3.9.8 Terminate: "FAILURE OF EQUILIBRATION"

3.10 Reestimate customer counts.

3.11 Allocate pipegate flows to reserve blocks and withdraw indicated amounts; report to BID; determine pipegate price.

3.12 Transfer primary flows to base network; calculate annual unit prices for primary transactions from annual price levels; for each system node, estimate secondary prices for base network arcs originating at this node.

3.13 Enter this system's contribution to state volumes and states sales costs by end-use sectors into the ledgers of the respective States.

END OF LOOP

3.14 Estimate secondary volumes for all base network arcs.

3.15 Total state volumes and sales costs by end-use sector and States; calculate average unit price.

4.6.4 <u>Set up demand projection table</u>
(requested by BID program)

FOR EACH price track:

FOR EACH look-ahead year:

4.1 Update reference volumes and prices for demand curves; determine cut-off prices.

4.2 Escalate tariff adjustment factor

4.3 Estimate expected flows, transmissions load factors and demand charges;

4.4 Maximize flows for specified pipegate price; combine flows.

4.5 Enter value into demand projection table

END OF LOOP

END OF LOOP

END OF LOOP

4.6.5 <u>Project system demand</u>
(query by BID)

5.1 Take row in demand projection table for specified year; interpolate projected demand at specified price and year from demands at bracketing grid prices.

CHAPTER 5

Network Representation of the Natural Gas Supply System.

This chapter describes GENNET, an automated procedure for generating a network representation of the domestic natural gas transmission and distribution system. GENNET consists of two distinct phases. The first phase is concerned with constructing the network, i.e., identifying pipeline and distribution companies to be represented in the network and determining the quantities involved in the commercial transactions among the companies. The second phase processes data on base year prices, storage capacities, transmission and storage loss rates, and consumption patterns and associates the processed data values with appropriate entities in the network. The output from GENNET consists of three data files, two of which are major input data sources for MARKET. The third output file provides information which can be used to identify by name the pipelines and distributors represented in the network.

In the network representation of the natural gas transmission and distribution system, nodes represent pipeline companies or distribution companies. Arcs represent commercial relationships, i.e. an arc connects two nodes if gas can be sold by one node to the other node. The direction of the arc corresponds to the direction of the sale. Note that the arcs do not necessarily correspond to any physical connection of nodes by actual transmission/distribution lines (see Section 3.3).

The major source of information used in the first phase of GENNET to create the gas market network is the Form EIA-50, "Alternative Fuel Demand Due to Natural Gas Curtailment". The form was designed to collect the data necessary to support the DOE responsibility for equitable allocation of oil and petroleum products among all regions of the U.S., all sectors of the petroleum industry, and all users. The Form EIA-50 is completed by all interstate and intrastate pipeline companies, municipalities, and other suppliers of natural gas to end users. Although GENNET does not use the curtailment data, it does make direct or indirect use of the following Form EIA-50 information:

- source of gas supplies;
- volume of gas purchased from each source;
- nature of supplies (interstate, intrastate, imports, or direct sales by producers);
- total volume of gas delivered annually to end-use customers and number of customers by category (residential, commercial, industrial, electric utility, and other).

5.1 Phase I: Network Generation.

This section describes the procedure used to generate the nodes and arcs of the network representation of the natural gas transmission and distribution system. The GENNET user must specify a list of pipeline companies to be represented explicitly in the model. These pipeline companies are specified by the 5-digit identification number used in the Form EIA-50 reporting system. The user also specifies aggregate pipeline companies, which are called intrastate pipeline companies in this report. They represent supplies to distributors from intrastate sources as well as from pipeline companies, which are not specifically listed as interstate companies. For the purposes of the model, such "intrastate" pipeline companies are characterized by groups of states which are assumed to be "somewhat homogeneous" with respect to the transmission and distribution of natural gas. (The role of these aggregate pipeline companies will be further clarified.) One network node, a P-node, is generated for each specified pipeline company.

After specifying the pipeline companies of the model, the GENNET user identifies groups of the previously defined pipeline companies which act as a single unit with respect to bidding for available reserves. Each such group forms the basis upon which GENNET constructs pipeline systems. Each pipeline system consists of one or more pipeline companies, all distributors for which the pipeline companies are the biggest (in terms of quantity) supplier, and all end use markets served by those pipeline companies and distributors. (The construction of pipeline systems will be explained in further detail.) The concept of pipeline systems was introduced in MARKET to capture some of the interdependencies among certain pipeline companies, e.g. Florida Gas and Southern Natural or Texas Eastern and Algonquin, and at the same time to reduce the computational requirements of MARKET which uses GENNET output. It is recommended that future analysis examine model sensitivity to pipeline system specification.

In addition to combining pipeline companies into pipeline systems, GENNET permits the user to consider several Form EIA-50 respondents as a single pipeline company, i.e. a single network P-node may represent more then one Form EIA-50 respondent. This feature was originally included in GENNET so that pipeline companies which appear in the Form EIA-50 data with more than one respondent ID number, either by design or by error, will not be represented by a separate network P-node for each different ID. Note, however that the feature can also be used intentionally to combine two different real pipeline companies and represent them as a single network P-node. Such combination might be desirable in the case of pipeline companies with sufficiently small sales volumes that could lead to potential anomolies in MARKET or elsewhere in GAMS if they are represented as separate P-nodes. Experience with GENNET and MARKET will provide the best indication of the need for combination nodes. Analyst judgment will be necessary to determine which nodes are appropriate for combination. Note that P-nodes of this type are not the same as the P-nodes representing "aggregate pipeline companies", i.e. groups of states acting as a pipeline company. Furthermore the user is reminded that all other data prepared for use by MARKET or the other models in GAMS should reflect the multiple companies represented by such P-nodes.

For each pipeline system containing more than one pipeline company, a pseudo pipeline node (with no correspondence to any Form EIA-50 respondent) is created by GENNET to serve as the root node for the system. These root nodes are also P-nodes and GENNET creates the arcs needed to connect these root nodes to each of the pipeline company P-nodes in the system. If there is only one pipeline company in a pipeline system, then the node corresponding to that pipeline serves as the root node for the system. All of the P-nodes corresponding to real or pseudo pipelines are designated as "PIPE" nodes. Table 5.1 lists the pipeline companies now modeled by GENNET and indicates the grouping of those pipeline companies into pipeline systems. Note that Midwestern gas and Great Lakes gas are treated as a single pipeline company.

Table 5.1 lists the states included in each of the seven aggregate pipelines. This selection of pipeline companies was approved by DOE/EIA and was input to GENNET for producing the network to which the October 1982 version of MARKET was applied. These specifications can be changed by the model user, provided of course that corresponding changes are made as appropriate in other data used throughout MARKET and the rest of GAMS.

Given a list of real and aggregate pipeline companies to be included in the model, GENNET places each of the corresponding P-nodes on a node list and then begins to read the Form EIA-50 Supply File to identify other nodes to be added to the network. In the Supply File, every respondent (pipeline or distributor) identifies each source of supply by 5-digit ID number and quantity in Mcf. For each respondent (not already represented as a P-node), a D-node node is generated and added to the node list if one or more of its supply sources is on the node list. At present, two complete passes are made through the Supply File creating and adding D-nodes according to the specified rule. Thus a respondent whose supplier is in the node list will be recorded in the node list during one pass, thereby becoming a potential supplier in the subsequent pass for some other previously unlisted respondent. Note that this procedure does not pick up every respondent and that inclusion of respondents on the node list may be dependent upon the order in which they appear in the Supply File. Some of the omitted respondents would be picked up if additional passes were made through the Supply File (Note 44) but most are omitted because they buy from a few small suppliers (perhaps producers) or intrastate pipelines which were not explicitly included by the user as P-nodes in the model. Those respondents which are not picked up during the first two passes through the Form EIA-50 Supply File are not explicitly represented in the model. Purchases and sales for these respondents are aggregated and associated with aggregate distributor D-nodes, at most one of which is created per state as the need is detected by GENNET.

Respondents with relatively small sales volumes (typical of those not explicitly represented in the network) cause considerable computational difficulties in MARKET when gas costs rise, sales volumes drop below a theoretical "critical mass", and prices skyrocket toward unreasonable values. The level of effort required to specify and model the detection of and response to such phenomena is unwarrented at this stage of the MARKET model development. In fact, rather than improvising ways to include more respondents in the network, subsequent versions of GENNET (not described herein) have been implemented and successfully interfaced with MARKET to produce network representations with even fewer respondents explicitly modeled, i.e., more of the small companies are included in the aggregate D-nodes.

Table 5.1. Pipeline Systems Modeled in GENNET

System 1:
El Paso Natural Gas Company

System 2:
Columbia Gas Transmission Corporation

System 3:
Tennessee Gas Pipeline Company
Tennessee Natural Gas Lines Inc.
Alabama Tennessee Natural Gas Company
East Tennessee Natural Gas Company

System 4:
Texas Eastern Transmission Corporation
Algonquin Gas Transmission Company
Consolidated Gas Supply Corporation

System 5:
Natural Gas Pipeline Company of America

System 6:
United Gas Pipeline Company
Mississippi River Transmission Corporation
Texas Gas Transmission Corporation

System 7:
Transcontinental Gas Pipeline Corporation

System 8:
Transwestern Pipeline Company
Cities Service Gas Company
Arkansas Louisiana Gas Company

System 9:
Florida Gas Transmission Company
Southern Natural Gas Company

System 10:
Michigan Wisconsin Pipeline Company
Midwestern Gas Transmission Inc./Great Lakes Gas Transmission Company
Intrastate Midwest

System 11:
Northwest Pipeline Corporation
Colorado Interstate
Mountain Fuel Supply Company
Kansas Nebraska Natural Gas Company
Montana Dakota Utilities
Intrastate Mountain

System 12:

Panhandle Eastern Pipeline Company
Trunkline Gas Company
Northern Natural Gas Company

System 13:

National Fuel Gas Supply Corporation
Intrastate Appalachia

System 14:

Pacific Gas Transmission Company
Intrastate Far West

System 15:

Intrastate Texas-New Mexico

System 16:

Intrastate Oklahoma-Kansas

System 17:

Intrastate Louisiana-Arkansas

Figure A-2. States Included in "Intrastate" Pipelines

Intrastate Appalachia:

Connecticut	Maryland	Pennsylvania
District of Columbia	Maine	Rhode Island
Delaware	North Carolina	South Carolina
Florida	New Hampshire	Tennessee
Georgia	New Jersey	Virginia
Kentucky	New York	Vermont
Massachusetts	Ohio	West Virginia

Intrastate Far West:

Arizona	Idaho	Oregon
California	Nevada	Washington

Intrastate Texas-New Mexico:

Texas	New Mexico

Intrastate Oklahoma-Kansas:

Iowa	Missouri	Oklahoma
Kansas	Nebraska	

Intrastate Louisiana-Arkansas:

Alabama	Louisiana	Mississippi
Arkansas		

Intrastate Midwest:

Illinois	Michigan	Wisconsin
Indiana	Minnesota	

Intrastate Mountain:

Colorado	North Dakota	Utah
Montana	South Dakota	Wyoming

After making two passes through the Supply File and adding appropriate D-nodes to the node list, GENNET makes a third pass to create the arcs of the network. Typically each respondent reports several supply sources. The arc generation procedure depends on whether or not there are nodes corresponding to the respondent and one or more sources on the node list. If there are nodes corresponding to both the respondent and the source on the node list, an arc is created with origin at the source node and destination at the respondent node. If the respondent node is on the list and the source node is not, than an arc is created with origin labeled zero and destination equal to the respondent node. When the state location of the respondent's end use sales is later identified, the origin of this arc will become the generic aggregate P-node which serves that state. If the respondent is not on the list, then <u>all</u> supplies to that respondent are aggregated and associated with an arc from the appropriate aggregate P-node origin to an aggregate D-node in the state indicated by the leading two digits of the 5-digit ID of the respondent.

The only exception to the arc generation rules described above occur in the case of a respondent represented as a P-node, i.e. a pipeline company explicitly modeled as such in the network. In the present version of GENNET, all supplies reported by respondents represented by P-nodes are ignored, i.e. No arcs are created to model the situation in which a pipeline company represented as a P-node buys gas from some other company represented either explicitly or in the aggregate. To be compatible with the other GAMS modules, pipeline companies represented by P-nodes are shown in the network as receiving all supplies via reserves available through the Gas Reserve Supply Table (GRST) or through the purchase of imports and/or Alaskan gas. Gas purchases by such companies cure incorporated in GAMS via modifications to the GRST or appropriate loading of arcs representing imports or gas from the Alaskan pipeline.

Two additional types of arcs created during the arc generation process are outer arcs and Alaskan arcs. Outer arcs are used to represent supplies of imported or synthetic gas; Alaskan arcs represent gas purchased from the Alaskan gas pipeline. There is one outer arc for every P-node, but Alaskan arcs are created only for specific P-nodes designated by GENNET user input. The origins of both Alaskan arcs and outer arcs are labeled zero. The destination of these arcs is always a P-node. Neither supply quantities nor prices are associated with these arcs by GENNET. GENNET does however produce a directory to identify these arcs by arc number so that a GAMS/MARKET user can specify price and quantity values for these arcs as appropriate for the scenario being modeled.

After the Supply File is read, GENNET reads the Form EIA-50 End Use Sales File to establish markets for each D-node in the network. Every Form EIA-50 respondent reports the following information for each state in which there were end use sales: total volume and average number of customers by customer category, i.e. Residential, Commercial, Industrial, Utility, and Other. The sales reported as "Utility" refer to electric utilities that burn gas, those reported as "Other" include sales to public facilities, e.g. schools and hospitals. As each End Use Sales record is read, GENNET immediately makes the following data transformation:

(i) In the states of Maine, Connecticut, New Hampshire, and Vermont, all utility sales are aggregated with commercial sales and the utility market is then set to zero. These states have local legislation to phase out the burning of gas by electric utilities. Thus utility sales, if any are reported, are assumed to have been commercial sales which were erroneously labeled.

(ii) All "Other" sales are aggregated with commercial sales and the "Other" sales are not distinguished subsequently.

(iii) The Industrial and Utility sales reported on the Form EIA-50 are each split into two markets, one of which has the capability of switching to alternate fuels. The heuristic used to split the markets evolved from a combination of informal conversations with representatives of several distribution companies and execution of MARKET to establish reasonable lower limits on market sizes. Details of the splitting procedure are presented later; it is a prime target for future study.

The data transformations described above lead to a maximum of six non-zero markets per state for each respondent: Residential, Commercial, Utility, Industrial, Utilities with alternate fuel capability, and Industrial with alternate fuel capability. Subsequent use of GENNET output by MARKET assumes that the end-use markets have priority in the order listed above, with residential customers the last to be curtailed during supply shortages.

Each end use market is explicitly associated with the one D-node from which the gas is purchased. Direct sales by a pipeline company to end users are treated in the model by creation of a pseudo D-node and an arc connecting it to the P-node corresponding to the pipeline company. The end use markets are then associated with the pseudo D-node and the quantity associated with the arc from the P-node to the pseudo D-node is set equal to the total end use sales by the pipeline company to end users.

