Final Report On

THE ALLOCATION OF INCREASING GAS SUPPLIES IN OHIO

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EXECUTIVE SUMMARY

The study reported on in the enclosed three volumes was requested by the Public Utilities Commission of Ohio (PUCO) to assist it in the formation of policies concerning the allocation of increasing gas supplies in Ohio.

There is a great number of potential new service policies that could have been subjected to evaluation in this study. Generally potential new service policies can be defined in terms of (a) the type of customer to receive new service, (b) the location of the customer in relation to the existing distribution system, and (c) the contractual arrangement under which the new service is to be provided. The potential of introducing combined policies in terms of the above categories and the differentiation of policies in terms of time of implementation increases vastly the number of policies that need to be analyzed.

Due to time and budget limitations only representative new service policies were studied under alternative assumptions concerning future conditions, especially those related to the availability of various types of energy and associated prices. In particular, four policies were analyzed under seven energy scenarios. The four policies are:

1. No New Service Policy - the present ban is continued;

2. Company Initiative Policy - this policy permits the company to provide new service within the supply limits and in a particular order of customer classes. Residential, commercial, and industrial customers within the currently served areas are hooked-up in sequence, followed by residential customers outside the currently served areas;

3. Selected Residential Service - only residential customers within the currently served areas are hooked-up;

4. Industrial Service - only industrial customers within the currently served areas are connected.

The mere existence of a multitude of possible new service policies suggests that the choice of the preferred policy be based on the capacity of the policy to satisfy regulatory objectives. Among the traditional objectives of regulatory policies are concerns for financial stability of the regulated utility and adequacy of the quantity and quality of the supplied services. More recently, due to the newly revealed energy scarcity and the associated growth in utility bills, regulatory policies have been increasingly subjected to evaluations in terms of changes in production and end-use efficiency and in terms of fairness and the redistribution of income that they induce.

The analysis of these policies was carried out with the regulatory simulation model that was developed for this purpose. The results were obtained by applying the model to the East Ohio Gas Company (EOGC). It is important to note that the extent to which the results indicate differences in achievement of the various regulatory objectives is a function of differences in policies and scenarios only. No other exogenous forces were permitted to influence the results. Differences in the achievement of objectives by policies cannot be attributed to changes in the behavior of the EOGC or the PUCO.

Table 1 contains a summary of policies ranked in terms of the desirability of their impacts on utility finances, on customers, and on net aggregate economic efficiency as calculated for the EOGC's service area. These results are based on averages of annual impacts only. No reference is made to the time incidence of the impacts.

Table 1 Policy Rankings by Type of Impact Based on Simulations for the Period 1978-2000

Policy	Rankings in Terms of		
	Impact on Utility Finances	Impact on Customers	Impact on Net Aggregate Efficency
No New Service Policy	3	1	4
Company Initiative Policy	2	4	1
Selected Residential Policy	1	2	2
Industrial Only Policy	3	3	3

The choice of the preferred policy is made difficult by a number of factors. Above all, the extent to which some of the regulatory objectives are attained and the repercussions of several policies in terms of the various criteria cannot be measured accurately. In addition, the comparison of policies in terms of their achievement of all the objectives is not possible because of the non-existence of an aggregate measure. The lack of such a measure is due to the fact that the standards by which the attainment of the objectives is measured are not equivalent.

Yet, even the limited information contained in Table 1 is too rich to yield an objective and unambiguous choice of the preferred policy. All policies, except the industrial only policy, emerge as the preferred policy in terms of at least one of the impact criteria used in this study. Two of the policies considered emerge as second best policies. Thus, concern for the company finances alone would lead the decision-maker to choose the selected residential policy as a guide for new service offering by Ohio's gas distribution companies. Concern for customers alone would lead the same decision-maker to prefer the current ban as the preferred policy. Concern for economic efficiency, on the other hand, would lead the decision-maker to select the selected residential policy. The choice of the preferred policy depends on the relative importance, in the form of weights, that decision-makers attach to the decision criteria.

No full-scale attempt has been made to select the preferred policy under various assumptions concerning the relative importance of the decision criteria. An examination of the results reveals, however, that in some cases the selected residential policy is clearly preferred. In other cases, where the policy is not ranked as the preferred policy, it is almost indistinguishable from the preferred policy. Overall, it is ranked as the best policy in terms of impacts on utility finances and second best in terms of impacts on customers and on economic efficiency.

Finally, these results are valid for the EOGC only. Generalizations based on these results may be subject to errors due to circumstances that could be unique to the EOGC service area. The determination of precise new service policies for other companies could benefit from a similar analysis with the regulatory simulation model.

ACKNOWLEDGEMENTS

Many individuals contributed to the completion of this study. During various stages of research the project benefited from the able assistance of Mr. Robert Indian, Mr. Ali Rabbani, and Ms. Janet Ruggles. Mr. James Detwiler provided his drafting expertise. Professors Oscar Fisch, Steven Gordon, Wilpen Gorr, Kenneth Pearlman, and Burkhard von Rabenau were kind enough to provide us with monthly gas consumption data. We have gained many insights through discussions with Mr. James Balthaser and Ms. Hollie Mion of the Public Utilities Commission of Ohio (PUCO), Mr. Robert Koblenzer and Mr. Michael Bartels of the East Ohio Gas Company, and Dr. Kevin Kelly, Associate Director of the National Regulatory Research Institute (NRRI). Mr. Dennis Yun and Mr. Thomas Flockens helped to adapt the computerized model to facilities at the disposal of the PUCO. Finally, the project staff would like to thank the secretaries at NRRI who patiently endured with us the final execution of the report.

PREFACE

The study reported on in the enclosed three volumes was requested by the Public Utilities Commission of Ohio (PUCO) to assist it in the formation of policies concerning the allocation of increasing gas supplies in Ohio. In the early research stages the National Regulatory Research Institute (NRRI) team proposed an economic-engineering model for analyzing the repercussions of new service policies in the case of one gas distribution company. The results of such analysis were to serve as a basis for generic recommendations. At the same time it was recognized that the computerized model would be useful for the analysis of new service policies on a company by company basis.

In light of those research objectives the report is divided into two major parts. An overview of the analysis together with a complete statement of findings is presented in Volume I. Volume I is intended for those readers interested in general policy issues and in the basis for choosing preferred policies from the many alternatives. Volume II is intended for those readers who will use the computerized model. In this volume the means of constructing the model and the meaning of its results are explained in the context of an application. Since each volume is intended to be self-contained, there is some repetition of information. Volume III is composed of appendixes to the information contained in Volume II.

Volume II:

A SIMULATION MODEL FOR THE ANALYSIS OF THE ALLOCATION OF INCREASING GAS SUPPLIES

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CHAPTER 1

INTRODUCTION

This volume is second in a series of three volumes that represent the final report on the allocation of increasing gas supplies in Ohio submitted to the Public Utilities Commission of Ohio (PUCO) by the National Regulatory Research Institute (NRRI). While Volume I is intended to provide readers with a brief overview of the analysis and a complete statement of findings, the purpose of this volume is to provide a detailed description of the regulatory simulation model that was developed for the analysis of new service policies. Volumes I and II are intended to be self-contained. Volume III is composed of appendixes to the information contained in Volume I and II, and as such contains data and information that is of interest to readers who intend to use the model.

The content of this volume is organized according to the logical structure of the analysis performed with the help of the regulatory simulation model. Thus, Chapter 2 contains description of the socio-economic forecasts used by the regulatory simulation model. Similarly, Chapter 3 contains description of the energy supply and price forecasts. The major purpose of Chapter 4 is to describe the means by which future gas reuqirements within the utility's service areas are forecasted at the customer class level. The major purpose of Chapter 5 is to describe the gas distribution system and to present the means by which capacity costs and operating and maintenance costs of a gas utility are forecasted. Chapter 6 contains descriptions of various potential new service policies that could be adopted by the PUCO and those policies that were actually analyzed in this study. The purpose of Chapter 7 is to present the means by which the monthly gas flows are managed by a gas distribution company. Chapter 8 contains description of the financial analysis, including calculations of rate base and new retail gas prices. The means by which new service policies were evaluated in this study are described in Chapter 9. Chapter 10 contains a synthesis of the model, while Chapter 11 presents selected results of the analysis of new service policies. The preliminary conclusions based on this analysis are presented in Chapter 12.

CHAPTER 2

SOCIO-ECONOMIC FORECASTS

Demographic and economic forecasts constitute basic inputs to most planning processes. It is the purpose of this chapter to describe the demographic and economic forecasts used in the model and policy analyses described in later chapters. These forecasts were generated exogenously to the present study. The methodology for producing them is presented in the first section. The spatial structure of the East Ohio Gas Company (EOGC) service area is described in the next section. This area is composed of five gas distribution divisions, on the basis of which forecasts of population, household size, commercial floor space and industrial fossil fuel energy requirements were organized. These are described in the last three sections.

The Forecasting Methodology: An Overview of the DEMOS Model

The forecasts presented in this chapter are based on those of the Demographic and Economic Modeling System (DEMOS) of Battelle-Columbus Laboratories. They were prepared for the Ohio Department of Health and published in a report entitled Demographic and Economic Projections for the State of Ohio, 1970-2000. The demographic and employment forecasts produced by DEMOS are the most easily available forecasts for Ohio at the county level.

The Battelle model allocates externally obtained growth projections to the various Ohio regions. The model combines external growth projections with information on the presence of export industries. The following description of the structure of DEMOS is extracted from the above-mentioned report:

> "The DEMOS model is composed of two independent submodels which interact through a set of linkages to generate sets of demographic and economic projections over time."[1]

Figure 2-1 illustrates the basic structure of DEMOS. In Figure 2-2, the logical order of calculations which are used to produce the forecasts is depicted in diagrammatic form.

> "Beginning in a base year (1970) and utilizing a set of baseline data for that year, DEMOS operates through an iterative process which modifies the original inputs over the projection horizon. Initial inputs consist of birth, death, and migration rates, population by age and sex, and employment by industry. Once these initial inputs are entered, a total population in a subsequent time period is calculated. Export-serving employment is first calculated using exogenous growth rates. Household-serving employment is projected as a function of population whereas business-serving employment is calculated as a function of non-business serving employment. After total employment has been calculated, labor force participation rates and unemployment rates are determined. In this fashion, projections are generated by single year over a specified time period, in this case, 1970 through the year 2000.
>
> A most basic assumption in DEMOS is that economic fluctuations generate demographic change, and vice-versa. The purpose of the feedback mechanisms of the model is to simulate these interrelationships. In particular, the model concentrates on the relationships between migration and unemployment, birth rates and unemployment, labor force participation rates and the ratio of employment to population, and labor availability and the demand for labor. These relationships provide a medium for the interplay of economic and demographic variables and, at the same time, a system of checks and balances for the entire system."[2]

The 1970 data on population structure were obtained from the 1970 Census of Population. Initial projections of birth rates were obtained from the Ohio Department of Health for all 88 counties in the state, whereas projections of death rates were derived from the Census national series. Initial projections of migration rates were computed on a county basis with data from the Department of Agriculture and the Ohio Department of Administrative Services. Finally, the rates of household formation in future years have been computed on the basis of the Census-projected

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[1]A.L. White, S. L. Haller and C. W. Minshall, Demographic and Economic Projections for the State of Ohio, 1970-2000, Report to the Ohio Department of Health, Columbus, Ohio: 1977.

[2]White, et.al., Ibid.

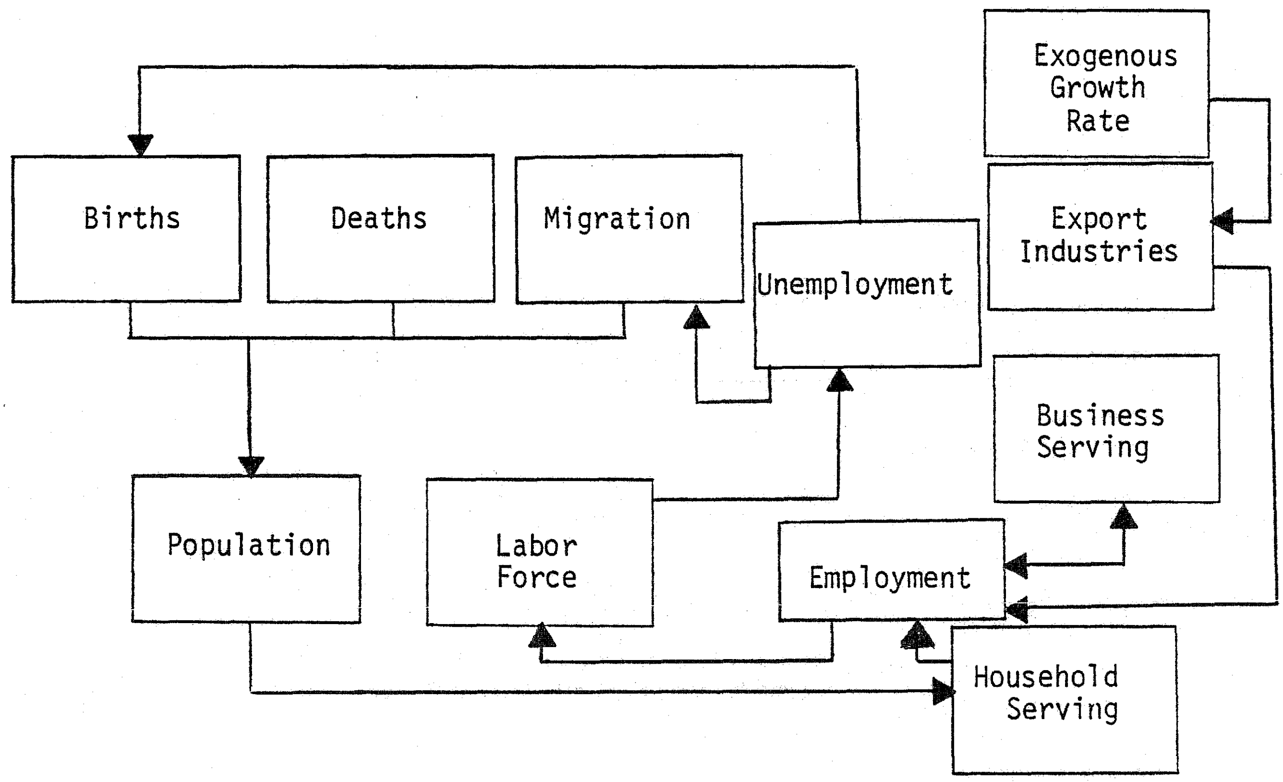

Figure 2-1: The Basic Structure of the Regional
Economic and Demographic Model (DEMOS)
Source: White, et. al., <u>Ibid</u>.

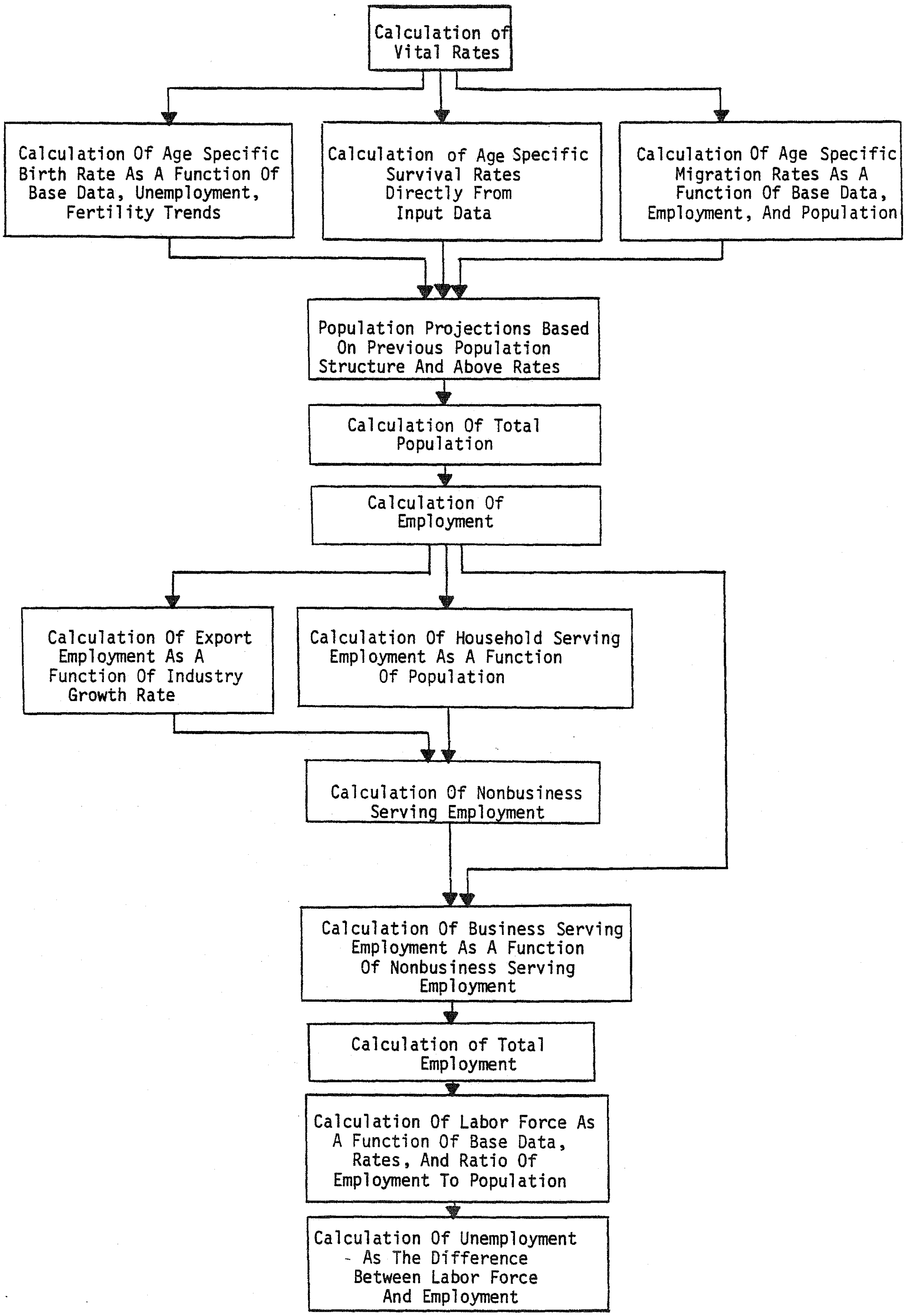

Figure 2-2: The Logical Order Of Calculations Used By The Demographic and Economic Projection Model
Source: White, et. al., Ibid.

number of households in the U.S. The model produces various demographic forecasts such as population by age and sex group, birth rates by age of mother, net annual migration by age group, total number of households and number of households by age of head of household. All these data are provided at the county level. Total population figures are also given at the level of communities and townships.

Employment is projected by place of residence and by industry over time. (See below Table 2-1)

> "The submodel operates on an export base approach in which certain key 'export industries' act as the driving force in generating change in the local economy. Employment is separated into 39 activities which correspond to the census categories of agricultural, manufacturing, and service sector employment. Each activity is then classified as export, business serving, or household serving, or a combination of more than one type. Employment in the export sector is a function of demand which is exogenous to a local area. Since this sector produces goods and services which are not consumed locally employment over time depends upon conditions exogenous to the local economy. If external demand for a given product increases, employment in that industry will increase. Alternatively, as external markets become depressed, local employment undergoes a concomittant decline.
>
> The classification of export industries is based on a specification of those industries which export most of their products outside of the area in which production is located. This classification is based on both input-output relationships and the specific characteristics of the Ohio regional economy. Agriculture and all manufacturing industries are classified as export. In addition, because of their strong linkages to the export economy, a number of service industries are classified in this group. These include the following: railroads, trucking, communications, finance, and business and repair services. 100 percent of the output of some industries is allocated to export-serving production. In other cases, a portion of total production--and, therefore, employment--is allocated to the household (HS) and business serving (BS) sectors."[2]

Annual growth rates for each county in Ohio and for each export-serving industry were estimated and form five different series, each reflecting the historical and projected economic trends in a set of counties. The assignment of growth rates to the eighteen counties included in the EOGC study area is indicated in Table 2-2. The criteria used in assigning counties to the series were geographic proximity and economic structure. Series I and II are based on the State of Ohio as a whole and Cleveland SMSA projections, respectively. The estimated average annual growth rates for these two series are presented in Table 2-3.

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[2]White, et.al., Ibid.

Table 2-1 Percentage Allocation of Industry Output for Exports, Household Services, and Business Services

Industry	Exports	Household Services	Business Services
Agriculture, Forestry, and Fishing	100	0	0
Mining	100	0	0
Construction	25	50	25
Furniture, Lumber, Wood	100	0	0
Metals Industry	100	0	0
Machinery, except Electrical	100	0	0
Electrical Machinery	100	0	0
Transportation Equipment	100	0	0
Other Durable Goods	100	0	0
Food and Kindred Products	50	25	25
Textiles and Textile Products	100	0	0
Printing and Publishing	33	34	33
Chemicals	100	0	0
Other Nondurable Goods	50	25	25
Railroad and Railway Express	25	0	75
Trucking	25	0	75
Other Transportation	0	50	50
Communications	25	50	25
Utilities and Sanitary Service	0	50	50
Wholesale Trade	0	0	100
Food and Dairy Stores	0	100	0
Eating and Drinking Places	0	100	0
General Merchandising	0	100	0
Motor Vehicle Retailing	0	100	0
Other Retail Trade	0	100	0
Finance	0	50	50
Insurance and Real Estate	75	0	25
Business and Repair Services	25	25	50
Private Households	0	100	0
Other Personal Services	0	100	0
Entertainment and Tourism	0	100	0
Hospitals	0	100	0
Other Health Services	0	100	0
Government Education	0	75	25
Private Education	0	100	0
Other Educational Services	0	100	0
Religious and Nonprofit Organization	0	100	0
Professional Organizations	0	100	0
Public Administration	0	100	0

Source: White, et. al., Ibid.

Table 2-2 Assignment of Counties to Growth Rate Series

County	Series	County	Series	County	Series
Ashland	I	Geauga	II	Portage	II
Ashtabula	I	Holmes	I	Stark	I
Carrol	II	Knox	I	Summit	II
Columbiana	I	Lake	II	Trumbull	II
Coshocton	I	Mahoning	II	Tuscarawas	I
Cuyahoga	II	Medina	II	Wayne	I

Source: White, et.al., Ibid.

Household-serving industries, which generally provide goods and services for local population, have been determined by reference to the percentage of each industry's total output destined for final consumption, assuming that the largest portion of final consumption is personal consumption. Household-serving employment is nonlinearly related to total population. Finally, business-serving industries, which provide goods and services to other industries in their area, have been determined by reference to the percentage of each industry's total output destined for intermediate consumption.

The employment projections produced by the DEMOS model are given at the county level and at five-year intervals from 1970 to 2000 for each of the 39 activity sectors. In order to transform these forecasts from the county level to the level of the divisions of the EOGC, it is necessary to describe the spatial structure of the company.

The Spatial Structure of the East Ohio Gas Company Service Area

The East Ohio Gas Company (EOGC) serves the northeastern part of the State of Ohio as indicated in Figure 2-3. Its service area includes Cleveland, Akron, Canton, Warren and Youngstown. The EOGC has partitioned its service area into five divisions bearing the names of the above cities. The adoption of this spatial partitioning of the service area in this study was governed by data availability, the potential for improved forecasts due to increased homogeneity, and the potential for future spatial cost of service studies. The 1977 spatial extent of each of these divisions

Table 2-3 Estimated Average Annual Growth Rates for Export-Serving Industries

Sectors	Series I				Series II			
	1970	1973	1980	1990	1970	1973	1980	1990
Agriculture, Forestry, & Fishing	0.30	0.30	0.40	0.40	3.56	3.56	0.70	0.70
Mining	4.80	4.80	4.00	4.00	-1.30	-1.30	-1.00	-1.00
Construction	2.10	2.10	1.70	1.70	-0.20	-0.20	1.40	1.40
Furniture, Lumber, Wood	3.05	3.05	1.02	1.02	5.20	5.20	-0.70	-0.70
Metals Industry	0.60	0.60	1.00	1.00	0.00	0.00	-0.10	-0.10
Machinery, Except Electrical	-0.20	-0.20	1.50	1.50	0.40	0.40	1.10	1.10
Electrical Machinery	-1.40	-1.40	1.50	1.50	-1.10	-1.10	1.00	1.00
Transportation Equipment	0.10	0.10	0.90	0.90	-3.10	-3.10	-1.80	-1.80
Other Durable Goods	0.00	0.00	1.90	1.90	0.00	0.00	1.90	1.90
Food & Kindred Products	-2.00	-2.00	-1.20	-1.20	-6.30	-6.30	-2.20	-2.20
Textiles & Textile Products	-2.10	-2.10	0.40	0.40	-3.90	-3.90	-1.60	-1.60
Printing & Publishing	-0.60	-0.60	0.50	0.50	-1.70	-1.70	0.20	0.20
Chemicals	0.60	0.50	1.60	1.60	-0.60	-0.60	1.00	1.00
Other Nondurable Goods	-5.40	-5.40	1.60	1.60	-3.70	-3.70	1.40	1.40
Railroad & Railway Express	-3.20	-3.20	-3.10	-3.10	-4.40	-4.40	-3.50	-3.50
Trucking	4.70	4.70	1.90	1.90	0.60	0.60	0.50	0.50
Communications	0.30	0.30	1.10	1.10	-0.40	-0.40	0.20	0.20
Insurance & Real Estate	2.70	2.70	2.60	2.60	1.10	1.10	1.40	1.40
Business & Repair Services	4.30	4.30	4.20	4.20	3.20	3.20	2.10	2.10

Source: White, et. al., Ibid.

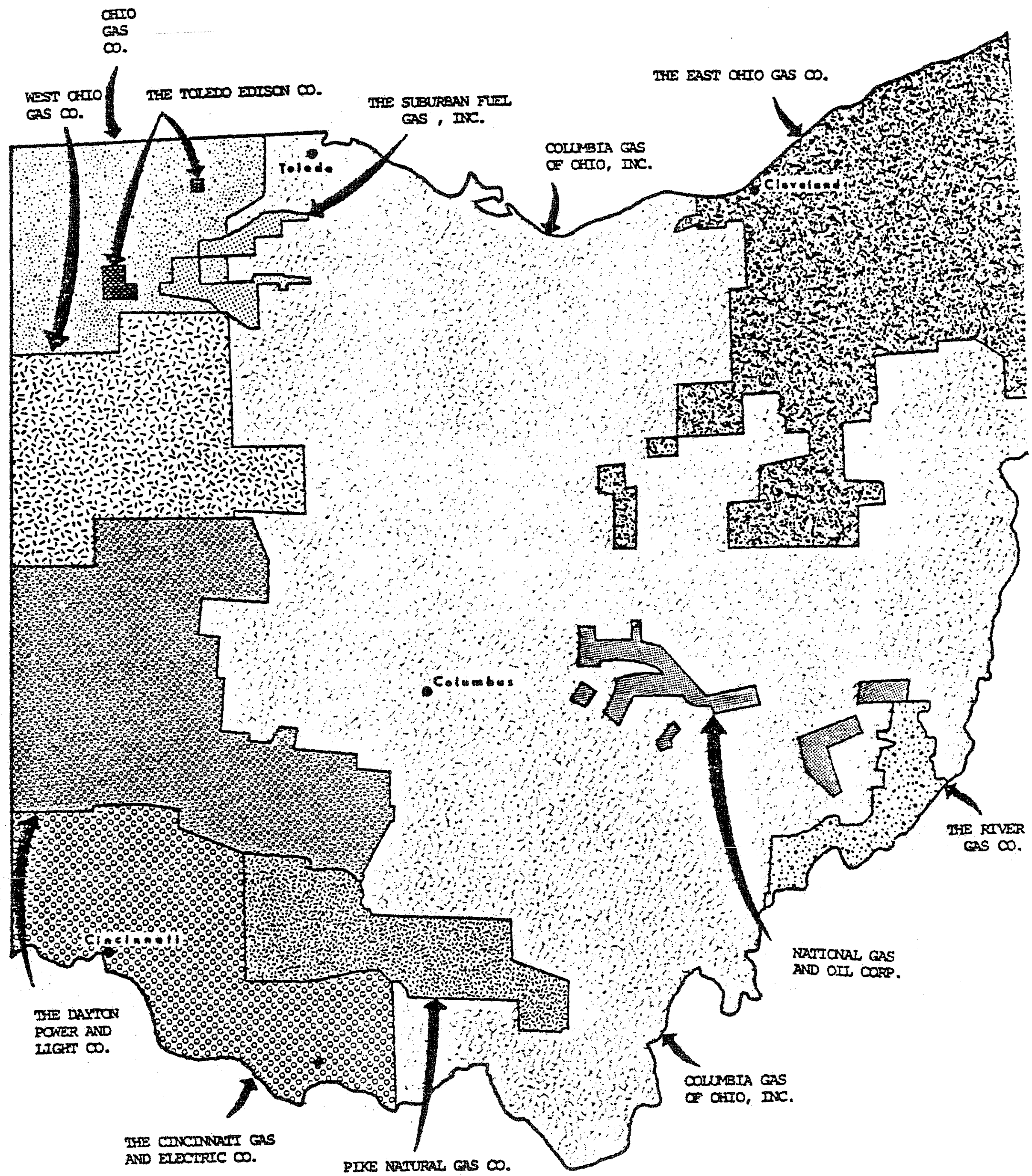

Figure 2-3 Major Gas Distribution Companies Service Areas in Ohio

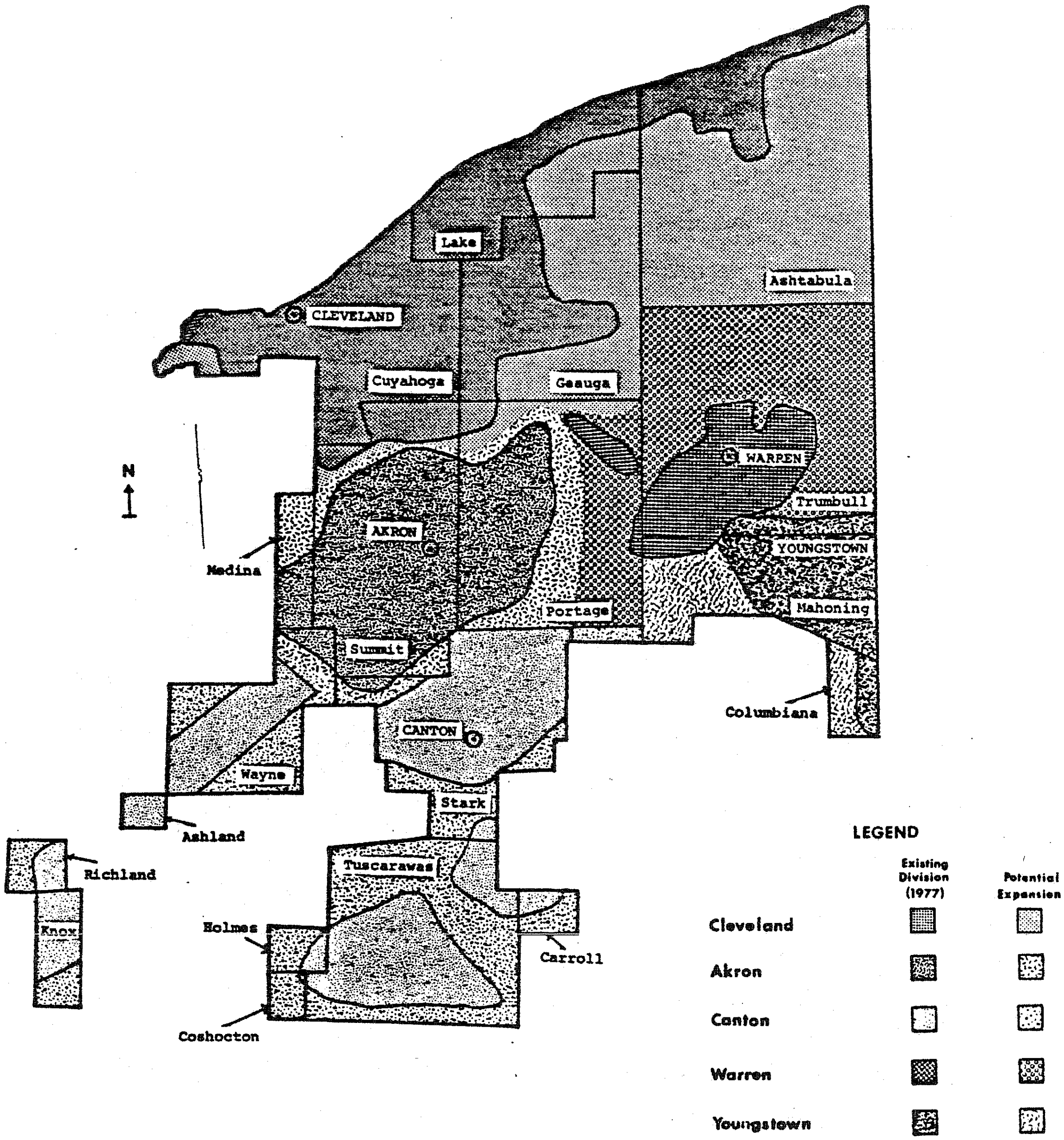

Figure 2-4 The East Ohio Gas Company Legal Service Area and Divisions

Table 2-4 Percentage of 1977 County Population Included in the EOGC Legal Service Area and In Its Divisions

Division and County	Legal Service Area Population As A Percentage of County Population	County Population Served In Division As A Percentage Of Total Served County Population	County Population Served In Division As A Percentage Of Total County Population
Cleveland			
Ashtabula	100.00	100.00	100.00
Cuyahoga	87.54	100.00	87.54
Geauga	100.00	100.00	100.00
Lake	100.00	100.00	100.00
Portage	100.00	12.99	12.99
Summit	100.00	3.37	3.37
Akron			
Medina	25.65	100.00	25.65
Portage	100.00	80.74	80.74
Stark	76.98	0.84	0.65
Summit	100.00	96.63	96.63
Wayne	69.13	3.98	2.75
Canton			
Ashland	8.45	100.00	8.45
Carrol	6.77	100.00	6.77
Coshocton	2.65	100.00	2.65
Holmes	8.80	100.00	8.80
Knox	4.68	100.00	4.68
Stark	76.98	99.16	76.33
Tuscarawas	88.73	100.00	88.73
Wayne	69.13	96.02	66.38
Warren			
Mahoning	92.93	0.53	0.49
Portage	100.00	6.27	6.27
Trumbull	100.00	95.52	95.52
Youngstown			
Columbiana	8.74	100.00	8.74
Mahoning	92.93	99.47	92.44
Trumbull	100.00	4.48	4.48

is presented in Figure 2-4. The cities, villages and unincorporated areas served in 1977 by the EOGC and included in these divisions are listed in Table A-1 of Appendix A.

Figure 2-4 reveals that the 1977 gas distribution divisions do not completely cover the service area in which the EOGC is legally bound to provide service upon request. In this area, which is termed the legal service area, there is still some room for spatial expansion of the distribution network. Potential expansion areas have been determined for each current division in order to provide a complete coverage of the legal service area. These expansion areas, also indicated in Figure 2-4, have been delineated somewhat arbitrarily due to the lack of established boundaries, while accounting for county borders.

The 1977 populations of the areas not included in the legal service area were subtracted from the total 1977 county population, and the percentage of the county's population legally, if not actually, served by the EOGC was computed and is presented in Table 2-4. This sharing method was also used for preparing the commercial and industrial forecasts.

A second county sharing process had to be applied to assign counties' populations among divisions in cases where a county is shared by more than one division. This sharing has been done on the basis of the populations included in the 1977 extension of these divisions and in a pro-rata fashion. The resulting percentages of inclusion are also presented in Table 2-4. These sharing coefficients will be used to transfer commercial and industrial activities forecasts from a county basis to a division basis.

Demographic Forecasts

Energy consumed in the residential sector is primarily used for space heating, air conditioning, water heating and, to a lesser extent, for cooking, washing, refrigeration and lighting. The total amount of energy needed by the residential sector is closely related to its population size and to the number of households composing this sector, and therefore forecasts of these characteristics are necessary to prepare forecasts of residential energy requirements. The purpose of the present section is to describe the method by which population and household size forecasts have been derived for the EOGC service area.

The Population Forecasts

The DEMOS model provides total population forecasts at the county, city and village levels, for each year between 1977 and 1986, and for the years 1990, 1995 and 2000. For each county, the forecasts of population included in the legal service area and in the cities, villages and unincorporated areas served in 1977 by the gas distribution network have been computed on the basis of the DEMOS outputs and are presented in Table A-2 in Appendix A, together with forecasts for the whole county population and with forecasts of the coverage level of the legal service area, under the assumption that the distribution network is not expanded. These forecasts are also presented in graphic form in Appendix A. These county forecasts were then aggregated at the level of the five divisions, according to the sharing process presented in Table A-3 in Appendix A. The resulting forecasts for the total service area and for the five divisions are presented in Tables 2-5 through 2-10 and in Figures 2-5 through 2-10.

According to these forecasts, the population of the total service area will decrease from 3,444,986 people in 1977 to 3,361,220 people in 1986, or -2.43%. Thereafter it will increase to 3,427,818 people by the year 2000. Within the service area, the Cleveland division will experience a steady decrease in population. To a lesser degree, so will the Akron division. These decreasing trends are counterbalanced by increasing population trends in the three other divisions and especially in the Canton and Youngstown divisions.

The Household Size Forecasts

The DEMOS model provides county forecasts of the number of households at five-year intervals from 1970 through 2000. Resulting county average household size forecasts have been derived by dividing the total population figures by the corresponding number of households. These data are presented in Table A-4 in Appendix A. The importance of the household size parameter is related to the fact that it makes it possible to determine the number of households included in a given total population. These households are also the basic residential energy customers.

Table 2-5 Forecasted Population in EOGC Legal Service Area, Forecasted Population in Area Served in 1977 and Forecasted Coverage Ratio

Year (1)	Forecasted Population in Legal Service Area (2)	Forecasted Population in Area Served in 1977 (3)	Coverage Ratio (3/2) (4)
1977	3,444,986	3,259,705	.944
1978	3,426,897	3,241,124	.946
1979	3,410,920	3,224,627	.945
1980	3,397,279	3,210,582	.945
1981	3,386,195	3,198,522	.945
1982	3,376,859	3,188,501	.944
1983	3,368,998	3,179,600	.944
1984	3,364,845	3,173,798	.943
1985	3,362,498	3,171,398	.943
1986	3,361,220	3,168,359	.943
1990	3,371,275	3,172,172	.941
1995	3,398,637	3,192,739	.939
2000	3,427,818	3,218,617	.939

Table 2-6 Forecasted Population in Cleveland Division Legal Service Area, Forecasted Population in Area Served in 1977 and Forecasted Coverage Ratio

Year (1)	Forecasted Population in Legal Service Area (2)	Forecasted Population in Area Served in 1977 (3)	Coverage Ratio (3/2) (4)
1977	1,818,403	1,716,402	.944
1978	1,802,740	1,700,575	.943
1979	1,788,915	1,686,544	.943
1980	1,776,614	1,674,102	.943
1981	1,765,792	1,662,755	.942
1982	1,756,126	1,652,717	.941
1983	1,748,086	1,644,172	.941
1984	1,741,558	1,636,565	.941
1985	1,736,393	1,631,387	.940
1986	1,732,168	1,626,412	.940
1990	1,725,421	1,616,904	.937
1995	1,725,420	1,613,767	.935
2000	1,725,401	1,611,515	.933

Table 2-7 Forecasted Population in Akron Division Legal Service Area, Forecasted Population in Area Served in 1977 and Forecasted Coverage Ratio

Year	Forecasted Population in Legal Service Area	Forecasted Population in Area Served in 1977	Coverage Ratio (3/2)
(1)	(2)	(3)	(4)
1977	648,252	639,634	.986
1978	643,611	634,849	.986
1979	639,333	630,546	.986
1980	635,405	626,587	.986
1981	632,005	623,141	.986
1982	628,851	619,952	.986
1983	626,038	617,133	.986
1984	623,816	614,792	.986
1985	622,197	613,534	.986
1986	620,433	611,429	.986
1990	617,595	608,345	.986
1995	620,225	610,797	.985
2000	626,715	617,575	.986

Table 2-8 Forecasted Population in Canton Division Legal Service Area, Forecasted Population in Area Served in 1977 and Forecasted Coverage Ratio

Year (1)	Forecasted Population in Legal Service Area (2)	Forecasted Population in Area Served in 1977 (3)	Coverage Ratio (3/2) (4)
1977	437,304	423,789	.969
1978	438,259	424,673	.969
1979	439,491	425,805	.969
1980	440,919	427,147	.969
1981	442,558	428,671	.969
1982	444,270	430,291	.969
1983	446,207	432,122	.968
1984	448,600	434,395	.968
1985	450,786	436,459	.968
1986	453,249	438,636	.968
1990	464,020	445,888	.961
1995	480,364	461,372	.960
2000	499,316	479,358	.960

Table 2-9 Forecasted Population in Warren Division Legal Service Area, Forecasted Population in Area Served in 1977 and Forecasted Coverage Ratio

Year (1)	Forecasted Population in Legal Service Area (2)	Forecasted Population in Area Served in 1977 (3)	Coverage Ratio (3/2) (4)
1977	237,424	192,918	.812
1978	237,846	193,226	.818
1979	238,512	193,752	.818
1980	239,320	194,408	.818
1981	240,285	195,188	.818
1982	241,391	196,082	.818
1983	242,623	197,082	.818
1984	243,935	198,144	.818
1985	245,204	199,223	.818
1986	246,542	200,261	.818
1990	251,401	204,208	.818
1995	254,607	206,806	.818
2000	254,626	206,843	.818

Table 2-10 Forecasted Population in Youngstown Division Legal Service Area, Forecasted Population in Area Served in 1977 and Forecasted Coverage Ratio

Year (1)	Forecasted Population in Legal Service Area (2)	Forecasted Population in Area Served in 1977 (3)	Coverage Ratio (3/2) (4)
1977	303,603	286,962	.945
1978	304,441	287,801	.945
1979	304,669	287,980	.945
1980	305,021	288,278	.945
1981	305,555	288,767	.945
1982	306,221	289,459	.945
1983	306,044	289,091	.945
1984	306,936	289,902	.945
1985	307,918	290,795	.944
1986	308,828	291,621	.944
1990	312,838	296,827	.949
1995	318,021	299,997	.944
2000	321,760	303,326	.944

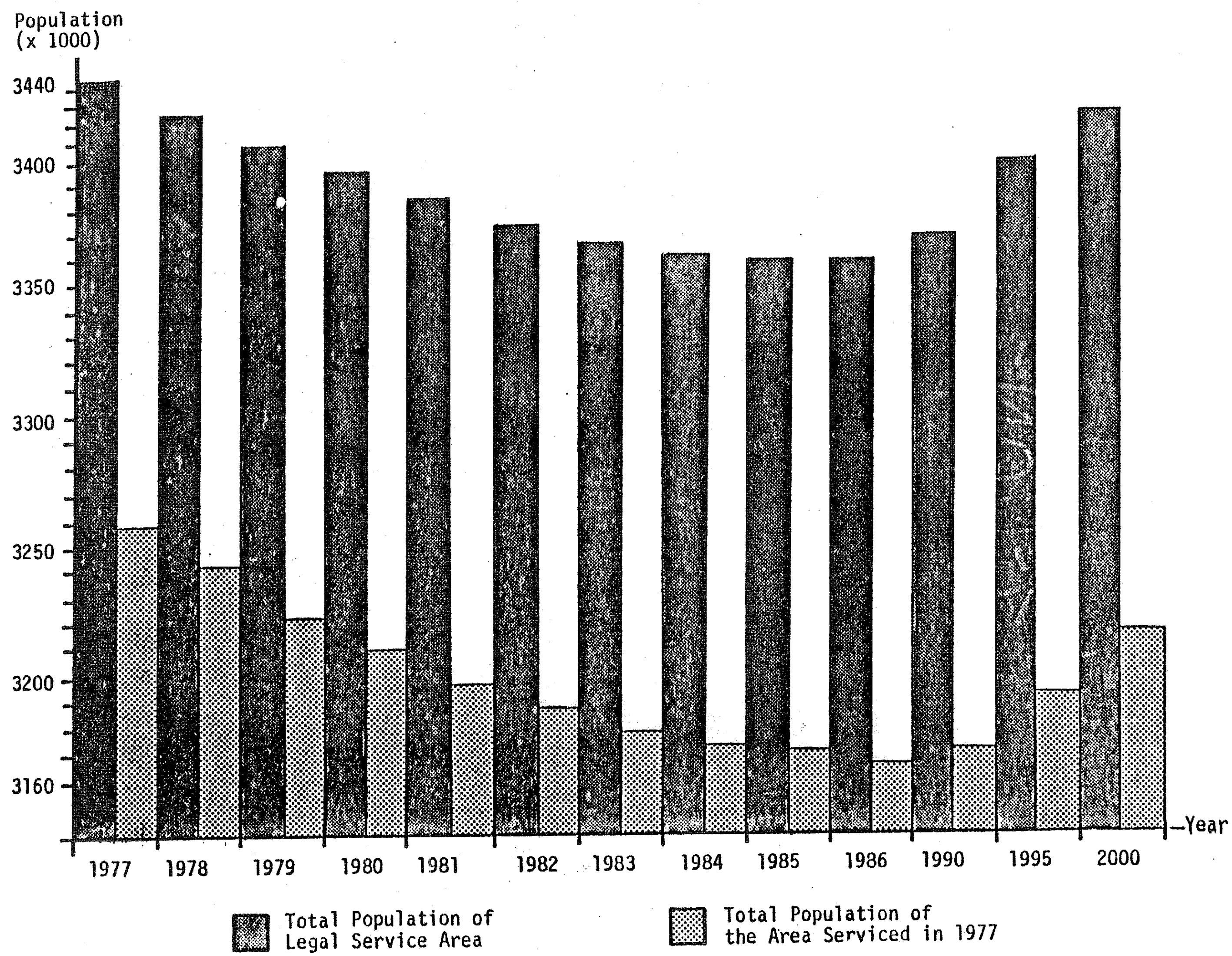

Figure 2-5 Population Projections for the Total Service Area

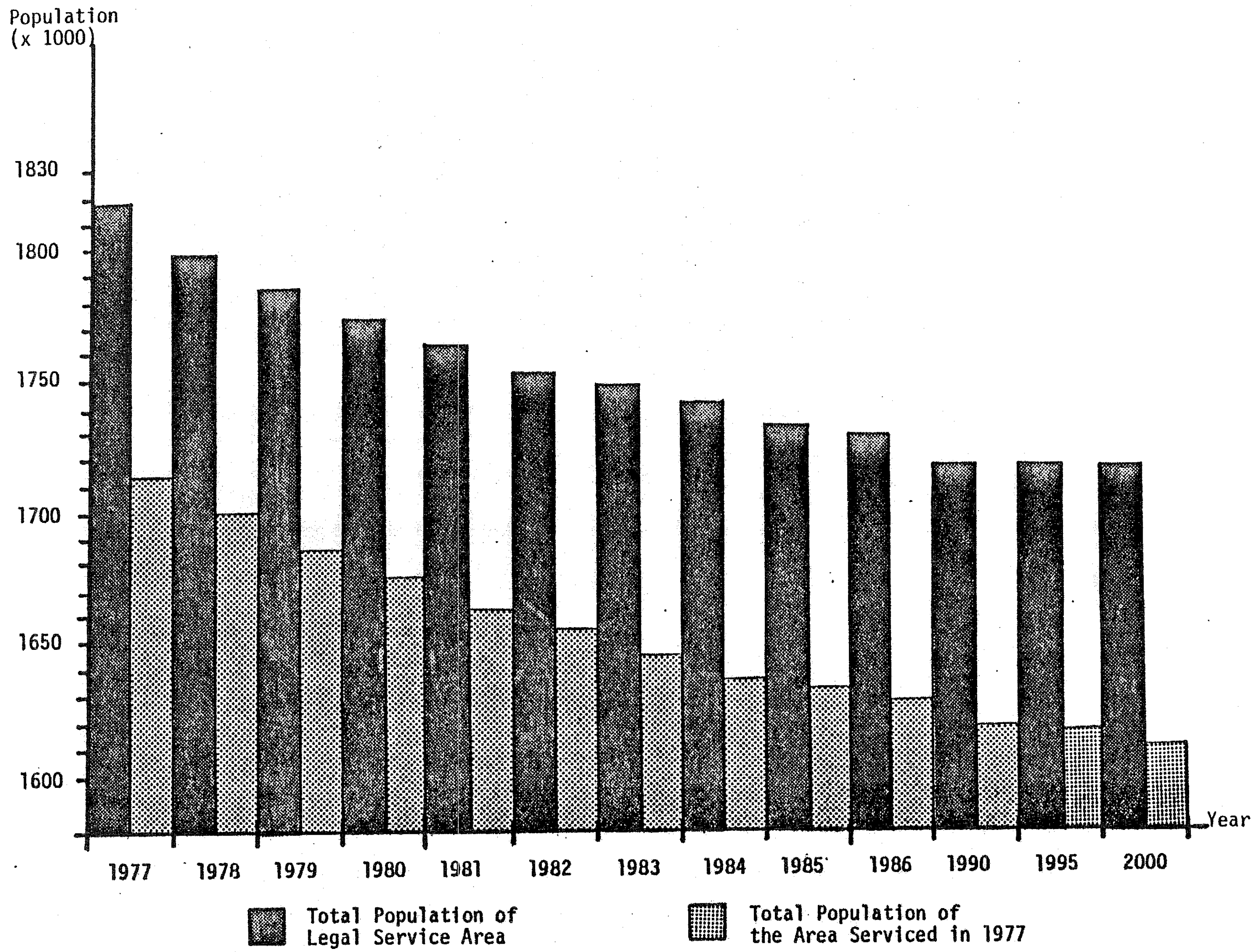

Figure 2-6 Population Porjections for the Cleveland Division

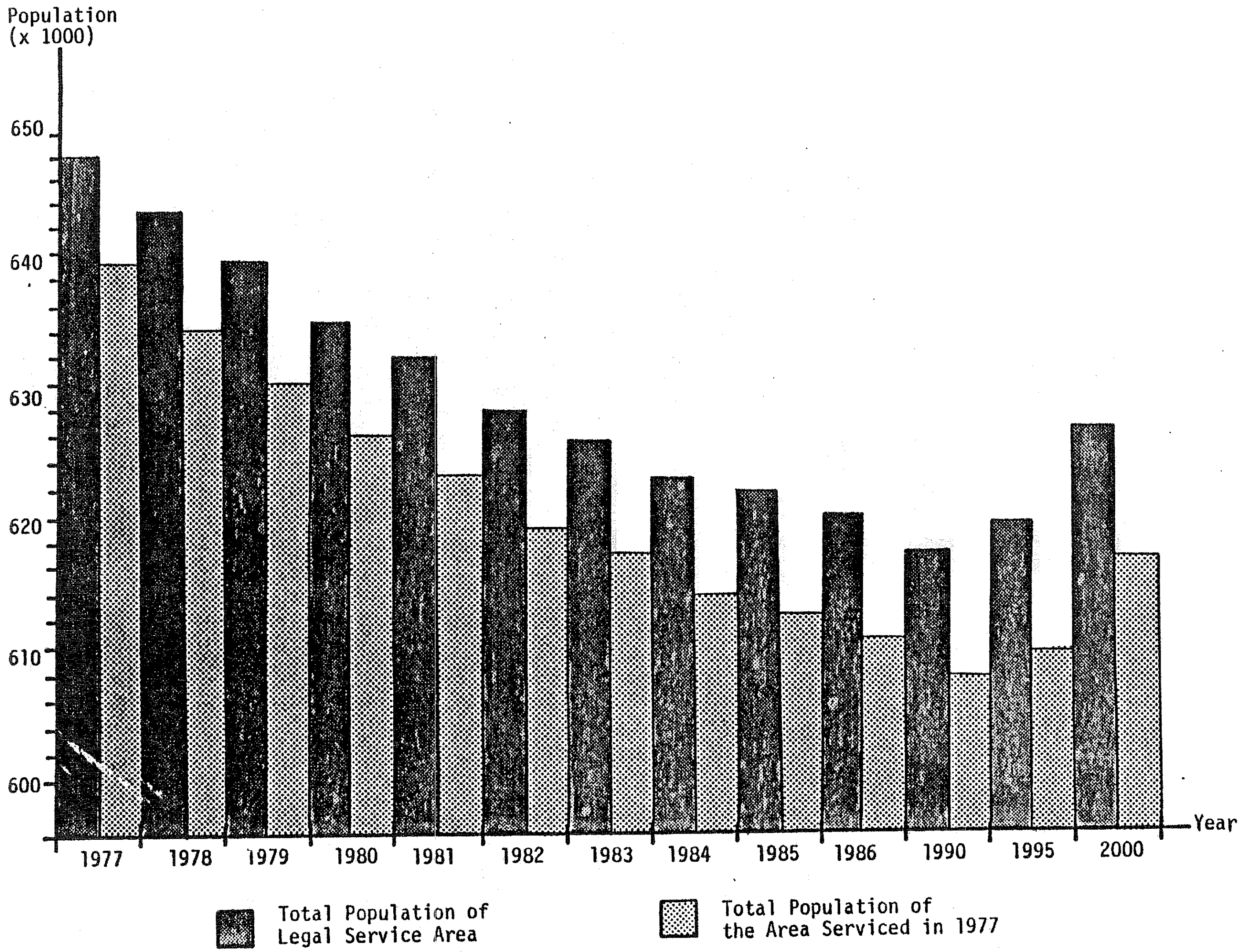

Figure 2-7 Population Projections for the Akron Division

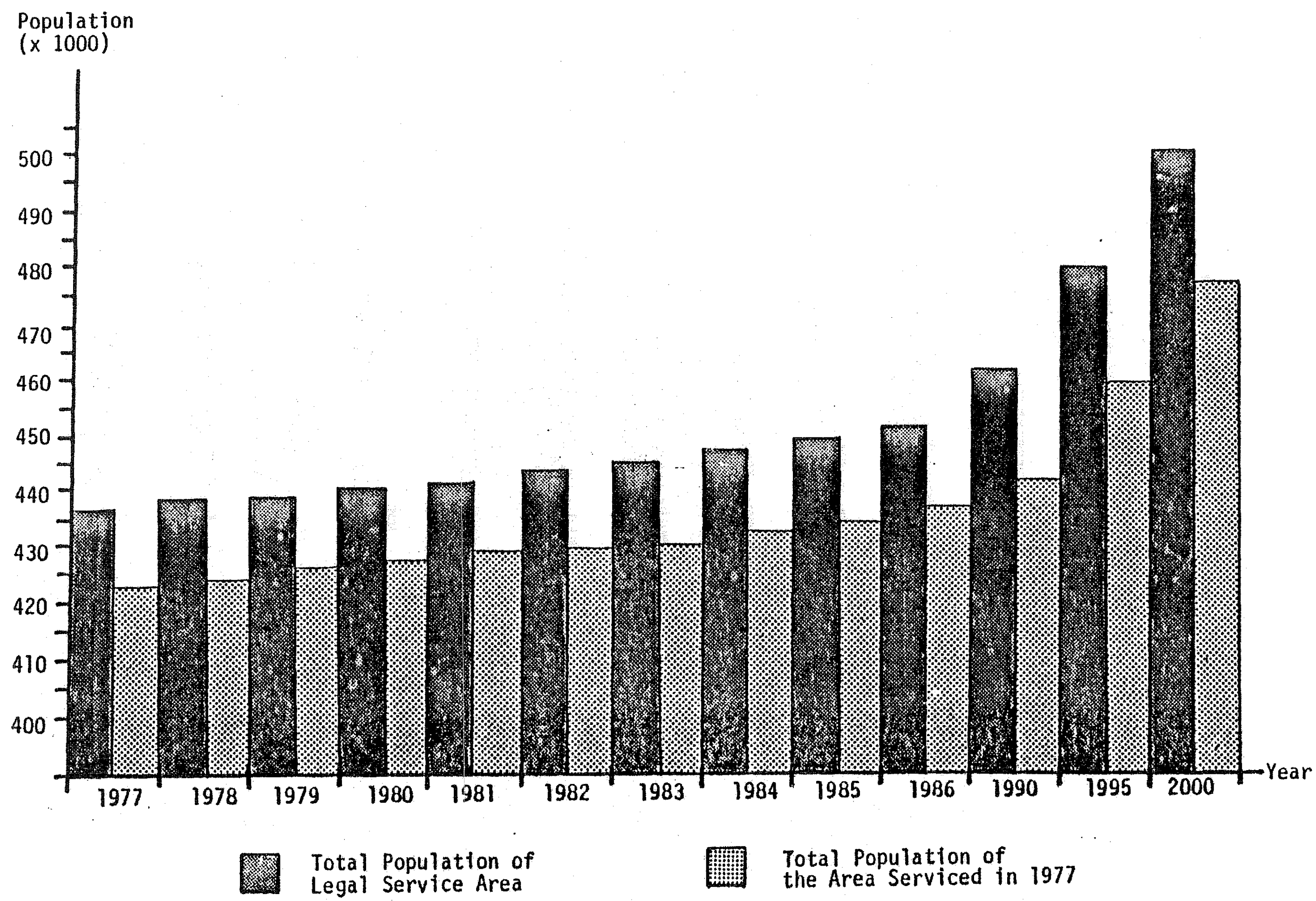

Figure 2-8 Population Projections for the Canton Division

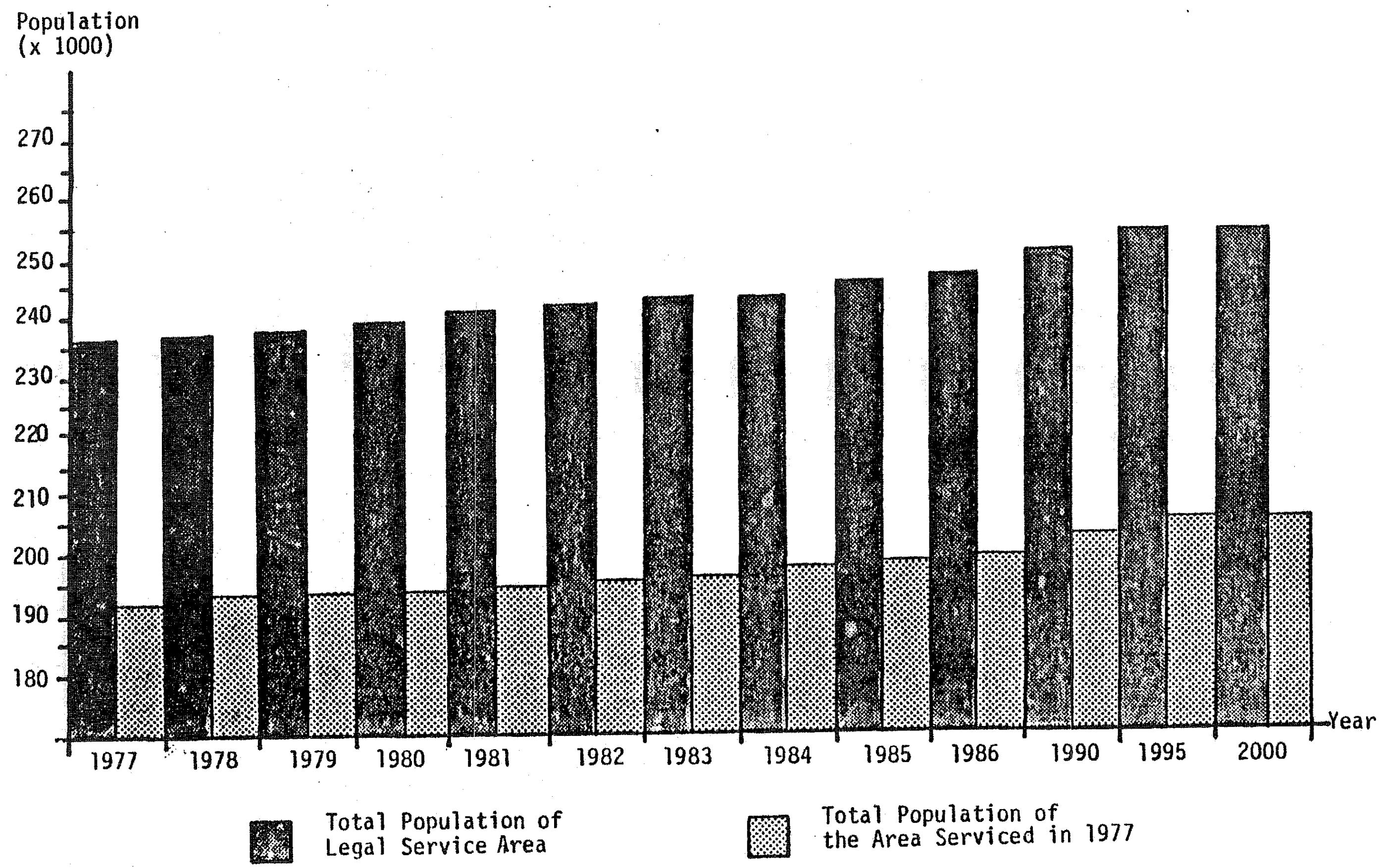

Figure 2-9 Population Projections for the Warren Division

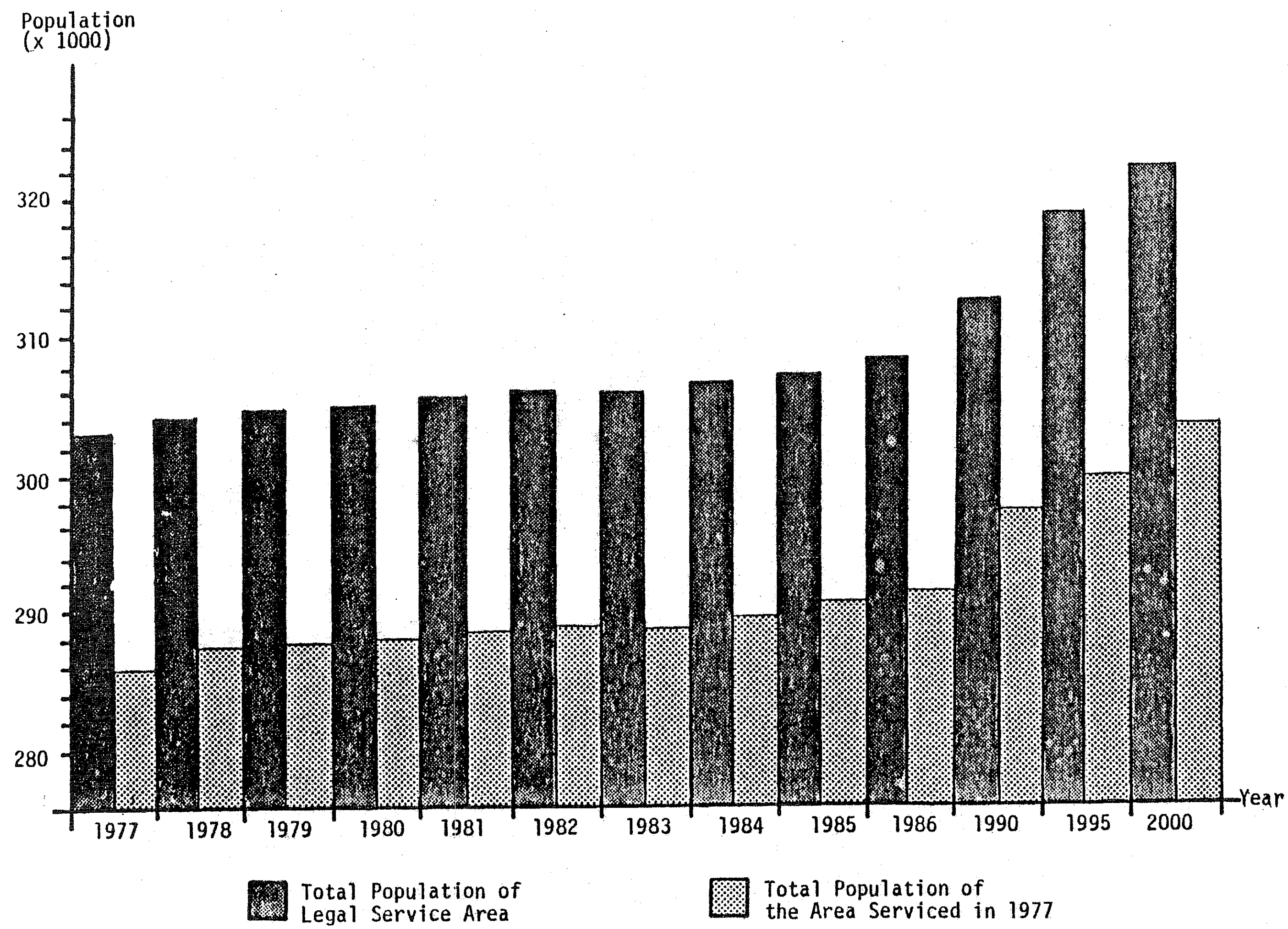

Figure 2-10 Population Projections for the Youngstown Division

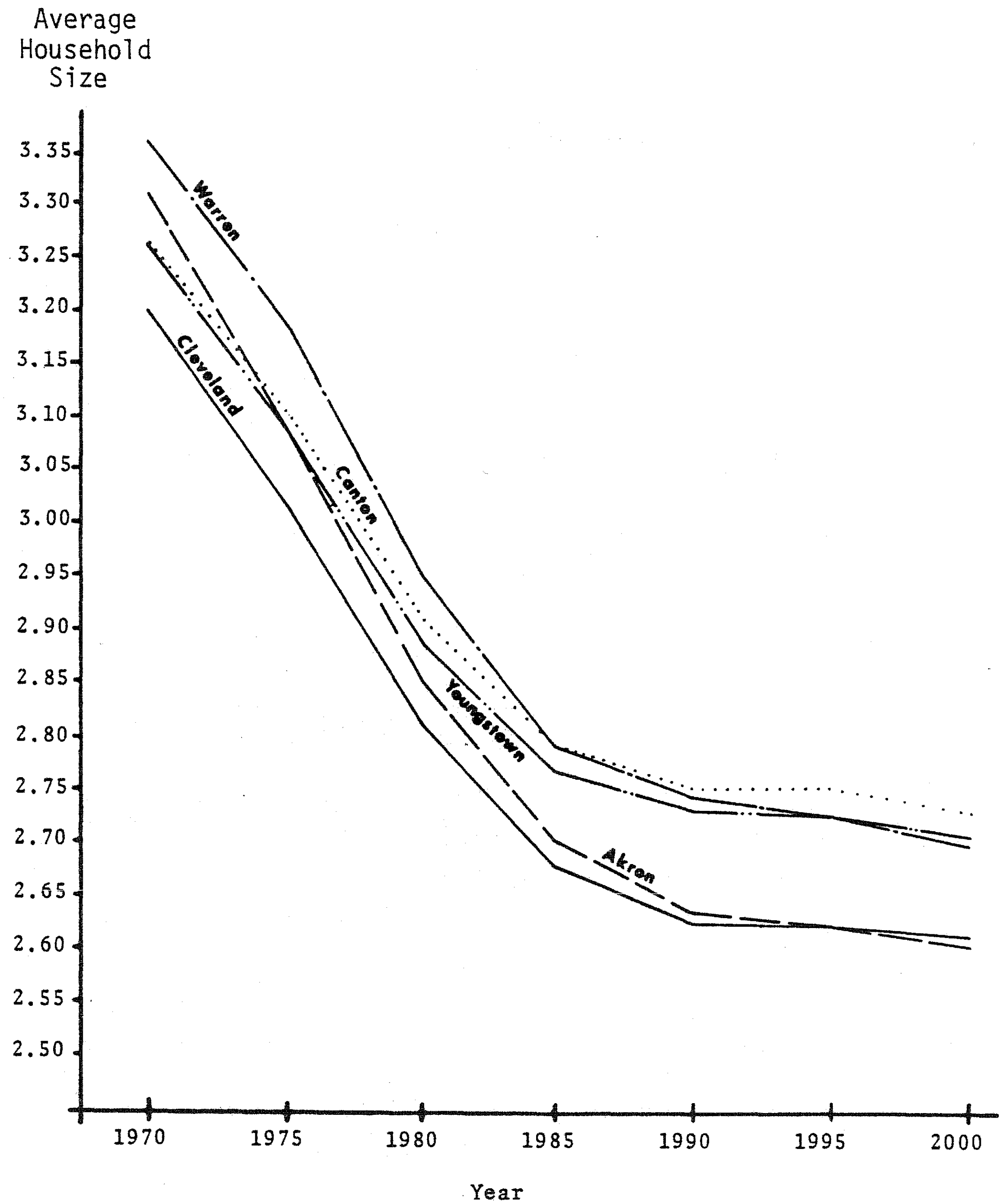

Figure 2-11 Average Household Size Forecasts in the East Ohio Gas Company Divisions

The county household size forecasts were averaged at the level of the five divisions, using as weighting factors the ratio of the 1980 legal service area population of each county to the total 1980 division population. The results are presented in Table 2-11 and in Figure 2-11. A strong decreasing trend is observed for all the divisions, from the (3.20-3.36) range to the (2.61-2.73) range.

Table 2-11 Household Size Forecasts for the Five Divisions of the EOGC Service Area

Year	1970	1975	1980	1985	1990	1995	2000
Cleveland	3.20	3.01	2.81	2.68	2.63	2.63	2.62
Akron	3.31	3.08	2.85	2.70	2.64	2.63	2.61
Canton	3.26	3.10	2.91	2.79	2.75	2.75	2.73
Warren	3.36	3.17	2.94	2.79	2.74	2.73	2.69
Youngstown	3.26	3.08	2.88	2.76	2.73	2.73	2.71

Commercial Activity Forecasts

In gas industry terminology, "commercial service" refers to customers primarily engaged in wholesale or retail trade, agriculture, forestry, fisheries, transportation, communication, sanitary services, finance, insurance, real estate, personal services (clubs, hotels, auto repair, etc.), government and any other non-manufacturing activity. The amount of floor space utilized by buildings sheltering such activities is a basic determinant of the amount of energy they need, since they use energy mostly for space heating and air conditioning. The purpose of this section is to describe how forecasts of floor space for commercial activities have been derived for the EOGC service area.

The Basic Data

The DEMOS model provides commercial employment forecasts at the county level. In order to express these forecasts in terms of floor space utilization, it was necessary to compute ratios of floor space requirements per employee in the various activities . These ratios are not available in the Census publications and could not be found in any government agency in Ohio. In the end, it was decided to use the information provided by Ide Associates, Inc. research report.[3] The objective of this research was to improve the accuracy of land area and floor space estimates based on employment projections, and the research report presents the findings of surveys conducted in 145 metropolitan areas, in which over 28,000 manufacturing and commercial establishments were covered. The measures reported include gross land area, floor area, area devoted to parking, and building site area. The commercial activities considered in this study were aggregated into six groups: (1) Transportation, Communication and Utilities; (2) Wholesale Trade; (3) Retail Trade; (4) Services: Finance, Insurance and Real Estate; (5) Services: Education; (6) Services: all others. Table 2-12 is extracted from the above-mentioned report and presents, for various floor space classes, the number of surveyed establishments as well as their relative frequencies.

As pointed out in the research report, the median response for the transportation, communication, and utilities group lies in the 15,000-24,999 square feet range, lower than for manufacturing firms. This group also has a significant number of very small (less than 1,000 square feet) floor space establishments, and one third of them have floor space in the range from 5,500 to 24,999 square feet.

[3] Edward A. Ide. "Estimating Land and Floor Area Implicit in Employment Projections." Report prepared for the Bureau of Public Roads, U.S. Department of Transportation. Philadelphia: Ide Associates, Inc. 1970. (Data from this report were made available to the research team through the courtesy of the Northeast Ohio Areawide Coordinating Agency.)

Table 2-12 Distribution of Surveyed Establishments by Total Floor Space And by Type of Activity

Floor Space (in Square Feet)	Number of Establishments	Transportation, Communication, and Utilities		Wholesale Trade		Retail Trade		Services-Finance, Insurance and Real Estate		Services-Educational		Services-All Others	
		Number of Estab-lishments	%	Number of Estab-lishments	%	Number of Estab-lishments	%	Number of Estab-lishments	%	Number of Estab-lishments	%	Number of Estab-lishments	%
Total	2364	165	100.0	221	100.0	822	100.0	246	100.0	215	100.0	695	100.0
Less than 1,000. . .	276	18	10.9	15	6.8	82	10.0	52	21.1	3	1.4	106	15.2
1,000-1,499. . .	201	1	0.6	6	2.7	78	9.5	34	13.8	2	0.9	80	11.5
1,500-2,499. . .	272	10	6.0	9	4.1	105	12.8	34	13.8	12	5.6	102	14.7
2,500-3,499. . .	172	6	3.6	12	5.4	68	8.3	21	8.5	1	0.5	64	9.2
3,500-5,499. . .	244	13	7.9	23	10.4	105	12.8	21	8.5	16	7.4	66	9.5
5,500-9,999. . .	206	15	9.1	33	14.9	71	8.6	20	8.1	18	8.6	49	7.0
10,000-14,999. . .	174	16	9.7	19	8.6	66	8.0	20	8.1	8	3.7	45	6.5
15,000-24,999. . .	222	28	16.9	33	14.9	84	10.2	15	6.1	20	9.3	42	6.0
25,000-34,999. . .	115	7	4.2	13	5.9	45	5.5	6	2.4	23	10.7	21	8.0
35,000-49,999. . .	118	15	9.1	14	6.3	31	3.8	8	3.3	29	13.5	21	3.0
50,000-99,999. . .	149	17	10.3	21	9.5	43	5.2		3.3	29	13.5	31	4.7
100,000-199,999. . .	100	10	6.1	11	5.0	21	2.5	3	1.2	34	15.8	21	3.0
200,000 or more. . .	87	8	4.8	9	4.1	15	1.8	4	1.6	17	7.9	34	4.9
Undetermined	28	1	0.6	3	1.3	8	1.0	0	0.0	3	1.4	13	1.9

Source: Ide Associates, Inc., IBID.

The wholesale and retail trade groups are characterized by firms that are even smaller than are firms in transportation, communication and utilities. Retail trade firms tend to be particularly small--more than half had floor space less than 5,500 square feet--while wholesale trade firms tend to be slightly larger.

The two non-educational services groups have similar floor space distributions. Firms in these groups tend to be quite small, the median floor space being in the 2,500-3,499 square feet range, the same as for retail trade.

Finally, the floor space distribution for the educational services group is highly concentrated in the larger floor space ranges, with a median response in the 35,000-49,999 square feet range.

Given these data, the next step was to compute, for each commercial group, the average floor space consumption per establishment. Such an average value was obtained by using the mid-point of each floor space class. These computations are summarized in Table 2-13. These average floor space consumption rates, computed on the basis of nationwide data, were then assumed to reflect floor space consumption patterns in northeastern Ohio, and the final step of this preliminary computation process was to evaluate the average number of employees per establishment in each of the six groups in northeastern Ohio. Data on the distribution of firms by employment size were drawn from the County Business Patterns publications for the eighteen counties included partly or totally in the EOGC service area and for each two-digit SIC sector.[4] These basic data were then aggregated into the six major groups according to the classification presented in Table 2-14. These data were finally aggregated over the eighteen counties, as presented in Table 2-15. The average number of employees and the average floor space per establishment, together with the derived average floor space per employee, are presented in Table 2-16, for each group of commercial activities.

[4] County Business Patterns - 1970: Ohio. Washington, D.C., U.S. Department of Commerce, Bureau of the Census.

Table 2-13 Total and Average Floor Space by Type of Surveyed Commercial Activities

Floor Space Class (Square Feet)	Transportation, Communication, and Utilities		Wholesale Trade		Retail Trade		Services-Finance, Insurance and Real Estate		Services-Educational		Services-All Others	
(Midpoint)	Number of Estab-lishments	Total Floor Space	Number of Estab-lishments	Total Floor Space	Number of Estab-lishments	Total Floor Space	Number of Estab-lishments	Total Floor Space	Number of Estab-lishments	Total Floor Space	Number of Estab-lishments	Total Floor Space
(500) Less than 1,000	18	9,000	15	7,500	82	41,000	52	26,000	3	1,500	106	53,000
(1,250) 1,000-1,499	1	1,250	6	7,500	78	97,500	34	42,500	2	2,500	80	100,000
(2,000) 1,500-2,499	10	20,000	9	18,000	105	210,000	34	68,000	12	24,000	102	204,000
(3,000) 2,500-3,499	6	18,000	12	36,000	68	204,000	21	63,000	1	3,000	64	192,000
(4,500) 3,500-5,499	13	58,500	23	103,500	105	472,500	21	94,500	16	72,000	66	297,000
(7,750) 5,500-9,999	15	116,243	33	255,750	71	550,250	20	155,000	18	139,500	49	379,750
(12,500) 10,000-14,999	16	200,000	19	237,500	66	825,000	20	250,000	8	100,000	45	562,500
(20,000) 15,000-24,999	28	560,000	33	660,000	84	1,680,000	15	300,000	20	400,000	42	840,000
(30,000) 25,000-34,999	7	210,000	13	390,000	15	1,350,000	6	180,000	23	690,000	21	630,000
(42,500) 35,000-49,999	15	637,500	14	595,000	31	1,317,500	8	5,100,000	29	1,232,500	21	892,500
(75,000) 50,000-99,999	17	1,275,000	21	1,575,000	43	3,225,000	8	600,000	29	2,175,000	31	2,325,000
(150,000) 100,000-199,999	10	1,500,000	11	1,650,000	21	3,150,000	3	4,500,000	34	5,100,000	21	3,150,000
(200,000) 200,000 or more	8	1,600,000	9	1,800,000	15	3,000,000	4	800,000	17	3,400,000	34	6,800,000
Total	164	6,205,493	218	7,335,750	814	16,122,750	246	12,179,000	212	13,340,000	682	16,425,750
Average Floor Space Per Establishment	37,838 sq. ft.		33,650 sq. ft.		19,807 sq. ft.		49,508 sq. ft.		62,925 sq. ft.		24,085 sq. ft.	

