MARGINAL COST PRICING FOR GAS DISTRIBUTION UTILITIES: PRELIMINARY ANALYSES AND MODELS

prepared by

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FOREWORD

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Douglas N. Jones
Director

EXECUTIVE SUMMARY

The effects of marginal cost pricing on the demand for natural gas and on changes in the capital and operating costs of gas distribution utilities are important issues in the Public Utility Regulatory Policies Act of 1978. However, the analysis of these effects has been, up to now, considerably inhibited because of lack of relevant data and methods on which to base the calculation of these marginal costs, in particular the marginal capacity costs. It is the purpose of this study to provide data and methods for the calculation of these costs and for the evaluation of the impacts of marginal cost pricing policies. These methods combine the use of econometric techniques and optimization/simulation algorithms.

Econometric models of distribution plant costs have been developed using community-level data for four U.S. gas distribution utilities: Long Island Lighting Company, Columbia Gas of Ohio, Inc., Pacific Gas and Electric Company, and National Fuel Gas Distribution Corporation. These cost models can be used for predicting future costs as well as for calculating marginal distribution capacity costs. Some major commonalities emerge from the comparison of the different models. Probably the most important one is the nonseparability of the distribution plant costs incurred to serve the different sectoral markets of the utility. Such a result is not surprising in view of the complex and nonseparable linkages that exist among the different customers served by the same pipeline network. The second most important commonality is related to the economies of scale achieved with respect to both residential and nonresidential gas sales. The two previous results imply that the sectoral sales marginal costs are (1) decreasing with the sector's size, and (2) depending upon the size of the other sector(s). Third, the population density variable turns out to be generally significant. Finally, the Pacific Gas and Electric Company analysis has demonstrated the usefulness of accounting for weather parameters when the utility's service territory is climatologically heterogeneous.

The exact calculation of the marginal supply, storage, and transmission costs implies the development of a complex gas network optimization model. In view of the problems involved in solving a complete network model, a simplified, aggregate, and nonspatialized model has been developed to calculate these marginal costs. This model, cast into a linear programming format, yields time-linked (monthly) marginal costs. In addition, it has been embedded into a larger simulation model designed to evaluate all the implications of marginal cost pricing under alternative assumptions (maximum supplies, demand elasticities, etc.). This general model has been applied to the East Ohio Gas Company. The major results of

the optimization/simulation analysis are that (1) marginal costs highly depend upon supply conditions (maximum availability, charges, contracts, etc,) and upon various technological constraints; (2) peak-shifting problems are very likely to occur if distribution capacity marginal costs are wholly assigned to the peak period (month); (3) the excess revenue problem does not necessarily always occur, and its occurrence depends upon supply conditions, costs, technological constraints, financial parameters, and the price elasticities of the monthly demands. Although it would be highly premature to draw final conclusions from this partial analysis, it should be noted that the results do not clearly point out the superiority of a marginal cost pricing policy.

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CHAPTER 1

INTRODUCTION

The theory and application of marginal cost pricing to electric utilities have been the subjects of much research and discussion during recent years, and following a tradition solidly established in Europe, various electricity marginal cost pricing experiments have been conducted in the U.S. There has been less discussion about applying marginal cost pricing principles to natural gas utilities, and such discussions have nearly always identified the relevant marginal cost as the commodity marginal cost;[1] that is, whenever an existing or new gas source is called upon to help fill the demand in a given system, the price for all gas sold in that system is set at the cost of this marginal supply. The marginal transmission and distribution capacity costs have often been dismissed as irrelevant because of an alleged excess capacity in those networks.

Nevertheless, it seems that marginal cost pricing for gas distribution utilities is slowly coming of age. For instance, the New York Public Service Commission issued on September 17, 1979, an opinion[2] stating that the marginal cost of gas is a relevant consideration in gas rate cases and requested explanations of calculations and estimates for the commodity and capacity marginal costs at different times, recognizing the effects of contract provisions with suppliers, storage costs, and plans for transmission,

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[1] R.A. Tybout, "Marginal Cost versus Rolled-in Pricing for Natural Gas," Public Utilities Fortnightly, March 31, 1977.

[2] Opinion No. 79-19 - State of New York Public Service Commission.

distribution, and storage. The commissioners also stated their awareness of the possibility that marginal cost based rates might provide excess revenues to the utility, and of the need to deal with this issue should it arise.

The effect of marginal cost pricing on the demand for natural gas and on changes in the capital and operating costs of gas distribution utilities is an important issue in the National Energy Act of 1978 (see PURPA: Section 306 - Gas Utility Rate Design Proposals). However, the analysis of these effects has been, up to now, considerably inhibited because of lack of relevant data on which to base the calculation of these marginal costs, in particular the marginal capacity costs. It is the purpose of this study to provide data and methods for the calculation of gas marginal costs, with a particular emphasis on capacity costs, and for the evaluation of the impacts of marginal cost pricing policies. The proposed methods are illustrated with data obtained from actual gas distribution utilities in the U.S. They combine the use of statistical/econometric techniques and of optimization/simulation algorithms.

The remainder of the report is organized as follows: chapter 2 presents general considerations for the estimation of gas distribution utilities' marginal costs and outlines the approach selected in this study; chapter 3 describes the rationale for the econometric modeling of the distribution plant costs and the results obtained for four different distribution utilities; chapter 4 presents an optimization/simulation model designed to compute monthly marginal costs and to analyze the impacts of marginal cost rates in terms of economic efficiency, energy conservation, and utility revenue requirements. The applicability of this model is illustrated with data from the East Ohio Gas Company; chapter 5 concludes the study and outlines areas for further research.