When a Form EIA-50 respondent reports end use sales in more than one state, additional D-nodes are created so that the respondent is represented by a different D-node for each state in which the sales are reported. Since supplies purchased by the respondent are not reported by state, the respondent's total supplies are allocated proportionally to the end use sales by state.

If end use sales are reported by a respondent for whom there is not a corresponding node on the node list, those markets are associated with the generic D-node in the state in which they occur. This might be one of the generic D-nodes created to accommodate supplies reported by a respondent not on the node list. Or, if no generic D-node exists for that state, one is created at this point and it is connected to the network by an arc from the appropriate aggregate P-node.

The Form EIA-50 End Use Sales File is also used to establish the state location of each D-node in accordance with the states in which the companies report end use sales. These state designations help determine appropriate tariff and distance data by contributing to the specification of pipeline "utility". GENNET assigns a utility number to each network arc with a P-node origin and a D-node destination. This utility assignment depends on the company represented by the P-node and the state associated with the D-node. Because MARKET uses the utility number to determine which transmission distance and tariff data apply to each arc originating at a P-node, the utility definitions must be consistent with the data discussed in section 5.1.6 of this report. Recall from that earlier discussion that the first 56 utilities correspond to the 56 jurisdictions described in section 5.1.1. Thus an arc originating at a P-node representing an aggregate pipeline company will be assigned a utility number between 1 and 56 inclusive corresponding to the state associated with the destination node. The other utility numbers, 57 and higher, are defined by the GENNET user. There should be one such utility for each rate zone of every pipeline company selected by the user to be represented explicitly in the network. The GENNET user supplies for each selected pipeline company the utility numbers and lists of states covered by the utilities. Then, for each arc originating at a P-node representing a real pipeline company (as opposed to a root node or a P-node representing an aggregate pipeline company), GENNET assigns the utility number corresponding to that pipeline company selling gas in the state associated with the destination node. Although the numbers defined for the utilities by the GENNET user are somewhat arbitrary, they must be integers greater than 56. It is recommended that they run consecutively beginning at 57 and that all utilities for a particular P-node be numbered consecutively.

The network associated with the natural gas market is quite complex; cycles are common, e.g. company A may sell to company B who sells to company C who sells to company A. To simplify the situation and render the model more computationally tractable, the concept of primary arcs is introduced. The primary arc associated with D-node j is that arc, of all arcs with destination j, with the largest 1980 supply. For a P-node in a multi-pipeline system, the single arc connecting the P-node to the system root node is the primary arc. Except in the case of ties (where an aribtrary choice could, if necessary, be made from among the candidate arcs), there is thus a unique primary arc for every non root node. Furthermore the primary arcs can then be used to decompose the network into the systems specified by the user. For each pipeline system, starting at the root node and working in the forward direction through the network, any node beyond the root node can be associated with the same system as that of the origin of its primary arc. All arcs in the network which are not primary arcs are then referred to as secondary arcs. Note that the outer arcs and Alaskan arcs are defined to be secondary arcs at the P-nodes. Subsequent use of GENNET output assumes that secondary arcs are representative of "take-or-pay" market relationships between the origin node (seller) and destination node (buyer).

At this point it is convenient to tighten the definitions of "network" and "pipeline system". Specifically the term "Base Network" will refer to all P-nodes and D-nodes and all primary and secondary arcs representing transactions among these nodes. Each "pipeline system" is an augmented subset of the Base Network consisting of the P-nodes corresponding to the user-specified grouping of pipeline companies for the system, a root P-node for multi-pipeline company systems, any D-node such that the origin node of its primary supply arc is in the system, and all primary arcs connecting these nodes. To complete the definition of a pipeline system, these nodes and arcs are augmented by all market nodes associated with the D-nodes in the system. Secondary arcs are in the Base Network, but no secondary arcs are in any pipeline system. Every node and every primary arc in the Base Network is in exactly one pipeline system.

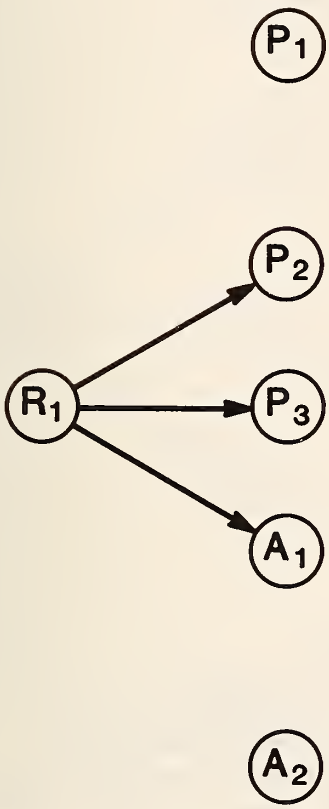
The Network generation procedure is illustrated in Figures 5.3 through 5.7 and the various steps are described below.

Step 1: Initialize the node list. The user specifies the pipeline companies of the network model and the grouping of these companies into pipeline systems. Interstate pipeline companies are specified by a 5-digit ID number used in the Form EIA-50. Aggregate pipeline companies are described by the two-letter state abbreviations for the states to be served. Note that every state should be served by exactly one of these aggregate pipeline companies. A P-node is created for every interstate and aggregate pipeline company specified. For every multi-pipeline company system a root P-node is generated and primary arcs are created to connect such nodes to the other P-nodes in the system. These P-nodes are the initial nodes on the node list. Figure 5.3 illustrates this step with five pipeline companies and three systems. The letter "P" designates interstate pipeline companies, "A" designates aggregate or generic intrastate pipeline companies, and "R" designates root nodes.

Step 2: Augment the node list. The Form EIA-50 Supply File is scanned (presently twice) and a D-node is created and added to the node list for every respondent who purchases supplies from a source represented by another node already on the node list. This step is illustrated in Figure 5.4 where the letter "D" represent the D-nodes added in this step.

Step 3: Create arcs and generic state distributors. In this step the Form EIA-50 Supply File is again scanned. This time if there is a D-node on the node list corresponding to a respondent, arcs are created to connect that D-node with the nodes corresponding to the supply sources. If there is a supply source not on the node list, an arc is created to the D-node from the P-node serving the state in which the respondent conducts business. If the respondent is not on the list then supplies to that respondent are associated with an arc from an appropriate P-node to a D-node representing a generic state distributor in the state where the respondent conducts business. In Figure 5.5 which illustrates this step, the generic state distributors are D-nodes represented by the letter G.

Step 4: Identify Primary Arcs. Consider all arcs with destination at a particular node. Except for ties which can be resolved arbitrarily, one of those arcs corresponds to the biggest supplies purchased by the company represented by the node. That arc becomes the primary arc of the node. All of the other arcs are secondary arcs. If cycles occur in the arcs of the network they are effectively eliminated by flow reduction techniques which might alter the identification of primary arcs. The resulting primary arcs then decompose the network into the systems specified by the user. This is accomplished by associating a node with the same system as the origin node of its primary arc. In Figure 5.6, the heavy lines represent primary arcs.



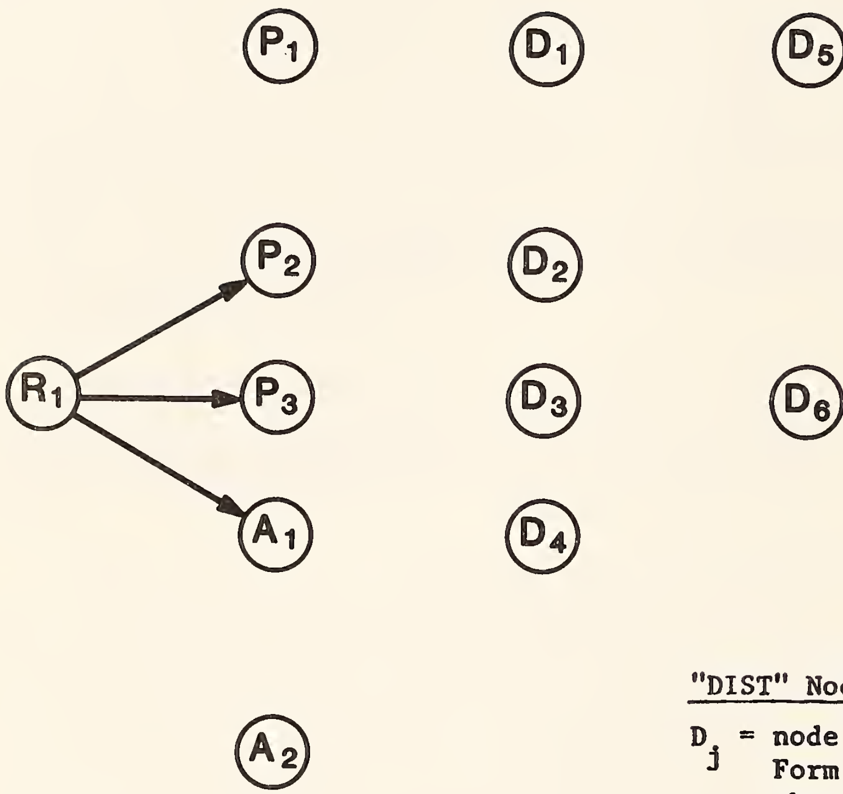
"PIPE" Nodes

P_j = interstate pipeline

A_j = aggregate pipeline

R_j = dummy root node for multi-pipeline systems

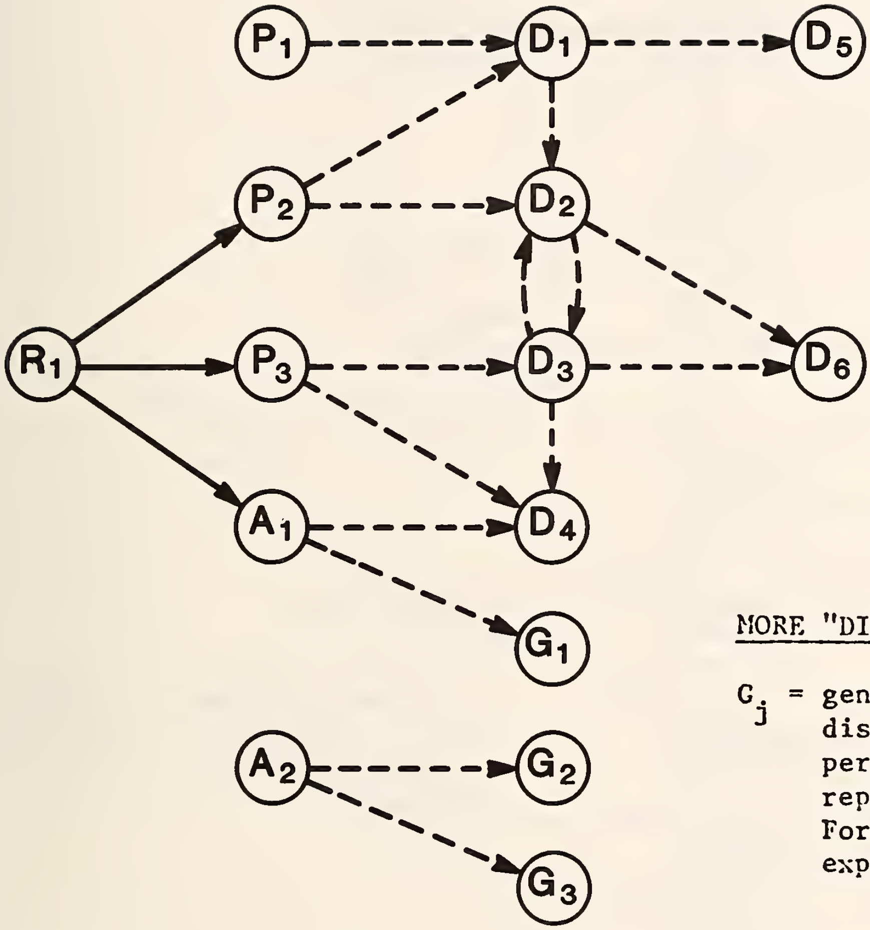
Figure 5.3. Step 1: Initialize the Node List



"DIST" Nodes

D_j = node corresponding to a Form EIA-50 respondent who purchases supplies from a PIPE node or another DIST node.

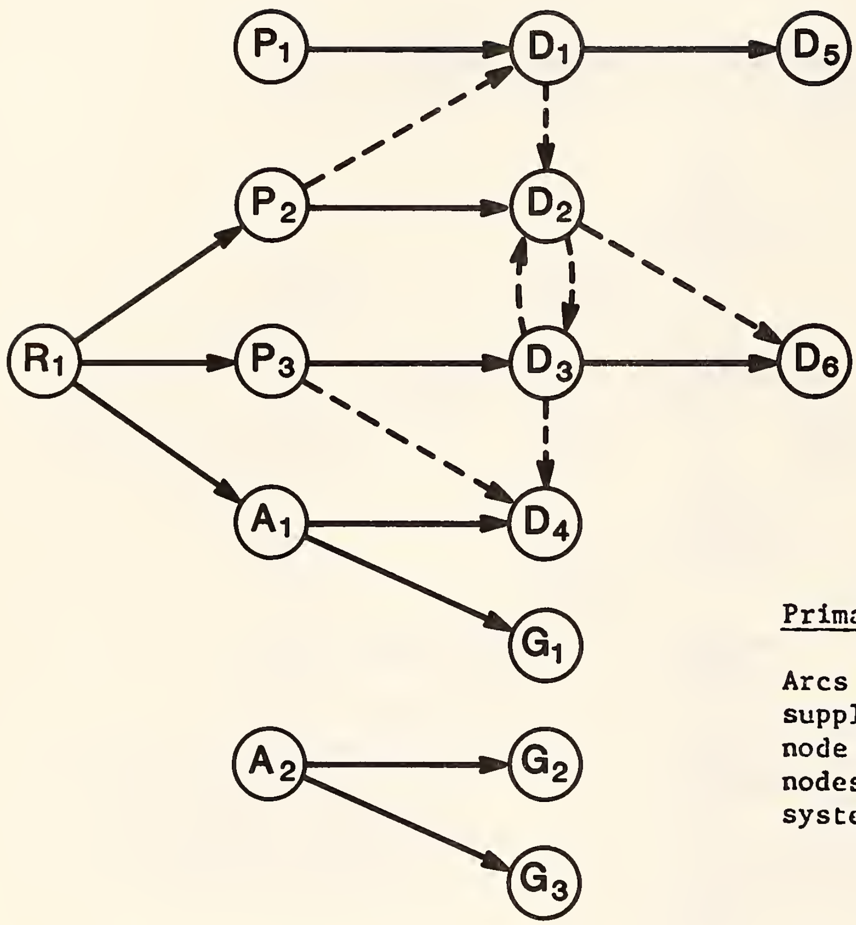
Figure 5.4. Step 2: Augument the Node List



MORE "DIST" Nodes

G_j = generic state distributors; at most one per state created to represent aggregation of all Form EIA-50 respondent not explicitly modeled.

Figure 5.5 Step 3: Create Arcs and Generic State Distributors



Primary Arcs

Arcs associated with largest supplies purchased by a DIST node plus arcs from system root nodes to PIPE nodes in that system.

Figure 5.6. Step 4: Designate Primary Arcs

More "DIST" Nodes

D_7 is D_1 with end-use sales in another state. D_8 is P_3 with end-use sales.