Source: Ide Associates, Inc., IBID.

Table 2-14 Classification of Non-Manufacturing Activities

Commercial Activities	SIC
Transportation, Communication, and Utilities	
Railroad and Railway Express	41
Trucking	42
Communications	48
Utilities and Sanitary Service	49
Wholesale Trade	50, 51
Retail Trade	
Food and Dairy Stores	54
Eating and Drinking Places	58
General Merchandising	53
Motor Vehicle Retailing	55
Other Retail Trade	59
Services - Finance, Insurance, and Real Estate	
Finance	61
Insurance and Real Estate	63, 64, 65
Services - Educational	
Government Education	82
Private Education	82
Services - All Others	
Business and Repair Services	76
Other Personal Services	72
Entertainment	78, 79
Hospitals	806
Other Health Services	80
Religious and Nonprofit Organizations	866
Professional Organizations	862
Public Administrations	89

Table 2-15 Distribution of Commercial Establishments by Employment Size in the Eighteen Counties of the EOGC Service Area - 1970

Employment Size Class	Transportation, Communication and Utilities		Wholesale Trade		Retail Trade		Services-Finance, Insurance and Real Estate		Services-Educational		Services-All Others	
(Midpoint)	Number of Estab-lishments	Total Employment	Number of Estab-lishments	Total Employment	Number of Estab-lishments	Total Employment	Number of Estab-lishments	Total Employment	Number of Estab-lishments	Total Employment	Number of Estab-lishments	Total Employment
(2) 1-3	801	1,602	1,932	3,864	8,106	16,212	3,517	7,034	138	276	11,460	22,920
(5.5) 4-7	328	1,804	1,164	6,402	4,451	24,481	452	2,486	101	556	3,296	18,128
(13.5) 8-19	405	5,468	1,144	15,444	46,475	627,413	625	8,438	147	1,985	2,532	34,182
(34.5) 20-49	295	10,178	782	26,979	1,441	49,715	288	9,936	94	3,243	980	33,810
(74.5) 50-99	122	9,089	218	16,241	372	27,714	115	8,568	23	1,714	301	22,425
(174.5) 100-249	80	13,960	87	15,182	168	29,316	69	12,041	14	2,443	156	27,222
(374.5) 250-499	16	1,992	14	5,243	46	17,227	13	4,869	4	1,498	51	19,100
(500) 500 or more	21	10,500	5	2,500	35	17,500	11	5,500	4	2,000	40	20,000
Total	2,068	82,734	5,346	91,855	61,094	809,578	5,090	58,872	525	13,715	18,816	197,787

Source: County Business Patterns, 1970: Ohio

Table 2-16 Average Number of Employees per Commercial Establishment and Average Number of Square Feet per Commercial Establishment and per Employee by Sector

Sector	Average Number of Employees per Establishment	Average Number of Square Feet per Establishment	Average Number of Square Feet per Employee
Transportation, Communication, and Utilities	40.00	37,838.00	945.95
Wholesale Trade	17.00	33,650.00	1979.41
Retail Trade	13.00	19,807.00	1523.62
Services - Finance, Insurance, and Real Estate	12.00	49,508.00	4125.67
Services - Educational	26.00	62,925.00	2420.19
Services - All Others	11.00	24,085.00	2189.55

The Forecasts

The employment forecasts produced by the DEMOS model were aggregated to fit the six classification groups for which floor space consumption rates per employee were obtained. These forecasts are presented, for all the eighteen counties of the service area, in Table B-1 in Appendix B.

As was pointed out in the second section of this chapter, some of these counties are only partly included in the EOGC service area. Under the assumption that commercial activities distributions are closely related to population distributions, the population coverage coefficient of each county was applied to its total commercial employment in order to obtain the forecasts of commercial employment taking place in the EOGC legal service area. The next step was then to multiply these employment projections by the corresponding floor space consumption rates in order to obtain projections of floor space consumption by county and activity group. These are presented in Table B-3 in Appendix B. Obviously, the implied assumption in these computations is that the floor space consumption rates would not change in the future. Such an assumption might be submitted to a sensitivity analysis in order to assess the importance of this parameter on policy conclusions, or it might be modified if commercial technology and production forecasts were available. These, however, were not available for the present study.

Finally, the county projections were aggregated at the level of the five divisions constituting the EOGC service area. When a county was across two or more divisions, the sharing coefficients determined for population apportionment were used to apportion county commercial floor space forecasts among divisions. The resulting forecasts are presented in Table 2-17. On the basis of these forecasts, commercial floor space indexes have been derived, with 1977 as a base year. These indexes are presented in Table 2-18 and Figure 2-12. Multiplied by the base year estimates of floor space, these indexes provide the appropriate forecasts of floor space use. The method utilized for estimating these base year

Table 2-17 Commercial Floor Space Forecasts for the Divisions of the EOGC Service Area (in 1000,000 Square Feet)

Year	Cleveland	Akron	Canton	Warren	Youngstown	Total
1970	9,120.51	2,779.65	1,614.12	792.74	1,200.62	15,507.64
1975	8,995.03	2,763.78	1,685.51	818.24	1,222.82	15,485.38
1977	8,865.40	2,734.65	1,705.72	821.44	1,224.42	15,351.63
1980	8,680.27	2,691,02	1,735.57	826.31	1,230.64	15,163.81
1985	8,538.33	2,652.13	1,804.64	852.14	1,248.32	15,095.56
1990	8,553.88	2,654.27	1,895.63	883.12	1,278.99	15,265.89
1995	8,643.01	2,716.41	2,000.45	905.02	1,311.55	15,576.44
2000	8,754.77	2,742.50	2,129.63	913.85	1,342.94	15,883.69

Table 2-18 Indexes of Commercial Floor Space Growth by Divisions of the EOGC Service Area

Year	Cleveland	Akron	Canton	Warren	Youngstown
1977	100,00	100.00	100.00	100.00	100.00
1978	99.30	99.47	100.58	100.19	100.17
1979	98.61	98.94	101.16	100.39	100.3
1980	97.91	98.41	101.75	100.59	100.51
1981	97.59	98.12	102.56	101.22	100.80
1982	97.27	97.84	103.37	101.85	101.08
1983	96.95	97.55	104.18	102.48	101.37
1984	96.63	97.27	104.99	103.11	101.66
1985	96.31	96.98	105.80	103.74	101.95
1986	96.35	96.99	106.87	104.49	102.45
1987	96.38	97.01	107.93	105.25	102.95
1988	96.42	97.03	109.00	106.00	103.45
1989	96.45	97.04	110.06	106.76	103.96
1990	96.49	97.06	111.13	107.51	104.46
1991	96.69	97.51	112.36	108.04	104.99
1992	96.89	97.97	113.59	108.58	105.52
1993	97.09	98.42	114.82	109.11	106.06
1994	97.29	98.88	116.05	109.65	106.59
1995	97.49	99.33	117.28	110.18	107.12
1996	97.74	99.52	118.79	110.39	107.63
1997	97.99	99.71	120.31	110.61	108.14
1998	98.25	99.91	121.82	110.82	108.66
1999	98.50	100.10	123.34	111.04	109.17
2000	98.75	100.29	124.85	111.25	109.68

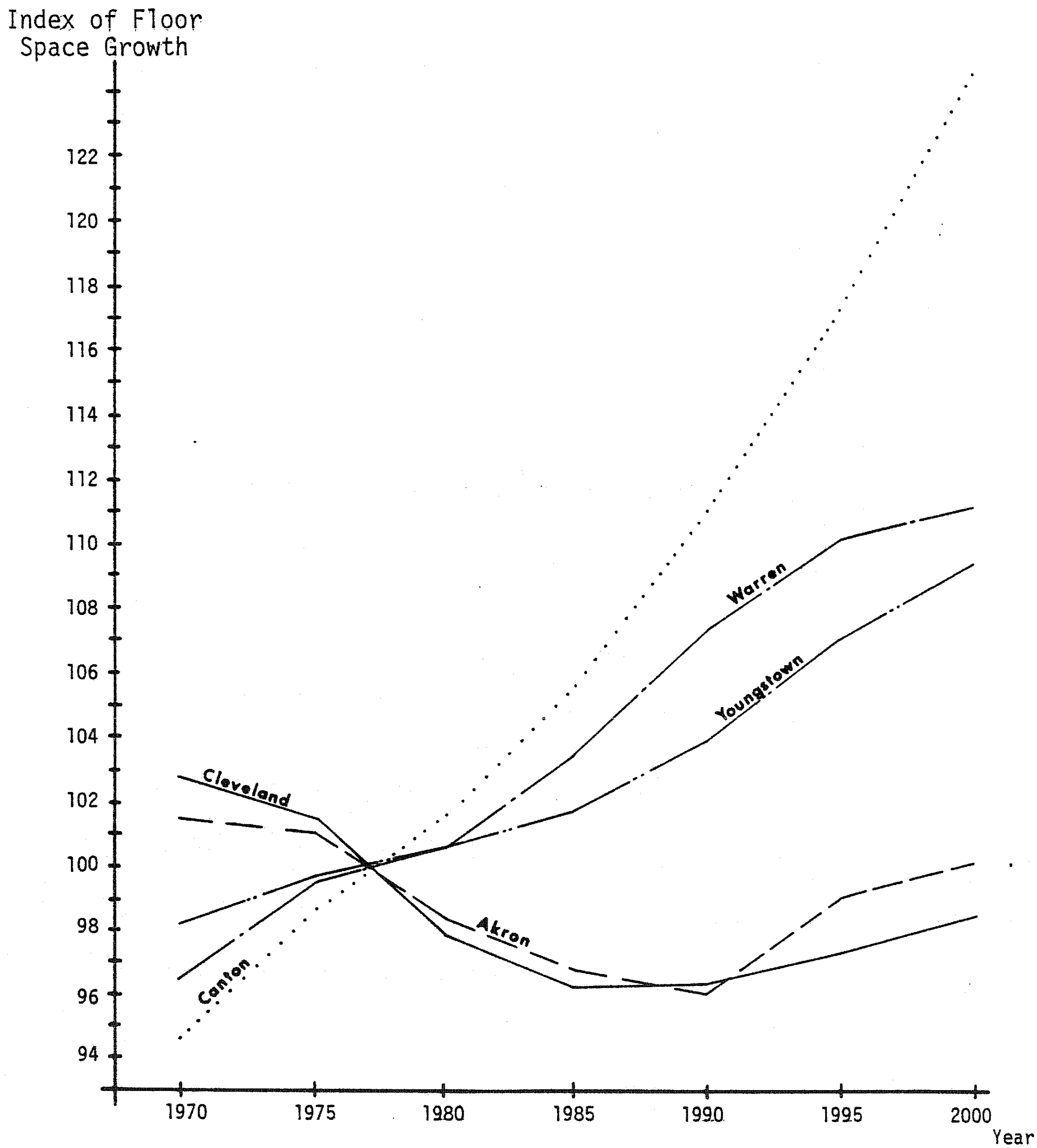

Figure 2-12 Indexes of Commercial Floor Space Growth for the Five Divisions of the East Ohio Gas Company (1977 = 100)

estimates is presented in Chapter 4. The need to use these estimates instead of the estimates obtained in the previous computation process will also be explained in Chapter 4.

Figure 2-12 shows patterns of decreasing commercial activity in the Cleveland and Akron divisions, of slightly increasing activity in the Warren and Youngstown divisions, and of strongly increasing activity in the Canton division.

Industrial Activity Forecasts

Introduction

Energy is used in the industrial sector primarily for process heating, secondarily for space heating, and, in some special industries like metal products (SIC 33), for feedstocks. (Coke, for example, is consumed in the process of steel production.) This energy is produced by the burning of fossil fuels, primarily gas, oil and coal, but it is also used in the form of electricity, for instance, in operating motors and in electrochemistry. In the present study, it will be assumed that fossil fuel and electrical energies are not substitutable in industrial processes. Although some substitution actually does take place, it is of little magnitude, and ignoring it should not introduce serious errors. The purpose of the present section is to describe how forecasts of total fossil fuel energy requirements by industrial activities have been derived for the EOGC service area.

The Basic Data

The DEMOS model provides employment forecasts, at the county level, for eleven industrial sectors: (1) furniture, lumber, wood; (2) metals; (3) non-electrical machinery; (4) electrical machinery; (5) transportation equipment; (6) other durable goods; (7) food and kindred products; (8) textile and textile products; (9) printing and publishing; (10) chemicals; (11) other nondurable goods. In order to convert these employment forecasts, presented in Table B-4 in Appendix B, into fossil fuel energy requirement forecasts, it was necessary to evaluate fossil fuel energy consumption rates per employee in the above-mentioned industrial sectors.

The 1971 Survey of Manufactures, coupled with the 1971 County Business Patterns, provided the basis for the computation of these consumption rates.[5,6] The total fossil fuel energy consumed in each sector in Ohio was evaluated in trillion BTU (TBTU) and divided by the corresponding total number of employees. In the case of the sector "other durable goods," including the SIC 32 and 34 sectors, the two sectorial coefficients were weighted by the employment in 1970 in each sector. The results are summarized in Table 2-19.

The Forecasts

The industrial employment forecasts produced by the DEMOS model were multiplied by the previously-derived fossil fuel energy consumption rates, and the resulting energy forecasts by industrial sector were then aggregated at the level of the county. The energy consumption forecasts for the eighteen counties of the EOGC service area are presented in Table 2-20.

The validity of these forecasts had to be evaluated in the light of two criteria: (1) how close are the figures computed for 1970 to the figures obtained directly by Census surveys, and (2) is it reasonable to assume that the consumption rates, computed with 1970 data, will not change over time due to technological change? The computed figures for 1970 have been compared with Census county figures for 1970 contained in Ohio Energy Profiles.[7] This comparison, presented in Table 2-21, reveals, that the computed figures are, on the average, three times larger than the Census ones, and this ratio is fairly stable, at least for the major industrial counties. The major reason for this gap may be that the industrial structure of northeastern Ohio is different from the Ohio average structure in terms of establishments' size distribution and technologies. It was assumed that the forecasted energy requirements correctly reflect future trends in relative but not absolute terms, i.e., it is legitimate to derive from these forecast index series to be applied

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[5] Annual Survey of Manufacturers, 1970-1971. Washington, D.C.: U.S. Department of Commerce, Bureau of the Census.

[6] County Business Patterns 1971 - Ohio. Washington, D.C.: U.S. Department of Commerce, Bureau of the Census.

[7] Ohio Energy Profiles. Report for the Ohio Energy Emergency Commission prepared by Mathematica, Inc. Columbus, Ohio: Ohio Energy Emergency Commission.

Table 2-19 Fossil Fuels Consumption Per Employee by Type of Industry, in Ohio, 1970

Industrial Activities	SIC	Energy Consumption per Employee (10^9 BTU)
Furniture, Lumber, Wood	24, 25	0.119
Metals	33	4.470
Non-electrical Machinery	35	0.170
Electrical Machinery	36	0.148
Transportation Equipment	37	0.193
Other Durable Goods	32, 34	0.660
Food and Kindred Products	20	0.364
Textile and Textile Products	22	0.213
Printing and Publishing	27	0.066
Chemicals	28	2.558
Other Nondurable Goods	29	5.228

Table 2-20 Forecasts of Industrial Energy Requirements in the EOGC Service Area by County (10^9 BTU)

County	1970	1975	1977	1980	1985	1990	1995	2000
Ashland	15,671.40	14,662.59	14,655.78	14,637.30	15,362.67	16,220.70	17,058.03	18,038.92
Ashtabula	36,157.16	35,364.42	35,794.83	36,424.58	38,831.04	41,436.70	44,151.11	46,943.01
Carrol	7,205.35	7,103.27	7,066.85	7,005.33	7,105.54	7,245.75	7,398.77	7,560.26
Coshocton	16,402.45	15,344.36	15,335.19	15,321.12	16,052.69	16,887.60	17,787.11	18,794.99
Columbiana	35,400.45	35,826.24	36,389.91	37,237.04	39,441.93	41,801.53	44,305.17	47,005.72
Cuyahoga	402,969.41	393,280.42	392,009.45	390,024.78	392,659.22	396,401.19	400,996.66	406,262.59
Geauga	17,621.67	16,961.40	16,950.22	16,942.66	17,521.66	18,207.26	18,898.75	19,564.42
Holmes	4,443.21	4,272.20	4,314.34	4,373.14	4,668.63	5,011.22	5,380.78	5,826.34
Knox	6,222.81	6,251.10	6,340.93	6,475.21	6,860.18	7,273.89	7,724.11	8,197.66
Lake	59,702.38	58,227.02	58,175.18	58,103.70	59,269.33	60,627.98	62,111.19	63,693.36
Mahoning	114,695.90	113,655.12	113,492.53	113,255.36	113,412.41	113,667.05	114,005.06	114,406.43
Medina	27,171.30	26,735.69	26,909.61	27,174.84	28,408.01	29,829.13	31,265.69	32,589.37
Portage	48,661.06	46,653.43	46,571.13	46,445.55	47,679.80	49,022.19	50,364.68	51,701.42
Stark	142,297.79	142,062.67	143,756.19	146,302.42	154,072.81	162,459.47	171,441.99	181,126.05
Summit	282,090.51	262,524.65	259,431.88	254,790.01	258,001.68	263,235.76	270,316.60	279,119.35
Trumbull	100,252.76	99,114.95	98,896.57	98,571.99	98,614.50	98,752.86	98,897.58	99,029.69
Tuscarawas	22,844.75	22,896.64	23,236.74	23,740.46	25,187.21	28,152.92	28,397.06	30,187.39
Wayne	35,066.81	32,776.43	32,962.22	33,156.01	34,826.36	36,675.46	38,642.57	40,793.53

Table 2-21 Comparison of 1970 Computed and Actual Industrial Energy Consumptions by County (10^9 BTU)

County (1)	Computed (2)	Actual (3)	Ratio (3/2) (4)
Ashland	15,671.40	5,008.6	0.319
Ashtabula	36,157.16	14,494.1	0.401
Carrol	7,205.35	898.9	0.125
Coshocton	16,402.45	5,296.5	0.323
Columbiana	35,400.45	7,986.0	0.225
Cuyahoga	402,969.41	176,219.2	0.437
Geauga	17,621.67	4,169.5	0.237
Holmes	4,443.21	1,682.4	0.378
Knox	6,222.81	2,803.0	0.450
Lake	59,702.38	30,471.0	0.510
Mahoning	114,695.90	36,474.5	0.318
Medina	27,171.30	5,247.6	0.193
Portage	48,661.06	6,964.3	0.143
Stark	142,297.79	47,985.1	0.337
Summit	282,090.51	62,943.3	0.223
Trumbull	100,252.76	38,804.1	0.387
Tuscarawas	22,844.75	6,946.5	0.304
Wayne	35,066.81	9,048.5	0.258
Total	1,374,877.20	463,443.1	0.337

to better evaluated base year figures of energy requirements. With respect to the second criterion, it is very hard, at present, to forecast structural changes in industrial energy consumption which are likely to alter the energy consumption rate per employee. As will be discussed in more detail in Chapter 4, it is very clear that many industries are currently achieving a high level of energy conservation, increasing their outputs while decreasing their energy needs. Unfortunately, the trend in energy conservation is very hard to predict for the middle and long run, and the best course is probably to submit this parameter to a sensitivity analysis, testing the implications of various levels of conservation. How to account for this conservation parameter will be explained in Chapter 4, and the indexes to be derived in this chapter are based upon the assumption of invariant energy consumption rates per employee.

The next step in preparing these indexes was to aggregate the county figures into division figures, using the same apportionment ratios as for the computation of population and commercial floor space figures. The energy forecasts of the divisions are presented in Table 2-22 and the derived indexes, with 1977 as a base year, are presented in Table 2-23 and in Figure 2-13. Although it is recognized that the above apportionment procedure is much less reliable in the case of industrial activities than in the case of commercial activities, because major plants are not necessarily closely linked to population concentrations, no better procedure was available, since such a procedure would have required precise knowledge of the locations of the industrial plants.

Figure 2-13 reveals an almost non-growth pattern of the Warren and Youngstown divisions, a moderate and similar growth for the Akron and Cleveland divisions (8% between 1977 and 2000), and a stronger growth for the Canton division (26% between 1977 and 2000).

Table 2-22 Forecasts of Industrial Energy Requirements of the EOGC Service Area by Division (10^9 BTU)

Division	1970	1975	1977	1980	1985	1990	1995	2000
Cleveland	482,068.39	469,737.88	468,877.74	467,518.33	474,244.17	482,520.56	491,845.66	501,965.39
Akron	320,731.75	300,028.01	297,033.74	292,536.82	297,049.54	303,660.96	312,070.96	322,115.06
Canton	155,092.33	153,304.63	155,027.02	157,551.51	166,006.61	176,420.68	184,957.98	195,548.08
Warren	99,374.49	98,156.68	97,942.12	97,623.05	97,741,82	97,959.39	98,183.46	98,395.43
Youngstown	113,610.21	112,634.36	112,523.54	112,363.80	112,703.59	113,151.40	113,689.16	114,302.13

Table 2-23 Industrial Energy Growth Index in the Divisions of the EOGC Service Area

Year	Cleveland	Akron	Canton	Warren	Youngstown
1977	100.00	100.00	100.00	100.00	100.00
1978	99.90	99.49	100.54	99.89	99.95
1979	99.81	98.99	101.08	99.78	99.91
1980	99.71	98.48	101.63	99.67	99.86
1981	99.99	98.78	102.72	99.69	99.92
1982	100.28	99.09	103.81	99.72	99.98
1983	100.57	99.39	104.90	99.74	100.04
1984	100.85	99.70	105.99	99.77	100.10
1985	101.14	100.00	107.08	99.79	100.16
1986	101.49	100.45	108.42	99.84	100.24
1987	101.85	100.89	109.77	99.88	100.32
1988	102.20	101.34	111.11	99.93	100.40
1989	102.56	101.78	112.46	99.97	100.48
1990	102.91	102.23	113.80	100.02	100.56
1991	103.31	102.79	114.90	100.07	100.65
1992	103.71	103.36	116.00	100.11	100.75
1993	104.10	103.93	117.11	100.16	100.84
1994	104.50	104.59	118.21	100.20	100.94
1995	104.90	105.06	119.31	100.25	101.03
1996	105.33	105.74	120.67	100.29	101.14
1997	105.76	106.41	122.04	100.33	101.25
1998	106.19	107.09	123.41	100.38	101.36
1999	106.62	107.76	124.77	100.42	101.47
2000	107.05	108.44	126.14	100.46	101.58

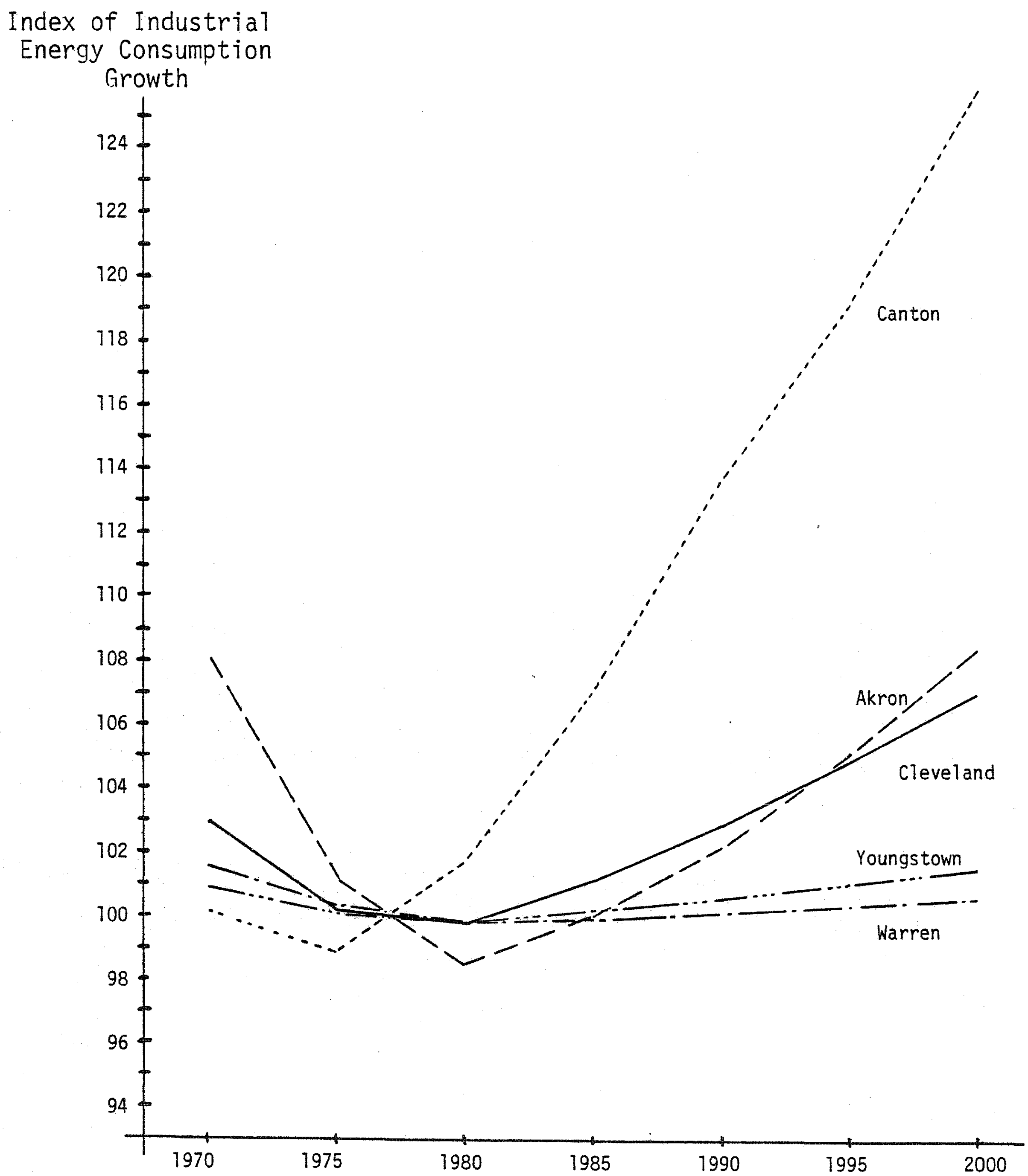

Figure 2-13 Indexes of Industrial Energy Consumption for the Five Divisions of the East Ohio Gas Company (1977 = 100)

CHAPTER 3

ENERGY SUPPLY AND PRICE FORECASTS

The extent to which new service policies should be adopted is dependent upon the future availability of gas, the price at which it is offered to consumers, and the future availability and price of alternative forms of energy.

There is much uncertainty, however, about future energy supplies and prices, since these are primarily dependent upon national policy decisions, as well as upon uncontrollable factors such as the price of imported oil. It is therefore necessary to consider alternative energy supply and price assumptions for the future and to analyze their implications for new service policies. It is the purpose of this chapter to describe the methods by which various forecasts were prepared for inclusion in the simulation model.

An analysis of past and present gas flow patterns in the U.S., with a specific focus on Ohio and the East Ohio Gas Company, is presented in the first section. In the next section, three different sets of energy forecasts are analyzed, and seven alternative energy supply and price scenarios based on these forecasts are finally selected to be used as the exogenous energy forecasts in the simulation model.[1] These scenarios are expressed in terms of indexes, with 1977 as a base year. These indexes are then applied to base year values of gas supply and prices of alternative energy forms to yield the appropriate forecasts used in the model. These forecasts are specifically related to wholesale gas supply and price, oil and electricity prices for both the residential and commercial

[1]These sets of energy forecasts were the only ones that this Research Team could find, which were comprehensive enough to be used in the present study.

sectors, and oil and coal prices for the industrial sector. The determination of the base year values, with specific reference to the East Ohio Gas Company service area, is described in the third and last section.

Historical Analysis of Gas Flow Patterns in the U.S. and in Ohio

This section presents an overview of past and current gas flows patterns for the U.S., the Appalachian region, Ohio, and, finally, the East Ohio Gas Company service area.

The state of Ohio belongs to the Appalachian market area (see Figure 3-1) and to the Appalachian-Illinois Basin Supply area (see Figure 3-2). Gas flows in 1975 between the various supply and market areas are presented in Tables 3-1 and 3-2. In the latter, only gas flows transported by pipelines regulated by the Federal Power Commission (FPC) are indicated.[2] The Appalachian market area gas consumption was equal to 3,190 BCF, or 15.14% of the total U.S. consumption, whereas the production of the Appalachian-Illinois Basin was equal to 399 BCF, and served, almost exclusively, the Appalachian market area. Although there is no perfect overlapping between the supply and market areas, it can be safely concluded that the Appalachian market area is an important importer of gas (its production covers approximately 12.5% of its needs). Table 3-3 indicates that the bulk of Ohio's gas also comes from outside the Appalachian region. Of 929 BCF of gas delivered to Ohio in 1975, only 151 BCF (or 16.2%) came from the Appalachian-Illinois Basin, the remainder coming almost entirely from the Southwest - 32 BCF from area 2, 567 BCF from area 3 (257 BCF onshore and 310 BCF offshore), 74 BCF from area 4 and 105 BCF from area 6. Table 3-3 also shows that 869 BCF of gas, or 93% of Ohio's consumption, were transported by FPC regulated pipelines, thus underlining the heavy reliance of Ohio's gas market on federal regulatory policy.

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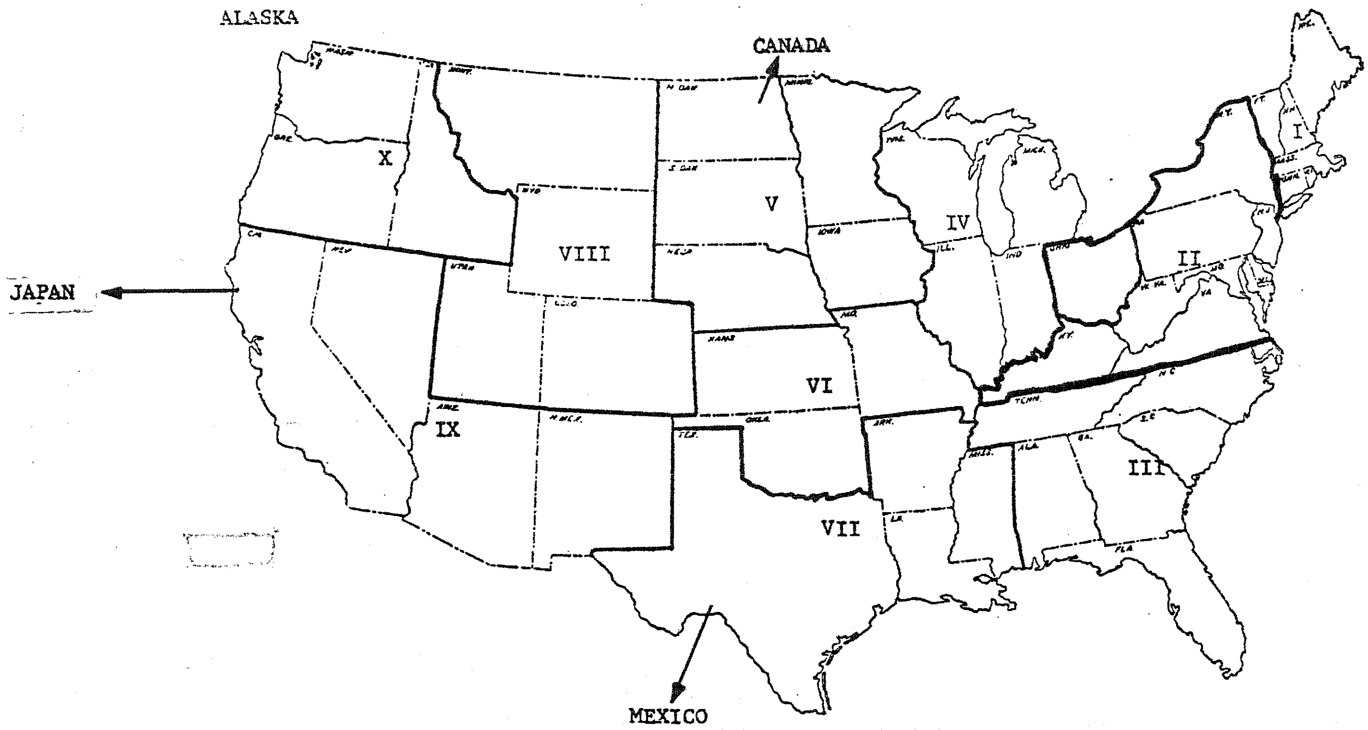
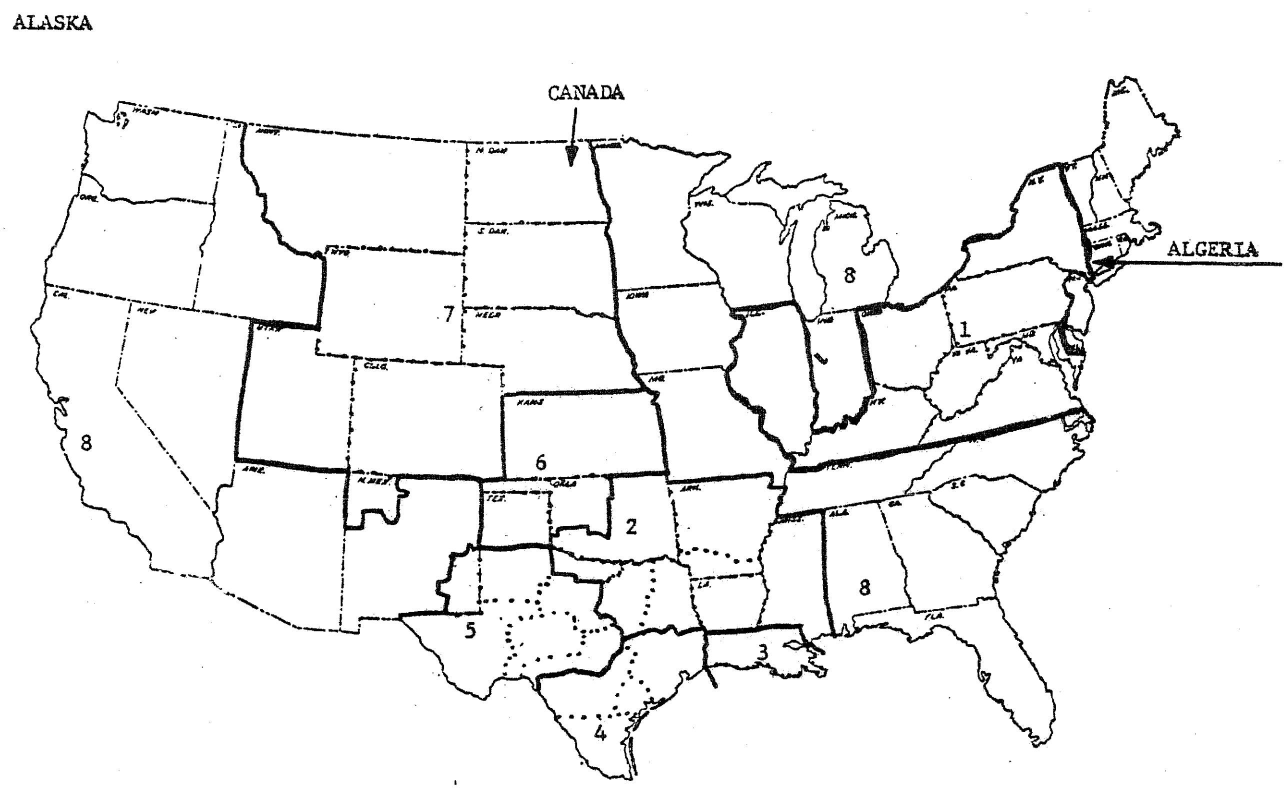
[2] This commission is now called Federal Energy Regulatory Commission (FERC).



Key: I New England (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont) II Appalachian (Delaware, District of Columbia, Kentucky, Maryland, New Jersey, New York, Ohio, Pennsylvania, Virginia, West Virginia) III Southeast (Alabama, Florida, Georgia, North Carolina, South Carolina, Tennessee) IV Great Lakes (Illinois, Indiana, Michigan, Wisconsin) V Northern Plains (Iowa, Minnesota, Nebraska, North Dakota, South Dakota) VI Mid-Continent (Kansas, Missouri, Oklahoma) VII Gulf Coast (Arkansas, Louisiana, Mississippi, Texas) VIII Rocky Mountain (Colorado, Montana, Utah, Wyoming) IX Pacific Southwest (Arizona, California, Nevada, New Mexico) X Pacific Northwest (Idaho, Oregon, Washington) Alaska, Gross Exports (Canada, Mexico, Japan).

Figure 3-1 1975 Gas Market Areas

Source: Federal Power Commission, Natural Gas Flow Patterns 1975, Washington, D.C., 1977.



Key: 1. Appalachian-Illinois Basin (Illinois, Kentucky, Maryland, New York, Ohio, Pennsylvania, Virginia, West Virginia) 2. Other Southwest (Arkansas-Northern, Arkansas-Southern, Louisiana-North, Mississippi, Oklahoma Other, Texas R.R. Dist. 5, Texas R.R. Dist. 6, Texas R.R. Dist. 9) 3. South Louisiana (Louisiana-South Onshore, Louisiana-South Offshore) 4. Texas Gulf Coast (Texas R.R. Dist. 1S, Texas R.R. Dist. 2 onshore, Texas R.R. Dist. 3 onshore, Texas R.R. Dist. 4 onshore, Texas-Offshore) 5. Permian Basin (New Mexico-Southeast, Texas R.R. Dist. 1N, Texas R.R. Dist. 7B, Texas R.R. Dist. 7C, Texas R.R. Dist. 8, Texas R.R. Dist. 8A) 6. Hugoton-Anadarko (Kansas, Oklahoma Anadarko, Oklahoma Panhandle, Texas R.R. Dist. 10) 7. Rocky Mountain (Colorado, Montana, Nebraska, New Mexico-Northwest, North Dakota, Utah, Wyoming) 8. Other Areas (Alabama, California, Florida, Michigan, Other) Alaska, Gross Imports (Algeria, Canada).

Figure 3-2 1975 Gas Supply Areas

Source: Federal Power Commission, Natural Gas Flow Patterns, 1975, Washington, D.C., 1977

Table 3-1 Summary of Gas Flows Transported by FPC Regulated Pipelines for 1975 (BCF/year)

Gas Requirements Committee Market Regions	1 New England	2 Appa- lachian	3 South- East	4 Great Lakes	5 Northern Plains	6 Mid Continent	7 Gulf Coast	8 Rocky Mountain	9 Pacific South West	10 Pacific North West	Other[1] Areas	Gross Exports	Total
Federal Power Commission Supply Areas													
1. Appalachian-Illinois Basin	0	389	0	1	0	0	0	0	0	0	8	0	399
2. Other Southwest	12	98	84	77	13	328	852	0	0	0	7	0	1,470
30. South Louisiana Onshore	61	863	591	359	0	46	1,084	0	0	0	46	11	3,062
31. South Louisiana Offshore	112	1,387	468	858	0	64	793	0	0	0	72	23	3,777
4. Texas Gulf Coast	50	324	97	270	0	25	2,667	0	0	0	16	3	3,451
5. Permian Basin	0	0	0	147	241	58	1,356	0	1,164	0	0	7	2,973
6. Hugoton-Anadarko	0	105	0	820	562	1,197	448	110	2	0	4	8	3,256
7. Rocky Moutain	0	0	0	6	71	0	0	487	493	32	0	10	1,099
8. Other Areas[2]	17	18	68	100	6	0	1	4	330	0	0	0	544
Alaska	0	0	0	0	0	0	0	0	0	0	102	53	155
Gross Imports	6	6	0	248	48	0	0	42	366	277	2	255	1,250
Total	258	3,190	1,309	2,886	941	1,716	7,201	643	2,355	310	258	370	21,434

1. Includes Alaska Consumption plus certain net-to-storage volumes which where included to balance the receipts and deliveries of eight interstate pipeline companies.

2. Includes 35 BCF of synthetic gas plus certain net-from-storage volumes which where included to balance the receipts and deliveries of two interstate pipeline companies.

Note: Totals may not add due to rounding.
Source: Federal Power Commission, National Gas Flow Patterns 1975

Table 3-2 Summary of Gas Flows Transported by FPC Regulated Pipelines Between Major Supply and Market Areas for 1975 (BCF/year)

Gas Requirements Committee Market Regions	1 New England	2 Appa-lachian	3 South-East	4 Great Lakes	5 Northern Plains	6 Mid Continent	7 Gulf Coast	8 Rocky Mountain	9 Pacific South West	10 Pacific North West	Other[1] Areas	Gross Exports	Total
Federal Power Commission Supply Areas													
1. Appalachian-Illinois Basin	0	277	0	0	0	0	0	0	0	0	8	0	285
2. Other Southwest	12	98	84	77	13	88	497	0	0	0	7	0	875
30. South Louisiana Onshore	61	863	591	359	0	46	184	0	0	0	46	11	2,162
31. South Louisiana Offshore	112	1,387	468	858	0	64	293	0	0	0	72	23	3,277
4. Texas Gulf Coast	50	324	97	270	0	25	282	0	0	0	16	3	1,066
5. Permian Basin	0	0	0	147	241	58	296	0	1,104	0	0	7	1,853
6. Hugoton-Anadarko	0	105	0	820	562	637	98	110	2	0	4	8	2,346
7. Rocky Moutain	0	0	0	6	54	0	0	387	418	32	0	10	907
8. Other Areas[2]	17	18	33	0	6	0	1	4	0	0	0	0	79
Alaska	0	0	0	0	0	0	0	0	0	0	0	53	53
Gross Imports	6	6	0	248	48	0	0	42	366	277	2	255	1,250
Total	258	3,078	1,274	2,785	924	916	1,651	543	1,890	310	156	370	14,153

1. Includes Alaska Consumption plus certain net-to-storage volumes which where included to balance the receipts and deliveries of eight interstate pipeline companies.

2. Includes 35 BCF of synthetic gas plus certain net-from-storage volumes which where included to balance the receipts and deliveries of two interstate pipeline companies.

Note: Totals may not add due to rounding.
Source: Federal Power Commission, National Gas Flow Patterns 1975.

Table 3-3 Summary of Gas Flows Between Major Supply Areas and Detailed Appalachian Market Areas for 1975 (BCF/year)

Federal Power Commission Supply Areas	1 Appalachian Illinois Basin	2 Other Southwest	30 South Louisiana Onshore	31 South Louisiana Offshore	4 Texas Gulf Coast	5 Permian Basin	6 Hugoton Anadarko	7 Rocky Mountain	8 Other Areas*	Alaska	Gross Imports	Total
Gas Requirements Committee Market Region-Appalachian												
TOTAL GAS												
Delaware	0	0	3	16	2	0	0	0	0	0	0	21
District of Columbia	3	0	9	11	2	0	0	0	0	0	0	25
Kentucky	17	11	86	88	14	0	0	0	0	0	0	216
Maryland	16	1	51	57	11	0	0	0	0	0	0	135
New Jersey	0	9	69	172	26	0	0	0	0	0	0	277
New York	44	19	135	317	87	0	0	0	11	0	6	620
Ohio	151	32	257	310	74	0	105	0	0	0	0	929
Pennsylvania	91	24	178	307	77	0	0	0	6	0	0	638
Virginia	10	1	37	59	11	0	0	0	0	0	0	119
West Virginia	57	1	38	51	19	0	0	0	0	0	0	166
Total	389	98	863	1,387	324	0	105	0	18	0	6	3,190
Gas Transported by FPC Regulated Pipeline												
Delaware	0	0	3	16	2	0	0	0	0	0	0	21
District of Columbia	3	0	9	11	2	0	0	0	0	0	0	25
Kentucky	15	11	86	88	14	0	0	0	0	0	0	214
Maryland	16	1	51	57	11	0	0	0	0	0	0	135
New Jersey	0	9	69	172	26	0	0	0	0	0	0	277
New York	44	19	135	317	87	0	0	0	11	0	6	620
Ohio	91	32	257	310	74	0	105	0	0	0	0	869
Pennsylvania	61	24	178	307	77	0	0	0	6	0	0	653
Virginia	10	1	37	59	11	0	0	0	0	0	0	119
West Virginia	37	1	38	51	19	0	0	0	0	0	0	146
Total	277	98	863	1,387	324	0	105	0	18	0	6	3,078

* Includes synthetic gas plus net-from-storage volumes.
Note: Totals may not add due to rounding.
Source: Federal Power Commission: Natural Gas Flow Patterns 1975.

Table 3-4 indicates that 85 BCF of Ohio's 87 BCF gas production remained in the Appalachian market area. Twenty-five of these 85 BCF were transported by FPC-regulated pipelines, whereas the remainder was traded in the unregulated intrastate market. The above patterns clearly point out that any gas supply forecasting methodology must integrate the implications of alternative federal regulatory policies, with respect both to well-head price in the Southern producing states and to costs of interstate pipeline transportation.

Given the previous analysis of gas flows for the state of Ohio as a whole, the next step is to focus on the gas supply pattern of the East Ohio Gas Company. The EOGC purchased, in recent years, more than 70% of its supply from the Consolidated Natural Gas Company. The receipts and deliveries of Consolidated by supply and market areas for 1975 are indicated in Table 3-5. Clearly, Consolidated is also dependent on Southwestern sources of natural gas, with 68% coming from Louisiana alone. Of total supplies of 625 BCF, 273 BCF (44%) went to Ohio with the remainder going to New York (31%), Pennsylvania (17%), and West Virginia (9%). Finally, the breakdown of the EOGC gas purchases and the associated charges, for the years 1970 through 1977, are indicated in Tables 3-6 through 3-8. Table 3-6 points out that between 87 and 91% of EOGC purchases are made from interstate pipeline companies, essentially the Consolidated and Panhandle gas companies. The remainder is obtained from well-head and field-line gas purchases in Ohio. Transmission line purchases listed in Table 3-7 indicate some temporary suppliers during 1975 and 1976. These temporary supplies, in low amounts, were purchased at prices much higher (about twice as high) than those for regular supplies. The average gas charge has increased more than three times from 1970 to 1977. The price increase for field line gas in Ohio has been higher than the average increase, possibly because there is no ceiling price for this gas and because the unfilled demand is high. In Table 3-8, the demand and commodity charges imposed by Consolidated and Panhandle on the EOGC are indicated. The demand charge is related to maximum daily rate of supply the pipeline company is committing itself to deliver to its retail

Table 3-4 Summary of Gas Flows Between Detailed Appalachian Supply Area and Major Market Areas for 1975 (BCF/year)

Gas Requirements Committee Market Regions	1 New England	2 App-lachian	3 South East	4 Great Lakes	5 Northern Plains	6 Mid-Continent	7 Gulf Coast	8 Rocky Moutain	9 Pacific South West	10 Pacific North West	Other* Areas	Gross Exports	Total
Federal Power Commission Supply Area-Appalachian Illinois Basin													
TOTAL GAS													
Illinois	0	0	0	1	0	0	0	0	0	0	0	0	1
Kentucky	0	57	0	0	0	0	0	0	0	0	2	0	60
Maryland	0	0.1	0	0	0	0	0	0	0	0	0	0	0.1
New York	0	8	0	0	0	0	0	0	0	0	1	0	9
Ohio	0	85	0	0	0	0	0	0	0	0	2	0	87
Pennsylvania	0	83	0	0	0	0	0	0	0	0	1	0	84
Virginia	0	6	0	0	0	0	0	0	0	0	0	0	6
West Virginia	0	150	0	0	0	0	0	0	0	0	2	0	152
Total	0	389	0	0	0	0	0	0	0	0	8	0	399
Gas Transported by FPC Regulated Pipeline													
Illinois	0	0	0	0	0	0	0	0	0	0	0	0	0
Kentucky	0	55	0	0	0	0	0	0	0	0	2	0	58
Maryland	0	0.1	0	0	0	0	0	0	0	0	0	0	0.1
New York	0	8	0	0	0	0	0	0	0	0	1	0	9
Ohio	0	25	0	0	0	0	0	0	0	0	2	0	27
Pennsylvania	0	53	0	0	0	0	0	0	0	0	1	0	54
Virginia	0	6	0	0	0	0	0	0	0	0	0	0	6
West Virginia	0	130	0	0	0	0	0	0	0	0	2	0	132
Total	0	277	0	0	0	0	0	0	0	0	8	0	285

*Includes gas consumption in Alaska plus net-to-storage volumes included to balance receipts and deliveries of eight interstate pipeline companies.
Note: Totals may not add due to rounding.
Source: Federal Power Commission: National Gas Flow Patterns 1975.

Table 3-5 Consolidated Natural Gas Company Receipts and Deliveries of Gas by Supply and Market Areas

Supply and Market Area	Receipts[1] From Supply Areas		Deliveries[2] To Market Areas		Percentage of Supply Area	Percentage of Market Area
	MMCF	%	MMCF	%		
New York	1075	0.1	191421	31	12	31
Pennsylvania	14312	2.0	104770	17	17	15
Virginia	617	0.1			10	
West Virginia	68457	11.0	55928	9	45	34
Indiana	10	0.0			6	
Louisiana North	20220	3.0			6	
Louisiana - South Onshore	167622	27.0			5	
Louisiana - Offshore	255852	41.0			7	
Mississippi	1472	0.1			2	
Texas R.R. Dist. 1 - South	2867	0.4			4	
Texas R.R. Dist. 2 - Onshore	10419	2.0			2	
Texas R.R. Dist. 3 - Onshore	17050	3.0			2	
Texas R.R. Dist. 4 - Onshore	52137	8.0			4	
Texas R.R. Dist. 6	8872	1.0			3	
Texas - Offshore	3969	1.0			1	
Ohio			273125	44		29
Total[3]	625413	100	625413	100	Not Additive	

1. receipts = company owned production plus purchase.
2. deliveries = sales, pipeline fuel, other company usage and unaccounted for and lost gas.
3. totals may not add due to rounding or omissions of receipts or deliveries which amounted to less than one-half percent of supply or market area totals.
Source: Federal Power Commission: National Gas Flow Patterns 1975.

Table 3-6 EOGC Well Head, Field Line, Transmission Company and Total Gas Purchases by Year

Year	Total Gas Purchases		Well Head Gas Purchases			Field Line Gas Purchases			Total Transmission Line Purchases		
	Quantity (MCF)	Average Charge (¢/MCF)	Quantity (MCF)	%	Average Charge (¢/MCF)	Quantity (MCF)	%	Average Charge (¢/MCF)	Quantity (MCF)	%	Average Charge (¢/MCF)
1970	388,657,713	43.35	15,153,636	3.9	26.8	20,447,154	5.3	31.6	353,056,923	90.8	44.99
1971	398,310,771	46.89	19,780,021	5.0	32.3	26,267,421	6.6	35.4	352,263,329	88.4	48.57
1972	408,516,831	50.73	25,167,631	6.2	37.9	28,365,620	6.9	41.6	354,983,580	86.9	52,37
1973	390,961,601	52.72	26,051,037	6.6	41.3	22,954,219	5.9	44.7	341,056,345	87.3	54.16
1974	398,956,666	64.07	27,242,179	6.8	47.0	19,651,875	4.9	48.9	352,062,612	88.2	67.00
1975	367,670,002	79.86	12,479,901	3.4	59.3	26,899,813	7.3	78.3	328,290,288	89.3	85.29
1976	375,323,198	101.97	11,249,803	3.0	69.0	26,259,937	7.0	115.6	337,873,458	90.0	104.30
1977	350,742,058	137.02	9,486,338	2.7	78.7	29,186,871	8.3	148.1	312,068,849	89.0	130.80

Source: EOGC Annual Reports

Table 3-7 EOGC Transmission Line Purchases by Company and Year

Year	Total Transmission Line Purchases			Consolidated			Panhandle		
	Quantity (MCF)	% of Total Purchases	Average Charge (¢/MCF)	Quantity (MCF)	% of Total Purchases	Average Charge (¢/MCF)	Quantity (MCF)	% of Total Purchases	Average Charge (¢/MCF)
1970	353,056,923	90.8	44.99	281,441,870	72.4	47.3	71,615,053	18.4	35.8
1971	352,263,329	88.4	48.57	288,132,218	70.8	51.2	64,131,111	16.1	37.1
1972	354,983,580	86.9	52.37	289,115,393	70.8	56.1	65,868,187	16.1	41.0
1973	341,056,345	87.3	54.16	276,198,848	70.6	56.7	64,857,497	16.6	45.5
1974	352,062,612	88.2	67.00	287,793,141	72.1	69.9	64,269,471	16.1	54.3
1975	328,290,288	89.3	85.29	264,830,632	72.0	87.6	58,519,130	15.9	65.8
1976	337,873,458	90.0	104.30	278,052,788	74.1	103.9	50,689,336	13.5	89.0
1977	312,068,849	89.0	130.80	259,308,819	73.9	134.4	52,760,030	15.0	113.2
	Michigan Consolidated			Oklahoma Natural Gas			Delphi Gas Pipeline		
1970	-	-	-	-	-	-	-	-	-
1971	-	-	-	-	-	-	-	-	-
1972	-	-	-	-	-	-	-	-	-
1973	-	-	-	-	-	-	-	-	-
1974	-	-	-	-	-	-	-	-	-
1975	4,940,526	1.3	202.0	-	-	-	-	-	-
1976	5,443	0.0	202.0	6,648,568	1.8	190.6	2,447,323	0.6	231.5
1977	-	-	-	-	-	-	-	-	-

Source: EOGC Annual Reports

Table 3-8 Demand and Commodity Charges for Consolidated and Panhandle Transmission Companies ($/MCF)

Year	CONSOLIDATED		PANHANDLE	
	Demand Charge	Commodity Charge	Demand Charge	Commodity Charge
1972	1.03	0.4579	3.05	0.3152
1973	1.11	0.4750	3.12	0.3952
1974	1.07	0.6108	2.16	0.4996
1975	1.27	0.7536	1.84	0.6634
1976	1.05	1.0997	1.92	1.0252
1977	0.98	1.2024	1.86	1.0092

Source: EOGC Annual Reports.

Table 3-9 Ohio Gas Production by the EOGC

Year	Local EOGC Gas Production (MMCF)
1972	3,740
1973	11,163
1974	9,486
1975	11,372
1976	6,785
1977	6,200

Source: The East Ohio Gas Company 10-Year Forecast Report, EOGC, Cleveland, 1977.

utility customer whereas the commodity charge is only related to the amount of gas actually supplied. The average charge increase (see Tables 3-6 and 3-7) is clearly correlated with the commodity charge increase from 1970 to 1977, the demand charges constituting a much smaller share of gas purchase costs. Finally, it should be noted that the EOGC is producing some gas itself. Production figures from 1972 to 1977 are indicated in Table 3-9. EOGC officials confirmed that the company had continually produced gas, even prior to 1972. However, no data could be obtained for 1970 and 1971. This local gas production equaled 2.5 to 3% of total purchases, and peaked in the 1973-1975 period. Since that time a downward trend seems perceptible.

Projections of Gas Supply and Energy Prices for Ohio

Introduction

The purpose of this section is to review and analyze gas supply forecasts related to the East Ohio Gas Company, to its major supplier, the Consolidated Gas Supply Corporation, and to the Midwest region. The assumptions and forecasting methodologies will be described whenever available, and a set of forecasts will finally be chosen to be used in the simulation model. The first two sets of gas supply forecasts, related to the EOGC and to the Consolidated Gas Supply Corporation, have been developed by the gas companies themselves. The third set of forecasts has been developed by the Energy Information Administration (EIA), using the Project Independence Evaluation System, and includes projections of the availability and prices of all forms of energy. The wide differences among these forecasts clearly reflect different basic assumptions about the response of gas supply to changes in technology and economics. In addition to the future wellhead prices for new gas, other factors likely to affect future gas availability are the amount of federal land, particularly in offshore areas, which can be leased for exploration, the development of new technologies for supplemental gas (such as liquid hydrocarbons and coal gasification), the moving of gas from the North Slope of Alaska, the availability of imported gas from Canada and Mexico, and, finally, the availability of liquefied natural gas (LNG) imported from Algeria and elsewhere.

As apparent in press reports and advertising leaflets, the two major Ohio gas retail utilities - Columbia Gas of Ohio and the East Ohio Gas Company - expect to take significant advantage of new gas supply sources.[3] With respect to Algerian LNG, the EOGC anticipates that the new natural gas supplies will increase their available supplies by 16%, while Columbia Gas sets the expected increase at 8.5%.[4] These companies claim that these added supplies will reduce the threat of cutoffs to industrial and commercial users, but also recognize that they will mean higher gas prices, due to the high cost of LNG. According to Columbia Gas, Arctic natural gas should become routinely available in the mid-1980's. (The proven recoverable natural gas reserves at Prudhoe Bay currently are placed at 26 trillion cubic feet, sufficient to provide about 5% of the U.S. natural gas requirements over the next 25 years at present rates of consumption. However, the potential Alaska gas reserves might be considerably higher.) The possibility of spurring Ohio gas production should also be noted. The staff of the Public Utilities Commission of Ohio (PUCO) is currently investigating incentives for the development of Ohio natural gas. Among these is the requirement that, when a company wishes to take on new customers, some percentage of the expected new load must be met with additional Ohio production. This incentive has already been implemented by the PUCO when it temporarily authorized the EOGC and the River Gas Company to take on new customers.[5] Self-sufficiency in producing gas, however, is an impossible goal for Ohio. which will remain 90 percent dependent on interstate gas in the near future.

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[3] Gaslines, 77/1084 and 78/288, Columbia Gas.

[4] PUCO Perspective, Vol. 3, 1, Feb. 1978.

[5] See PUCO Docket #77-1440-GA-SLF.

East Ohio Gas Company Projections

Projections prepared by the EOGC in November 1977 are presented in Table 3-10, together with historical data. The projected supplies are broken down according to the various supply sources, and, for each individual projections, indexes have been computed with 1977 as a base year. Total supplies, which have been decreasing from 1971 to 1977, are expected to increase by 8.4% from 1977 to 1978, and by 15% from 1977 to 1987, or by 1% per year from 1978 to 1987. The individual supply sources show different patterns of change over time. The major supplier, Consolidated, shows a supply increase of 26% over the 10-year period (i.e. approximately 68,000 MMCF). Panhandle, however, shows a supply decrease of 20%, or approximately 10,000 MMCF. Appalachian supply, which consists of field line, well head and EOGC's own production, is characterized by a decrease of 10%, or 4,000 MMCF. However, the loss of 14,000 MMCF from the smaller suppliers is more than offset by the increase in projected supplies from Consolidated, with an overall increase of approximately 54,000 MMCF.

The forecasting methodology is described as a combination of statistical techniques and subjective analysis.[6,7] Unfortunately, no explicit documentation is available.

Consolidated Gas Supply Corporation Projections

Gas supplies that will be available to Consolidated are projected by Consolidated to decline by 13.5% from 1977 to 1987. The various supply sources show trends in different directions. There is an increase in LNG and Louisiana supply, and a decrease in pipeline contracts and Appalachian supply. The strong decrease (40%) in pipelines contract supplies seems to be attributable to federally regulated

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[6] Annual Summary of Requirements and Supplies. Cleveland: The East Ohio Gas Company, 1977.

[7] The East Ohio Gas Company 10-Year Forecast Report. Cleveland: The East Ohio Gas Company, 1977.

Table 3-10 Actual & Estimated Gas Supply by Source for the EOGC (MMCF/Year)

Source	Actual[1]							Estimated[2]									
	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
(Index)[3]																	
1. Consolidated	288,132	289,115	276,199	287,793	264,831	278,053	259,309	288,143	295,387	304,822	306,419	308,350	311,432	316,294	317,457	322,872	328,103
2. Index	(111.1)	(111.5)	(106.5)	(110.9)	(102.1)	(107.2)	(100)	(111.1)	(113.9)	(117.6)	(118.1)	(118.9)	(120.1)	(121.9)	(122.4)	(124.5)	(126.5)
3. Panhandle[4]	64,131	65,868	64,857	64,269	58,519	50,689	52,760	54,554	51,501	46,957	47,289	48,126	46,452	44,721	43,663	42,736	42,369
4. Index	(121.5)	(124.8)	(122.9)	(121.8)	(110.9)	(96.0)	(100)	(103.4)	(97.6)	(89.0)	(89.6)	(91.2)	(88.0)	(84.8)	(82.7)	(81.0)	(80.3)
5. Field Line	26,267	28,366	22,954	10,651	26,899	26,260	29,187	Not Available 1978-1987									
6. Well Head	19,780	25,168	16,951	27,242	12,480	11,250	9,486	Not Available 1978-1987									
7. Production	N.A.	3,740	11,163	9,486	11,372	6,785	6,200	Not Available 1978-1987									
8. Appalachian Supply (5+6+7)	46,047	57,274	61,068	47,379	50,751	44,295	44,972	46,376	43,057	41,650	40,724	40,515	40,515	40,626	40,515	40,515	40,515
9. Index	(102.4)	(127.3)	(135.8)	(105.4)	(112.8)	(98.4)	(100)	(98.6)	(95.7)	(92.6)	(90.5)	(90.0)	(90.0)	(90.3)	(90.0)	(90.0)	(90.0)
10. Short Term Gas					4,940	9,131											
11. Total - (1+3+8+10)	398,310	412,257	402,124	399,441	379,041	382,168	357,041	387,073	389,945	393,429	394,432	386,991	398,399	401,641	401,635	406,123	410,987
12. Index	(111.5)	(115.4)	(112.6)	(111.8)	(106.1	(107.0)	(100)	(108.4)	(109.2)	(110.2)	(110.4)	(111.2)	(111.6)	(112.5)	(112.5)	(113.7)	(115.1)

1. East Ohio Gas Annual Reports - F.P.C. Form #2.
2. "Annual Summary of Requirements and Supplies" - November 1977 Gas Estimate; The East Ohio Gas Company.
3. Index = $\frac{\text{year x}}{\text{base year}}$ x 100; base year = 1977.
4. 1978-1987 Panhandle are net of curtailments.

and mandated curtailments, which are to increase from 80,269 MMCF in 1977 to 306,653 MMCF in 1987. These various data are presented in Table 3-11, and short-term, monthly projections of Consolidated's operations are presented in Appendix C. Explicit documentation of the forecasting method is not available.

As pointed out previously (see Table 3-5), 44% of Consolidated gas is supplied to Ohio, almost totally to the EOGC, with a very small share to the River Gas Company in southeastern Ohio. Some concern has been raised at recent hearings before the PUCO about the seemingly contradictory forecasts of Consolidated and the EOGC.[8] Indeed, the EOGC forecasts a 26% increase in its purchases from Consolidated from 1977 to 1987, whereas Consolidated forecasts for itself an overall decreasing supplying ability (13.5% for the same period). This seeming contradiction can be explained if it is assumed that Consolidated will increase EOGC's share of its gas sales. Unfortunately no documentation about such plans can be found. Another explanation is that Consolidated's estimates are very conservative and account only for what is currently ascertained through its pipeline contracts. If one accounts for the additional impact of several gas development projects currently underway the contradiction can be resolved. This was clearly the opinion of Mr. Cumming, President of the River Gas Company, when he testified before the PUCO to obtain a relief order on the ban of new customer hook-ups.[9] Mr. Cumming pointed out such new gas supply sources as: a) PEMEX gas from Mexico, expected to be delivered before 1984, b) the TAPCO project, expected to deliver gas through Canada before 1984, c) increased capacity for LNG deliveries at Cove Point, Maryland, before 1984, and, d) gas from coal gasification. Mr. Cumming's view is that new gas is discovered and produced every year, and therefore additional reserves will be available for Consolidated's system in the foreseeable future.

[8] See PUCO docket #77-1440-GA-SLF.

[9] See PUCO docket #77-1525-GA-UNC.

Table 3-11 Summary of Projected Supplies for the Consolidated Natural Gas System by Source and Year (MMCF/Year)

Source	1976**	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
Pipeline Contracts:												
Texas Eastern	225,599	254,956	254,956	254,956	255,599	254,956	254,956	254,956	255,599	254,956	254,956	254,956
Texas Gas	111,690	111,690	111,690	111,690	111,690	111,690	111,690	111,690	111,690	111,690	111,690	111,690
Tennessee	225,443	224,855	224,855	224,855	225,443	224,855	224,855	224,855	225,443	224,855	224,855	224,855
Transco	9,980	9,980	9,980	9,980	9,980	9,980	9,980	9,980	9,980	9,980	9,980	9,980
Panhandle	66,532	66,350	66,350	66,350	66,532	66,350	66,350	66,350	66,532	66,350	66,350	66,350
Total Contracts	669,244	667,831	667,831	667,831	669,244	667,831	667,831	667,831	669,244	667,831	667,831	667,831
(Curtailments)	(105,469)	(80,269)	(96,933)	(146,968)	(166,637)	(189,694)	(231,774)	(240,623)	(260,058)	(276,069)	(291,417)	(306,653)
Net Pipeline Supplies	563,775	587,562	570,898	520,863	502,607	478,137	454,057	427,208	409,186	391,762	376,414	361,178
Index (Net Pieline Supply)	95.95	100	97.16	88.64	85.54	81.37	77.29	72.70	69.64	66.67	64.06	61.47
Appalachian Supply	162,709	160,756	163,324	160,515	158,276	157,107	156,516	156,055	155,503	154,826	154,222	153,555
Louisiana Supply	27,565	24,229	44,571	63,960	71,810	83,169	81,070	73,520	72,147	69,938	63,492	62,127
L.N.G.I.	--	--	31,287	121,190	131,324	131,324	131,324	131,324	131,324	131,324	131,324	131,324
Short Term Purchase	9,131	6,455	--									
Subtotal	763,180	779,002	810,080	866,528	864,017	849,737	822,967	788,107	768,160	747,850	725,452	708,184
Index (subtotal)*	97.96	100	103.9	111.23	110.9	109.08	105.64	106.16	98.60	96.0	93.12	90.90
Storage Service	51,474	73,270	77,740	77,740	64,470	57,303	53,115	41,800	41,800	41,800	41,800	41,800
Storage Withdrawals	292,387	253,494	266,198	232,833	231,929	220,718	219,527	231,967	218,590	208,695	212,084	206,616
Total Supply	1,107,041	1,105,766	1,154.018	1,177,101	1,160,416	1,127,758	1,095,609	1,061,874	1,028,550	998,345	979,336	956,600
Index (with storage supply)*	100.1	100	104.36	106.45	104.94	101.98	99.08	96.03	93.01	90.28	88.56	86.51
Estimated New Supply Needed to meet Estimated Requirements	--	--	--	--	--	--	--	--	48,125	84,500	111,875	139,250
Estimated Excess Supply	--	--	--	8,908	33,214	16,545						

Source: Consolidated Natural Gas System "Annual Summary of Requirements and Supplies", November 1977 Gas Estimate.

* Index = $\frac{\text{year x}}{\text{base year}}$ x 100; base year = 1977.

** 1976 - Actual

Project Independence Evaluation System (PIES) Projections

The Project Independence Evaluation System is an energy model consisting of three basic components:

1. A demand function, derived from an econometric demand model, which relates fuel quantities demanded to fuel prices.
2. An integrated supply function, derived from fuel specific supply and conversion models, which shows the prices at which the energy market would be willing to produce and deliver specific fuel quantities.
3. An equilibrating mechanism, which determines the energy market conditions which must be satisfied by demand and supply, and which controls the iterative process by which a market equilibrium is reached.[10]

The general structure of the model is illustrated in Figures 3-3 and 3-4. The PIES model, linked to the macroeconomic model developed by Data Resources, Inc. (DRI),[11] has been run in 1977 under six different sets of assumptions or scenarios.[12]

The macroeconomic forecasts developed by DRI - CEASPIRIT, TRENDLONG, and CYCLELONG - were used to generate high, medium, and low energy demand variations. The major features of the three forecasts are summarized in Table 3-12. The following description of these macroeconomic forecasts is extracted from Projections of Energy Supply and Demand and Their Impacts;

> "TRENDLONG depicts a situation of relatively stable long-term economic growth. The economy approaches full employment of labor and capital during the early 1980's and grows steadily along its potential GNP path thereafter

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[10] Project Independence Evaluation System Documentation. Vol. 14, Washington, D.C.: Federal Energy Administration, 1977.

[11] U.S. Long-Term Review. Data Resources, Inc. Fall, 1977.

[12] Projections of Energy Supply and Demand and Their Impacts. Annual Report to Congress, 1977, Vol. II, Energy Information Administration.

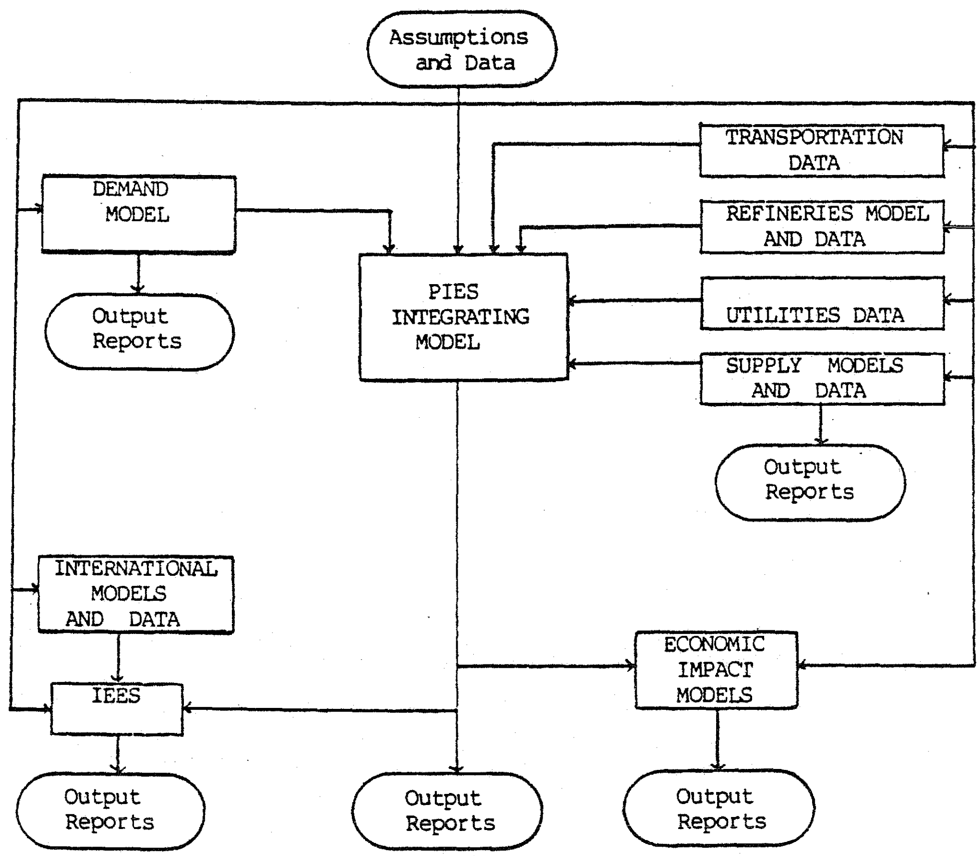

Figure 3-3 Overall Structure of the Project Independence Evaluation System

Source: <u>Project Independence Evaluation System Documentation</u>, Vol. 14, Federal Energy Administration, Washington, D.C., 1977.

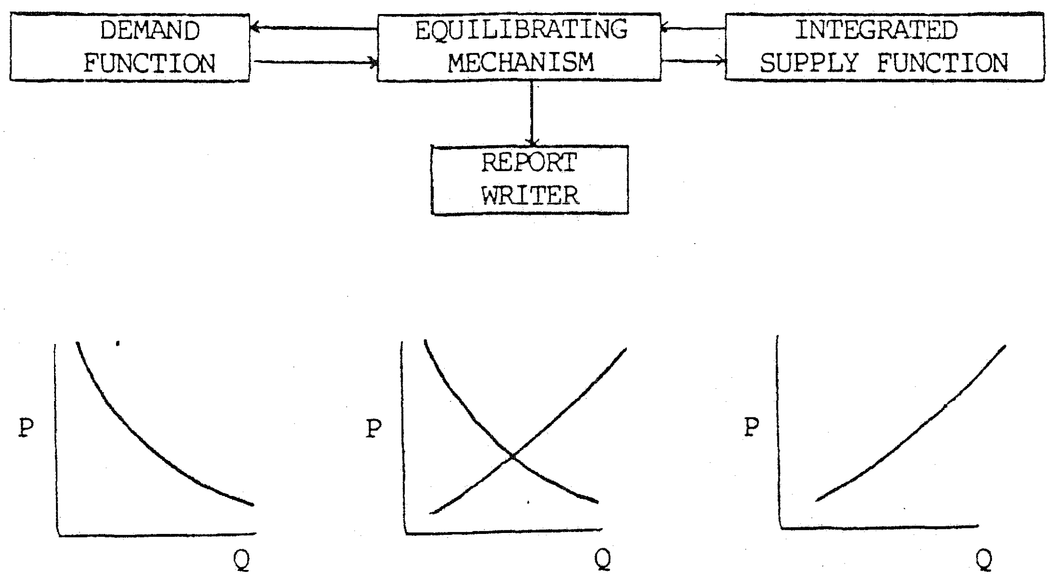

Figure 3-4 PIES Integrating Model Structure

Source: Project Independence Evaluation System Documentation, Vol. 14, Federal Energy Administration, Washington, D.C., 1977.

Economic stability is achieved through complementary monetary and fiscal policies and an absence of exogenous shocks to the economy.

CEASPIRIT is a relatively stable economic growth forecast developed by DRI in conjunction with the staff at the Council of Economic Advisors (CEA). It reflects the near-term economic targets of the CEA as of early 1977, but should not be construed as a CEA assessment of likely economic developments. CEASPIRIT is more optimistic than TRENDLONG, particularly through the early 1980's.

CYCLELONG presents a future characterized by marked cyclical fluctuations. Destabilizing monetary and fiscal policies generate the instability and result in slower growth and higher rates of inflation than in TRENDLONG."

The major differences in assumptions among these three scenarios are presented in Table C-12 in Appendix C.

The previous DRI macroeconomic and related levels of energy demand forecasts were combined with alternative assumptions about the physical availability of oil and gas, and therefore of their costs of production and distribution, with the costs of production and distribution for all the other energy sources held fixed. The median U.S. Geological Survey (USGS) estimates provide the basis for the mid-supply assumption. The alternative geological outlooks translate into a swing of 1.5 million barrels per day in projected domestic petroleum liquids production by 1985, and of 3.5 trillion cubic feet (Tcf) in natural gas production also by 1985. These differences magnify between 1985 and 1990, as illustrated in Figures 3-5 and 3-6.

Finally, two assumptions about the price of imported oil were considered.