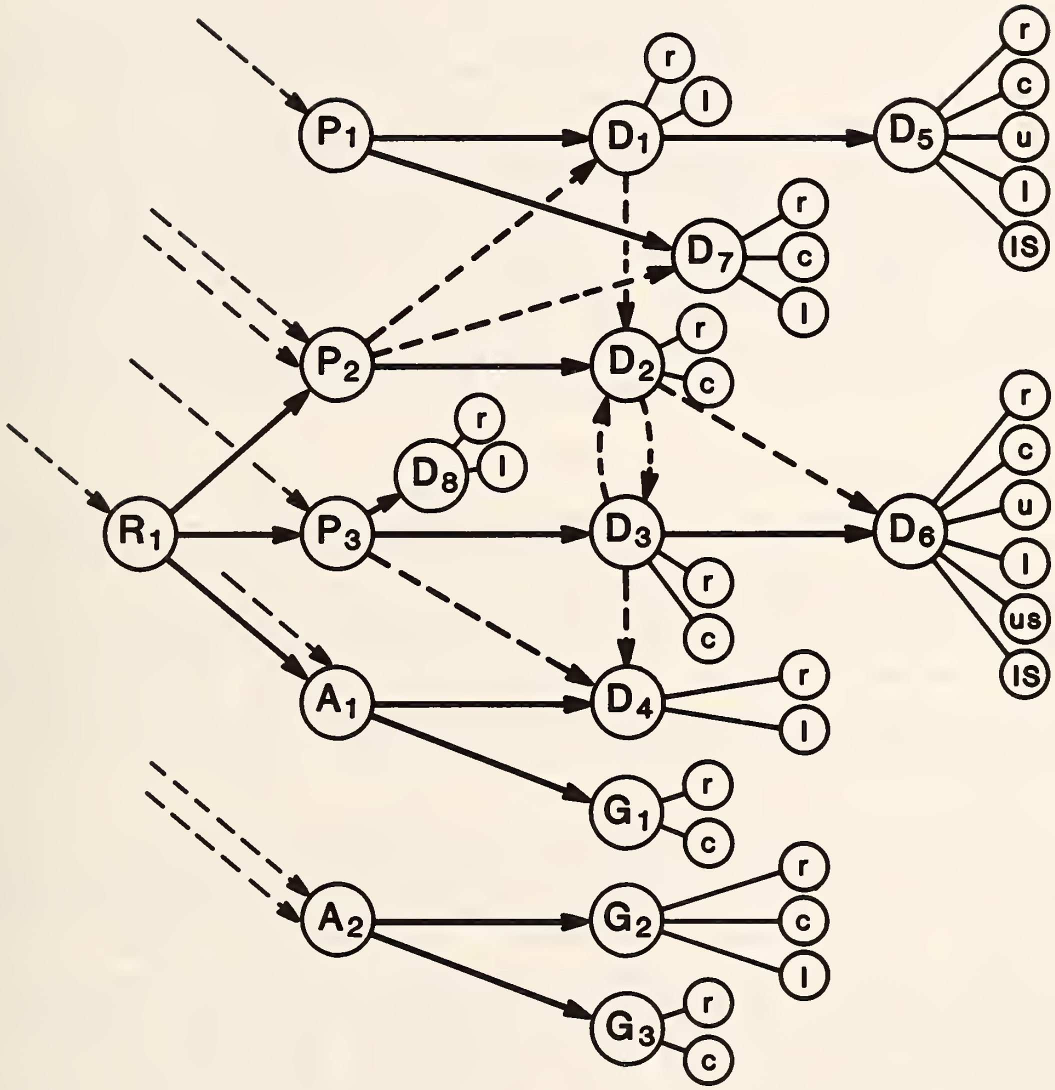


Figure 5.7. Step 5: Create Markets and Outer Arcs

Step 5: Create Markets and Outer Arcs. The Form EIA-50 End Use Sales file is processed to determine the markets associated with each D-node. The transformations for converting from Form EIA-50 customer categories to GENNET markets is described later in this appendix. Since markets require different data from the other network nodes, market nodes and arcs leading to them are not treated by GENNET as a part of the Base Network. Their inclusion in the network shown in Figure 5.7 is, however, conceptually accurate. Note that D_7 and D_8 are new D-nodes created in this step. D_7 is created because the Form EIA-50 End Use Sales file indicates that the respondent associated with node D_1 has end use sales in more then one state. There will be one D-node for each state in which a respondent has end use sales. D-node D_8 is created because the respondent associated with P-node P_3 has end use sales. Because MARKET does not permit end use sales by P-nodes, a psuedo D-node (D_8 in the example), is created to accommodate these sales. Finally, note the secondary arcs coming into each P-node. These are "Outer Arcs" designed to represent imports, synthetic fuel, etc. There is one "outer arc" for each P-node. In addition, the GENNET user specifies which, if any, P-nodes have access to Alaskan gas. These P-nodes have an extra secondary arc coming into them. One of the GENNET outputs is a directory which gives the arc numbers of the outer arcs and Alaskan arcs for the P-nodes. MARKET users refer to this directory when "loading" these arcs with projected price and quantity estimates.

Before describing the second phase of GENNET, this section of the appendix concludes with a discussion of the heuristic used to establish the sizes of the Industrial and Utility Markets with alternate fuel capabilities, i.e., gas consumers capable of switching to another fuel source. As described earlier, GENNET transforms the Industrial and Utility markets reported on the Form EIA-50 into two markets each, one of which has the capability of switching to alternate fuels. Conversations with several pipeline company representatives indicated that as a general rule-of-thumb, approximately 15 percent of the industrial sales and 50 percent of the utility sales are subject to immediate loss if consumers with dual-fuel capability find an alternate fuel more desirable.

Early versions of GENNET used the rule-of-thumb verbatim, i.e. if V_I and V_U are the volumes reported on Form EIA-50 for Industrial and Utility markets respectively, then $.15\ V_I$ and $.50\ V_u$ were base year quantities for the corresponding switching markets for GENNET. The remaining volumes, $.85\ V_I$ and $.50\ V_u$, became the base year quantities for the non-switching counterparts. The same transformations were used with the number of customers. Subsequent use of GENNET output encountered difficulties as a result of very small switching markets which occurred in some instances. Accordingly the following procedure was devised to eliminate very small markets and to insure reasonable average consumption levels.

> Let V_{min} equal some minimum volume level which is acceptable for a switching market. (Presently V_{min} = 10000 Mcf.) Then if $V_I < V_{min}$, the entire industrial volume V_I is added to the commercial market and no industrial market is created for that respondent. If, $.15V_I < V_{min}$, then no industrial switching market is created; all of the industrial market is assumed to lack dual-fuel capability. Otherwise, the transformation was as before for volume, but the number of customers in the switching market was calculated differently.

If C_I is the number of industrial customers reported by a Form EIA-50, the number of industrial customers with dual fuel capability is calculated as the minimum of $.15C_I$ and $.15V_I/V_{min}$. This calculation ensures an average consumption of at least V_{min} for each customer in the switching market. Note that the number of customers is always rounded to the closest integer and there must be at least one customer if the volume is positive.

The calculations for the utility market are identical to those for the industrial market except that the switching factor is .5 instead of .15.

The switching factors (.15 and .50) and the minimum acceptable volume (10000 Mcf.) are all parameters of the GENNET model. Their values can be changed by the user. In fact, it is highly recommended that they be carefully considered for reasonability, and that the sensitivity of model results to these parameters be thoroughly investigated. After the network was "finalized" for a first run of the base case, switching factors for the industrial markets became available on a DOE demand region bases. Because these factors would generate a new network, it was decided to postpone their inclusion in GENNET until after a reasonable base case had been modeled successfully.

5.2 Phase II: Processing Additional Data.

This section describes the operation in GENNET associated with processing data on prices, storage capacities, transmission and storage losses, and consumption patterns.

There are several types of price data processed by GENNET. For sales by a P-node representing an interstate pipeline company to another company represented by a D-node, prices are taken directly from the average annual prices reported in the Form FERC-2 by the pipelines for each recipient of "Sales for Resale". In those instances where Form EIA-50 reports a transaction which is not reported in Form 2, the weighted average price of sales by the pipeline is used.

For sales by a P-node representing an interstate pipeline company to a pseudo D-node created to accommodate direct sales by that pipeline, the base year price is taken from the Form 2 as the average annual price reported by state for "Field and Main Line Industrial Sales." The appropriateness of the use of this price depends entirely on subsequent use of GENNET output. It is noted here that Form 2 also includes prices for "Distribution Type Sales" by the reporting pipeline. These prices are further subdivided by "Residential", "Commercial", and "Industrial". At present, GENNET and MARKET do not use these prices from Distribution Type Sales. Although their use would require keypunching and analysis, future versions of the model should consider the impact of this more detailed information on direct sale prices.

Prices on sales from P-nodes representing aggregate pipeline companies to D-nodes are the "Resale Prices" reported in the 1980 Gas Facts [1]. According to a Gas Facts footnote, these state average prices are representative of city-gate prices. The reported prices are used directly for D-nodes in any of the following states: Alabama, Arkansas, California, Kansas, Louisiana, Mississippi, New Mexico, Ohio, Oklahoma, Texas, West Virginia, and Wyoming. These twelve states all have substantial intrastate gas sales which would be reflected in the reported prices and would account for many of the transactions represented in the network by sales from P-nodes representing aggregate pipelines. For all other states, the average of these twelve prices is used for sales from P-nodes representing aggregate pipelines to D-nodes in those states.

The only remaining resale prices are those for sales from one D-node to another D-node. No source for price data on these transactions has yet been identified. The following procedure is used in GENNET to calculate prices for these sales. The network nodes are first ordered in such a way that if node A precedes node B, then the longest path (i.e. most number of arcs) from a root node to node A is less than the longest path from a root node to node B. Proceeding through the network ordered in this way, the prices on all sales by D-node A can be calculated as the weighted average of the prices paid for supplies by D-node A increased by some markup. The markup currently used in GENNET is 10 percent.

Another important data item provided through GENNET is storage capacity. GENNET was designed to accept input specifying non-zero storage capacities available at P-nodes or D-nodes identified by their 5-digit Form EIA-50 ID number. GENNET then determines the network node corresponding to each 5-digit ID and associates the storage capacities with those nodes.

Initial attempts to obtain storage capacity data were complicated by unsubstantiated data sources with incomplete and often conflicting values. As a result of these complications, the following procedure was used to obtain usable values for storage capacities. A complete run of GENNET and a base-year-only run of MARKET was made with all storage capacities set equal to zero. MARKET calculates the storage requirement at each market as one half of the difference between summer and winter consumption. These needs are then aggregated back (from destination to origin) along the primary arcs of the Base Network to determine total storage needs at each P-node (excluding P-nodes which are pseudo root nodes). GENNET is then rerun using these calculated storage needs as the capacities available at the P-nodes and zero storage capacities at all other nodes. If this procedure for obtaining storage values had been anticipated at model inception, all storage calculations would have been handled in MARKET without the need for intervention via GENNET.

Data describing consumption patterns are input to GENNET for each Form EIA-50 respondent with end-use sales. For each respondent, identified by its 5-digit Form EIA-50 identification number, this data set includes a "heating factor" and a "monthly load factor" for each Form EIA-50 customer category (Residential, Commercial and and other, Industrial and Utility) in each state in which the respondent reports end-use sales. GENNET simply identifies the network D-node corresponding to the respondent in the appropriate state and then associates the factors with the corresponding market nodes.

The consumption pattern data which are input to GENNET were generated by Science Management Corporation (SMC) under contract to EIA/DOE. Using the Form EIA-50 monthly end-use sales data for the period April 1980 through March 1981, SMC calculated a heating factor and a monthly load factor for each of the four Form EIA-50 customer categories in each state served by every Form EIA-50 respondent. At the present time, Industrial and Utility markets with alternate fuel capabilities are assigned the same heating and load factors as their non-switching counter parts. Thus the four categories processed by SMC are used to establish values for six categories in GENNET. Roughly speaking, the heating factor is the ratio of winter consumption to total annual consumption. The heating factor is defined as end use sales to a customer category from October through March divided by total annual end use sales (April through March) to that customer category. MARKET uses the heating factors to differentiate between summer and winter demand. The monthly load factor is defined as the peak monthly sales to a customer category divided by the average monthly sales to the customer category. MARKET uses daily load factors. The transformation from monthly load factors to daily load factors in performed in MARKET.

There are two remaining data items which GENNET prepares for use by MARKET. These are storage loss factors for each node with non-zero storage capacity, and transmission loss factors for each arc between two nodes, neither of which is a market node or a pseudo node, i.e. a pseudo P-node or a pseudo d-node. Sources of information regarding precise values for these data items have not been identified. At present GENNET parameters set the value of storage loss factors to .02 and transmission loss factors to .04. MARKET uses the storage loss factor in such a way that all quantities of gas stored experience a one-time 2 percent storage loss. This corresponds to the loss incurred during the process of retrieving gas from storage. Each time that a quantity of gas "flows" from an origin node to a destination node, the quantity leaving the origin node is reduced by 4 percent before it it received at the destination node. MARKET has the capability of ignoring some of these factors and substituting calculated loss factors based on transmission distance.

5.3 GENNET Output.

The output from GENNET consists of three data files, two of which are major input files for MARKET. The GENNET output file which is not used by MARKET is a dictionary relating Form EIA-50 identification numbers and network nodes. There is a DOE Form EIA-50 data file which contains names, addresses, telephone numbers, a personal contact, and the 5-digit identification number for each Form EIA-50 respondent. The dictionary can be used in conjunction with this Form EIA-50 name and address file to identify the individual pipeline and distribution companies represented by each node in the network. The ability to determine the respondent represented by particular network nodes has proven useful when unusual data values are observed and it becomes desirable to determine the source and possible explanation for the values. The network nodes are not otherwise identified by company in any of the GAMS or MARKET output in an attempt to preserve anonymity.

The two GENNET output files used by MARKET contain data describing the Base Network and each of the individual pipeline systems. Much of the data in these files is concerned with a computationally convenient method for describing the nodes and arcs of the network. The GENNET/MARKET user is unlikely to be concerned with these data; further details will be presented in the computer program documentation. For the sake of completeness, all output data items are listed below, but only those marked with an asterisk (*) are likely to be of interest to readers of this document.

The Base Network data file hereafter referred to as NETWORK, contains information about all of the PIPE and DIST nodes and all of the primary and secondary arcs connecting PIPE and DIST nodes. This file does not contain any data relating to market nodes or arcs connecting market nodes to DIST nodes. The following data are contained in the NETWORK file for each PIPE and DIST node in the Base Network:

- a number corresponding to the state in which the company represented by the node does business;
- the type of node, i.e. "PIPE" or "DIST" for P-nodes and D-nodes respectively;
- the arc number of the first arc in the forward star[†] of the node;
- the arc number of the first arc in the backward star[††] of the node;
- the number of arcs in the backward star of the node;
- the arc number of the primary arc supplying the node;

* the storage capacity available at the node;
* the storage loss rate at the node, zero if storage capacity is zero for the node.

The following conventions were used in developing the structural description of the Base Network: (i) the ordering or numbering of arcs is arbitrary provided that all arcs with the same destination are numbered sequentially; and (ii) since arcs with the same origin are not sequentially numbered, each arc should indicate the next arc with the same origin. With these conventions in mind, the reader is advised that the following data are contained in the NETWORK file for each arc joining two nodes in the

---

[†]The forward star of a node is the set of all arcs with origin at the node. There is no special significance to the ordering of arcs within the forward star so that the designation of first arc is arbitrary.

[††]the backward star of a node is the set of all arcs with destination at the node.

Base Network:

- the node number of the origin of the arc;

- the node number of the destination of the arc;

- the next arc in the forward star of the origin of this arc;

* the quantity of gas sold by the company represented by the origin node to the company represented by the destination node; units are Mcf;

* the average price of the gas sold by the company represented by the origin node to the company represented by the destination node; units are hundredths of a cent per Mcf.;

* a "utility" number indicating the pipeline rate zone under which tariffs are determined for arcs from P-nodes to D-nodes; for arcs from P-nodes to pseudo D-nodes this value is -1; for all other arcs the value of this number is zero.

- the transmission loss rate for the arc.

At the end of the NETWORK file there is some additional information which is not used directly by MARKET. It is furnished for reference by the MARKET user who may wish to prepare input data files for MARKET to represent transactions involving imports or Alaskan gas. Recall that one Outer Arc, with origin labeled zero, is created for each P-node in the Base Network. Such arcs can be used in MARKET to represent imports or synthetic gas supplies. An Alaskan arc, also with origin zero is created only for those P-nodes specified by the GENNET user as having access to Alaskan gas. The following information is available at the end of the NETWORK file for each P-node:

- node number;

- pipeline system of the node,

- the arc number of the Outer Arc for the node;

- the arc number of the Alaskan arc for the node; zero indicates there is no Alaskan arc for the node.

The second output file created by GENNET for use by MARKET contains data describing the pipeline systems. This file, referred to as the THREAD file, contains the following information for each pipeline system:

- pipeline system number;

- number of nodes (including all P-nodes, D-nodes, and market nodes) in the system.

For each node in the system, the following information is provided:

- network node number, e.g. the first node in the system might be network node number 9; this is blank for market nodes.

- node type, i.e. "PIPE", "DIST" or "MART"

- the system node number of the origin of the primary arc into the node;

- the number of primary arcs for which the node is an origin; this is zero for all market nodes;

- the system node number of the first node connected to this node by a primary arc originating at this node; this is zero for all market nodes;

- the type of market node, i.e."RSDL", "CMCL", "UTIL", "INDL", "UTSW", or "INSW" to designate residential, commercial, utility, industrial, utility with alternate fuel capability, or industrial with alternate fuel capability respectively; this is blank for all P-nodes and D-nodes;

- the quantity of gas consumed at a market node; units are Mcf.; this is blank or all P-nodes and D-nodes;

- the number of customers at each market node; this is blank for all P-nodes and D-nodes;

- the heating factor at each market node; this is blank for all P-nodes D-nodes;

- the monthly load factor for each market; this is blank for all P-nodes and D-nodes.

NOTES

Note 1 Model years (p. 30)

A recent modification and extension of its input data has enabled GAMS to handle model years 1980-1995 with year 2000 as horizon.

Note 2 Absence of absorbable quantity (p. 32)

The model may determine that there is no absorbable quantity at all at a given price in a price track. This happens whenever secondary supplies cannot be accomodated, leading to persistent negative flows (see Section 4.2.4). Otherwise, there will always be a positive absorbable quantity because the model maintains a very small positive flow in excess of 1.0 BBtu.

If zero absorbable quantity is found for one of the track prices, then zero absorbable quantity is immediately assigned to all subsequent prices in the same track. Absence of an absorbable quantity for the first year in the cheapest price track is considered a model error and terminates the model run.

Note 3 Demand projection table look-up (p. 32)

Currently the interpolation is linear, and default conventions are as follows: for query prices that are smaller than the smallest grid price for the future year in question, the absorbable quantity is considered equal to that of the smallest grid price; for query prices that are bigger than the biggest grid price, the absorbable quantity is considered zero. Exponential interpolation and using a declining exponential default for large prices would be preferable. By exponential interpolation, we mean linear interpolation between logarithms of the table quantities to find the logarithm of the absorbable quantity.

Note 4 Different configurations for pipeline systems (p. 35)

The MARKET model has the flexibility to accept representations of pipeline systems that differ from the rooted pipeline clusters described in Section 3.3.1. For instance, several P-nodes connected "in series" may be used to represent the various rate zones of a pipeline company and also to mimic its physical layout to some extent.

Note 5 GENNET and Form EIA-50 (p. 36)

Form EIA-50 provides volume data for input into GENNET. Although GENNET is essentially a generic network generator, a considerable amount of its structure is specifically geared towards Form EIA-50, so that a change-over to another form of volume input, say, to Form EIA-176, would require some reprogramming. Because it is based on calendar years rather than heating years, the Form EIA-176 would be more consistent with other inputs to GENNET, although it is by no means clear whether it can fully replace Form EIA-50 for the purposes of MARKET. A benchmarking capability has been included into MARKET to provide compatibility with Form EIA-176 data (Note 11).

Note 6 Alaskan gas (p. 37)

For the handling of Alaskan gas, MARKET provides the option of specifying general cost and volume figures and of identifying participating pipeline companies on a percentage basis. The price and volume tracks for corresponding outer arcs will then be created automatically.

Note 7 Estimation of pipeline fuel (pp. 37, 38)

The input of transmission losses due to fueling pipeline compressors between pipe-gate and city-gate is in conjunction with the input of the base network. The input is arc specfic and is in terms of the relative loss, e.g., .04 means a loss of 4%. A loss specification of 1.0 or more is considered as a flag which triggers calculation of the transmission loss for a particular arc from a mileage estimate on the basis of .0008% per mile.

In all networks used so far, a uniform loss of 4% per arc has been specified (transmission loss factor = .96). No transmission losses have been calculated from mileage.

Note 8 Secondary transactions (p. 39)

Although the MARKET model will accept secondary arcs between P-nodes in the base network, the networks that have been created using GENNET do not include such secondary arcs. The reason is that Form EIA-50 contains information on supplies from one pipeline company to another only if the latter sells to end-users. Because of this incomplete reporting requirement, it was decided, for the first production versions of MARKET, to leave P-P arcs out of the network altogether (with the exception of the improper arcs which connect pipelines to their roots within a rooted cluster (see Section 3.3.1)) rather than "manually" supplementing the network. An estimate of deliveries between pipeline companies for the base year 1980 was found in Form FERC-15. This information was used to shift corresponding shares of reserves from one pipeline system to another by adjusting the GRST-table (see Note 15). In later versions, the Form FERC-15 data were used to introduce P-P secondary arcs. However, these arcs were not introduced explicitly into the base network, but rather a coding change in MARKET was made by EIA in order to accomodate them as virtual arcs. Currently, the volumes and prices on these secondary transactions are kept fixed for all model years.

One reason for using virtual P-P arcs, as opposed to including actual arcs in the base network, was the fact that GENNET searches for and eliminates feed-back cycles in the base-network (see Chapter 5). These feed-back cycles represent supplies which are passed on in a circular fashion until they are returned to one of the original suppliers. The pattern of P-P arcs as derived from Form FERC-15 contains such feed-back cycles, the removal of which was considered undesirable by EIA.

The 15% estimate of secondary flow includes only secondary flows between different pipeline systems. However, secondary arcs between nodes of the same pipeline system are accepted by MARKET and do occur in networks generated by GENNET. The 15% estimate of secondary flow also does not include arcs of the P-P variety.

Note 9 Subdivision of end-use sectors (p. 39)

The actual determination of base year volumes at M-nodes which belong to subdivisions of the industrial or utilities sectors, respectively, is part of the network generation process. For the pertinent assumptions in GENNET, the reader is referred to Chapter 5.

New kinds of demand curves, such as recently introduced ones for utilities, tend to obliterate the distinction between switching and nonswitching subsectors. On the other hand, important specific uses of gas, such as refinery fuel, are suggesting different additional subdivisions. It should be understood, that MARKET is not conceptually tied to any particular pattern of subdivisions.

Note 10 Use of back-up storage (p. 40)

A vast amount of information is associated with each pipeline system. To keep all this information simultaneously in memory would increase the memory space occupied by the program and thereby slow down model execution. For this reason, pipeline system information is kept in back-up memory and only the information pertaining to a single pipeline system is kept in core memory at any given time.

Note 11 Benchmarking (p.40, Notes 5, 29)

The definition of end-use categories in EIA data collection efforts is not uniform. Commercial and industrial use, for instance, are defined differently for Forms EIA-50 and EIA-176. Furthermore, the time frames differ: Form EIA-50 reports on a heating year (April-March) basis, whereas Form EIA-176 reports on a calendar basis. The reporting basis of EIA-176 is preferable since it also forms the basis of NGA compilations. In addition, the price data, which are extracted from the Forms FERC-2 filed by the individual interstate pipelines, are for calendar years. For these reasons, the burnertip volumes in the network data are "benchmarked", that is, scaled by state and end-use specific factors, so that burnertip volumes by state and end-use sector match the ones reported by the NGA in the base year. As was mentioned before, the NGA data derive from Form EIA-176.

The benchmarking code has been included in the MARKET model, rather than in GENNET for the following reasons: (i) More recent developments extend benchmarking to years after the base year. In the latter use, the network to be benchmarked is no longer the one generated by GENNET. Thus a benchmarking capability is needed in MARKET anyway. (ii) The NGA data would have represented a new input item for GENNET, whereas they are already an input item into MARKET because they are needed for burnertip price calibrations (see Note 34). (iii) The benchmarking capability reduces the need for network generators like GENNET to account for all burner-tip volumes.

Besides the state-level benchmarking refered to above, MARKET also has the optional capability to benchmark at the regional level using regional reference volumes (QRRSIY, ORCMIY, QRINIY, QRUTIY) (see Section 3.6). Starting from benchmarked local burner-tip volumes in the base-year, which in each region are supposed to add up for respective end-use sectors to the regional base year reference volumes, the local reference volumes are multiplied by the ratio of the next year's over the present year's regional reference volume. These updated local reference volumes are then chosen as volumes at the corresponding M-nodes. Summed by region for each end-use sector, the local volumes will reproduce the regional volumes. In particular, if the regional volumes agree with available NGA data, the above procedure benchmarks at the region level. The procedure does not guarantee agreement at the state level, although the divergence should be minimal. Nevertheless, EIA felt it necessary to benchmark to state levels rather than regional levels for those years for which NGA state level data are available.

Note 12 Monthly and daily loadfactors (p. 42,58)

(Oral communication by P. Curley of AGA to R.E. Schofer of NBS on November 17, 1981).

Peaking factors are defined as the ratio of the peak day sendout to the average day sendout in the peak month. The peak day may or may not lie within the peak month. 1980 input data was used and included all reporting companies which qualified in each region. Qualification is defined as follows:

1 - Company must report all data required for determining peak ratio.

2 - Company service territory cannot extend beyond regional boundaries.

3 - The reporting company cannot be a transmission company.

The results for the nine 1980 census regions are as follows:

Census Region	Ratio, Peak Day to Average Day in Peak Month	Sample Size
New England	1.47	59%
Mid Atlantic	1.45	53%
South Atlantic	1.36	42%
East North Central	1.28	62%
East South Central	1.36	34%
West North Central	1.14	10%
West South Central	1.58	19%
Mountain	1.44	26%
Pacific	1.40	53%
All Lower 48	1.37	---

Sample Size is the ratio of gas sales by companies used in this sample to total gas sales for regions from 1980 editions of Gas Facts.

Note 13 Loadfactors for interruptible customers (p. 42,58)

In the MARKET model, loadfactors on arcs leading to M-nodes are used for two purposes: (i) to estimate peak-day loads at the burnertip to which demand rates may be applied in order to establish fixed distribution tariff increments; (ii) to estimate peak-day usage at the city-gate in order to establish transportation tariffs in a similar fashion.

Industrial customers and utilities with dual firing capability involving residual oil (switching subsectors in Section 3.4.1) can be considered interruptible customers. As such they are not likely to contribute to peak loads or be billed on the basis of peak loads. These customers rather act as peak-sharers. As a consequence, loadfactors of 1.0 or less are recommended for M-nodes in switching subsectors or, more generally, for all industrial customers and utilities. Most recently loadfactors of .1 have been used for all utilities. Of course, the name "loadfactors" is then a misnomer. The practice of introducing loadfactors which are smaller than 1.0 makes even more sense, when the loadfactors of all end-use sales of a particular distributor are combined to estimate the loadfactor pertaining to the primary supply of the distributor. The weighted sum of all loadfactors of sales yields an unrealistic worst-case estimate of peak usage, because it is based on the assumption that all end-use consumption peaks at the same day. Load factors that are smaller than 1.0 will contribute to a more realistic combined loadfactor.

Note 14 Root loss rate (p. 42)

The MARKET model contains a provision for a single root-loss rate to be entered into the model as a loss quantity for all root nodes. This number might be interpreted as representing losses between the wellhead and the pipe-gate. Since current reserve data have been adjusted for processing losses and lease-and-plant fuel (Note 15), the root loss has been entered as zero in all production runs so far.

Note 15 The GRST table (p. 64, Notes 8, 30, 37)

The data structure which contains reserve information is called the "GRST table". It is input and maintained by the GAMS driver rather than by MARKET, although MARKET does update the quantities of reserves by subtracting the amounts withdrawn from each of the reserve blocks. MARKET does not access the complete GRST information, such as production regions and production categories.

In addition to reserve blocks of the various NGPA categories and flavors, th GRST table contains reserve blocks of socalled "888 gas". These are highly priced pseudo-reserves which may be interpreted as supplemental gas sources such as butane or coal gas and which are only utilized in the case of extreme gas shortage. In a very recent development, pseudo-reserves representing import committments have been introduced.

Note also that all versions of the GRST table used so far contained reserve data and prices which were adjusted to account for removal of lease-and-plant fuel, typically 5%-7.5% of gross production at the wellhead.

<u>Note 16</u> <u>Mathematical discussion of minimum cost take supply curves</u> (p. 45)

Consider K reserve blocks dedicated to a given pipeline system, and let

$$q_k = \text{available annual production}$$

$$u_k = \text{unit price at the wellhead}$$

$$t_k = \text{take-or-pay portion } (0 \le t_k \le 1)$$

for the k^{th} reserve block, $1 \le k \le K$. The reserve blocks are numbered by increasing price:

$$u_1 \le u_2 \le \ldots \le u_K.$$

The supply curve which results from the minimum cost-take strategy described in Section 3.5.1 has a constant unit price for all quantitites between zero and the total take-or-pay quantity

$$\overline{Q}_o = \sum_{1 \le i \le K} t_i \, q_i.$$

This constant price is given by

$$P_o = \frac{\sum_{1 \le i \le K} t_i q_i u_i}{\sum_{1 \le i \le K} t_i q_i} = \frac{\sum_{1 \le i \le K} t_i q_i u_i}{\overline{Q}_o},$$

which is the average price paid if the take-or-pay obligations were satisfied but no purchases were made beyond these minimum limits.