"Assuming current practices, most of the projection series embody the assumption of a constant real price of imported oil (at $15.32 per barrel in 1978 dollars). However, an analysis of future world energy supply and demand reveals that upward pressures on world oil prices could develop during the decade of the 1980's. To illustrate the effects of such an eventuality, an alternative assumption termed "rising world oil prices" was developed. In this case, world prices in real terms are held constant (as before) through 1979, then assumed to

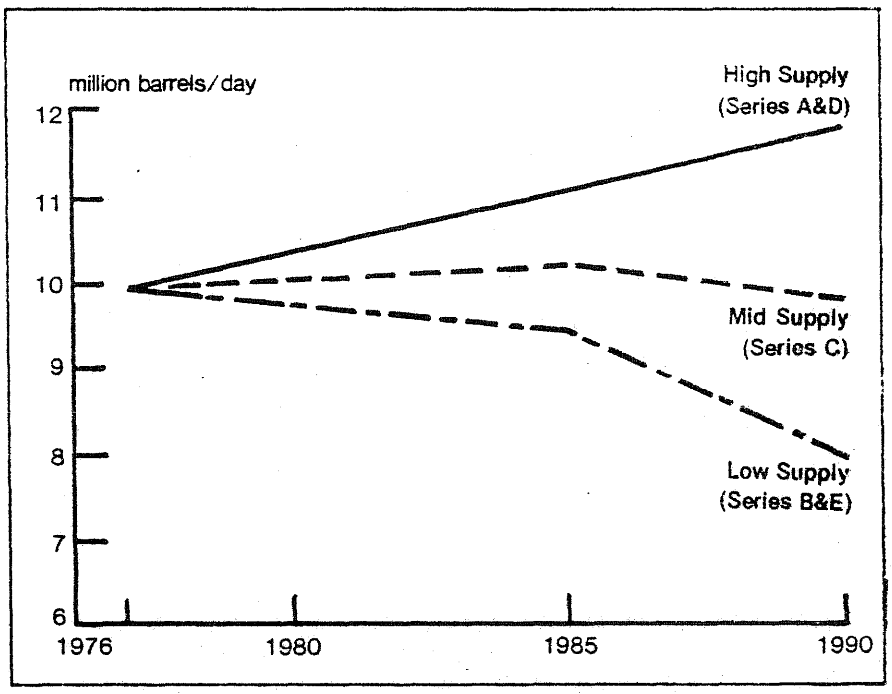

Figure 3-5 Effects of Geology on Liquids Production*
(MMB/D)

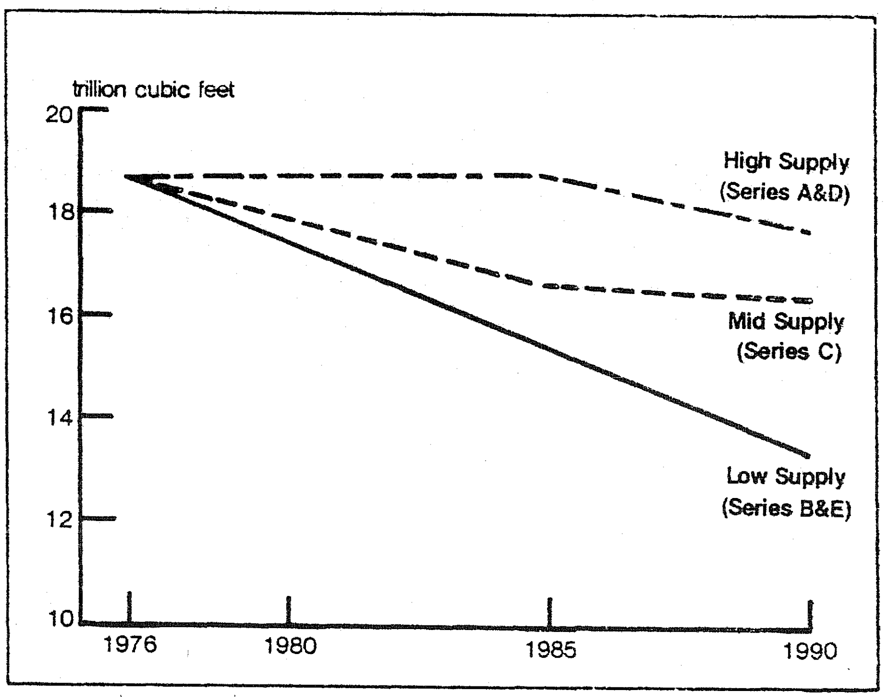

Figure 3-6 Effects of Geology on Gas Production*
(Tcf/yr)

*Source: Energy Information Administration Report

Table 3-12 Summary of DRI Long-Term Forecasts

Forecast	Real Gross National Product (billions of 1972 dollars)			
	1977	1980	1985	1990
CEASPIRIT	$1,327	$1,557	$1,843	$2,131
TRENDLONG	1,336	1,515	1,813	2,109
CYCLELONG	1,336	1,511	1,755	1,976
	GNP Implicit Price Deflator (base year 1972 = 1.000)			
CEASPIRIT	1.416	1.658	2.088	2.539
TRENDLONG	1.413	1.671	2.180	2.721
CYCLELONG	1.414	1.715	2.586	4.094
	Unemployment Rate (percent)			
CEASPIRIT	7.4	5.1	4.6	4.7
TRENDLONG	7.1	6.0	4.7	4.6
CYCLELONG	7.1	6.2	5.8	6.5
	Real Gross National Product (annual growth rates percent)			
	1977-1980	1980-1985	1985-1990	1977-1990
CEASPIRIT	5.5	3.4	2.9	3.7
TRENDLONG	4.3	3.7	3.1	3.6
CYCLELONG	4.2	3.0	2.4	3.1
	GNP Implicit Price Deflator (annual growth rates percent)			
CEASPIRIT	5.4	4.7	4.0	4.6
TRENDLONG	5.7	5.5	4.5	5.2
CYCLELONG	6.6	8.6	9.5	8.5

Source: Projections of Energy Supply and Demand and Their Impacts, Annual Report to Congress, Vol. II, Energy Information Administration, 1977.

increase at the rate of 5 percent per year through the year 1990."[13]

In the latter case, the oil import prices are assumed equal to \$19.55 and \$24.95 per barrel in 1985 and 1990, respectively (prices expressed in 1978 dollars).

The characteristics of the six scenarios considered are summarized in Figure 3-7 and Table 3-13. Additional assumptions common to all the six scenarios are presented in Table 3-14.

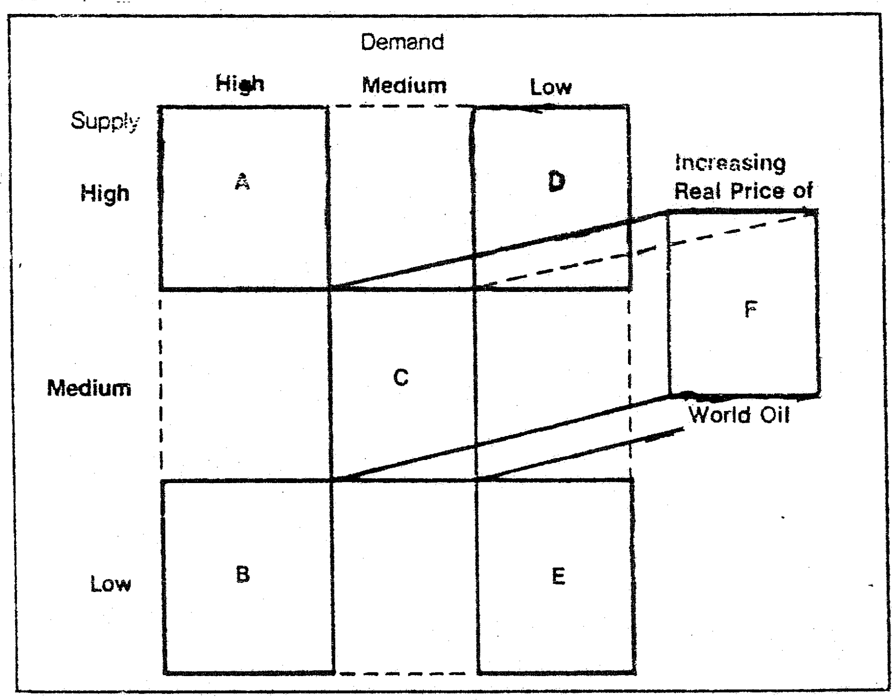

Figure 3-7 The Projection Series

Source: Energy Information Administration Report.

The base year of the simulation runs is 1975. Basic energy consumption and price data for the U.S. and the Midwest in 1975 are

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[13]Energy Information Administration's Annual Report to Congress, 1977.

Table 3-13 PIES Projections Scenarios Assumptions

Scenario	Macro-economic Forecast	Energy Demand	Energy Supply	World Oil Price	PIES Projection Series	Acronym
1	TRENDLONG	MEDIUM	MEDIUM	INCREASING	F	MRTSF
2	TRENDLONG	MEDIUM	MEDIUM	CONSTANT	C	MRTSC
3	CEASPIRIT	HIGH	HIGH	"	A	HRCSA
4	CYCLELONG	LOW	HIGH	"	D	HRCSD
5	CYCLELONG	LOW	LOW	"	E	LRCSE
6	CEASPIRIT	HIGH	LOW	"	B	LRCSB

Table 3-14 Assumptions Common to All PIES Scenarios

Assumptions Common to All Scenarios	1985	1990
1. Wellhead cap ($/MCF)	1.72	1.72
2. North Slope gas availability (MMCF/D, converted from 1138 to 1032 BTU/CF)	2,202.30	2,423.40
3. Canadian gas availability (MMCF/D)	2,482.19	1,871.23
4. Liquefied natural gas availability (MMCF/D)	3,849.31	5,698.64
5. Offshore Continental Shelf (OCS) lease sales follow the 9/77 schedule of the Bureau of Land Management (BLM) through 1981, with 4 sales per year thereafter, at 300,000 acres per sale.		

presented in Table C-13 in Appendix C. The results of the simulation runs for the six scenarios are also presented in Tables C-14 through C-16 in Appendix C. For each scenario, and for both years 1985 and 1990, the following outputs are indicated:

- level of gas production in producing areas, and gas flows to the Midwest;
- intrastate, unregulated gas prices in the consuming regions;
- various forms of energy consumption in the different economic sectors in the Midwest and the U.S. as a whole, as well as Midwest retail prices for the different forms of energy.

Gas Supply and Energy Prices Forecasts for Ohio

It was decided to test the implications of the six scenarios produced by the PIES system and of the supply forecasts developed by the EOGC on new customers hook-up policies. In order to integrate these exogenous forecasts into the simulation model, it was necessary to express them in terms of forecasting indexes which would be applied to base year (1977) data in order to produce forecasts in absolute terms. The reason for creating these indexes is related to the fact that all the forecasts, except EOGC's gas supply forecasts, apply to the Midwest on an average basis, but not specifically to the EOGC service area. However, under the assumption that the energy variables will display the same trends anywhere in the Midwest in relative terms if not in absolute values, it is acceptable to build indexes based on the average Midwest value forecasts and to apply them to the corresponding base year values characterizing the area of study, i.e., the EOGC service area. The base year data preparation is described in the next section, and the purpose of the present section is to show how comprehensive sets of indexes were derived.

With respect to the PIES forecasts, total gas supply for the U.S. and energy prices for the Midwest were initially used. The trends in these variables were assumed to parallel closely those of the same variables in Ohio. Since the PIES forecasts are only available for 1985 and 1990, yearly projections were obtained by interpolation for the

1975-1990 period, and by extrapolation for the 1990-2000 period. It was also necessary to convert the energy prices from 1978 dollars to 1977 dollars as all prices in the simulation model are expressed in 1977 dollars.

Each scenario is characterized by the forecasts of the following variable:

- total gas supply for the U.S.;
- Midwest residential natural gas price;
- Midwest residential electricity price;
- Midwest residential distillate oil price;
- Midwest commercial natural gas price;
- Midwest commercial electricity price;
- Midwest commercial distillate oil price;
- Midwest commercial residual oil price;
- Midwest industrial natural gas price;
- Midwest industrial electricity price;
- Midwest industrial distillate oil price;
- Midwest industrial residual oil price;
- Midwest industrial average coal price (through averaging the Met[14] coal and other coal prices produced by the PIES model).

These data are presented in Tables C-17 through C-29 in Appendix C. The choice of these parameters will be justified in Chapter 4, because they are closely related to the specifications of the consumption models.

The final indexes for the six PIES scenarios are presented in Tables 3-15 through 3-23 In the case of electricity prices for all the consumption sectors, of distillate oil price for the residential sector, and of coal price for the industrial sector, the indexes have been derived directly from the above-mentioned data. The oil price indexes for the commercial and industrial sectors have been computed as averages of the corresponding distillate and residual oil indexes, as presented in Tables C-29 through C-33 in Appendix C. The wholesale natural gas price index has been assumed to be equal to the average of the residential, commercial and industrial retail prices indexes,

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[14]Met Coal - includes 70% premium coal and 30% bituminous low sulfur coal.

as presented in Tables C-34 through C-36 in Appendix C.

With respect to the EOGC forecasts, supply figures for the 1988-2000 period were calculated by extrapolating the average growth forecast for the 1977-1987 period. The corresponding supply index is indicated in the last column of Table 3-15. In order to run the simulation model, however, this supply forecast must be complemented by energy prices forecasts. It was assumed that the set of price forecasts produced by the PIES model most likely to fit with EOGC supply forecasts was that of the MRTSF scenario. Indeed, the relatively high level of forecasted supply is likely to be the result of strong gas price increases, which do characterize the MRTSF scenario. This seventh scenario is noted EOGCS (EOGC's scenario).

On the basis of Tables 3-14 through 3-23 it is worthwhile to note that:

1. EOGCS is, by far, the most optimistic scenario as far as wholesale gas supply is concerned. Only MRTSF shows a net increase of 3.5% by the year 2000; MRTSC, HRCSA and HRCSD show a slight net decrease of 2-3% by the year 2000, while LRCSE and LRCSB show a 35% decrease in supply over the planning horizon (these two scenarios correspond to the low geological outlooks for gas and oil and, therefore, high production and distribution costs). MRTSF, MRTSC, HRCSA and HRCSD all experience an initial decrease in supply.
2. The wholesale price of natural gas is increasing at least threefold over the planning horizon and nearly five times for scenarios MRTSF and EOGCS.
3. The oil prices for the three consumption sectors increase by 25-40% over the planning horizon, except in the case of scenarios MRTSF and EOGCS, which imply imported oil prices increasing by 130-140%.
4. The electricity prices increase by 10-15% for the residential and commercial sectors, except for scenarios MRTSF and EOGCS, where they experience a decrease by 13% and 5% respectively. The industrial electricity price shows stronger increase trends, in particular for scenarios MRTSF and EOGCS. (The industrial electricity price index is presented here for documentary purposes but will not be used in the industrial energy consumption model presented in Chapter 4.)
5. The industrial coal price indexes are characterized by a homogeneous and moderate increase (45-55%) in all the scenarios.

Table 3-15 Index of Wholesale Natural Gas Supply by Scenario

Year	Scenarios						
	MRTSF	MRTSC	HRCSA	HRCSD	LRCSE	LRCSB	EOGCS
1977	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1978	95.5	95.5	95.5	95.5	95.5	95.5	108.4
1979	92.9	92.9	92.9	92.9	92.9	92.9	109.2
1980	93.1	92.8	94.5	94.0	91.7	92.1	110.2
1981	93.2	92.8	95.9	95.2	90.5	91.3	110.4
1982	93.4	92.8	97.5	96.3	89.4	90.4	111.2
1983	93.5	92.7	99.0	97.4	88.2	89.6	111.6
1984	93.7	92.6	100.5	98.5	87.0	88.7	112.5
1985	93.9	92.9	102.1	99.6	85.8	87.9	112.5
1986	94.5	93.2	101.8	99.5	84.3	86.4	113.7
1987	95.2	93.5	101.6	99.3	82.8	84.9	115.1
1988	95.8	93.8	101.3	99.2	81.3	83.4	115.8
1989	96.4	93.8	101.0	99.0	79.8	81.8	116.4
1990	97.1	94.0	100.7	98.9	78.3	80.3	117.1
1991	97.7	94.3	100.5	98.8	76.8	78.8	117.8
1992	98.4	94.6	100.3	98.7	75.3	77.3	118.5
1993	99.0	94.8	99.9	98.6	73.8	75.8	119.1
1994	99.7	95.1	99.7	98.4	72.3	74.3	119.8
1995	100.3	95.4	99.4	98.3	70.8	72.8	120.5
1996	100.9	95.7	99.2	98.2	69.2	71.2	121.1
1997	101.6	95.9	98.9	98.1	67.8	69.7	121.8
1998	102.2	96.2	98.6	97.9	66.3	68.2	122.5
1999	102.8	96.5	98.4	97.8	64.8	66.7	123.1
2000	103.5	96.7	98.1	97.7	63.2	65.2	123.8

Table 3-16 Index of Wholesale Natural Gas Price by Scenario

Year	Scenario						
	MRTSF	MRTSC	HRCSA	HRCSD	LRSCE	LRCSB	EOGCS
1977	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1978	108.7	107.1	107.2	106.6	107.1	107.1	108.7
1979	116.9	114.3	113.8	113.3	114.3	114.3	116.9
1980	125.0	121.4	120.9	119.9	122.0	122.0	125.0
1981	133.1	127.9	128.1	125.9	129.2	129.2	133.1
1982	141.3	135.1	140.7	132.5	136.3	136.3	141.3
1983	150.0	142.2	141.9	139.2	143.5	143.5	150.0
1984	158.1	149.4	148.5	145.8	150.6	150.6	158.1
1985	166.3	156.5	155.7	152.4	157.8	157.8	166.3
1986	187.2	166.1	165.9	163.9	167.3	167.3	187.2
1987	207.5	175.6	176.0	174.7	177.4	176.8	207.5
1988	228.4	185.7	186.2	186.1	186.9	185.7	228.4
1989	248.8	195.2	196.4	196.9	197.0	195.2	248.8
1990	269.8	204.8	206.6	208.4	206.5	204.8	269.8
1991	290.7	214.3	216.8	219.9	216.1	214.3	290.7
1992	311.0	223.8	226.9	230.1	226.2	223.8	311.0
1993	331.9	233.9	237.1	242.2	235.7	232.7	331.9
1994	352.3	243.5	247.3	253.0	245.8	242.3	352.3
1995	373.2	252.9	257.5	264.5	255.4	251.8	373.2
1996	394.2	262.5	267.7	275.9	264.9	261.3	394.2
1997	414.5	272.0	277.8	286.7	275.0	270.8	414.5
1998	435.5	282.1	288.0	298.2	284.5	279.8	435.5
1999	455.8	291.6	298.2	309.0	294.6	289.3	455.8
2000	476.7	301.2	308.4	320.5	304.2	298.8	476.7

Table 3-17 Index of Residential Retail Oil Price by Scenario

Year	Scenario						
	MRTSF	MRTSC	HRCSA	HRCSD	LRCSE	LRCSB	EOGCS
1977	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1978	104.2	102.7	102.3	102.3	102.7	102.7	104.2
1979	108.0	105.0	104.6	104.7	104.9	104.9	108.0
1980	112.2	107.3	107.0	107.0	107.6	107.6	112.2
1981	116.1	109.7	109.3	109.0	109.9	109.9	116.1
1982	120.3	112.0	111.6	111.3	112.6	112.6	120.3
1983	124.1	114.7	114.0	113.7	114.9	114.9	124.1
1984	128.3	117.0	116.3	115.7	117.6	117.6	128.3
1985	132.2	119.3	118.6	118.1	119.9	119.9	132.2
1986	138.3	120.3	119.3	118.7	120.6	121.3	138.3
1987	144.4	121.7	120.0	119.1	121.6	122.3	144.4
1988	150.2	122.7	121.0	119.7	122.3	123.6	150.2
1989	156.3	124.0	122.0	120.1	123.3	124.6	156.3
1990	162.4	125.0	122.7	120.7	123.9	125.9	162.4
1991	164.5	126.0	123.3	121.4	124.6	127.2	164.5
1992	174.6	127.3	124.3	121.7	125.6	128.2	174.6
1993	180.4	128.3	125.0	122.4	126.2	129.6	180.4
1994	186.5	129.7	126.0	122.7	127.2	130.6	186.5
1995	192.6	130.7	126.7	123.4	127.9	131.9	192.6
1996	198.7	131.7	127.3	124.1	128.6	133.2	198.7
1997	204.8	133.0	128.3	124.4	129.6	134.2	204.8
1998	210.9	134.0	129.0	125.1	130.2	135.5	210.9
1999	216.7	135.3	130.0	125.4	131.2	136.5	216.7
2000	228.8	136.3	130.7	126.1	131.9	137.9	228.8

Table 3-18 Index of Residential Retail Electricity Price by Scenario

Year	Scenario						
	MRTSF	MRTSC	HRCSA	HRCSD	LRCSE	LRCSB	EOGCS
1977	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1978	101.1	100.5	100.6	100.4	100.5	100.5	101.1
1979	102.2	101.0	101.2	100.7	100.7	101.2	102.2
1980	103.3	101.5	101.7	101.1	101.2	101.8	103.3
1981	104.3	101.9	102.3	101.5	101.5	102.5	104.3
1982	105.3	102.5	102.8	101.8	101.9	103.0	105.3
1983	106.4	102.9	103.5	102.2	102.4	103.7	106.4
1984	107.5	103.5	104.0	102.6	102.7	104.2	107.5
1985	108.6	103.9	104.6	102.9	103.1	104.8	108.6
1986	107.2	104.6	105.1	103.3	103.5	105.3	107.2
1987	105.7	105.2	105.7	103.8	103.8	105.8	105.7
1988	104.2	106.0	106.2	104.1	104.1	106.3	104.2
1989	102.7	106.6	106.7	104.6	104.4	106.9	102.7
1990	101.3	107.2	107.3	104.9	104.8	107.3	101.3
1991	99.8	107.9	107.8	105.3	105.1	107.8	99.8
1992	98.4	108.5	108.4	105.8	105.4	108.3	98.4
1993	96.8	109.3	108.9	106.2	105.8	108.8	96.8
1994	95.4	109.9	109.5	106.6	106.1	109.3	95.4
1995	93.9	110.5	110.1	106.9	106.4	109.8	93.9
1996	92.4	111.2	110.6	107.3	106.8	110.2	92.4
1997	91.0	111.8	111.2	107.8	107.1	110.8	91.0
1998	89.5	112.6	111.7	108.2	107.4	111.3	89.5
1999	88.0	113.2	112.3	108.6	107.7	111.8	88.0
2000	86.6	113.8	112.8	109.0	108.1	112.3	86.6

Table 3-19 Index of Commercial Retail Oil Price by Scenario

Year	Scenario						
	MRTSF	MRTSC	HRCSA	HRCSD	LRCSE	LRCSB	EOGCS
1977	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1978	104.4	103.1	102.7	102.7	103.1	103.1	104.4
1979	109.2	105.8	105.4	105.0	105.7	105.7	109.2
1980	113.6	108.5	108.1	107.7	108.8	108.8	113.6
1981	118.1	111.1	110.8	110.4	111.5	111.5	118.1
1982	122.9	113.8	113.5	112.7	114.6	114.6	122.9
1983	127.3	116.9	116.2	115.4	117.2	117.2	127.3
1984	132.1	119.6	118.8	117.8	120.3	120.3	132.1
1985	136.5	122.3	121.5	120.5	122.9	122.9	136.5
1986	143.2	123.8	122.7	121.2	123.8	124.5	143.2
1987	150.2	125.0	123.4	122.0	124.9	126.7	150.2
1988	156.8	126.5	124.6	122.4	125.7	127.2	156.8
1989	163.8	127.7	125.4	123.2	126.8	128.4	163.8
1990	170.5	129.2	126.5	123.9	127.6	129.9	170.5
1991	177.1	130.8	127.7	124.7	128.4	131.4	177.1
1992	184.1	131.9	128.5	125.5	129.5	132.6	184.1
1993	190.8	133.5	129.6	125.9	130.3	134.1	190.8
1994	197.8	134.6	130.4	126.6	131.4	135.2	197.8
1995	204.4	136.2	131.5	127.4	132.2	136.8	204.4
1996	211.1	137.7	132.7	128.2	133.0	138.3	211.1
1997	218.1	138.8	133.5	128.9	134.1	139.5	218.1
1998	224.7	140.3	134.6	129.3	134.9	141.0	224.7
1999	231.7	141.5	135.4	130.1	136.0	142.1	231.7
2000	238.4	143.1	136.5	130.8	136.8	143.7	238.4

Table 3-20 Index of Commercial Retail Electricity Price by Scenario

Year	Scenario						
	MRTSF	MRTSC	HRCSA	HRCSD	LRCSE	LRCSB	EOGCS
1977	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1978	101.3	100.7	100.8	100.6	100.6	100.8	101.3
1979	102.6	101.4	101.5	101.2	101.2	101.6	102.6
1980	103.9	102.1	102.3	101.8	100.8	102.4	103.9
1981	105.1	102.9	103.1	102.3	102.3	103.2	105.1
1982	106.4	103.5	103.8	102.9	102.9	104.1	106.4
1983	107.7	104.3	104.6	103.6	103.6	104.8	107.7
1984	108.9	104.9	105.3	104.1	104.2	105.7	108.9
1985	110.2	105.7	106.2	104.7	104.7	106.5	110.2
1986	109.2	106.3	106.7	105.1	105.1	106.9	109.2
1987	108.1	107.0	107.4	105.5	105.4	107.5	108.1
1988	107.1	107.7	107.9	105.9	105.8	108.0	107.1
1989	105.9	108.4	108.5	106.4	106.1	108.6	105.9
1990	104.9	109.1	109.1	106.7	106.5	109.0	104.9
1991	103.9	109.7	109.7	107.1	106.8	109.5	103.9
1992	102.8	110.4	110.3	107.6	107.1	110.0	102.8
1993	101.8	111.1	110.9	107.9	107.5	110.5	101.8
1994	100.7	111.8	111.6	108.4	107.8	111.1	100.7
1995	99.7	112.4	112.1	108.8	108.1	111.5	99.7
1996	98.7	113.1	112.7	109.2	108.5	112.0	98.7
1997	97.6	113.7	113.3	109.6	108.8	112.6	97.6
1998	96.6	114.5	113.9	110.0	109.2	113.0	96.6
1999	95.5	115.1	114.5	110.5	109.4	113.6	95.5
2000	94.4	115.8	115.1	110.9	109.8	114.1	94.4

Table 3-21 Index of Industrial Retail Oil Price by Scenario

Year	Scenario						
	MRTSF	MRTSC	HRCSA	HRCSD	LRCSE	LRCSB	EOGCS
1977	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1978	104.4	102.7	102.3	102.7	102.7	102.7	104.4
1979	108.8	105.4	105.0	105.0	105.4	105.7	108.8
1980	113.7	108.1	107.7	107.7	108.4	108.4	113.7
1981	118.1	111.1	110.4	110.0	111.1	111.1	118.1
1982	122.5	113.8	113.1	112.7	113.8	114.2	122.5
1983	126.9	116.5	115.4	115.1	116.5	116.9	126.9
1984	131.7	119.2	118.1	117.8	119.5	119.9	131.7
1985	136.2	121.9	120.8	120.1	122.2	122.6	136.2
1986	142.8	123.1	121.9	120.8	122.9	124.1	142.8
1987	149.8	124.2	122.7	121.2	124.1	125.3	149.8
1988	156.5	125.8	123.8	122.0	124.9	126.8	156.5
1989	163.5	126.9	124.6	122.3	126.1	127.9	163.5
1990	170.1	128.1	125.8	123.1	126.8	129.5	170.1
1991	176.8	129.2	126.9	123.9	127.6	131.0	176.8
1992	183.8	130.4	127.7	124.3	128.7	132.2	183.8
1993	190.4	131.9	128.8	125.1	129.5	133.7	190.4
1994	197.4	133.1	129.6	125.4	130.7	134.9	197.4
1995	204.1	134.2	130.8	126.3	131.4	136.4	204.1
1996	210.7	135.4	131.9	127.0	132.2	137.9	210.7
1997	217.7	136.5	132.7	127.4	133.3	139.1	217.7
1998	224.4	138.1	133.8	128.1	134.1	140.6	224.4
1999	231.4	139.2	134.6	128.6	135.2	141.8	231.4
2000	238.0	140.4	135.7	129.3	136.0	143.3	238.0

Table 3-22 Index of Industrial Retail Electricity Price by Scenario

Year	Scenario						
	MRTSF	MRTSC	HRCSA	HRCSD	LRCSE	LRCSB	EOGCS
1977	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1978	103.2	103.3	103.4	103.2	103.2	103.4	103.2
1979	106.2	106.6	106.8	106.2	106.3	106.8	106.2
1980	109.3	110.0	110.3	109.3	109.5	110.3	109.3
1981	112.5	113.3	113.5	112.5	112.6	113.6	112.5
1982	115.5	116.6	116.9	115.5	115.8	117.2	115.5
1983	118.7	119.9	120.4	118.7	118.9	120.6	118.7
1984	121.6	123.1	123.8	121.6	122.0	124.0	121.6
1985	124.8	126.4	127.2	124.8	125.2	127.6	124.8
1986	128.8	127.4	128.1	125.5	125.6	128.4	128.8
1987	133.0	128.4	128.9	126.1	126.2	129.2	133.0
1988	137.0	129.6	129.8	126.8	126.6	130.0	137.0
1989	141.2	130.6	130.6	127.4	127.2	130.7	141.2
1990	145.2	131.6	131.5	128.1	127.6	131.6	145.2
1991	149.2	132.6	132.3	128.8	128.1	132.4	149.2
1992	153.4	133.6	133.2	129.4	128.6	133.1	153.4
1993	157.4	134.7	134.0	130.1	129.1	133.9	157.4
1994	161.5	135.7	134.9	130.7	129.6	134.7	161.5
1995	165.6	136.7	135.8	131.4	130.1	135.6	165.6
1996	169.6	137.7	136.6	132.1	130.5	136.4	169.6
1997	173.7	138.7	137.5	132.7	131.1	137.1	173.7
1998	177.8	139.9	138.3	133.4	131.5	137.9	177.8
1999	181.9	140.9	139.2	134.0	132.1	138.7	181.9
2000	185.9	141.9	140.0	134.7	132.5	139.5	185.9

Table 3-23 Index of Industrial Retail Coal Price by Scenario

Year	Scenario						
	MRTSF	MRTSC	HRCSA	HRCSD	LRCSE	LRCSB	EOGCS
1977	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1978	103.6	103.5	103.6	103.6	102.8	103.5	103.6
1979	107.1	106.4	107.1	106.5	106.3	106.3	107.1
1980	110.7	109.9	110.7	110.0	109.1	109.7	110.7
1981	114.3	113.5	113.6	112.9	111.9	113.2	114.3
1982	117.9	116.3	117.1	116.5	115.4	115.9	117.9
1983	121.4	119.9	120.7	119.4	118.2	119.4	121.4
1984	125.0	122.7	123.6	123.0	121.6	122.2	125.0
1985	128.6	126.2	127.1	125.9	124.5	125.7	128.6
1986	130.0	127.7	128.6	127.3	125.9	127.1	130.0
1987	132.1	129.1	130.7	129.5	127.3	128.5	132.1
1988	133.6	131.2	132.1	130.9	127.9	129.2	133.6
1989	135.7	132.6	134.3	133.1	129.4	130.5	135.7
1990	137.1	134.0	135.7	134.5	130.8	131.9	137.1
1991	138.6	135.5	137.1	135.9	132.1	133.3	138.6
1992	140.7	136.9	139.3	138.1	133.6	134.7	140.7
1993	142.1	139.0	140.7	139.6	134.3	135.4	142.1
1994	144.3	140.4	142.9	141.7	135.7	136.8	144.3
1995	145.7	141.8	144.3	143.2	137.1	138.2	145.7
1996	147.1	143.3	145.7	144.6	138.5	139.6	147.1
1997	149.3	144.7	147.9	146.8	139.9	140.9	149.3
1998	150.7	146.8	149.3	148.2	140.6	141.7	150.7
1999	152.9	148.2	151.4	150.4	141.9	143.1	152.9
2000	154.3	149.6	152.8	151.8	143.4	144.4	154.3

Base Year Energy Supply and Price Data

The exogenous energy forecasts are obtained by applying the forecasting indexes to the base year (1977) values of the relevant parameters as they characterize the EOGC service area. These parameters are: a) the wholesale gas supply and price, b) the oil and electricity prices for both the residential and commercial sectors, and c) the oil and coal prices for the industrial sector. These data are presented in Table 3-24. The industrial electricity price has been added for documentary purposes, as well as the gas retail prices for the residential, commercial and industrial sectors. Future retail gas prices are to be determined endogenously to the simulation model, as will be explained in detail in Chapter 8.

Gas supply and prices data have been extracted from the 1977 Annual Report of the EOGC.

The 1977 residential price of oil for the Cleveland area (46.9¢/gallon) was obtained from the Cleveland Area Mobil Distributor. No prices could be obtained for the commercial and industrial sectors, in which oil is traded through bulk contract with the price dependent upon the contract. The 1977 oil prices of the HRCSA scenario were used to evaluate these prices for the EOGC service area. Both commercial and industrial oil prices are assumed to be equal and to bear the same relationship to the residential oil price as in the HRCSA scenario, in which they are equal to 92% of the residential price.

Retail electricity prices were taken as the averages of the prices charged by the Ohio Edison Company and the Cleveland Electric Illuminating Company, the two major electric utilities providing electricity in the EOGC service area. These basic data are indicated in the 1977 Annual Reports of these utilities and are summarized in Table 3-25.

An average industrial coal price of 30 $/ton was obtained from the Cardinal Coal Company of Columbus which operates in northeastern Ohio. This price, converted to $1.3326/MMBTU, is slightly lower than the prices for the Midwest as yielded by the alternative scenarios, which range from $1.39 to $1.44/MMBTU. As a compromise between these varying data, a base price of $1.40/MMBTU was finally selected.

Table 3-24 Base Year Supply and Price Values in the EOGC Service Area

Energy Parameter / Consumption Sector	Gas Supply (MCF)	Gas Price ($/MMBTU)	Oil Price ($/MMBTU)	Electricity Price ($/MMBTU)	Coal Price ($/MMBTU)
Wholesale	350,742,058	1.41816	-	-	-
Residential	-	2.22920	3.3814	13.6862	-
Commercial	-	2.06230	3.1109	12.3088	-
Industrial	-	1.98470	3.1109	7.8249	1.400

Table 3-25 Ohio Edison and Cleveland Electric Electricity Rates in 1977 (¢/kwh)

Sector	Ohio Edison	Cleveland Electric
Residential	4.56	4.78
Commercial	4.28	4.12
Industrial	2.51	2.83

Note: The following conversion factors have been used in preparing the above data:

- 3412. 193 BTU per kWh of electricity;
- 1035 BTU per Cf of natural gas;
- 1 barrel equals 42 gallons of oil;
- 1 barrel of oil contains 5.8254 million BTU's.

CHAPTER 4

GAS CONSUMPTION ANALYSIS

Forecasting potential gas requirements of residential, commercial and industrial customers is an essential step in planning the utility's operations and plant expansions. Such forecasts must account for potential growth or decline in population and in the number of commercial and industrial enterprises that are expected to locate in or move from the service area. They must also take into account potential changes in the prices of energy and the technology of consuming it. In particular, the price competitiveness of other sources of energy may be a critical factor in the estimation of future potential gas requirements. Also, at the intra-annual time scale, these requirements are also dependent upon weather, particularly temperature. Indeed, space-heating constitutes a significantly large component of end-use requirements, especially in the residential and commercial sectors. It is necessary, therefore, to account for the meteorological factor in the forecasting process.

The purpose of the present chapter is to develop a modeling approach integrating the above-mentioned factors and aiming at forecasting future gas requirements by major class of customers. This forecasting model comprises two steps. First, future aggregate requirements are forecasted at the annual level, under the assumption of a "normal weather" pattern. Three models making these forecasts for the residential, commercial and industrial sectors are presented in the next three sections. Second, these aggregate annual requirements are broken down on a monthly basis to account for temperature variations. The method of estimating these monthly loads is presented in the last section.

Annual Residential Gas Consumption Analysis and Forecasting

The purpose of this section is to present a specification of the residential gas consumption model at the annual level. The purpose of this model is to forecast the potential new residential gas demand in a given year. This potential new demand is assumed to be a function of demographic changes, price differentials between gas and alternative sources of energy, customer attrition rates and energy conservation efforts. In the following, these factors will be successively analyzed, and then a synthesis of the modeling approach will be presented.

Market Sharing of New Potential Energy Residential Customers

The market sharing of a given pool of new residential customers among alternative energy forms is a function of their relative prices as well as of the technology of residential energy usage.

In the present approach the technological change factor will be ignored, i.e., it is assumed that technologies related to residential energy usage do not change over the planning horizon of the present study (e.g. furnace efficiencies, etc.). Thus, the sharing of the residential fuel market is determined solely on the basis of fuel prices, and the specification of the sharing model is based upon an analysis of aggregated state data of 1971. It can be reasonably assumed that at that time no major fuel curtailment was impeding the competitive operation of the market and, therefore, that the observed fuel consumption shares reflect a free, competitive market situation. Only gas, oil and electricity were considered. Although coal may also be used for residential energy consumption, the difficulty of handling it constitutes a major barrier to its widespread use. This is confirmed by the data presented in Table F-1 in Appendix F. It appears that coal comprises only 2.43% of residential energy consumption in the eighteen counties containing the EOGC service area. Also, no attempt was made in the present study to model this market sharing process according to specific end-uses such as house heating, air conditioning, water heating, cooking, refrigeration, lighting, etc. Table F-2 in Appendix F presents the shares of the different residential energy uses in the eighteen counties of the EOGC service area. As could be expected, house heating is the major energy intensive end-use, with a share varying between 62% and 76%. The distribution of fuel shares for house heating for these eighteen counties is presented in Table F-3, and a synthesis of this information at the level of the EOGC divisions is presented in Table F-4. Clearly, some uses require a specific fuel and no substitute fuel can be used. This is typically the case of electricity for lighting or refrigeration. Also, once a fuel, like gas, is chosen for space heating, it is very likely to be used also for water heating and cooking, and maybe even for air conditioning. Each of these interactions should be modeled. Unfortunately, given the time and budget limits of the present study, such a modeling effort could not be undertaken. Thus, the sharing process is assumed to be correctly represented by an aggregate model based upon an analysis of total residential energy usage.

The data used for calibrating the residential market sharing model are presented in Table 4-1. They consist of oil, electricity and gas consumption levels and the corresponding average prices in the U.S. and in each state. Electricity and gas related data were obtained from professional publications of the corresponding industries.[1,2] Distillate oil consumption data were obtained from the American Petroleum Institute. Oil prices were gathered from Energy Prices 1960-73 and supplemented by prices derived from 1975 prices and average price growth rates for the period 1972-1975 for states included in Federal Regions 6 and 8 (see Figure C-1 in Appendix C).[3]

Various market sharing models have been developed in recent years and are briefly described in Appendix E. The structure of the sharing model

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[1] Statistical Year Book of the Electric Utility Industry - 1971. Edison Electric Institute.

[2] Gas Facts. 1971. American Gas Association, Department of Statistics, 1515 Wilson Boulevard, Arlington, VA. 22209.

[3] Foster Associates, Inc. Energy Prices 1960-73, Ballinger Publishing Company, Cambridge, Mass., 1974.

developed here for the residential sector is similar to that of the industrial sharing model proposed by Limaye and Sharko. This model is based on the hypothesis that the market share of a given fuel is a half-bell shaped function of a price index for that fuel.

The price index for gas is defined as:

$$PIG = \frac{PRGR - \langle PROR,PRER \rangle}{\overline{P}} \tag{4-1}$$

where:

PRGR = residential price of gas;
PRER = residential price of electricity;
PROR = residential price of oil;
SHGR = residential share of gas;
SHER = residential share of electricity;
SHOR = residential share of oil;
$\langle PROR,PRER \rangle$ = composite average price of oil and electricity;
$\overline{P}$ = composite average price of all fuels.

with:

$$\langle PROR,PRER \rangle = \frac{PROR.\ SHOR + PRER.\ SHER}{SHOR + PRER} \tag{4-2}$$

$$\overline{P} = PRGR.\ SHGR + PROR.\ SHOR + PRER.\ SHER \tag{4-3}$$

Similar price indexes are defined for oil and electricity, by simply exchanging the price and share variables in Equations 4-1 and 4-2. The states' shares and price indexes in 1971 are presented in Table 4-2. A graphical representation of the points (market share - price index) for both oil and gas reveals patterns very similar to the pattern suggested by Limaye and Sharko. The relationship between market share and price index is clearly non-linear. Although a polynomial regression analysis was performed to relate market share to price

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[4] D.R. Limaye and J.R. Sharko, "Simulation of Energy Market Dynamics", in D.R. Limaye and J.R. Sharko (eds.), Energy Policy Evaluation, Lexington Books, Lexington, Mass., 1974.

Table 4-1 Fuel Consumption and Average Price in the Residential Sector by State in 1971

State	Oil Consumption (TBTU)	Electricity Consumption (TBTU)	Gas Consumption (TBTU)	Average Price of Oil ($/MMBTU)	Average Price of Electricity ($/MMBTU)	Average Price of Gas ($/MMBTU)
USA	1915.875	1634.713	5039.699	1.33209	6.41306	1.11813
Maine	36.326	6.425	0.800	1.43509	7.65252	3.05625
New Hampshire	27.707	5.657	3.900	1.43509	7.65758	1.92000
Vermont	17.313	4.439	1.200	1.43509	6.49404	1.85917
Massachusetts	209.152	33.528	90.300	1.43509	8.67070	2.03242
Rhode Island	29.696	5.057	12.800	1.43509	8.12747	1.85938
Connecticut	72.746	22.929	32.300	1.43509	7.38606	2.12582
New York	386.650	90.051	361.100	1.44196	8.98332	1.47401
New Jersey	207.189	43.799	148.600	1.44196	8.43765	1.70740
Pennsylvania	153.967	80.702	319.000	1.44196	7.65882	1.24876
Ohio	54.300	76.723	481.800	1.33724	6.82942	0.96693
Indiana	64.747	43.342	156.200	1.30463	6.22686	1.08428
Illinois	81.648	73.058	465.100	1.30463	7.85540	1.05391
Michigan	105.631	61.065	355.100	1.33724	6.80787	1.02079
Wisconsin	71.851	34.583	114.200	1.33724	6.53027	1.22935
Minnesota	56.689	28.601	104.800	1.29261	7.13202	1.17855
Iowa	18.827	23.083	95.300	1.36986	7.50709	1.01073
Missouri	17.889	35.726	159.600	1.36986	7.43456	0.97370
N. Dakota	4.587	4.866	8.700	1.63051	7.40063	1.09310
S. Dakota	4.811	5.432	11.500	1.63051	7.34067	1.09252
Nebraska	6.424	12.536	53.900	1.36986	6.17306	0.93627
Kansas	1.625	17.276	95.600	1.36986	6.93526	0.70868
Delaware	12.153	4.252	8.400	1.23081	7.67334	1.56404
Maryland & Washington, D.C.	54.159	29.655	88.700	1.41621	7.29998	1.50310

Sources: Statistical Year Book of the Electric Utility Industry - 1971, Edison Electric Institute
Gas Facts - 1971, American Gas Association
American Petroleum Institute
Foster Associate, Inc. Energy Prices 1960-1973, Ballinger Publishing Company, Cambridge, Mass. 1974.

Table 4-1 Fuel Consumption and Average Price in the Residential Sector by State in 1971 (cont'd)

State	Oil Consumption (TBTU)	Electricity Consumption (TBTU)	Gas Consumption (TBTU)	Average Price of Oil ($/MMBTU)	Average Price of Electricity ($/MMBTU)	Average Price of Gas ($/MMBTU)
Virginia	45.514	40.557	51.100	1.23081	5.92793	1.48446
W. Virginia	2.395	12.226	57.300	1.23081	6.39723	0.88134
N. Carolina	39.655	52.084	28.900	1.23081	5.55263	1.32951
S. Carolina	13.217	25.714	20.100	1.23081	5.75353	1.41512
Georgia	8.566	45.682	87.200	1.23081	5.17693	1.16212
Florida	13.467	88.598	17.600	1.23081	5.92543	1.89188
Kentucky	5.115	29.618	83.000	1.23081	5.08822	0.88206
Tennessee	5.635	66.493	46.200	1.23081	3.70645	0.95900
Alabama	1.798	40.076	56.100	1.23081	4.63005	1.20984
Mississippi	2.444	20.449	31.200	1.23081	5.22013	0.93978
Arkansas	0.879	15.147	47.000	1.45647	6.54855	0.80268
Louisiana	0.930	32.713	71.700	1.45647	6.29434	0.81234
Oklahoma	1.354	21.060	78.300	1.45647	7.05291	0.82490
Texas	5.849	106.798	225.000	1.45647	5.98675	0.97144
Montana	2.116	5.507	24.400	1.63051	6.21520	0.84631
Idaho	6.841	8.875	8.700	1.58787	4.66270	1.39218
Wyoming	1.134	2.198	13.000	1.63051	7.12946	0.65777
Colorado	2.778	12.765	84.800	1.63051	7.36075	0.73738
New Mexico	0.439	4.927	26.700	1.45647	7.73157	0.85637
Arizona	0.453	15.856	35.100	1.58787	6.54911	1.12356
Utah	2.788	6.162	43.500	1.63051	6.53089	0.73467
Nevada	1.813	7.316	8.000	1.58787	4.25413	1.39600
Washington	28.142	60.420	36.600	1.58787	2.98263	1.31828
Oregon	15.344	35.326	22.800	1.58787	3.68336	1.51715
California	3.145	128.824	662.900	1.58787	6.41812	0.98176
Alaska	7.493	1.853	2.600	1.58787	8.81423	1.65461
Hawaii	0.207	4.682	0.900	1.58787	8.18370	3.71889

Sources: Statistical Year Book of the Electric Utility Industry - 1971, Edison Electric Institute
Gas Facts - 1971, American Gas Association
American Petroleum Institute
Foster Associate, Inc. Energy Prices 1960-1973, Ballinger Publishing Company, Cambridge, Mass. 1974.

Table 4-2 Residential Fuels Market Shares and Price Indexes by State in 1971

State	Share of Oil	Share of Electricity	Share of Gas	Price Index of Gas	Price Index of Electricity	Price Index of Oil
USA	0.223028	0.190298	0.586674	-1.174747	2.409059	-0.498231
Maine	0.834099	0.147532	0.018369	-0.288280	2.595354	-2.396380
New Hampshire	0.743528	0.151816	0.104656	-0.234595	2.535538	-1.596867
Vermont	0.754299	0.193419	0.052284	-0.249777	2.065666	-1.672039
Massachusetts	0.628121	0.100691	0.271188	-0.172996	3.033779	-1.029708
Rhode Island	0.626631	0.105733	0.267636	-0.240179	2.909870	-0.974770
Connecticut	0.568437	0.179171	0.252393	-0.274874	2.144732	-1.074352
New York	0.461506	0.107485	0.431009	-0.614443	3.320695	-0.675503
New Jersey	0.518507	0.109610	0.371883	-0.414024	2.983711	-0.779015
Pennsylvania	0.278085	0.145758	0.576157	-1.042180	2.837604	-0.492230
Ohio	0.088606	0.125196	0.786198	-2.068616	3.359849	-0.250912
Indiana	0.244986	0.163994	0.591021	-1.107218	2.562563	-0.452484
Illinois	0.131732	0.117873	0.750395	-1.770707	3.581424	-0.356141
Michigan	0.202438	0.117028	0.680534	-1.316875	3.243023	-0.302308
Wisconsin	0.325658	0.156742	0.517600	-0.856757	2.509951	-0.536537
Minnesota	0.298220	0.150461	0.551319	-0.982887	2.804799	-0.551317
Iowa	0.137213	0.168234	0.694553	-1.736896	2.989953	-0.421562
Missouri	0.083900	0.167558	0.748543	-2.123637	3.072949	-0.375951
N. Dakota	0.252709	0.268040	0.479252	-1.201340	2.096876	-0.590833
S. Dakota	0.221268	0.249833	0.528899	-1.286244	2.196336	-0.528951
Nebraska	0.088171	0.172060	0.739769	-1.924445	2.767529	-0.295691
Kansas	0.014189	0.150880	0.834930	-3.467916	3.749875	-0.176052
Delaware	0.489948	0.171404	0.338648	-0.545969	2.576186	-0.974810
Maryland & Washington, D.C.	0.313940	0.171901	0.514159	-0.806901	2.358047	-0.622644
Virginia	0.331806	0.295668	0.372526	-0.722028	1.681214	-0.817893
W. Virginia	0.033298	0.169991	0.796711	-2.550846	3.005452	-0.338944

Table 4-2 Residential Fuels Market Shares and Price Indexes by State in 1971 (cont'd)

State	Share of Oil	Share of Electricity	Share of Gas	Price Index of Gas	Price Index of Electricity	Price Index of Oil
N. Carolina	0.328710	0.431732	0.239558	-0.754718	1.371722	-0.902069
S. Carolina	0.223901	0.435603	0.340496	-0.858832	1.351705	-0.802573
Georgia	0.060561	0.322961	0.616478	-1.377110	1.627616	-0.532510
Florida	0.112541	0.740381	0.147078	-0.710703	0.899304	-0.838108
Kentucky	0.043448	0.251567	0.704984	-1.860573	2.140755	-0.387371
Tennessee	0.047621	0.561940	0.390439	-1.015183	1.080314	-0.536316
Alabama	0.018355	0.409047	0.572598	-1.254853	1.310552	-0.538168
Mississippi	0.045196	0.378035	0.576778	-1.499159	1.656598	-0.545951
Arkansas	0.013948	0.240325	0.745726	-2.493092	2.615005	-0.340507
Louisiana	0.008826	0.310537	0.680638	-2.122018	2.171791	-0.425883
Oklahoma	0.013448	0.209107	0.777445	-2.757790	2.911098	-0.322376
Texas	0.017322	0.316302	0.666377	-1.862718	1.949589	-0.440062
Montana	0.066071	0.171979	0.761950	-2.248968	2.913223	-0.112249
Idaho	0.280196	0.363488	0.356317	-0.732999	1.208122	-0.552341
Wyoming	0.069448	0.134554	0.795998	-2.881804	4.005741	0.023156
Colorado	0.027686	0.127214	0.845101	-3.489258	4.109855	0.016550
New Mexico	0.013681	0.153659	0.832660	-3.311879	3.573895	-0.245176
Arizona	0.008819	0.308433	0.682748	-1.887718	1.934841	-0.436974
Utah	0.053155	0.117490	0.829355	-2.917937	3.924226	0.120695
Nevada	0.105867	0.427092	0.467042	-0.883014	1.070413	-0.444955
Washington	0.224845	0.482733	0.292422	-0.559558	0.708951	-0.351411
Oregon	0.208847	0.480824	0.310329	-0.595166	0.830687	-0.484089
California	0.003957	0.162069	0.833974	-2.852869	2.913053	-0.149289
Alaska	0.627256	0.155098	0.217646	-0.501563	2.647327	-1.118482
Hawaii	0.035827	0.808703	0.155470	-0.576982	0.670585	-0.810105

index, it was not used in this study due to a poor fit. Instead a curve passing in the middle of the cloud of points was traced and the closest mathematical expression of this complex curve was formulated.

The market sharing curves for gas and oil are presented in Figures 4-1 and 4-2. Their piecewise mathematical approximations are described below.

Case of Gas

- $PIG \leq -3.5 \rightarrow SHGR = 0.84$ (4-4)
- $-3.5 < PIG \leq -1.4 \rightarrow SHGR = 0.84 \exp[-0.051 * (PIG + 3.5)^2]$ (4-5)
- $-1.4 < PIG \leq -0.6 \rightarrow SHGR = 1.242 \exp[-0.140 * (PIG + 3.5)^2]$ (4-6)
- $PIG > -0.6 \rightarrow SHGR = 11.059 \exp[-0.40 * (PIG + 3.5)^2]$ (4-7)

Case of Oil

- $PIO \leq -2.4 \rightarrow SHOR = 0.83$ (4-8)
- $-2.4 < PIO \leq -1.4 \rightarrow SHOR = 0.83 \exp[-0.17 * (PIO + 2.4)^2]$ (4-9)
- $-1.4 < PIO \leq -0.8 \rightarrow SHOR = 0.916 \exp[-0.269 * (PIO + 2.4)^2]$ (4-10)
- $PIO > -0.8 \rightarrow SHOR = 2.441 \exp[-0.652 * (PIO + 2.4)^2]$ (4-11)

(PIO is the price index for oil)

Once the gas and oil market shares are determined, the residual market share for electricity is automatically determined. Because of very limited data for observed low shares and the resulting uncertainty of the above functions for high values of the indexes, it was assumed that there is a discontinuity at the level of the 5% share -- yielding zero market shares below the 5% level. To evaluate the validity of the above models, two tests were made. First, it was checked whether the application of these models to the EOGC service area would yield results comparable to observed values. Under the assumption that the 1970 market shares of oil, gas and electricity (0.104, 0.800, and 0.096, respectively) are equal to the corresponding 1977 market shares, the gas and oil price indexes for 1977 were computed using the base year residential prices presented in Table 3-24 (in Chapter 3). These computed

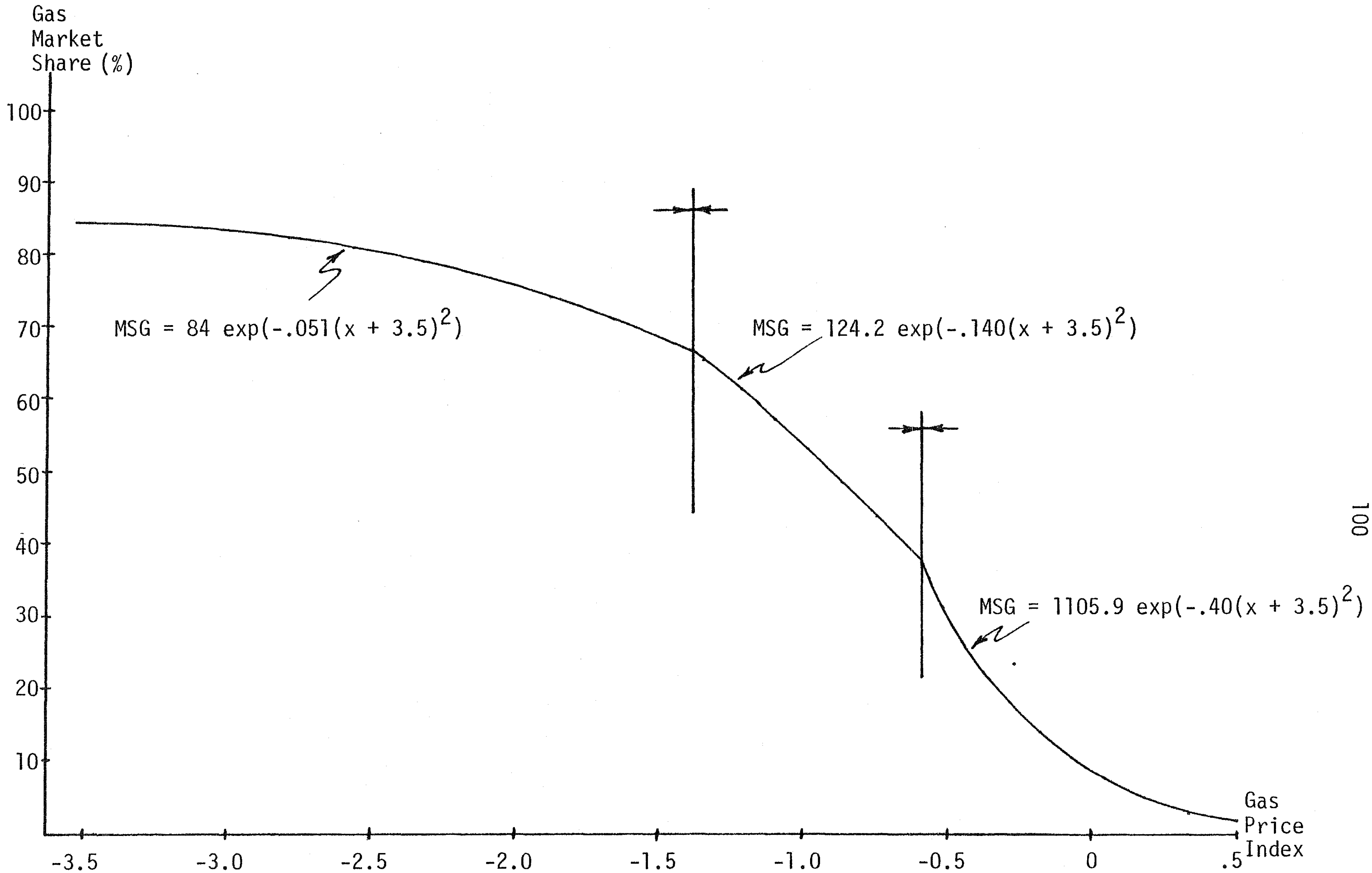


Figure 4-1 Gas Market Share Function for the Residential Sector

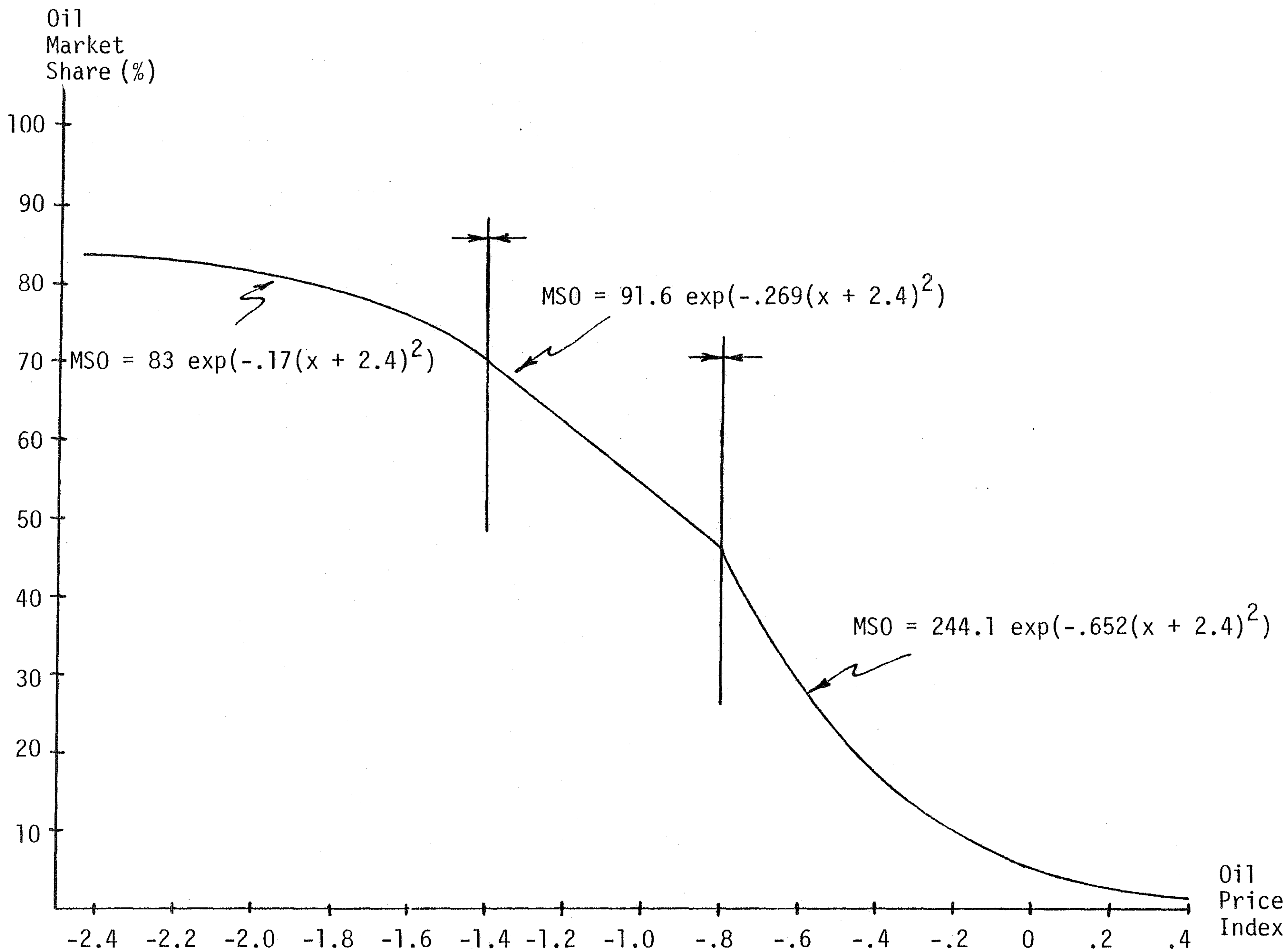


Figure 4-2 Oil Market Share Function for the Residential Sector

indexes and the resulting computed market shares are equal to:

$PIG_{77} = -1.768 \rightarrow SHGR_{77} = 0.721$ (observed value = 0.800)

$PIO_{77} = -0.022 \rightarrow SHOR_{77} = 0.061$ (observed value = 0.104)

Thus, in the case of the EOGC service area, the models slightly underestimate the gas and oil market shares and, consequently, slightly overestimate the electricity market share. The second test consisted in comparing, through correlation analysis, the observed and computed market shares for oil and gas for all the states and the U.S. as a whole. The results are:

Gas: [Computed share] = 0.08248 + 0.901 * [Observed share]
$R^2 = 0.943$ (4-12)

Oil: [Computed share] = 0.11606 + 0.751 * [Observed share]
$R^2 = 0.865$ (4-13)

(number of observations: 51)

In both cases, the models overestimate the shares for low share values and underestimate them for high values. The shares of the most populated and Midwest states are rather well approximated by the models, and the discrepancies are mostly related to smaller states. Clearly, the models might be considerably refined by considering specific characteristics of the state in terms of residential energy consumption, and applying the previous analysis to more homogeneous groups of states. Unfortuneately, such an endeavour could not be undertaken in the present research effort.

Finally, the base year (1977) market shares of gas, electricity and oil for the five divisions of the EOGC service area have been assumed equal to those of 1970, which were computed on the basis of the data presented in Table F-4 in Appendix F. These 1970 consumptions and shares are presented in Table 4-3.

Table 4-3 Residential Consumption of Gas, Electricity, and Oil in 1970 in the Five Divisions of the EOGC Service Area (1000 MMBTU)

Division	Gas (share)	Electricity (share)	Oil (share)
Cleveland	99857.8 (0.8302)	10923.6 (0.0908)	9502.3 (0.0790)
Akron	31780.9 (0.7829)	3884.6 (0.0957)	4926.2 (0.1214)
Canton	17985.4 (0.7281)	2984.6 (0.1208)	3732.1 (0.1511)
Warren	9551.2 (0.6923)	1430.5 (0.1037)	2815.0 (0.2040)
Youngstown	14865.7 (0.8193)	1559.7 (0.0860)	1718.6 (0.0947)

Note: According to the above data, the EOGC service area residential gas consumption was equal to 174.041 TBTU, whereas the EOGC reports total sales of 189.796 TBTU, or 9% more. This difference is probably primarily due to the method of computation of the above data, consisting of multiplying the number of residential appliances by their average rates of fuel use, and not accounting for temperature variations. The counties' apportionments among divisions may also have introduced some discrepancies.

Residential Gas Customers Attrition

The attrition rate of residential gas customers is the result of factors such as a) technological progress and relative price changes, and b) population outmigration or urban development and redevelopment. In the first case, for example, a customer may decide to replace a worn-out gas furnace by shifting to an alternative energy source. He may decide so if other energy sources are more price-attractive than gas -- i.e. if the operating cost reductions justify the increased investment of, say, an electric furnace. In the second case, net outmigration from a given area is likely to lead to a decrease in the number of gas customers remaining in this area.

Clearly, the attrition rate should be modeled as a complex function of the above factors. Unfortunately, the specification of such a function was not feasible in the present research effort, and an average attrition rate for residential gas customers was computed on the basis of historic EOGC data. This basic rate was adjusted to account for demographic changes. According to EOGC officials, the company's average residential attrition during recent years has been 4,150 customers per year, which represent 0.45% of the number of EOGC residential customers in 1977. In the simulation model, this rate is assumed equal to 0.5%. The attrition rate for customers of other energy sources, such as oil and electricity, is assumed to be equal to 0.25%. This rate is assumed lower than the gas rate because the corresponding customers in the EOGC service area are rather recent ones, less likely to shift to other heating equipment soon after their initial investment. The uncertainty related to the value of these attrition rates warrants sensitivity analyses to be made over this parameter, since this attrition may become quite critical for the determination of future gas supply available for new customers.

The above basic attrition rates are assumed to hold both for a stable and an increasing population. If the population is decreasing at a rate RP, then it is assumed that the above basic attrition rates are increased by

RP. This is of course a rather rough approximation of complex interactions, and sensitivity analysis should also be performed in this respect.

Finally, it will be assumed that the above composite attrition rates are only applied to the customers serviced in 1977, and not to new customers hooked up later on because these new customers, who are willing to receive gas (or another energy source), are less likely to leave the system.

Residential Gas Consumption and Conservation Rates

In attempting to estimate the residential customer gas consumption rate for a given year, two factors should be taken into consideration: (1) the severity of the winter of that given year, and (2) the level of energy conservation effort deployed in the residential sector since the base year of analysis. In this chapter, all the consumption analyses are made at the annual level under the assumption of a "normal weather" characterized by an annual number of 6317 degree-days. The variations of consumption above or below this "normal" consumption are dealt with in the monthly gas flows management model presented in Chapter 7. The gas consumption rate in 1977 in the EOGC service area has been computed on the basis of the data presented in Table F-9 in Appendix F. As 1977 is very close to a "normal weather" year, this consumption rate is taken as the "normal weather" base year (1977) residential consumption rate and will be modified in subsequent years due to conservation efforts. This base consumption rate is:

$$RGCRAT_1 = 197.08 \text{ MMBTU/customer } (t=1 \rightarrow 1977)$$

where:

$RGCRAT_t$ = rate of residential gas consumption per customer in year t.

Future conservation efforts will depend on both conservation technology and costs (i.e. insulation, etc.) and the price of energy. The conservation effort should be determined endogenously to the model because it will depend in part on future gas prices which are computed within the model. Unfortunately, not enough data were available to model this relationship, and the conservation rate was assumed constant over the planning horizon and taken equal to an average 1% per year. The residential customer consumption rate in year t is then:

$$RGCRAT_t = RGCRAT_1 * [1 - 0.01 * (t-1)] \quad (t=1 \rightarrow 1977) \tag{4-14}$$

The above conservation rate is somewhat lower than those observed in recent years. For instance, Columbia Gas of Ohio claims that its residential gas users consumed 15.7% less gas in 1977 than they did five years before and this change corresponds to an average annual conservation rate of 3.1%. This drastic conservation effort has been, most probably, the result of the strong recent changes in energy prices. It is, however, unlikely to continue at such a rate. Conservation actions such as lowering thermostats and better insulating a house have limits, and some basic energy requirements will remain non-reducible. Therefore, a rate of 1% seems a more reasonable guess for the future. However, there is still much uncertainty about this parameter and sensitivity analyses should be applied to determine the policy implications of alternative conservation rates.

Synthesis of the Residential Gas Consumption Model

The residential model is applied separately to each division r of the EOGC service area, and for each year t of the planning horizon. In order to completely specify the model, the following variables are defined:

$TGCSA_{rt}$ = total number of gas customers in serviced areas in division r at the beginning of year t;

$TNGCSA_{rt}$ = total number of customers of other energy sources in serviced areas in division r at the beginning of year t;

$TNGCNS_{rt}$ = total number of customers of other energy sources in areas not serviced by the distribution network in division r at the beginning of year t;

$PECSA_{rt}$ = potential new energy customers in serviced areas in division r during year t;

$PECNSA_{rt}$ = potential new energy customers in non-serviced areas in division r during year t;

$PGCSA_{rt}$ = potential new gas customers in serviced areas in division r during year t;

$PGCNSA_{rt}$ = potential new gas customers in non-serviced areas in division r during year t;

$SHGR_{rt}$ = residential gas market share in division r during year t;

$NGCSA_{rt}$ = new hooked-up gas customers in serviced areas in division r during year t;

$NGCNSA_{rt}$ = new hooked-up gas customers in non-serviced areas in division r during year t;

$TPOP_{rt}$ = total population in division r at the beginning of year t;

$SPOP_{rt}$ = total population in serviced areas in division r at the beginning of year t;

HS_{rt} = household size in division r during year t;

$DPSA_{rt}$ = population contained in areas newly serviced (developed) in division r during year t;

$REXTSA_{rt}$ = rate of extension of the gas distribution network into non-serviced areas in division r during year t, measured in terms of population coverage;

$ATRG_{rt}$ = residential gas customers attrition rate in division r during year t;

$ATRO_{rt}$ = attrition rate of residential customers of other energy sources in division r during year t;

ATRGB = base attrition rate for residential gas customers;

ATROB = base attrition rate for residential customers of other forms of energy;

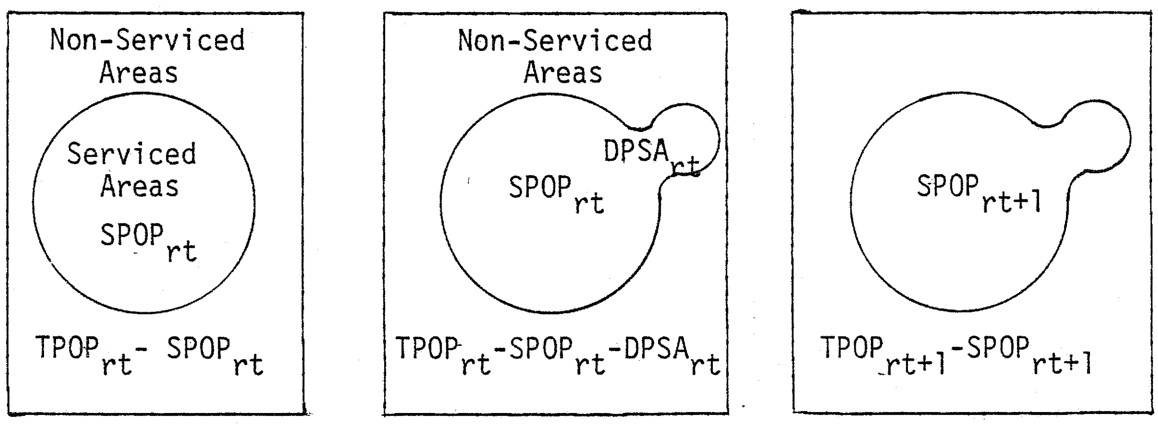
$PNDGRS_{rt}$ = potential new demand of gas in serviced areas in division r during year t;

$PNDGRN_{rt}$ = potential new demand of gas in non-serviced areas in division r during year t.

For any given year t, the first step is to evaluate the size of the population included in serviced areas, $SPOP_{rt}$, accounting for the network extensions which may have taken place in the preceding period. Assuming that energy customers are distributed among gas and other energy forms in the same proportions everywhere, it follows that, in year t-1 and division r:

$$DPSA_{rt-1} = \frac{NGCNSA_{rt-1} * HS_{rt-1}}{SHGR_{rt-1}} \tag{4-15}$$

Figure 4-3 illustrates this serviced areas expansion process.



Division r Beginning of year t

The serviced areas are extended to include a new population $DPSA_{rt}$

Division r Beginning of year t+1

Figure 4-3 The Expansion Process of Serviced Areas

The rate of development of non-serviced areas during year t-1 is:

$$REXTSA_{rt-1} = \frac{DPSA_{rt-1}}{TPOP_{rt-1} - SPOP_{rt-1}} \tag{4-16}$$

Assuming that the rates of growth of the serviced areas and of the total division are the same, it follows that:

$$SPOP_{rt} = [SPOP_{rt-1} + DPSA_{rt-1}] * \frac{TPOP_{rt}}{TPOP_{rt-1}} \tag{4-17}$$

The next step is to estimate the attrition rates for year t-1, accounting for eventual population decreases:

$$ATRG_{rt-1} = \begin{cases} ATRGB + \left[1 - \dfrac{TPOP_{rt}}{TPOP_{rt-1}}\right] & \text{if } \dfrac{TPOP_{rt}}{TPOP_{rt-1}} < 1 \\ ATRGB & \text{otherwise;} \end{cases} \tag{4-18}$$

$$ATRO_{rt-1} = \begin{cases} ATROB + \left[1 - \dfrac{TPOP_{rt}}{TPOP_{rt-1}}\right] & \text{if } \dfrac{TPOP_{rt}}{TPOP_{rt-1}} < 1 \\ ATROB & \text{otherwise.} \end{cases} \tag{4-19}$$

Given the previous variables, it is now possible to compute the customers' stock variables $TGCSA_{rt}$, $TNGCSA_{rt}$ and $TNGCNS_{rt}$ for the beginning of year t:

$$TGCSA_{rt} = TGCSA_{rt-1} + NGCSA_{rt-1} + NGCNSA_{rt-1} - ATRG_{rt-1} * TGCSA_{r1} \tag{4-20}$$

$$\begin{aligned} TNGCSA_{rt} = {} & TNGCSA_{rt-1} + [PECSA_{rt-1} - NGCSA_{rt-1}] + \\ & REXTSA_{rt-1} * [PECNSA_{rt-1} - NGCNSA_{rt-1}] - \\ & ATRO_{rt-1} * [TNGCSA_{r1} + REXTSA_{rt-1} * TNGCNS_{r1}] \end{aligned} \tag{4-21}$$

$$\begin{aligned} TNGCNS_{rt} = {} & TNGCNS_{rt-1} + (1-REXTSA_{rt-1}) * [PECNSA_{rt-1} - \\ & NGCNSA_{rt-1} - ATRO_{rt-1} * TNGCNS_{r1}] \end{aligned} \tag{4-22}$$

The above stock variables for year t are equal to the corresponding variables for year t-1 modified by customers attrition and new hook-up flows that took place during year t-1. (Note that the attrition rates are applied only to the core of customers existing in the 1977 base year noted in the equations above as year 1.) Given the values of the above stock variables, it is now straightforward to compute the number of new energy customers in both serviced and non-serviced areas. (A household is considered as equivalent to a basic energy customer):

$$PECSA_{rt} = \frac{SPOP_{rt}}{HS_{rt}} - TGCSA_{rt} - TNGCSA_{rt} \tag{4-23}$$

$$PECNSA_{rt} = \frac{TPOP_{rt} - SPOP_{rt}}{HS_{rt}} - TNGCNS_{rt} \tag{4-24}$$

The next and final step in this accounting procedure is to apply the sharing model to determine the number of potential gas customers, and, subsequently, the corresponding potential demand of gas:

$$PGCSA_{rt} = PECSA_{rt} * SHGR_{rt} \tag{4-25}$$

$$PGCNSA_{rt} = PECNSA_{rt} * SHGR_{rt} \tag{4-26}$$

$$RGCRAT_{t} = RGCRAT_{1} * [1 - 0.01 \quad (t-1)] \tag{4-27}$$

$$PNDGRS_{rt} = RGCRAT_{t} * PGCSA_{rt} \tag{4-28}$$

$$PNDGRN_{rt} = RGCRAT_{t} * PGCNSA_{rt} \tag{4-29}$$

The potential gas demand flows are inputs to the Capacity Expansion model where it is decided how to supply these demands, depending upon the hook-up policy tested as well as upon the maximum available wholesale gas supply.

Finally, it must be pointed out that the computation of the market shares for year t is based upon the market shares and prices of year t-1. Indeed, it is reasonable to assume that consumers make their decisions at the beginning of year t on the basis of past price behavior, and probably the most recent one, i.e., of year t-1, and that they are not yet aware of the prices that will be effective during year t. The market shares of the previous year t-1 are necessary to compute year t-1 composite and average prices which enter the computation of the market shares for year t. All the energy prices except the price of gas are forecasted exogenously. Thus, all that is needed for the proper functioning of the residential sharing model is the set of base year market shares, which are presented in Table 4-3, the subsequent years market shares being computed on the basis of each previous years market shares and prices. The base year prices are presented in Table 3-24 in Chapter 3. The base year values of the customers' stock variables are presented in Table 4-4. They have been derived by combining population data presented in Tables 2-6 through 2-10 in Chapter 2 with gas customers figures presented in Table F-9 in Appendix F.

Table 4-4 Number of Gas and Other Energy Customers In and Outside the EOGC Serviced Areas, by Division, in the Base Year 1977.

Division	Number of Gas Customers in Serviced Areas (TGCSA)	Number of Other Energy Customers in Serviced Areas (TNGCSA)	Number of Other Energy Customers in Non-Serviced Areas (TNGCNS)
Cleveland	492,390	81,657	34,114
Akron	174,284	39,640	2,882
Canton	109,185	31,142	4,475
Warren	44,884	17,752	14,450
Youngstown	87,713	7,941	5,547

The values of the other flow variables, such as the numbers of hooked-up customers, are assumed to be equal to zero for the base year.

Besides the base year values of the different variables, the only exogenously forecasted variables used in this residential model are the total population ($TPOP_{rt}$), household size (HS_{rt}), attrition rates ($ATRG_{rt}$, $ATRO_{rt}$), and consumption rates ($RGCRAT_t$) variables. All the other variables are computed within the residential model for any future year t (t>1), except the number of new hooked-up gas customers and gas retail prices, which are determined in the Capacity Expansion and Financial models, respectively.

Annual Commercial Gas Consumption Analysis and Forecasting

The purpose of this section is to present a specification of the commercial gas consumption model. The model is used to determine the level of new commercial gas demand in a given year. The following discussion is concerned with: a) the basic model to be used, b) the evaluation of customer attrition rates and energy conservation efforts, and c) the synthesis of the modeling approach.

The Basic Model of Energy Demand by Commercial Customers.