Withdrawal proceeds in several stages. Each corresponds to a smooth portion of the supply curve. Withdrawal up to the total take-or-pay limit Q_o corresponds to the constant portion of the beginning of the supply curve. In each of the stages which follow the initial constant stage, the supply curve takes the form of a hyperbola,

$$P(Q_{k-1}+q) = (Q_{k-1}P_{k-1}+qu_k)/(Q_{k-1}+q), \quad 0 \le q \le (1-t_k)q_k,$$

where

$$Q_k = \sum_{1 \le i \le k} q_i + \sum_{k \le i \le K} t_i q_i \, ,$$

$$P_k = \sum_{1 \le i \le k} q_i u_i + \sum_{k \le i \le K} t_i q_i u_i / Q_k \, .$$

Q_{k-1}, P_{k-1} and Q_k, P_k, respectively, are the coordinates of the two endpoints of the k-th hyperbolic curve segment. The values

$$Q_K = \sum_{1 \leq i \leq K} q_i$$

$$P_K = \sum_{1 \leq i \leq K} p_i q_i / Q_K$$

are the coordinates of right most or "last" point of the supply curve. The asymptotic value of the k^{th} hyperbolic segment as $q \to \infty$ is p_k. It follows that if $P_{k-1} > p_k$ the segment is convex and decreasing; if $P_{k-1} < p_k$ the segment is concave and increasing, and if $p_{k-1} = p_k$ the segment is a horizontal line at value p_k. The supply curve will always assume its minimum at a breakpoint between two curve segments. In particular, the curve point with the coordinates Q_k, P_K, $1 \leq k \leq K$, is minimum if $P_{k-1} \geq p_k$ and either $p_k \leq p_k$ or $k = K$. In the latter case, the minimum is assumed at the last point. In the absence of take-or-pay provisions, minima are at $Q_o = 0$, $P_o = u_1$ as well as at $Q_1 = q_1$, $P_1 = u_1$, and the curve points in between. In these extreme cases, the supply curves exhibit either economy or diseconomy of scale, respectively. In the general case, a regime of economy of scale is followed by a regime of diseconomy of scale. According to current data, economy of scale dominates for most pipelines systems.

<u>Note 17</u> <u>Handling supplemental gas under rateable take</u> (p. 46)

Reserve blocks of supplemental gas (<u>Note 15</u>) must clearly be excluded from the across-the-board withdrawal assignment specified by the rateable take option. This is achieved by assigning a zero take-or-pay ratio to supplemental reserve-blocks. During the second phase of the rateable take withdrawal process, zero take-or-pay is treated as a flag causing supplemental reserve blocks to be removed from consideration. Supplemental reserves are tapped only after all others are exhausted, and then they are withdrawn on a minimum cost-take basis.

<u>Note 18</u> <u>Rectangular production profiles</u> (p. 50)

A rectangular profile requires $T_1=T_2$, and $q(T)=0$ for $T>T_3$. The latter condition can be met only approximately by choosing $T_1=T_2$, T_3, and Q_{res} such that

$$T_e \cdot q_{max} = Q_{res} - (T_3 - T_2) \cdot q_{max} = 1.1 \cdot \text{BBtu} > 0$$

<u>Note 19</u> <u>Average versus marginal prices in equilibration</u> (p. 51)

S. Wade of BNL pointed out that the quantity of gas purchased in the presence of fixed charges depends both on the fixed charge and the marginal price. More precisely, a price-quantity relationship should be of the form

$$Q = d^{marginal}(p^M, C^F),$$

where P^M denotes the marginal price and C^F the fixed cost of doing business. Q then stands for the maximum quantity of gas absorbable by a particular purchasing entity under the indicated pricing assumptions. In the particular case of the MARKET model, the marginal price is assumed to be constant, that is, independent of the quantity purchased. It thus coincides with the full commodity tariff, that is, the average price of gas at the city gate plus the commodity mark-up. Let P^A denote the corresponding average price of gas at the burnertip. Then

$$P^A = P^M + C^F/Q$$

and

$$A = d^{\text{marginal}}(P^A + C^F/Q,\ C^F).$$

The latter relation defines implicitly a price-quantity relationship of the form

$$Q = d^{\text{average}}(P^A, C^F).$$

S. Wade further provided the following interesting argument which derives a price-quantity relationship from a utility maximization principle. His basic assumption is that a given "income" may be spent either on gas or on "other goods". If Q^G denotes the purchased quantity of gas and Q^O the purchased quantity of other goods, then the "utility function"

$$U = (Q^G)^\alpha (Q^O)^\beta,\quad \alpha,\beta > o,$$

determines the "utility" of having amounts Q^G and Q^O at one's disposal. The combined cost of this purchase equals the given income I:

$$C^F + P^M Q^G + P^O Q^O = I\ ,$$

where P^O is the average price of other goods, and C^F and P^M are as above. With I, C^F, P^M, P^O as well as α and β being given, the question is what is the most advantageous purchase pattern? In other words,

$$\text{Maximize } U = (Q^G)^\alpha\ (Q^O)^\beta \text{ for } Q^G,\ Q^O > o$$

$$\text{subject to}\quad P^M Q^G + P^O Q^O = I - C^F\ .$$

This maximization problem is equivalent to the following one:

$$\text{Maximize } V = \alpha\cdot\log Q^G + \beta\cdot\log Q^O \text{ for } Q^G,\ Q^O > o$$

$$\text{subject to } P^M Q^G + P^O Q^O = I - C^F.$$

The objective function of the second problem is simply the natural logarithm of the first, and since the logarithm is a monotonically increasing function, the second objective function is maximized for the same values of Q^G and Q^O. In addition, one may assume that

$$\alpha + \beta = 1\ ,\ \alpha,\beta > o\ ,$$

since this relation can always be achieved by multiplying the objective function in the second problem by a suitable positive normalization factor.

With the Lagrange multiplier λ, the (necessary) conditions

$$\frac{\partial V}{\partial Q^G} = \lambda \frac{\partial I}{\partial Q^G} , \quad \frac{\partial V}{\partial Q^O} = \lambda \frac{\partial V}{\partial Q^O} ,$$

yield

$$\frac{\alpha}{Q^G} = \lambda P^M , \quad \frac{\beta}{Q^O} = \lambda P .$$

From that and from the constraint equation follows

$$\alpha \; P^O Q^O - \quad P^M Q^G = 0$$

$$P^O Q^O - \quad P^M Q^G = I - C^F.$$

Solving this linear system gives:

$$Q^G = \alpha(I - C^F)/P^M = d^{\text{marginal}}(P^M, C^F),$$

or in terms of the average price P^A:

$$Q^G = (\alpha I + \beta C^F)/P^A = d^{\text{average}}(P^A, C^F).$$

For most users, particularly residential ones, one would expect that the fixed cost C^F represents a very small portion of the disposable income I,

$$I \gg C^F ,$$

so that the price-quantity relationship takes the form

$$Q^G \approx \theta / P^M$$

in which the quantity depends only on the marginal price P^M. In contrast, the corresponding formula featuring the average price, arrived at by substituting $P^M = P^A - C^F/Q^G$ into the above formula, is

$$Q^G = (\theta + C^F)/P^A ,$$

and definitely depends on C^F. (The reader notices that the fixed cost C^F enters with a seemingly wrong sign: increase of the fixed cost seems to increase the amount purchased. This conclusion, however, is erroneous because an increase of the fixed cost entails an increase in average price.)

One might be tempted to interpret the preceding observations as implying that demand curves should be in terms of marginal rather than average prices. We do not agree with this interpretation. One reason is that, for industrial users, fixed costs C^F may not be neglible when compared to a suitable interpretation of disposable income I. Furthermore, the utility function on which the analysis is based is clearly oversimplified. For instance, the second form of the utility function indicates that the amount of other goods purchased does not affect the utility of gas. This is certainly not the case if the other goods include alternative fuels. In reality, the amount of the payment required up-front influences the willingness to accept particular marginal prices. There is a definite need for further research. Until a better understanding has been reached, the assumption that the price-quantity relationship depend on the average price P^A alone appears to be justifiable. The argument by S. Wade, however, is illuminating and points the way towards improving the foundations of demand models.

Note 20 EIA supplied demand curves (p. 51, Note 40)

Demand for natural gas has two kinds of elastic responses to price increases. There may be an immediate restriction of consumption such as residential customers turning down their thermostats or industrial boilers switching to another fuel in the presence of a dual firing capability. There may be other actions, however, whose effects will not be immediately apparent such as boosting insulation, installing equipment for burning alternative fuels, and so on. The terms "shortterm" and "longterm" elasticity are used for these two kinds of responses to price changes, respectively.

EIA provided demand curves for use in GAMS which are of constant elasticity but make the demand also responsive to the consumption observed during the previous year. The intent of the latter scheme is to represent longterm elasticity effects.

The demand curves provided by EIA are of the following form:

$$Q = \overline{Q}_{ref} \cdot \left(\frac{P}{P_{ref}}\right)^{\beta} = Q_{ref} \cdot \left(\frac{L}{L_{ref}}\right)^{\gamma} \cdot \left(\frac{P}{P_{ref}}\right)^{\beta} .$$

Here Q is the dependent variable representing the quantity of gas expected to be consumed, price P is the independent variable, and the following are parameters:

Q_{ref} = reference volume (QTRFV)

P_{ref} = reference prices (PTRFV)

L = previous year's volume (QLYRV)

L_{ref} = previous year's reference volume (QLRFV)

$\overline{Q}_{ref}$ = lag-adjusted reference volume

β = price elasticity (RBET) (negative)

γ = lag exponent (RGAM)

Price elasticities and lag exponents are given for end-use sectors rather than end-use subsectors. Therefore some supplementary decisions had to be made regarding these values for subsectors. For nonswitching end-use subsectors, the lag exponents of the respective sectors are used. The switching end-use subsectors are equipped to exploit opportunities for cheap fuel. Their short term elasticity is consequently high. Their long term elasticity as individual customers, on the other hand, is very small: if the previous year yielded fewer opportunities for purchasing cheap gas, then this would not deter these customers from exploiting this year's opportunities. A nonzero lag exponent, however, would predict -- incorrectly -- a diminishing effect on demand. Therefore, zero lag exponents were assumed for the demand curves of switching end-use subsectors. The same price elasticities are assumed to apply for both the switching and nonswitching subsectors of individual end-use sectors.

In order to avoid for computational purposes unacceptably large demand values in the neighborhood of zero prices, the demand curves are defined to be level in the price range from zero to half of the reference price. Also the quantity L, which represents consumption during the previous year, is bounded below and above by $.5 \cdot L_{ref}$ and $1.5 \cdot L_{ref}$, respectively, to avoid an excessively large influence by the lag factor.

For early versions of the model it became apparent that the above supply curves were not robust enough to achieve "normal" model termination in the case of steep price increases. Minimum demand levels were therefore introduced to prevent demand from falling in a given year below a specified percentage of the corresponding reference volume no matter what the price. Such demand floors have been lowered or removed in later versions of the model.

Recently, different demand curves have been specified for the utilities sector. These demand curves have been developed by EIA in connection with the IFFS model. They are specified on a regional and yearly basis, and do not take into account the amount consumed during the previous year.

It is important, that the lag exponent be considerably smaller than 1.0 in order to avoid unstable behavior. Indeed, once the consumption falls below the reference volume, then the demand in the next year is biased also towards falling below the reference volume in that year, and so on, resulting in a cumulative demand depression unless either the lag effects are small or prices drop sufficiently below the reference prices to push demand back towards the reference volume. Analogously, once the consumption exceeds the reference volume, demand in the following year is biased also towards further exceeding the reference volume, and again this effect feeds upon itself. As a result, a very small difference in consumption in an initial year may lead to a big difference in later years, depending on which side of the reference volume the initial consumption happened to fall. This situation amounts to a "switch" as described in Section 2.7.

Although the above effect of "correcting away" from the reference will not necessarily hurt the model and may capture some features of the real world provided the lag exponents are sufficiently small, it is clear that a fully satisfactory representation of both shortterm and longterm elasticities has yet to be developed.

Another issue concerning demand estimation is the role of the numbers of customers. Because of the close relationship between customers to be served and the particular distribution company with which it is connected physcially as well as commercially, the number of customers of a distribution company is important to the latter's expectation of demand. Changes in the number of customers in response to price provide a natural measure for longterm elasticity, whereas changes in the average usage indicate shortterm elasticity.

Note 21 Utility demand curves (p. 53)

By the Summer of 1982, the original EIA-supplied utility demand curves were replaced by a set of regional demand curves of quite different character. Instead of having log-linear demands curves scaled by an input track of annual regional prices and demands, a different set of demand curves are input for each year and region. These demand curves are "step-linear" functions, that is, they drop off discontinuously at each of a finite set of breakpoints and are linearly nonincreasing between adjacent breakpoints.

The curves are generated by the utility submodel of the EIA-developed IFFS model. For stand-alone runs of GAMS, the output of some particular IFFS run may be chosen to provide a suitable set of utility demand curves. IF Gams operates in conjunction with IFFS, then various sets of utility demand curves are generated by IFFS in real time and transmitted to GAMS.

Note 22 Example of a violation of the RDC condition (p. 54)

Suppose the regional demand curve for some end-use sector has the form

$$Q = Q_R(P_R/P)$$

(elasticity = -1), with regional reference quantity Q_R stipulated at some regional reference price P_R. Suppose further that there are only two markets of that particular end-use sector in the region, and that the demand curves of these markets are characterized by stipulated local reference quantities q_{R1}, q_{R2} and prices p_{R1}, p_{R2}, respectively. The corresponding individual demand curves then take the form

$$q = q_{R1}(p_{R1}/p) \ , \ q = q_{R2}(p_{R2}/p).$$

Suppose, finally, that the local reference parameters are compatible with the regional reference parameters, that is, they satisfy

$$\text{(RDC)} \ q_{R1} + q_{R2} = Q_R \ , \ p_{R1}q_{R1} + p_{R2}q_{R2} = P_RQ_R.$$

The purpose of this note is to show that the above compatibility relations do not imply the RDC condition. The latter requires

$$q_1 + q_2 = Q_R \ , \ p_1q_1 + p_2q_2 = P_RQ_R$$

for every set of local prices p_1, p_2 and the corresponding quantities q_1, q_2 as determined from the local demand curves:

$$q_1 = q_{R1}(p_{R1}/p_1) \ , \ q_2 = q_{R2}(p_{R2}/p_2).$$

The second of the RDC conditions is satisfied for the special case (elasticity = -1) under consideration. However, the first of the RDC conditions is violated for the following reference values

$$Q_R = 1000 \qquad P_R = 1.10$$

$$q_{R1} = 300 \qquad p_{R1} = 1.50$$

$$q_{R2} = 700 \qquad p_{R2} = 0.80$$

and the local prices

$$p_1 = 1.80 \qquad p_2 = 0.70.$$

For those prices,

$$q_1 = 450/1.80 = 250, \quad q_2 = 560/0.70 = 800$$

and

$$q_1 + q_2 = 1050 \neq 1000 = Q_R .$$

Note 23 Cut-off prices (p. 56)

For each supply curve, a cut-off price (PCUTV) is calculated from state prices for alternative fuels. It indicates the price above which an alternative fuel would be preferred over gas. Only the cut-off price derived from the price of residual fuel oil will be low enough to influence model calculations appreciably; this cut-off price is used for those industrial and utilities end-use subsectors which can switch to residual fuel oil (Section 3.4.1). The other cut-off prices are included for consistency. Residential cut-off is currently set at twice the price for distillate fuel oil ("Number 2"), commercial cut-off at 1.5 times the price of distillate fuel oil, and for non-switching industrial users and utilities, the minimum of the commercial cut-off and seven times the price for coal is used as a cut-off price.

If in the base year the cut-off price lies below the reference price, then the cut-off price should be increased to 1.1 times the reference price to ensure that the consumption observed at an M-node agrees with its reference volume and that, in subsequent model years the reference price and volume define a point on the demand curve. While this procedure was followed for all years, not just the base year, in the first versions of MARKET, it has been discarded altogether in recent versions.

Cut-off prices are not invoked for recent directly specified demand curves for the utilities sector, because switching effects are already built into these demand curves.

Note 24 The transmission tariff module (p. 59)

J.-M. Guldmann, who developed the regressions upon which the distribution tariff module is based, also developed regressions for determining transmission tariffs from rate base and distance information. A corresponding transmission module was coded in 1982 by R.E. Chapman and R.E. Schofer, but has not been included into the MARKET model.

Note 25 Implementation of tariff escalation procedures (p. 59)

A single tariff escalation factor may be specified, which increases all mark-up tariffs, for transmission as well as for distribution, by a fixed percentage model year after model year. The factor works indirectly by increasing the tariff adjustment factors (RTAFV) (See Note 33). If the latter are found to be negative, then they are reduced rather than increased.

Note 26 Recent developments concerning the distribution tariff module (p. 61)

S. Wade of BNL has upgraded several aspects of the distribution tariff module. He has reintroduced a tax component into the rate calculation. NBS had removed tax terms from the original equations developed by J.-M. Guldmann. He has also removed an instance of double counting. Finally a scheme was attempted for reducing tariff mark-ups to customers with residual oil burning capability whenever the burnertip price with the original mark-ups would exceed the residual oil price. The latter feature, however, does not affect the distribution tariff module as such, but is rather a part of the equilibration process, since the burnertip price is calculated by equilibration and not by application of the distribution tariff module.

A. Davies of NBS has investigated the variables in an earlier version of the distribution tariff module as to their significance, using T-statistics provided by J.-M. Guldmann. His major finding was that values for the annual general costs (GENA) of the distributor were exceeded by their error bounds. In other words, they were not significantly different from zero. This indicates that present data do not support a further refinement of the distribution tariff module along the lines of its present design.

Note 27 Storage losses (pp. 62,71)

Storage losses are assumed to be 2% of gas put into storage. This assumption is made for all network nodes uniformly.

Note 28 Storage tariffs (p. 62)

In the semiannual equilibration mode, the constant $\sigma = .25$ has been chosen arbitrarily. For annual equilibration, the combined constant $\alpha.\sigma$ has been set to .15. It would be desirable to calibrate the constants σ and α by conducting experiments in the base year and following it.

Note 29 Options other than equilibration (p. 63)

The MARKET model contains options for "benchmarking" (Note 11) rather than equilibration for years following the base-year. For 1981 and 1982 state level data are available for benchmarking at the state level. Benchmarking at the regional level is available for any number of years after the base year. Once the model enters the equilibration mode, however, it stays in this mode for all subsequent model years.

Note 30 Determining initial reserve profiles (p. 33)

The GRST-table of dedicated reserves (Note 15) is initiated with a base year estimate of the dedicated reserves available to the respective pipeline sytems. The GRST-table provides both content and deliverability information. Content information, namely the total amount of gas contained in each particular reserve block, is given directly as an entry in the GRST-table. The deliverability, namely the amount that can be actually produced during the base year, is calculated in MARKET from profile information contained in the GRST-table. This profile information is representative of the "maturity" of the reserve block in question: reserve-production ratios are large before production reaches its optimum plateau, and decrease subsequently to a value which remains constant during the decline phase.

So far in GAMS, initial reserves have been assumed to be in the decline phase, with pre-base year production equated with the profile parameter q_{max}, and the calculation of the deliverabilities for the base year as well as the following model years are based on these assumptions. A more exact approach would be to derive maturity information from observed reserve-production ratios.

The first step in such a scheme, is to estimate the (constant) reserve-production ratio for the decline phase. To this end, the reserve-production ratios of suitable populations of reserves (grouped, say, by NGPA category and production region) are plotted, and an accumulation point will be observed, which indicates the expected decline-phase reserve-production ratio for the class of reserve blocks. The existence of an accumulation point is due to the fact, that reserve-production ratios approach the decline-phase ratio assymptotically as reserves are exploited. If a population of reserve blocks exhibits several different accumulation points, then one either splits the population accordingly or choses a suitably weighted mean of the corresponding ratios.

In the second step, assumptions need to be made about the typical durations of the start-up and maximum production periods. These assumptions, together with the above determined reserve-production ratios during the decline phase ($=T_e$), determine both the profile and the maturity of a reserve block. This determination can be based on the following formulas (C. Witzgall, April 1982).

(0) Given: a) TELI = 1/2 (TLCON-TLIN) = half-length of linear phase

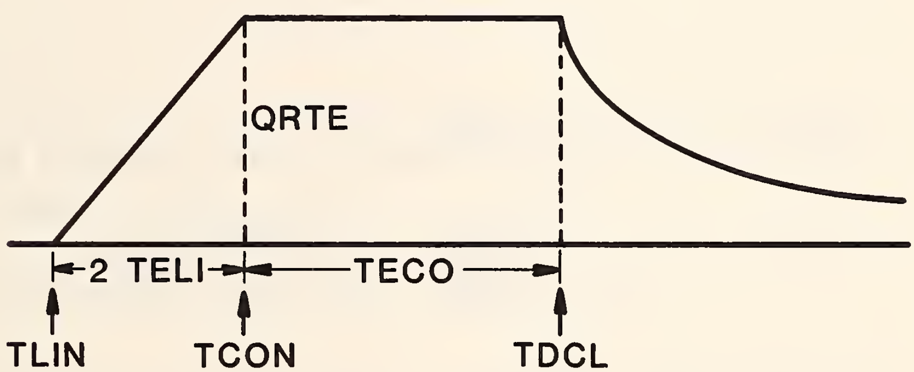
b) TECO = TDCL-TCON = length of constant phase

c) TEXP = exponential decline factors

QRTE*TELI = production during linear phase

QRTW*TECO = production during constant phase

QRTE*TEXP = production during decline phase



Given also: d) available reserves at start of 1979 = R

e) 79/80 production = P

Task: determine profile and start of production from a),..., e), in particular:

=> QRTE = maximum production rate

=> TLIN = start of production

Assumption:

TELI ⩾ 1 ; TECO ⩾ 2 ;

(1) Regime #1:

T = time at end of production period (actual production start = 0)

$0 < T < 1$: $\frac{H}{T} = \frac{QRTE}{2*TELI}$; $H = QRTR \cdot \frac{T}{2*TELI}$

$$P = 1/2\ HT = QRTE* \frac{T^2}{4*TELI}$$

R = QRTE*(TELI+TECO+TEXP)

$$\Pi = \frac{P}{R} = \frac{T^2}{4*TELI*(TELI + TECO + TEXP)}$$

$$T_1 = 1 \ ; \ \Pi_1 = \frac{1}{4*TELI*(TELI + TECO + TECP)} \ ;$$

$$QRTE = \frac{R}{TELI + TECO + TEXP}$$

(2) Regime #2:

$$P = 1/2\,(H_o + H_1)\ ;\ H_o = QRTE* \frac{T-1}{2*TELI}\ ;\ \ H_1 = QRTE* \frac{T}{2*TELI}$$

$$P = QRTE* \left[\frac{2T - 1}{4*TELI} \right]$$

$$R = QRTE*(TELI + TECO + TEXP - 1/2*(T-1)*H_o)$$

$$= QRTE*(TELI + TECO + TEXP - \frac{(T-1)^2}{4*TELI}$$

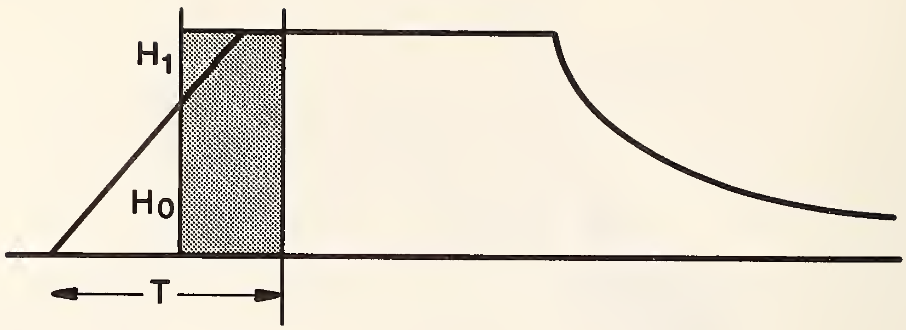
$$\Pi = \frac{2T-1}{4*TELI*(TELI + TECO + TEXP) - (T-1)^2} = \frac{P}{R}$$

$$T_2 = 2*TELI\ ; \qquad \Pi_2 = \frac{4*TELI - 1}{4*TELI*(TELI + TECO + TEXP) - (2\cdot TELI-1)}$$

$$\Pi_2 = \frac{4*TELI - 1}{4*TELI(TECO + TEXP + \$*TELI - 1}$$

$$QRTE = \frac{R}{TELI + TECO + TEXP - \frac{(T-1)^2}{4*TELI}}$$

(3) Regime #3:



remaining reserves as before:

$$R = QRTE*(TELI + TECO + TEXP - \frac{T-1/2}{4*TELI} \; ; \; H_o = \frac{T-1}{2*TELI} \cdot QRTE$$

$$P = \frac{QRTE + H_o}{2} * (2*TELI + 1 - T) + QRTE * (T - 2*TELI)$$

$$= QRTE * \frac{1 + \frac{(T-1)}{2*TELI}}{2} (2*TELI * 1-T) + T - 2 * TELI$$

$$= QRTE * \frac{4*TELI^2 - (T-1)^2}{4*TELI} + T -2 * TELI$$

$$= QRTE * \frac{-(T-1)^2 - 4*TELI^2 + 4*TELI * (T-1) + 4*TELI}{4*TELI}$$

$$= QRTE * \frac{4*TELI - (2*TELI + 1-T)}{4*TELI}$$

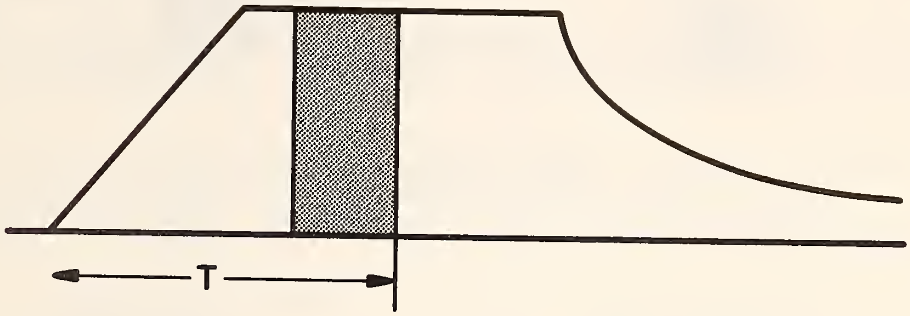
$$\Pi_3 = \frac{4*TELI - (2*TELI + 1 - T)^2}{4*TELI*(TELI + TECO + TEXP) - (T-1)^2}$$

$$T_3 = 2*TELI + 1 \; ; \quad \Pi_3 = \frac{4*TELI}{4*TELI*(TELI+TECO+TEXP) - 4.TELI^2}$$

$$T_3 = \frac{1}{TECO + TEXP}$$

$$QRTE = \frac{R}{TELI + TECO + TEXP - \frac{(T-1)^2}{4*TELI}}$$

(4) Regime #4:



R = (TECP + TEX] - (T-2*TELI) + 1) QRTE

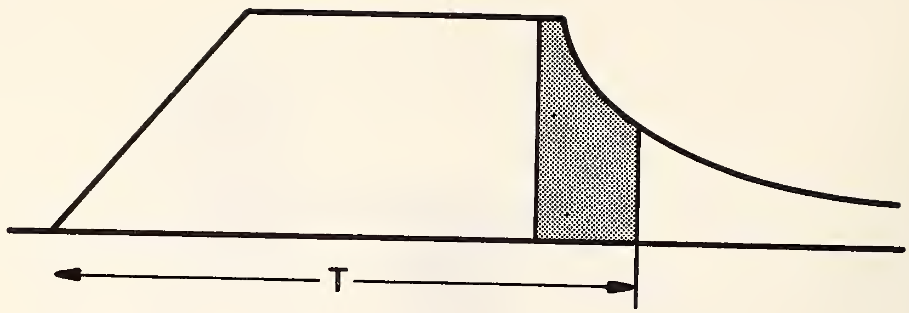
P = QRTE

$$\Pi = \frac{1}{2*TELI + TECO + TEXP - T + 1}$$

$$T_4 = 2*TELI + TECO \; ; \; \Pi_4 = \frac{1}{TEXP + 1}$$

$$QRTE = \frac{R}{2*TELI + TECO + TEXP - T + 1}$$

(5) Regime #5



$$R = \text{as before} = QRTE * (2*TELI + TECO + TEXP - T + 1)$$

$$P = QRTE * (2*TELI + TECO - T + 1) + E * QRTE$$

$$E = \int_{o}^{T-2*TELI-TECO} \exp\left(\frac{-s}{TEXP}\right) ds \qquad = - TEXP* \int_{o}^{T-2*TELI-TECO} \exp\left(\frac{-s}{TEXP}\right) ds$$

$$= -TEXP* \quad -1 + \exp\left(-\frac{T-2*TELI-TECO}{TEXP}\right) \quad *QRTE$$

$$P = QRTE* (2*TELI*TECO-T+1) + TEXP*(1 - \exp\left(-\frac{T-2*TELI-TECO}{TEXP}\right))$$