The commercial sector energy demand forecasting model used by K.P. Anderson in his simulation model of U.S. energy demand, supply and prices will be used.[5] This model is based on econometric studies of the residential sector and of the combined residential and commercial sectors as well as on engineering cost analyses of representative commercial buildings. Three commercial energy systems are considered:

System 1: all electric;
System 2: conventional (electric air conditioning with fossil fuel heating);
System 3: total energy (on site electricity generation with waste

[5] Kent P. Anderson, A Simulation Analysis of U.S. Energy Demand, Supply, and Prices, Research Report R-1591-NSF/EPA, October 1975, The Rand Corporation (See the summary of that report in Appendix E).

heat recovery).

The shares of these three systems are determined by the relative system costs of each of them. It is assumed that 80% of new (or renovated) floor space will be serviced by the cheapest system, and 10% by each of the other two. These small shares are intended to account for the combined effects of error and regional or local variations in operating conditions. The formulation of the trade-off functions used to determine these shares requires the following definitions:

$S1_{rt}$ = share of system 1 in division r during year t;

$S2_{rt}$ = share of system 2 in division r during year t;

$S3_{rt}$ = share of system 3 in division r during year t;

$PRGC_{rt}$ = commercial price of gas in division r during year t;

$PROC_{rt}$ = commercial price of oil in division r during year t;

$PREC_{rt}$ = commercial price of electricity in division r during year t;

$PRFC_{rt}$ = commercial price of "fossil fuels" in division r during year t, taken as the minimum of the gas and oil prices.

Under the same rationale as for the residential sector, the shares for year t are assumed to be functions of prices in year t-1. Then, the determination of the shares is made as follows:

$$S1_{rt} = \begin{cases} 0.8 \text{ if } PRFC_{rt-1} > -3.1704 + 0.8 * PREC_{rt-1}, \\ 0.1 \text{ otherwise;} \end{cases} \tag{4-30}$$

$$S2_{rt} = \begin{cases} 0.8 \text{ if } PRFC_{rt-1} \begin{cases} \leq -3.1704 + 0.8 * PREC_{rt-1}, \text{ and} \\ \geq -2.5061 + 0.3507 * PREC_{rt-1} \end{cases} \\ 0.1 \text{ otherwise;} \end{cases} \tag{4-31}$$

$$S3_{rt} = \begin{cases} 0.8 \text{ if } PRFC_{rt-1} < -2.5061 + 0.3507 * PREC_{rt-1} \\ 0.1 \text{ otherwise,} \end{cases} \tag{4-32}$$

(In the above statements, all prices are expressed in $/MMBTU).

The above conditions are summarized graphically in Figure 4-4.

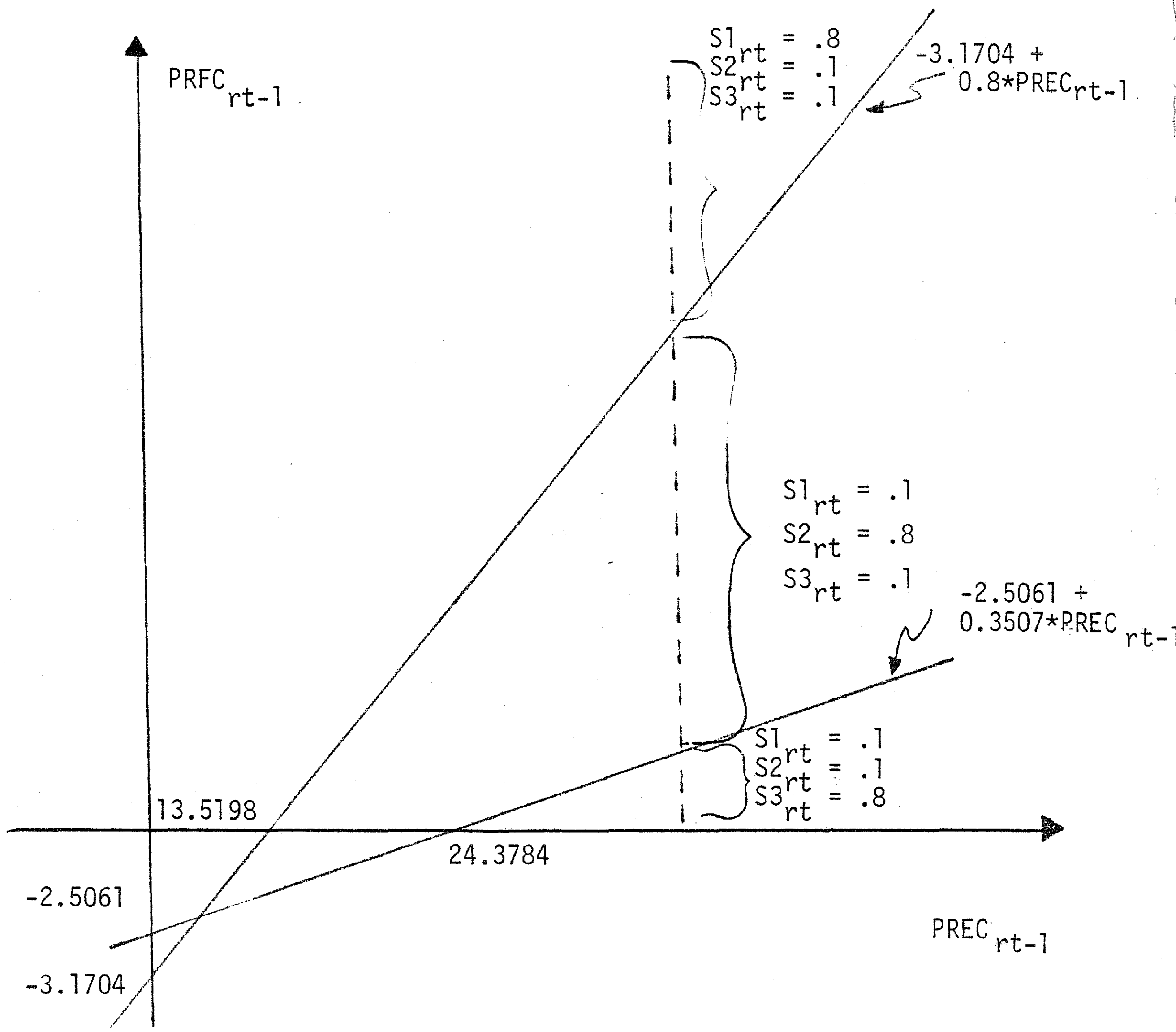


Figure 4-4 Commercial Energy Systems Shares Trade-off Functions

Defining:

CFA_{rt} = total commercial floor space in division r during year t,

ATC_{rt} = commercial customers attrition rate in division r during year t ,

the net amount of new or renovated commercial floor space requiring energy supply ($DCFA_{rt}$) is:

$$DCFA_{rt} = CFA_{rt} - CFA_{rt-1} + ATC_{rt-1} * CFA_{r1} \tag{4-33}$$

The corresponding new demands for gas, oil and electricity are:

<u>Gas</u>:
$$PNDGC_{rt} = DCFA_{rt} * \left(\frac{PRGC_{rt-1}}{PRGCO}\right)^{-0.3} * \frac{0.053*S2_{rt} + 0.191*S3_{rt}}{\left[1 + \left(\frac{PRGC_{rt-1}}{PROC_{rt-1}}\right)^{3.17}\right]} \tag{4-34}$$

(PRGCO = 1.2998 \$/MMBTU = 1972 price of gas expressed in 1977 dollars)

<u>Oil</u>:
$$PNDOC_{rt} = DCFA_{rt} * \left(\frac{PROC_{rt-1}}{PROCO}\right)^{-0.3} * \left(\frac{PRGC_{rt-1}}{PROC_{rt-1}}\right)^{3.17} * \frac{0.053\ S2_{rt} + 0.191\ S3_{rt}}{\left[1 + \left(\frac{PRGC_{rt-1}}{PROC_{rt-1}}\right)^{3.17}\right]} \tag{4-35}$$

(PROCO = 1.1680 \$/MMBTU = 1972 price of oil expressed in 1977 dollars)

<u>Electricity</u>:
$$PNDEC_{rt} = DCFA_{rt} * \left(\frac{PREC_{rt-1}}{PRECO}\right)^{-0.3} * [0.091*S1_{rt} + 0.054*S2_{rt}] \tag{4-36}$$

(PRECO = 10.02195 \$/MMBTU = 1972 price of electricity expressed in 1977 dollars).

Coal consumption is not considered in the above model, as in the case of the residential sector. A major characteristic of the commercial sector analysis - one that is not included in the residential sector analysis - is that the total energy requirement per unit of commercial activity is determined simultaneously with its sharing among the alternative fuels. The coefficients of the shares $S1_{rt}$, $S2_{rt}$ and $S3_{rt}$ represent fuel requirements per unit of share for each of the three energy systems. The exponent -0.3 represents the long-run elasticity of demand with respect to own-price, and therefore the ratios $(PRCG_{rt-1}/PRGCO)^{-0.3}$, $(PROC_{rt-1}/PROCO)^{-0.3}$ and $(PREC_{rt-1}/PRECO)^{-0.3}$ are indicative of the level of energy conservation efforts that have taken place since 1972 due to rising energy prices.

As could be expected, the all electric system requires only electricity, the conventional system requires the three energy sources, and the total energy system requires only gas and oil, electricity being generated at the site. The more complex equations of the potential demands for gas and oil are due to the fact that it is necessary to account for the price differential between oil and gas when sharing the potential "fossil fuel" demand, which is equal to :

$$PNDFC_{rt} = 0.053 * S2_{rt} + 0.191 * S3_{rt} \qquad (4\text{-}37)$$

With respect to gas demand, the same "breaking point" assumption as for the residential case will be made here, i.e., whenever the potential gas demand per floor space unit falls below 5% of the total potential energy demand per floor space unit, this demand will be considered as nil. The determination of this breaking point is less straightforward than in the residential (and industrial) case because the share functions $S1_{rt}$, $S2_{rt}$ and $S3_{rt}$ are characterized by discontinuities when they shift from 0.1 to 0.8 or inversely. Therefore, the search for the breaking point implies a computerized search by successive approximations.

When applying the model with the 1977 commercial energy prices in the EOGC service area, the following energy inputs per unit of floor space are obtained:

- gas: 42,107.27 BTU/ft.^{2} ,
- oil: 9,792.94 BTU/ft.^{2} ,
- electricity: 49,172.54 BTU/ft.^{2} .

These energy inputs correspond to the following shares:

- gas: 41.66%,
- oil: 9.69%,
- electricity: 48.65%.

The above shares for new demand are somewhat different from those observed in the eighteen counties comprising the EOGC service area in 1970, as presented in Table F-5 in Appendix F. In particular, the 1977 gas share is lower than the 1970 gas share, and the 1977 electricity share is higher than the 1970 electricity share, the oil share remaining approximately the same. These differences may reflect:

(1) changes in commercial energy use technology, which may have occurred after 1970 and are accounted for by the model;

(2) the relatively lower increase in electricity price from 1970 to 1977, as compared to the gas price increase.

Commercial Gas Customers Attrition

As in the case of residential customers, the attrition rate of commercial gas customers (as well as of customers of other energy sources) is the product of various interacting factors which are very difficult to model. Therefore, an approach similar to that adopted in the residential model has been applied here. It consists in adjusting a basic attrition rate, ATCB, according to changes in the level of the commercial activity, whenever this activity is declining. EOGC officials reported an average annual attrition of 250 commercial customers in recent past years, which corresponds to 0.47% of the 52,867 commercial customers served by the EOGC in 1977. A value of 0.5% has been finally adopted for ATCB. As for the residential case, the attrition rate is only to be applied to the core of customers existing in 1977.

Commercial Gas Consumption and Conservation Rates

Although the energy demand forecasting and market sharing model is applied to total floor space and not to number of customers, it is necessary to somehow define an "average" commercial customer for the evaluation of customer-related hook-up costs made in the Capacity Costs model. (See Chapter 5.)

The gas consumption rate per commercial customer in 1977 in the whole EOGC service area was computed on the basis of the data presented in Table F-11 in Appendix F. (These data include annual gas sales, revenues and average number of customers for each division of the EOGC service area, from 1970 to 1977). This rate, taken as the "normal weather" base year commercial consumption rate ($CGCRAT_1$) is found to be equal to 1267.054 MMBTU per customer. This 1977 base year rate will be modified in subsequent years due to conservation efforts. Here, however, in contrast to the residential case, the level of conservation can be determined endogenously to the model. The conservation rate characterizing the period extending from the base year (t=1) to any year t, $CONSVC_t$, is straightforwardly expressed as a function of commercial gas price as:

$$CONSVC_t = 1 - \left[\frac{\left(\frac{PRGC_{rt-1}}{PRGCO} \right)^{-0.3}}{\left(\frac{PRGC_{r1}}{PRGCO} \right)^{-0.3}} \right] = 1 - \left(\frac{PRGC_{rt-1}}{PRGC_{r1}} \right)^{-.03} \qquad (4\text{-}38)$$

The "average" commercial customer gas consumption rate in year t is then:

$$CGCRAT_t = CGCRAT_1 * [1 - CONSVC_t] \qquad (4\text{-}39)$$

The above conservation rate, when computed with the 1970 and 1977 gas prices charged to the EOGC commercial customers, implies an average annual conservation rate of 1.9% between 1970 and 1977. Actual consumption rates in 1970 and 1977, computed on the basis of the data presented in Table F-11 in Appendix F, reveal an average annual conservation rate of 1.2% for the same period.

Synthesis of the Commercial Gas Consumption Model

The commercial modeling approach is applied separately to each division r of the EOGC service area, and for each year t of the planning horizon. No distinction is made between serviced and non-serviced areas, and therefore the spatial expansion process of the gas distribution system is not modeled as explicitly as in the case of residential customers. In fact, it will be implicitly assumed that all the new commercial customers are located within the serviced areas.

The first step is to computer the total amount of commercial floor space (CFA_{rt}) for all the years of the planning horizon. If:

$ICOMGR_{rt}$ = the commercial floor space growth index in division r during year t,

then:

$$CFA_{rt} = CFA_{r1} * (ICOMGR_{rt}/100) \tag{4-40}$$

The next step is to compute the commercial customer attrition rate:

$$ATC_{rt-1} = \begin{cases} ATCB + \left[1 - \dfrac{CFA_{rt}}{CFA_{rt-1}}\right] & \text{if } \dfrac{CFA_{rt}}{CFA_{rt-1}} \leq 1 \\ ATCB & \text{if } \dfrac{CFA_{rt}}{CFA_{rt-1}} > 1 \end{cases} \tag{4-41}$$

The next steps have already been described and consist in computing the net increments in floor space, $DCFA_{rt}$, and the resulting potential demands of gas, oil and electricity (see equations 4-34, 4-35 and 4-36).

Finally, the base year commercial floor space data have been computed by assuming that the gas share of total commercial energy consumption in 1977 is the same as in 1970. The commercial consumptions and shares of coal, oil, gas and electricity, by division, in 1970, are presented in Table 4-5. These data have been established on the basis of the same data for the eighteen counties of the EOGC service area, as presented in Table F-5 in Appendix F, using the same apportionment ratios as for population to aggregate these data at the level of the divisions. The 1977 actual gas sales and estimated total energy requirements and floor spaces are presented in Table 4-6.

Table 4-5 Commercial Consumption of Coal, Gas, Electricity and Oil in 1970 in the Five Divisions of the EOGC Service Area (1000 MMBTU)

Division	Coal (share)	Gas (share)	Electricity (share)	Oil (share)
Cleveland	1,498.6 (0.0277)	39,816.1 (0.7375)	8,900.7 (0.1649)	3,771.3 (0.0699)
Akron	833.5 (0.0447)	12,670.8 (0.6803)	3,165.3 (0.1699)	1,954.6 (0.1051)
Canton	1,802.5 (0.1395)	7,171.2 (0.5551)	2,431.9 (0.1882)	1,513.1 (0.1172)
Warren	510.2 (0.0773)	3,808.3 (0.5769)	1,165.5 (0.1766)	1,117.1 (0.1692)
Youngstown	1,016.0 (0.1144)	5,911.9 (0.6657)	1,270.9 (0.1431)	682.1 (0.0768)

Note: According to the above data, the EOGC service area commercial gas consumption in 1970 was equal to $69{,}378.3 * 10^3$ MMBTU, whereas the EOGC reports total sales of $71{,}294.0 * 10^3$ MMBTU, or 2.7% more. This slight difference is most probably related to the way the counties data are apportioned to yield divisions data.

Table 4-6 Commercial Gas Sales, Estimates of Total Energy Requirements, and Estimates of Floor Space in 1977 in the Five Divisions of the EOGC Service Area

Division	Gas Sales (MMBTU)	Total Energy Requirements (MMBTU)	Total Floor Space (10^6 ft^2)
Cleveland	38,481,398	52,178,167	516.244
Akron	11,781,233	17,317,702	171.339
Canton	7,741,357	13,945,878	137.979
Warren	3,308,268	5,734,561	56.737
Youngstown	5,609,702	8,426,772	83.373

Note: The above floor space estimates have been obtained by using an energy per floor space unit rate equal to 101,072.75 BTU/ft.^{2}. This consumption rate is equal to the sum of the basic consumption rates for gas, oil and electricity (42,107.27 BTU/ft.^{2}, 9,792.94 BTU/ft.^{2} and 49,172.54 BTU/ft.^{2}), computed by applying to Anderson's model the 1977 energy prices.

Annual Industrial Gas Consumption Analysis and Forecasting

The purpose of this section is to present a specification of the industrial gas consumption model used to determine the level of potential new industrial gas demand in a given year. The following discussion is structured in the same way as that related to residential gas consumption - i.e., the various factors affecting the potential industrial gas demand are analyzed and a synthesis of the modeling approach is presented.

Market Sharing of New Potential Energy Industrial Customers

The sharing of a given demand of energy by industrial customers among alternative energy sources is assumed to be only a function of the prices of these sources of energy. Future changes in the technology related to industrial energy use are not accounted for in the present approach, due to a lack of data related to this problem. Only the major fossil fuels - oil, gas, and coal - are considered for this sharing process the electricity industrial requirements are assumed not substitutable. The total amount of fossil fuel energy needed in a given year is computed by applying to the base year energy needs the energy growth index determined in Chapter 2. The net increment in energy needs is then shared among competing energy sources. As these energy needs are forecasted for the aggregate industrial sector, it is consistent to develop the sharing model at the same aggregate level. However, in so doing, it is unavoidable to lose precision in the analysis, because there are significant variations among the different industrial branches in terms of their requirements of and preference for the various fuels. In order to account for such variations, market sharing models should have been developed for each of the major industrial branches. Although some partial, good results have been obtained in preliminary analyses, further research is necessary, and could not be undertaken within the framework of the present study, in order to develop satisfactory sectorial sharing models.

The data used in the determination of the aggregate industrial market sharing model are presented in Table 4-7. They have been extracted from the 1971 Survey of Manufacturers.[6]

The modeling approach is strictly the same as for the residential sector, coal replacing electricity, and is based on the ideas suggested by Limaye and Sharko (see Appendix E). The 1971 observed market shares and price indexes are presented in Table 4-8. The half-bell shaped market sharing curves have been determined empirically as previously for the residential sector. The market sharing curves for gas and oil are presented in Figures 4-5 and 4-6. Their piecewise mathematical approximations are described below:

Case of Gas

- $PIG \leq -1.6 \rightarrow SHGI = 1.00$ (4-42)
- $-1.6 < PIG \leq -0.1 \rightarrow SHGI = \exp[-0.218 * (PIG + 1.6)^2]$ (4-43)
- $-0.1 < PIG \leq 0.6 \rightarrow SHGI = 1.9643 \exp[-0.5175 * (PIG + 1.6)^2]$ (4-44)
- $PIG > 0.6 \rightarrow SHGI = 0.41146 \exp[-0.19515 * (PIG + 1.6)^2]$ (4-45)

Case of Oil

- $PIO \leq -1.0 \rightarrow SHOI = 1.00$ (4-46)
- $-1.0 < PIO \leq 0.0 \rightarrow SHOI = \exp[-0.26 * (PIO + 1.0)^2]$ (4-47)
- $0.0 < PIO \leq 0.3 \rightarrow SHOI = 5.4496 \exp[-1.9556 * (PIO + 1.0)^2]$ (4-48)
- $PIO > 0.3 \rightarrow SHOI = 0.50785 \exp[-0.5514 * (PIO + 1.0)^2]$ (4-49)

(SHGI and SHOI are the industrial market shares for gas and oil respectively).

Once the gas and oil market shares are computed, the residual coal market share is automatically determined. Because of the very limited data for observed low shares and the resulting uncertainty of the above functions for high values of the indexes, it was again assumed that there is a discontinuity at the level of the 5% share - yielding zero market shares below the 5% level.

[6] Survey of Manufacturers - 1971, U.S. Department of Commerce, Washington D.C., Bureau of the Census.

Table 4-7 Fuel Consumption and Average Price in the Industrial Sector by State in 1971

State	Oil Consumption (TBTU)	Coal Consumption (TBTU)	Gas Consumption (TBTU)	Average Price Of Oil ($/MMBTU)	Average Price Of Coal ($/MMBTU)	Average Price Of Gas ($/MMBTU)
USA	1496.125	1800.411	6680.305	0.66124	0.54193	0.38320
Maine	66.797	0.484	1.035	0.54194	0.82644	0.96618
New Hampshire	20.178	0.145	1.656	0.64427	0.37741	0.84541
Vermont	3.870	0.327	1.449	0.72356	0.30609	0.55210
Massachusetts	72.882	0.808	28.359	0.71897	0.61860	0.64177
Rhode Island	12.506	0.000	6.417	0.64767	0.77966	0.67009
Connecticut	61.779	0.128	15.421	0.64909	0.77966	0.88188
New York	124.243	76.183	111.780	0.69299	0.64449	0.65307
New Jersey	174.428	14.949	87.147	0.74414	0.80941	0.56341
Pennsylvania	162.535	236.227	397.336	0.69769	0.46650	0.55318
Ohio	37.113	338.693	411.516	0.76254	0.55389	0.53947
Indiana	57.597	81.321	248.296	0.66322	0.49556	0.47846
Illinois	55.047	136.322	324.990	0.74845	0.62132	0.50186
Michigan	27.521	150.480	239.395	0.66857	0.55556	0.53342
Wisconsin	14.925	70.951	111.262	0.73032	0.54403	0.51859
Minnesota	17.208	14.430	62.100	0.67992	0.57518	0.44444
Iowa	8.522	33.805	107.226	0.75100	0.45851	0.40755
Missouri	5.827	36.337	103.086	0.75514	0.45408	0.42683
N. Dakota	0.733	1.535	1.656	0.81870	0.45609	0.48309
S. Dakota	0.918	0.036	2.070	0.76202	0.36272	0.38647
Nebraska	2.553	5.454	31.878	0.74406	0.40335	0.35761
Kansas	2.406	0.832	65.308	0.66508	0.60082	0.42567
Delaware	22.507	0.068	11.799	0.68421	0.44274	0.51699
Maryland	57.895	22.829	39.744	0.67191	0.44680	0.54599
Washington, D.C.	0.315	0.000	0.517	0.63393	0.44680	0.57971

Source: Manufacturers Survey - 1971, U.S. Dept. of Commerce, Bureau of the Census.

Table 4-7 Fuel Consumption and Average Price in the Industrial Sector by State in 1971 (cont'd)

State	Oil Consumption (TBTU)	Coal Consumption (TBTU)	Gas Consumption (TBTU)	Average Price Of Oil ($/MMBTU)	Average Price Of Coal ($/MMBTU)	Average Price Of Gas ($/MMBTU)
Virginia	54.320	56.557	41.503	0.53755	0.76913	0.53971
W. Virginia	5.038	114.326	68.931	0.71462	0.36649	0.50775
N. Carolina	69.255	44.464	68.724	0.62089	0.60948	0.51656
S. Carolina	39.823	39.021	65.929	0.55495	0.54330	0.48688
Georgia	53.782	14.853	107.640	0.56152	0.47801	0.47659
Florida	66.636	0.981	76.279	0.53725	0.40783	0.41820
Kentucky	3.878	59.592	67.482	0.69621	0.75513	0.47568
Tennessee	12.990	75.219	117.472	0.61582	0.43872	0.43499
Alabama	19.142	68.363	163.116	0.70002	0.66849	0.37703
Mississippi	4.435	0.034	110.331	0.72153	0.38371	0.31995
Arkansas	11.980	0.848	121.612	0.60098	1.20798	0.30095
Louisiana	13.666	0.156	619.965	0.59272	1.28435	0.22146
Oklahoma	0.357	1.306	94.495	0.55948	0.84204	0.24233
Texas	15.445	33.850	1619.982	0.52442	0.65830	0.22735
Montana	1.569	1.938	27.324	0.63740	1.08366	0.32938
Idaho	1.510	5.241	26.185	0.79468	0.62968	0.46209
Wyoming	1.313	1.687	14.179	0.83799	0.23701	0.24683
Colorado	11.298	7.714	42.228	0.61959	0.50557	0.29838
New Mexico	0.200	0.000	11.074	0.49958	0.50557	0.33410
Arizona	1.022	0.000	38.916	0.68460	0.50557	0.42142
Utah	4.554	4.693	11.074	0.65874	0.66058	0.28895
Nevada	0.833	2.439	11.592	0.95977	0.57391	0.45721
Washington	33.942	2.836	93.460	0.60987	0.66985	0.40659
Oregon	19.462	1.372	44.815	0.63199	0.72868	0.48644
California	26.258	4.543	483.966	0.65885	1.12253	0.42234

Source Manufacturers Survey - 1971 U.S. Dept. of Commerce, Bureau of the Census.

Table 4-8 Industrial Fuels Market Shares and Price Indexes by State in 1971

State	Share of Oil	Share of Coal	Share of Gas	Price Index of Gas	Price Index of Coal	Price Index of Oil
USA	0.149960	0.180459	0.669581	-0.469372	0.237806	0.538746
Maine	0.977765	0.007085	0.015150	0.767091	0.505152	-0.689911
New Hampshire	0.918059	0.006597	0.075345	0.294927	1.080724	-0.367282
Vermont	0.685441	0.057917	0.256642	-0.211990	-0.565721	0.330734
Massachusetts	0.714186	0.007918	0.277896	-0.109225	-0.113022	0.111727
Rhode Island	0.660889	0.000000	0.339111	0.034215	0.189824	-0.034215
Connecticut	0.798922	0.001655	0.199423	0.334210	0.120836	-0.333389
New York	0.397952	0.244015	0.358033	-0.032218	-0.044378	0.065077
New Jersey	0.630788	0.054060	0.315152	-0.269117	0.181671	0.209509
Pennsylvania	0.204165	0.296731	0.499104	-0.013561	-0.230953	0.317488
Ohio	0.047138	0.430184	0.522678	-0.062974	-0.007252	0.389365
Indiana	0.148747	0.210016	0.641237	-0.169986	-0.034716	0.354326
Illinois	0.106606	0.264006	0.629388	-0.278779	0.149624	0.377512
Michigan	0.065935	0.360521	0.573544	-0.071982	0.014909	0.230059
Wisconsin	0.075708	0.359905	0.564386	-0.106324	0.000731	0.371153
Minnesota	0.183575	0.153940	0.662485	-0.369654	0.156848	0.415186
Iowa	0.056983	0.226040	0.716977	-0.250432	0.058530	0.755141
Missouri	0.040117	0.250169	0.709714	-0.154102	0.021676	0.718880
N. Dakota	0.186799	0.391182	0.422018	-0.168515	-0.242840	0.651319
S. Dakota	0.303571	0.011905	0.684524	-0.720685	-0.278152	0.751621
Nebraska	0.064009	0.136743	0.799248	-0.397256	0.043966	0.977269
Kansas	0.035101	0.012138	0.952762	-0.511001	0.382035	0.543804
Delaware	0.654768	0.001978	0.343254	-0.265821	-0.293705	0.267662
Maryland	0.480584	0.189503	0.329913	-0.105933	-0.295817	0.275832
Washington, D.C.	0.378606	0.000000	0.621394	-0.090330	-0.255628	0.090331

Table 4-8 Industrial Fuels Market Shares and Price Indexes by State in 1971 (cont'd)

State	Share of Oil	Share of Coal	Share of Gas	Price Index of Gas	Price Index of Coal	Price Index of Oil
Virginia	0.356477	0.371158	0.272365	-0.185816	0.369569	-0.215481
W. Virginia	0.026756	0.607164	0.366080	0.296050	-0.363377	0.690022
N. Carolina	0.379598	0.243714	0.376687	-0.172541	0.070065	0.117186
S. Carolina	0.275072	0.269532	0.455396	-0.119629	0.059114	0.090422
Georgia	0.305103	0.084260	0.610637	-0.133018	-0.053473	0.168632
Florida	0.463084	0.006817	0.530098	-0.247586	-0.139202	0.251832
Kentucky	0.029614	0.455068	0.515319	-0.452673	0.438915	0.146839
Tennessee	0.063156	0.365707	0.571137	-0.066574	-0.031880	0.400590
Alabama	0.076378	0.272774	0.650847	-0.620025	0.535196	0.492335
Mississippi	0.038632	0.000296	0.961071	-1.189360	0.143798	1.196963
Arkansas	0.089110	0.006308	0.904582	-1.020242	2.639791	0.881053
Louisiana	0.021562	0.000246	0.978192	-1.650071	4.591900	1.614928
Oklahoma	0.003713	0.013582	0.982706	-2.142049	2.378345	1.227782
Texas	0.009241	0.021451	0.969308	-1.632152	1.788859	1.202225
Montana	0.050890	0.062859	0.886251	-1.413176	1.879268	0.657542
Idaho	0.045847	0.159127	0.795027	-0.405740	0.296537	0.604438
Wyoming	0.076431	0.098201	0.825369	-0.869987	-0.205886	2.034727
Colorado	0.184487	0.125963	0.689549	-0.716498	0.363245	0.753660
New Mexico	0.017740	0.000000	0.982260	-0.490986	0.500049	0.490987
Arizona	0.025590	0.000000	0.974411	-0.614684	0.180811	0.614685
Utah	0.224103	0.230943	0.544954	-0.810066	0.576587	0.566322
Nevada	0.056041	0.164088	0.779871	-0.426014	0.164526	0.955901
Washington	0.260615	0.021776	0.717609	-0.446818	0.449394	0.420217
Oregon	0.296455	0.020899	0.682646	-0.284143	0.370653	0.258775
California	0.051009	0.008825	0.940166	-0.692037	1.561605	0.522031

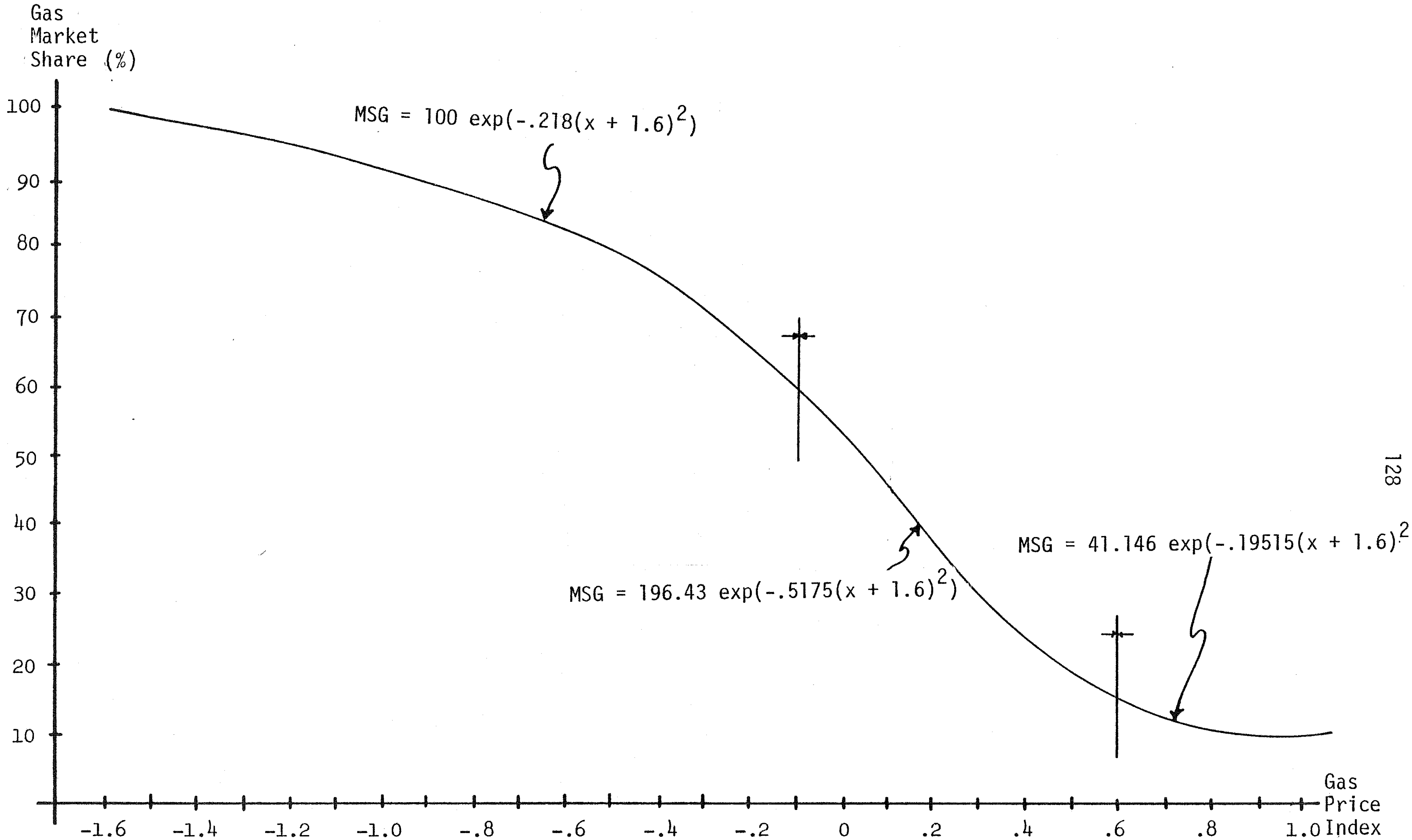


Figure 4-5 Gas Market Share Function for the Industrial Sector

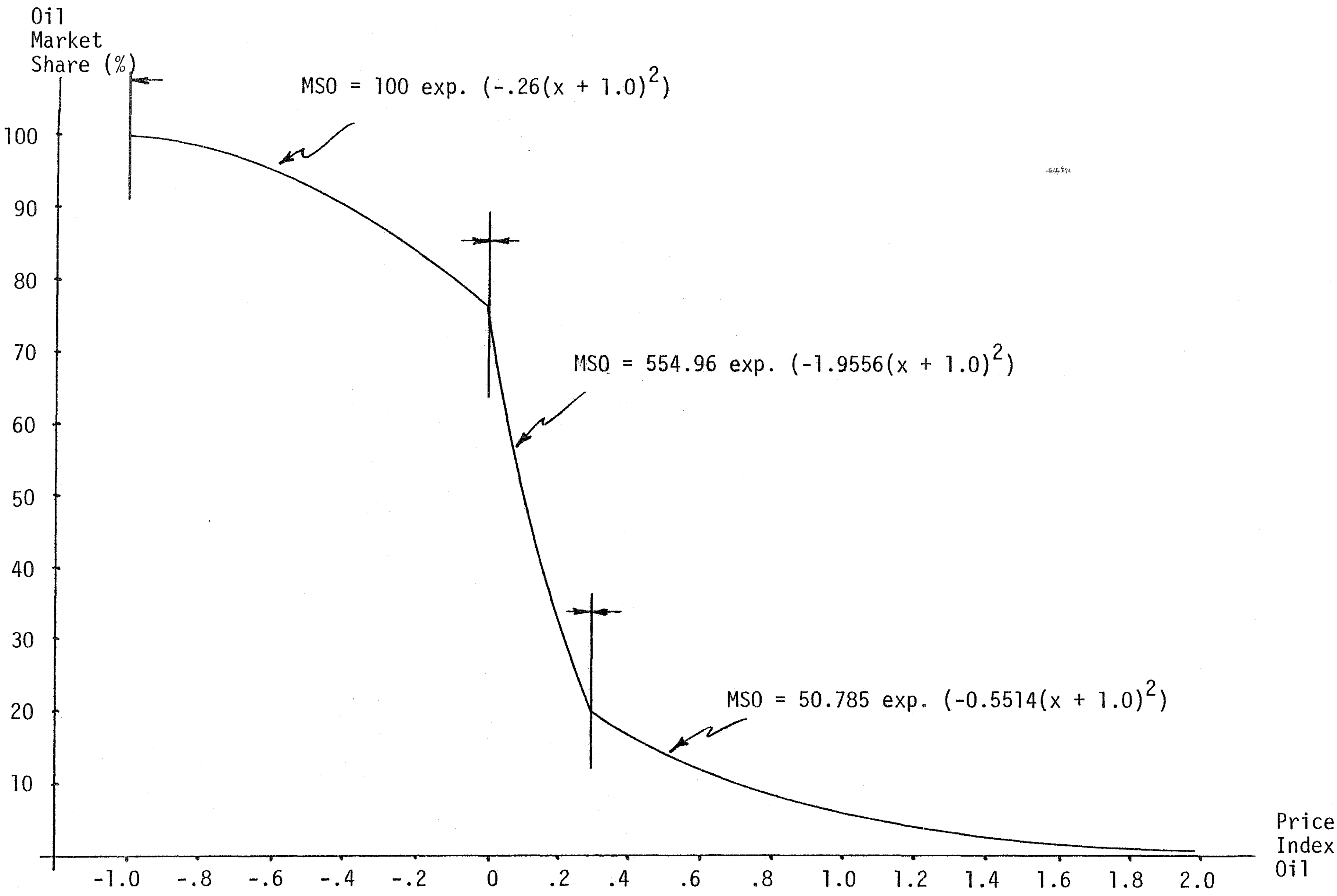


Figure 4-6 Oil Market Share Function for the Industrial Sector

The same tests of validity as in the residential case have been performed here. First, under the assumption that the 1970 industrial market shares of coal, gas and oil (0.572, 0.352 and 0.076, respectively) for the whole EOGC service area are equal to the corresponding 1977 market shares, the gas and oil price indexes for 1977 were computed, using the base year industrial prices presented in Table 3-24 (in Chapter 3). These computed indexes and the resulting computed market shares are equal to:

$PIG_{77} = 0.2214 \rightarrow SHGI_{77} = 0.353$ (observed value = 0.352)

$PIO_{77} = 0.8573 \rightarrow SHOI_{77} = 0.076$ (observed value = 0.076)

Thus, in the case of the EOGC service area, the fit between actual and computed market shares is quasi-perfect. The second test consisted in correlating observed and computed market shares for all the states and the U.S. as a whole in 1977. The results are:

- Gas: [Computed share] = 0.32664 + 0.603 * [Observed share]

$$R^2 = 0.824 \qquad (4\text{-}50)$$

- Oil: [Computed share] = 0.06604 + 0.841 * [Observed share]

$$R^2 = 0.855 \qquad (4\text{-}51)$$

In both cases the models overestimate the shares for low share values and underestimate them for high values. However, the model is in good agreement with the observed data related to the most industrialized states such as Ohio; the largest discrepancies are mostly related to small, poorly industrialized states. As in the residential case, the above models might probably be refined by applying the previous analysis to groups of states homogeneous from the viewpoint of their industrial composition and level of activity.

Finally, the base year (1977) market shares of coal, gas and oil for the five divisions of the EOGC service area have been assumed equal to those of 1970, which were computed on the basis of the data presented in Table F-6 in Appendix F. These 1970 consumptions and shares are presented in Table 4-9.

Table 4-9 Industrial Comsumption of Coal, Gas and Oil in 1970 in the Five Divisions of the EOGC Service Area (1000 MMBTU)

Division	Coal (share)	Gas (share)	Oil (share)
Cleveland	118,107.5 (0.5722)	72,682.8 (0.3521)	15,632.3 (0.0757)
Akron	38,004.1 (0.5560)	24,976.0 (0.3654)	5,371.7 (0.0786)
Canton	28,128.9 (0.5660)	17,753.4 (0.3572)	3,818.3 (0.0768)
Warren	20,326.3 (0.5394)	14,282.8 (0.3790)	3,071.8 (0.0816)
Youngstown	23,158.9 (0.6406)	10,694.3 (0.2958)	2,300.1 (0.0636)

Besides the Youngstown division which is more oriented toward coal consumption because of its important steel industries, the shares are very much similar across divisions. According to the data in Table 4-9, the EOGC industrial gas consumption in 1970 was equal to 140.3893 TBTU, whereas the EOGC reports total industrial sales of 135.1328 TBTU, or 3.5% less. This small difference is most probably due to the way the counties data were apportioned among divisions. Overall, the fit seems quite satisfactory.

Industrial Gas Customers Attrition

As in the case of residential and commercial gas customers, the attrition rate of industrial gas customers (as well as of customers of other energy sources) is the complex product of various interacting factors, such as production technology, energy costs, and level of activity. These interactions are very difficult to model, and therefore an approach similar to those adopted for the residential and commercial sectors has been applied here, consisting in adjusting some basic attrition rate, ATIB, according to changes in the level of activity in the industrial sector, whenever this activity is decreasing. The basic attrition rate is taken equal to 0.5%. As for residential and commercial customers, the attrition rate is only applied to the core of customers existing in 1977.

Industrial Gas Consumption and Conservation Rates

Although the energy demand forecasting and market sharing models are applied to total energy requirements, and not to numbers of customers, as was the case in the residential sector, it is necessary to somehow define an "average" industrial customer for the evaluation of customer-related hook-up costs made in the Capacity Costs model. (See Chapter 5.)

The gas consumption rate per industrial customer in 1977 in the whole EOGC service area has been computed on the basis of the data presented in Table F-13 in Appendix F. This rate, taken as the "normal weather" base year (1977) industrial consumption rate is equal to:

$$IGCRAT_1 = 105{,}965.37 \text{ MMBTU/customer.}$$

This base year rate will be modified in subsequent years due to conservation efforts, which will depend on both conservation technology and costs, and the costs of obtaining energy. As for the residential sector, the yearly conservation rate is assumed constant, and taken equal to an average 2% per year. The industrial gas customer consumption rate in year t is then:

$$IGCRAT_t = IGCRAT_1 * [1 - 0.02 * (t-1)] \tag{4-52}$$

The above-chosen conservation rate is somewhat higher than the rate derived when comparing the 1970 and 1977 industrial customers gas consumption rates in the EOGC service area, which is equal to an average 0.44%. Clearly, there is much room for sensitivity analyses over this parameter.

Synthesis of the Industrial Gas Consumption Model

The industrial modeling approach is applied separately to each division r of the EOGC service area, and for each year t of the planning horizon. As in the commercial case, it is assumed that all the new industrial customers are located within the serviced areas. In order to specify the model, the following variables are defined:

$TENCI_{rt}$	=	total industrial energy requirements in division r during year t;
$SHGI_{rt}$	=	industrial gas market share in division r during year t;
ATI_{rt}	=	industrial customers attrition rate in division r during year t;
$PNDGI_{rt}$	=	potential new industrial demand of gas in division r during year t.

The first step is to compute the total energy requirements ($TENCI_{rt}$) for all the years of the planning horizon. If $IINDGR_{rt}$ is the corresponding index as defined in Chapter 2, the rate of growth of these total energy requirements from year t-1 to year t is:

$$DINGR_{rt} = (IINDGR_{rt} - IINDGR_{rt-1})/100 \tag{4-53}$$

If there is a decrease in energy requirements ($DINGR_{rt} < 0$), it is assumed that this decrease is caused by the industrial plants existing in 1977. If there is an increase ($DINGR_{rt} > 0$), then it is assumed that the new industrial activities are characterized by the forecasted energy consumption rate for year t.

In mathematical terms:

$$\mathrm{TENCI}_{rt} = \mathrm{TENCI}_{rt-1} + \mathrm{DINGR} * \mathrm{TENCI}_{r1} \qquad \text{if } \mathrm{DINGR}_{rt} \leq 0 \qquad (4\text{-}54)$$

$$\mathrm{TENCI}_{rt} = \mathrm{TENCI}_{rt-1} + \mathrm{DINGR} * \mathrm{TENCI}_{r1} * [1 - 0.02 * (t-1)]$$
$$\text{if } \mathrm{DINGR}_{rt} > 0. \qquad (4\text{-}55)$$

The next step is to compute the industrial customers attrition rate:

$$\mathrm{ATI}_{rt-1} = \begin{cases} \mathrm{ATIB} + \left[1 - \dfrac{\mathrm{TENCI}_{rt}}{\mathrm{TENCI}_{rt-1}}\right] & \text{if } \dfrac{\mathrm{TENCI}_{rt}}{\mathrm{TENCI}_{rt-1}} < 1 \\ \mathrm{ATIB} & \text{if } \dfrac{\mathrm{TENCI}_{rt}}{\mathrm{TENCI}_{rt-1}} \geq 1 \end{cases} \qquad (4\text{-}56)$$

Given the previous variables it is possible to compute the level of new energy demand in industry in year t:

$$\mathrm{DTENCI}_{rt} = \mathrm{TENCI}_{rt} - \mathrm{TENCI}_{rt-1} + \mathrm{ATI}_{rt-1} * \mathrm{TENCI}_{r1} \qquad (4\text{-}57)$$

If DTENCI_{rt} is negative, there is an overall net decrease, even when accounting for attrition, and, of course, the potential new demand of gas is nil. If DTENCI_{rt} is positive, then the new potential demand for gas is:

$$\mathrm{PNDGI}_{rt} = \mathrm{DTENCI}_{rt} * \mathrm{SHGI}_{rt} \qquad (4\text{-}58)$$

The computation of the industrial market shares is done in the same lagged way as for the residential market shares. The base year industrial energy prices and market shares are indicated in Tables 3-24 and 4-9, and the base year total demand of energy has been obtained by dividing the actual gas sales per division in 1977, as presented in Table F-13 in Appendix F, by the corresponding gas market shares. The results of this computation are presented in Table 4-10.

Table 4-10 Base Year Total Industrial Energy Requirements (MMBTU)

Division	1977 Total Energy Requirements (MMBTU)
Cleveland	152,708,820
Akron	20,318,803
Canton	69,529,239
Warren	38,026,108
Youngstown	57,366,705

Analysis and Forecasting of Monthly Gas Loads

In the previous sections, the residential, commercial and industrial annual gas consumption models were developed to forecast annual gas requirements corresponding to a given level of activity and a "normal weather" pattern characterized by a total of 6317 degree-days per year. However, it is also necessary to develop a method to predict variations in customers' requirements on account of variations in temperature. These variations may have important implications for the ability of the company to fulfill its mandate of "service on demand".

Although there are other factors, such as wind speed and cloud cover, which affect gas requirements, temperature is by far the dominant one and will be the only factor considered in the following analysis. At any time, the total load of a given customer consists of two sub-loads: (1) a "base load", corresponding to usages which are not affected by temperature, and (2) a "heating load", which is sensitive to temperature. Of course, the relative importance of these two loads depends upon the type of activity: the heating load is by far dominant in the residential and commercial sectors, whereas it is of secondary importance in the industrial sector. In any case, the heating load is generally assumed to be a linear function of degree-days, and the specification of this relationship is generally made through regression analysis techniques. The linear approximation is generally quite satisfactory, although it has been shown that the relationship is not strictly linear during periods with mean temperature slightly below 65^{0} (base value for computing degree-days) and during periods of very cold weather when the heating equipment is operating at full capacity.

In the following sections these relationships will be empirically established for the residential, commercial and industrial sectors.

Residential Monthly Gas Load

Monthly residential gas sales per customer have been regressed on monthly degree-days for each year from 1970 to 1976. Each year has been treated separately in order to eventually single out conservation efforts over time. The data used are presented in Table F-16 in Appendix F. For each year t, the following equation has been calibrated:

$$GDR_{tm} = AR_t + BR_t * DD_{tm} \tag{4-59}$$

where:

GDR_{tm} = residential gas requirement per customer during month m of year t;

AR_t = residential base load coefficient during year t;

BR_t = residential heating load coeffficient during year t;

DD_{tm} = number of degree-days during month m of year t.

The results of the regression analyses are presented in Table 4-11.

Table 4-11 Residential Customer Gas Load as a Function of Degree-Days, 1970-1976 (Load unit: MMCF/month)

Year	Base Load Coefficient AR_t	Heating Load Coefficient BR_t	Correlation Coefficient R^2
1970	3.62201	0.02651	0.98060
1971	3.85790	0.02645	0.98296
1972	3.60893	0.02693	0.98870
1973	4.69215	0.02544	0.99298
1974	3.50794	0.02658	0.97589
1975	3.04181	0.02652	0.98209
1976	3.24271	0.02443	0.99232

The very strong correlations revealed in Table 4-11 are further illustrated in Figures F-35 through F-41 in Appendix F. No clear-cut time trends can be discerned for the coefficients AR_t and BR_t, and therefore it has been decided to compute their averages over the seven years, and to use the resulting function for residential monthly gas load forecasting in the simulation model, and, more specifically, in the monthly gas flows management model described in Chapter 7. This function is:

$$GDR_m = 3.68 + 0.026 * DD_m \qquad (4\text{-}60)$$

Clearly both the base load and heating load coefficients are likely to change in the future, because of energy conservation measures, such as house insulation, and because of changes in the patterns of energy usage by households. As was explained previously, the energy conservation effect is accounted for when predicting annual requirements under "normal weather" conditions. By so doing, it is implicitly assumed that conservation measures apply, at the same rate, to base and heating loads. This may not prove to be correct, but technological forecasting in this area was clearly out of the range of the present study. Again, sensitivity analyses might help to clarify the implications of this and alternative assumptions.

Considering a year with a "normal weather" pattern, i.e., with 6317 degree-days, the annual gas requirements per customer are:

$$\begin{aligned} GDRT &= (3.68) * (12) + (0.026) * (6317) \\ &= 44.16 + 164.24 = A + B = 208.40 \qquad (4\text{-}61) \end{aligned}$$

The above results reveal that the base and heating loads of a residential customer, during a "normal weather" year, are equal to 21.2% and 78.8% of the total load, respectively. Clearly, the space-heating component of gas requirements in the residential sector is by far the dominant one. It is this sharing among base and heating loads which is assumed constant in any future year, and it is on the basis of this sharing that future residential monthly gas load equations will be established, as described in Chapter 7.

Commercial Monthly Gas Load

Total monthly commercial gas sales have been regressed on monthly degree-days for each year from 1970 to 1976. Each year has been treated separately both because the number of customers changed from year to year, and in order to eventually single out conservation efforts in this sector. The data used are presented in Table F-17 in Appendix F. For each year t, the following equation has been calibrated:

$$GDC_{tm} = AC_t + BC_t * DD_{tm} \tag{4-62}$$

where:

GDC_{tm} = total commercial gas requirement during month m of year t;

AC_t = commercial base load coefficient during year t;

BC_t = commercial heating load coefficient during year t.

The results of the regression analyses are presented in Table 4-12.

Table 4-12 Total Commercial Gas Load as a Function of Degree-Days, 1970-1976 (Load unit: MMCF/month)

Year	Base Load Coefficient AC_t	Heating Load Coefficient BC_t	Correlation Coefficient R^2
1970	1378.265	8.346	0.990
1971	1530.311	8.625	0.991
1972	1525.205	9.153	0.989
1973	1814.471	8.638	0.992
1974	1521.328	9.152	0.977
1975	1141.880	9.138	0.981
1976	1159.359	8.868	0.989

The very strong correlations revealed in Table 4-12 are further illustrated in Figures F-42 through F-48 in Appendix F. The above commercial load coefficients display relatively more important variations than the corresponding residential load coefficients. This is due, partly, to the fact that the set of EOGC commercial customers is undergoing changes from year to year, with addition and attrition of customers with size and other characteristics much more variable than in the case of residential customers. It was decided to keep, for further purposes, the equation calibrated with 1971 data, because the monthly number of commercial customers in 1971 varies relatively less than in 1973, although the correlation coefficient is slightly lower than that of 1973. The equation is:

$$GDC_m = 1530.311 + 8.625 * DDM \qquad (4\text{-}63)$$

As for the residential sector, it is assumed that the conservation effect applies to base and heating loads at the same rate.

Considering a year with a "normal weather" pattern, i.e., with 6317 degree-days, the annual gas requirements of the 1977 EOGC commercial customers are:

$$GDCT = (1530.311) * (12) + (8.625) * (6317)$$

$$= 18363.732 + 54484.125 = A + B = 72847.857 \qquad (4\text{-}64)$$

Thus, the base and heating loads constitute 25.21% and 74.79% of the total load, respectively. As in the residential case, the space-heating component of gas requirements in the commercial sector is by far the dominant one. It is on the basis of this sharing that future commercial monthly gas load equations will be established, as described in Chapter 7.

Industrial Monthly Gas Load

In a first analysis similar to that undertaken for the residential and commercial sectors, total monthly industrial gas sales have been regressed on monthly degree-days for each year separately, from 1970 to 1976. The data used are presented in Table F-18 in Appendix F. For each year t, the following equation has been calibrated:

$$GDI_{tm} = AI_t + BI_t * DD_{tm} \quad (4\text{-}65)$$

where:

GDI_{tm} = total industrial gas requirement during month m of year t;

AI_t = industrial base load coefficient during year t;

BI_t = industrial heating load coefficient during year t.

The results of the regression analyses are presented in Table 4-13.

Table 4-13 Total Industrial Gas Load as a Function of Degree-Days, 1970-1976

Year	Base Load Coefficient AI_t	Heating Load Coefficient BI_t	Correlation Coefficient R^2
1970	9,416.513	2.718	0.943
1971	9,397.960	4.296	0.941
1972	10,148.455	3.556	0.920
1973	11,070.179	2.878	0.912
1974	11,225.311	2.553	0.872
1975	8,523.044	2.614	0.798
1976	9,282.409	2.101	0.831

The highest correlation coefficients are obtained in 1970 and 1971, with a significant decrease in 1974 through 1976, most probably because of the curtailments which took place in this period. Because of possible curtailment effects, even in 1970 and 1971, the previous regression equations do not really represent the potential requirements of the industrial customers, but, in fact, their actual supply after curtailment.

To overcome this problem, it was decided to use the base allocations of the 501 major industrial customers of the EOGC. These base allocations, which were established in 1970 through discussions between the EOGC and its industrial customers, represent estimates of what each customer really needs. The aggregate base allocations by 2 digit SIC group are presented in Tables F-19 through F-37 in Appendix F. The total monthly base allocations for all the 501 firms are presented in Table 4-14.

Table 4-14 Monthly Base Allocations for the 501 Major Industrial Customers of the EOGC

Month	Base Allocation (MMCF)	Month	Base Allocation (MMCF)
1	14,107	7	9,774
2	13,512	8	10,063
3	12,902	9	10,720
4	12,527	10	11,528
5	11,318	11	12,551
6	10,752	12	13,464

These monthly base allocations have been determined on the basis of the meteorological conditions prevailing in 1970. Therefore, they have been regressed on 1970 monthly degree-days, and the following regression equation was obtained:

$$BA_m = 10435.426 + 2.848 * DD_m \qquad (4\text{-}66)$$

$$(R^2 = 0.9524)$$

The above regression equation, which displays a higher correlation coefficient than in the case of actual sales, will be kept for further forecasting purposes. As pointed out in Appendix F, the 501 firms may be considered as representative of all the EOGC industrial customers.[7]

[7]The results of the same regression analysis applied to 2 digit SIC monthly base allocations are presented in Appendix F.

Considering a year with a "normal weather" pattern, i.e., with 6317 degree-days, the annual gas requirements of these 501 firms are:

$$\begin{aligned} BAT &= (10{,}435.426) * (12) + (2.848) * (6317) \\ &= 125225.11 + 17992.88 = A + B = 143218.00 \end{aligned} \tag{4-67}$$

Thus, the base and heating loads constitute 87.44% and 12.56% of the total load, respectively. The base load is clearly the dominant one. It is on the basis of this sharing that future industrial monthly gas load equations will be established, as described in Chapter 7. As for the residential and commercial sectors, it is here also assumed that the conservation effect applies to base and heating loads at the same rate.

CHAPTER 5

GAS DISTRIBUTION SYSTEM ANALYSIS

The purpose of this chapter is to describe two forecasting models: (a) a capacity costs model, and (b) an operating and maintenance costs model of the EOGC distribution system. Since the capacity expansion process may involve any or all the elements of the EOGC distribution plant, these elements are briefly described in this chapter. Similarly, the forecasts of operating and maintenance costs necessitate an understanding of the EOGC gas management principles. These principles are circumscribed by technological and cost relationships, which are also briefly described here. The outputs of the two forecasting models are inputs into the financial analysis process described in Chapter 8.

The first section is devoted to a general description of the EOGC gas distribution system, including its major components such as transmission lines, storage fields and compressors, etc. In the next section the problem of designing optimal network expansion plans is analyzed and possible research paths are reviewed. In the third section capacity expansion cost models are described for the three classes of customers - residential, commercial, and industrial. In the last section two cost forecasting models are developed to measure storage and other operating and maintenance costs (O&M).

General Description of the EOGC Gas Distribution System

The EOGC distribution system is described in a diagrammatic way in Figure 5-1, with its major storage fields, transmission lines, connections to pipeline suppliers and Ohio gas producers, and gas sales divisions. At the level of detail displayed in Figure 5-1 it was not possible to identify gas distribution lines which carry gas from a point of local supply (i.e., city gate) to end-use customers, represented by the sales meters.

The EOGC plant is composed of five major types:

- The production plant (including wells, field lines, etc.) for the production of gas by the EOGC. In 1977, this plant represented 11.92% of the total value of the EOGC plant.

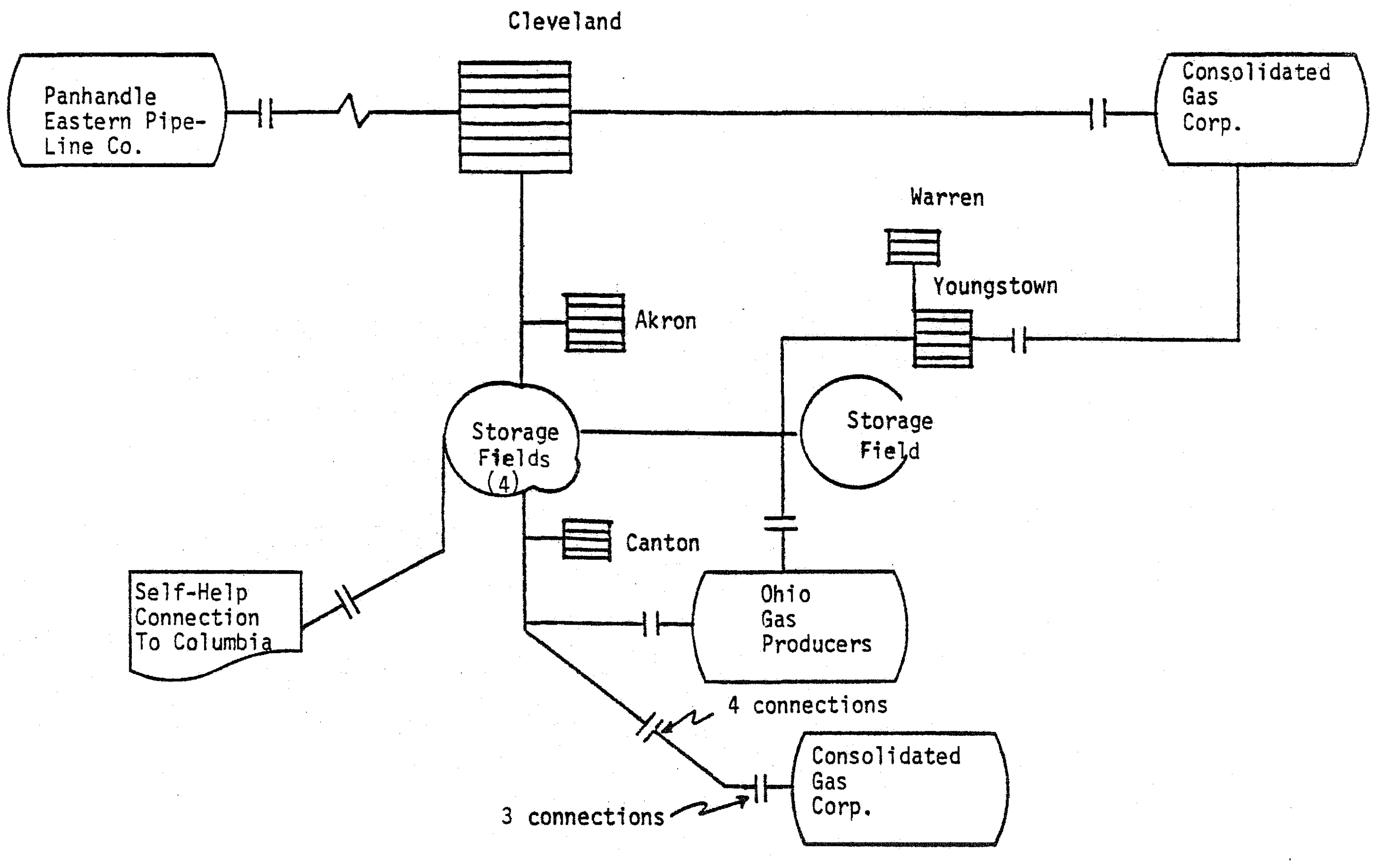


Figure 5-1 Diagrammatic Representation of the EOGC Distribution System

- The storage plant (including wells and storage rights, non-recoverable gas, lines, compressors and regulators, etc.) for summer gas injections and winter gas withdrawals. In 1977, this plant represented 8.92% of the total value of the EOGC plant.
- The transmission plant (including mostly transmission mains and regulating equipment) to transmit gas from the points of connection with suppliers to the distribution centers. In 1977, this plant represented 16.73% of the total value of the EOGC plant.
- The distribution plant (including mains, services and equipment which carry or control the supply of gas from the point of local supply to and including the sales meters). It is the major component of the EOGC system, representing 60.55% of the total plant value in 1977.
- The general plant (including assets not directly related to the gas production and distribution process, such as offices, etc.). In 1977 it represented about 1.89% of the total plant value.

Consideration of the monetary value of the various plant components between 1970 and 1975 reveals a steady increase in the production plant both in absolute terms and as a share of the total plant. This is due to recent efforts by the EOGC to increase its own gas production in Ohio. The share of the distribution plant has decreased, and this is due mostly to the ban on new hook-ups in recent years and natural customers attrition. The share of the storage plant increased from 1970 to 1975, due to important investments for storage capacity expansion. The shares of the transmission and general plants remained relatively constant. Table G-1 in Appendix G contains more data on the value of the EOGC plant.

A detailed description of the existing (1977) transmission system is provided by the EOGC in its 10-Year Forecast Report submitted to the Ohio Power Siting Commission.[1] In this report, a system map graphically shows the piping system (for large lines only) and each pipe is described in detail including its dimensions and usual gas pressure. Planned replacements of existing facilities with similar facilities are also indicated. According to this report no transmission lines

[1] The East Ohio Gas Company, 10-Year Forecast Report, December 15, 1977. Report submitted to the Ohio Power Siting Commission.

and associated facilities above 125 psi and no substantial additions to existing facilities are planned by the EOGC.[1]

The connections between the EOGC system and its interstate pipeline suppliers are listed in Table 5-1 and their locations are indicated in Figure 5-2. (For a detailed description of the amounts of wholesale gas supplied in recent years, the reader is referred to Chapter 3.) The capacities and locations of the storage fields are indicated in Table 5-2 and in Figure 5-3. (More details about the storage system can be found in Chapter 7 and Appendix H.) Finally, the size and cost characteristics of the field and underground storage compressors of the EOGC system, for the years 1970 through 1977, are indicated in Table G-2 in Appendix G, and the locations of the major ones are presented in Figure G-1. The aggregate power of the field compressors has increased from 9,120 H.P. (horsepower) in 1970 to 14,225 H.P. in 1977, which is a 56% increase, mostly due to the addition of the Noble station (3,480 H.P.). The aggregate power of the underground storage compressors has increased from 7,194 H.P. in 1970 to 19,660 H.P. in 1977 (a 173% increase) due to the addition of the Robinson station.

The Distribution Network Expansion Problem

The gas utility's problem is to determine how its distribution system should be altered to provide adequate service to its customers both new and existing. The changes to the system, based on new customers who are to be connected, manifest themselves primarily as equipment additions. In particular, it will be necessary to answer such questions as: 1) how many metering devices are needed, 2) how much piping is needed to connect these new customers to main lines, 3) are new main and transmission lines necessary, 4) are new compressors and is other control equipment necessary, 5) should storage fields be expanded, etc.?

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[1]The Ohio Power Siting Commission has no jurisdiction on facilities and pipelines with pressures below 125 psi (Ohio Revised Code, Section 4906).

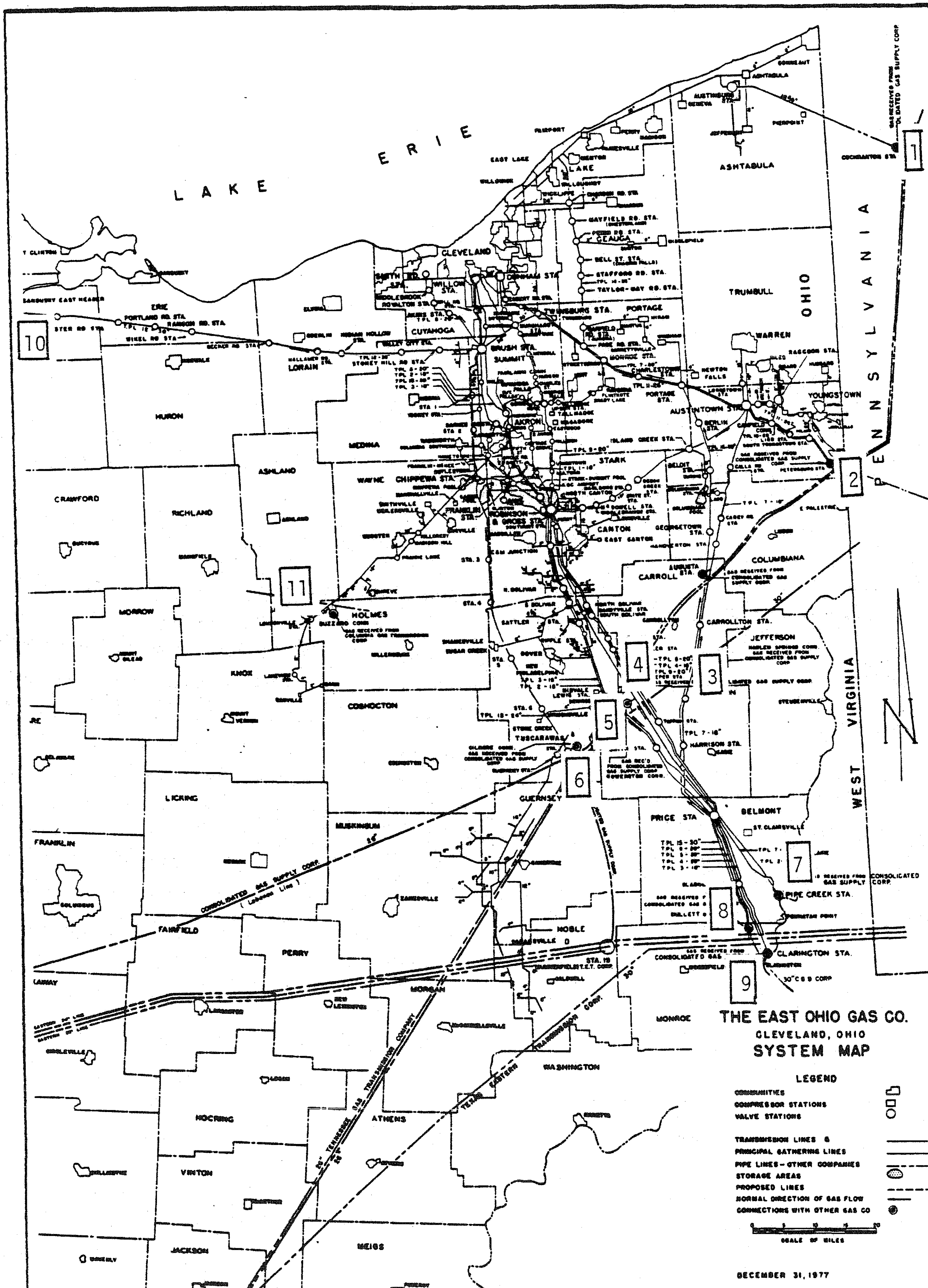
Table 5-1 EOGC Connections with Transmission Companies

Receiving Station	Transmission Company	Comments
1 Cochranton	Consolidated	
2 Petersburg	Consolidated	
3 Harlem Springs	Consolidated	
4 Leeper	Consolidated	
5 Smith	Consolidated	
6 Gilmore	Consolidated	
7 Pipe Creek	Consolidated	
8 Mullett	Consolidated	
9 Clarington	Consolidated	Consolidated connections account for approximately 75% of all received gas*
10 Maumee	Panhandle Eastern	Approximately 15% of all received gas*
11 Buzzard	Columbia Gas	Self-Help connection

*The EOGC also receives about 10% of its gas supplies from Ohio producers.

Table 5-2 Certified Capacity of EOGC Storage Fields

Area	1977 Certified Capacity (MCf)	Comments
1 Stark-Summit	130,322,000	88.3% of total capacity
2 Chippewa	10,934,700	7.4% of total capacity
3 Columbiana	3,111,100	2.1% of total capacity
4 Gabor	3,012,100	2.0% of total capacity
5 Wertz	214,200	Experimental Field - No longer in operation.


THE EAST OHIO GAS CO.
CLEVELAND, OHIO
SYSTEM MAP
LEGEND
COMMUNITIES
COMPRESSOR STATIONS
VALVE STATIONS
TRANSMISSION LINES & PRINCIPAL GATHERING LINES
PIPE LINES - OTHER COMPANIES
STORAGE AREAS
PROPOSED LINES
NORMAL DIRECTION OF GAS FLOW
CONNECTIONS WITH OTHER GAS CO
SCALE OF MILES
DECEMBER 31, 1977
LAKE ERIE
PENNSYLVANIA
OHIO
WEST VIRGINIA
1
2
3
4
5
6
7
8
9
10
11
CLEVELAND
ASHTABULA
TRUMBULL
WARREN
YOUNGSTOWN
CUYAHOGA
LORAIN
HURON
MEDINA
SUMMIT
AKRON
PORTAGE
STARK
CANTON
WAYNE
ASHLAND
CRAWFORD
RICHLAND
COLUMBIANA
CARROLL
JEFFERSON
HOLMES
TUSCARAWAS
COSHOCTON
KNOX
MORROW
LICKING
MUSKINGUM
GUERNSEY
BELMONT
FRANKLIN
FAIRFIELD
PERRY
NOBLE
MORGAN
MONROE
WASHINGTON
HOCKING
ATHENS
VINTON
JACKSON
MEIGS
CHIPPEWA STA.
ROBINSON & GROSS STA.
AUSTINTOWN STA.
PRICE STA
PIPE CREEK STA.
CLARINGTON STA.
CONSOLIDATED GAS SUPPLY CORP.
CONSOLIDATED GAS

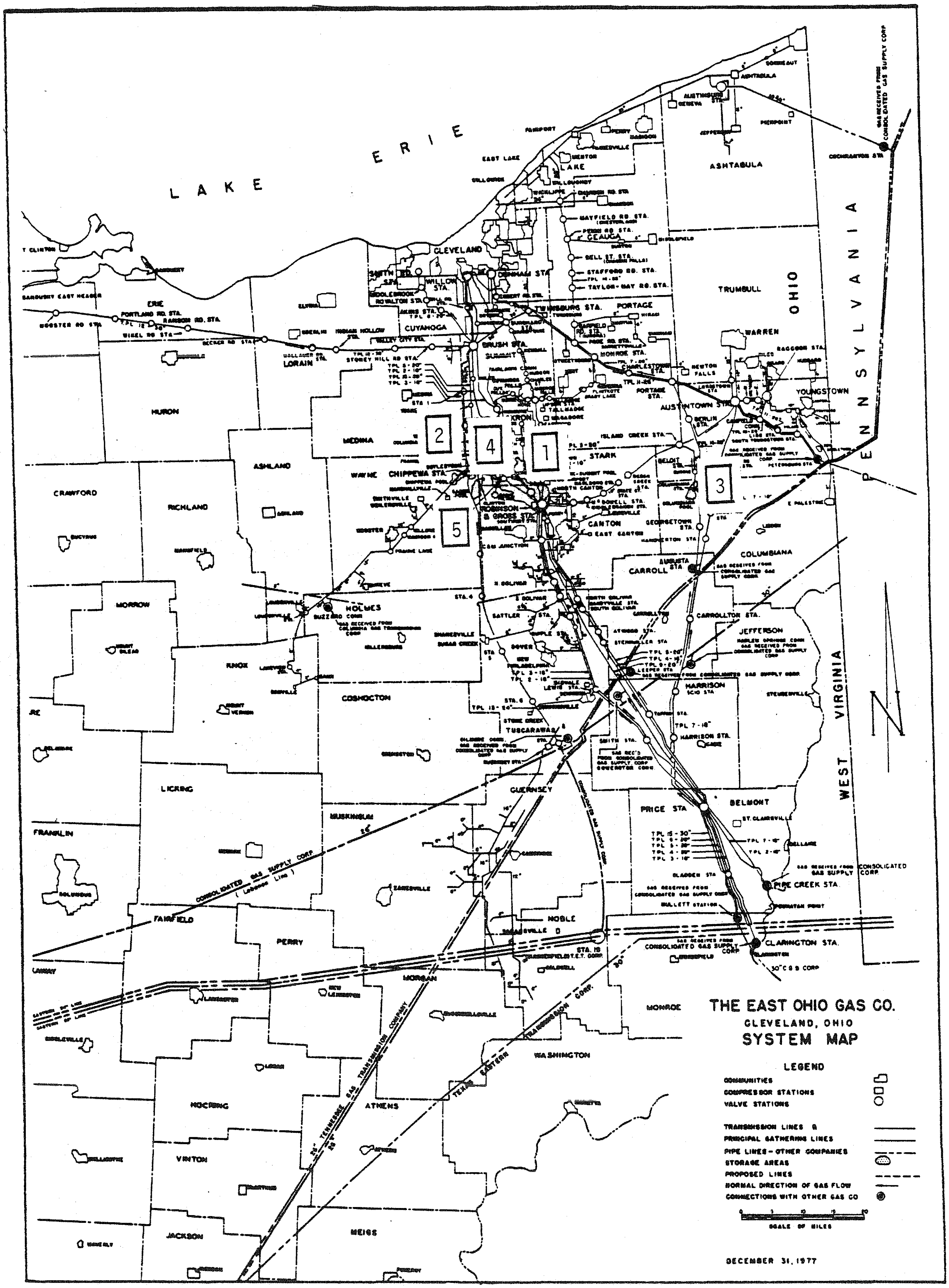


Figure 5.3 EOGC Storage Fields

In order to derive precise expansion plans it is obviously necessary to model the complete distribution system, using physical quantities variables such as pressure, system volume and capacity, gas flow etc., as well as cost parameters. A network flow computer program could simulate and analyze all feasible system operations to determine which components (pipes, compressors, etc.) should be expanded or modified to transport the assumed flow as economically as possible - i.e., at a minimum cost. This simulation should indicate estimates of the maximum flow in each pipeline segment after accounting for all the many interrelated factors which affect pipeline flows, such as: 1) daily fluctuations in supply, 2) daily operation of storage projects, 3) transfer of volumes between different parts of the system, 4) daily shifts in market requirements, and 5) deliveries from various supplemental supply projects. The daily operation of the system could then be simulated by using a material balance computer model of the pipeline network. This model would be particularly useful for planning new facilities in newly developed territories.

Unfortunately, the development of such a detailed model could not be undertaken within this study, due to time and other limitations. However, the impact of this shortcoming is somewhat alleviated by the fact that the EOGC, at the time its <u>10-Year Forecast Report</u> was issued (1977), anticipated that its projected supply (see scenario EOGCS in Chapter 3) could be handled through existing supply points without new major transmission lines and associated facilities.[1] EOGC officials have indicated that the peak daily sales of the EOGC occurred on January 8, 1970, with a volume of 2.8531 Billion Cubic Feet (BCF), and that the EOGC is anticipating peak daily sales for January 1979 of 2.5 BCF. A conservative estimate of the EOGC system capacity expressed in terms of maximum daily gas sales would thus be 2.8531 BCF. However, without the above-mentioned model it is impossible to estimate the exact carrying capacity of the system.

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[1]The East Ohio Gas Company, <u>10-Year Forecast Report</u>, December 15, 1977. Report to the Ohio Power Siting Commission.