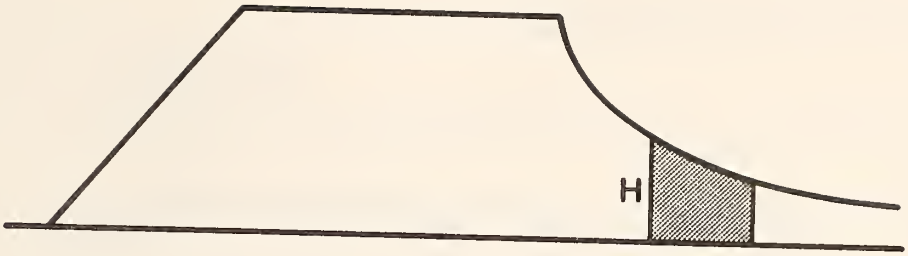
$$\Pi = \frac{2*TELI + TECO - T + 1 + TEXP *(1 - \exp\left(-\frac{T-2*TELI - TECO}{TEXP}\right))}{2*TELI + TECO + TEXP - T + 1}$$

$$T_5 = 2*TELI + TECO + 1$$

$$\Pi_5 = \frac{TEXP * (1 - \exp(\frac{-1}{TEXP}))}{TEXP} = (1 - \exp\left(\frac{-1}{TEXP}\right))$$

$$QRTE = \frac{R}{2*TELI*TECO + TEXP - T + 1}$$

(6) <u>Regime #6</u>



$$R = TEXP*H \;;\; H = QRTE*^{\exp\left(-\frac{T-1-2*TELI-TECO}{TEXP}\right)}$$

$$P = QRTE* \int_{T-2*TELI-TECO-1}^{T-2*TELI-TECO} \exp\left(\frac{-s}{TEXP}\right) ds$$

$$= QRTE*\; TEXP* \left[\exp\left(\_\frac{T-2*TELI-TECO}{TEXP}\right) - \exp\left(\_\frac{T-2*TELI-TECO-1}{TEXP}\right)\right]$$

$$= QRTE*TEXP*\; \exp\left(\_\frac{T-2*TELI-TECO-1}{TEXP}\right) * \left(1 - \exp\left(\frac{-1}{TEXP}\right)\right)$$

$$\Pi = \frac{QRTE*TEXP*\exp\left(\_\frac{T-2*TELI-TECO-1}{TEXP}\right) * \left(1 - \exp\left(\frac{-1}{TEXP}\right)\right)}{TEXP * QRTE* \exp\left(\_\frac{T-2*TELI-TECO-1}{TECP}\right)}$$

$$\boxed{\begin{array}{l} \Pi = 1 - \exp\left(\frac{-1}{TEXP}\right) \\ \\ QRTE = \dfrac{R}{TEXP * \exp\left(\_\frac{T-2*TELI-TECO-1}{TEXP}\right)} \end{array}}$$

(7) Summary:

a) P/R - ratio break points:

$$\Pi_1 = \frac{1}{4*TELI*(TELI + TECO + TEXP)}$$	Regime #1 / Regime #2
$$\Pi_2 = \frac{4*TELI - 1}{4*TELI*(TECO + TEXP) + 4*TELI - 1}$$	Regime #2 / Regime #3
$$\Pi_3 = \frac{1}{TECO + TEXP}$$	Regime #3 / Regime #4
$$\Pi_4 = \frac{1}{TEXP + 1}$$	Regime #4 / Regime #5
$$\Pi_5 = 1 - \exp\left(\frac{-1}{TEXP}\right)$$	Regime #5 / Regime #6 (constant form Regime #6)

b) Π,QRTE formulas:

$0 < \Pi < \Pi 1$: $$QRTE = \frac{R}{TELI+TECO+TEXP}$$

$$\Pi = \frac{T^2}{4*TELI*(TELI+TECO+TEXP)}$$

$\Pi_1 < \Pi < \Pi 2$: $$QRTE = \frac{4*TELI*R}{4TELI*(TELI+TECO+TEXP) - (T-1)^2}$$

$$\Pi = \frac{2*T-1}{4TELI*(TELI+TECO+TEXP) - (T-1)^2}$$

$\Pi_2 < \Pi < \Pi_3$: $$QRTE = \frac{4*TELI*R}{4TELI*(TELI+TECO+TEXP) - (T-1)^2}$$

$$\Pi = \frac{4*TELI-(2*TELI+1-T)^2}{4TELI*(TELI+TECO+TEXP) - (T-1)^2}$$

$\Pi_3 < \Pi < \Pi_4$: $$QRTE = \frac{R}{2*TELI + TECO + TEXP + 1}$$

$$\Pi = \frac{1}{2*TELI + TECO + TEXP + 1}$$

$\Pi_4 < \Pi < \Pi_5$: $$QRTE = \frac{R}{2*TELI + TECO + TEXP + 1}$$

$$\Pi = \frac{2*TELI + TECO - T + 1 + TEXP*\left(1 - \exp\left(-\frac{T-2*TELI-TECO}{TEXP}\right)\right)}{2*TELI + TECO + TEXP + 1}$$

$\Pi_5 < \Pi$: $$QRTE = \frac{R}{TEXP} * \exp\left(\frac{T-2*TELI-TECO-1}{TEXP}\right)$$

$$\Pi = 1 - \exp\left(\frac{-1}{TEXP}\right)$$

c) <u>Continuity checks:</u>

$$T_1 = 1 : \quad \Pi_1^- = \frac{1}{4*TELI*(TELI + TECO + TEXP)}$$

$$\Pi_1^+ = \frac{1}{4*TELI*(TELI + TECO + TEXP)}$$

$$T_2 = 2*TELI : \quad \Pi_2^- = \frac{4*TELI-1}{4*TELI*(TELI + TECO + YEXP) - (2 \cdot TECI-1)^2}$$

$$\Pi_2^+ = \frac{4*TELI-1}{4*TELI*(TELI + TECO + TEXP) - (2 \cdot TELI-1)^2}$$

$$T_3 = 2*TELI+1 : \quad \Pi_3^- = \frac{4*TELI}{4*TELI*(TECO + TEXP)} = \frac{1}{TECO + TEXP}$$

$$\Pi_3^+ = \frac{1}{TECO = TEXP}$$

$$T_4 = 2*TELI+TECO : \quad \Pi_4^- = \frac{1}{TEXP + 1}$$

$$\Pi_4^+ = \frac{1 + TEXP*(1-1)}{TEXP + 1} = \frac{1}{TEXP + 1}$$

$$T_5 = 2*TELI+TECO+1 : \quad \Pi_5^- = \frac{0 + TEXP* \quad 1 - \exp\left(\frac{-1}{TEXP}\right))}{TEXP} = 1 - \exp\left(\frac{-1}{TEXP}\right)$$

$$\Pi_5^+ = 1 - \exp\left(\frac{-1}{TEXP}\right)$$

Note 31 Calibration of tentative distribution loss rates (p. 71)

These 4% have nothing to do with the 4% loss assumed for transmission losses, that is, pipeline fuel. The setting of a tentative distribution loss rate can be calibrated by comparing the actual total national production with the total national production as calculated by MARKET. In April 1982, a set of such calibration experiments was performed by BNL and NBS, and a tentative distribution loss rate of 4% was found to lead to a reasonable agreement between observed and calculated production.

The tentative distribution loss rate is a parameter of the MARKET model. It is called "tentative", because it may be boosted by the model during the base year at selected nodes in the case of so called "market adjustments" (See Note 32).

Note 32 Market adjustments (p. 72, Note 31)

The minimum acceptable flow of each node should be adjusted as needed for different networks and data. The purpose of the adjustment is not just to exhibit a positive flow in the base year, but to provide a cushion to keep flows positive during the following model years. A typical rule for defining flow is that the total secondary inflow into a node should not exceeds its primary inflow. Currently it is also required that the primary inflow is not exceeded by 1.5 times the excess of secondary outflow over secondary inflow. This rule guarantees that the primary outflow is more than one half of this excess, and is designed to limit the dependency of burnertip prices on the costs of secondary sales. This rule is responsible for the majority of the current market adjustments, which are typically below 1% of the total consumption.

Note 33 Transmission tariff adjustment (p.75, Note 25)

Mechanically, the tariff adjustments are handled by associating a tariff adjustment factor (RTAFV) with each node in a system network. A multiplicative correction factor for transmission tariffs, that is, an RTAFV value associated with P-nodes, is calculated as follows.

Note that the price $\overline{P}_o$ of primary supplies at the root node, as calculated from the citygate prices by the backwards averaging procedure described above, is a linear function

$$\overline{P}_o = a + \sum m_i \cdot M_i + \sum n_i \cdot C_i$$

of the tariff parameters M_i and C_i for all those system nodes that participated in the procedure. The coefficients a, m_i, n_i, depend only on primary and secondary flows, secondary costs, and citygate price levels. If the tariffs in the above expression are multiplied by a single variable x, then a linear function in x results:

$$P_o(x) = a + (\sum m_i \cdot M_i + \sum n_i \cdot C_i) \cdot x = a + b \cdot x$$

with

$$P_o(1) = \overline{P}_o .$$

Instead of calculating a and b directly, which would be too complicated, the model repeats the backward averaging procedure with all parameters halved. This then provides the value

$$P_o(1/2) = a + b \cdot 1/2 .$$

The question is: what value x will yield

$$P_o(x) = P_o ,$$

where P_o is the target price at the root? All one has to do to answer this question is write P_o as weighted mean

$$P_o = \lambda \cdot P_o(1) + \mu \cdot P_o(1/2), \quad \lambda + \mu = 1,$$

which amounts to solving a linear system of two unknowns, and then combine the adjustment factor x from the values 1 and 1/2 with the weights so calculated:

$$x = \lambda \cdot 1 + \mu \cdot 1/2.$$

For several systems, it was found that a full reconciliation between citygate prices and reserve prices was not possible without adjusting negative add-on tariffs. This conflicts to some extent with the concept of multiplicative adjustments. S. Wade of BNL has therefore modified the transmission tariff adjustment scheme by including additive adjustments and by assigning an artifical compensatory add-on tariff at the root-node.

Note 34 Distribution tariff adjustment (p. 75, Note 11)

The modeling effort was particularly hampered by the absence of sufficiently detailed burnertip price information for the base year. The MARKET model was therefore forced to estimate burnertip prices from known citygate prices using estimates of tariff mark-ups. The latter were obtained by applying the Guldmann distribution tariff module. The strength of this procedure is that it displays the correct "dynamics", but it is not well suited to the actual reproduction of base line data, because it is based on national averages and does not capture local behavior. The baseline of burnertip prices for the base year as calculated by the above procedures is therefore not a fully satisfactory substitute for actual data, necessitating an adjustment of the distribution tariffs associated with M-nodes. Adjustment factors for these tariffs are desired so as to approximate given averages of burnertip prices by state and end-use sector in the base year. The end-use sectors considered here are the main sectors: residential, commercial, industrial, electric utilities. In order to calculate these adjustment factors, burnertip prices are first determined on the basis of nonadjusted distribution tariffs. These tentative burnertip prices are averaged, with volume weights, by State and end-use sector. Each such average is compared with the corresponding target value and a correction factor is derived. By multiplying the burnertip price at each M-node with the correction factor that is associated with the State and the end-use sector of the M-node, we determine at each M-node a desired burnertip price.

At each M-node, except those serviced by direct sales distributors, the difference between the desired and the tentative burnertip price is to be absorbed by multiplicatively adjusting the tariff parameters of the M-node. This requires that these parameters are not both zero, which is why direct sales customers have been excluded. For all other M-nodes i, let

j = predecessor of M-node i (j is a D-node)

$\overline{P}_i$ = tentative price level at M-node i

P_i = desired price level at M-node i

Q_i = primary supply at M-node i

$\overline{P}_j$ = tentative price level at D-node j.

Then the adjustment factor x must satisfy:

$$M_i \cdot x + \frac{C_i \cdot x}{Q_i} = (\overline{P}_i - \overline{P}_j) \cdot x = P_i - \overline{P}_j \; .$$

Hence

$$x = \frac{P_i - \overline{P}_j}{\overline{P}_i - \overline{P}_j} \; .$$

Because of limiting the adjusted tariffs mark-ups to nonegative values and because the burnertip prices of direct sales customers will not be changed -- their burnertip tariff mark-up is zero and therefore not affected by multiplicative adjustments -- , the average adjusted burnertip prices will only approximate their target values. Again, the step of admitting negative tariff mark-ups has been taken by EIA. The corresponding change from a multiplicative to an additive adjustment scheme has been developed by S. Wade of BNL, but as of the time of this report has yet to be incorporated into production versions.

Note 35 Seasonality of supply at the citygate (p. 77)

Spreading secondary supplies equally over both seasons is a controversial judgemental assumption concerning the semiannual mode of operating the MARKET model. An analysis of this assumption ties in with questions concerning the use of storage. Indeed, if a secondary flow from one pipeline system to another occurs predominantly during the heating season, then the first system storage requirements are increased whereas those of the second system are decreased. Finetuning the seasonal variations in secondary transactions should therefore go hand in hand with a detailed exploration of storage availability and use.

The storage capacities owned by the various pipeline and distribution companies are available data. There is a major difficulty, however, in that storage ownership and storage usage do not coincide. So far NBS has not been able to determine a pattern of storage using indicating whether a company is able to satisfy its storage needs by using its own facilities or whether it leases storage and, if so, from whom.

Note 36 On failure of equilibration (p. 78)

The issues surrounding "failure of equilibration" have been the topic of extensive discussions and controversies during the development of the MARKET model. These issues are summarized in a 6/11/83 memorandum to EIA from C. Witzgall. This memorandum is quoted verbatim below:

I have become increasingly aware of a need for clarifying issues concerning "failure of equilibration" (FOE). Please do read and react to the following ideas and concerns because they affect the planning and mode of operation of GAMS development.

1) Why are there FOEs

Basically, a FOE indicates that the supplies of a pipeline system are priced too high at the wellhead, resulting in burnertip prices which are to high for consumers to accept. Whether consumers in a given market will or will not accept a given price, depends on the demand curve specified at that market. A FOE is thus caused by a mismatch between supply and demand as modeled by GAMS.

While a FOE may indicate a true market failure, it is more likely caused by glitches in model procedures. A discussion of potential remedies is one of the purposes of this memo.

2) Friend or FOE?

Should FOE's be avoided at all reasonable costs? The answer depends on the part of GAMS you are talking about. MARKET, for one, is the messenger of bad tydings. We thus ask more specifically, should Market refrain from producing FOEs?

This question is still ambiguous. It may be ionterpreted in two ways:

a) Should MARKET abend GAMS because of a FOE?

b) Should MARKET be made "robust" so that FOEs don't happen in the first place?

The second question is of greater concern to me, and I would like to discuss it first.

3) BID/AWARD has responsibility to avoid FOEs!

This statement will be qualified below. However, it basically stands: The purpose of the BID/AWARD routine is to make sure that each pipeline system acquires sufficiently many new reserves at prices that will be acceptable with respect to specified demand curves. This may not be possible for a given set of market parameters, because these parameters would not support the gas market in real life. In this case, FOE is for real and constitutes a legitimate model result.

In most cases, however, the FOE will be the result of the way the bidding procedure is modeled: if the bidding goes too high compared to available demands, then there will be a FOE. The FOE is simply a signal to the BID/AWARD routine that it needs adjustment. In this function, FOE is a friend. Under certain circumstances, it may well be desirable to "bail out" a pipeline system which experiences a FOE, rather than to abend the entire GAMS run. However, to completely avoid the occurrence of FOEs by means fair and foul would not be in the best interests of the developers of BID/AWARD.

4) Concern with present mode of operation

Presently, new MARKET versions are run with an antiquated version of BID/AWARD, and the criterion of success is avoidance of FOE. Some of that is quite justified. The danger to guard against is to make model adjustments in MARKET simply so as to make it perform without FOE for a specific BID/AWARD pattern. If this pattern then changes, the MARKET adjustments may turn out to be unneccessary or even counter-productive, once a new BID/AWARD routine is installed.

5) Not all is the fault of BID/AWARD

In order to be successful, BID/AWARD needs

a) anticipation of supply price developments.

b) anticipation of demand.

It is clear that without reasonably correct anticipation in the supply and demand areas, BID/AWARD will not be able to prevent shortages or FOEs.

In addition, BID/AWARD may be done in by spurious FOEs, resulting from design inadequacies in MARKET.

6) Anticipating supply and demand

The need for BID/AWARD to anticipate prospective regulatory/deregulatory price movements is well recognized, and no elaboration on this point is needed.