In this study the expansion process is therefore characterized only by the number of new customers to be connected to the system and by the correspondingly required new gas loads after accounting for energy conservation effects. The capacity costs incurred by such connections are evaluated on the basis of historical and engineering data, as described in the next section.

Capacity Expansion Costs Forecasting Models

Cost models have been developed separately for the three classes of customers - residential, commercial, and industrial. The parameters of the models have been estimated with historic EOGC data available in the EOGC Annual Reports, and with data provided directly to this research team by the EOGC. The expansion cost for any class of customers contains two major components: a) costs related directly to the number of customers connected, and b) costs related to the new gas load. Each major component may be further decomposed into such categories as : (1) meter and regulator costs, (2) distribution plant costs, (3) general plant costs, (4) production plant costs, (5) storage plant costs, and (6) transmission plant costs. This differentiation is necessary because different expansion paths may not necessitate the same expansion of all components.

The Residential Capacity Cost Model

The general formulation of the cost function is:

$$CACR_t = NGCR_t * [C_1 + A_2*C_2 + C8 + C9 + A10*C10] + CNDGR_t * [A5*C5 + C6 + C7 + A11*C11 + A12*C12 + A13*C13] \quad (5\text{-}1)$$

where:

$CACR_t$ = residential capacity expansion cost in year t;

$NGCR_t$ = number of residential customers connected to the system in year t;

$CNDGR_t$ = new residential gas load to be served in year t.

The estimates of the cost parameters are:

C1 = meter cost = \$27.60/customer (Source: data provided by the EOGC);

C2 = regulator cost = \$2.021/customer (Source: Annual Report 1977);

C8 = structures and improvements = \$12.2104/customer (Source: Annual Report 1977);

C9 = land rights = \$2.1869/customer (Source: Annual Report 1977);

C10 = general plant cost = \$12.0424/customer (Source: Annual Report 1977);

C5 = distribution line average cost = \$1.89637/MCF (Source: data provided by the EOGC);

C6 = distribution services cost = \$0.19443/MCF (Source: Annual Report 1977);

C7 = regulating station cost = \$0.02929/MCF (Source: Annual Report 1977);

C11 = production plant cost = \$0.20871/MCF (Source: Annual Report 1977);

C12 = storage plant cost = \$0.15617/MCF (Source: Annual Report 1977);

C13 = transmission plant cost = \$0.29282/MCF (Source: Annual Report 1977).

The cost function also includes the following "share" parameters:

A2 = share of homes with a regulator;

A10 = ratio of the marginal increase of the general plant due to the addition of one new customer to the corresponding average increase;

A11 = same definition as for A10, but for the production plant;

A12 = same definition as for A10, but for the storage plant;

A13 = same definition as for A10, but for the transmission plant;

Two types of residential hook-ups have been considered:

(1) those made within the currently (i.e., year t) served areas, and

(2) those made in remote areas, not currently served by the distribution network.

In the first case, the parameter A5 is set equal to 1, and in the second it is set arbitrarily equal to 3, implying much higher pipeline costs to serve remote areas.

The "share" parameters have been given the following values:

(1) A2 = 1: it is assumed that all homes are to be equiped with a regulator;

(2) A10 = 1: it is assumed that the general plant costs are proportional to the number of residential customers;

(3) A11 = 0.2: it is assumed that the production plant must be expanded so that new gas production will cover 20% of the new gas requirements;

(4) A12 = A13 = 0: whatever the expansion plan, it is assumed that no change will occur in the storage and transmission plants.

The major cost component, measured by the parameter C5, is the distribution line cost. The parameter C5 has been determined as the unknown of the equation obtained when setting the following values in equation (5-1):

$CACR_t$ = \$456 (this is the cost per new domestic customer addition, as provided directly by EOGC officials);

$NGCR_t$ = 1 (one customer is assumed to be hooked-up);

$CNDGR_t$ = 190.41 MCF (this is the 1977 residential consumption rate, as determined from the Annual Report data).

In the previous computation, it has of course been assumed that the total cost figure of \$456 per new domestic customer corresponded to customers located within currently served areas. Of this total cost, 11.8% represents customer costs, and 88.2% represents gas transportation costs. Under the assumption that piping costs would be three times higher in the case of residential customers located outside of the currently served areas, the total hook-up costs would be \$1178 for each of these customers.

The final cost equations used in the Capacity Cost model are:

$$CACRS_{rt} = NGCSA_{rt} * [C1 + C2 + C8 + C9 + C10] + CNDGRS_{rt} * [C5 + C6 + C7 + 0.2*C11] \quad (5\text{-}2)$$

$$CACRN_{rt} = NGCNSA_{rt} * [C1 + C2 + C8 + C9 + C10] + CNDGRN_{rt} * [3*C5 + C6 + C7 + 0.2*C11] \quad (5\text{-}3)$$

where:

$NGCSA_{rt}$ = number of new residential gas customers hooked-up in division r during year t within the currently served areas;

$NGCNSA_{rt}$ = same definition as for $NGCSA_{rt}$, but outside of the currently served areas;

$CNDGRS_{rt}$ = new residential gas load connected within the currently served areas in division r during year t;

$CNDGRN_{rt}$ = new residential gas load connected outside of the currently served areas in division r during year t;

$CACRS_{rt}$ = capacity expansion cost for residential gas customers connected within the currently served areas in division r during year t;

$CACRN_{rt}$ = capacity expansion cost for residential gas customers connected outside of the currently served areas in division r during year t.

The Commercial Capacity Cost Model

All the new commercial customers to be hooked-up are assumed to be exclusively located within the currently served areas. The distribution line average cost, C5, is applied to commercial gas flows in the same way it is applied to residential flows. The only difference between the commercial and residential cost models is related to the cost of a regulator, taken as: C3 = \$49.256/customer (Source: Annual Report 1977). The commercial cost equation used in the Capacity Cost model is:

$$CACC_{rt} = NCGC_{rt} * [C1 + C3 + C8 + C9 + C10] + CNDGC_{rt} * [C5 + C6 + C7 + 0.2*C11] \quad (5\text{-}4)$$

where:

$NCGC_{rt}$ = number of new commercial gas customers hooked-up in division r during year t;

$CNDGC_{rt}$ = new connected commercial gas load in division r during year t;

$CACC_{rt}$ = capacity expansion cost for commercial gas customers hooked-up in division r during year t.

The Industrial Capacity Cost Model

The specific assumptions made for new commercial customers are assumed to hold for industrial customers. The cost of a regulator for an industrial customer, C4, is assumed to be the same as for a commercial customer. The industrial cost equation used in the Capacity Cost model is:

$$CACI_{rt} = NIGC_{rt} * [C1 + C4 + C8 + C9 + C10] + CNDGI_{rt} * [C5 + C6 + C7 + 0.2*C11] \quad (5\text{-}5)$$

where:

$NIGC_{rt}$ = number of new industrial gas customers hooked-up in division r during year t;

$CNDGI_{rt}$ = new connected industrial gas load in division r during year t;

$CACI_{rt}$ = capacity expansion cost for industrial gas customers hooked-up in division r during year t.

Operating and Maintenance Costs Forecasting Models

Operation and maintenance expenses are related to: a) gas production and exploration, b) purchases from transmission companies, c) storage, d) transmission and distribution within the EOGC network, and e) customers and administrative costs.

In this study these costs were separated into: a) gas purchases, which account for approximately 80-90% of the total cost, and were estimated separately within the revenue requirements model, and b) operating and maintenance (O&M) costs, including storage O&M costs and other O&M costs, labeled general O&M.

Storage O&M costs are mostly related to the operation of the storage compressors, needed to inject gas into storage. A measure of the activity of these compressors is the amount of gas injected into storage. It was assumed therefore that storage O&M costs are a function of total annual inflow into storage.

The other O&M costs were assumed to be a function of total annual gas sales. Although this assumption is probably true for transmission and distribution costs, because field compressors and control equipments activity is related to these sales, it is less so for the other cost categories. Customer and administrative expenses are probably better related to the number of customers, and the production costs are, in fact, related to the amount of gas produced. However, as the latter items constitute a relatively small share of total O&M costs, the present approximation does not introduce serious errors.

The basic costs and gas flows data used to prepare the cost forecasting models are presented in Tables 5-4 and 5-5. The modeling approach is to use these historical data to calibrate forecasting models of cost variations. More detailed cost data are presented in Table G-3 in Appendix G.

Various regression models were tested to relate storage O&M costs with annual storage inflow. Discarding the 1977 cost figure which is abnormally high and could not be explained, the best fit was obtained based on the regression of O&M costs per unit of gas injected into storage on the total annual storage inflow:

$$OMSTOC_t = GDELIV_t * [0.126169 - 0.99385*10^{-6} * GDELIV_t] \qquad (R^2 = 0.626) \qquad (5\text{-}6)$$

where:

$OMSTOC_t$ = storage operation and maintenance costs during year t (in 1977 $);

$GDELIV_t$ = total amount of gas delivered to storage in year t (in MCF).

Table 5-4 Storage Operating and Maintenance Costs (O&M), Annual Storage Inflow Rates and Storage Cost per MCF of Inflow, by Year, for the EOGC

Year	Storage O&M Cost (1000 current $)	Storage O&M Cost* (1000 1977 $)	Storage Inflow (MCF)	Storage Cost per MCF of Inflow (3 ÷ 4)
1	2	3	4	5
1970	1,979	3,255.65	55,116,780	.05906
1971	2,748	4,224.76	53,958,347	.07830
1972	2,442	3,512.82	47,775,888	.07353
1973	3,045	4,070.86	55,619,480	.07319
1974	3,349	4,071.71	57,414,981	.07092
1975	3,738	4,149.55	59,987,547	.06928
1976	3,699	3,099.12	45,242,027	.08618
1977	6,657	6,657.00	57,977,731	.11482

*Adjusted for inflation using GNP inflator
Source: Based on EOGC Annual Reports.

Table 5-5 Total Operation and Maintenance Expenses, Storage Operating and Maintenance Expenses (O&M), Total Gas Sales and Ratio of O&M Expenses to Sales

Year	Operation and Maintenance Expenses (1000 $)	Storage O&M Expenses (1000 $)	O&M Expenses Net of Storage Expense* (1000 $)	Gas Sales (1000 MCF)	Ratio of Net Expenses to Sales 4 ÷ 5 ($/MCF)
1	2	3	4	5	6
1977	93,625	6,657	86,968	351,203	.24763
1976	85,562	3,699	86,292	375,626	.22973
1975	82,510	3,738	87,445	359,301	.24337
1974	74,579	3,349	86,601	392,828	.22046
1973	67,777	3,045	86,540	385,232	.22464
1972	62,559	2,442	86,478	412,304	.20974
1971	58,940	2,748	86,390	397,997	.21706
1970	55,356	1,979	87,811	382,824	.22938

*Adjusted for inflation using GNP inflator.
Source: EOGC Annual Report.

The above model implies very slight economies of scale in storage injection costs, at least within the range of values which characterized the inflows from 1970 to 1976.

With respect to non storage-related O&M costs, the best fit was obtained when regressing the O&M cost per unit of gas sales on the total annual gas sales:

$$OMGENC_t = GSALES_t * [0.47064 - 0.6356*10^{-6} * GSALES_t] \quad (R^2 = 0.994) \tag{5-7}$$

where:

$OMGENC_t$ = general operation and maintenance costs during year t (in 1977 $)

$GSALES_t$ = total amount of gas sold during year t (in MCF)

In addition, the general O&M costs ($OMGENC_t$) are assumed to increase at a yearly rate of 4%, mostly reflecting wage increases above the inflation rate. Thus, equation (5-7) becomes:

$$OMGENC_t = GSALES_t * [0.47064 - 0.6356*10^{-6} * GSALES_t]*[1 - 0.04(t-1)] \quad (\text{with } t=1 \rightarrow 1977) \tag{5-8}$$

CHAPTER 6

THE CAPACITY EXPANSION PROCESS

There are a number of considerations that will determine the precise process and form by which Ohio's gas distribution companies will provide new service in the coming years. Besides the very important questions of how much new service will be demanded in the future and the desire of gas distributors to provide new service, the most important determinants of what new service will actually be provided are the general policies of the PUCO and the precise form of the relief order concerning the current ban on such service. The purpose of this chapter is to describe various potential policies concerning new service that could be adopted by the PUCO, those policies that were actually analyzed, and the formal structure of these policies.

The Need for New Service Policies

The moratorium on new customer hook-ups in Ohio dates to 1972. When Columbia Gas of Ohio asked and received permission from the PUCO to cease taking on new customers, other major gas distributors followed soon afterwards. In January 1979, the East Ohio Gas Company will become the first major gas utility to begin new hook-ups after obtaining a relief order from this moratorium. In May 1978, Columbia Gas of Ohio announced that it intends to ask the PUCO for a similar relief order in the spring of 1979.[1]

The interest of Ohio's gas distributors in new service is not unique. A number of public utility commissions throughout the United States have recently provided relief orders from similar bans on new service. For example, in California only luxury hook-ups such as swimming pools remain curtailed. In the state of Illinois such essential uses such as residential and schools have been allowed to hook-up new customers since October 15, 1977. Non-essential users are still not permitted to be hooked-up. In the state of Iowa,

[1] "Gas Sales May Be Resumed", Columbus Dispatch, May 28, 1978, p B-3.

the Iowa Power and Light Company has been permitted to accept requests for extension of mainlines in new developments that meet certain energy efficiency criteria. In the state of Michigan residential hook-ups are allowed. Light industrial and commercial applications are being accepted by gas companies in anticipation of receiving gas supply, but apparently no such hook-ups are permitted. In the state of Missouri the situation concerning new service is unclear. This is due to a legal dispute over the Federal Power Commission order not to supply interstate gas to Missouri distributors for new customers. In the state of New Jersey the Public Service Commission has allowed two companies to accept new customers on a limited basis according to Commission established priorities. In the state of New York, the Commission is studying long-term gas supplies. It does allow new industrial customers to hook-up if they purchase gas from existing non-essential industrial users. And in the state of Wisconsin the public service commission has allowed new residential hook-ups at least until January 18, 1977.

The sudden reawakening of interest among gas distributors in various states in service extensions is due to reduced growth in gas consumption by the existing customers so that market requirements are below their minimum annual contract obligations with gas transmission companies. Under "take-or-pay" contracts, if the gas purchaser (gas distribution company) cannot accept delivery of quantities of gas equal to the minimum quantity provided for in the contract, they must pay for that quantity of gas which represents the difference between the minimum called for under the contract and the amount of gas actually delivered. They are, therefore, advancing money for gas which will be delivered later. Since there are no deductions for royalty or operating costs, the net amount of money received by a gas producer is greater than if the gas had been taken. When the gas is actually delivered in the future, it will be delivered at the price then in effect, which will be higher than the current price.

It should also be pointed out that the purchaser must take delivery of the gas, for which prepayment has been made, within the specified period, failing which, the right to recover the gas terminates. The recovery of this gas can only be accomplished by the purchaser after meeting its minimum quantity commitment in any contract year. Obviously, these circumstances breed a strong incentive for the purchaser to expand his market and increase deliveries. Otherwise the prepayment is left with the producer without the delivery of the gas, and it should be apparent that the purchaser cannot allow that to happen.

Furthermore, the apparent over-supply problem has been caused in large part by the activities of producers many years ago when gas prices were very low and there was no incentive by the industry to develop reserves, particularly shallow gas. Large contract areas were assigned to the industry participants, even though only relatively little acreage could at that time be considered as proven. As gas prices have increased to level of $1.25-1.50 per mcf, more development has resulted in increases in gas reserves. Adding to the current-over supply has been the lower than forecasted increased usage of natural gas in the U.S.

In particular the supply position of Consolidated Natural Gas Company, a major supplier of the East Ohio Gas Company, has improved substantially during the past year as a result of a start up of the El Paso Algeria LNG program and rising production rates. Gas sales are expected to rise by 7.3% in 1978, primarily because no deliveries were curtailed and because the weather was extremely cold during the first quarter. Similarly, the supply position of the Columbia system is enhanced by deliveries, which began in March, 1978, of LNG from Algeria to the Cove Point, Maryland terminal, ownership of which is shared with Consolidated Natural Gas. When full deliveries from Algerian trades are reached in the late 1978, Cove Point will contribute a 110 billion cf annually to Columbia Gas supply over a 25 year period. The average cost of the revaporized LNG delivered into the transmission system is estimated to be $1.66 per mcf. Negotiations continue for securing additional LNG supplies for deliveries to Cove Point. To meet future requirements, the company also has to contruct a new storage field in Fairfield County, Ohio, which eventually will increase total present storage capacity to 590 billion cf, or by 19%.

Potential New Service Policies

In general, potential PUCO policies concerning new service can be defined in terms of: (a) the type of customer to receive new service, (b) the location of the customers to receive new service, and (c) the contractual arrangement under which new service is to be provided. This typology of policies is helpful in an attempt to evaluate the alternative courses of action that are open to the PUCO in terms of the regulatory objectives listed below in Chapter 9.

For example, the provision of excess gas supply to residential customers, at the expense of industrial customers, will have a major impact on end-use efficiency, while the provision of new service to customers who are located within the currently serviced regions of the company's legal service area will result in a smaller change of the company's rate base than provisions of a similar quantity of gas to similar customers located elsewhere. At the same time, provision of the excess gas supply under interruptable contracts will cause smaller economic dislocations during unusual heating months.

Out of the above crude typology of policies emerge 19 potential PUCO policies, including a policy of no new service. For further details see Figure 6-1, in which each of the 19 policies is listed. Each box in the figure represents an alternative policy. The possible introduction of mixed policies, e.g. in terms of figure 6-1 policies #5, #7, and #15 together, increases the number of potential policies and complicates the analysis of potential impacts.

Potential PUCO policies can be further differentiated in terms of the specified time of their implementation. For example, policy #2 in Figure 6-1 can become two different policies: one implemented in 1978 and another implemented in 1985. Furthermore, the date of implementation of policies may be prespecified, or may depend upon some set of events that become known as an output of the simulation exercise. In such a case the implementation date of a policy is unknown ex ante.

It is noteworthy that, in the limit, new policies can be construed as a means for the definition of new legal service boundaries for Ohio's power utilities. In the absence of franchises, the boundaries of utilities' territories are not firmly set. Adjustment in these boundaries by permitting one utility to expand while holding another utility to its present service, or the extension of one utility service area at the expense of another, has the potential of becoming a major source of competition among utilities of the type that can lead to an overall increase in the efficiency with which resources are allocated. In the least, this type of competition would lead to the elimination of price of gas differences which are due to differences in the efficiency with which utilities operate. The only price differences permitted would be those based on "true" cost of service differentials.

Policies Selected for Simulation

Of all the potential policies that the PUCO may adopt only a small selected number were subjected to evaluation through the simulation model. The choice of policies was guided by the need for certain types of information necessary for general evaluation of very broad policies. In other words, this study seeks to point out the repercussions of very general policies that the PUCO might adopt. It did not evaluate in detail very specific policies. Such an evaluation can be carried out by PUCO staff in the context of specific hearings. It is for this purpose that the analytical model was developed.

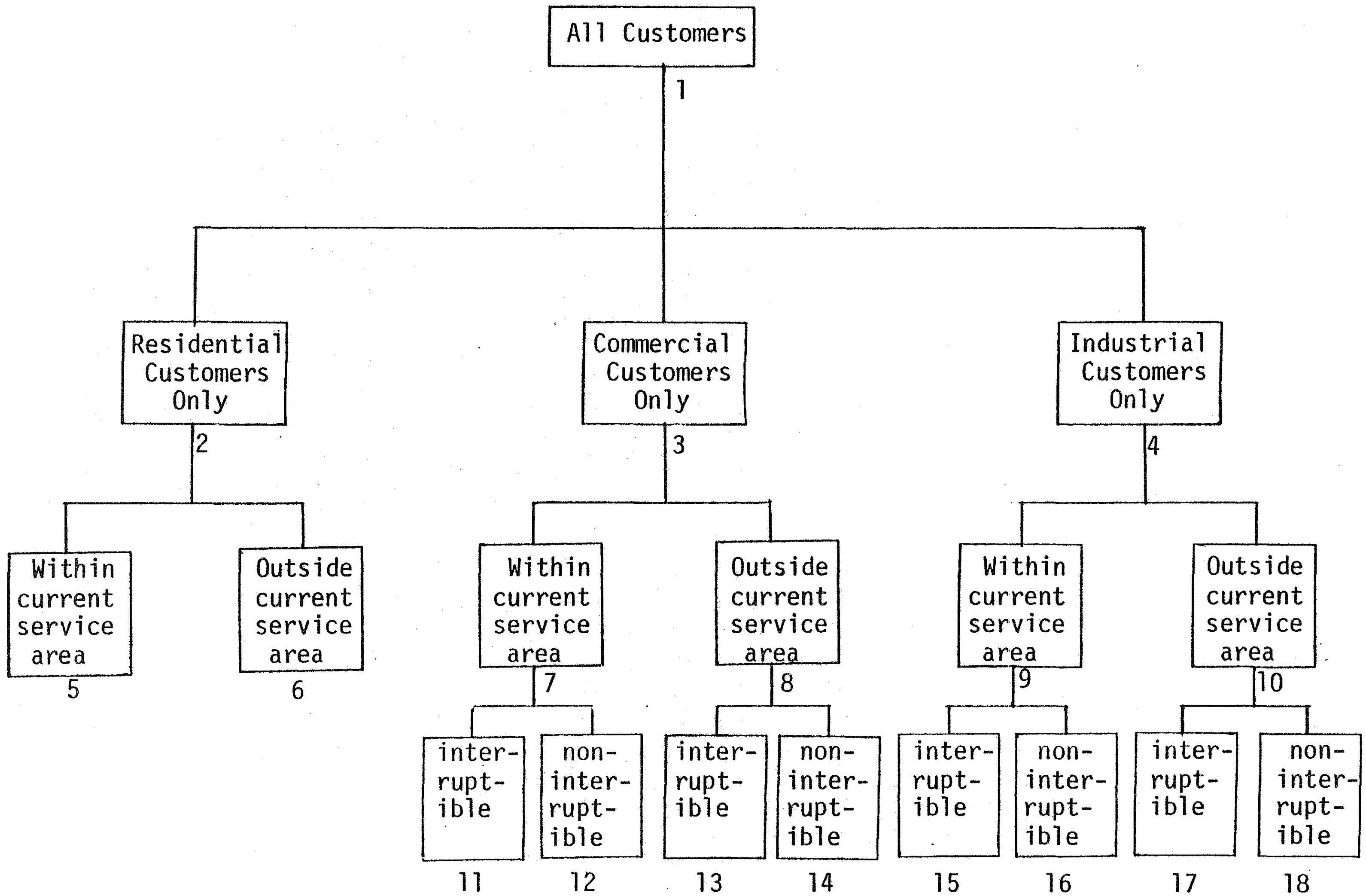

Figure 6-1 Potential PUCO Policies in Terms of Customer Type and Location and Type of Contract

Among the policies that were analyzed are two extreme courses of action. The intention of the analysis of these policies is to point out the consequences of a limited involvement by the PUCO in the whole issue of new service. These policies range from a "do nothing" policy to a policy of "laissez faire":

Policy 1: No relief order is issued.

Policy 2: A complete relief order is granted.

Policy 2 permits the gas company to make decisions that are in its own best interest. It is not at all clear that such a policy will lead to the achievement of regulatory objectives such as adequacy of service and end-use efficiency. Nevertheless, it is important to examine this policy in terms of the policy evaluation criteria selected. Similarly, Policy 1 may result in an adverse financial position for the company, as well as inadequate service and inefficiency of end-use.

While Policies 1 and 2 were used to analyze the repercussions of extreme courses of action by the PUCO, other policies were used to examine the least adverse impacts of alternative policies. Two additional policies were analyzed:

Policy 3: A partial release order is granted, covering residential customers within the currently serviced areas of the company's legal service area.

Policy 4: A partial relief order is granted, covering industrial customers located anywhere within the legal service area.

The aim of testing Policies 3 and 4 is to examine the extent to which the mild effects of Policies 1 and 2 can be localized. Policies 3 and 4 increase the rate base of the utility, but without endangering it to price competition from other fuels. In light of possible deregulation of natural gas well-head price the policies can lead the company to capture part of the energy market. Policy 4 has the added advantage that it can be implemented on an interruptible contract basis, thus avoiding the possibility of an adverse future impact on adequacy of service.

It is important to note, however, that new hook-ups are permitted to occur only when excess supply of gas is forecasted for the year under consideration. Before any calculations of the impacts associated with the newly connected load are performed, the model calculates the base demands at the beginning of the year. The base demands for year t are defined as:

$$BASEDR_t = \sum_{r=1}^{5} [TCDR_{rt-1} - ATRG_{rt-1} * TCDR_{rt-1}] \tag{6-1}$$

$$BASEDC_t = \sum_{r=1}^{5} [TCDC_{rt-1} - ATC_{rt-1} * TCDC_{rt-1}] \tag{6-2}$$

$$BASEDI_t = \sum_{r=1}^{5} [TCDI_{rt-1} - ATI_{rt-1} * TCDI_{rt-1}] \tag{6-3}$$

where:

$BASEDR_t$ = base committed gas requirement by residential customers before any new connections at the beginning of year t, for all divisions ($r=1 \rightarrow 5$), after the attrition which took place from year t-1 to year t has been accounted for;

$BASEDC_t$ = base committed gas requirement by commercial customers before any new connections at the beginning of year t, for all divisions ($r=1 \rightarrow 5$), after the attrition which took place from year t-1 to year t has been accounted for;

$BASEDI_t$ = base committed gas requirement by industrial customers before any new connections at the beginning of year t, for all divisions ($r=1 \rightarrow 5$), after the attrition which took place from year t-1 to year t has been accounted for;

$TCDR_{rt-1}$ = total residential gas demand in division r during year t-1, after the initial hook-ups have been accounted for, but before the attrition has been accounted for;

$TCDC_{rt-1}$ = total commercial gas demand in division r during year t-1, after the initial hook-ups have been accounted for, but before the attrition has been accounted for;

$TCDI_{rt-1}$ = total industrial gas demand in division r during year t-1, after the initial hook-ups have been accounted for, but before the attrition has been accounted for;

$ATRG_{rt-1}$ = residential gas customers' attrition rate in division r and year t-1;

ATC_{rt-1} = commercial gas customers' attrition rate in division r and year t-1;

ATI_{rt-1} = industrial gas customers' attrition rate in division r and year t-1.

It is noteworthy that the above attrition rates are applied only to the existing demand in year 1. Based on equations (6-1), (6-2), and (6-3) the total base demand is computed as:

$$BASEDT_t = BASEDR_t + BASEDC_t + BASEDI_t \tag{6-4}$$

where:

$BASEDT_t$ = base committed gas requirements by all customers at the beginning of year t, for all divisions, after the attrition has been accounted for.

Then, the available excess gas supply is computed as:

$$EXCSUP_t = WGS_t - BASEDT_t \tag{6-5}$$

where:

$EXCSUP_t$ = total annual excess gas supply at the beginning of year t, before any new load has been connected;

WGS_t = maximum wholesale gas supply in year t.

If excess supply of gas is forecasted, new hook-ups are permitted to the extent of the excess supply and according to the new service policy in effect. The results are in terms of values for the following variables:

$CNDGRS_{rt}$ = newly connected residential gas load in division r, during year t, within the currently serviced areas;

$CNDGRN_{rt}$ = newly connected residential gas load in division r, during year t, outside the currently serviced areas;

$CNDGC_{rt}$ = newly connected commercial gas load in division r, during year t;

$CNDGI_{rt}$ = newly connected industrial gas load in division r, during year t.

The new cumulated demand for gas during year t is then defined as:

$$TCDR_{rt} = TCDR_{rt-1} - ATRG_{rt-1} * TCDR_{r1} + CNDGRS_{rt} + CNDGRN_{rt} \quad (6\text{-}6)$$

$$TCDC_{rt} = TCDC_{rt-1} - ATC_{rt-1} * TCDC_{r1} + CNDGC_{rt} \quad (6\text{-}7)$$

$$TCDI_{rt} = TCDI_{rt-1} - ATI_{rt-1} * TCDI_{r1} + CNDGI_{rt} \quad (6\text{-}8)$$

where:

$TCDR_{rt}$ = total cumulated committed gas requirements in division r, during year t, by residential customers;

$TCDC_{rt}$ = total cumulated committed gas requirements in division r, during year t, by commercial customers;

$TCDI_{rt}$ = total cumulated committed gas requirements in division r, during year t, by industrial customers.

The total cumulated requirements over all the company divisions, are calculated and serve as inputs to the monthly gas flows management model:

$$TCYDR_t = \sum_{r=1}^{5} TCDR_{rt} \quad (6\text{-}9)$$

$$TCYDC_t = \sum_{r=1}^{5} TCDC_{rt} \quad (6\text{-}10)$$

$$TCYDI_t = \sum_{r=1}^{5} TCDI_{rt} \quad (6\text{-}11)$$

where:

$TCYDR_t$ = total committed gas requirements for residential customers, during year t;

$TCYDC_t$ = total committed gas requirements for commercial customers, during year t;

$TCYDI_t$ = total committed gas requirements for industrial customers, during year t.

CHAPTER 7

MONTHLY GAS FLOWS MANAGEMENT

Because of its high sensitivity to weather, primarily temperature, potential gas demand is unequally distributed over the year. Although gas distribution companies have a limited ability to vary the quantity of gas that they purchase from their suppliers during the winter months, many U.S. gas distributors have developed storage facilities to store excess summer gas for use during the winter.

The purpose of the present chapter is to present an analytic description of the monthly gas management by the EOGC and to develop a sub-model which depicts these management rules, and which may be reasonably expected to be applicable to any other company operating storage facilities and having similar supply contract arrangements. This sub-model will be integrated with the general simulation model, the synthesis of which is presented in Chapter 10. It will be used to predict those months during which the potential monthly gas demand will not be satisfied because of a supply deficit. Through the use of this sub-model, the extent of a supply deficit and the resulting curtailments will be forecasted. This sub-model is also useful in attempts to forecast the need for additional storage capacity.

In the next section a method is presented for generating yearly weather patterns characterized by monthly degree-days. In the following section a simple method for computing monthly potential gas demands by residential, commercial and industrial customers, based on a weather profile, or scenario, is described. Next, an analysis of the past monthly gas purchases of the EOGC is presented, along with simple rules and constraints governing these purchases. In the following section, the storage movements of the EOGC are analyzed. Based on this analysis, constraints on maximum deliveries to and withdrawals from storage are calculated. In the final section of this chapter, the allocation procedures to be used in the model are presented, their validity analyzed, and possible extensions suggested.

Generation of Weather Scenarios

The purpose of this section is to derive statistical distributions of monthly degree-day patterns in the EOGC service area from past data. These distributions are then to be used to generate weather scenarios.

The Basic Data

The source of data for this analysis is: Climatological Data: Ohio, January 1950 - December 1976, published by the U.S. Department of Commerce. There are several stations that maintain records of daily temperature readings within each of the eighteen counties served by the EOGC. It was decided that the Akron-Canton Airport, the Cleveland Airport and the Youngstown Airport would provide the most reliable and consistent data and it was also determined that these three stations were a fair representation of the temperature variances throughout the EOGC service area.

Degree day readings from the three data collecting stations for January through December for the years 1950-1976 are presented in Tables H-1 through H-27 of Appendix H. All of the following analyses are related to the average degree-day values of the three stations.

Yearly degree-day totals (January-December) are presented in Table 7-1, and degree-day totals for the winter season extending from November to April are presented in Table 7.2. The choice of this winter period is related to wholesale gas supply management rules described later in this chapter.

Table 7-1 - Yearly Degree-Day Totals for the EOGC Service Area

Year	Degree-days	Year	Degree-days	Year	Degree-days
1950	6,403	1959	6,151	1968	6,492
1951	6,243	1960	6,596	1969	6,461
1952	5,984	1961	6,369	1970	6,345
1953	5,852	1962	6,551	1971	6,208
1954	5,903	1963	6,848	1972	6,813
1955	6,035	1964	6,148	1973	5,468
1956	6,133	1965	6,223	1974	6,033
1957	6,086	1966	6,638	1975	5,925
1958	6,643	1967	6,328	1976	6,784

Table 7-2 Winter Degree-Day* Totals for the EOGC Service Area

Winter Season	Degree-days	Winter Season	Degree-days	Winter Season	Degree-days
1950/1951	5,672	1959/1960	5,549	1968/1969	5,451
1951/1952	5,388	1960/1961	5,694	1969/1970	5,979
1952/1953	4,950	1961/1962	5,672	1970/1971	5,098
1953/1954	4,927	1962/1963	6,015	1971/1972	5,671
1954/1955	5,155	1963/1964	5,615	1972/1973	4,937
1955/1956	5,712	1964/1965	5,988	1973/1974	4,974
1956/1957	5,141	1965/1966	5,353	1974/1975	5,316
1957/1958	5,417	1966/1967	5,278	1975/1976	4,952
1958/1959	5,691	1967/1968	5,644		

*The winter season is defined as the months November through April.

The Statistical Characteristics of the Degree-day Data

The descriptive statistics of the yearly degree-day totals for the years 1950-1976 are:

Mean: 6,284 degree-days;

Variance: 108,876 degree-days;

Standard Deviation: 330 degree-days.

The descriptive statistics of the winter degree-day totals for the years 1950-1975 are:

Mean: 5,432 degree-days;

Variance: 116,730 degree-days;

Standard deviation: 342 degree-days.

The frequency distributions of the yearly degree-day totals and of the winter degree-day totals for the years 1950-1975 are given in Tables 7-3 and 7-4, respectively.

The yearly and winter totals have been ranked and cumulative frequency curves derived under the assumption that each yearly or seasonal pattern has the same probability of occurrence. These curves are presented in Figures 7-1 and 7-2.

The minimum and maximum relative frequencies of the yearly totals and of the seasonal totals are given in Tables 7-5 and 7-6, respectively.

Table 7-3 Frequency Distributions of Yearly Degree-Day Totals 1950-1976

Class of Yearly Totals of Degree-days	Absolute Frequency	Relative Frequency (%)
1. 5468- 5606	1	3.70
2. 5607- 5745	0	0.00
3. 5746- 5884	0	0.00
4. 5885- 6023	4	14.81
5. 6024- 6162	6	22.22
6. 6163- 6301	3	11.11
7. 6302- 6440	4	14.81
8. 6441- 6579	3	11.11
9. 6580- 6718	3	11.11
10. 6719- 6857	3	11.11
Total	27	100.00

Table 7-4 Frequency Distributions of Winter Degree-Day Totals 1950-1976

Class of Seasonal Totals of Degree-days	Absolute Frequency	Relative Frequency(%)
1. 4927- 5036	5	19.23
2. 5037- 5146	2	7.69
3. 5147- 5256	1	3.85
4. 5257- 5366	3	11.54
5. 5367- 5476	3	11.54
6. 5477- 5586	1	3.85
7. 5587- 5696	7	26.92
8. 5697- 5806	1	3.85
9. 5807- 5916	0	0.00
10. 5917- 6026	3	11.54
Total	26	100.00

Table 7-5 Minimum and Maximum Relative Frequency of Yearly Totals of Degree-Days (January - December), 1950-1976.

Year	Minimum	Maximum
1950	.630	.666
1951	.481	.518
1952	.148	.185
1953	.037	.074
1954	.074	.111
1955	.222	.259
1956	.296	.333
1957	.259	.296
1958	.852	.888
1959	.370	.407
1960	.777	.815
1961	.592	.630
1962	.741	.777
1963	.963	1.000
1964	.333	.370
1965	.444	.481
1966	.815	.852
1967	.518	.555
1968	.704	.741
1969	.666	.704
1970	.555	.592
1971	.407	.444
1972	.926	.963
1973	.000	.037
1974	.185	.222
1975	.111	.148
1976	.888	.926

Table 7-6 Minimum and Maximum Relative Frequency of Seasonal Totals of Degree-Days (November - April), 1950-1975.

Winter Season	Minimum	Maximum
1950/1951	.692	.731
1951/1952	.423	.462
1952/1953	.077	.115
1953/1954	.000	.039
1954/1955	.269	.308
1955/1956	.846	.885
1956/1957	.231	.269
1957/1958	.462	.500
1958/1959	.769	.808
1959/1960	.539	.577
1960/1961	.808	.846
1961/1962	.731	.769
1962/1963	.962	1.000
1963/1964	.577	.615
1964/1965	.923	.962
1965/1966	.385	.423
1966/1967	.308	.346
1967/1968	.615	.654
1968/1969	.500	.539
1969/1970	.885	.923
1970/1971	.192	.231
1971/1972	.654	.692
1972/1973	.039	.077
1973/1974	.154	.192
1974/1975	.346	.385
1975/1976	.115	.154

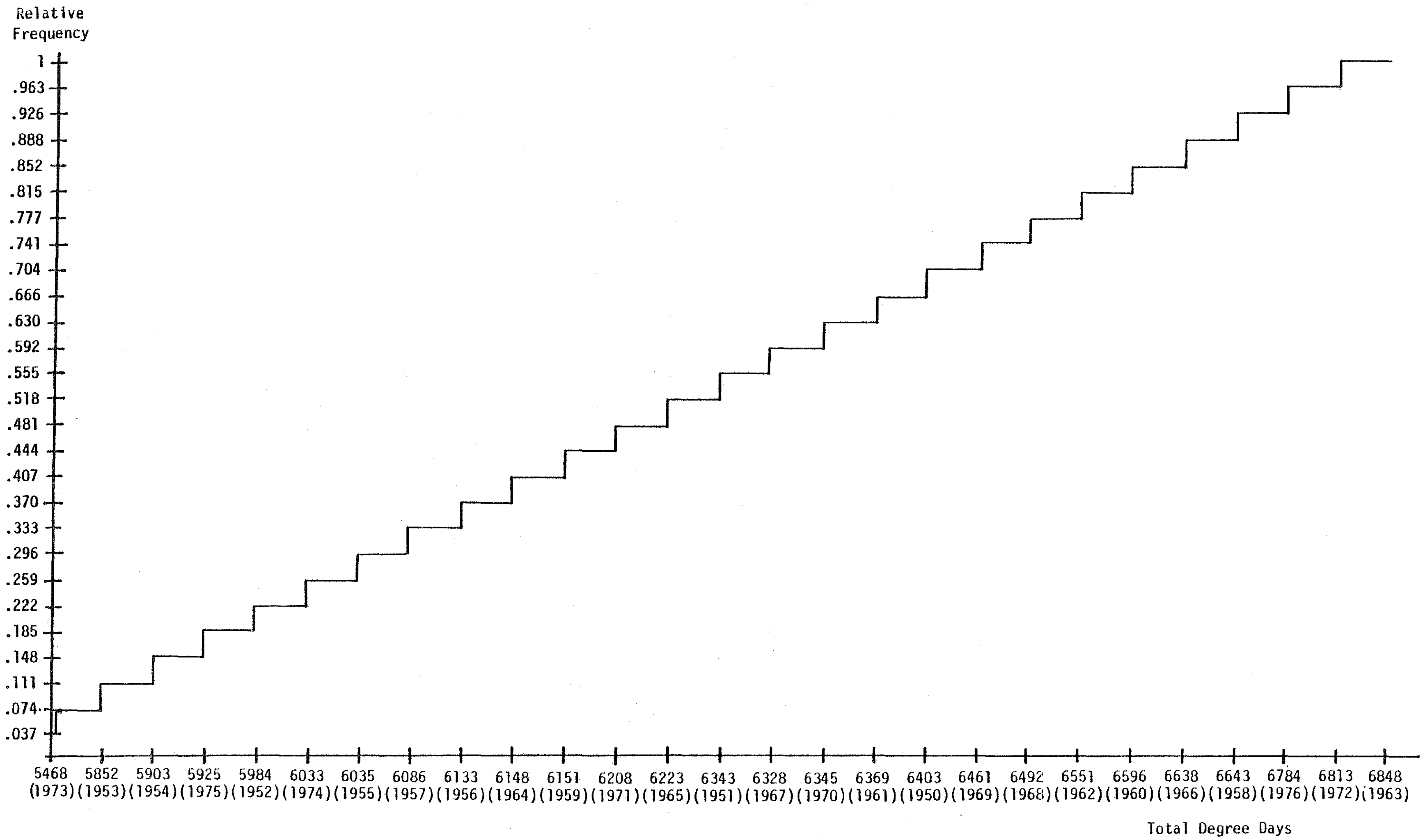

Figure 7-1 Cumulative Frequency Curve of Yearly Degree-Day Totals

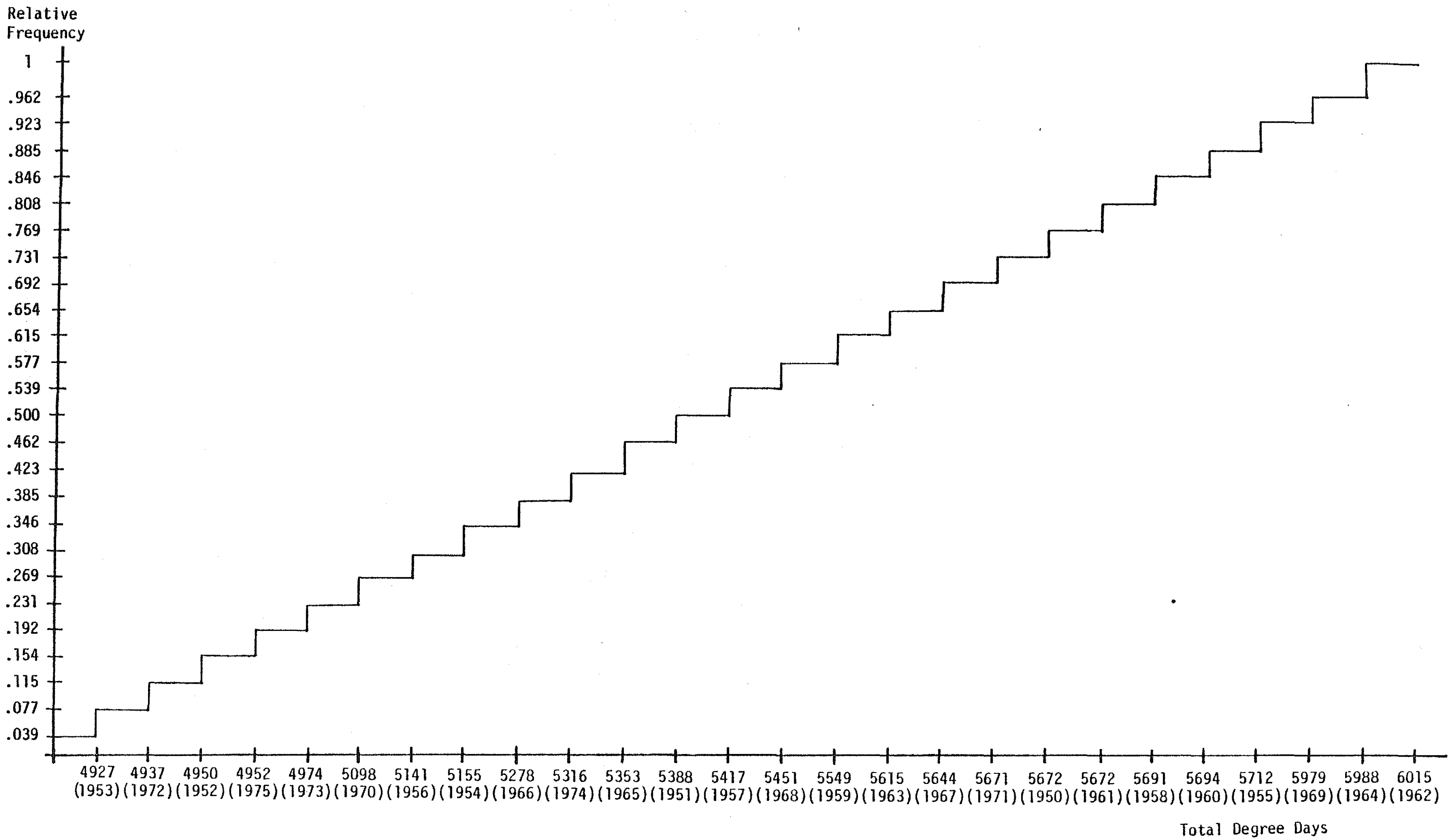

Figure 7-2 Cumulative Frequency Curve of Winter Degree-Day Totals

The weather pattern generation procedure

As will be explained in more detail in later sections, a realistic simulation of monthly gas flows management must be based on a time breakdown reflecting seasonal changes. These changes are not correctly integrated into the regular calendar year, so a "shifted" year starting in May of a given calendar year and ending in April of the next calendar year has been defined for use in the simulation model. The monthly degree-days for these years, from 1950 to 1976, are presented in Table 7-7. Each of these years is, for the purpose of gas management, characterized by its winter season extending from November to April. The winter season weather has been previously characterized by an interval ranking corresponding to specified degree-day totals (see Table 7-6). The procedure for generating a monthly degree-day pattern for any future year t is then: (a) generate a random number within the complete interval from 0.000 to 1.000; (b) find out within which frequency interval this number is located; (c) select the corresponding year and its associated monthly pattern of degree-days, which is then used to compute potential monthly gas demands. These simulated degree-days for year t and month m are noted: DDS_{tm}(m=1: May $\rightarrow$ m=12: April).

The above procedure relies on three simple assumptions:

(1) the meteorological patterns which have characterized these 26 past years are a fair coverage of the possible future meteorological patterns;

(2) the total number of degree-days in the winter is representative of the yearly weather pattern, and can therefore be used to determine a statistical frequency distribution of weather patterns;

(3) there is no temporal correlation between weather patterns, i.e., the weather pattern occurring during year t and month m does not bear any relationship to the weather patterns of previous years and months.

Table 7-7 Monthly Degree-Day Totals for the EOGC Service Area

Year	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	March	April
1950/1951	197	58	5	29	121	293	864	1266	1110	1000	865	567
1951/1952	186	38	5	24	139	312	907	1090	1040	971	907	473
1952/1953	261	29	6	15	106	540	664	972	992	907	804	611
1953/1954	452	25	12	8	119	299	636	987	1151	849	951	353
1954/1955	311	43	10	12	71	365	714	1073	1222	989	847	311
1955/1956	162	60	0	4	81	366	816	1177	1196	995	931	597
1956/1957	296	73	6	21	194	258	706	860	1326	922	846	481
1957/1958	225	35	8	13	126	460	702	942	1187	1210	931	445
1958/1959	250	100	2	30	111	384	654	1339	1292	1009	922	475
1959/1960	154	60	1	1	92	391	809	945	1065	1064	1259	407
1960/1961	270	49	26	3	59	409	671	1314	1341	916	790	662
1961/1962	359	87	17	4	79	299	700	1115	1283	1087	946	541
1962/1963	123	34	13	17	179	361	723	1244	1435	1312	799	502
1963/1964	311	53	27	39	161	204	650	1355	1115	1164	861	470
1964/1965	170	80	4	50	126	477	607	1024	1219	1070	1028	563
1965/1966	116	67	19	52	83	447	680	879	1341	1046	829	578
1966/1967	363	55	5	15	174	464	681	1087	1042	1134	867	467
1967/1968	405	14	24	30	166	384	844	969	1323	1246	824	438
1968/1969	319	56	22	31	71	384	679	1099	1206	1020	979	468
1969/1970	208	7	5	10	140	416	769	1233	1428	1084	989	476
1970/1971	165	50	13	11	83	320	692	1034	1340	1016	1016	615
1971/1972	280	14	8	19	69	197	759	875	1213	1220	992	612
1972/1973	196	130	36	31	120	542	783	938	1102	1064	579	471
1973/1974	274	3	4	13	90	261	617	990	1057	1066	815	429
1974/1975	270	51	3	5	187	447	663	1040	1035	966	934	678
1975/1976	142	41	5	4	186	381	537	1016	1340	884	693	482

Clearly, the above procedure might be refined on the basis of more detailed statistical analyses of degree-day patterns, involving serial correlation analyses both over years and over months within given years. Such analyses might yield conditional probabilities of occurrence of degree-day levels, which could then be used to generate more reliable forecasts of weather patterns. Although such an endeavor is clearly out of the scope of the present research effort, it may however constitute a fruitful path for further research.

Monthly load forecasting

Estimates of monthly gas requirements by the residential, commercial and industrial customers are based on the corresponding total yearly gas requirements, which are obtained as outputs from the Capacity Expansion sub-model presented in Chapter 6. These yearly requirements are qualified as "committed" requirements, i.e., the gas company is committed to fulfill these requirements under normal conditions of service. Whether these requirements will be fulfilled or will be curtailed will be determined by the sub-model presented in this chapter. They are defined as:

$TCYRR_t$: total committed residential gas requirement in year t;

$TCYRC_t$: total committed commercial gas requirement in year t;

$TCYRI_t$: total committed industrial gas requirement in year t.

The above estimates of gas requirements represent the sum of estimated requirements for the five divisions of the EOGC service area (Cleveland, Akron, Canton, Warren and Youngstown). It was decided to exclude any spatial analysis of monthly load forecasting because of lack of adequate data (at this stage of the research) for developing a spatial model of the distribution network and of its operations.

The total yearly gas requirements reflect consumption needs based on the assumption of a "normal" weather pattern, characterized by 6317 degree-days per year (see Chapter 4). For any weather pattern that differs from that norm, gas requirements and their monthly incidence differ. The choice of a particular weather scenario is based on the weather pattern generation procedure described in the previous section and leads to a series of twelve monthly degree-day values: DDS_{tm} ($m = 1 \rightarrow 12$). The procedure used to compute monthly gas requirements for each customer class is described below.

Residential gas requirements

The average monthly requirement function for each customer was estimated in Chapter 4 as:

$$GRR_m = 3.68 + 0.026 \times DD_m \tag{7-1}$$

where:

GRR_m = gas requirements in MCF per residential customer during month m;

DD_m = number of degree-days during month m.

The customer's total yearly requirement, GRRT, under "normal" weather conditions, is then estimated as:

$$\begin{aligned} GRRT &= 3.68 * 12 + 0.026 * 6317 \\ &= 44.160 + 164.242 = A + B = 208.402 \end{aligned} \tag{7-2}$$

where:

$$\left.\begin{aligned} A &= 0.211898 * GRRT = \alpha_1 * GRRT, \\ B &= 0.788102 * GRRT = \beta_1 * GRRT. \end{aligned}\right\} \tag{7-3}$$

It is assumed that the shares α_1 and β_1, corresponding to base load and space-heating load, remain constant throughout the simulation period. In other words, it is assumed that the effect of conservation, as discussed in Chapter 4, is the same for both loads, and can therefore be introduced into the model by adjusting total yearly gas requirements.

It follows that:

$$DGMR_{tm} = A1 + B1 * DDS_{tm} \tag{7-4}$$

where:

$DGMR_{tm}$ = potential demand (requirement) for gas by all residential customers during year t and month m;

$$\left.\begin{aligned} A1 &= (0.211898/12) * TCYRR_t\text{: base load coefficient,} \\ B1 &= (0.788102/6317) * TCYRR_t\text{: heating load coefficient.} \end{aligned}\right\} \tag{7-5}$$

If year t happens to be characterized by a "normal" weather pattern, the yearly potential gas demand by the residential class of customers becomes:

$$\sum_{m=1}^{12} DGMR_{tm} = A1 * 12 + B1 * \left[\sum_{m=1}^{12} DDS_{tm}\right] = TCYRR_t \tag{7-6}$$

Commercial gas requirements

The computation procedure for the commercial class of customers is similar to that of the residential potential demand. The total monthly commercial gas demand function, calibrated with 1971 data (which yielded the highest correlation coefficient: 0.991) and specified in Chapter 4, forms the basis of the estimates:

$$GRC_m = 1530.31 + 8.625 * DD_m \tag{7-7}$$

where:

GRC_m = gas requirements (in MCF) for all commercial customers during month m of 1971.

Considering a year with a "normal" weather pattern, the total potential gas requirements by the 1971 commercial customers are:

$$GRCT = 1530.31 * 12 + 8.625 * 6317 \qquad (7\text{-}8)$$
$$= 18363.72 + 54484.125 = A + B = 72847.845$$

where:

$$\left.\begin{aligned} A &= 0.252083 * GRCT = \alpha_2 * GRCT, \\ B &= 0.747917 * GRCT = \beta_2 * GRCT. \end{aligned}\right\} \qquad (7\text{-}9)$$

As in the potential residential demand estimation method, it is assumed that the shares α_2 and β_2 are invariant over time. The potential demand for gas by all commercial customers during year t and month m, $DGMC_{tm}$, is then:

$$DGMC_{tm} = A2 + B2 * DDS_{tm} \qquad (7\text{-}10)$$

where:

$$\left.\begin{aligned} &A2 = (0.252083/12) * TCYRC_t\text{: base load coefficient,} \\ &B2 - (0.747917/6317) * TCYRC_t\text{: heating load coefficient.} \end{aligned}\right\} \qquad (7\text{-}11)$$

Industrial gas requirements

The computation procedure for the industrial sector is strictly similar to those for the residential and commercial ones. The base allocation function, based on the 1970 behavior of the 501 major industrial customers of the EOGC and specified in Chapter 4, is:

$$GRI_m = 10435.426 + 2.848328 * DD_m \qquad (7\text{-}12)$$

where:

GRI_m = gas requirements (in MCF) for all the 501 major industrial customers of the EOGC during month m of 1970.

Considering a year with a "normal" weather pattern, the total potential gas requirements of these industrial customers would be:

$$\begin{aligned} GRIT &= 10435.426 * 12 + 2.848328 * 6317 \\ &= 125225.11 + 17992.88 = A + B = 143217.99. \end{aligned} \tag{7-13}$$

Thus:

$$\left.\begin{aligned} A &= 0.874367 * GRIT = \alpha_3 * GRIT, \\ B &= 0.125633 * GRIT = \beta_3 * GRIT. \end{aligned}\right\} \tag{7-14}$$

As in the case of the residential and commercial requirements, it is assumed that the shares α_3 and β_3 are invariant over time. The potential demand for gas by all industrial customers during year t and month m, $DGMI_{tm}$, is then:

$$DGMI_{tm} = A3 + B3 * DDS_{tm} \tag{7-15}$$

where:

$$\left.\begin{aligned} A3 &= (0.874367/12) * TCYRI_t\text{: base load coefficient,} \\ B3 &= (0.125633/6317) * TCYRI_t\text{: heating load coefficient.} \end{aligned}\right\} \tag{7-16}$$

Monthly Supply Analysis

Under specific assumptions related to gas and energy policies, the maximum total annual supply of gas to the EOGC is accepted as being known for any future year t. The various possible sets of assumptions and corresponding supply forecasts have been described in Chapter 3. Although the EOGC forecasts that it may increase is supply through emergency gas purchases at higher costs, such an alternative will not be considered in the modeling approach because it does not represent the typical course of doing business. The maximum supply is here assumed to form an absolutely binding constraint. It is computed as follows:

$$WGS_t = WGS_1 * IWGS_{ts}/100 \tag{7-17}$$

where:

WGS_t = the maximum wholesale gas supply in year t (t = 1 for the base year of the simulation);

$IWGS_{ts}$ = the index of maximum wholesale gas supply growth for year t and for energy scenario s (see Chapter 3).

Note that: WGS_1 = 350,742,058 MCF.

Once the total annual supply has been determined, the problem is finding out how much gas supply is available each month and what other constraints bear on this supply. Clearly, the amount of gas purchased by the company depends upon current and forecasted potential demands, upon the amount of gas in storage, upon storage policies, and, of course, upon the various associated costs. Thus, the purchase, or external supply, variable is likely to be the product of a complex decisional process. Since the time and budget constraints of the present research effort did not permit a complete analysis, this process was modeled as a set of simple rules based upon past observations and intended to replicate as closely as possible the actual management rules. In the forthcoming analysis, the monthly gas supply figures are defined first and then seasonal and monthly breakdown rules are determined.

Monthly gas deliveries to the EOGC

The monthly gas deliveries to the EOGC were obtained as follows:

$$\begin{pmatrix}\text{Monthly gas}\\\text{delivery}\end{pmatrix} = \begin{pmatrix}\text{Total monthly}\\\text{consumption}\end{pmatrix} + \begin{pmatrix}\text{Monthly delivery}\\\text{to storage}\end{pmatrix} - \begin{pmatrix}\text{Monthly withdrawal}\\\text{from storage}\end{pmatrix} \quad (7\text{-}18)$$

The deliveries/withdrawals data were obtained from the Annual Reports of the EOGC and are described in the next section of this chapter. Monthly consumption figures have been presented in Chapter 4. Monthly gas delivery data for 1971 through 1976 are listed in Table 7-8, and a sample graph is shown for 1972 in Figure 7-3. (Graphs for the years 1971-1976 are shown in Appendix H, Figures H-1 through H-5.)

Table 7-8 Gas Deliveries to the East Ohio Gas Company by Month, 1971-1976 (in MMCF)

Month \ Year	1971	1972	1973	1974	1975	1976
January	41,475.9	37,024.1	40,271.1	41,548.1	37,056.5	38,812.8
February	52,240.2	47,365.9	42,928.6	40,411.6	38,797.2	45,473.5
March	41,531.2	43,062.1	36,160.9	37,347.5	36,732.4	30,706.3
April	51,831.9	49,534.9	44,524.6	47,334.2	47,138.1	32,191.5
May	39,695.5	37,013.3	38,044.6	37,499.9	34,843.5	30,579.5
June	28,069.5	27,551.8	30,087.9	29,655.9	25,362.1	26,465.7
July	21,616.9	22,351.5	25,253.7	26,225.8	22,404.7	23,572.8
August	21,361.1	25,084.5	24,927.4	25,127.8	22,595.6	23,851.7
September	21,001.7	24,412.6	24,857.2	26,589.3	24,814.6	24,244.5
October	25,115.1	28,193.8	27,115.9	32,684.6	28,234.5	28,412.3
November	21,488.2	27,087.3	24,941.3	21,263.1	20,689.5	26,783.6
December	36,344.5	37,175.4	29,154.5	33,228.9	31,872.1	37,493.6

Sources: Annual Reports of the EOGC
Gas Sendouts File of the EOGC

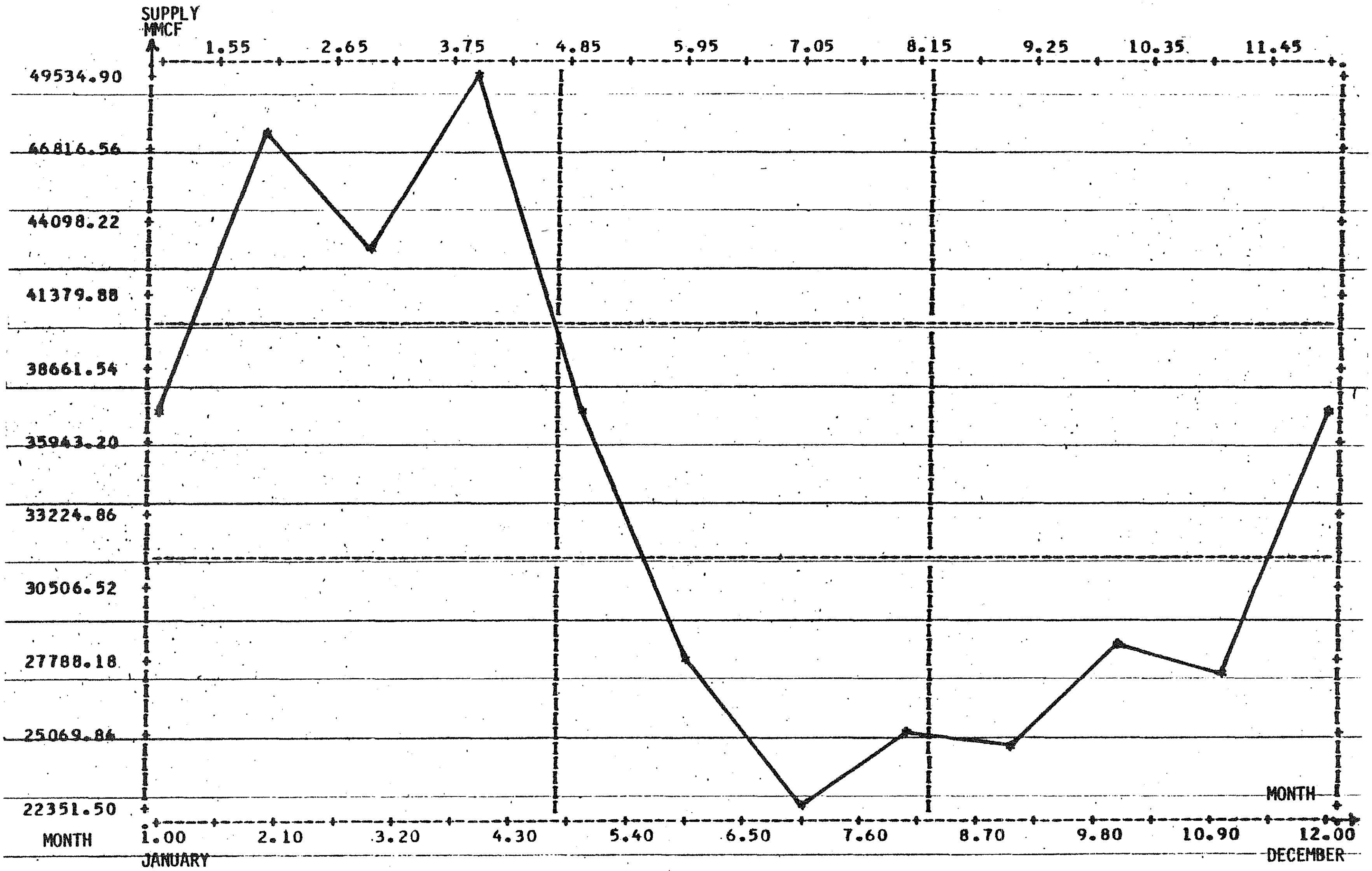

Figure 7-3 Monthly Gas Deliveries to the EOGC in 1972

Seasonal supply analysis

Total yearly gas deliveries to the EOGC were disaggregated into summer and winter gas deliveries. Since the EOGC does not use any specific delineation of the winter/summer periods, three different breakdown proposals were considered:

Proposal A: Winter period from October through March,
Summer period from April through September.
Proposal B: Winter period from November through March,
Summer period from April through October.
Proposal C: Winter period from November through April,
Summer period from May through October.

The results of the computations are presented in Table 7-9.

Table 7-9 Winter Deliveries to the EOGC for Specified Periods (in MMcf)

Year	October-March (% of yearly deliveries)	November-March (% of yearly deliveries)	November-April (% of yearly deliveries)
1971-1972	210,399.75 (52.085)	185,284.69 (46.388)	234,819.56 (58.789)
1972-1973	211,817.00 (53.019)	183,623.19 (46.086)	228,147.75 (57.261)
1973-1974	200,518.81 (51.029)	173,402.94 (43.512)	220,737.13 (55.389)
1974-1975	199,762.63 (52.999)	167,078.06 (44.857)	214,216.13 (57.512)
1975-1976	195,788.56 (54.893)	167,554.13 (46.953)	199,745.63 (55.974)

The years 1970 and 1977 were not included in the analysis because of missing data. The average values of the winter deliveries as a percentage of yearly deliveries are:

Proposal A: 53.005% (standard deviation: 1.367%)
Proposal B: 45.559% (standard deviation: 1.378%)
Proposal C: 56.985% (standard deviation: 1.340%)

Monthly Supply Analysis

For each of the proposed definitions of the winter season, and for each monthly supply, a monthly share of the total yearly deliveries was calculated. A similar calculation was performed for the winter and summer months in terms of the seasonal supplies. These percentages are presented in Table 7-1C for Proposal C and in Appendix H, Tables H-28 and H-29, for Proposals A and B. Similar results emerge in terms of the monthly shares, no matter which definition of season is adopted. Proposal C was selected as a basis for further analysis because its winter season starts in November and ends in April, fairly reflecting Ohio's conditions. This proposal is described and analyzed in more details in the next section.

Further Analysis of Proposal C

Proposal C has been selected because its winter and summer periods approximate most closely the natural weather patterns in Ohio. Both periods are of six months duration. The winter supply corresponds, on the average, to 57% of the total yearly supply, and, in the model, it is assumed that this share will remain constant in the future.

In the winter period, initially low monthly deliveries to the EOGC are observed. These typically increase over time and peak in February, decrease in March, and peak again in April. When monthly deliveries are below average (16.6%), high levels of gas withdrawals from storage are observed. (For further details, see the following section.) The final peak supply in April is associated with the start of deliveries to storage. Officials at the EOGC justify the high levels of storage

TABLE 7-10 Monthly Deliveries to EOGC as a Percentage of Total, Summer and Winter Deliveries.*

Year	Percentage of	NOV.	DEC.	JAN.	FEB.	MAR.	APR.	MAY	JUN.	JUL.	AUG.	SEP.	OCT.
1970-1971	total	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
	winter	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.						
	summer							25.306	17.895	12.781	13.618	13.389	16.011
1971-1972	total	5.380	9.099	9.269	11.858	10.781	12.401	9.267	6.898	5.596	6.280	6.112	7.059
	winter	9.151	15.478	15.767	20.171	18.338	21.095						
	summer							22.486	16.738	13.579	15.230	14.831	17.128
1972-1973	total	6.798	9.330	10.107	10.774	9.076	11.175	9.549	7.552	6.338	6.256	6.239	6.806
	winter	11.873	16.294	17.651	18.816	15.850	19.516						
	summer							22.342	17.669	14.830	14.638	14.597	15.924
1973-1974	total	6.258	7.316	10.426	10.140	9.372	11.877	9.410	7.442	6.581	6.305	6.672	8.201
	winter	11.200	13.208	18.822	18.308	16.919	21.444						
	summer							21.093	16.681	14.752	14.134	14.956	18.385
1974-1975	total	5.709	8.921	9.949	10.416	9.862	12.565	9.355	6.809	6.015	6.066	6.662	7.580
	winter	9.926	15.512	17.200	18.111	17.147	22.005						
	summer							22.017	16.026	14.157	14.278	15.680	17.841
1975-1976	total	5.798	8.931	10.876	12.743	8.605	9.021	8.569	7.316	6.606	6.684	6.788	7.962
	winter	10.358	15.956	19.431	22.766	15.373	16.116						
	summer							19.464	16.846	15.004	15.182	15.419	18.085
1970-1976	total	5.989	8.719	10.125	11.186	9.539	11.426	9.230	7.223	6.227	6.318	6.495	7.523
	(s.d.)	(.551)	(.802)	(.596)	(1.087)	(.831)	(1.459)	(.383)	(.343)	(.425)	(.425)	(.225)	(.588)
	winter	10.522	15.290	17.794	19.634	16.725	20.035						
	(s.d.)	(1.083)	(1.211)	(1.424)	(1.926)	(1.163)	(2.378)						
	summer							22.118	16.975	14.351	14.515	14.812	17.229
	(s.d.)							(1.921)	(.691)	(.596)	(.631)	(.802)	(1.062)

* According to proposal C, the winter season encompasses the months November through April.

** n.a.: not applicable.

withdrawal at the beginning of the winter by the need to use as much as possible of the gas in storage; if they delayed this use, they might not be able to withdraw all the working gas in storage during the winter because of maximum flow constraints. The delivery to storage in April is correspondingly explained by the need to start replenishing storage as soon as possible; otherwise, it might not be possible to put as much gas as is desirable into storage before the next winter.

In the summer period, initially high monthly supplies are observed to decrease to their lowest values in July and August and then to increase again towards winter. The initially high supplies correspond to high deliveries to storage.

From this analysis the following simple rules emerge and will be applied in the model:

(1) Upper and lower bounds on monthly supply shares.

* During the winter period, monthly supply shares should vary between 10% and 20% of the total winter supply.
* During the summer period, monthly supply shares should vary between 14% and 22% of the total summer supply.

(2) Monthly supply levels.

* During the winter period, stored gas should be used in priority and at the highest possible level, complemented by external supply to meet the demand.
* During the summer period, gas should be delivered to storage as soon as possible and at the highest possible rate, while, however, also satisfying demand.

Storage Operations Modeling

The gas storage system of the EOGC has been described in Chapter 5. It is the purpose of this section to present the variables and parameters that describe the whole system and not its individual components.

Only the total storage capacity, equal to the sum of the capacities of the storage units, will be considered. Technological operation constraints will be derived for the total system only. A complete description of storage operations at the storage units level is given in Appendix H. In the following analysis, basic storage data are presented first. Later, simple technological models describing storage operations are derived and presented.

Gas storage data

Data on gas storage operations are presented in Tables 7-11 through 7-14. Table 7-11 contains data on capacity and gas present in the storage system at the end of each year. It is possible to discern an increase from 1970 to 1977 in the total storage capacity of 7460 MCF, or 5.32%. This increase was made necessary at least in part by storage requirements that exceeded capacity in 1970 and 1971. In Table 7-12, data concerning the total flows out of and into storage are presented. It is noteworthy that withdrawals have been higher than deliveries in 1972, 1974 and 1976. However, over this 7-year period, from the beginning of 1970 to the end of 1977, there is a very slight increase in the net balance of gas in storage. (See bottom line of Table 7-12). These total flows are disaggregated at the monthly level in Tables 7-13 and 7-14. Although most deliveries take place between April and October some low level inputs during some winter months are noticeable, probably due to temporary excess supply over demand. Most withdrawals take place between November and March. Again some withdrawals during the summer periods can be observed but of very low level, and probably due to temporary excess demand over supply. The general trends of deliveries to and withdrawals from storage can be seen in Figures 7-4 and 7-5 using 1976 data. (For all the years from 1970 to 1975, see Figures H-10 through H-19 of Appendix H.)

Table 7-11 Gas Storage Stock Variables

Year	Total Cushion Gas in Storage End of Year (MCF)	Total Working Gas in Storage End of Year (MCF)	Total Gas in Storage End of Year (MCF)	Certified Storage Capacity (MCF)
1970	not listed	not listed	148,703,443	140,134,400
1971	not listed	not listed	151,496,059	140,134,400
1972	90,695,638	52,733,556	143,429,194	142,560,000
1973	90,937,838	54,927,326	145,865,164	145,872,000
1974	90,937,838	54,201,112	145,138,950	145,872,000
1975	90,937,838	63,099,887	154,037,725	147,094,100
1976	90,937,838	55,319,590	146,257,428	147,594,100
1977	90,937,838	53,103,859	144,041,697	147,594,100

Sources: Annual Reports - EOGC

Table 7-12 Gas Storage Flow Variables

Year	Total Deliveries to Storage (MCF)	Total Withdrawals from Storage (MCF)	Total Amount of Gas Lost in Storage (MCF)
1970	55,116,780	49,617,321	294,809
1971	53,958,347	51,165,731	410,821
1972	47,775,888	55,842,754	327,981
1973	55,619,470	53,425,700	301,087
1974	57,414,981	58,141,195	347,544
1975	59,897,547	50,998,772	316,468
1976	45,242,027	53,022,324	248,981
1977	57,977,731	56,705,635	207,885
Total	433,002,780	428,919,432	2,455,576

Sources: Annual Reports - EOGC

Table 7-13 Deliveries to Storage by Month (MCF)

Month \ Year	1970	1971	1972	1973	1974	1975	1976	1977
January	1,770,882	690,129	435,986	669,875	-	-	-	939,200
February	1,242,484	2,451,706	411,840	376,542	-	-	-	1,298,830
March	227,933	-	-	-	822	-	120,966	440,874
April	5,711,523	8,609,219	6,935,585	8,305,397	8,216,465	6,867,016	1,336,869	8,685,619
May	8,481,143	8,720,266	9,182,152	9,050,675	9,544,057	10,721,065	5,348,258	9,743,153
June	8,002,828	7,120,161	6,770,913	2,455,821	9,459,829	9,563,819	8,281,959	7,890,414
July	8,384,750	6,346,980	5,398,898	8,312,326	9,319,470	9,206,006	8,680,399	7,525,128
August	7,995,504	6,512,648	8,044,627	7,940,234	7,992,164	8,359,688	8,265,892	8,171,390
September	6,937,137	6,676,969	7,256,191	6,989,810	7,837,336	7,953,852	7,480,609	7,459,162
October	5,291,380	5,939,986	3,286,046	5,518,543	5,010,744	6,999,304	5,661,246	5,444,933
November	458,971	141,718	635	247	34,094	219,394	-	322,844
December	612,245	748,565	53,015	-	-	7,403	65,829	55,584

Sources: Annual Reports - EOGC

Table 7-14 Withdrawals from Storage by Month (MCF)

Year / Month	1970	1971	1972	1973	1974	1975	1976	1977
January	15,036,210	14,985,243	13,284,944	13,409,824	12,956,935	13,667,494	13,493,199	17,215,361
February	9,244,066	10,929,462	10,292,049	8,899,952	10,306,382	9,166,799	5,911,546	8,047,601
March	8,519,546	9,382,825	9,030,889	8,033,062	8,978,341	8,998,562	6,191,667	5,285,354
April	319,082	67,281	583,693	123,754	238,293	699,946	863,431	218,101
May	86,303	155,801	96,857	69,117	71,184	132,552	126,841	122,469
June	150,959	292,701	105,105	86,938	47,947	201,705	112,261	124,025
July	114,986	195,149	95,416	84,615	150,703	183,296	169,557	110,133
August	231,011	187,517	118,131	89,819	103,359	171,121	141,219	118,831
September	213,181	100,305	93,598	74,639	70,954	170,303	139,085	132,319
October	77,582	149,857	87,182	73,550	93,065	105,804	286,966	145,768
November	3,499,840	5,768,506	9,174,278	7,730,937	10,442,973	5,370,913	11,313,374	9,102,449
December	12,124,555	8,951,084	12,880,612	14,749,493	14,681,059	12,130,277	14,273,178	16,083,224

Source: Annual Reports - EOGC

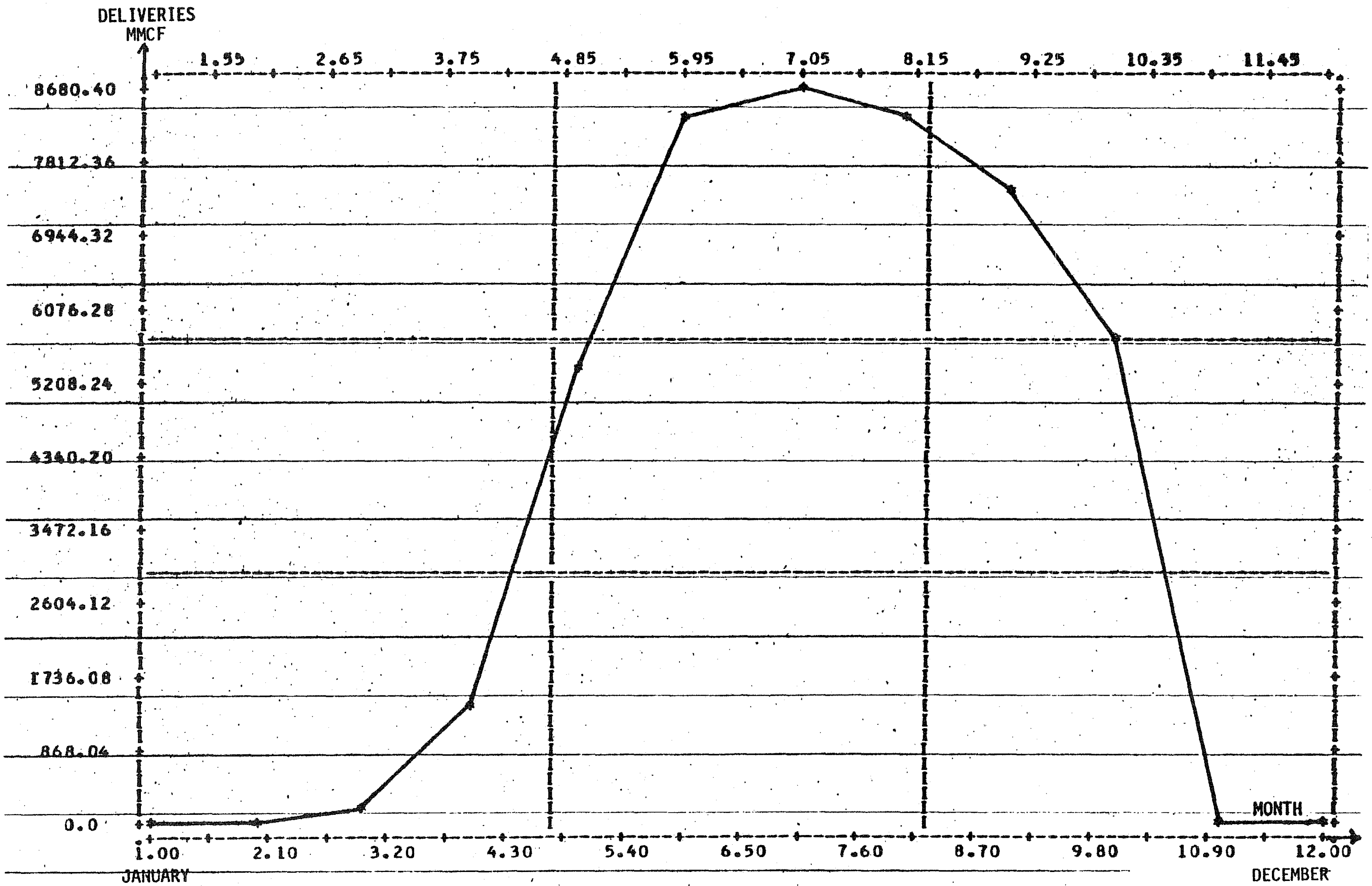

Figure 7-4 Monthly Deliveries to Storage - Year: 1976

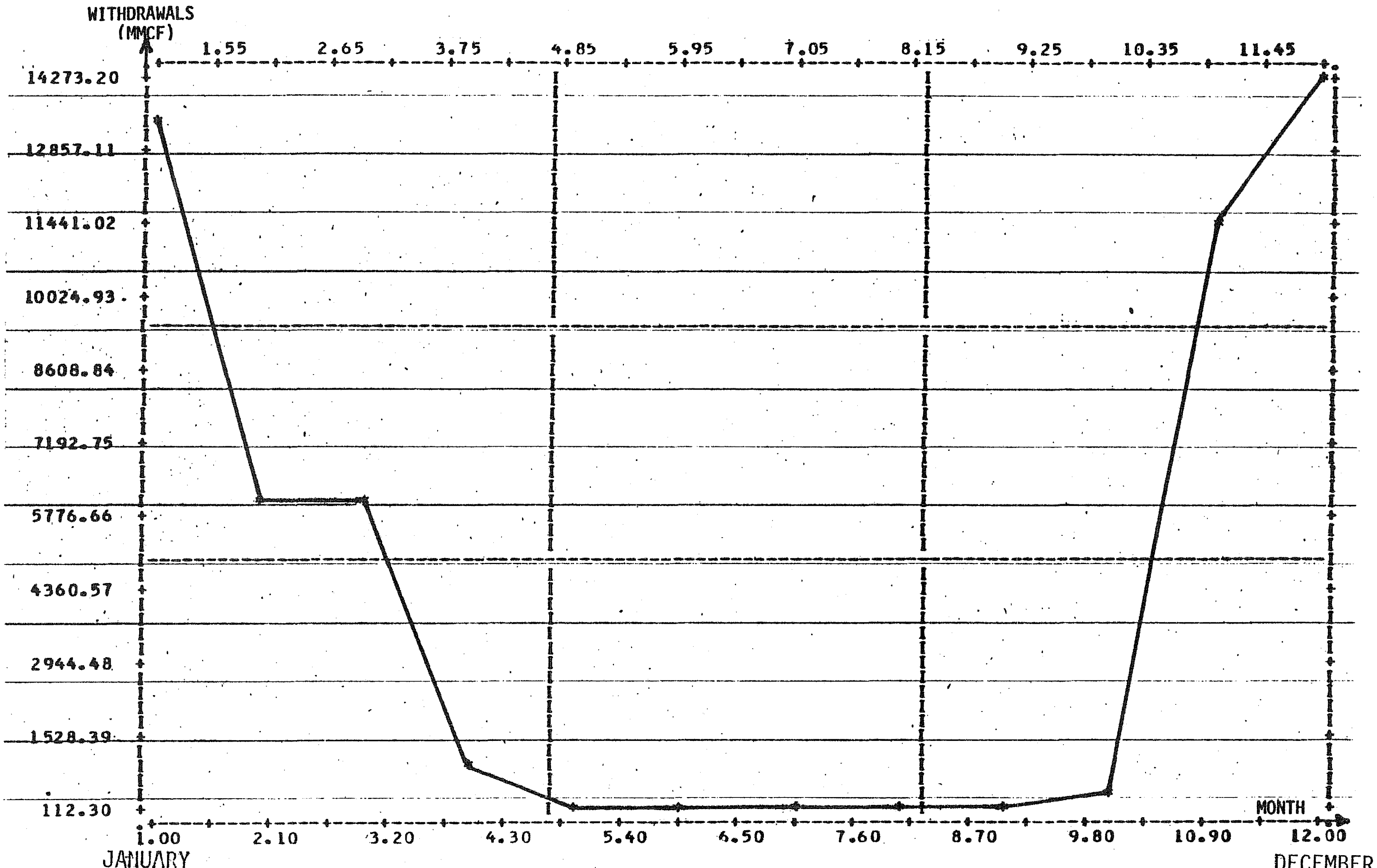

Figure 7-5 Monthly Withdrawals from Storage - Year: 1976

Storage Inflow and Outflow Constraints

The main technological difference between the withdrawal of gas from storage and its delivery to storage is that compressors are required for injection, whereas natural storage pressure is used to transfer gas out of storage into the mains. The maximum daily withdrawal capacity for a storage field varies depending upon many conditions such as the volume of gas in this field and the volume and pressure of gas in the mains which the storage field is feeding. The maximum daily delivery capacity depends upon such factors as the volume of gas in storage, the storage field capacity as well as the compressors power. For both gas inflows and outflows the pressure of the gas in the storage field is a very important factor, determining the maximum possible inflows and outflows. In the present section quantitative relationships between these maximum flows and the storage pressure will be presented.

Since the analysis of gas management is carried out on a monthly time scale the observed inflows or outflows during a given m of year t are here related to the ratio of gas in storage at the beginning of month m of the same year to the certified storage capacity of that year. The following parameters and variables form part of this analysis:

- $STCAP_t$ = certified storage capacity in year t;
- $DGMT_{tm}$ = total gas sendouts during month m of year t;
- $SUPM_{tm}$ = total external gas supply during month m of year t;
- $GSTORD_{tm}$ = gas in storage (i.e. working gas and cushion gas) at the beginning of month m of year t;
- $MAXINS_{tm}$ = maximum inflow to storage during month m of year t;
- $MAXOUS_{tm}$ = maximum outflow from storage during m of year t;
- $GINST_{tm}$ = inflow to storage during month m of year t;
- $GOUST_{tm}$ = outflow from storage during month m of year t.

A storage saturation rate, $RSTOR_{tm}$, is defined as the ratio of gas in storage at the beginning of month m to the certified storage capacity of year t:

$$RSTOR_{tm} = \frac{GSTORD_{tm}}{STCAP_t} \tag{7-19}$$

For a given certified storage capacity it is assumed that the maximum monthly inflows and outflows depend upon the storage saturation rate at the beginning of the month. It is hypothesized that the functional forms presented in Figure 7-6 apply.

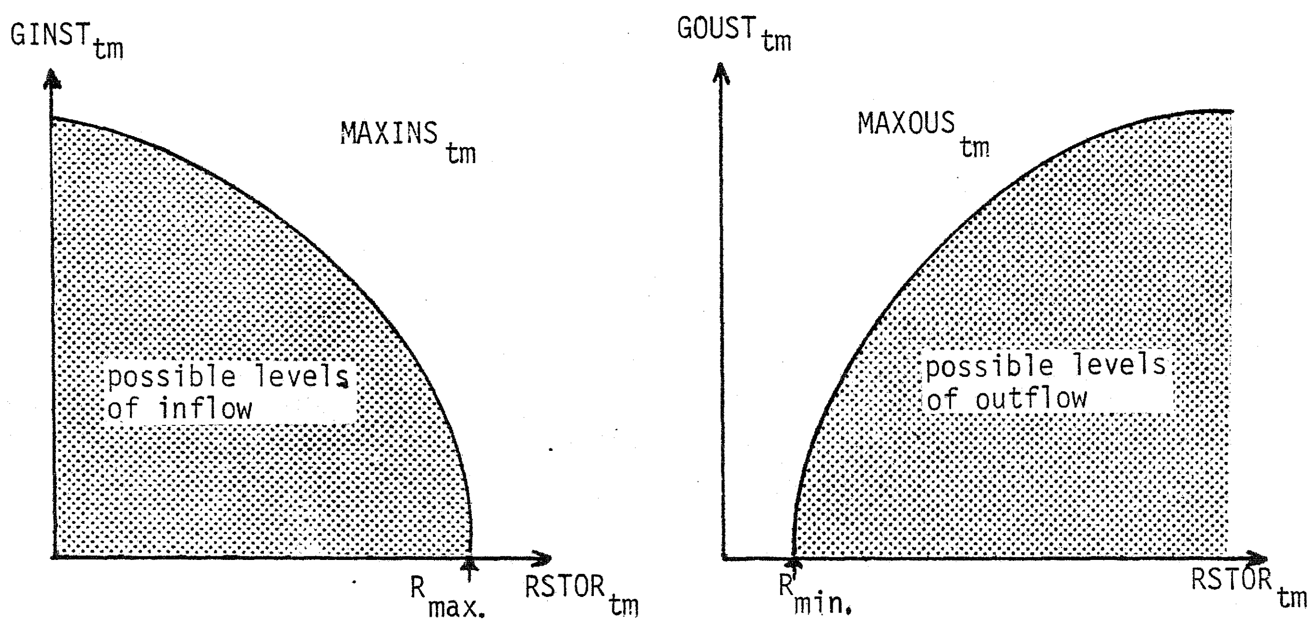

Figure 7-6 Feasible Gas Inflows and Outflows as Functions of Storage Saturation.

According to the above functions:

- at high pressures in storage, the maximum outflows are highest, and the maximum inflows minimal or nil over some maximum saturation rate R_{max};
- at low pressures in storage, inflow is easy whereas outflows will be low, or even nil below a minimum saturation rate R_{min}.

Using the 1971-1976 EOGC data on monthly deliveries and withdrawals, the levels of gas in storage at the beginning of each month were determined. The observed monthly inflows and outflows were plotted against the corresponding monthly saturation rates. The results are presented in Figures 7-7 and 7-8. Maximum inflow and outflow envelopes for the points representing observed inflows and outflows were easily drawn confirming previously made assumptions. It was assumed that the effect of the storage capacity increase from 1971 to 1976 was negligible and that the maximum inflow and outflow functions were adequately describing a storage system with a certified capacity equal to the 1977 capacity.

An attempt was made to specify maximum inflow and outflow functions of the following form:

$$\text{MAXINS} = k_1 \cdot (R_{max} - R)^{\alpha_1} \tag{7-20}$$

$$\text{MAXOUS} = k_2 \cdot (R - R_{min})^{\alpha_2} \tag{7-21}$$

Using a double log transformation, a regression analysis was performed on the estimated envelope to determine the coefficients k_1, k_2, α_1, α_2. The results were as follows:

$$\text{MAXINS}_{tm} = 13{,}121 \cdot (1.18 - \text{RSTOR}_{tm})^{0.24913} \quad \text{(MMCF)} \quad (R^2 = .974) \tag{7-22}$$

$$\text{MAXOUS}_{tm} = 23{,}112 \cdot (\text{RSTOR}_{tm} - 0.76)^{0.37548} \quad \text{(MMCF)} \quad (R^2 = .965) \tag{7-23}$$

The actual inflows and outflows are the results of interactions between supply and demand within the limits set by the storage saturation rate. Once the flows of a specific month have been determined, the "new" saturation rate is determined and the maximum flows for the next month are known. This iterative process is illustrated in Figures 7-9, 7-10, and 7-11.

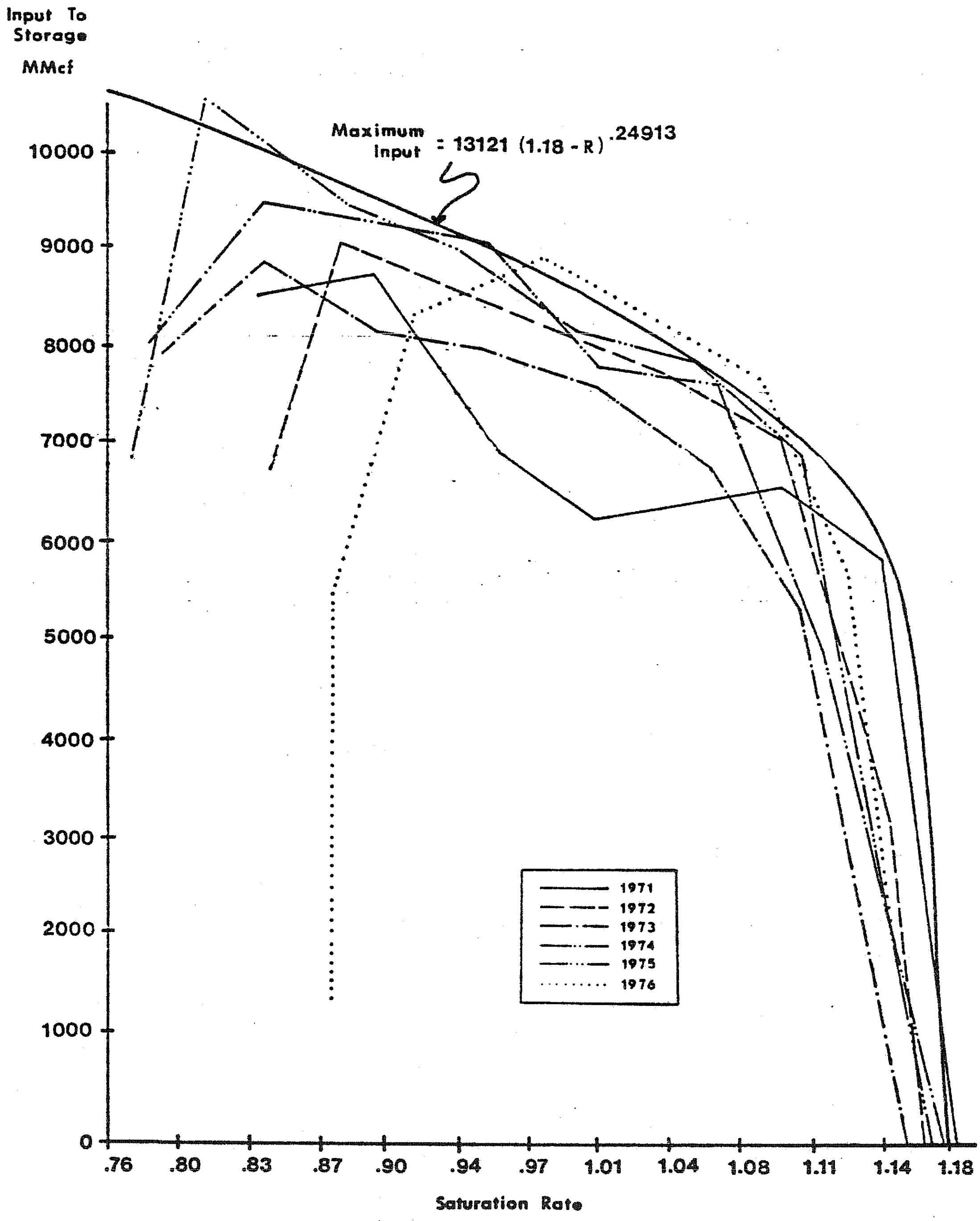

Figure 7-7 Maximum Delivery to Storage

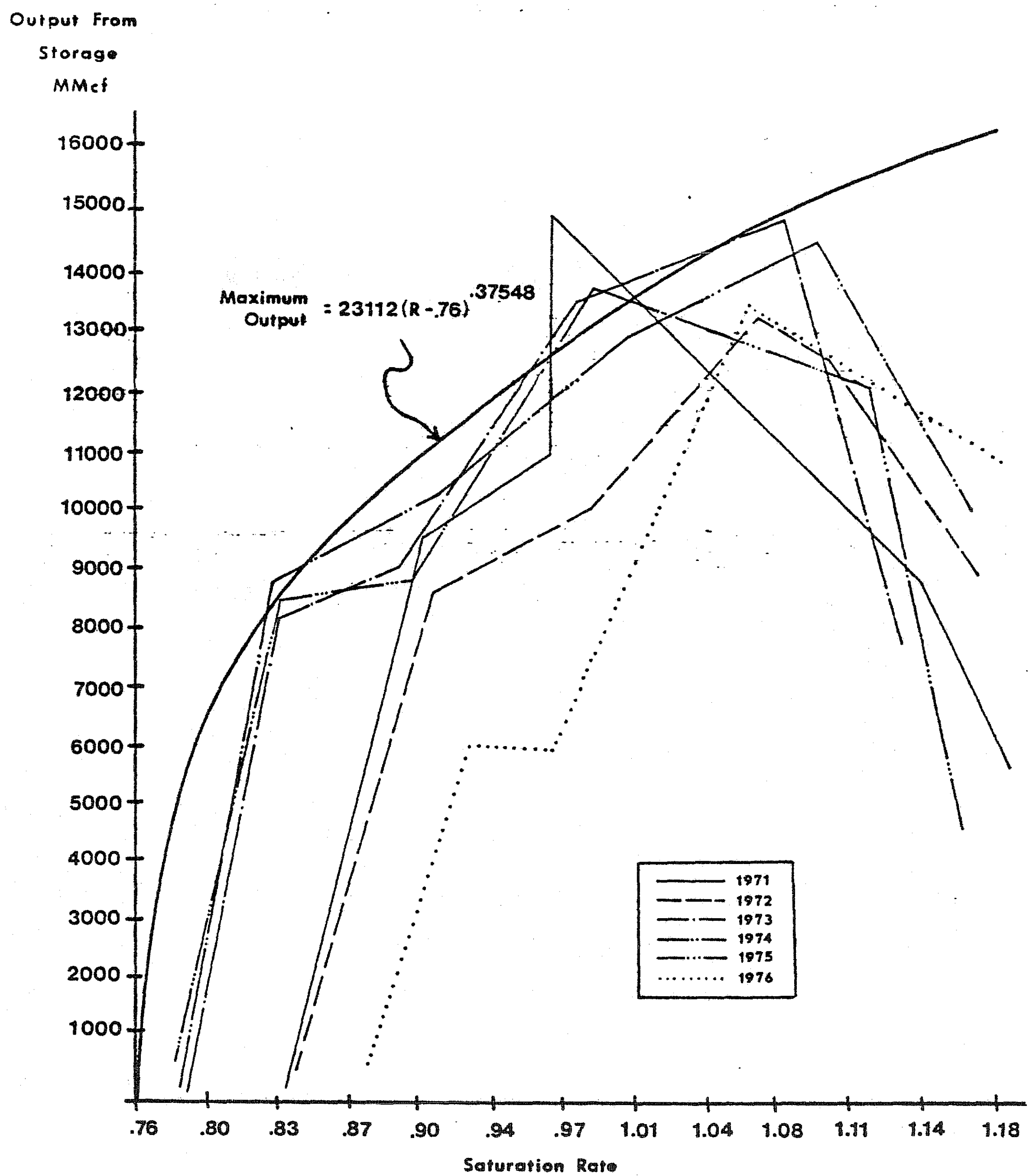

Figure 7-8 Maximum Withdrawal from Storage

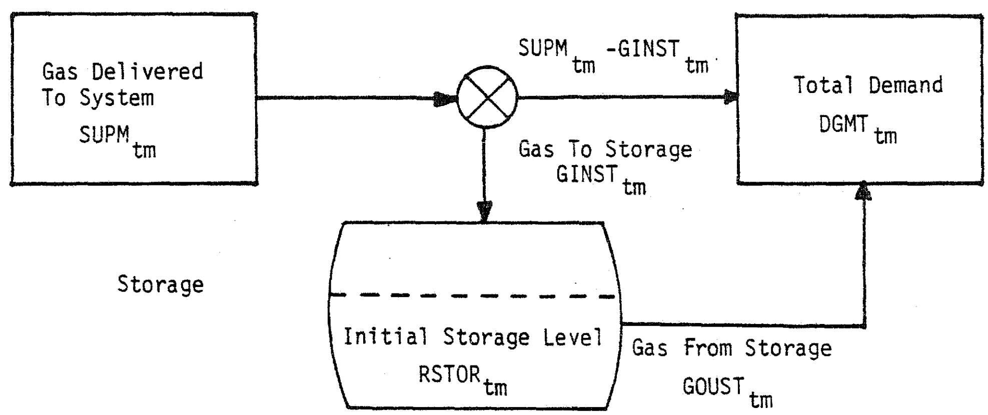

Figure 7-9 Gas Supply, Demand and Storage Delivery and Withdrawal

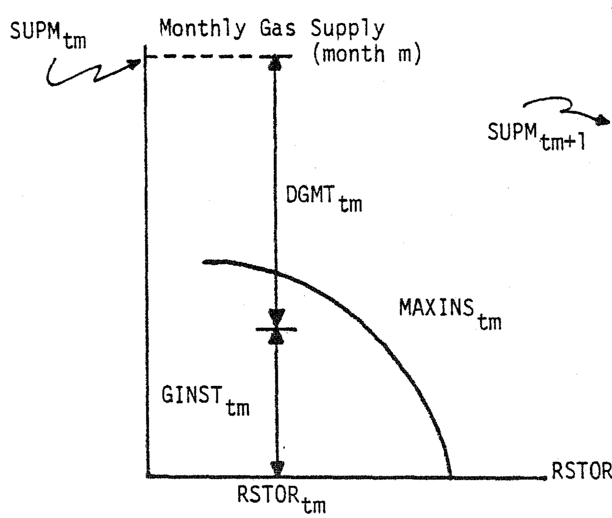

Figure 7-10 Gas Flows During Month m

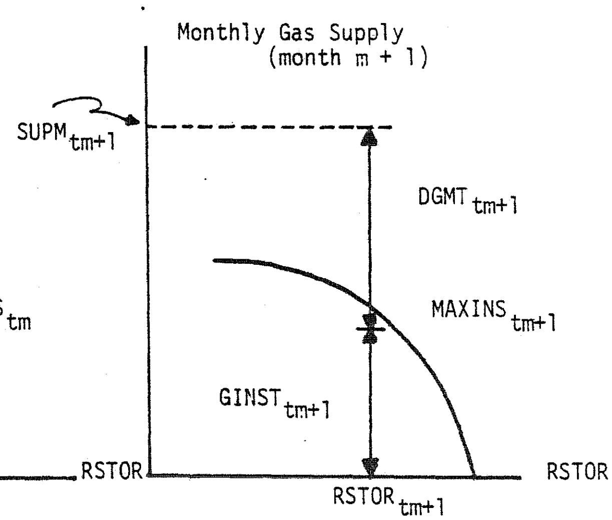

Figure 7-11 Gas Flows During Month m + 1

In the previous discussion, it was assumed that the storage capacity and the power of the storage compressors were fixed. If this capacity and this power are changing and, probably, increasing, then the maximum inflow and outflow functions have to be modified to account for these new parameters. Such an adjustment may be very important if storage capacity expansion policies are introduced into this modeling approach. However, no such policies will be considered in the present research effort, and the assumption that storage capacity will remain at its 1977 level will hold. Possible formulations of this adjustment process are presented below:

$$MAXINS_{t+1,m} = \left(\frac{STCAP_{t+1}}{STCAP_t}\right)^{\alpha} \cdot \left(\frac{HP_{t+1}}{HP_t}\right)^{\beta} \cdot MAXINS_{tm}, \qquad (7\text{-}24)$$

$$MAXOUS_{t+1,m} = \left(\frac{STCAP_{t+1}}{STCAP_t}\right)^{\gamma} \cdot MAXOUS_{tm}, \qquad (7\text{-}25)$$

where HP_t is the gas injection compressor's power during year t. Actual data would be necessary to calibrate the above models and to determine the values of the coefficients α, β and γ.

Synthesis of the intra-annual gas allocation model

Principles of the management model

The yearly cycle has been shifted from the regular yearly calendar (January-December) to a yearly cycle based upon the season, starting in May and ending in April. The start of the whole simulation will therefore be set at May 1978 instead of January 1978. Because of a lack of data for 1978, it will be assumed that the amount of gas stored at the beginning of May 1978 is equal to the amount of gas stored at the same period in 1977. The reader is referred to the previous section for the definition of some of the variables used in the following analysis. The initial values of the variables describing the storage system situation are:

$$GSTORD_{1,1} = GSTORD_{2,1} = 120{,}795.534 \text{ MMCF} , \tag{7-26}$$

$$RSTOR_{1,1} = RSTOR_{2,1} = \frac{GSTORD_{2,1}}{STCAP} = 0.82591, \tag{7-27}$$

with: STCAP = 147,594.100 MMCF = certified storage capacity. STCAP is assumed not to change over time.

For any given year t, before any monthly allocation takes place, the following steps are to be taken:

(1) A weather scenario is generated.

(2) Monthly potential demands of gas for the residential, commercial and industrial sectors are computed, along with the corresponding total demand $DGMT_{tm}$, with:

$$DGMT_{tm} = DGMR_{tm} + DGMC_{tm} + DGMI_{tm} \tag{7-28}$$

(3) Total yearly deliveries to the EOGC, and summer and winter entitlements are computed. Then upper and lower limits on monthly supplies for both summer and winter are determined. The following variables are defined:

- WENT : winter entitlement share of total annual supply (this share is assumed invariant over time and equal to 0.57);
- $SUMETL_t$: summer supply entitlement for year t;
- $WINETL_t$: winter supply entitlement for year t;
- MAXSUS : maximum monthly supply in summer;
- MINSUS : minimum monthly supply in summer;
- MAXSUW : maximum monthly supply in winter;
- MINSUW : minimum monthly supply in winter.

In addition the following relational definitions are given:

$$WINETL_t = WENT * WGS_t; \tag{7-29}$$

$$SUMETL_t = WGS_t - WINETL_t; \tag{7-30}$$

$$MAXSUS = SUMETL_t * 0.22; \tag{7-31}$$

$$MINSUS = SUMETL_t * 0.14; \tag{7-32}$$

$$MAXSUW = WINETL_t * 0.20; \tag{7-33}$$

$$MINSUW = WINETL_t * 0.10 \tag{7-34}$$

Once the above computations have been made, the model's computations will proceed with summer and winter allocations.

Summer management procedure

For each month m, the following steps are taken:

(1) Maximum inflow to and withdrawal from storage are computed.

(2) New upper and lower limits on monthly supply are determined:

$$MAXSU1 = \text{minimum } (MAXSUS, RESUEN_{tm}), \tag{7-35}$$

with:

$RESUEN_{tm}$ = residual summer entitlement at the beginning of month m of year t;

$$MINSU1 = \begin{cases} MINSUS \text{ if } MAXSU1 \geq MINSUS \\ 0 \text{ otherwise.} \end{cases} \tag{7-36}$$

(3) The following tests and computations are made.

Case A: the total potential gas demand is lower that the maximum purchasable gas supply, i.e.:

$$DGMT_{tm} \leq MAXSU1. \tag{7-37}$$

In this case, the maximum amount of gas available for storage is:

$$MAXGST = MAXSU1 - DGMT_{tm}. \tag{7-38}$$

The assumed management rule now is to store as much gas as possible, subject to the constraints on maximum supply and maximum delivery to storage. Therefore:

$$GINST_{tm} = \text{minimum}\ (MAXGST,\ MAXINS_{tm}); \tag{7-39}$$

$$GOUST_{tm} = 0; \tag{7-40}$$

$$SUPM_{tm} = DGMT_{tm} + GINST_{tm}. \tag{7-41}$$

$SUPM_{tm}$ is the amount of gas purchased during month m of year t. If $SUPM_{tm} < MINSU1$, then the minimum supply cannot technically be purchased during month m. In any case, there is no curtailment during this month. A general monthly curtailment status variable, $CURT_{tm}$, is set equal to zero if there is no curtailment and to one if there is a curtailment, whatever its magnitude. In the present case:

$$CURT_{tm} = 0. \tag{7-42}$$

<u>Case B</u>: the total potential gas demand is higher than the maximum purchasable gas supply; i.e.:

$$DGMT_{tm} > MAXSU1 . \tag{7-43}$$

This supply may be supplemented by gas withdrawn from storage. Two sub-cases should then be considered.

<u>Sub-Case B1:</u> the supply deficit is lower than the maximum withdrawal from storage, i.e.:

$$DGMT_{tm} - MAXSU1 \leq MAXOUS_{tm}. \tag{7-44}$$

In this case, the gas deficit will be supplied by the gas in storage, the maximum amount of gas will be purchased and no curtailment will occur. This situation is described by the following equations:

$$GINST_{tm} = 0; \tag{7-45}$$

$$GOUST_{tm} = DGMT_{tm} - MAXSU1; \tag{7-46}$$

$$SUMP_{tm} = MAXSU1; \tag{7-47}$$

$$CURT_{tm} = 0. \tag{7-48}$$

<u>Sub-Case B2</u>: the supply deficit is higher than the maximum withdrawal from storage, i.e.:

$$DGMT_{tm} - MAXSU1 > MAXOUS_{tm}. \tag{7-49}$$

In this case there will be some curtailment, although the maximum amount of gas is purchased, and the maximum amount of gas is withdrawn from storage. This situation is described by the following equations:

$$GINST_{tm} = 0; \tag{7-50}$$

$$GOUST_{tm} = MAXOUS_{tm}; \tag{7-51}$$

$$SUPM_{tm} = MAXSU1; \tag{7-52}$$

$$CURT_{tm} = 1. \tag{7-53}$$

(4) Storage condition parameters are updated, according to the following equations:

$$GSTORD_{tm+1} = GSTORD_{tm} + GINST_{tm} - GOUST_{tm}; \tag{7-54}$$

$$RSTOR_{tm+1} = GSTORD_{tm+1}/STCAP . \tag{7-55}$$

(5) The residual summer entitlement is updated, accounting for the amount of gas actually purchased during the current month m:

$$RESUEN_{tm+1} = RESUEN_{tm} - SUPM_{tm} . \tag{7-56}$$

If, at that stage, the end of the summer is reached, i.e., m=6, and if the residual summer entitlement is positive, it should be transferred to the winter entitlement, with:

$$WINETL_{t} = WINETL_{t} + RESUEN_{tm} - SUPM_{tm} . \tag{7-57}$$

(6) Effective gas supplies and curtailment levels are computed. Two cases must be considered.

Case A: there is no curtailment, i.e.:

$$CURT_{tm} = 0 \qquad (7\text{-}58)$$

In such a case, the actual supplies are equal to the potential demands (or requirements) and the following conditions hold:

$$DGMRE_{tm} = DGMR_{tm} \quad \text{: actual monthly residential supply;} \qquad (7\text{-}59)$$

$$DGMCE_{tm} = DGMC_{tm} \quad \text{: actual monthly commercial supply;} \qquad (7\text{-}60)$$

$$DGMIE_{tm} = DGMI_{tm} \quad \text{: actual monthly industrial supply;} \qquad (7\text{-}61)$$

$$CURTR_{tm} = 0 \text{ : residential monthly curtailment rate;} \qquad (7\text{-}62)$$

$$CURTC_{tm} = 0 \text{ : commercial monthly curtailment rate;} \qquad (7\text{-}63)$$

$$CURTI_{tm} = 0 \text{ : industrial monthly curtailment rate.} \qquad (7\text{-}64)$$

Case B: some curtailment must be applied, i.e.:

$$CURT_{tm} = 1. \qquad (7\text{-}65)$$

The gas deficit is equal to:

$$GASDEF_{tm} = DGMT_{tm} - SUPM_{tm} - GOUST_{tm} \cdot \qquad (7\text{-}66)$$

This deficit will be successively "allocated" to industrial, commercial and residential customers. Industrial customers are curtailed first. If the gas deficit is higher than their potential demand, these customers are totally curtailed and the residual deficit is imputed to the commercial customers. If the residual deficit is higher than the commercial potential demand, the commercial customers are totally curtailed, and the residual deficit is imputed to the residential customers. This procedure yields the actual monthly supplies to the three customers' groups. Their curtailment levels are then computed as follows:

$$CURTR_{tm} = 1 - DGMRE_{tm}/DGMR_{tm} \quad \text{for the residential sector;} \tag{7-67}$$

$$CURTC_{tm} = 1 - DGMCE_{tm}/DGMC_{tm} \quad \text{for the commercial sector;} \tag{7-68}$$

$$CURTI_{tm} = 1 - DGMIE_{tm}/DGMI_{tm} \quad \text{for the industrial sector.} \tag{7-69}$$

Winter management procedure

The major difference between this procedure and the summer procedure is that here the assumed management objective is to use as much as possible of the stored gas as soon as possible. Nevertheless, the general structures of the two procedures are very similar. Only new variables and computations will be described below. A new variable is used to define, for each month m, the residual winter entitlement:

$REWIEN_{tm}$ = residual winter entitlement at the beginning of month m of year t.

Four different ranges of values for the total potential demand of gas must be considered, which have different management implications.

Case A: the total potential demand is lower than the minimum monthly supply, i.e.:

$$DGMT_{tm} \leq MINSU1 \;. \tag{7-70}$$

In such a case the demand is so low that some gas will have to be delivered to storage, in order to respect the minimum gas purchase constraint. This situation is summarized by the following equations:

$$GOUST_{tm} = 0; \tag{7-71}$$

$$GINST_{tm} = \text{minimum}\ (MINSU1 - DGMT_{tm},\ MAXINS_{tm}); \tag{7-72}$$

$$SUPM_{tm} = DGMT_{tm} + GINST_{tm} \;. \tag{7-73}$$

If $SUPM_{tm} < MINSU1$, the minimum supply cannot technically be purchased during that month. There is no curtailment, i.e.,

$$CURT_{tm} = 0. \tag{7-74}$$

Case B: the total potential demand is higher than the minimum supply, but lower than this supply supplemented with the maximum amount of gas withdrawable from storage, i.e.:

$$MINSU1 \leq DGMT_{tm} \leq MINSU1 + MAXOUS_{tm} \;. \tag{7-75}$$

In this case, the minimum supply is purchased, and complemented by gas withdrawn form storage. There is no curtailment, and the situation is summarized by the following equations:

$$GINST_{tm} = 0; \tag{7-76}$$

$$GOUST_{tm} = DGMT_{tm} - MINSU1; \tag{7-77}$$

$$SUPM_{tm} = MINSU1; \tag{7-78}$$

$$CURT_{tm} = 0. \tag{7-79}$$

Case C: the total potential demand is higher than the minimum supply supplemented by the maximum amount of gas withdrawable from storage, but lower than the maximum supply supplemented by the maximum amount of gas withdrawable from storage; i.e.:

$$MINSU1 + MAXOUS_{tm} < DGMT_{tm} \leq MAXSU1 + MAXOUS_{tm} . \tag{7-80}$$

In this case, a maximum amount of gas is withdrawn from storage, and complemented by external gas purchases up to the requirement level. These purchases are higher than the minimum purchases, but lower than the maximum ones. The situation is summarized by the following equations.

$$GINST_{tm} = 0; \tag{7-81}$$

$$GOUST_{tm} = MAXOUS_{tm} ; \tag{7-82}$$

$$SUPM_{tm} = DGMT_{tm} - GOUST_{tm} ; \tag{7-83}$$

$$CURT_{tm} = 0. \tag{7-84}$$

Case D: the total potential demand is higher than the maximum gas purchases supplemented by the maximum amount of gas withdrawable from storage; i.e.:

$$DGMT_{tm} > MAXSU1 + MAXOUS_{tm} . \tag{7-85}$$

In this case, there will be some curtailment, and the situation is summarized by the following equations:

$$GINST_{tm} = 0; \tag{7-86}$$

$$GOUST_{tm} = MAXOUS_{tm}; \tag{7-87}$$

$$SUPM_{tm} = MAXSU1; \tag{7-88}$$

$$CURT_{tm} = 1. \tag{7-89}$$

Finally, the previous procedure has been modified for the last month of the winter season in order to account for the unused residual winter entitlement. During the month of April (m=12), the maximum monthly supply constraint is withdrawn and as much gas as possible is delivered to storage. (Historically, it can be verified that deliveries to storage start in April.)

Example Application of the Allocation Model

In order to check the predictive capacity of the management model, it has been used to simulate the period extending from November 1974 to October 1975. Given:

the total supply for this period: 372,467. MMCF,

the amount of gas in storage at the beginning of November 1974: 170,229 MMCF,

the potential monthly demands, which are equal to the observed sendouts, the following parameters were derived:

- the winter supply entitlement: 212,306 MMCF;
- the summer supply entitlement: 160,161 MMCF;
- the winter monthly supply lower and upper limits: 21,230 MMCF $\leq$ SUPM $\leq$ 42,461 MMCF;
- the summer monthly supply lower and upper limits: 22,422 MMCF $\leq$ SUPM $\leq$ 35,235 MMCF.

The storage certified capacity was taken as equal to: 147,594 MMCF.

The results of this one-year simulation, as well as the values of various important intermediate variables, are presented in Table 7-15, along with the observed actual values of storage deliveries, withdrawals, and external supply. The simulation ends with an unused summer entitlement of 1,041 MMCF, equal to 0.65% of the total summer entitlement. The modeled and actual values for storage deliveries, storage withdrawals, and external supply are very close. Correlation coefficients based on regression analyses confirmed these observations. The following results were obtained:

$$[\text{Actual delivery}] = 0.999 * [\text{Computed delivery}] + 193 \quad (R^2 = .9896); \tag{7-90}$$

$$[\text{Actual withdrawal}] = 0.966 * [\text{Computed withdrawal}] + 267 \quad (R^2 = .9945); \tag{7-91}$$

$$[\text{Actual external supply}] = 1.045 * [\text{Computed external supply}] - 1307 \quad (R^2 = .9962). \tag{7-92}$$

On the basis of the above results, it can be concluded that the management model is very reliable and simulates very closely the intra-annual operations of the company.

Further Extensions of the Allocation Model

Are the management rules applied in the simulation model optimal in the economic sense? One way to answer this question is to transform the simulation model into a cost minimization model and to compare the

Table 7-15 Results Produced by the Allocation Model Simulated from November 1974 to October 1975 (flows measured in MMCF)

Month	Initial Residual Supply Entitlement	Initial amount of gas in storage	Initial saturation rate in storage	Maximum storage delivery	Maximum storage withdrawal	Potential gas demand	Modeled storage delivery (actual value)	Modeled storage withdrawal (actual value)	Modeled external supply (actual value)
November	212,306	170,229	1.153	5,335	16,276	31,672	0. (34)	10,442 (10,443)	21,230 (21,263)
December	191,076	159,787	1.083	7,337	15,120	47,910	0. (0)	15,120 (14,681)	32,790 (33,229)
January	158,286	144,667	0.980	8,787	13,090	50,724	0. (0)	13,090 (13,667)	37,634 (37,056)
February	120,652	131,577	0.891	9,631	10,774	47,964	0. (0)	10,774 (9,167)	37,190 (38,797)
March	83,462	120,803	0.818	10,186	7,935	45,731	0. (0)	7,935 (8,998)	37,796 (36,732)
April	45,666	112,868	0.765	10,541	3,088	40,971	4,695 (6,867)	0. (700)	45,666 (47,138)
May	160,161	117,563	0.796	10,337	6,634	24,255	10,337 (10,721)	0. (133)	34,592 (34,843)
June	125,569	127,900	0.866	9,832	9,951	16,000	9,832 (9,564)	0. (202)	25,832 (25,362)
July	99,737	137,732	0.933	9,262	11,960	13,382	9,262 (9,206)	0. (183)	22,644 (22,405)
August	77,093	146,994	0.996	8,606	13,439	14,407	8,606 (8,360)	0. (171)	23,013 (22,595)
September	54,080	155,600	1.054	7,831	14,595	17,031	7,831 (7,954)	0. (170)	24,862 (24,815)
October	29,218	163,431	1.107	6,836	15,532	21,341	6,836 (6,999)	0. (106)	28,177 (28,234)

results of both models. In the following, the basic framework for such an optimization model is presented.

In addition to the parameters and variables defined above, the following are used:

- CGP_t = gas unit purchase cost during year t;
- CSI_t = gas injection into storage unit cost during year t;
- ρ_m = monthly discount rate;
- M_w = set of monthly indices corresponding to the winter season;
- M_s = set of monthly indices corresponding to the summer season;

The rationale of the present optimization model is that the company tries, within given constraints, to minimize its short-term annual costs of supplying the gas requested by its customers. These cost include:

- gas purchase costs, and
- storage injection costs.

The model is then:

$$\text{minimize } C = \sum_{m=1}^{12} \frac{1}{(1+\rho_m)^m} \quad [CGP_t * SUPM_{tm} + CSI_t * GINST_{tm}] \qquad (7\text{-}93)$$

subject to:

$$\sum_{M\varepsilon M_w} SUPM_{tm} \leq WINETL_t : \text{ winter entitlement constraint;} \qquad (7\text{-}94)$$

$$\sum_{M\varepsilon M_s} SUPM_{tm} \leq SUMETL_t : \text{ summer entitlement constraint;} \qquad (7\text{-}95)$$

$$MINSUW_t \leq SUPM_{tm} \leq MAXSUW_t \quad (M\varepsilon M_w)\text{: upper and lower constraints on monthly supply in winter;} \qquad (7\text{-}96)$$

$$MINSUS_t \leq SUPM_{tm} \leq MAXSUS_t \quad (M\varepsilon M_s)\text{: upper and lower constraints on monthly supply in summer;} \qquad (7\text{-}97)$$

$$SUPM_{tm} - GINST_{tm} + GOUST_{tm} = DGMT_{tm}$$: balance between net supply and demand; (7-98)

$$GINST_{tm} \leq k_1 \cdot (R_{max} - RSTOR_{tm})^{\alpha_1}$$: maximum storage delivery constraint; (7-99)

$$GOUST_{tm} \leq k_2 \cdot (RSTOR_{tm} - R_{min})^{\alpha_2}$$: maximum storage withdrawal constraint; (7-100)

$$RSTOR_{tm} = (GSTORD_{t1} + \sum_{\tau=1}^{m} [GINST_{t\tau} - GOUST_{t\tau}])/STCAP_t$$: definition of the storage saturation rate. (7-101)

The above model is a mathematical program with a linear objective function and primarily linear constraints, except for the constraints on maximum storage delivery and withdrawal. The solution of this model might constitute an interesting and useful path for further research. In particular, it will point out whether other management rules are more efficient than the currently implemented ones; that is, whether they lead to a lower cost of monthly gas flows management. Also, this model, with some additional refinements could help to determine the optimal capacity of the storage system for a given gas demand pattern and for given supply constraints.

CHAPTER 8

FINANCIAL ANALYSIS

Policies concerning the extension of service by gas distribution utilities affect the financial position of such companies in at least two major ways. Inasmuch as such policies lead to changes in the value of the plant, they affect the company's rate base, the prices that the company charges for its gas, and the resulting revenues. At the same time such policies lead to changes in the cost of doing business. The purpose of this chapter is to describe the model used in this research effort to analyze the financial repercussions of alternate new service policies. The output of the financial analysis model includes new gas prices used primarily in the analysis of gas consumption and various financial indicators used to evaluate the impact of new service policies on the financial position of the utility.

The general structure of this model is typical of other financial analysis models.[1] Its major distinguishing feature is its simplicity. As such, it is consistent with the other parts of the modeling effort described in this volume. Essentially, the model permits simulations of the main calculations that are typically performed prior to regular rate case proceedings. Following the calculation of rate base, changes in required income are calculated. From the calculated required income new gas rates are constructed.

In the first section of this chapter the method of calculating rate base is presented. In the second section the method of calculating income deficits or surpluses is described. The third section contains a description of the method of generating new gas prices. In the last section some examples of the application of this model are presented.

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[1] See, for example, Temple, Barker, and Sloane, Inc., Regulatory Analysis Financial Model RAm Descriptive Documentation, October 1977.

Rate Base Calculation

Rate base is an essential ingredient in the determination of a utility's cost of service. The typical cost of service components include (a) operating expenses, (b) depreciation expenses, (c) taxes, and (d) a reasonable return on the net valuation of the company's property, or rate base. Thus, rate base is the total net value of the company's tangible and intangible capital. It is typically composed of the plant and equipment used and useful in providing the company's service, or "plant in service." In many jurisdictions the rate base also includes an allowance for working capital and occasionally it may include the overhead costs of organizing the business, other intangibles, and going-concern value.[2]

Not all the elements typically composing a rate base are included in this model. The major criterion used to discriminate between elements to be included or excluded was the potential of such an action for distorting the evaluation of the relative worth of alternate new service policies. Perhaps the single most troublesome decision made concerned the inclusion of "Construction Work in Progress," CWIP. The decision to exclude CWIP from the rate base is a result of the choice of a very special capacity expansion assumption. As was pointed out in Chapter 6, all construction projects are assumed to be completed within a single year. The replacement of this assumption by a more realistic one would have resulted in additional modeling costs that could not be justified by the overall objectives of this effort, nor by its budget.

Four major elements were included in the calculation of the utility's rate base. These are: (a) existing plant in service at the beginning of each year, (b) replacement plant added during the year and adjusted for retirements, (c) extensions of existing plant due to service expansion, and (d) depreciation on the above three plant categories. Figure 8-1 presents a flowchart of the rate base determination process.

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[2] For an extended discussion of these concepts see Paul J. Garfield and Wallace F. Lovejoy, Public Utility Economics (Englewood Cliffs: Prentice-Hall Inc., 1964), Chapter 6.

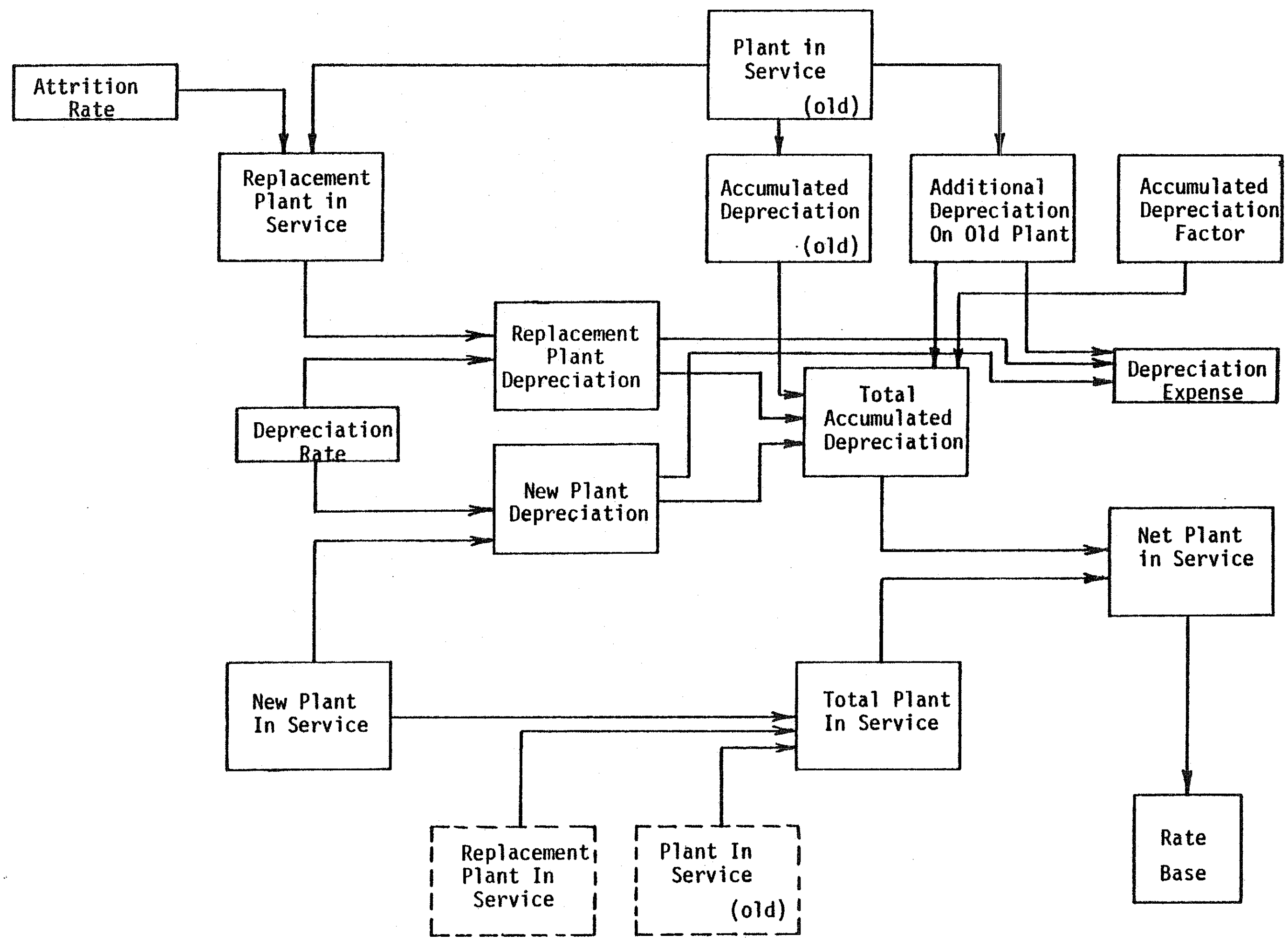

Figure 8-1 The Rate Base Determination Process

Plant in Service Elements

The major part of the plant in service account is composed of the original cost of the utility's plant at the beginning of the year, indicated as "Plant in Service (old)." The EOGC reports the value of this plant as line 1d on page 110 of its Annual Reports. For the base year value of the simulation exercise the 1977 value is taken. For 1978 and all the following years, through 2000, the estimated "Total Plant in Service" of the previous year becomes in the model "Plant in Service (old)", or

$$PISBEG_t = TOTPIS_{t-1} \tag{8-1}$$

where :

$PISBEG_t$ = plant in service (old) at the beginning of year t;

$TOTPIS_{t-1}$ = total plant in service at the end of year t-1.

The second major plant category is the "Replacement Plant in Service." This account includes additions to the existing plant to replace plant that has been retired. It is calculated on the basis of an estimated annual value of plant retirements, or

$$REPPIS_t = (ATPIS_t)(PISBEG_t) \tag{8-2}$$

where :

$REPPIS_t$ = replacement plant in service during year t;

$ATPIS_t$ = attrition rate of plant in service (old).

The attrition rate used in the model was estimated on the basis of data obtained from the EOGC. Two methods of calculating the attrition rate were attempted. First, a linear regression was computed of replacement plant expressed as a percentage of plant in service in constant dollars on annual total plant in service in constant dollars. It was assumed that during the 1969-1977 period replacement plant accounted for the total annual change of plant in service.

The following results were obtained:

Table 8-1 Calculation of Attrition Rate

Year (1)	Plant in Service, end of Year ($) (2)	Annual Change in Plant in Service (Replacement Plant) ($) (3)	Annual Change As a % of Plant in Service (%) (4)
1969	468,049,388	--	--
1970	481,302,059	13,252,671	2.8315
1971	502,277,309	20,975,250	4.3580
1972	518,330,411	16,053,102	3.1961
1973	546,496,716	28,166,305	5.4340
1974	568,535,640	22,038,924	4.0328
1975	587,988,407	19,452,767	3.4216
1976	606,205,797	18,217,390	3.0983
1977	617,338,511	11,132,714	1.8365

Source: Annual Reports of the EOGC.

$$Y = 3.047 - .358(X); \qquad R^2 = .571 \qquad (8\text{-}3)$$

where :

Y = replacement plant as a percentage of plant in service;

X = annual change in total plant in service.

Second, an average attrition rate was calculated based on nominal dollars. Table 8-1 contains the data used for these calculations. Based on column 4 the average attrition rate was calculated as 3.625% with a standard deviation of 1.047%. Analysts from the EOGC confirmed the suspicion that this attrition rate is realistic.

The third major plant category consists of the extension of plant due to the provision of new service. The method of estimating this plant category has been presented in Chapter 5 and will not be repeated here.

Depreciation Accounts

In general terms, the depreciation of capital assets is the accrued cost which is not restored by current maintenance, and which ultimately indicates the retirement of the asset. Thus in the case of a gas plant, it means the loss in service value that is incurred "in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance."[3] The purpose of the depreciation accounts is to distribute the investment associated with the utility's depreciable plant to the production expenses of each year in order to: (1) determine the annual income, and (2) recover gradually the company's investment.

In the rate base determination process there is a need to adjust the gross value of the plant, as it appears in the plant in service accounts, for the accumulated value of depreciation, amortization, and depletion. The basis for such a calculation is the accumulated provision for depreciation, amortization, and depletion at the beginning of the year. During the previous year this account has been adjusted for the book cost of retired

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[3] Garfield and Lovejoy, p. 95.

property and the cost of removal of such property. It has also been credited with the salvage values and any other amounts recovered, such as insurance. The EOGC reports this depreciation account as line 4a on page 110 of its Annual Reports.

During the year, additional depreciation is accumulated on old, replacement, and expansion plant. For the existing plant the additional depreciation was calculated as:

$$DEPADD_t = (DEPREX_t)(PISBEG_t) \tag{8-4}$$

where :

$DEPADD_t$ = additional depreciation on existing plant during year t;

$DEPREX_t$ = depreciation rate of existing plant during year t.

Similar calculations are made for replacement and expansion plants:

$$DEPREP_t = (DEPRRP_t)(REPPIS_t) \tag{8-5}$$

where :

$DEPREP_t$ = depreciation on replacement plant during year t;

$DEPRRP_t$ = depreciation rate of replacement plant during year t.

Finally, for the new plant:

$$DEPNEW_t = (DEPRNW_t)(NEWPIS_t) \tag{8-6}$$

where :

$DEPNEW_t$ = depreciation on new, or expansion plant during year t;

$DEPRNW_t$ = depreciation rate on new plant during year t;

$NEWPIS_t$ = new plant in service, introduced during year t.

Although three individual depreciation rates were defined above, data limitations permit the calculation of a single average depreciation rate only. The basis for this calculation was the depreciation expense rate defined as:

$$DEPEXR_t = DEPEXP_t/PISBEG_t \tag{8-7}$$

where:

$DEPEXR_t$ = depreciation expense rate during year t;

$DEPEXP_t$ = depreciation expense during year t.

The total depreciation rate, including depreciation on replacement assets is:

$$DEPEXR_t = (DEPAVG_t) + (DEPAVG_t)(ATPIS_t) \tag{8-8}$$

where:

$DEPAVG_t$ = average depreciation rate for year t.

It is evident from Table 8-2 that no temporal trend exists in the depreciation expense rate. An average of such rates for the year 1970-1977 yields a rate of 3.0454% with a standard deviation of 0.1700%. On this basis the average annual depreciation rate is calculated as 2.939%. The total depreciation expense during year t is expressed in terms of the plant in service at the beginning of year t.

Given the three types of plants and the associated depreciation rate, the total depreciation expense is defined as the sum of new, replacement, and additional depreciations:

$$DEPEXR_t = DEPADD_t + DEPREP_t + DEPNEW_t \tag{8-9}$$

Finally, the total accumulated provision for depreciation, amortization, and depletion is credited for any amounts recovered during the year, such as insurance and salvage value of plant. The accumulated provision factor is used for this purpose:

$$TAPDAD_t = TAPDAD_{t-1} + (APDADF_t)(DEPEXP_t) \tag{8-10}$$

Table 8-2 Depreciation Expense Rate Calculation

Year (1)	Depreciation Expense[1] ($) (2)	Plant in Service[2] ($) (3)	Depreciation Expense Rate[3] (%) (4)
1970	13,003,957	468,049,388	2.778
1971	13,658,188	481,302,059	2.838
1972	14,594,184	502,277,309	2.906
1973	16,246,601	518,330,411	3.134
1974	17,867,183	546,496,716	3.269
1975	18,292,212	562,535,640	3.217
1976	18,381,996	587,988,407	3.126
1977	18,759,876	606,205,797	3.095

1. Obtained from FPC account 403.
2. From the EOGC Annual Reports.
3. Column (2) divided by (3).

Table 8-3 Calculation of the Accumulated Depreciation Factor

Year (1)	Change in Accumulated Provision ($) (2)	Depreciation Expense ($) (3)	Accumulated Depreciation Factor in % (2)/(3) (4)
1970	11,333,051	13,003,957	87.15
1971	10,712,603	13,658,188	78.43
1972	11,634,738	14,594,184	79.72
1973	14,345,211	16,246,601	88.30
1974	14,329,188	17,867,183	80.20
1975	15,591,356	18,292,212	85.24
1976	14,550,712	18,381,996	79.16
1977	15,388,252	18,759,876	82.03

Source: EOGC Annual Report.

where :

$TAPDAD_t$ = total accumulated provision for depreciation, amortization, and depletion during year t;

$APDADF_t$ = accumulated provision factor.

The annual report data are not extensive enough to calculate this factor precisely. Table 8-3 contains the data on the basis of which an average factor was calculated. Its value is 82.528% of the total depreciation expense, with a 3.60% standard deviation.

The Rate Base

The sought after rate base is obtained by adjusting the total plant in service for the total accumulated provision for depreciation, amortization, and depletion. Total plant in service is defined as:

$$TOTPIS_t = PISBEG_t + REPPIS_t + NEWPIS_t \tag{8-11}$$

where:

$TOTPIS_t$ = total plant in service during year t.

The rate base is defined as the net plant in service, $NETPIS_t$:

$$NETPIS_t = TOTPIS_t - TAPDAD_t \tag{8-12}$$

Income Deficit Calculation

The purpose of this section is to describe the method of calculating the income deficit, or surplus, associated with revenues generated through the current gas rates, the current cost of doing business, and the permissible income. It is noteworthy that all three determinants of income deficit change constantly. Even in the absence of new customers' hook-ups, the rate base changes as a result of depreciation, gas revenues decrease because of customer attrition and changing consumption patterns, and the cost of doing business goes up because of its sensitivity to inflationary pressures. In the current research, however, purely inflationary changes are not permitted. Most variables are expressed in real terms, or constant dollars.

The logical structure of the income deficit calculations is depicted in Figure 8-2. Income deficits are calculated on the basis of forecasted allowed operating income and actual operating income, adjusted for income taxes. Forecasts of actual operating income are based on forecasted actual operating expenses and forecasted actual gas revenues and non-utility income.

Allowed Operating Income

Since natural gas distribution systems are regulated monopolies, the extent to which they can earn income is regulated. Various criteria have been suggested as bases for such regulation. The almost universally accepted criterion is based on the assumption that investors in public utilities should be permitted to earn a return on their investment equivalent to the return that could be earned elsewhere. The lack of a possibility for earning an extraordinary return on investment in utilities is typically justified by the fact that since utilities are protected from competition, investors are subject to a lesser degree of risk associated with doing business.

The limit on allowed operating income is set as:

$$AOPINC_t = (ALLROR_t)(NETPIS_t) \tag{8-13}$$

where :

$AOPINC_t$ = allowed operating income during year t;

$ALLROR_t$ = allowed rate of return during year t;

$NETPIS_t$ = net plant in service (rate base) during year t.

Since the allowed rate of return is based on the cost of capital, the projection of the allowed rate of return must be based on projections of the cost of capital. There is no unique index of the cost of capital. This is because the cost of internally generated capital differs from the cost of capital financed by various outside money sources. Nevertheless, long-term interest rates typically are used as an average index of capital cost. The only available interest projections are summarized in

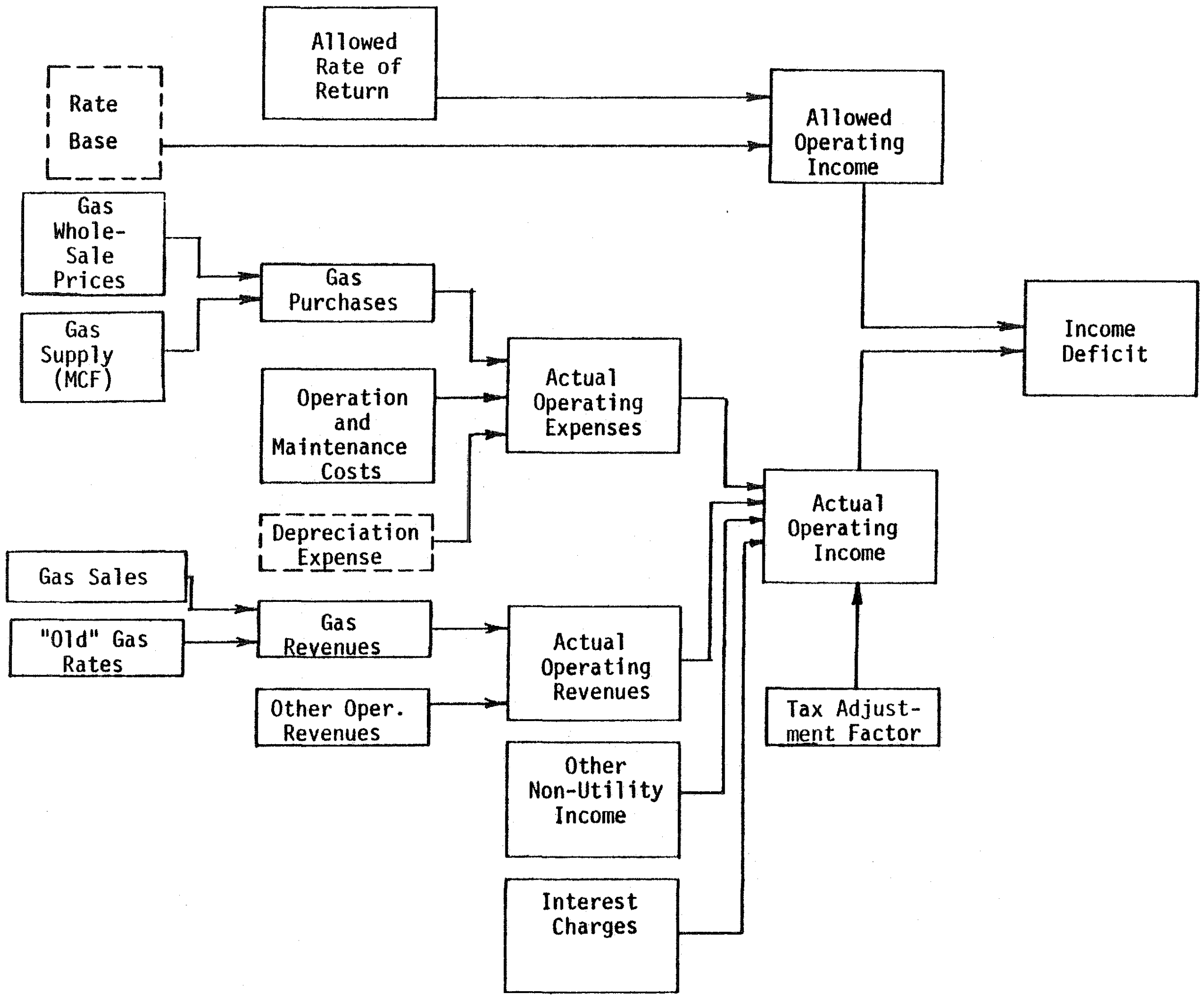

Figure 8-2 The Calculation of Income Deficit

Table 8-4. As is illustrated in Figure 8-3, the projections do not extend beyond 1984 for AA bonds. Furthermore, the current upswing in interest rates is projected to continue to 1983, although not all analysts agree about these projections.

The lack of well-accepted projections suggests that simulation experiments be conducted based on three indexes used to project changes in the current earned rate of return of the EOGC. The three indexes are based on the following assumptions: (1) interest rates will rise to a high of 11.00% by the year 2000, (2) interest rates will not change and will remain at the current 8.67%, and (3) interest rates will drop to 8.00% by the year 2000. The indexes and the projected allowed rates of return are presented in Table 8-5.

Utility's Revenues

The utility's revenues are composed of gas revenues and other incomes not directly related to gas sales. Gas revenues are determined on the basis of the previous year's average gas prices and the resulting consumption streams. Thus,

$$GASRER_t = (PRGAVR_{t-1})(GASSLR_t) \tag{8-14}$$
$$GASREC_t = (PRGAVC_{t-1})(GASSLC_t) \tag{8-15}$$
$$GASREI_t = (PRGAVI_{t-1})(GASSLI_t) \tag{8-16}$$

where:

$GASRER_t$ = revenues from gas sales to residential customers during year t;
$GASREC_t$ = revenues from gas sales to commercial customers during year t;
$GASREI_t$ = revenues from gas sales to industrial customers during year t;

$$\left.\begin{array}{ll} PRGAVR_{t-1} & = \text{average gas price for residential customers,} \\ PRGAVC_{t-1} & = \text{average gas price for commercial customers,} \\ PRGAVI_{t-1} & = \text{average gas price for industrial customers,} \end{array}\right\} \begin{array}{l}\text{determined at the end} \\ \text{of year t-1 and applied} \\ \text{during year t;}\end{array}$$

$GASSLR_t$ = gas sales to residential customers during year t;
$GASSLC_t$ = gas sales to commercial customers during year t;
$GASSLI_t$ = gas sales to industrial customers during year t.

Table 8-4 Projections of Various Interest Rates Under Alternate Macro-economic Assumptions

	Average Yield on New AA Utility Bonds			Prime Rate on Short-term Business Loans			Average Yield on New High Grade Bonds		
	A[1]	B[2]	C[3]	A	B	C	A	B	C
1977	8.49	8.34	8.33	6.57	6.74	6.77	8.25	8.07	8.08
1978	8.60	8.86	8.97	7.01	7.68	7.96	8.30	8.54	8.65
1979	8.29	8.83	8.98	6.47	7.17	7.49	8.00	8.50	8.64
1980	8.61	9.06	9.31	6.39	7.37	7.07	8.31	8.72	8.96
1981	8.58	9.04	9.87	6.32	7.53	8.21	8.28	8.71	9.51
1982	8.69	8.96	10.73	6.24	7.41	9.74	8.38	8.65	10.34
1983	8.74	8.74	10.71	6.16	7.34	7.67	8.43	8.43	10.29
1984	8.60	8.54	9.69	6.17	7.21	7.38	8.29	8.24	9.32

1. Column A is based on the assumption of high supply and high demand.
2. Column B is based on the assumption of medium supply and medium demand.
3. Column C is based on the assumption of low supply and low demand.

Source: Energy Information Administration, Annual Report to Congress, 1977.

Figure 8-3 Average Yield on New A A Rated Corporate Utility Bonds

Table 8-5 Allowed Rate of Return Projections and Associated Indexes

Year	High Index	Rate of Return Projection Based on the High Index	Medium Index	Rate of Return Projection Based on Medium Index	Low Index	Rate of Return Projection Based on the Low Index
1977	100.0	12.06	100	12.06	100.0	12.06
1978	100.1	12.19	100	12.06	99.6	12.01
1979	102.1	12.31	100	12.06	99.3	11.97
1980	103.1	12.43	100	12.06	98.9	11.92
1981	104.3	12.58	100	12.06	98.6	11.89
1982	105.4	12.71	100	12.06	98.2	11.84
1983	106.4	12.83	100	12.06	97.9	11.80
1984	107.5	12.96	100	12.06	97.6	11.77
1985	108.6	13.09	100	12.06	97.2	11.72
1986	109.6	13.22	100	12.06	96.9	11.68
1987	110.6	13.34	100	12.06	96.6	11.65
1988	111.8	13.48	100	12.06	96.3	11.61
1989	112.8	13.60	100	12.06	95.9	11.56
1990	113.8	13.72	100	12.06	95.6	11.53
1991	114.9	13.85	100	12.06	95.2	11.48
1992	115.9	13.98	100	12.06	94.9	11.44
1993	117.0	14.11	100	12.06	94.5	11.39
1994	118.2	14.25	100	12.06	94.2	11.36
1995	119.2	14.38	100	12.06	93.8	11.31
1996	120.2	14.50	100	12.06	93.5	11.28
1997	121.3	14.63	100	12.06	93.3	11.25
1998	122.4	14.76	100	12.06	92.9	11.20
1990	123.4	14.88	100	12.06	92.7	11.18
2000	125.6	15.14	100	12.06	92.6	11.17

Other revenues, not directly related to gas sales, include transactions such as the transportation of gas owned by others through the utility's pipelines. Since there do not seem to be any management rules that explain the systematic variations in this component of the utility's revenues, the following regression was estimated:

$$\frac{OOPREV_t}{TOTPIS_t} = \alpha + \beta\ (t-1977) \qquad (8-17)$$

where :

$OOPREV_t$ = other operating revenues during year t.
Based on data obtained from the annual reports of the EOGC, the following regression equation was estimated:

$$\frac{OOPREV_t}{TOTPIS_t} = .005229 + .001131\ (t-1977)$$

$$R^2 = .9582$$

Since no further growth in the self-help or other similar programs is anticipated, the above equation was not used. Instead, the resulting forecasting equation is based on an average ratio:

$$OOPREV_t = .002288\ TOTPIS_t \qquad (8-18)$$

Since all utilities derive some small percentage of income from non-utility business, another category of revenues was included in the analysis. Since no trend could be ascertained in the historic data of EOGC, a simple average was used for forecasting purposes:

$$ONUINC_t = .002975\ TOTPIS_t \qquad (8-19)$$

where:

$ONUINC_t$ = other non-utility income during year t.

Actual operating revenues are the sum of the above three types of revenues, or:

$$ACOPRV_t = GASRER_t + GASREC_t + GASREI_t + OOPREV_t + ONUINC_t \quad (8\text{-}20)$$

Actual Operating Expenses:

The actual operating expenses include all the expenses associated with gas operations. Thus:

$$ACOPEX_t = GPURCH_t + O\&M_t + DEPEXP_t \quad (8\text{-}21)$$

where:

$ACOPEX_t$ = actual operating expenses during year t;
$GPURCH_t$ = value of total gas purchased during year t;
$O\&M_t$ = operating and maintenance expenses during year t;
$DEPEXP_t$ = depreciation expenses during year t.

The value of total gas purchased is obtained by multiplying the amount of gas purchased by the utility by the average wholesale gas price. Thus:

$$GPURCH_t = (GASSUP_t)(WGP_1)(IWGP_t) \quad (8\text{-}22)$$

where:

$GASSUP_t$ = total amount of gas supplied to the utility;
WGP_1 = base year (1977) wholesale average gas price;
$IWGP_t$ = index of wholesale gas price growth.

Since depreciation expenses were described above, the only elements of the actual operating expenses in need of clarification are the operating and maintenance costs. These include costs of production, storage, transmission, distribution, administration, and customer services. Two regression equations were used to forecast general O&M expenses and those expenses associated with storage facilities. (See Chapter 5.)

The regression equation used for forecasting general O&M expenses is:

$$OMGENC_t = GSALES_t\,[.47064 - .6356(GSALES_t/10^6)] \qquad (8\text{-}23)$$
$$R^2 = .9941$$

where:

$OMGENC_t$ = general operating and maintenance expenses during year t;
$GSALES_t$ = total gas sales during year t.

The costs of operating storage facilities are forecasted with the following regression equation:

$$OMSTOC_t = GDELIV_t\,[.12616 - (.99385)(10^{-6})(GDELIV_t)] \qquad (8\text{-}24)$$
$$R^2 = .6260$$

where:

$OMSTOC_t$ = operation and maintenance costs of storage during year t;
$GDELIV_t$ = gas deliveries to storage during year t.

It is apparent that in both equations there is evidence of economies of scale. The total O&M expenses for each year are obtained by combining the above forecasts with an adjustment for an observed wage roll-out effect that is similar in nature to the Averch-Johnson effect.

$$O\&M_t = (OMGENC_t + OMSTOC_t)/AJROEI \qquad (8\text{-}25)$$

where:

AJROEI = Index of the wage roll-out effect.

The use of general inflationary increases for the wage roll-out index is justified by the lack of a better index of wage roll-out in regulated utilities. In the simulation, however, only general O&M costs were adjusted by 4% annually since it was assumed that storage O&M was not labor intensive.

Income Deficit

In order to calculate the existing income deficit there is a need to calculate the after tax and interest payments income. Interest payments are peculiar in that they are not subject to taxation. In this effort no attempt was made to disaggregate the various interest payments. An average interest charge was estimated. Similar treatment was afforded to taxes. Thus:

$$INTCHG_t = (INTAVG_t)(TOTPIS_t) \tag{8-26}$$

where:

$INTCHG_t$ = interest charge during year t;
$INTAVG_t$ = average interest charge as a percent of plant in service during year t, estimated as 1.759%.

The average tax adjustment rate was calculated as:

$$REVTXR_t = STTAX_t + PUCOMT_t + CONSCN_t \tag{8-27}$$
$$TAXADJ_t = (1 - REVTXR)(1 - FEDITR_t) \tag{8-28}$$

where:

$REVTXR_t$ = revenue tax rate during year t;
$STTAX_t$ = state excise tax rate during year t;
$PUCOMT_t$ = PUCO maintenance contribution rate during year t;
$CONSCN_t$ = consumers' council contribution rate during year t;
$TAXADJ_t$ = average tax adjustment rate during year t;
$FEDITR_t$ = federal income tax rate during year t.

The above rates were assumed to remain constant over time. The following estimates were made:

STTAX = 4.00%
PUCOMT = 0.10%
CONSCN = 0.02%
FEDITR = 48.00%

Finally: TAXADJ = 0.4986.

Based on the above, it is possible to calculate income after taxes and interest, and finally to calculate the resulting income deficit:

$$INCAT_t = [ACOPRV_t - ACOPEX_t][TAXADJ] - (INTCHG) \tag{8-29}$$

and

$$INCDEF_t = AOPINC_t - INCAT_t \qquad (8\text{-}30)$$

where:

$ACOPRV_t$ = actual operating revenues during year t;

$INCDEF_t$ = income deficit during year t;

$INCAT_t$ = income after taxes during year t.

Determination of New Gas Rates

No attempt is made in the present effort to develop a complete rate-making sub-model. Indeed, only average prices are considered. This is in part due to the fact that no clear cost responsibility is established and no attempt is made to incorporate this responsibility into rate making.

The first step in the process of adjusting average rates is the calculation of required change in average rates:

$$CPRGAVG_t = PRGAVG_t - PRGAVG_{t-1} = INCDEF_t/[(GSALES_t)(TAXADJ)] \qquad (8\text{-}31)$$

where:

$CPRGAVG_t$ = required change in average price for all customers during year t;

$PRGAVG_t$ = average price for all customer groups during year t;

$INCDEF_t$ = income deficit during year t;

$GSALES_t$ = total gas sales during year t;

TAXADJ = average tax adjustment rate on income.

In the absence of clear responsibility for the income deficit, all three prices are adjusted equally:

$$PRGAVR_t = PRGAVR_{t-1} + CPRGAVG_t \qquad (8\text{-}32)$$

$$PRGAVC_t = PRGAVC_{t-1} + CPRGAVG_t \qquad (8\text{-}33)$$

$$PRGAVI_t = PRGAVI_{t-1} + CPRGAVG_t \qquad (8\text{-}34)$$

where :

$$\left.\begin{array}{l} PRGAVR_t = \text{average gas price for residential customers} \\ PRGAVC_t = \text{average gas price for commercial customers} \\ PRGAVI_t = \text{average gas price for industrial customers} \end{array}\right\} \text{to be applied during year } t+1.$$

The method of adjusting prices is almost equivalent to the present prevalent pricing practice. Alternative pricing methods can be introduced through an appropriate cost analysis.

Two Applications

Although the majority of the relationships expressed in the financial analysis model were the result of statistical estimation, the overall soundness of the model has not been subjected to statistical tests. The purpose of this section is to illustrate the model's capability to yield results that at least intuitively are plausible.

The first application is based on data contained in the 1976 Annual Report of the EOGC and on 1977 consumption and wholesale price data. The purpose of the application is to simulate 1977 financial data and compare them with the actual 1977 data obtained from the 1977 Annual Report of the EOGC. The following results were obtained.

1. Based on equation (8-11) and the assumption that no new hook-ups take place, total plant in service was estimated as $628,180,757.
2. Based on equation (8-9) depreciation expense was estimated to be $18,462,232.
3. On the basis of equation (8-10) the total accumulated provision for depreciation, amortization, and depletion was estimated as $224,538,778.
4. On the basis of equation (8-12) the rate base, or net plant in service, was estimated as $403,641,979.
5. The allowed operating income was estimated on the basis of equation (8-13) and an allowed rate of return of 12.06% as $48,679,223.
6. Gas purchases were estimated by equation (8-22) as $480,601,644.

7. The operating and maintenance expenses, including storage, were estimated with equation (8-25) as $92,111,922.
8. The actual operating expense was calculated according to equation (8-20) as $591,179,798.
9 Operating revenues, on the other hand, were estimated by equation (8-18) as $551,669,874.
10. According to equation (8-29) income after taxes was estimated as $29,817,547.
11. The resulting income deficit, according to equation (8-30), was $78,496,768, and
12. The average increase in rates was .4489 $/mcf, or 1.7% below the actual increase.

In the second application, an attempt was made to simulate the results of expanding the company's distribution system. In addition to the above assumptions, it was assumed that the total cost of expanding the system was $15,214,000 and the associated gas flow was 14,900,000 Mcf/year. In addition it was assumed that the wholesale gas price increased by only 5.8% so that the wholesale gas price was assumed to be $1.45/Mcf. Following the above calculations the following results were obtained:

1. Total plant in service = $666,166,309.
2. Depreciation expense = $ 19,578,628.
3. Total accumulated provision for depreciation = $240,696,628.
4. Net plant in service = $425,469,681.
5. Allowed operating income = $51,311,643.
6. Gas purchases = $530,850,069.
7. Operating and maintenance costs = $97,288,094.
8. Actual operating expenses = $647,716,791.
9. Actual operating revenues = $740,837,052.
10. Income after taxes and interest payments = $35,700,045.
11. Income deficit = $15,611,598.
12. Increase in average gas rate = .086 $/Mcf.