Demand anticipation is a different story. The main source for this information is provided by MARKET during its demand projection phase. The demand projections currently suffer from the fact that secondary volumes and prices are kept constant in overly optimistic assessments, especially for later years. Discounting would help as well as making secondary volumes price-sensitive. The latter feature has been coded and tested, but still awaits inclusion into the production package.

7) Demand anticipation on the demand file

The basic source for estimating demands is the specification via input of annual reference volumes and prices for each demand region and end-use sector. These numbers are used as indexes for the reference volumes and prices at the individual markets. Under the old log-linear demand procedure, these reference volumes and prices are the primary determinants of demand. Under the new procedures, their influence is drastically reduced. In both cases, however, the understanding is that the reference volumes and prices represent a point on the regional demand curve for the year in question.

Should the demand file be altered to reflect an anticipated price hike? The answer is no, unless a corresponding drop in volumes is also included. Increasing just the price would in effect signal increased tolerance to price increases. While this would make it less likely that a price increase would result in FOE, it appears to be not justifiable on any factual basis.

8) Minimum demand levels.

A more justifiable means of demand stabilization is to impose minimum demand levels regardless of price.

The demand/supply equilibration in MARKET is formulated in terms of unit prices rather than marginal prices. This feature, together with fixed charges resulting from demand rates and predetermined secondary transactions, is responsible for the fact that prices occasionally grow very large. Indeed zero consumption in the presence of a fixed charge will lead to an infinitely high unit price. It may well reach a level at which demand curves, say log-linear ones, become very small if not zero. Demand will then be choked off and FOE results.

Dramatic drop-off in demand, say below one half of the reference volume is not realistic, and it is therefore recommended to maintain minimum demand levels at least for residential and commercial end-use-sectors. This would make demand more robust and thereby prevent unnecessary FOEs.

Tariff calculations may also be thrown out of whack if consumption becomes unrealistically small. The next section will provide a procedural reason for minimum demand levels.

9) Two types of FOE.

There are two different situations in the computer program, in which a FOE is declared. The first is simply a failure of pipegate supply and demand curves to overlap. The second situation is the persistent occurence of a negative flow beyond tolerable limits. This is a local phenomenon. It will be discussed later in more detail.

For now it suffices to note that in the presence of some minimum demand levels, demand and supply curves will always intersect, and the only FOE that can therefore occur is of the local kind involving negative flows. This knowledge is useful since fewer possibilities need be considered in diagnosing the reasons for a FOE.

10) <u>FOE during demand iteration</u>.

During the first iteration, parameters may assume unrealistic values and thereby cause a FOE. This FOE does not occur once the iteration parameters have settled down. Thus the model will run successfully once it gets past the first iteration.

Remedies are: good initial values plus anything improving robustness as, for instance, minimum demand levels.

11) <u>FOEs due to secondary quantitites</u>.

Secondary quantities currently stay either fixed (P-P arcs), are predetermined (imports), or are estimated on the basis of last year's results. In all these cases there is lack of anticipation of major supply price movements. In the model, the pipeline systems are thus likely to be caught <u>undercharging</u> or <u>overdelivering</u> on secondary sales.

The effect of undercharging is serious for systems with predominantly secondary sales (#13, #14, #8). This is because in the model, pipeline systems must recoup losses from secondary sales by increasing the price for primary ones. The resulting price increase at primary markets may stifle demand to the point of a FOE.

Overdelivering on secondary sales -- and this includes imports -- will cause <u>negative flows</u>, as incoming secondary volume exceeds demand. This also can cause FOE.

There is an almost sure-fire curve for both these problems: use equilibration with the secondary quantities as estimated currently in order to get a fairly correct estimate of the supply prices from the reserve prices of the actual model year, and to reduce observed overdeliveries. Then equilibrate again. This additional equilibration doubles equilibration time (but not the larger time required for NXTSYS). If one is unwilling to invest this time, then various stop-gap measures can be taken, which are discussed below.

For IFFS/GAMS integration, the information from a previous iteration could be used to improve the modeling of secondary quantities.

12) <u>Improving secondary price estimation</u>.

M. Minasi has proposed to <u>input yearly escalation factors</u> which would reflect anticipated supply price increases. These escalation factors would be used to improve secondary price estimates by providing missing anticipation. This simple device may go a long way towards improved secondary prices, but does not address the problem of overdeliveries.

13) <u>Adjusting the network</u>.

Experience has shown that certain "trouble spots" exist in the network: these are downstream nodes with a high incidence of negative flows, although the demand involved is very small (typically less than 10,000 BBTU). Furthermore, this reduction in secondary supply does not affect the quantity of supplies available overall: it just reroutes supply from one pipeline system to another. The elimination of such trouble spots can be regarded as a legitimate part of the network generation process.

The model has a build in "market adjustment" procedure, which boosts demands if necessary to ensure that, in the base year, primary flows exceed a fractin of the total adjacent secondary inflow. This fraction is currently set at .5. The resulting market adjustment is very small, and would remain negligible even if the fraction was increased to, say, .6. This would also increase robustness of the model.

14) Imports

Since imports are hardwired, they may cause FOE. Some limited rearrangement of imports within a pipeline system is possible. To gear import prices automatically to world oil prices would help. Even more beneficial would be the capability to treat some imports as production from a pseudoreserve in the GRST table.

15) "Bail outs"

Sometimes it is undesirable to stop GAMS because of a FOE. To "bail out" the affected pipeline system, either demand must be boosted, or supply prices reduced, prior to a subsequent new try at equilibration.

Boosting demand can be achieved by increasing reference prices at the markets: this will increase the tolerance of consumers to price rises. Of course, reference volume may be increased also, effecting an even more direct increase in demand. Such demand increases may be restricted to occur down stream from arcs with negative flow problems, and therefore be small enough not to affect overall model results.

Reducing supply prices is problematical, because it is difficult to assess how this would influence the bidding procedure -- bid prices being then not really binding -- and because this may interfere with supply price scenarios.

Neither the implementation (logically a new level of loops) nor the understanding of the effects of a "bail out" is easy.

A possibility is a "silent bail out", by ignoring negative flows entirely. Suitable warning messages would have to be posted, since the conservation of flow principle may now be seriously jeopardized.

Note 37 Distribution in the case of excess demand (p. 81)

In the case of excess demand, the question arises how to distribute the available resources. If some market represented by an M-node in a pipeline system receives less than it would be willing to consume at the specified price, then we say that this market has been "curtailed". Curtailment in the model is not of a short term nature: it represents a shortage extending over an entire season. It would be especially serious if it extended to residential or commercial markets. In the case of the industrial and utilities end-use subsectors with residual fuel oil capability, a curtailment of the above kind would not necessarily be serious. In this case, it would rather highlight the opportunistic (no value judgement!) market behavior that is characteristic for these end-use subsectors.

For these reasons, an order of service priority has been established, and each distributor serves residential customers before commercial customers, and so on (see Section 4.2.3). The problem with the current version lies in the way delivery is made to the distributors themselves: their supply is curtailed by the same fraction for all D-nodes in the pipeline system. If a distributor has only residential customers, then he must curtail them, whereas if the distributor has industrial customers, the latter may be able to absorb the curtailment so that the commercial and residential end-use customers are fully served. Whether a residential market will be curtailed thus depends, in the MARKET model, on the sector profile of the distributor serving the market. This obvious inequity has not had a major effect on model results so far, because the incidence of excess demands in final model results was minor, and also because of the inclusion of so called "888 gas" reserves (see Note 15). This "888 gas" from pseudo-reserve blocks representing synthetic and expensive alternatie gas sources. The price of this gas is set sufficiently high to enter the picture only in case of a shortage. The "888" artifice effects the residential sectors mor than the other sectors because of the low elasticity of the former.

The amount of curtailment in the result of an equilibration is of considerable interest to the analyst and should therefore be compiled by the MARKET model by State and end-use sector. In the presence of "888" gas, this cannot be done because, the amount of "888 gas" at the pipegate can be readily determined at the burnertip.

Note 38 Tolerance limit for negative flows (p. 85)

At the time of this report, the negative flow tolerance is set at 25% of the total secondary inflow or 2000 BBtu, whichever is bigger.

Note 39 Averaging of seasonal prices (p. 86)

The fact that the price averaging method is only approximate for prices at the root node, if secondary inflow or outflow are present, does have undesirable effects during the demand projection phase, where it leads to a slight inconsistency between the stipulated pipegate price and the one calculated by averaging. To correct this shortcoming, and also to permit a certain consistency check, the correct formula for calculating annual prices has been included by NBS in a developmental version of semiannual equilibration, but is not yet included in production versions.

Note 40 Estimation of the number of customers (p. 87)

The estimation of the number of customers, in particular, residential customers, is a recognized weakness of the GAMS system. The roots for this shortcoming lie in the demand modeling portion of the system, for which NBS did not have responsibility (see Note 20). We contend that a proper representation of "shortterm" and "longterm" elasticity requires a two-tier modeling approach in which the effect of price on average usage per customer and changes in the number of customers depending on price are estimated separately.

Note 41 General remarks about updating secondary transactions. (p. 89)

It is clear that the estimation of next year's prices for secondary outflows is very rough. Moreover, this estimation is based entirely on results for the current year. Should there be any major changes in supply prices caused, say, by deregulation, the price estimates will not reflect this development. Since the prices determine the quantities vis the equal cost shares assumption, the estimate of secondary volumes is also problematic.

For the purposes of a general discussion of this problem we recapitulate briefly the role of secondary transactions. They are distinguished from primary transactions, on the basis of a 1980 snapshot of supply relationships compiled from Form EIA-50, by designating dominant suppliers as primary. Each node in the base network is connected via a unique string of several primary arcs to a root node. All nodes connected to the same root node define a pipeline system (see Section 3.4.1).

The volumes and prices of secondary transactions are specified prior to equilibration, for which they serve as a boundary condition (See section 4.2.2). The equilibration can then be carried out in an efficient and straight-forward manner, because each demand curve is connected to a single supply curve. As a consequence of the latter observation all demand curves in a pipeline system can be thought of as combining into a single root demand curve, which then can be matched against the supply curve in classical fashion (see Section 3.9). After two seasonal equilibrations the secondary flows and prices are reestimated on the basis of retaining expected (financial) market shares among suppliers of the same node (Section 4.3). These estimates then serve as boundary conditions for next year's equilibration. In Operations Research parlance: we set up a decomposition method and abort it after the initial iteration step.

The different treatment for primary and secondary arcs is not entirely without parallel in reality. In many instances, a distribution company will have a major and a minor supplier, with strong contractual obligations to buy from the minor supplier. Indeed, the minor supplier will be needed in times of high demand, and will insist on contractual protection in return for his availability. Also a shift away from expected demand may hit the minor supplier relatively harder. (In view of these considerations, one would expect deliveries by minor suppliers to occur predominantly in the heating season. This clashes with another assumption of the model, namely that all secondary supplies are divided equally between seasons.

By halting the equilibration process early, we hope to preserve some of the qualitative take-or-pay aspects of secondary transactions. In addition, we avoid the extensive computational effort of additional iterations. However, the effect of secondary arcs on the functioning of the model may be more pronounced than anticipated. Although their total influence on model results is minor, secondary transactions do cause trouble spots in the base network and consequently led to unnecessary failures of equilibration.

Two typical problem situations occur. In the first such situation, a secondary inflow occurs at a system node with a comparatively small sales potential. A price increase in the system may well reduce the demand at this system node below the fixed inflows from the secondary arc. Thus a "negative flow" would be required to balance the in-and outflows of gas for this system node (see Section 4.2.4). In the second situation, a small "intrastate" pipeline system has a secondary outflow which exceeds the primary demand considerably. Systems 13 and 14 are prime examples. In these cases, a sudden price increase at the wellhead may cause a price imbalance because the secondary revenues are based on the price expectation of the previous year and may therefore be priced too low. In the current version, the ensuing losses are recouped by price increases to primary customers which may be unrealistically high.

A somewhat academic problem is the occasional overpricing of secondary outflows, the revenues from which may exceed the total cost of supplies (see "negative prices" in Section 4.2.4)

All these problems are caused by the reliance on past year's results in order to estimate the prices and from these, via the equal market shares assumption, the volumes of secondary transactions. If the results of the ensuing equilibration, or a modification thereof, would be used to reestimate secondary transactions for the current year, thus permitting current pipegate supply prices to affect the estimation of secondary transactions, then the aforementioned problems may well disappear. This amounts, of course, to executing the second step of an iterative decomposition procedure, and the question arises, whether the iteration should be continued, if possible to convergence. We surmise at this time, that two iterations will be sufficient for the purpose of making the equilibration procedure more robust and of improving the quality of secondary estimates, while preserving some of the desirable qualitative effects of fixed boundary conditions. We are also hesitant to recommend more iterations because of the difficulties involved in monitoring the performance of such iterations for large systems, in particular, since each of these iterations already contains several nested levels of iterations.

Note 42 Effect on secondary transactions of sudden loss in primary volume (p. 89)

Suppose that the primary supply of a node dropped suddenly to QEPS = 1BBtu (the smallest permissible quantity) from, say, 50,000 BBtu. Typically this happens in the presence of secondary supplies of say 40,000 BBtu, if a negative flow within tolerance limits was encurred. In order to enforce the equal cost shaver assumption, the secondary volumes are -- provided there are no major price changes -- multiplied by a factor of roughly reduced to zero for the next year. In that year's equilibration, the primary supplier is therefore without competition and will consequently bounce back to a healthy level, say, 35,000, which causes the secondary supplier to be blown yp accordingly. In this oscillatory process, the danger of negative flows beyond the tolerance level is ever present.

It is to guard against this and similar drains of events, that measures are taken to prevent large changes in secondary volumes. In particular, secondary volumes may not be decreased by more than 50% or increased by more than 25% in a single year.

Note 43 Elasticity of demand projections (p. 92)

During the demand projection process, secondary quantities and prices are kept constant (see Section 4.5) throughout the entire projection period. This leads to certain distortions of the system demand elasticity, in particular, for prices which deviate strongly from the last pipegate price calculated by the model. What is needed to improve the elasticity of demand projection are simple plausibility assumptions about how secondary transactions would be affected by primary price changes. A very straightforward modification rule would be to keep, for the first projection year only, the secondary transactions at the same volumes as during the last year for which modeling has been completed; to determine prices of secondary sales from the prices of primary and secondary supplies and to employ equal market share rules to update secondary volumes for all subsequent projection years.

Note 44 Experiments with passes through Form EIA-50 (p. 99)

In an experiment conducted with the pipelines listed in Table 5.1, 1202 nodes were on the node list after 2 passes and no additional nodes were added beyond the fifth pass at which time there were 1242 nodes on the list and 224 nodes which would never be included by additional passes.

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☐ Document describes a computer program; SF-185, FIPS Software Summary, is attached.

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This report describes the MARKET submodel, one of three that combine to form the Gas Analysis Modeling System (GAMS). GAMS was developed for use by the Energy Information Administration of the U.S. Department of Energy. It provides a tool for analyzing the regional effects on the domestic natural gas market of various policies for regulating the price of natural gas at the wellhead. MARKET is concerned with the production of gas reserves and the transmission and distribution of gas to consumers. It solves a network equilibration problem to arrive at estimates of production quantities and prices.

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