In conclusion it seems that the model operates in a reasonable fashion, yielding predictable results.

CHAPTER 9

POLICY EVALUATION CRITERIA

The purpose of this chapter is to present the means by which the variety of possible new service policies will be evaluated. The mere existence of a multitude of potential hook-up policies suggests that the choice of the preferred policy be based on the capacity of the policy to satisfy regulatory objectives. Such choice is made difficult, however, by the constantly changing inventory of accepted regulatory objectives and by the inherent inability of analysts to aggregate non-equivalent measures of the extent to which objectives have been attained. In the present effort no attempt is made to choose the preferred policy, or set of policies. Instead, a set of representative policies will be analyzed separately to determine their relative achievement of each objective. Inasmuch as there are policies that are unequivocally either superior or inferior in terms of all the regulatory objectives considered, such policies will be indicated.

Among the traditional objectives of regulatory policies are concerns for the financial stability of the regulated utility and the adequacy of the quantity and quality of the supplied services. More recently, due to the newly revealed energy scarcity and the associated growth in utility bills, regulatory policies have been increasingly subjected to evaluations in terms of changes in production and end-use efficiency and in terms of fairness and redistribution of income that they induce. As the recognition grows that public utilities' services can serve as stimuli and constraints for regional development, there is an increasing speculation about the potential for the evaluation of regulatory policies on the basis of their regional development repercussions. The following sections of this chapter will contain descriptions of various criteria for policy evaluation based on concerns for: (1) utilities' finances, (2) adequacy of service, (3) end-use efficiency, (4) aggregate economic efficiency, (5) fairness, (6) regional development.

The Impact of Hook-up Policies on Utilities' Finances

Ultimately, the concern for utilities' finances is a concern for its stock-holders and customers. An aggravated financial position of a regulated company can lead to the necessity of internal financing of projects needed to assure an adequate level of service. Inevitably such financing leads to higher rates. In the end lack of a financing source can lead to service curtailments and losses for the stockholders. In particular, the expansion of a gas distribution system, or the lack of such an expansion, may affect the gas company's financial position in two ways. Changes in its rate base can affect its allowed operating income, while changes in its realized operating expenses and its operating revenues can affect the actual operating income. Such changes inevitably lead to further repercussions in terms of changes in gas rates, in the relative prices of all fuels, and further changes in the potential demand for gas. In an extreme situation failure of the company to grow may lead to the eventual disappearance of the utility, while indiscriminate growth may lead to inadequate service and associated economic costs, causing eventual cut-backs brought about by customers who switch to other fuels.

There are at least three general aspects of the company's finances that can be affected by such changes. First, expansion policies have a major impact on the company's ability to generate revenues. Second, they alter the company's financial structure. Finally, they change the company's ability and willingness to control expenses associated with doing business. Inasmuch as regulated monopolies have a limited set of built-in incentives to control expenditures strictly, expense control is a particularly important aspect of gas companies' finances.

A number of financial indicators will be used to analyze the repercussions of new service policies on all three aspects of gas companies' finances.

The ratio of total asset turnover will be used as an overall measure of the use of total assets employed by such companies. Essentially, the ratio measures dollars of sales generated by a gas company per dollar of investment. It is typically measured as the value of net sales divided by total company assets. In the case of the analysis of the EOGC, it is defined as:

$$TATR_t = \frac{(GASRER_t + GASREC_t + GASREI_t + OOPREV_t)}{NETPIS_t} \qquad (9\text{-}1)$$

where:

$TATR_t$ = total asset turnover ratio during year t;
$GASRER_t$ = revenues from gas sales to residential customers during year t;
$GASREC_t$ = revenues from gas sales to commercial customers during year t;
$GASREI_t$ = revenues from gas sales to industrial customers during year t;
$OOPREV_t$ = other operating revenues during year t;
$NETPIS_t$ = net plant in service, or rate base, during year t.

Net profit margin ratio is the most commonly used index to evaluate a firm's performance from the common shareholders' point of view. It is defined as net profits after taxes per dollar of sales. The gross profit margin ratio is used with a similar intent. It is simpler to calculate, however, since it is defined as gross profits before taxes per dollar of sales and thus does not involve tax rate calculations. The return on total assets ratio is similar in that net profits after taxes are calculated per dollar of total assets. In the calculation of the impacts associated with the potential new service policies of the EOGC, the following definitions of these ratios will be used:

$$NPMR_t = \frac{(GASRER_t + GASREC_t + GASREI_t + OOPREV_t + ONUINC_t - ACOPEX_t)(TAXADJ) - INTCHG_t}{GASRER_t + GASREC_t + GASREI_t + OOPREV_t + ONUINC_t} \qquad (9\text{-}2)$$

where:

$NPMR_t$ = net profit margin ratio during year t;
$GASRER_t$ = revenues from gas sales to residential customers during year t;
$GASREC_t$ = revenues from gas sales to commercial customers during year t;
$GASREI_t$ = revenues from gas sales to industrial customers during year t;
$OOPREV_t$ = other operating revenues during year t;
$ACOPEX_t$ = actual operating expense during year t;
$INTCHG_t$ = interest charge during year t.

$$GPMR_t = \frac{(GASRER_t + GASREC_t + GASREI_t + OOPREV_t) - (ACOPEX_t)}{GASRER_t + GASREC_t + GASREI_t + OOPREV_t} \qquad (9\text{-}3)$$

where:

$GPMR_t$ = gross profit margin ratio during year t.

$$RTAR_t = (NPMR_t)(TATR_t) \tag{9-4}$$

where:

$RTAR_t$ = return on total assets ratio during year t.

A much more general indicator, one that encompasses all the three crucial financial analysis elements, is the return on common equity index. It is defined as:

$$ROCER_t = (NPMR_t)(TATR_t)(EM_t) \tag{9-5}$$

where:

$ROCER_t$ = return on common equity index during year t;
EM_t = equity multiplier during year t.

The equity multiplier is indicative of the potential magnification of change in net profits for common shareholders given a change in the level of operating profit. In this study the equity multiplier is defined as:

$$EM_t = \frac{(GASRER_t + GASREC_t + GASREI_t + OOPREV_t) - (ACOPEX_t)}{[(GASRER_t + GASREC_t + GASREI_t + OOPREV_t) - (ACOPEX_t)][TAXADJ] - INTCHG_t} \tag{9-6}$$

where:
TAXADJ = average tax adjustment rate (assumed constant over time).

An additional financial indicator is the interest coverage ratio. In this study it is defined as:

$$INTCOV_t = \frac{(GASRER_t + GASREC_t + GASREI_t + OOPREV_t) - (ACOPEX_t)}{INTCHG_t} \tag{9-7}$$

Two additional indicators will be used to analyze the impact of new service policies on the EOGC. The percentage change in the value of net plant in service will be used as an indicator of changes in the company's size. The number of rate increases made necessary by the various policies will be used as an indicator of the extent of adjustments needed to keep the company's finances sound. Only rate increases that exceed the annual change in wholesale fuel price will be counted. These indicators are formulated as follows:

$$IRBC_t = (NETPIS_t - NETPIS_{t-1})/NETPIS_{t-1} \tag{9-8}$$

where:

$IRBC_t$ = the percentage change in rate base during year t,

and

$$IORIT = \sum_{t=1}^{T} IORI_t \quad \text{with:} \quad IORI_t = \begin{cases} 1 \text{ if } CPRGAVG_t > (WGP_t - WGP_{t-1}) \\ 0 \text{ if } CPRGAVG_t \leq (WGP_t - WGP_{t-1}) \end{cases} \tag{9-9}$$

where:

$IORIT$ = aggregate index of rate increases;

$CPRGAVG_t$ = required change in average price for all customers during year t;

WGP_t = wholesale gas price during year t.

The Impact of Hook-Up Policies on the Adequacy of Service

The notion of adequate utility service has been interpreted in the past as its availability upon demand. Thus, for example, electricity brown-outs and black-outs and natural gas curtailments are deemed to be symptoms of inadequate service. The need to consider the impact of hook-up policies on the adequacy of service arises out of a concern for the availability of adequate gas supply to serve the expanded demand associated with the new service. In the face of given gas supply forecasts and unusually severe heating seasons, the granting of a relief order concerning the ban on new service may lead to an increased risk of forced curtailments. The need for such curtailments is traditionally viewed as a symptom of inadequate utility service.

In the present effort adequacy of service will be evaluated with the help of two types of indicators: annual curtailments indexes and monthly curtailments indexes.

The purpose of the annual indexes is to analyze the extent to which a new service policy that calls for an increase in committed requirement[1] in one year leads to unfilled potential demand in other years. One index will indicate the average annual excess demand and a second index will indicate the number of years during which such excess demand occurred. They are formulated as follows:

$$AEDI = \frac{1}{T}\sum_{t=\theta}^{T} (BASEDT_t - WGS_t)/BASEDT_t \tag{9-10}$$

$$\theta = \{t | BASEDT_t - WGS_t > 0\}$$

where:

$AEDI$ = average annual excess demand index;

T = number of year comprising the simulation horizon;

WGS_t = maximum wholesale annual gas supply to the gas distributor during year t;

$BASEDT_t$ = total gas demand based on "normal weather", in the absence of hook-ups, during year t.

$$AEDFI = EDY/T \tag{9-11}$$

where:

$AEDFI$ = average annual excess demand frequency index

EDY = number of years with excess demand.

The purpose of the monthly curtailments indexes is to analyze the extent to which unpredictable winter weather together with changes in the number of customers leads to short-term curtailments in winter. They are formulated as follows:

$$AMCIR_t = \frac{1}{6}\sum_{m=7}^{12} CURTR_{tm}$$

$$AMCIC_t = \frac{1}{6}\sum_{m=7}^{12} CURTC_{tm} \tag{9-12}$$

$$AMCII_t = \frac{1}{6}\sum_{m=7}^{12} CURTI_{tm}$$

[1]For a full discussion of the concept of "committed requirements" see Chapter 6.

where:

$AMCIR_t$ = average monthly curtailment index of residential users during year t;

$AMCIC_t$ = average monthly curtailment index of commercial users during year t;

$AMCII_t$ = average monthly curtailment index of industrial users during year t;

$CURTR_{tm}$ = actual residential curtailment rate during year t and month m;

$CURTC_{tm}$ = actual commercial curtailment rate during year t and month m;

$CURTI_{tm}$ = actual industrial curtailment rate during year t and month m.

Another index will be used to compute the frequency of the monthly curtailments:

$$\left.\begin{aligned} WMCRT &= \frac{1}{T}\sum_{t=1}^{T} MWRC_t \\ WMCCT &= \frac{1}{T}\sum_{t=1}^{T} MWCC_t \\ WMCIT &= \frac{1}{T}\sum_{t=1}^{T} MWIC_t \end{aligned}\right\} \tag{9-13}$$

where:

WMCRT = average monthly residential curtailment frequency index;

WMCCT = average monthly commercial curtailment frequency index;

WMCIT = average monthly industrial curtailment frequency index;

$MWRC_t$ = number of months with residential curtailment during year t;

$MWCC_t$ = number of months with commercial curtailment during year t;

$MWIC_t$ = number of months with industrial curtailment during year t.

No attempt is made in the present effort to estimate the economic costs associated with both types of curtailments. The Ohio Department of Energy is conducting research with the aim of estimating such economic costs. Should these results become public they will be incorporated herein.

The Impact of Hook-Up Policies on End-Use Efficiency

Use of "end-use efficiency" as a criterion for the evaluation of regulatory policies has a relatively short history. It is increasingly linked to the notions of "wasteful" or "unjustified" consumption of natural gas, or to the need for conservation. A direct implication of the notion of end-use efficiency is that natural gas entitlements should be redistributed from the "wasteful" consumers to those who are "justified" in their consumption.

"The idea of justified consumption, when coupled with the notion of consumer sovereignty, takes on a very precise meaning. In a free economy, it is convenient to assume that the individual gas consumer knows best the extent to which natural gas benefits him and he expresses its usefulness to him by his willingness to pay for it. The more useful an mcf of natural gas is to the individuals with a low willingness-to-pay, while individuals willing to pay more find gas unavailable, some "wasteful" or "unjustified" consumption has occurred. For example, it is considered wasteful for an industry to receive summer gas at $1.60 for firing boilers that could burn $2.00 coal, while other customers who require a clean source of energy turn to $5.00 propane or $7.00 electricity.[2] On the other hand, a gas allocation policy that would redirect the flow of gas from the low willingness-to-pay to the high willingness-to-pay individual is a gas conservation policy. It leads to greater end-use efficiency and an improved allocation of resources in general."[3]

Instead of being determined through the interaction and bargaining of very many suppliers and demanders, the price of natural gas is determined by government regulation. Because this government set price is below a freely operating market price, there is a constantly prevailing excess demand for gas over supply. In order to use the efficiency standard of willingness-to-pay to evaluate gas hook-up policies it is necessary to estimate excess demand.

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[2] It should be noted that these figures mean $2.00, $5.00, $7.00 per equivalent energy unit depending on the particular energy source.

[3] This discussion is from a previous report to the PUCO, Benefits and Costs of Gas Storage Development in Ohio, August 1977, pp. 32-34.

The regulatory agencies have resorted to natural gas curtailment to reduce the excess demand to meet available supply, so that today it is still not possible to know individuals' willingness-to-pay for natural gas by directly observing their consumption patterns. The actual quantities of gas that individuals consume are not the quantities that they would buy without a curtailment policy. Besides the directly-ordered curtailment, excess demand exists because of hidden "curtailments" due to the prohibition of new gas hook-ups for all customer classes. The quantity of excess demand can be inferred from what economists call a demand curve. A typical demand curve is illustrated in Figure 9-1. At the regulated price P* a customer would demand the quantity of gas Q. Because of existing curtailments, however, he can obtain only the quantity D.

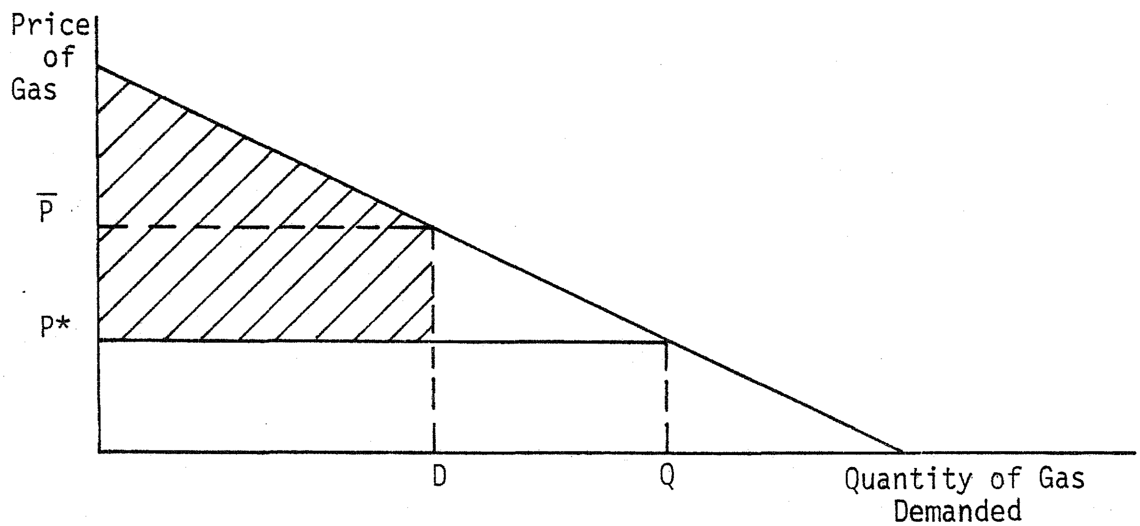

Figure 9-1 Typical Demand Curve for Natural Gas by a Single Customer. (Shaded Area Shows Consumer's Surplus)

"Note that for the last unit that a hypothetical customer was able to obtain he would have been willing to pay $\overline{P}$ but actually paid only P*. The difference between the price he was willing to pay and the price that he actually pays is a benefit to the consumer that is not captured and expressed by the commodity's price. Thus, for all the previous units there is an excess of benefits over price. The dollar value of these benefits, given by the shaded area in Figure 9-1. is called consumer's surplus."[4]

Each consumer has a consumer's surplus. The higher the individual's willingness-to-pay the greater will be his consumer's surplus associated with any given quantity of natural gas. If the object of a gas allocation policy is to distribute the gas to the individuals with the highest willingness-to-pay (i.e., to promote end-use efficiency), it should aim at attaining the highest sum of all consumer's surplus. By taking gas from some consumers and giving it to others, some consumers' surplus will shrink while others' will grow. A well-designed policy can reallocate gas so that the net change is positive.

The Net Aggregate Consumer's Surplus

The removal of a ban on new hook-ups has the potential of affecting the consumer's surplus of many individuals. In order to assess the desirability of various new hook-ups policies, it is necessary to estimate the change in net aggregate consumers' surplus less the cost of policy implementation.

A typical policy will consist of:

(a) the allocation of the gas supply for year t to existing customers of the gas company, and

(b) the allocation of excess gas supply for year t to new customers by customer class.

Accordingly, within the supply constraint a new group of customers will be supplied with gas up to its potential demand at the current level of price. Alternative gas allocation programs will be evaluated in terms of net aggregate consumer's surplus generated.

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[4]The concept of consumer's surplus is a fundamental concept in economic theory, explained in any basic economic text. It is an essential ingredient in cost-benefit analyses. The concept was explained and applied in a previous report to the PUCO. <u>Alternative Policies for Pricing Non-Historic Gas</u>, October 1974.

The net aggregate consumer's surplus is calculated under six different situations. These are defined in terms of the amount of gas received by the three major consumer groups. The need to distinguish the six different situations is necessitated by the requirement that the opportunity cost of each gas allocation be considered along with the direct benefits of that allocation. For the three hypothetical consumer groups, i, j, and k, the following cases will be considered.

CASE 1: Group i receives some of the gas that it demands. There is not enough gas for groups j and k.

CASE 2: Group i receives all the gas that it demands. There is not enough gas for groups j and k.

CASE 3: Group i receives all the gas that it demands. Group j receives some of the gas that it demands. Group k receives no gas.

CASE 4: Groups i and j receive all the gas that they demand while group k receives no gas.

CASE 5: Groups i and j receive all the gas that they demand, while group k receives some the gas that it demands.

CASE 6: All three groups receive all the gas that they demand.

In order to specify the net aggregate consumer's surplus, three demand functions, corresponding to groups i, j, and k, are needed. In general these are:

$$\left.\begin{aligned} Q_i &= f_i\ (P_i) \\ Q_j &= f_j\ (P_j) \\ Q_k &= f_k\ (P_k) \end{aligned}\right\} \qquad (9\text{-}14)$$

where:

Q_i = demand for gas by group i;
Q_j = demand for gas by group j;
Q_k = demand for gas by group k;
P_i = price of gas sold to group i;
P_j = price of gas sold to group j;
P_k = price of gas sold to group k.

The following aggregate consumer's surplus calculations are made depending on the choice of policy.

CASE 1: $\overline{Q}_i > Q^s$

where:

$\overline{Q}_i$ = potential demand of group i at the regulated price $\overline{P}_i$ according to the demand function $\overline{Q}_i = f_i\ (\overline{P}_i)$;

Q^s = excess gas supply .

The situation is illustrated in Figure 9-2.

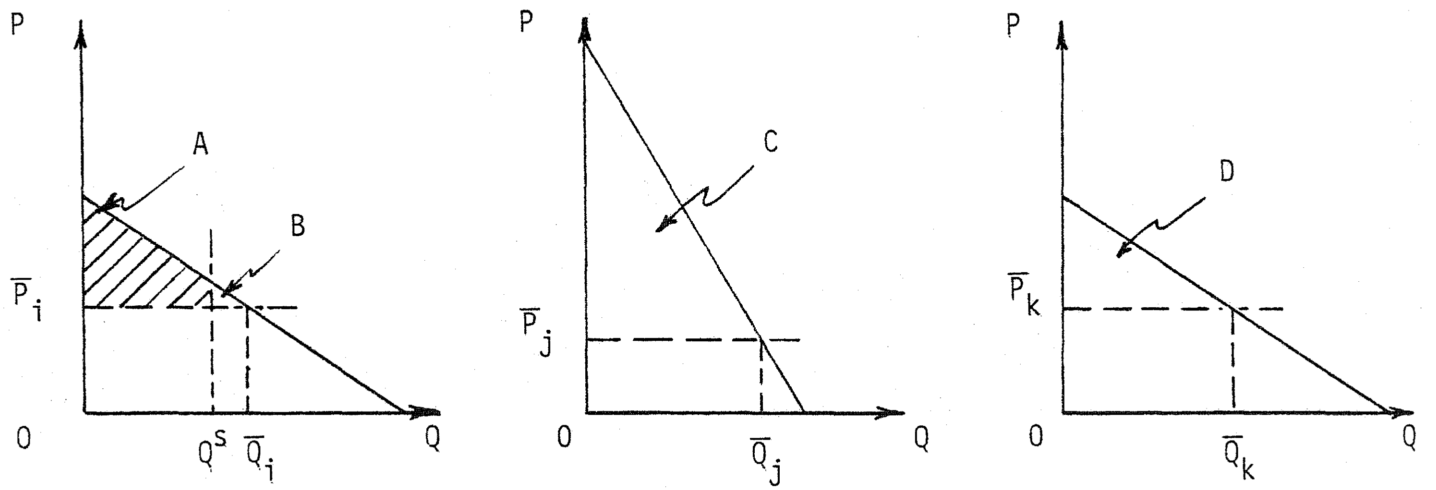

Figure 9-2 Illustration of CASE 1

The net aggregate consumer's surplus associated with this situation is:

$$W_i = \left[\int_0^{Q^S} f^{-1}(P_i)\,dP_i - Q^S\overline{P}_i\right] - \left[\int_{Q^S}^{\overline{Q}_i=f_i^{-1}(\overline{P}_i)} f^{-1}(P_i)\,dP_i - (\overline{Q}_i - Q^S)\,\overline{P}_i\right]$$

$$- \left[\int_0^{\overline{Q}_j=f_j^{-1}(\overline{P}_j)} f_j^{-1}(P_j)\,dP_j - \overline{Q}_j\overline{P}_j\right]$$

$$- \left[\int_0^{\overline{Q}_k=f_k^{-1}(\overline{P}_k)} f_k^{-1}(P_k)\,dP_k - \overline{Q}_k\overline{P}_k\right] \qquad (9\text{-}15)$$

In terms of Figure 9-2 , W_1 is equivalent to the area A-B-C-D.

CASE 2: $\overline{Q}_i = Q^S$

This situation is illustrated in Figure 9-3. The net aggregate consumer's surplus associated with this situation is:

$$W_2 = \left[\int_0^{\overline{Q}_i=f_i^{-1}(\overline{P}_i)} f_i^{-1}(P_i)\,dP_i - \overline{Q}_i\overline{P}_i\right]$$

$$- \left[\int_0^{\overline{Q}_j=f_j^{-1}(\overline{P}_j)} f_j^{-1}(P_j)\,dP_j - \overline{Q}_j\overline{P}_j\right]$$

$$- \left[\int_0^{\overline{Q}_k=f_k^{-1}(\overline{P}_k)} f_k^{-1}(P_k)\,dP_k - \overline{Q}_k\overline{P}_k\right] \qquad (9\text{-}16)$$

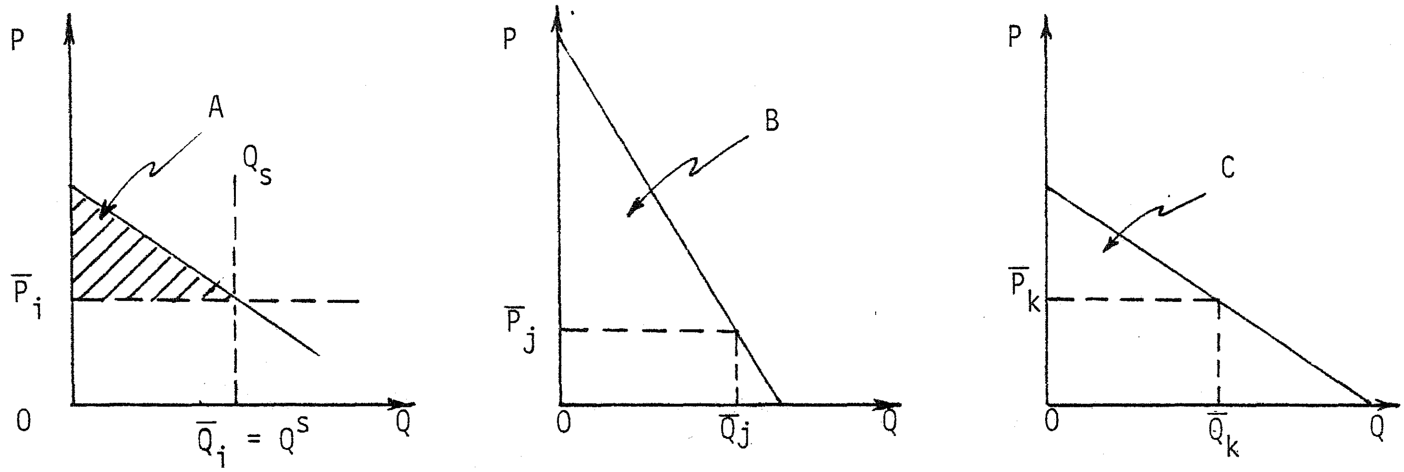

Figure 9-3 Illustration of Case 2

In terms of Figure 9-3, W_2 is equivalent to the area A-B-C.

Case 3: $\overline{Q}_i < Q^S$, $\overline{Q}_j > (Q^S - \overline{Q}_i)$

This situation is illustrated in Figure 9-4. The net aggregate consumer's surplus associated with this situation is:

$$
\begin{aligned}
W_3 \quad = & \left[\int_0^{\overline{Q}_i = f_i^{-1}(\overline{P}_i)} f_i^{-1}(P_i)\,dP_i - \overline{Q}_i\overline{P}_i \right] \\
+ & \left[\int_0^{Q^S - \overline{Q}_i} f_j^{-1}(P_j)\,dP_j - (Q^S - \overline{Q}_i)\overline{P}_j \right] \\
- & \left[\int_{Q^S - \overline{Q}_i}^{\overline{Q}_j = f_j^{-1}(\overline{P}_j)} f_j^{-1}(P_j)\,dP_j - [\overline{Q}_j - (Q^S - \overline{Q}_i)]\overline{P}_j \right] \\
- & \left[\int_0^{\overline{Q}_k = f_k^{-1}(\overline{P}_k)} f_k^{-1}(P_k)\,dP_k - \overline{Q}_k\overline{P}_k \right]
\end{aligned}
\qquad (9\text{-}17)
$$

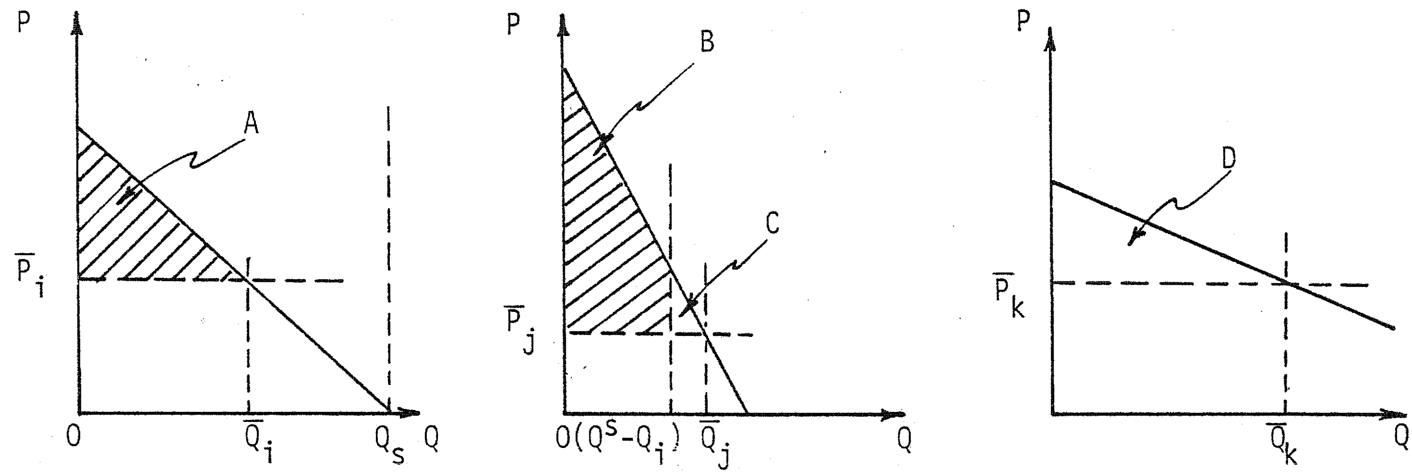

Figure 9-4 Illustration of CASE 3

In terms of Figure 9-4, W_3 is equivalent to the area A+B-C-D.

Case 4: $\overline{Q}_i < Q^S$, $\overline{Q}_j = (Q^S - \overline{Q}_i)$

This situation is illustrated in Figure 9-5. The net aggregate consumer's surplus associated with this situation is:

$$W_4 = \left[\int_0^{\overline{Q}_i=f_i^{-1}(\overline{P}_i)} f_i^{-1}(P_i)dP_i - \overline{Q}_i\overline{P}_i\right]$$

$$+ \left[\int_0^{\overline{Q}_j=f_j^{-1}(\overline{P}_j)} f_j^{-1}(P_j)dP_j - \overline{Q}_j\overline{P}_j\right]$$

$$- \left[\int_0^{\overline{Q}_k=f^{-1}(\overline{P}_k)} f_k^{-1}(P_k)dP_k - \overline{Q}_k\overline{P}_k\right] \tag{9-18}$$

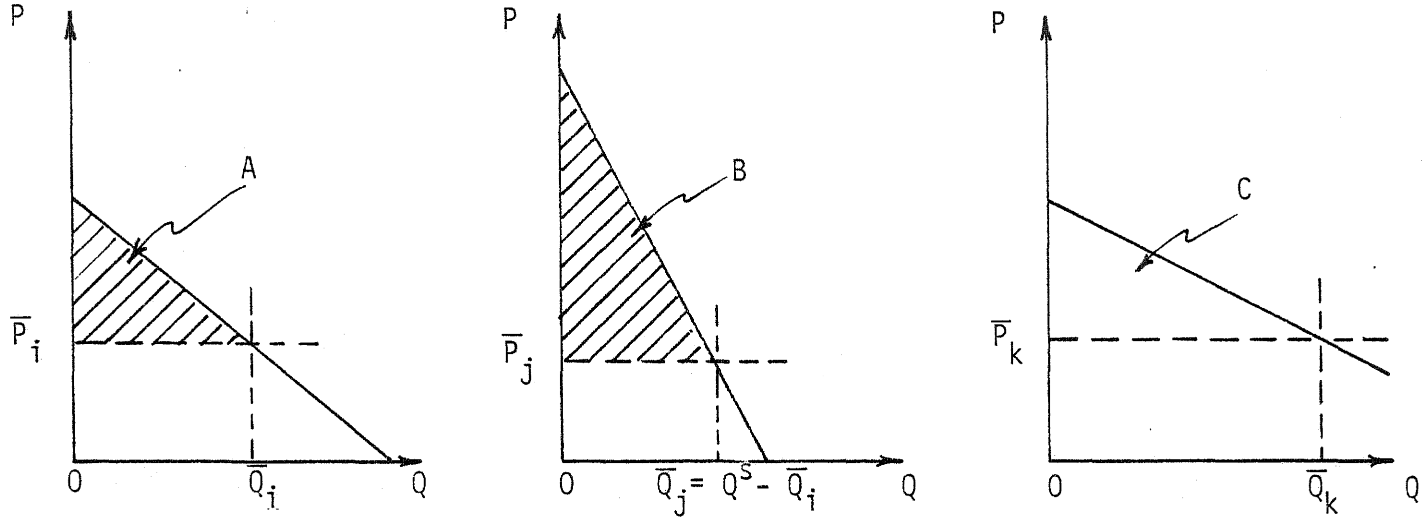

Figure 9-5 Illustration of CASE 4

In terms of Figure 9-5, W_4 is equivalent to the area A+B-C.

Case 5: $\overline{Q}_i < Q^S$, $\overline{Q}_j < (Q^S - \overline{Q}_i)$, and $\overline{Q}_k > (Q^S - \overline{Q}_i - \overline{Q}_j)$

This situation is illustrated in Figure 9-6. The net aggregate consumer's surplus associated with this situation is:

$$
\begin{aligned}
W_5 = & \left[\int_0^{\overline{Q}_i = f_i^{-1}(\overline{P}_i)} f_i^{-1}(P_i)\,dP_i - \overline{Q}_i \overline{P}_i \right] \\
& + \left[\int_0^{\overline{Q}_j = f_j^{-1}(\overline{P}_j)} f_j^{-1}(P_j)\,dP_j - \overline{Q}_j \overline{P}_j \right] \\
& + \left[\int_0^{Q^S - \overline{Q}_i - \overline{Q}_j} f_k^{-1}(P_k)\,dP_k - [(Q^S - \overline{Q}_i - \overline{Q}_j)\overline{P}_k] \right] \\
& - \left[\int_{Q^S - \overline{Q}_i - \overline{Q}_j}^{\overline{Q}_k = f_k^{-1}(\overline{P}_k)} f_k^{-1}(P_k)\,dP_k - [\overline{Q}_k - (Q^S - \overline{Q}_i - \overline{Q}_j)]\overline{P}_k \right]
\end{aligned} \tag{9-19}
$$

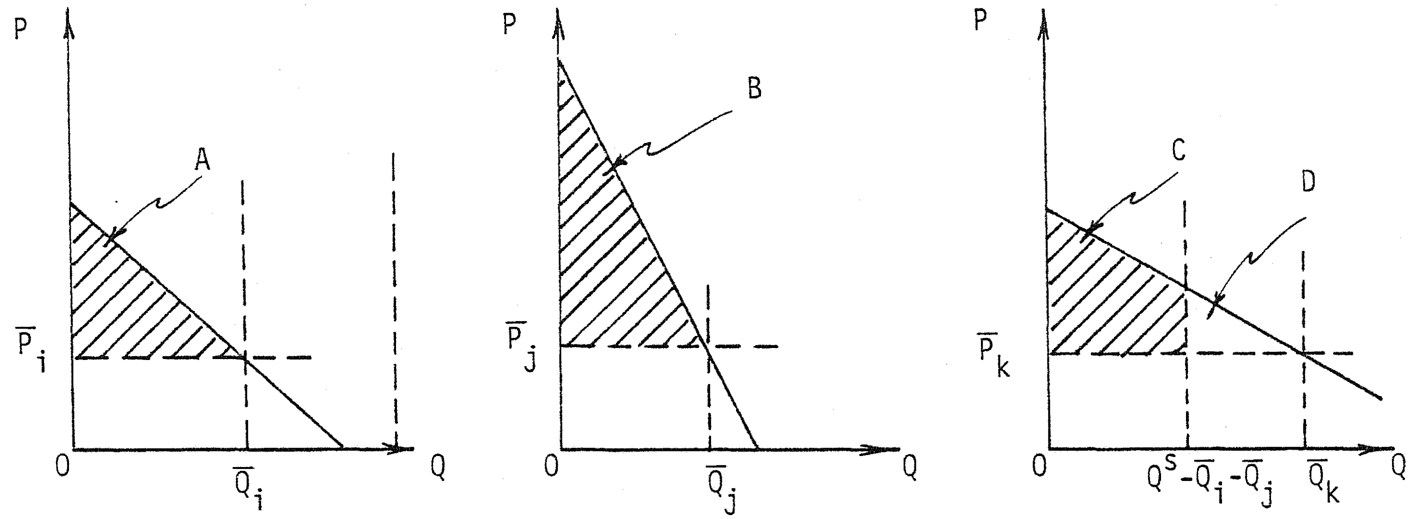

Figure 9-6 Illustration of CASE 5

In terms of Figure 9-6, W_5 is equivalent to the area A+B+C-D.

Case 6: $\overline{Q}_i < Q^S$, $\overline{Q}_j < (Q^S - \overline{Q}_i)$, and $\overline{Q}_k = (Q^S - \overline{Q}_i - \overline{Q}_j)$

The situation is illustrated in Figure 9-7. The net aggregate consumer's surplus is:

$$W_6 = \left[\int_0^{\overline{Q}_i=f_i^{-1}(\overline{P}_i)} f_i^{-1}(P_i)\,dP_i - \overline{Q}_i\overline{P}_i\right]$$

$$+ \left[\int_0^{\overline{Q}_j=f_j^{-1}(\overline{P}_j)} f_j^{-1}(P_j)\,dP_j - \overline{Q}_j\overline{P}_j\right]$$

$$+ \left[\int_0^{\overline{Q}_k=f_k^{-1}(\overline{P}_k)} f_k^{-1}(P_k)\,dP_k - \overline{Q}_k\overline{P}_k\right] \qquad (9\text{-}20)$$

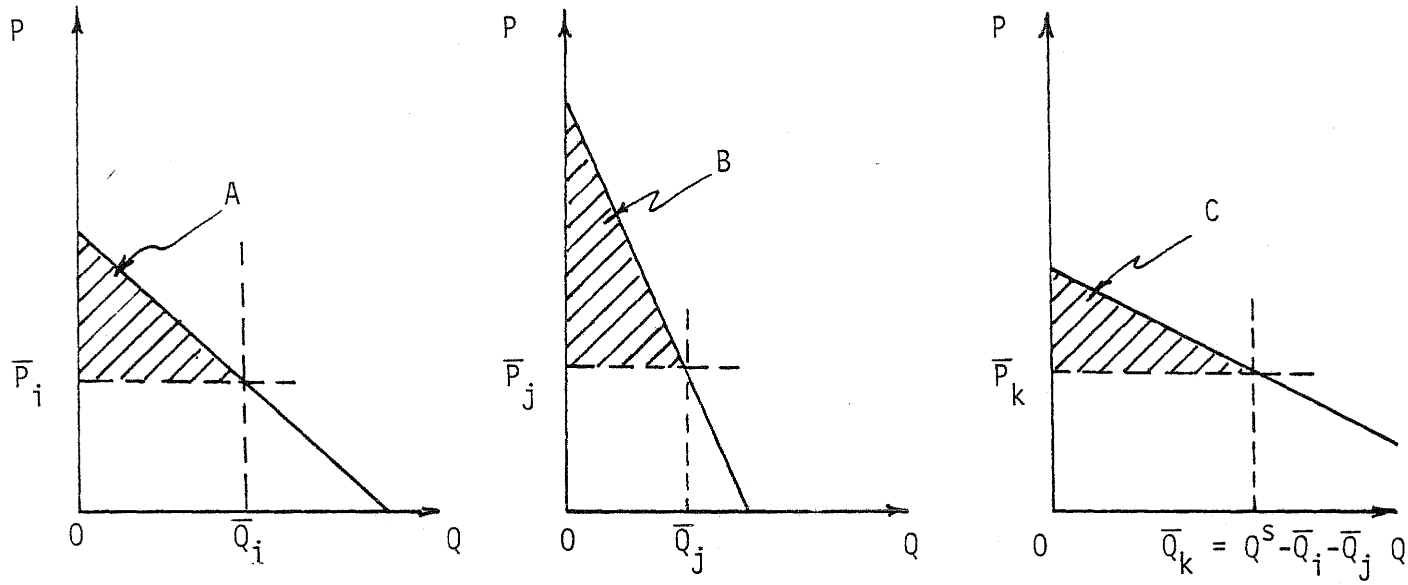

Figure 9-7 Illustration of CASE 6

In terms of Figure 9-7, W_6 is equivalent to the area A+B+C.

It is noteworthy that the above cases are descriptive of welfare gain calculations for one time period only. In fact, however, once an allocation is made during any given year the benefits and costs of that allocation will continue to be felt by the affected individuals as long as relative price changes, changing technology, and changes in preferences do not change the individual's willingness-to-pay for gas and other fuels. Furthermore, the allocation of gas is not performed once for all time. As new excess gas supply appears it is allocated repeatedly to new customers as long as there appears a potential demand for this gas.

Demand Curves Estimation Method

Since the primary welfare calculations that are appropriate for this model are based upon the allocation of newly created excess gas supply to new customers each year, there is a need for demand curves estimated for each year and for each group that potentially could receive the excess gas supply. Long-run demand curves were estimated for residential, commercial, and industrial customers based on the consumption analysis described in Chapter 4. Each demand curve is assumed to be linear between the current demand at the regulated price and that price that is so high that demand is essentially zero.[5] Hence, two points were estimated: current demand and a hypothetical price that would force demand to zero.

In general, a demand curve such as that in Figure 9-8 is estimated on the basis of estimates of points A and B.

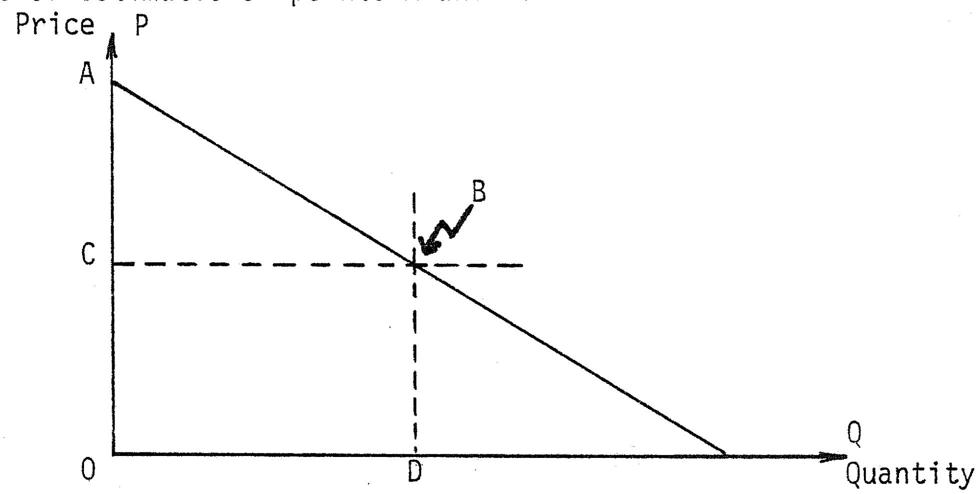

Figure 9-8 Hypothetical Demand Curve

Once points A and B are know a demand curve is expressed as:

$$P = A - \left(\frac{A - C}{D}\right) Q,$$

where:

P = price of gas per Mcf;

A = price of gas at which demand for gas is zero;

C = current price of gas;

D = the quantity of gas demanded at the current price;

$\frac{A-C}{D}$ = the marginal propensity to consume;

Q = quantity of gas, in Mcf.

[5] In fact, the exact formulation of the demand curve can be derived from the market share functions described in Chapter 4. However, it is unlikely that such a tedious computation procedure might bring significant gains in terms of precision in the consumers' surplus evaluation, hence the suggested linear approximation.

In the case of each class of customers points D are estimated directly from the energy market sharing models described in Chapter 4 as the current potential gas demands. The methods of obtaining points A are not as straightforward.

They are obtained on the basis of the assumption that a drop in the gas market share to 5 percent constitutes a signal that gas price is no longer competitive, or that gas price has reached point A. Although it can be argued that 5 percent is not a sufficiently small market share, lack of better market share equations precludes a more precise estimation of points A.

The basis for the residential sector calculation is equation (9-21) fully described in Chapter 4:

$$MSGR_t = 11.059 \exp[-.400(RPIG_{t-1} + 3.5)^2] \tag{9-21}$$

where:

$MSGR_t$ = market share of gas in the residential sector during year t;

$RPIG_t$ = residential sector gas price index during year t.

By setting $MSGR_t$ equal to 5 percent and solving (9-21), the corresponding $RPIG_{t-1}$ is obtained, on the basis of which point A is calculated.

The basis for calculating point A in the commercial sector is equation (9-22), also fully explained in Chapter 4:

$$GCC_t = \left(\frac{\overline{P}_{g,t-1}}{1.2998}\right)^{-.3} \left(\frac{.053\ S_{2t} + 0.191\ S_{3t}}{1 + \left[P_{g,t-1}/P_{r,t-1}\right]^{3.17}}\right) \tag{9-22}$$

where:

GCC_t = potential gas demand per unit of floor space in the commercial sector during year t;

P_{gt} = price of gas during year t;

S_{2t} = the share of new and renovated commercial floor space using type 2 energy system during year t;

S_{3t} = the share of new and renovated commercial floor space using type 3 energy system during year t;

P_{rt-1} = price of oil during year t-1.

The determination of point A implies first the computation of oil and electricity potential demands per unit of floor space in year t, given the prices of year t-1, and then the total potential energy demand per unit of floor space. The next step is to compute 5 percent of this total demand, and to find out which price of gas would lead to such a gas demand. Since equation (9-22) cannot be solved directly, P_{gt} will be obtained by successive approximations.

The basis for the calculation of point A in the industrial sector is equation (9-23), again fully described in Chapter 4:

$$MSGI_t = 0.4146\exp[-.19515(IPIG_{t-1} + 1.6)^2] \qquad (9\text{-}23)$$

where:

$MSGI_t$ = market share of gas in the industrial sector during year t;

$IPIG_t$ = industrial sector gas price index during year t.

Once $IPIG_t$ corresponding to a 5 percent market share is calculated, the index is broken down to obtain point A.

The End-Use Efficiency Index

Knowledge of points A and B, depicted in Figure 9-8, permits the calculation of net aggregate consumer's surplus according to Cases 1-6 described above. The benefits and costs that accrue over the years to customers who "requested" new service during year t are assumed to remain unchanged during each year. Thus, it is assumed that :

$$W_t^t = W_{t+1}^t = \ldots. = W_\tau^t = \ldots = W_T^t = W^t \qquad (9\text{-}24)$$

where:

W_τ^t = the net aggregate consumer's surplus of customers who requested new service during year t, accruing to them in year τ (τ = t$\rightarrow$ T).

This assumption is partly justified by the fact that the consumer's surplus calculations are based on long-run demand curves. The additional complexity associated with the use of a dynamic social welfare model does not seem to offer additional real insights into the regulatory incentives to provide new gas service.

The present value of this stream of net aggregate consumer's surplus is given by:

$$WT^t = W^t \sum_{\tau=t}^{T} \frac{1}{(1+\rho)^{\tau}} \tag{9-25}$$

where:

ρ = social discount rate.

The literature on the choice of a propoer discount rate is voluminous. There is a myriad of arguments for the choice of higher and lower discount rates.[6] In the present effort 8% was chosen.

Based on equation (9-25) the end-use efficiency index is calculated as:

$$EUEI = \sum_{t}^{T} WT^t \tag{9-26}$$

where:

EUEI = end-use efficiency index.

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[6] For a concise list of arguments see Peter G. Sassone and William A. Schaffer, Cost-Benefit Analysis, A Handbook (New York: Academic Press, 1978), Chapter 6.

The Impact of Hook-Up Policies on the Allocation of Resources

The end-use efficiency index represents a partial description of the efficiency with which resources are allocated as a result of new service policies. In fact, it is descriptive of the efficiency with which resources are consumed only. An equally important determinant of the overall efficiency of resource allocation is the efficiency with which resources are transformed into consumables. It is typically termed production efficiency.

In a perfectly competitive environment, an environment in which producers are subjected to rivalry from each other, highest production efficiency is assured by the survival of those who combine resources most efficiently. It is generally claimed that within a regulated environment the absence of rivalry has led to the partial decline in the extent to which production efficiency is sought and achieved. In the economic literature the lack of incentives and the resulting misallocations have become known as the "Averch-Johnson effects."

In the absence of a perfectly competitive environment, the only means for measuring the extent to which production efficiency has been achieved is to compare an idealized production process to the actual. In the present effort the lack of resources prohibits such an exercise. Instead, information from the Financial Analysis model described in Chapter 8 will be used to assess the extent to which maximum "producer's surplus" has been attained.

The notion of producer's surplus is symmetric to the notion of consumer's surplus. The extent to which a producer is willing to sell his products depends upon his marginal cost. The supply curve, illustrated in Figure 9-9, depicts the quantity of a good that a producer is willing to sell at various prices of the good. Thus, at price P_i the producer would be willing to sell Q_i of the commodity and yet, because the price is regulated at $\overline{P}$, if he were to sell only Q_i he would have realized an unusual profit of $(\overline{P} - P_i)$ on the last unit sold. The shaded area in Figure 9-9 depicts all such unusual profits, termed producer's surplus.

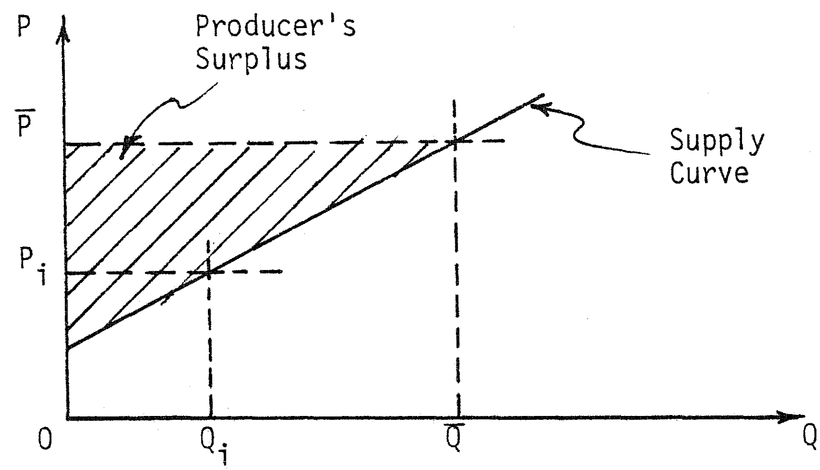

Figure 9-9 Illustration of Producer's Surplus

In the present research an indirect measure of the aggregate value of producer's surplus is given by the total revenues of a gas distribution company less its total cost of providing its service. It is given by the company's Actual Operating Income. Thus,

$$PEI = \sum_{t=1}^{T} \frac{INCAT_t}{(1 + \rho)^t} \tag{9-27}$$

where:

PEI = production efficiency index;

$INCAT_t$ = income after taxes during year t.

On the basis of this calculation and the previous estimate of the end-use efficiency index, the aggregate efficiency index is defined as the sum of the two, or:

$$AEI = EUEI + PEI \tag{9-28}$$

where:

AEI = aggregate efficiency index.

Fairness and New Hook-up Policies

In a previous report to the PUCO it was argued that the concept of fairness is at once both difficult and vague.[6] Consequently, this evaluation criterion has received a variety of interpretations, each of which suits a particular interest group. Bonbright delineated four standards of fairness that are often applied in practice; these are good faith or reasonable expectations, ability to pay, notional equality, and the compensation principle. These are further described as follows:[7]

1 Good faith or reasonable expectation standards refer to what may be called a moral obligation to live up to previous commitments. Such standards are typically held by customers who wish to maintain the low rates to which they have become accustomed. Suppose, for example, that customers were led to buy electric appliances on the basis of low electric rates. They might argue that since they made these purchases on the expectation of low rates, those rates should be maintained, even though conditions have changed. Bonbright points out, however, that, "As a matter of legal doctrine, such an argument has dubious standing in view of the generally accepted principle that public utility rates are subject to revision if and when they become 'unreasonable.'"

2. Ability-to-pay standards are based on egalitarian ideas of social justice and are used to "support whatever deviations from cost can feasibly be applied in order to minimize burdens falling on those customers with lower income." Use of this standard essentially results in redistributing income and consequently represents what Bonbright refers to as a "quasi-tax." Bonbright further points out that "The ability-to-pay principle cannot be carried beyond severe limits, since any attempt to do so would lead to a breakdown in the other functions of utility rates."

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6 Daniel Z. Czamanski, et al., Electricity Pricing Policies for Ohio, PUCO, Policy Analysis Series Number 7, October 1977, pp. 20-22.

7 The following discussion is based on J. C. Bonbright, Principles of Public Utility Rates, Columbia University Press, New York, 1961, especially Chapter VIII, and repeats a summary contained in a previous OSU report to PUCO entitled, "Alternative Policies for Pricing Non-Historic Gas," 1975, pp. 26-27.

3. Notional equality standards are based on the popular impression that uniform rates for the same kind of service are fair despite differences in the costs of delivery. In the context of natural gas, for example, the temptation to apply this standard may be great because even though the costs of historic and non-historic gas are quite different the service provided is the same. Bonbright, however, argues that, "This tendency is really a distored reflection of an income-distributive standard," (i.e., ability to pay). "It certainly fails to accord with any of the more general theories of proper income distribution. Instead, it accepts a specious egalitarianism."

4. The compensation standard is based on the idea that the payment of the consumer to the producer should offset or counterbalance the cost incurred by the producer in delivering the service. Under this standard, rates are not designed to reflect egalitarian principles to any degree.

In terms of new gas hook-ups and the allocation of excess gas supply there are at least three implications of the above. First, based on the first consideration alone those already consuming gas should not be curtailed in the future in order to supply the gas needs of newly connected customers. Secondly, the capacity and other costs associated with the connection of new customers should be borne by these new customers and should not be spread equally over all Mcf's of gas sold by the company. And thirdly, there is an unclear implication associated with the fairness objective concerning who should be connected to the system. As long as natural gas price remains regulated by the Federal Energy Regulatory Commission (FERC), there is an economic gain associated with the priviledge of being able to consume it. Allocation of excess gas supply on the basis of end-use efficiency considerations alone may result in an undesirable distribution of these economic gains.

In order to assess the desirability of hook-up policies in terms of the distribution of such gains, however, there is a need for information concerning customers' income. No such data is currently available and no such assessment is possible within this model. Partial information concerning potential impacts will be gained from the following price indexes:

$$ACPDI_i = \frac{1}{T} \sum_{t=1}^{T} \frac{P_{git}}{P_{cit}} \quad ; \tag{9-29}$$

$$AOPDI_i = \frac{1}{T} \sum_{t=1}^{T} \frac{P_{git}}{P_{oit}} \quad ; \tag{9-30}$$

$$AEPDI_i = \frac{1}{T} \sum_{t=1}^{T} \frac{P_{git}}{P_{eit}} \quad ; \tag{9-31}$$

where:

$ACPDI_i$ = average coal price differential index for customer class i;
$AOPDI_i$ = average oil price differential index for customer class i;
$AEPDI_i$ = average electricity price differential index for customer class i;
P_{git} = price of gas per MMBTU for customer class i during year t;
P_{cit} = price of coal per MMBTU for customer class i during year t;
P_{oit} = price of oil per MMBTU for customer class i during year t;
P_{eit} = price of electricity per MMBTU for customer class i during year t.

Regional Development Impact of Hook-up Policies

The regulatory policies of FERC with respect to natural gas prices have resulted in a perpetual imbalance between gas prices in non-producing states and the prices of other fuels per equivalent Btu. Because of this competitive advantage that natural gas possesses, the spatial distribution of gas consumption priviledges may be viewed as a tool of growth management policies. For example, a gas hook-up policy that removes the ban on inner city hook-ups while maintaining such a ban elsewhere would lead to a possible increase in housing starts and potential growth if either population, jobs, or both migrate into the inner city. Since examination of regional development impacts would constitute a major study on its own, no such impacts are evaluated within this study directly.

CHAPTER 10

SYNTHESIS OF THE SIMULATION MODEL

The purpose of this chapter is to present a synthesis of the gas distribution system model, the various components of which have been described in the previous chapters. In the first section, the general structure and functioning of the model are described. In the next section, the structure of the computer program of the model is presented. In the final section, each component of this program is described in terms of its inputs, outputs and references to the mathematical equations used.

An Overview of the Simulation Approach

The model used for the analysis is an engineering-econometric-regulatory simulation model of a regional gas distribution system. It is a mathematical representation of a set of behavioral and accounting relationships and optimization rules that characterize the real world system. Although not all the complex real-world social, political, environmental, institutional and economic interactions can be represented in detail in the model, the integration of the most important elements of the system, however, guarantees that a robust and consistent tool has been obtained. Indeed, the major, if any, contribution of the approach does not stem so much from the way any of the individual portions of the model are structured, but rather from the consistency and scope derived from the integration of interrelated sub-models representing the various components of the gas distribution system.

Simulation models are most frequently used as forecasting tools. With their help decision-makers can anticipate the repercussions of alternative assumptions concerning uncertain future events that they cannot control and alternative policies that they can adopt. By reference to regulatory objectives, the comparison of forecasted repercussions associated with alternative assumptions enables a choice of the preferred policy. (See Figure 10-1)

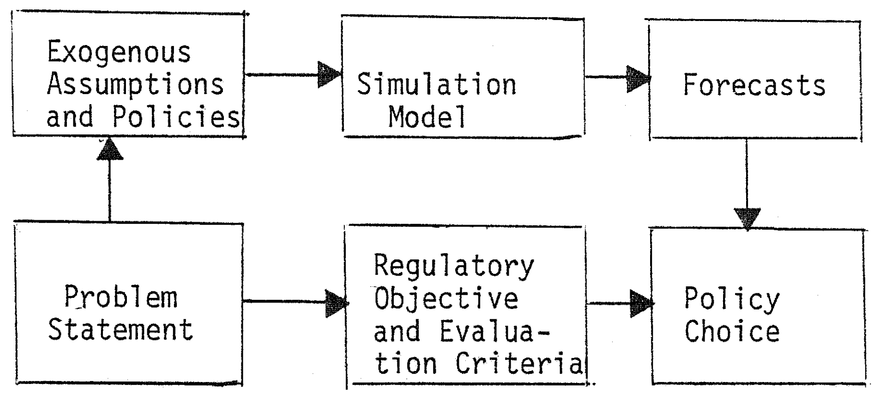

Figure 10-1 The Role of Simulation Models in Policy Choice

A broad flow diagram of the simulation model is shown in Figure 10-2. The driving force of the simulation model is a set of exogenously supplied data and expansion policies.

The exogenous data are indicative of events that are outside the sphere of influence of state regulatory bodies. These data are of four types: (1) forecasts of socio-economic changes, (2) technological forecasts, (3) forecasts of energy supply in terms of quantities and prices, and (4) weather forecasts. This information is the basis on which patterns of gas requirements and sales are forecasted. Socio-economic forecasts including demographic characteristics, such as household size, and economic characteristics, such as industrial employment and commercial floor area, are used to determine numbers and types of potential gas customers. Energy supply data, which include quantities and prices of various energy forms, are used to examine the utility's ability to serve and the willingness of customers to buy gas, as opposed to other forms of energy. Weather data are used to forecast potential monthly heating loads. These various data have been described in Chapters 2, 3, 4, and 7.

The expansion policies, the repercussions of which are to be analyzed through the model, have been described in Chapter 6. They can be considered as exogenous data to the expansion analysis component of the model.

Based on the above-mentioned socio-economic forecasts, annual increments in the number of potential energy consumers by spatial divisions of the service area are calculated. These forecasts, together with exogenously supplied forecasts of relative prices of various energy forms and

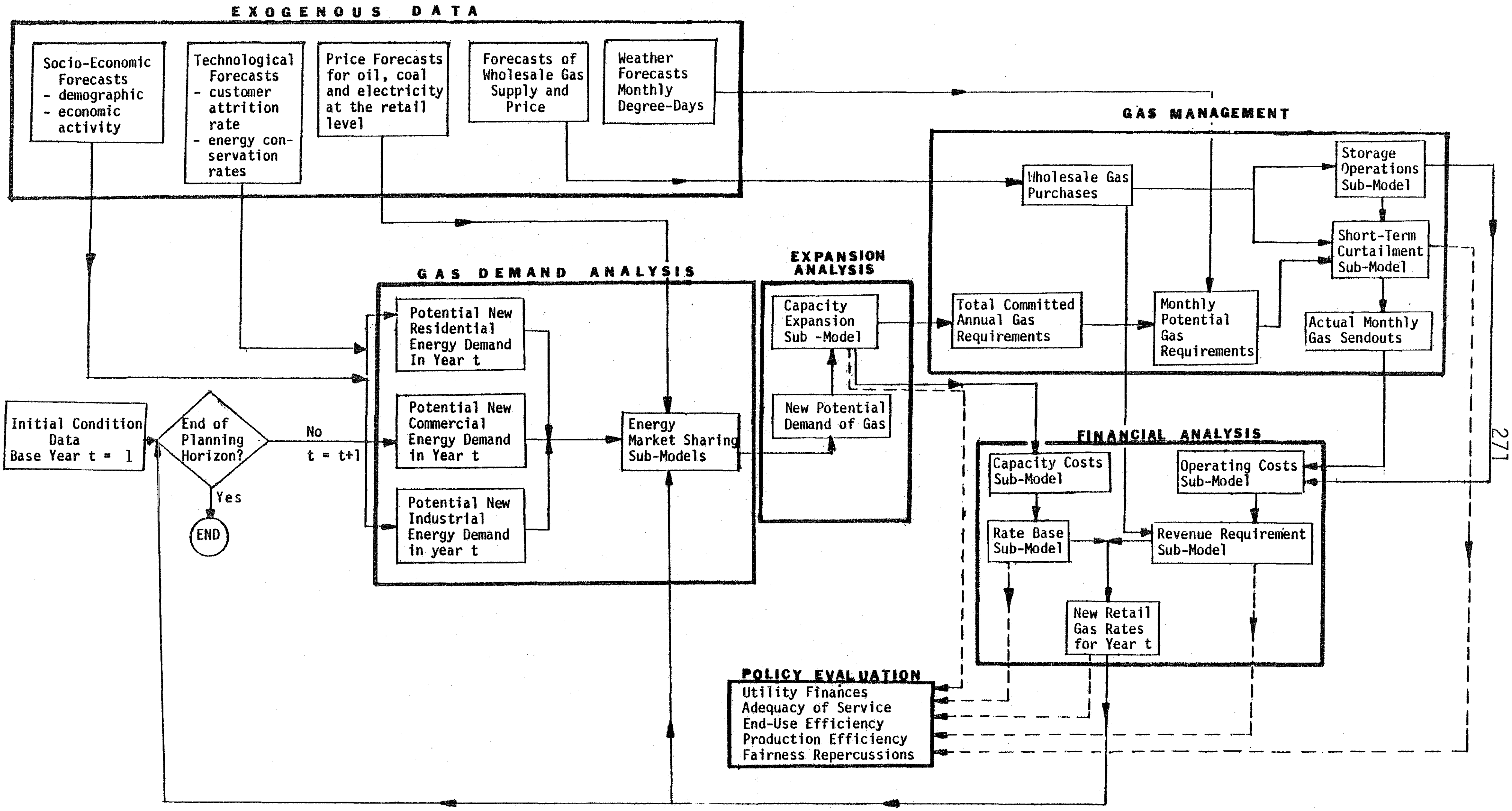

FIGURE 10-2: STRUCTURE OF THE SIMULATION MODEL

retail prices of gas calculated by the model, are the basis for calculating the potential demand for natural gas by class of customers through appropriate "market sharing" models. The various aspects of this analysis of gas demand have been described in Chapter 4.

Output of the consumption analysis serves as input to the capacity expansion analysis, through which decisions are made concerning the extent of new customer hook-ups. Inasmuch as the supply forecasts indicate that no excess demand exists, natural gas may be committed to satisfy the forecasted growth in potential demand. However, the extent to which new customers are hooked-up to the system is circumscribed by the tested expansion policy. Existing and new customers' demands constitute the basic service commitment of the company. The expansion analysis has been described in Chapter 6.

The company's committed requirements, together with randomly selected weather scenarios, serve as inputs into the gas management model. These requirements, together with data on gas availability to the company from its transmission company(s) and storage, are the basis for the calculation of monthly gas sendouts, curtailments by class, and inputs to and withdrawals from storage. Such calculations are described in Chapter 7.

The next set of calculations comprises the financial analysis. The purpose of this analysis is to simulate calculations that are typically made in the context of rate cases. Through an engineering-economic analysis, a capacity cost model calculates the capacity costs associated with system growth. Likewise, gas sendouts and storage deliveries data are used to calculate operations and maintenance costs in the corresponding model. These cost models have been described in Chapter 5. Based upon these cost data and on exogenously supplied data on such variables as allowed rate of return, depreciation rates, and tax rates, the gas company's rate base, income deficit, and new gas rates for each class of customers are calculated next. The new gas rates, which should enable the company to earn its allowed operating income, are used to augment the exogenously obtained energy supply data used in the consumption analysis during the next period.

The previously described cycle of computations is then repeated while, of course, integrating the results derived during the previous cycle. This iterative process is repeated until the end of the planning horizon is reached. The planning horizon extends from year 1978 to year 2000.

The last set of calculations make up the policy evaluation model. It includes the calculation of criteria related to utility finances, adequacy of service, efficiency in the allocation of resources, and distributive impacts and fairness. These criteria have been described in Chapter 9.

The General Structure of the Computer Program of the Simulation Model

The sequence of computations described in the previous section is carried out by a digital computer, under the instructions contained in a program. The complete listing of this program is presented in Appendix J. The organization of this program is outlined in Figure 10-3. It is composed of:

- a main program, where the basic exogenous data are either read from data cards or derived by calculations, and where various sub-programs (or subroutines) are called in sequence;
- a set of subroutines, each corresponding to a specific set of computations.

The simulation process itself involves the operations of 14 sub-programs interrelated as indicated in Figure 10-3:

- Subroutine SHRES involves the computation of residential energy market shares exclusively; it is based on the procedure described in Chapter 4.
- Subroutine RESIDC involves the determination of the potential demand of gas in the residential sector and the updating of the stocks of residential customers; it is based on the procedure described in Chapter 4.
- Subroutine COMMEC involves the determination of the potential demand of gas in the commercial sector; it is based on the procedure described in Chapter 4.
- Subroutine SHIND involves the computation of industrial energy market shares exclusively; it is based on the procedure described in Chapter 4.
- Subroutine INDUSC involves the determination of the potential demand of gas in the industrial sector; it is based on the procedure described in Chapter 4.

- Subroutine CAPEXP involves the determination of the new gas customers to be connected to the system, and their corresponding gas loads; it is based on the procedure described in Chapter 6.
- Subroutine WEATHR involves the random generation of monthly degree-days; it is based on the procedure described in Chapter 7.
- Subroutine GASALL involves the determination of monthly potential gas requirements, wholesale purchases, deliveries to and withdrawals from storage; it is based on the procedure described in Chapter 7.
- Subroutine SUPCUR involves the determination of monthly curtailment rates by customer classes; it is based on the procedure described in Chapter 7.
- Subroutine CAPCST and OMCOST involve the determination of capacity and operation and maintenance costs, respectively; they are based on the procedure described in Chapter 5.
- Subroutines RATBAS, INCOME and NEWRAT involve the determination of the utility annual rate base, income requirements, and new rates enabling the utility to earn its allowed operating income; they are based on the procedure described in Chapter 8.

Once the simulation computations have been iterated over the planning horizon, various results are used to compute the evaluation criteria in subroutine CRITER. Various simulation results and evaluation criteria are then printed out through subroutine LIST.

Description of the Exogenous Data and the Computer Subroutines

The purpose of this section is to describe, in Tables 10-1 through 10-16 the exogenous data used in the computer program, as well as the structure of each of its subroutines, including its input variables, output variables, and a reference to the equations used in this subroutine. The origin and destinations of the variables are also included.

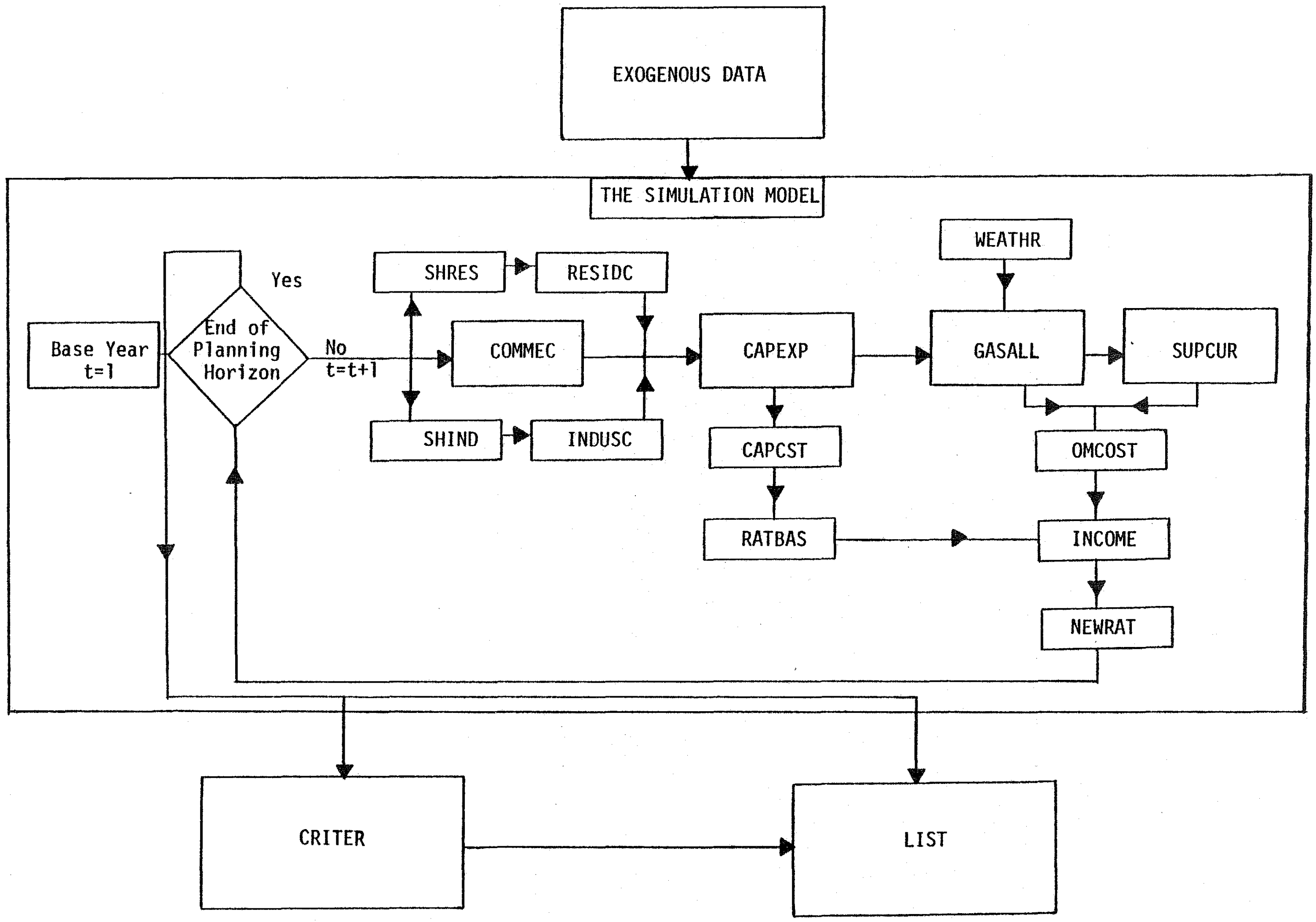

Figure 10-2 Structure of the Computer Program of the Simulation Model

Table 10-1 Exogenous Data

Variable	Definitions
	BASE YEAR DATA
$PRGR_{r1}$ $(r=1\to5)$	Residential price of gas in division r
$PROR_{r1}$ $(r=1\to5)$	Residential price of oil in division r
$PRER_{r1}$ $(r=1\to5)$	Residential price of electricity in division r
$PRGC_{r1}$ $(r=1\to5)$	Commercial price of gas in division r
$PROC_{r1}$ $(r=1\to5)$	Commercial price of oil in division r
$PREC_{r1}$ $(r=1\to5)$	Commercial price of electricity in division r
$PRGI_{r1}$ $(r=1\to5)$	Industrial price of gas in division r
$PROI_{r1}$ $(r=1\to5)$	Industrial price of oil in division r
$PRCI_{r1}$ $(r=1\to5)$	Industrial price of coal in division r
WGS_1	Maximum wholesale gas supply
WGP_1	Average wholesale gas price
$TGCSA_{r1}$ $(r=1\to5)$	Total number of residential gas customers in division r within serviced areas
$TNGCSA_{r1}$ $(r=1\to5)$	Total number of non-gas residential customers in division r within serviced areas
$TNGCNS_{r1}$ $(r=1\to5)$	Total number of non-gas residential customers in division r within non-serviced areas
ATRGB	Base attrition rate for residential gas customers
ATROB	Base attrition rate for non-gas residential customers
CONSVR	Annual residential energy conservation rate
$RGCRAT_1$	Average gas consumption per residential customer
$PECSA_{r1}$ $(r=1\to5)$	Number of potential residential energy customers in division r within serviced areas (assumed equal to zero)
$PECNSA_{r1}$ $(r=1\to5)$	Number of potential residential energy customers in division r within non-serviced areas (assumed equal to zero)
$NGCSA_{r1}$ $(r=1\to5)$	Number of newly connected residential gas customers in division r within serviced areas (assumed equal to zero)
$NGCNSA_{r1}$ $(r=1\to5)$	Number of newly connected residential gas customers in division r within non-serviced areas (assumed equal to zero)
$TCDR_{r1}$ $(r=1\to5)$	Total cumulated committed gas requirement in division r by residential customers

Table 10-1 Exogenous Data (cont)

Variable		Definitions
$SHGR_{r1}$	($r=1\to5$)	Residential gas market share in division r
$SHOR_{r1}$	($r=1\to5$)	Residential oil market share in division r
$SHER_{r1}$	($r=1\to5$)	Residential electricity market share in division r
CFA_{r1}	($r=1\to5$)	Commercial floor space in division r
ATCB		Base attrition rate for commercial gas customers
$CGCRAT_1$		Average gas consumption per commercial customer
$TCDC_{r1}$	($r=1\to5$)	Total cumulated committed gas requirement in division r by commercial customers
$TENCI_{r1}$	($r=1\to5$)	Total industrial energy requirement in division r
CONSVI		Annual industrial energy conservation rate
ATIB	($r=1\to5$)	Base attrition rate for industrial gas customers
$IGCRAT_1$	($r=1\to5$)	Average gas consumption per industrial customer
$TCDI_{r1}$	($r=1\to5$)	Total cumulated committed gas requirement in division r by industrial customers
$SHGI_{r1}$	($r=1\to5$)	Industrial gas market share in division r
$SHOI_{r1}$	($r=1\to5$)	Industrial oil market share in division r
$SHCI_{r1}$	($r=1\to5$)	Industrial coal market share in division r
STCAP		Certified storage capacity
$GSTORD_{2,1}$		Amount of gas in storage at the beginning of the first month of year 2 (the year of effective start of the simulation)
$RSTOR_{2,1}$		Storage saturation rate at the beginning of the first month of year 2
$NETPIS_1$		Net plant in service at the end of year 1
$TAPDAD_1$		Accumulated provision for depreciation, amortization and depletion at the end of year 1
$PISBEG_2$		Plant in service at the beginning of year 2
ATPIS		Attrition rate of plant in service
		METEOROLOGICAL DATA
$DDH_{th,m}$	$\begin{pmatrix} th=1\to25 \\ m=1\to12 \end{pmatrix}$	Historical degree-days for year th and month m
$DDMIN_{th}$	($th=1\to25$)	Lower limit of the frequency interval corresponding to year th
$DDMAX_{th}$	($th=1\to25$)	Upper limit of the frequency interval corresponding to year th

Table 10-1 Exogenous Data (cont)

BASIC FORECAST DATA		
$TPOP_{rt}$	$\binom{r=1\to5}{t=1\to23}$	Total population in division r during year t
$BPOP_{rt}$	"	Total population in division r during year t within the areas served by the distribution network in year 1
HS_{rt}	"	Household size in division r during year t
$ICOMGR_{rt}$	"	Commercial floor space growth index in division r during year t
$IINDGR_{rt}$	"	Total industrial energy requirement growth index in division r during year t
$IWGS_t$	$(t=1\to23)$	Maximum wholesale gas supply growth index during year t
$IWGP_t$	$(t=1\to23)$	Average wholesale gas price growth index during year t
$IPROR_t$	$(t=1\to23)$	Residential price of oil growth index during year t
$IPRER_t$	$(t=1\to23)$	Residential price of electricity growth index during year t
$IPROC_t$	$(t=1\to23)$	Commercial price of oil growth index during year t
$IPREC_t$	$(t=1\to23)$	Commercial price of electricity growth index during year t
$IPROI_t$	$(t=1\to23)$	Industrial price of oil growth index during year t
$IPRCI_t$	$(t=1\to23)$	Industrial price of coal growth index during year t
ALLROR		Allowed rate of return
DERIVED FORECAST DATA		
CFA_{rt}	$\binom{r=1\to5}{t=1\to23}$	Commercial floor space in division r during year t
$TENCI_{rt}$	"	Total industrial energy requirement in division r during year t
$PROR_{rt}$	"	Residential price of oil in division r during year t
$PRER_{rt}$	"	Residential price of electricity in division r during year t
$PROC_{rt}$	"	Commercial price of oil in division r during year t
$PREC_{rt}$	"	Commercial price of electricity in division r during year t
$PROI_{rt}$	"	Industrial price of oil in division r during year t
$PRCI_{rt}$	"	Industrial price of coal in division r during year t
WGS_t	$(t=1\to23)$	Maximum wholesale gas supply in year t
WGP_t	$(t=1\to23)$	Average wholesale gas price in year t

Table 10-1 Exogenous Data (cont)

EQUATIONS USED FOR DERIVED FORECASTED DATA	
Chapter	Number
4	(4-40); (4-53) → (4-55)
7	(7-17)

Table 10-2 Inputs, Outputs, and Equations of Subroutine SHRES - Year t

INPUTS		
Variable	Definition	Origin
$SHGR_{rt-1}$ (r=1→5)	Residential gas market share in division r during year (t-1)	SHRES (t-1)
$SHOR_{rt-1}$ (r=1→5)	Residential oil market share in division r during year (t-1)	SHRES (t-1)
$SHER_{rt-1}$ (r=1→5)	Residential electricity market share in division r during year (t-1)	SHRES (t-1)
$PRGR_{rt-1}$ (r=1→5)	Residential price of gas in division r during year (t-1)	NEWRAT (t-1)
$PROR_{rt-1}$ (r=1→5)	Residential price of oil in division r during year (t-1)	Exogenous data
$PRER_{rt-1}$ (r=1→5)	Residential price of electricity in division r during year (t-1)	Exogenous data
OUTPUTS		
Variable	Definition	Destination
$SHGR_{rt}$ (r= 1→5)	Residential gas market share in division r during year t	RESIDC (t), CRITER LIST
$SHOR_{rt}$ (r= 1→5)	Residential oil market share in division r during year t	CRITER, LIST
$SHER_{rt}$ (r= 1→5)	Residential electricity market share in division r during year t	CRITER, LIST
EQUATIONS		
Chapter	Number	
4	(4-1) → (4-11)	

Table 10-3 Inputs, Outputs, and Equations of Subroutine RESIDC - Year t

INPUTS		
Variable	Definition	Origin
ATRGB	Base attrition rate for residential gas customers	Exogenous data
ATROB	Base attrition rate for non-gas residential customers	Exogenous data
CONSVR	Annual residential energy conservation rate	Exogenous data
$TPOP_{rt-1}$ $(r=1\rightarrow5)$	Total population in division r during year (t-1)	Exogenous data
$TPOP_{rt}$ $(r=1\rightarrow5)$	Total population in division r during year t	Exogenous data
HS_{rt-1} $(r=1\rightarrow5)$	Household size in division r during year (t-1)	Exogenous data
HS_{rt} $(r=1\rightarrow5)$	Household size in division r during year t	Exogenous data
$TGCSA_{r1}$ $(r=1\rightarrow5)$	Total number of residential gas customers in division r during year 1 (base year) within serviced areas	Exogenous data
$TNGCSA_{r1}$ $(r=1\rightarrow5)$	Total number of non-gas residential customers in division r during year 1 within serviced areas	Exogenous data
$TNGCNS_{r1}$ $(r=1\rightarrow5)$	Total number of non-gas residential customers in division r during year 1 within non-serviced areas	Exogenous data
$TGCSA_{rt-1}$ $(r=1\rightarrow5)$	Total number of residential gas customers in division r during year (t-1) within serviced areas	RESIDC (t-1)
$TNGCSA_{rt-1}$ $(r=1\rightarrow5)$	Total number of non-gas residential customers in division r during year (t-1) within serviced areas	RESIDC (t-1)
$TNGCNS_{rt-1}$ $(r=1\rightarrow5)$	Total number of non-gas residential customers in division r during year (t-1) within non-serviced areas	RESIDC (t-1)
$PECSA_{rt-1}$ $(r=1\rightarrow5)$	Number of potential residential energy customers in division r during year (t-1) within serviced areas	RESIDC (t-1)

Table 10-3 Inputs, Outputs, and Equations of Subroutine RESIDC - Year t (cont)

Variable		Definition	Origin
$PECNSA_{rt-1}$	$(r=1\rightarrow5)$	Number of potential residential energy customers in division r during year (t-1) within non-serviced areas	RESIDC (t-1)
$NGCSA_{rt-1}$	$(r=1\rightarrow5)$	Number of newly connected residential customers in division r during year (t-1) within serviced areas	CAPEXP (t-1)
$NGCNSA_{rt-1}$	$(r=1\rightarrow5)$	Number of newly connected residential customers in division r during year (t-1) within non-serviced areas	CAPEXP (t-1)
$SPOP_{rt-1}$	$(r=1\rightarrow5)$	Population included in serviced areas of division r during year (t-1)	RESIDC (t-1)
$SHGR_{rt-1}$	$(r=1\rightarrow5)$	Residential gas market share in division r during year (t-1)	SHRES (t-1)
$SHGR_{rt}$	$(r=1\rightarrow5)$	Residential gas market share in division r during year t	SHRES (t)

OUTPUTS

Variable		Definition	Destination
$DPSA_{rt-1}$	$(r=1\rightarrow5)$	Population included in newly serviced areas in division r during period (t-1)	LIST
$REXTSA_{rt-1}$	$(r=1\rightarrow5)$	Rate of coverage by the distribution network of non-serviced areas in division r during period (t-1)	LIST
$SPOP_{rt}$	$(r=1\rightarrow5)$	Population included in serviced areas of division r during year t	RESIDC (t+1), LIST
$ATRG_{rt-1}$	$(r=1\rightarrow5)$	Residential gas customers attrition rate in division r during year (t-1)	CAPEXP (t)
$ATRO_{rt-1}$	$(r=1\rightarrow5)$	Non-gas residential customers attrition rate in division r during year (t-1)	LIST (t)
$TGCSA_{rt}$	$(r=1\rightarrow5)$	Total number of residential gas customers in division r during year t within serviced areas	RESIDC (t+1), LIST
$TNGCSA_{rt}$	$(r=1\rightarrow5)$	Total number of non-gas residential customers in division r during year t within serviced areas	RESIDC (t+1), LIST
$TNGCNS_{rt}$	$(r=1\rightarrow5)$	Total number of non-gas residential customers in division r during year t within non-serviced areas	RESIDC (t+1), LIST

Table 10-3 Inputs, Outputs, and Equations of Subroutine RESIDC - Year t (cont)

Variable	Definition	Destination
$PECSA_{rt}$ (r=1→5)	Number of potential residential energy customers in division r during year t within serviced areas	RESIDC (t+1), LIST
$PECNSA_{rt}$ (r=1→5)	Number of potential residential energy customers in division r during year t within non-serviced areas	RESIDC (t+1), LIST
$PGCSA_{rt}$ (r=1→5)	Number of potential residential gas customers in division r during year t within serviced areas	LIST
$PGCNSA_{rt}$ (r=1→5)	Number of potential residential gas customers in division r during year t within non-serviced areas	LIST
$PNDGRS_{rt}$ (r=1→5)	Potential new demand of gas by residential customers in division r during year t within serviced areas	CAPEXP (t), CRITER, LIST
$PNDGRN_{rt}$ (r=1→5)	Potential new demand of gas by residential customers in division r during year t within non-serviced areas	CAPEXP (t), CRITER, LIST

EQUATIONS

Chapter	Number
4	(4-15) → (4-29)

Table 10-4 Inputs, Outputs, and Equations of Subroutine COMMEC - Year t

INPUTS		
Variable	Definition	Origin
CFA_{r1} (r=1→5)	Commercial floor space in division r in year 1	Exogenous data
CFA_{rt-1} (r=1→5)	Commercial floor space in division r in year (t-1)	Exogenous data
CFA_{rt} (r=1→5)	Commercial floor space in division r in year t	Exogenous data
ATCB	Base attrition rate for commercial gas customers	Exogenous data
$PRGC_{rt-1}$ (r=1→5)	Commercial price of gas in division r in year (t-1)	NEWRAT (t-1)
$PROC_{rt-1}$ (r=1→5)	Commercial price of oil in division r in year (t-1)	Exogenous data
$PREC_{rt-1}$ (r=1→5)	Commercial price of electricity in division r in year (t-1)	Exogenous data
OUTPUTS		
Variable	Definition	Destination
ATC_{rt-1} (r=1→5)	Commercial gas customers attrition rate in division r in year (t-1)	CAPEXP (t)
$S1_{rt}$ (r=1→5)	Commercial share of the "all electric" energy technology in division r in year t	CRITER, LIST
$S2_{rt}$ (r=1→5)	Commercial share of the "conventional" energy technology in division r in year t	CRITER, LIST
$S3_{rt}$ (r=1→5)	Commercial share of the "integrated" energy technology in division r in year t	CRITER, LIST
$PNDGC_{rt}$ (r=1→5)	Potential new demand of gas by commercial customers in division r in year t	CAPEXP (t), CRITER, LIST

EQUATIONS	
Chapter	Number
4	(4-30) → (4-36); (4-38); (4-39); (4-41)

Table 10-5 Inputs, Outputs, and Equations of Subroutine SHIND - Year t

INPUTS		
Variable	Definition	Origin
$SHGI_{rt-1}$ $(r=1 \to 5)$	Industrial gas market share in division r during year (t-1)	SHIND (t-1)
$SHOI_{rt-1}$ $(r=1 \to 5)$	Industrial oil market share in division r during year (t-1)	SHIND (t-1)
$SHCI_{rt-1}$ $(r=1 \to 5)$	Industrial coal market share in division r during year (t-1)	SHIND (t-1)
$PRGI_{rt-1}$ $(r=1 \to 5)$	Industrial price of gas in division r during year (t-1)	NEWRAT (t-1)
$PROI_{rt-1}$ $(r=1 \to 5)$	Industrial price of oil in division r during year (t-1)	Exogenous data
$PRCI_{rt-1}$ $(r=1 \to 5)$	Industrial price of coal in division r during year (t-1)	Exogenous data

OUTPUTS		
Variable	Definition	Destination
$SHGI_{rt}$ $(r=1 \to 5)$	Industrial gas market share in division r during year t	INDUSC (t), CRITER, LIST
$SHOI_{rt}$ $(r=1 \to 5)$	Industrial oil market share in division r during year t	CRITER, LIST
$SHCI_{rt}$ $(r=1 \to 5)$	Industrial coal market share in division r during year t	CRITER, LIST

EQUATIONS	
Chapter	Number
4	(4-42) → (4-49)

Table 10-6 Inputs, Outputs, and Equations of Subroutine INDUSC - Year t

INPUTS		
Variable	Definition	Origin
$TENCI_{r1}$ (r=1→5)	Total industrial energy requirement in division r in year 1	Exogenous data
$TENCI_{rt-1}$ (r=1→5)	Total industrial energy requirement in division r in year (t-1)	Exogenous data
$TENCI_{rt}$ (r=1→5)	Total industrial energy requirement in division r in year t	Exogenous data
ATIB	Base attrition rate for industrial gas customers	Exogenous data
$SHGI_{rt}$ (r=1→5)	Industrial gas market share in division r in year t	SHIND (t)
OUTPUTS		
Variable	Definition	Destination
ATI_{rt-1} (r=1→5)	Industrial gas customers attrition rate in division r in year (t-1)	CAPEXP (t)
$PNDGI_{rt}$ (r=1→5)	Potential new demand of gas by industrial customers in division r in year t	CAPEXP (t), CRITER, LIST
EQUATIONS		
Chapter	Number	
4	(4-56)→ (4-58)	

Table 10-7 Inputs, Outputs, and Equations of Subroutine CAPEXP - Year t

INPUTS		
Variable	Definition	Origin
$RGCRAT_1$	Average gas consumption per residential customer in year 1	Exogenous data
$CGCRAT_1$	Average gas consumption per commercial customer in year 1	Exogenous data
$IGCRAT_1$	Average gas consumption per industrial customer in year 1	Exogenous data
CONSVR	Annual residential energy conservation rate	Exogenous data
CONSVI	Annual industrial energy conservation rate	Exogenous data
$PRGC_{r1}$ $(r=1 \rightarrow 5)$	Commercial price of gas in division r in year 1	Exogenous data
$PRGC_{rt-1}$ $(r=1 \rightarrow 5)$	Commercial price of gas in division r in year (t-1)	NEWRAT (t-1)
WGS_t	Maximum wholesale gas supply in year t	Exogenous data
$TCDR_{r1}$ $(r=1 \rightarrow 5)$	Total cumulated committed gas requirement in division r in year 1 by residential customers	Exogenous data
$TCDR_{rt-1}$ $(r=1 \rightarrow 5)$	Total cumulated committed gas requirement in division r in year (t-1) by residential customers	CAPEXP (t-1)
$TCDC_{r1}$ $(r=1 \rightarrow 5)$	Total cumulated committed gas requirement in division r in year 1 by commercial customers	Exogenous data
$TCDC_{rt-1}$ $(r=1 \rightarrow 5)$	Total cumulated committed gas requirement in division r in year (t-1) by commercial customers	CAPEXP (t-1)
$TCDI_{r1}$ $(r=1 \rightarrow 5)$	Total cumulated committed gas requirement in division r in year 1 by industrial customers.	Exogenous data
$TCDI_{rt-1}$ $(r=1 \rightarrow 5)$	Total cumulated committed gas requirement in division r in year (t-1) by industrial customers	CAPEXP (t-1)
$ATRG_{rt-1}$ $(r=1 \rightarrow 5)$	Residential gas customers attrition rate in division r in year (t-1)	RESIDC (t)
ATC_{rt-1} $(r=1 \rightarrow 5)$	Commercial gas customers attrition rate in division r in year (t-1)	COMMEC (t)

Table 10-7 Inputs, Outputs, and Equations of Subroutine CAPEXP - Year t (cont)

Variable	Definition	Origin
ATI_{rt-1} (r=1→5)	Industrial gas customers attrition rate in division r in year (t-1)	INDUSC (t)
$PNDGRS_{rt}$ (r=1→5)	Potential new demand of gas by residential customers in division r during year t within serviced areas	RESIDC (t)
$PNDGRN_{rt}$ (r=1→5)	Potential new demand of gas by residential customers in division r during year t within non-serviced areas	RESIDC (t)
$PNDGC_{rt}$ (r=1→5)	Potential new demand of gas by commercial customers in division r during year t	COMMEC (t)
$PNDGI_{rt}$ (r=1→5)	Potential new demand of gas by industrial customers in division r during year t	INDUSC (t)
	OUTPUTS	
Variable	**Definition**	**Destination**
$BASEDR_{t}$	Base committed gas requirement by residential customers before any new connections at the beginning of year t	LIST
$BASEDC_{t}$	Base committed gas requirement by commercial customers before any new connections at the beginning of year t	LIST
$BASEDI_{t}$	Base committed gas requirement by industrial customers before any new connections at the beginning of year t	LIST
$BASEDT_{t}$	Base committed gas requirement by all customers' classes before any new connections at the beginning of year t	CRITER, LIST
$EXCSUP_{t}$	Total annual excess gas supply at the beginning of year t before any new load has been connected	CRITER, LIST
$NGCSA_{rt}$ (r=1→5)	Number of newly connected residential gas customers in division r during year t within serviced areas	CAPCST (t), LIST RESIDC (t+1)
$NGCNSA_{rt}$ (r=1→5)	Number of newly connected residential gas customers in division r during year t within non-serviced areas	CAPCST (t), LIST RESIDC (t+1)

Table 10-7 Inputs, Outputs, and Equations of Subroutine CAPEXP - Year t (cont)

Variable		Definition	Destination
$NCGC_{rt}$	$(r=1\rightarrow 5)$	Number of newly connected commercial gas customers in division r during year t	CAPCST (t), LIST
$NIGC_{rt}$	$(r=1\rightarrow 5)$	Number of newly connected industrial gas customers in division r during year t	CAPCST (t), LIST
$CNDGRS_{rt}$	$(r=1\rightarrow 5)$	Newly connected residential gas load in division r during year t within serviced areas	CAPCST (t), CRITER, LIST
$CNDGRN_{rt}$	$(r=1\rightarrow 5)$	Newly connected residential gas load in division r during year t within non-serviced areas	CAPCST (t) CRITER, LIST
$CNDGC_{rt}$	$(r=1\rightarrow 5)$	Newly connected commercial gas load in division r during year t	CAPCST (t) CRITER, LIST
$CNDGI_{rt}$	$(r=1\rightarrow 5)$	Newly connected industrial gas load in division r during year t	CAPCST (t) CRITER, LIST
$TCDR_{rt}$	$(r=1\rightarrow 5)$	Total cumulated committed gas requirement in division r during year t residential customers	CAPEXP (t+1) LIST
$TCDC_{rt}$	$(r=1\rightarrow 5)$	Total cumulated committed gas requirement in division r during year t by commercial customers	CAPEXP (t+1) LIST
$TCDI_{rt}$	$(r=1\rightarrow 5)$	Total cumulated committed gas requirement in division r during year t by industrial customers	CAPEXP (t+1) LIST
$TCYDR_{t}$	$(r=1\rightarrow 5)$	Total committed gas requirement by residential customers during year t	GASALL (t) LIST
$TCYDC_{t}$	$(r=1\rightarrow 5)$	Total committed gas requirement by commercial customers during year t	GASALL (t) LIST
$TCYDI_{t}$	$(r=1\rightarrow 5)$	Total committed gas requirement by industrial customers during year t	GASALL (t) LIST

EQUATIONS

Chapter	Number
6	(6-1) → (6-11)

Table 10-8 Inputs, Outputs, and Equations of Subroutine WEATHR - Year t

INPUTS		
Variable	Definition	Origin
$DDH_{th,m} \binom{th=1\rightarrow 25}{m=1\rightarrow 12}$	Historical degree-days for year th and month m	Exogenous data
$DDMIN_{th}$	Lower limit of the frequency interval corresponding to year th	Exogenous data
$DDMAX_{th}$	Upper limit of the frequency interval corresponding to year th	Exogenous data
OUTPUTS		
Variable	Definition	Destination
DDS_{tm} $(m=1\rightarrow 12)$	Simulated monthly degree-days for month m of year t	GASALL(t), LIST
EQUATIONS		
Chapter	Number	
7	No equations explicitly stated - Use of a random number generation procedure.	

Table 10-9 Inputs, Outputs, and Equations of Subroutine GASALL - Year t

INPUTS		
Variable	Definition	Origin
WSG_t	Maximum wholesale gas supply in year t	Exogenous data
WENT	Winter season share of annual gas supply	Exogenous data
DDS_{tm} (m=1→12)	Simulated monthly degree-days for month m of year t	
$TCYDR_t$	Total committed gas requirment by residential customers during year t	CAPEXP (t)
$TCYDC_t$	Total committed gas requirement by commercial customers during year t	CAPEXP (t)
$TCYDI_t$	Total committed gas requirement by industrial customers during year t	CAPEXP (t)
STCAP	Certified storage capacity	Exogenous data
$RSTOR_{t1}$	Storage saturation rate at the beginning of the first month of year t	GASALL (t-1)
$GSTORD_{t1}$	Amount of gas in storage at the beginning of the first month of year t	GASALL (t-1)

OUTPUTS		
Variable	Definition	Destination
$DGMR_{tm}$ (m=1→12)	Potential residential gas demand in year t and month m	SUPCUR (t) OMCOST (t),LIST
$DGMC_{tm}$ (m=1→12)	Potential commercial gas demand in year t and month m	SUPCUR (t) OMCOST (t),LIST
$DGMI_{tm}$ (m=1→12)	Potential industrial gas demand in year t and month m	SUPCUR (t) OMCOST (t),LIST
$DGMT_{tm}$ (m=1→12)	Total potential gas demand in year t and month m	LIST
$RSTOR_{tm}$ (m=2→12)	Storage saturation rate at the beginning of month m of year t	LIST
$RSTOR_{t+1,1}$	Storage saturation rate at the beginning of month 1 of year (t+1)	GASALL (t+1) LIST
$GSTORD_{tm}$ (m=2→12)	Amount of gas in storage at the beginning of month m of year t	LIST
$GSTORD_{t+1,1}$	Amount of gas in storage at the begin- of month 1 of year (t+1)	GASALL (t+1) LIST

Table 10-9 Inputs, Outputs, and Equations of Subroutine GASALL - Year t (cont)

Variable	Definition	Destination
$MAXINS_{tm}$ $(m=1\rightarrow 12)$	Maximum gas delivery to storage during month m of year t	LIST
$GINST_{tm}$ $(m=1\rightarrow 12)$	Actual gas delivery to storage during month m of year t	OMCOST (t) LIST
$MAXOUS_{tm}$ $(m=1\rightarrow 12)$	Maximum gas withdrawal from storage during month m of year t	LIST
$GOUST_{tm}$ $(m=1\rightarrow 12)$	Actual gas withdrawal from storage during month m of year t	SUPCUR (t) LIST
$SUPM_{tm}$ $(m=1\rightarrow 12)$	Actual supply of wholesale gas during month m of year t	OMCOST (t) SUPCUR (t),LIST
$CURT_{tm}$ $(m=1\rightarrow 12)$	Overall gas curtailment indicator for month m of year t	SUPCUR (t)
$RESUEN_{tm}$ $(m=1\rightarrow 12)$	Residual summer entitlement of gas for month m of year t	LIST
$REWIEN_{tm}$ $(m=1\rightarrow 12)$	Residual winter entitlement of gas for month m of year t	LIST

EQUATIONS

Chapter	Number
7	(7-4); (7-5); (7-10); (7-11); (7-15); (7-16);
7	(7-28) → (7-57)
7	(7-70) → (7-89)

Table 10-10 Inputs, Outputs, and Equations of Subroutine SUPCUR - Year t

INPUTS		
Variable	Definition	Origin
$DGMR_{tm}$ (m=1→12)	Potential residential gas demand in year t and month m	GASALL (t)
$DGMC_{tm}$ (m=1→12)	Potential commercial gas demand in year t and month m	GASALL (t)
$DGMI_{tm}$ (m=1→12)	Potential industrial gas demand in year t and month m	GASALL (t)
$SUPM_{tm}$ (m=1→12)	Actual supply of wholesale gas during month m of year t	GASALL (t)
$GOUST_{tm}$ (m=1→12)	Actual withdrawal from storage during month m of year t	GASALL (t)
$CURT_{tm}$ (m=1→12)	Overall gas curtailment indicator for month m of year t	GASALL (t)

OUTPUTS		
Variable	Definition	Destination
$DGMRE_{tm}$ (m=1→12)	Actual gas sendouts to residential customers in year t and month m	OMCOST (t) INCOME (t)
$DGMCE_{tm}$ (m=1→12)	Actual gas sendouts to commercial customers in year t and month m	OMCOST (t) INCOME (t)
$DGMIE_{tm}$ (m=1→12)	Actual gas sendouts to industrial customers in year t and month m	OMCOST (t) INCOME (t)
$CURTR_{tm}$ (m=1→12)	Curtailment rate for residential customers in year t and month m	CRITER, LIST
$CURTC_{tm}$ (m=1→12)	Curtailment rate for commercial customers in year t and month m	CRITER, LIST
$CURTI_{tm}$ (m=1→12)	Curtailment rate for industrial customers in year t and month m	CRITER, LIST

EQUATIONS	
Chapter	Number
7	(7-58) → (7-69)

Table 10-11 Inputs, Outputs, and Equations of Subroutine CAPCST - Year t

INPUTS		
Variable	Definition	Origin
$NGCSA_{rt}$ (r=1→5)	Number of newly connected residential gas customers in division r during year t within serviced areas	CAPEXP (t)
$NGCNSA_{rt}$ (r=1→5)	Number of newly connected residential gas customers in division r during year t within non-serviced areas	CAPEXP (t)
$NCGC_{rt}$ (r=1→5)	Number of newly connected commercial gas customers in division r during year t	CAPEXP (t)
$NIGC_{rt}$ (r=1→5)	Number of newly connected industrial gas customers in division r during year t	CAPEXP (t)
$CNDGRS_{rt}$ (r=1→5)	Newly connected residential annual gas load in division r during year t within serviced areas	CAPEXP (t)
$CNDGRN_{rt}$ (r=1→5)	Newly connected residential annual gas load in division r during year t within non-serviced areas	CAPEXP (t)
$CNDGC_{rt}$ (r=1→5)	Newly connected commercial annual gas load in division r during year t	CAPEXP (t)
$CNDGI_{rt}$ (r=1→5)	Newly connected industrial annual gas load in division r during year t	CAPEXP (t)

OUTPUTS		
Variable	Definition	Destination
$CACRS_{rt}$ (r=1→5)	Capacity costs for new residential customers in division r during year t within serviced areas	LIST
$CACRN_{rt}$ (r=1→5)	Capacity costs for new residential customers in division r during year t within non-serviced areas	LIST
$CACC_{rt}$ (r=1→5)	Capacity costs for new commercial customers in division r during year t	LIST
$CACI_{rt}$ (r=1→5)	Capacity costs for new industrial customers in division r during year t	LIST
$CACRST_t$	Total capacity costs for new residential customers during year t within serviced areas	LIST

Table 10-11 Inputs, Outputs, and Equations of Subroutine CAPCST - Year t (cont)

Variable	Definition	Destination
$CACRNT_t$	Total capacity costs for new residential customers during year t within non-serviced areas	LIST
$CACCT_t$	Total capacity costs for new commercial customers during year t	LIST
$CACIT_t$	Total capacity costs for new industrial customers during year t	LIST
$NEWPIS_t$	New plant in service during year t	RATBAS(t), LIST

EQUATIONS	
Chapter	Number
5	(5-2) → (5-5)

Table 10-12 Inputs, Outputs, and Equations of Subroutine OMCOST - Year t

INPUTS		
Variable	Definition	Origin
$DGMRE_{tm}$ (m=1→12)	Actual gas sendouts to residential customers in year t and month m	SUPCUR (t)
$DGMCE_{tm}$ (m=1→12)	Actual gas sendouts to commercial customers in year t and month m	SUPCUR (t)
$DGMIE_{tm}$ (m=1→12)	Actual gas sendouts to industrial customers in year t and month m	SUPCUR (t)
$SUPM_{tm}$ (m=1→12)	Actual supply of wholesale gas during month m of year t	GASALL (t)
$GINST_{tm}$ (m=1→12)	Actual gas delivery to storage during month m of year t	GASALL (t)
WGP_t	Average wholesale gas price during year t	Exogenous data
OUTPUTS		
Variable	Definition	Destination
$GASSUP_t$	Total amount of wholesale gas supplied during year t	LIST
$GPURCH_t$	Total cost of wholesale gas purchased during year t	INCOME (t) LIST
$GSALES_t$	Total amount of gas sold to all customers during year t	NEWRAT (t), CRITER, LIST
$GDELIV_t$	Total amount of gas delivered to storage during year t	LIST
$OMSTOC_t$	Total storage operation and maintenance cost during year t	INCOME (t) LIST
$OMGENC_t$	Total general operation and maintenance costs (except storage) during year t	INCOME (t) LIST

EQUATIONS	
Chapter	Number
5	(5-6); (5-8)

Table 10-13 Inputs, Outputs, and Equations of Subroutine RATBAS - Year t

INPUTS		
Variable	Definition	Origin
ATPIS	Attrition rate of plant in service	Exogenous data
DEPAVG	Average depreciation rate for all types of plants in service	Exogenous data
$NEWPIS_t$	New plant in service during year t	CAPCST (t)
$PISBEG_t$	Plant in service at the beginning of year t	RATBAS (t-1)
$TAPDAD_{t-1}$	Accumulated provision for depreciation, amortization and depletion at the end of year (t-1)	RATBAS (t-1)

OUTPUTS		
Variable	Definition	Destination
$REPPIS_t$	Replacement plant put in service during year t	LIST
$DEPEXP_t$	Total depreciation expense during year t	INCOME (t), LIST
$TAPDAD_t$	Accumulated provision for depreciation, amortization and depletion at the end of year t	RATBAS (t+1) LIST
$TOTPIS_t$	Total plant in service during year t	INCOME (t), LIST
$NETPIS_t$	Net plant in service during year t	INCOME (t) CRITER, LIST
$PISBEG_{t+1}$	Plant in service at the beginning of year (t+1)	RATBAS (t+1) LIST

EQUATIONS	
Chapter	Number
8	(8-1); (8-2); (8-4) $\rightarrow$ (8-12)

Table 10-14 Inputs, Outputs, and Equations of Subroutine INCOME - Year t

INPUTS		
Variable	Definition	Origin
ALLROR	Allowed rate of return	Exogenous data
TAXADJ	Tax adjustment factor	Exogenous data
$DEPEXP_t$	Total depreciation expense during year t	RATBAS (t)
$TOTPIS_t$	Total plant in service during year t	RATBAS (t)
$NETPIS_t$	Net plant in service during year t	RATBAS (t)
$GPURCH_t$	Total cost of wholesale gas purchased during year t	OMCOST (t)
$OMSTOC_t$	Total storage operation and maintenance costs during year t	OMCOST (t)
$OMGENC_t$	Total general operation and maintenance costs (except storage) during year t	OMCOST (t)
$DGMRE_{tm}$ $(m=1\rightarrow12)$	Actual gas sendouts to residential customers in year t and month m	SUPCUR (t)
$DGMCE_{tm}$ $(m=1\rightarrow12)$	Actual gas sendouts to commercial customers in year t and month m	SUPCUR (t)
$DGMIE_{tm}$ $(m=1\rightarrow12)$	Actual gas sendouts to industrial customers in year t and month m	SUPCUR (t)
$PRGR_{rt-1}$ $(r=1\rightarrow5)$	Residential price of gas in division r during year (t-1)	NEWRAT (t-1)
$PRGC_{rt-1}$ $(r=1\rightarrow5)$	Commercial price of gas in division r during year (t-1)	NEWRAT (t-1)
$PRGI_{rt-1}$ $(r=1\rightarrow5)$	Industrial price of gas in division r during year (t-1)	NEWRAT (t-1)

OUTPUTS		
Variable	Definition	Destination
$GASREV_t$	Total gas sales revenues during year t	CRITER, LIST
$ACOPEX_t$	Actual operating expenses during year t	CRITER, LIST
$OOPREV_t$	Other operating revenues during year t	CRITER, LIST
$ONUINC_t$	Other non-utility income during year t	LIST
$INTCHG_t$	Interest charges during year t	CRITER, LIST
$INCAT_t$	Income after taxes and interest charges payment	LIST

Table 10-14 Inputs, Outputs, and Equations of Subroutine INCOME - Year t (cont)

Variable	Definition	Destination
$AOPINC_t$	Allowed operating income during year t	LIST
$INCDEF_t$	Income deficit during year t	NEWRAT (t) LIST

EQUATIONS	
Chapter	Number
8	(8-13) → (8-16); (8-18) → (8-22); (8-25) → (8-30)

Table 10-15 Inputs, Outputs, and Equations of Subroutine NEWRAT - Year t

INPUTS		
Variable	Definition	Origin
TAXADJ	Tax adjustment factor	Exogenous data
$GSALES_t$	Total amount of gas sold to all customers during year t	OMCOST (t)
$INCDEF_t$	Income deficit during year t	INCOME (t)
$PRGR_{rt-1}$ $(r=1 \rightarrow 5)$	Residential price of gas in division r during year (t-1)	NEWRAT (t-1)
$PRGC_{rt-1}$ $(r=1 \rightarrow 5)$	Commercial price of gas in division r during year (t-1)	NEWRAT (t-1)
$PRGI_{rt-1}$ $(r=1 \rightarrow 5)$	Industrial price of gas in division r during year (t-1)	NEWRAT (t-1)

OUTPUTS		
Variable	Definition	Destination
DPR_t	Average gas price increment in year t	CRITER, LIST
$PRGR_{rt}$ $(r=1 \rightarrow 5)$	Residential price of gas in division r during year t	SHRES (t+1) NEWRAT (t+1) CRITER, LIST
$PRGC_{rt}$ $(r=1 \rightarrow 5)$	Commercial price of gas in division r during year t	COMMEC (t+1) NEWRAT (t+1) CRITER, LIST
$PRGI_{rt}$ $(r=1 \rightarrow 5)$	Industrial price of gas in division r during year t	SHIND (t+1) NEWRAT (t+1) CRITER, LIST

EQUATIONS	
Chapter	Number
8	(8-31) $\rightarrow$ (8-34)

Table 10-16 Inputs, Outputs, and Equations of Subroutine CRITER - Year t

INPUTS		
Variable	Definition	Origin
RO	Annual discount rate	Exogenous data
WGP_t $(t=1\rightarrow 23)$	Average wholesale gas price during year t	Exogenous data
WGS_t $(t=1\rightarrow 23)$	Maximum wholesale gas supply during year t	Exogenous data
$PRGR_{rt}$ $\binom{r=1\rightarrow 5}{t=1\rightarrow 23}$	Residential price of gas in division r in year t	NEWRAT (t)
$PROR_{rt}$ "	Residential price of oil in division r in year t	Exogenous data
$PRER_{rt}$ "	Residential price of electricity in division r in year t	Exogenous data
$PRGC_{rt}$ "	Commercial price of gas in division r in year t	NEWRAT (t)
$PROC_{rt}$ "	Commercial price of oil in division r in year t	Exogenous data
$PREC_{rt}$ "	Commercial price of electricity in division r in year t	Exogenous data
$PRGI_{rt}$ "	Industrial price of gas in division r in year t	NEWRAT (t)
$PROI_{rt}$ "	Industrial price of oil in division r in year t	Exogenous data
$PRCI_{rt}$ "	Industrial price of coal in division r in year t	Exogenous data
DPR_t $(t=1\rightarrow 23)$	Average gas price increment in year t	NEWRAT (t)
$BASEDT_t$ $(t=1\rightarrow 23)$	Base committed gas requirement for all customers classes before any new connections at the beginning of year t	CAPEXP (t)
$EXCSUP_t$ $(t=1\rightarrow 23)$	Total annual excess gas supply at the beginning of year t before any new load has been connected	CAPEXP (t)
$SHGR_{rt}$ $\binom{r=1\rightarrow 5}{t=1\rightarrow 23}$	Residential gas market share in division r during year t	SHRES (t)
$SHOR_{rt}$ "	Residential oil market share in division r during year t	SHRES (t)
$SHER_{rt}$ "	Residential electricity market share in division r during year t	SHRES (t)

Table 10-16 Inputs, Outputs, and Equations of Subroutine CRITER - Year t (cont)

Variable	Definition	Origin
$SHGI_{rt}$ $\binom{r=1\to 5}{t=1\to 23}$	Industrial gas market share in division r during year t	SHIND (t)
$SHOI_{rt}$ "	Industrial oil market share in division r during year t	SHIND (t)
$SHCI_{rt}$ "	Industrial coal market share in division r during year t	SHIND (t)
$PNDGRS_{rt}$ "	Potential new demand of gas by residential customers in division r during year t within serviced areas	RESIDC (t)
$PNDGRN_{rt}$ "	Potential new demand of gas by residential customers in division r during year t within non-serviced areas	RESIDC (t)
$PNDGC_{rt}$ "	Potential new demand of gas by commercial customers in division r during year t	COMMEC (t)
$PNDGI_{rt}$ "	Potential new demand of gas by industrial customers in division r during year t	INDUSC (t)
$CNDGRS_{rt}$ "	Newly connected residential gas load in division r during year t within serviced areas	CAPEXP (t)
$CNDGRN_{rt}$ "	Newly connected residential gas load in division r during year t within non-serviced areas	CAPEXP (t)
$CNDGC_{rt}$ "	Newly connected commercial gas load in division r during year t	CAPEXP (t)
$CNDGI_{rt}$ "	Newly connected industrial gas load in division r during year t	CAPEXP (t)
$CURTR_{tm}$ $\binom{m=1\to 12}{t=1\to 23}$	Curtailment rate for residential customers in year t and month m	SUPCUR (t)
$CURTC_{tm}$ "	Curtailment rate for commercial customers in year t and month m	SUPCUR (t)
$CURTI_{tm}$ "	Curtailment rate for industrial customers in year t and month m	SUPCUR (t)
$GSALES_{t}$ $(t=1\to 23)$	Total amount of gas sold to all customers during year t	OMCOST (t)
$GASREV_{t}$ $(t=1\to 23)$	Total gas sales revenues during year t	INCOME (t)

Table 10-16 Inputs, Outputs, and Equations of Subroutine CRITER - Year t (cont)

Variable		Definition	Origin
$OOPREV_t$	$(t=1\rightarrow 23)$	Other operating revenues during year t	INCOME (t)
$ACOPEX_t$	$(t=1\rightarrow 23)$	Actual operating expenses during year t	INCOME (t)
$INTCHG_t$	$(t=1\rightarrow 23)$	Interest charges during year t	INCOME (t)
$NETPIS_t$	$(t=1\rightarrow 23)$	Net plant in service during year t	RATBAS (t)

OUTPUTS

Variable		Definition
$ACOPRV_t$	$(t=1\rightarrow 23)$	Actual operating revenue during year t
$TATR_t$	$(t=1\rightarrow 23)$	Total asset turnover ratio during year t
$NPMR_t$	$(t=1\rightarrow 23)$	Net profit margin ratio during year t
$GPMR_t$	$(t=1\rightarrow 23)$	Gross profit margin ratio during year t
$RTAR_t$	$(t=1\rightarrow 23)$	Return on total assets ratio during year t
$ROCER_t$	$(t=1\rightarrow 23)$	Return on common equity index during year t
$INTCOV_t$	$(t=1\rightarrow 23)$	Interest coverage ratio during year t
$IRBC_t$	$(t=1\rightarrow 23)$	Percentage change in rate base during year t
$IORI_t$	$(t=1\rightarrow 23)$	Index of rate increase during year t
IORIT		Aggregate index of rate increases
AED_t	$(t=1\rightarrow 23)$	Annual excess demand index for year t
AEDI		Average annual excess demand index
AEDFI		Average annual excess demand frequency index
$AMCIR_t$	$(t=1\rightarrow 23)$	Average monthly curtailment index of residential customers during year t
$AMCIC_t$	$(t=1\rightarrow 23)$	Average monthly curtailment index of commercial customers during year t
$AMCII_t$	$(t=1\rightarrow 23)$	Average monthly curtailment index of industrial customers during year t
$MWRC_t$	$(t=1\rightarrow 23)$	Number of winter months with residential gas curtailment during year t
$MWCC_t$	$(t=1\rightarrow 23)$	Number of winter months with commercial gas curtailment during year t
$MWIC_t$	$(t=1\rightarrow 23)$	Number of winter months with industrial gas curtailment during year t
WMCRT		Average monthly residential curtailment frequency index
WMCCT		Average monthly commercial curtailment frequency index
WMCIT		Average monthly industrial curtailment frequency index

Table 10-16 Inputs, Outputs, and Equations of Subroutine CRITER - Year t (cont)

Variable	Definition
AEPDIR	Average electricity price differential index for residential customers
AEPDIC	Average electricity price differential index for commercial customers
AOPDIR	Average oil price differential index for residential customers
AOPDIC	Average oil price differential index for commercial customers
AOPDII	Average oil price differential index for industrial customers
ACPDII	Average coal price differential index for industrial customers
PEI	Production efficiency index
PRA_t	Zero-demand gas price for residential customers during year t
PCA_t	Zero-demand gas price for commercial customers during year t
PIA_t	Zero-demand gas price for industrial customers during year t
$WRSA_t$ $(t=1 \rightarrow 23)$	Net aggregate surplus in year t of residential customers within serviced areas requesting new service in year t
$WRNS_t$ $(t=1 \rightarrow 23)$	Net aggregate surplus in year t of residential customers within non-serviced areas requesting new service in year t
WC_t $(t=1 \rightarrow 23)$	Net aggregate surplus in year t of commercial customers requesting new service in year t
WI_t $(t=1 \rightarrow 23)$	Net aggregate surplus in year t of industrial customers requesting new service in year t
WRSAT	Present value of net aggregate surpluses of residential customers within serviced areas
WRNST	Present value of net aggregate surpluses of residential customers within non-serviced areas
WCT	Present value of net aggregate surpluses of commercial customers
WIT	Present value of net aggregate surpluses of industrial customers

Table 10-16 Inputs, Outputs, and Equations of Subroutine CRITER - Year t (cont)

Variable	Definition
EUEI	End-use efficiency index
AEI	Aggregate efficiency index
EQUATIONS	
Chapter	Number
9	(9-1) → (9-5); (9-7) → (9-13); (9-25) → (9-29)

CHAPTER 11
SELECTED RESULTS

The basic premise upon which potential PUCO new service policies were evaluated in this research is that the choice of the preferred policy be based on the capacity of the policy to satisfy regulatory objectives. The variety of potential policies was introduced in Chapter 6 of this volume. Chapter 9 of this volume contains descriptions of the means by which a selected number of these policies was evaluated. The purpose of this chapter is to present results of such evaluations by means of the regualtory simulation model.

The evaluation was carried out separately for each potential policy in terms of each evaluation criterion, under seven alternative future energy scenarios. As was pointed out in Chapter 3 all but one of the energy scenarios are the results of "Project Independence Evaluation System"(PIES) carried out by the U.S. Department of Energy. One scenario, almost radically different from the other six, is primarily the result of forecasting efforts by the EOGC. As was pointed out in Chapter 6 the four policies selected for evaluation differed primarily in terms of classes of customers that were permitted to receive new service and in terms of the location of these customers.

It is important to note that the extent to which the results indicate differences in achievement of the various regulatory objectives is a function of differences in policies and scenarios only. No other exogenous forces were permitted to influence the results. Differences in the achievement of objectives by policies cannot be attributed to changes in the behavior of the EOGC or the PUCO. For example, the model assumes that the cost of doing business will expand at an average historic rate as new services are offered by the EOGC. Should new hook-ups lead the company to incurr reduced or increased operating costs, the model does not take such possibility into account. Similarly, the model does not take into account changes in the operations of the PUCO.

New Service Policies and Utility Finances

Two extreme arguments are typically made concerning the impact of alternative new service policies on utility finances. The utilities argue that lack of new hook-ups coupled with rising costs, leads to incessant income deficits, rising prices to consumers and, losses to investors. Consumers argue that indiscriminate hook-ups lead to company overexpansion that results in a need for financing through higher rates. Both groups agree that the choice of a wrong policy may lead to noncompetitive gas prices. It is the purpose of this section to describe the potential impacts of new service policies on various aspects of utility finances.

Perhaps the most telling indicator of the overall impact of hook-up policies on utility finances is the return on total assets ratio. It is indicative of the effects of new service policies on all the major aspects of managing a gas distribution utility - i.e., profit margin, and asset and financial management. Since the simulation model did not explicitly investigate the capital structure of the utility several approximations have been used to estimate financial management (see Chapter 8). Profit margins and asset turnover were estimated on actual simulation results. As an indicator of the latter two the average return on total assets was calculated for each policy and each scenario. Table 11-1 contains the results for this indicator. It is noteworthy

Table 11-1 Average Annual Return on Total Asset Ratio, (RTAR) by Policy and Energy Scenario, Based on Simulations for the Period 1978-2000.

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	0.10949	0.11116	0.11050	0.10929
MRTSC	0.17535	0.17312	0.17596	0.17545
HRCSA	0.17168	0.17215	0.17330	0.17249
HRCSD	0.16815	0.16882	0.16959	0.16895
LRCSE	0.17758	0.17758	0.17758	0.17758
LRCSB	0.17883	0.17883	0.17883	0.17883
EOGCS	0.11103	0.11787	0.11603	0.11180

* The various energy scenarios were fully described in Chapter 3.
** The various new service policies were fully described in Chapter 6.

that throughout the financial analysis average net plant in service served as a proxy for total company assets resulting in inflated estimates of return on total assets and return on common equity. It is important to note that this general indicator does not yield unequivocal results. Examination of Table 11-1 reveals that the choice of the preferred policy based on this index depends crucially on the choice of energy scenario. If the assumption is made that the EOGC forecast is the most likely, than the "company initiative" policy yields the best results in terms of this index. If, on the other hand, it is assumed that one of the other energy scenarios is more likely, then other policies emerge with better scores in terms of this ratio.

The reasons for these contradictory results are not difficult to identify. First, alternate energy scenarios imply different constraints on doing business and the associated costs. Lack of adequate supply limits sales in general and new hook-ups in particular. In terms of a particular new service policy, however, investments remain by-and-large unchanged. Only incremental changes occur due to the constraint on new hook-ups imposed by gas availability. In general, gas availability characteristics determine the cost of doing business such as that associated with gas storage operations. At the same time higher gas prices affect both the cost of providing gas and gas revenues. Secondly, the alternate policies imply different investments and profit margins and thus affect the return on total assets ratio. Similar reasoning can be used to understand the much more general indicator the return on common equity index. As can be seen from Table 11-2 various policies emerge as superior depending on the energy scenario considered. In order to better understand the financial implications of the various energy scenarios and new service policies it is necessary to exaimine other financial indicators that will permit a more focused view of the different aspects of utilitiy's finances.

From the common shareholder's point of view the most telling indicators are the gross and net profit margin ratios. The ratios measure profits before and after taxes per dollar of sales, respectively.

Table 11-2 Average Annual Return on Common Equity Ratio, (ROCER) by Policy and Energy Scenario, Based on Simulations for the Period 1978-2000.

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	0.23487	0.22639	0.23277	0.23131
MRTSC	0.40582	0.39683	0.40657	0.40549
HRCSA	0.40167	0.39460	0.40187	0.40055
HRCSD	0.39359	0.38572	0.39435	0.39260
LRCSE	0.40862	0.40862	0.40862	0.40862
LRCSB	0.41198	0.41198	0.41198	0.41198
EOGCS	0.23727	0.66498	0.22920	0.21653

* The various energy scenarios were fully described in Chapter 3.
** The various new service policies were fully described in Chapter 6.

Tables 11-3 and 11-4 present estimates of these ratios. A striking fact that emerges from examination of these tables is that the choice of the preferred policy from the shareholder's point of view is made very easy. No matter which energy scenario is considered, the company initiative policy yields the highest estimates for both ratios. Comparison of results generated by this policy under alternate energy scenarios leads to the conclusion that the success of this policy does not depend upon the extent to which there exists an excess gas supply. The choice of company initiative policy as a means to the achievement of shareholders' interests is supported further by consideration of the impact of the various policies on the interest coverage ratio. As is evidenced by Table 11-5 the highest estimates of this ratio are associated with the company initiative policy.

A different conclusion emerges from the consideration of total asset turnover ratio. It is considered the best indicator of the use of total assets employed by the company. Table 11-6 reveals that no matter which energy scenario is considered the policy that favors the continuation of the present ban on new service leads to the highest estimates of this ratio. This is not difficult to explain in light of the fact the the ratio

Table 11-3 Average Annual Gross Profit Margin Ratio, (GPMR) by Policy and Energy Scenario, Based on Simulations for the Period 1978-2000.

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	0.11260	0.11620	0.11503	0.11329
MRTSC	0.12966	0.13337	0.13177	0.13080
HRCSA	0.12861	0.13630	0.13311	0.13047
HRCSD	0.12865	0.13628	0.13320	0.13051
LRCSE	0.12877	0.12877	0.12877	0.12877
LRCSB	0.12823	0.12823	0.12823	0.12823
EOGCS	0.11223	0.12344	0.11995	0.11418

Table 11-4 Average Annual Net Profit Margin Ratio, (NPMR) by Policy and Energy Scenario, Based on Simulations for the Period 1978-2000.

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	0.04422	0.04539	0.04506	0.04439
MRTSC	0.07741	0.07828	0.07811	0.07769
HRCSA	0.07521	0.07822	0.07718	0.07586
HRCSD	0.07378	0.07683	0.07558	0.07438
LRCSE	0.08763	0.08763	0.08763	0.08763
LRCSB	0.08660	0.08660	0.08660	0.08660
EOGCS	0.04352	0.04917	0.04749	0.04433

* The various energy scenarios were fully described in Chapter 3.
** The various new service policies were fully described in Chapter 6.

Table 11-5 Average Annual Interest Coverage Ratio, (INTLOV) by Policy and Energy Scenario, Based on Simulations for the Period 1978-2000.

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	8.74862	9.07031	8.96305	8.81314
MRTSC	8.83214	9.11128	8.99123	8.92315
HRCSA	8.82573	9.37464	0.15276	8.97799
HRCSD	8.82890	9.37035	9.15674	8.98209
LRCSE	8.00984	8.00984	8.00984	8.00984
LRCSB	8.06929	8.06929	8.06924	8.06929
EOGCS	8.74250	9.55425	9.30200	8.90231

Table 11-6 Average Annual Total Asset Turnover Ratio, (TATR) and Energy Scenario, Based on Simulations for the Period 1978-2000.

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	2.72499	2.68352	2.69627	2.71712
MRTSC	2.27919	2.24940	2.26324	2.27200
HRCSA	2.30403	2.22764	2.25996	2.28922
HRCSD	2.31069	2.23039	2.26554	2.29551
LRCSE	2.04647	2.04647	2.04647	2.04647
LRCSB	2.07183	2.07183	2.07183	2.07183
EOGCS	2.73682	2.57757	2.62630	2.71048

* The various energy scenarios were fully described in Chapter 3.
** The various new service policies were fully described in Chapter 6.

measures value of sales per dollar of investment. The results indicate that the growth in sales that is associated with all policies, except the no new service policy, is not sufficient to compensate the company for the growth in investment that new hook-ups entail. Although no detailed study has been conducted to ascertain the reason for this finding, it is reasonable to assume that the resulting gap in the value of sales is due to the non-competitive price at which gas would have to be offered. As rate base increases are translated into higher prices the model's forecasts indicate that gas consumption will not grow sufficiently to generate high total asset turnover ratio.

Table 11-7 contains estimates of the average annual percentage changes in company's rate base that are necessitated by the various policies under alternate energy scenarios. Although the highest increases are associated with the company initiative policy and the lowest with the no new service policy, the striking feature of the results is the small range of values between the highest and lowest increase. While the highest increase is estimated to be 2.85 percent the lowest increase is only 2.04 percent.[1] In light of the discussion of total asset turnover ratio estimates this is a surprising finding. The most likely explanation of this result is that no matter which energy scenario is considered the extent of the excess supply of gas that emerges does not permit vast numbers of customers to be hooked-up. Furthermore, because of the prescribed order in which customers are to be connected the limited excess supply of gas meant that the majority of the newly connected customers were located within the currently served areas requiring only small additions to company's plant.

It is noteworthy, however, that no consideration was given in this model to the possible need for additions to the company's gas storage plant. Such plant additions would have resulted in different estimates of percentage changes in plant, as well as different estimates of curtailments associated with the various policies and energy scenarios.

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[1] The implications of this for ratepayers are analyzed below.

Table 11-7 Average Annual Percentage Change in Rate Base, (IRBL) by Policy and Energy Based on Simulations for the Period 1978-2000.

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	0.02039	0.02350	0.02247	0.02098
MRTSC	0.02039	0.02355	0.02219	0.02136
HRCSA	0.02039	0.02614	0.02382	0.02196
HRCSD	0.02039	0.02608	0.02377	0.02196
LRCSE	0.02039	0.02039	0.02039	0.02039
LRCSB	0.02039	0.02039	0.02039	0.02039
EOGCS	0.02039	0.02857	0.02597	0.02192

* The various energy scenarios were fully described in Chapter 3.
** The various new service policies were fully described in Chapter 6.

The results in terms of the impact of new service policies on company finances seem to be somewhat contradictory. In the absence of a reliable estimate of the probability with which each energy scenario can be expected to occur, this probability is considered to be the same for all scenarios. In order to reduce the number of alternatives that need to be considered the various scenarios were assigned to three group based on similarity of forecasted energy prices and quantities. Thus, group A consists of scenarios MRTSF and EOGCS, group B consists of scenarios MRTSC, HRCSA and HRCSD, while group C is composed of scenarios LRCSE and LRCSB.

The rankings of the policies in terms of the various indicators under group A are presented in Table 11-8. Clearly there is no one policy that has the most desirable impacts under all the scenarios and in terms of all the criteria. For group B similarly calculated results are presented in Table 11-9. Since values of all the financial indicators were the same no matter which policy was considered under the assumptions of group C, no results are presented.

Table 11-8 Policy Rankings by Policy and Financial Indicator Under the Assumptions of Group A.

Financial Indicator	New Service Policies			
	No New Service Policy	Company Initiative	Selected Residential Only	Industrial Only
TATR	1	2	3	2
RTAR	4	1	2	3
ROCER	1	4	2	3
NPMP	4	1	2	3
GPMR	4	1	2	3
INTCOV	4	1	2	3
IRBC	1	4	3	2

Table 11-9 Policy Rankings by Policy and Financial Indicator Under the Assumptions of Group B.

Financial Indicator	New Service Policies			
	No New Service Policy	Company Initiative	Selected Residential Only	Industrial Only
TATR	1	4	3	2
RTAR	4	3	1	2
ROCER	2	4	1	3
NPMR	4	1	2	3
GPMR	4	1	2	3
INTCOV	4	1	2	3
IRBC	1	4	3	2

In order to obtain a weighted average evaluation of the policies each policy was weighted by 1 in case it was the best policy, by .66 in case it was the second best policy, by .33 in case it was the second worst policy and by 0 in case it was the worst policy. Using these arbitrary weights, the weighted average was calculated as $\sum_i P_i W_i$, where P_i is the occurence of the policy as best, second best, etc. The results of these calculations for groups A and B are presented in Table 11-10.

Table 11-10 The Weighted Rankings of Policies Under Groups A and B

Policy	Weighted Average Rankings	
	Under Group A	Under Group B
No New Service Policy	0.43	0.38
Company Initiative	0.57	0.48
Selected Residential Only	0.56	0.67
Industrial Only	0.40	0.47

Based on the assumptions implicit in the above calculations and financial impacts alone, the choice of the preferred policy is relatively easy. If energy scenarios comprising group A are considered, the company initiative policy emerges superior, although the selected residential policy is almost indistinguishable from it. If energy scenarios comprising group B are considered, the selected residential policy is deemed preferred, with no policy coming close to it in terms of the financial impacts. It is noteworthy, however, that no analysis was carried out to examine how harmful would be the choice of the alternative policies if their implementation deviated from the implementation process selected.

Based on the assumptions implicit in the above calculations and financial impacts alone, the choice of the preferred policy is relatively easy. If energy scenarios comprising group A are considered, the company initiative policy emerges superior, although the selected residential policy is almost indistinguishable from it. If energy scenarios comprising group B are considered, the selected residential policy is deemed preferred, with no policy coming close to it in terms of the financial impacts. It is noteworthy, however, that no analysis was carried out to examine how harmful would the choice of the alternative policies be if their implementation deviated from the implementation process selected.

New Service Policies and The Consumers

From the consumers' point of view two aspects of new service policies are of interest: the impact of policies on the quality of service and their impact on customers' bills. Since the Btu content of natural gas does not vary to a great extent, quality of service is most often understood in terms of gas flow interruptions. Policies' impact on customers' bills, on the other hand, is typically evaluated in terms of the resulting relative burdens and customers' ability to pay.

It is significant to note that in terms of quality of service there is no policy that does not lead to the necessity of curtailments. The extent to which curtailments are made necessary varies greatly depending on the policy and scenarios considered. Tables 11-11, 11-12, and 11-13 contain estimates of the average number of months with industrial, commercial, and residential curtailments respectively.

In terms of industrial customers the need for curtailments is almost universal. The only exception occurs under the EOGC assumption concerning energy supply. Under the other energy supply assumptions, the company initiative policy, quite naturally, leads to the most extensive curtailments, while the no new service policy results in minimal curtailments. In terms of commercial customers the results are more varied. The company initiative policy results in curtailments under all but the EOGC supply forecasts, while the other policies result in no commercial curtailments under several other energy scenarios. In terms of residential customers the

Table 11-11 Average Number of Months with Industrial Curtailments, WMCIT, by Policy and Energy Scenario, Based on Simulations for the Period 1978-2000.

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	0.52174	0.73913	0.65217	0.60870
MRTSC	0.82609	0.95652	0.86957	0.86957
HRCSA	0.26087	0.52174	0.30435	0.26087
HRCSD	0.30435	0.65217	0.34783	0.30435
LRCSE	4.08695	4.08695	4.08695	4.08695
LRCSB	3.73913	3.73913	3.73913	3.73913
EOGCS	0.00000	0.00000	0.00000	0.00000

Table 11-12 Average Number of Months with Commercial Curtailments, WHCCT, by Policy and Energy Scenario, Based on Simulations for the Period 1978-2000.

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	0.00000	0.04348	0.04348	0.00000
MRTSC	0.04348	0.04348	0.04348	0.04348
HRCSA	0.00000	0.04348	0.00000	0.00000
HRCSD	0.00000	0.04348	0.00000	0.00000
LRCSE	1.65217	1.65217	1.65217	1.65217
LRCSB	1.34783	1.34783	1.34783	1.34783
EOGCS	0.00000	0.00000	0.00000	0.00000

* The various energy scenarios were fully described in Chapter 3.
** The various new service policies were fully described in Chapter 6.

Table 11-13 Average Number of Months with Residential Curtailments, WMCRT, by Policy and Energy Scenario, Based on Simulations for the Period 1978-2000.

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	0.00000	0.00000	0.00000	0.00000
MRTSC	0.00000	0.00000	0.00000	0.00000
HRCSA	0.00000	0.00000	0.00000	0.00000
HRCSD	0.00000	0.00000	0.00000	0.00000
LRCSE	0.39130	0.39130	0.39130	0.39130
LRCSB	0.34783	0.34783	0.34783	0.34783
EOGCS	0.00000	0.00000	0.00000	0.00000

Table 11-14 Average Annual Excess Demand Frequency Index, AEDFI, by Policy and Energy Scenario, Based on Simulations for the Period 1978-2000.

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	0.30435	0.30435	0.30435	0.30435
MRTSC	0.34783	0.34783	0.34783	0.34783
HRCSA	0.17391	0.17391	0.17391	0.17391
HRCSD	0.17391	0.17391	0.17391	0.17391
LRCSE	1.00000	1.00000	1.00000	1.00000
LRCSB	1.00000	1.00000	1.00000	1.00000
EOGCS	0.00000	0.00000	0.00000	0.00000

* The various energy scenarios were fully described in Chapter 3.
** The various new service policies were fully described in Chapter 6.

results are unambiguous. No policy results in curtailments except under energy scenarios LRCSE and LRCSB, under which no new hook-ups are authorized. The need for universal curtailments when these two scenarios are assumed is not surprising. As is evident from Table 11-14 the natural gas supplies implicit in these scenarios are such that there is no year of the simulation period, during which the average historic demand can be fully satisfied. And thus, according to the assumptions of the capacity expansion sub-model this situation does not permit new hook-ups and so there is no distinction between the various policies.

The impact of the new service policies on customers' bills was studied with the help of forecasts of the absolute frequency with which the annual reviews of rates that are implicit in the model, led to rate increases, beyond those necessitated by wholesale price changes, and forecasts of average annual change in projected retail price by customer class. The results are presented in Tables 11-15 and 11-16, respectively.

Consideration of these results reveals that in terms of average annual change in retail gas prices the differences among energy scenarios are greater than the differences among new service policies. Although this may seem peculiar this result is easily explained. First, differences among energy scenarios are primarily due to great differences in wholesale prices. Secondly, the differences among policies are slight because the cost of the increased capacity associated with new hook-ups is spread over greater quantities of gas sold. This interpretation is further corroborated by reference to the rate increases frequency index. It is important to note that this index does not take into account rate increases made necessary by wholesale price increases, and therefore, that the frequency of need for additional revenues is lesser under the company initiative policy.

The impact of the alternative policies on customers in terms of natural gas bills can be considered neutral. In terms of service quality, however, the results are difficult to interpret. Since the impact of curtailing a customer is dependent upon the frequency, duration, and time of the curtailment, as well as the use to which gas is put, in the absence of a calculation that assigns monetary values to the curtailments a very imprecise conclusion emerges: The frequency and extent of curtailments is inversely related to the extent of new hook-ups.

Table 11-15 Forecasted Absolute Frequency of Rate Increases, IORIT, by Policy and Energy Scenario, Based on Simulations for the Period 1978-2000.

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	14.0	14.0	14.0	14.0
MRTSC	14.0	13.0	13.0	13.0
HRCSA	15.0	12.0	15.0	15.0
HRCSD	15.0	13.0	13.0	15.0
LRCSE	19.0	19.0	19.0	19.0
LRCSB	18.0	18.0	18.0	18.0
EOGCS	14.0	14.0	14.0	15.0

Table 11-16 Average Annual Change in Projected Natural Gas Price by Policy and Energy Scenario, for Residential Customers Based on Simulations for the Period 1978-2000 ($/MMBTU)

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	0.260	0.259	0.259	0.260
MRTSC	0.151	0.150	0.150	0.150
HRCSA	0.156	0.154	0.154	0.155
HRCSD	0.163	0.162	0.162	0.162
LRCSE	0.167	0.167	0.167	0.167
LRCSB	0.163	0.163	0.163	0.163
EOGCS	0.263	0.258	0.259	0.262

* The various energy scenarios were fully described in Chapter 3.
** The various new service policies were fully described in Chapter 6.

Finally, the various new service policies were analyzed from the point of view of relative energy prices and the implicit subsidies that may be denied to some deserving customers. It is reasonable to assume that as long as natural gas price is below the price of a competing fuel a policy that denies gas to a customer is less "fair" than a policy that permits customers to hook-up to the system. Tables 11-17, 11-18 and 11-19 contain estimates of the retail price of natural gas as a percentage of the retail prices of electricity and oil in the case of residential customers, and coal for industrial customers.

Several conclusions can be reached on the basis of these results. First, irrespective of the energy scenario considered the possibility of consuming natural gas does represent a price break to residential energy consumers. In some cases natural gas price may represent as little as 26.2 percent of the price of electricity and 85.8 percent of the price of oil. Secondly, new service policies affect relative energy prices. The more customers are permitted to hook-up the lower the resulting price of gas will be in relation to other fuels. In some sense a partial new service policy is less fair from the point-of-view of customers who cannot hook-up to the system than an universal ban on new service. Thirdly, from the industrial customers' point of view, natural gas will cease to hold a competitive edge on other fuels very shortly. On the average, when the entire simulation period is considered, natural gas price represents at least 193.3 percent of the price of coal. Indeed, the price of gas becomes so high relative to other fuel prices in the case of industrial customers that industrial consumption of natural gas is forecasted to be limited to feedstocks only. (See Appendix K).

Based on the consideration of impacts on customers alone, two major conclusions emerge concerning new service policies. Curtailments are inversely related to hook-ups and industrial hook-ups are forecasted to last for a few years only, since in the future industrial energy users will not consume natural gas.

New Service Policies and Economic Efficiency

Two aspects of economic efficiency were taken into account in an attempt to analyze the repercussions of new service policies. Calculations

Table 11-17 Average Residential Price of Natural Gas as a Percentage of Retail Price of Electricity, (AEPDIR) by Policy and Energy Scenario Based on Simulations for the Period 1978-2000.

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	36.2	36.2	36.2	36.2
MRTSC	26.2	26.2	26.2	26.2
HRCSA	26.5	26.4	26.4	26.4
HRCSD	27.3	27.2	27.2	27.3
LRCSE	27.9	27.9	27.9	27.9
LRCSB	26.9	26.9	26.9	26.9
EOGCS	36.2	36.1	36.1	36.2

Table 11-18 Average Residential Price of Natural Gas as a Percentage of Retail Price of Oil, (AOPDIR) by Policy and Energy Scenario Based on Simulations for the Period 1978-2000.

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	86.2	86.0	86.1	86.1
MRTSC	92.1	92.0	92.0	92.1
HRCSA	94.8	94.6	94.6	94.7
HRCSD	97.2	97.0	96.9	97.1
LRCSE	96.5	96.5	96.5	96.5
LRCSB	93.7	93.7	93.7	93.7
EOGCS	86.1	85.8	85.8	86.0

* The various energy scenarios were fully described in Chapter 3.
** The various new service policies were fully described in Chapter 6.

Table 11-19 Average Industrial Price of Natural Gas As A Percentage Of The Retail Price Of Coal, (ACPDII) By Policy and Energy Scenario Based On Simulations For The Period 1978-2000

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	236.9	236.5	236.6	236.9
MRTSC	194.8	194.5	194.6	194.7
HRCSA	193.8	193.3	193.3	193.6
HRCSD	196.7	196.3	196.2	196.5
LRCSE	207.2	207.2	207.2	207.2
LRCSB	203.3	203.3	203.3	203.3
EOGCS	236.7	235.8	235.9	236.6

* The various energy scenarios were fully described in Chapter 3.

** The various new service policies were fully described in Chapter 6.

value it the most. Calculations of production efficiency were performed to analyze the extent to which new service policies encourage or discourage wasteful production. The impacts of the new service policies on overall economic efficiency were estimated by reference to the sum of end-use and production efficiency.

Table 11-20 contains estimates of end-use efficiency associated with various policies under various energy scenarios. Several aspects of these results are noteworthy. First, the almost universal presence of negative values in Table 11-20 is due to the fact that under most energy scenarios and under most new service policies the value of unsatisfied demand for natural gas exceeds the value of the satisfied demand. Thus, while the volume of the satisfied demand may exceed the volume of the unsatisfied demand, its value, measured in terms of consumers' willingness-to-pay for gas, may not. Secondly, the company initiative policy leads to the highest estimates of end-use efficiency. This is not surprising because this policy consists of the provision of new service to the greatest number of new customers and, thus, the elimination of the greatest amount of unsatisfied demand. Thirdly, in the absence of the company initiative policy, the selected residential policy leads to highest end-use efficiency followed by the industrial only and, finally, the no new service policies. Implicit in this order is the fact that residential customers value gas more than industrial customers. This is primarily due to the ready availability of coal to many industrial customers at competitive prices.

Table 11-21 contains estimates of production efficiency associated with the new service policies under various energy scenarios. The results, in terms of the desireability of the new service policies, are almost identical to those associated with end-use efficiency. A potential implication of these results is that at least in the context of the new service policies considered, increasing sales generate more revenues than costs. This is due to the fact that the aggregate demand for gas is sufficiently inelastic so that as the price of gas is raised revenues do not decline. It is important to note that the information available is not sufficient to judge the economies of scale in the distribution of natural gas.[2] From production efficiency point-of-view

[2] These statements are not a contradiction to the explanation of total assets turnover ratio estimates.

Table 11-20 Present Value of Aggregate End Use Efficiency Index (EUEI), by Policy and Energy Scenario, Based on Simulations for the Period 1978-2000.

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	-1,039,022,080	-647,378,432	-722,427,392	-993,706,752
MRTSC	-1,028,616,700	-761,248,000	-830,892,800	-966,765,824
HRCSA	-1,028,020,740	-151,624,880	-403,337,728	-851,245,312
HRCSD	-1,030,512,640	-148,733,744	-406,049,792	-848,013,568
LRCSE	-988,881,536	-998,881,536	-998,881,536	-998,881,536
LRCSB	-1,017,921,020	-1,017,921,020	-1,017,921,020	-1,017,921,020
EOGCS	-1,038,089,980	1,039,731,970	-583,605,504	-757,539,584

Table 11-21. Present Value of Aggregate Production Efficiency Index by Policy and Energy Scenario, Based on Simulations for the Period 1978-2000.

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	200,008,480	208,457,248	205,874,832	201,432,240
MRTSC	326,045,184	334,999,808	331,682,560	328,875,262
HRCSA	319,894,784	347,521,024	336,839,424	326,314,496
HRCSD	316,429,824	343,438,592	333,272,576	322,777,600
LRCSE	329,603,072	329,603,072	329,603,072	329,603,072
LRCSB	330,427,648	330,427,648	330,427,648	330,427,648
EOGCS	197,334,992	245,034,304	230,086,688	204,485,792

* The various energy scenarios were fully described in Chapter 3.

** The various new service policies were fully described in Chapter 6.

of end-use efficiency were performed to estimate the extent to which new service policies result in the allocation of gas to those consumers who the results could be different if a policy of full new service outside the currently served areas were considered.

Table 11-22 contains estimates of aggregate economic efficiency associated with the new service policies and the various energy scenarios. Aggregate economic efficiency consists of the sum of end-use efficiency and production efficiency. In light of results contained in Tables 11-20 and 11-21, the estimates in Table 11-22 are not surprising. Considering each energy scenario in isolation, the company initiative policy yields the highest economic efficiency index followed by the selected residential policy. Comparison of the alternate energy scenarios yields a variety of results. It is fairly certain, however, that higher forecasts of gas supply and policies that lead to greatest hook-ups generate the best results in terms of economic efficiency.

Table 11-22 Present Value of Aggregate Economic Efficiency Index by Policy and Energy Scenario, Based on Simulation for the Period 1978-2000.

Energy Scenario*	New Service Policies**			
	No New Service	Company Initiative	Selected Residential Only	Industrial Only
MRTSF	-839,013,376	-438,920,960	-516,552,448	-792,274,432
MRTSC	-702,571,520	-426,248,192	-499,210,240	-637,890,560
HRCSA	-708,125,952	195,896,144	-66,498,304	-524,930,816
HRCSD	-714,082,816	194,704,848	-72,777,216	-525,235,968
LRCSE	-669,278,464	-669,278,464	-669,278,464	-669,278,464
LRCSB	-687,493,376	-687,493,376	-687,493,376	-687,493,376
EOGCS	-840,754,944	1,284,766,210	813,692,160	-553,053,691

* The various energy scenarios were fully described in Chapter 3.
** The various new service policies were fully described in Chapter 6.

Synthesis of Results

Based on the results described above Table 11-23 contains a summary of policies ranked in terms of the desireability of their impacts on utility finances, on customers, and on net aggregate economic efficiency. These results are based on averages of annual impacts only. No reference is made to the time incidence of the impacts. Nor is there reference to the best or worst results.

Table 11-23 Policy Rankings by Type of Impact Based on Simulations for the Period 1978-2000.*

Policy	Impact on Utility Finances	Impact on Customers	Impact on Net Aggregate Efficiency
No New Service Policy	3	1	4
Company Initiative Policy	2	4	1
Selected Residential Policy	1	2	2
Industrial Only Policy	3	3	3

Yet, even the limited information contained in Table 11-24 is too rich to yield an objective and unambiguous choice of the preferred policy. All policies, except the industrial only policy, emerge as the preferred policy in terms of at least one of the impact criteria used in this study. Two of the policies considered emerge as second best policies. Thus, concern for company finances alone would lead the decision-maker to choose the selected residential policy as a guide for new service offering by Ohio's gas distribution companies. Concern for customers alone would lead the same decision-maker to prefer the current ban as the preferred policy. Concern for economic efficiency, on the other hand, would lead the decision-maker to select the selected residential policy. The choice of the preferred policy depends on the relative importance, in the form of weights, that decision-makers attach to the decision criteria.

Finally, although no full-scale attempt has been made to select the preferred policy under various assumptions concerning the relative importance of the decision criteria, a more detailed examination of the results reveals that in some cases the selected residential policy is clearly preferred. In other cases, where the policy is not ranked as the preferred policy, it is almost indistinguishable from the preferred policy. Overall, it is ranked as the best policy in terms of impacts on utility finances and second best in terms of impacts on customers and on economic efficiency.

CHAPTER 12

CONCLUSIONS

The purpose of the research effort reported on in these volumes has been to provide the PUCO with an analysis of potential impacts that can be expected to follow various new service policies. A realted objective of this project has been to provide the PUCO with a tool of analysis that can be used by the PUCO staff to evaluate potential impacts of specific future requests for relief orders from the current ban on new service by Ohio's gas utilities. The present volume contains a detailed description of the analytic structure of the regulatory simulation model that has been developed as a result. In addition, the volume contains details of the analysis that was carried out with the help of this model concerning alternative new service policies in the case of the East Ohio Gas Company (EOGC). Several aspects of the results of this research are noteworthy.

The regulatory simulation model that has been developed is perfectly flexible in its adaptability to a variety of analyses prompted by general regulatory issues and jurisdiction specific problems. The analysis of different policy issues requires that adjustments be made in the model. By far the major change is required in the policy evaluation sub-model. The operational measuring of such regulatory objectives as "optimal end-use efficiency" changes depending on the type of scarcity and the resulting allocation problems that are raised by the policy issue. Changes in the policy evaluation sub-model may lead to the necessity for changes in other sub-models, due to new data requirements. Indeed, under certain curcumstances the relative emphasis on the different sub-models may require adjustment. For example, policy issues concerning intra-annual gas allocation require an emphasis on the gas management sub-model, whereas policy issues dealing with long-term growth of the company require an emphasis on the capacity expansion sub-model.

Furthermore, the model will continue to be updated and refined. In the coming year the model will be augmented by the introduction of a jurisdictional cost-of-service sub-model and the refinement of the industrial consumption sub-model to account for inter-industry differences at the two-digit SIC level.

There is a great number of potential new service policies that could have been subjected to evaluation in this study. Generally potential new service policies can be defined in terms of: (a) the type of customer to receive new service, (b) the location of the customer in relation to the existing distribution system, and (c) the contractual arrangement under which the new service is to be provided. The potential of introducing mixed policies in terms of the above categories and the differentiation of policies in terms of time of implementation increases vastly the number of policies that need to be analyzed. Not all such policies were in fact studied.

Yet, the mere existence of a multitude of potential policies serves to emphasize that the choice of the preferred policy must be based on its capacity to satisfy regulatory objectives. With the exception of the end-use efficiency and fairness objectives, the criteria used in the policy evaluation sub-model are traditional and standard. Thus, the impact of new service policies on the utilities' finances was evaluated with the help of such standard financial indicators as: (a) total asset turnover ratio, (b) net profit margin ratio, (c) gross profit margin ratio, (d) return on total assets ratio, (e) return on common equity ratio, and (f) interest coverage ratio. The extent to which the adequacy of service is affected by these policies was assessed with the help of average annual excess demand indexes. In addition, monthly curtailment indexes were calculated for each customer class.

Due to time and budget limitations only representative new service policies were studied under alternative assumptions concerning future conditions, especially those related to the availability of various types of energy and associated prices. In particular, four policies were analyzed under seven energy scenarios. The four policies are:

1. No New Service Policy - the present ban is continued;
2. Company Initiative Policy - this policy permits the company to provide new service within the supply limits and in a

particular order of customer classes. Residential, commercial, and industrial customers within the currently served areas are hooked-up in sequence, followed by residential customers outside the currently served areas;

3. Selected Residential Service - only residential customers within the currently served areas are hooked-up;
4. Industrial Service - only industrial customers within the currently served areas are connected.

Six of the seven energy scenarios were based on U.S. Department of Energy Project Independence Evaluation System (PIES), 1977.

It is important to note that the extent to which the results indicate differences in achievement of the various regulatory objectives is a function of differences in policies and scenarios only. No other exogenous forces were permitted to influence the results. Differences in the achievement of objectives by policies cannot be attributed to changes in the behavior of the EOGC or the PUCO. For example, the model assumes that the cost of doing business will expand at an average historic rate as new services are offered by the EOGC. Should new hook-ups lead the company to incur reduced or increased operating costs, the model does not take such possibility into account. Similarly, the model does not take into account changes in the operations of the PUCO.

Based on the results fully described in Chapter 11 Table 12-1 contains a summary of policies ranked in terms of the desireability of their impacts on utility finances, on customers, and on net aggregate economic efficiency. These results are based on averages of annual impacts only. No reference is made ot the time incidence of the impacts. Nor is there reference to the best or worst results.

Table 12-1 Policy Rankings by Type of Impact Based on Simulations for the Period 1978-2000.*

Policy Ranking	Impact on Utility Finances	Impact on Customers	Impact on Net Aggregate Efficiency
Best Policy	3	1	2
Second Best Policy	2	3	3
Second Worst Policy	1, 4	4	4
Worst Policy	--	2	1

* Policy 1 is the no new service policy,
Policy 2 is the company initiative policy,
Policy 3 is the selected residential policy, and
Policy 4 is the industrial only policy.

Yet, even the limited information contained in Table 12-1 is too rich to yield an objective and unambiguous choice of the preferred policy. All policies, except the industrial only policy, emerge as the preferred policy in terms of at least one of the impact criteria used in this study. Two of the policies considered emerge as second best policies. Thus, concern for company finances alone would lead the decision-maker to choose the selected residential policy as a guide for new service offering by Ohio's gas distribution companies. Concern for customers alone would lead the same decision-maker to prefer the current ban as the preferred policy. Concern for economic efficiency, on the other hand, would lead the decision-maker to select the selected residential policy. The choice of the preferred policy depends on the relative importance, in the form of weights, that decision-makers attach to the decision criteria.

Finally, although no full-scale attempt has been made to select the preferred policy under various assumptions concerning the relative importance of the decision criteria, a more detailed examination of the results reveals that in some cases the selected residential policy is clearly preferred. In other cases, where the policy is not ranked as the preferred policy, it is almost indistinguishable from the preferred policy. Overall, it is ranked as the best policy in terms of impacts on utility finances and second best in terms of impacts on customers and on economic efficiency.

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