CHAPTER 2

NATURAL GAS DISTRIBUTION UTILITIES COSTS AND PRICING: GENERAL CONSIDERATIONS

The purpose of this chapter is to analyze, in a general way, the problems involved in natural gas pricing at the distribution level, and to present the rationale for the methodology adopted in this study. In the first section, the theoretical underpinnings of marginal or peak-load pricing for public utilities are summarily presented. The next section reviews the principles of marginal cost pricing application to gas distribution. The third section describes the conceptually optimal approach to marginal costs calculation and the problems involved in its actual implementation. The final section outlines the practical methodology selected in this study.

The Theoretical Rationale for Utility Marginal Cost Pricing

The theory of marginal cost pricing and its application to public utility pricing have been discussed in numerous recent books and articles.[3] Public utilities, in particular gas and electric distribution utilities, supply a commodity the demand for which is periodic and that is only partially, if at all, storable. What should then be the price charged to the users of this commodity?

To simplify the analysis, consider a commodity with two distinct demand periods: an off-peak period T_1 and a peak period T_2, of durations

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[3] See, for instance, the "Symposium on Peak Load Pricing", The Bell Journal of Economics 7, 1 (Spring 1976).

τ_1 and τ_2, respectively. Define the corresponding demands per unit of time for the commodity as Q_1 and Q_2. These demands are charged at prices P_1 and P_2, and the demand function $P_1(Q_1)$ and $P_2(Q_2)$ are assumed to be known. The operating costs for the utility per unit of commodity produced are C_1 and C_2, and the unit capacity cost is noted as b_2. The utility's capacity must be able to provide the peak demand Q_2, and under the assumption that no reserve margins are necessary, this capacity is taken exactly equal to Q_2. The total cost for the utility of producing (Q_1,Q_2) is

$$TC = \tau_1 C_1 Q_1 + \tau_2 C_2 Q_2 + b_2 Q_2 \tag{2.1}$$

The net revenue for the utility - or the producer's surplus (PS) - is equal to the difference between gross sales revenue and costs, with

$$PS = \tau_1 P_1(Q_1) Q_1 + \tau_2 P_2(Q_2) Q_2 - TC \tag{2.2}$$

The net consumers' surplus (CS) is equal to the difference between their gross surplus and the cost of obtaining the commodity, with

$$CS = \tau_1 \int_0^{Q_1} P_1(Q)dQ + \tau_2 \int_0^{Q_2} P_2(Q)dQ - \tau_1 P_1(Q_1)Q_1 - \tau_2 P_2(Q_2)Q_2 \tag{2.3}$$

The total welfare function (W) for both the utility and its customers is the sum of the above defined producer's and consumers' surpluses, with

$$W = \tau_1 \int_0^{Q_1} P_1(Q)dQ + \tau_2 \int_0^{Q_2} P_2(Q)dQ - \tau_1 C_1 Q_1 - \tau_2 C_2 Q_2 - b_2 Q_2 \tag{2.4}$$

The above welfare W is a function of the commodity quantities Q_1 and Q_2 produced and consumed

$$W = W(Q_1,Q_2) \tag{2.5}$$

The optimal production/consumption situation is reached when W is maximized, i.e., when the partial derivatives of W with respect to Q_1 and Q_2 are equal to zero. Such conditions are restated as

$$\frac{\partial W}{\partial Q_1} = \tau_1 P_1(Q_1) - \tau_1 C_1 = 0 \tag{2.6}$$

$$\frac{\partial W}{\partial Q_2} = \tau_2 P_2(Q_2) - \tau_2 C_2 - b_2 = 0 \tag{2.7}$$

or, after simplification

$$P_1(Q_1) = C_1 \tag{2.8}$$

$$P_2(Q_2) = C_2 + \frac{b_2}{\tau_2} \tag{2.9}$$

The interpretation of equations (2.8) and (2.9) is that

(1) the off-peak price should be set equal to the off-peak unit operating cost, which is also the marginal off-peak operating cost,

(2) the peak price should be set equal to the sum of the marginal peak operating cost and of the marginal capacity cost.

In the above example, linear cost functions have been used for the sake of simplicity, and therefore average and marginal costs are equal. However, if nonlinear cost functions are used, then the results are valid only with the marginal costs, hence the "marginal cost pricing" term.

The above theoretical framework will be useful for understanding the optimization/simulation approach presented in chapter 4. However, it clearly fails to account for various important real-world features of public utilities. First, it is clear that no public utility is characterized by a homogeneous production capacity. Electricity can be produced by different types of generators (coal, nuclear, oil, gas) with different operating and capacity costs. A gas distribution utility can purchase its gas from many different suppliers with widely different prices and contractual requirements, as well as extract gas from the ground or manufacture it (propane plant). Also, storage may be technologically feasible. Second, the demand for such commodities as gas or electricity varies daily, weekly, and seasonally, and therefore the number of relevant demand periods is considerably larger than in the above example. Third, this demand, even in a given period, is uncertain (it varies with weather and other random factors), and so is the supply because of equipment failures; therefore, the interactions between pricing and curtailment or rationing costs must be accounted for. Finally, it must be noted that in the above example, it was implicitly assumed that even with marginal cost pricing, the second period T_2 would remain the peak one. However, it is quite possible that the consumers, reacting to the new peak and off-peak prices, would shift their demand from the peak to the off-peak period, making the latter the new peak period. Then, the original prices would no longer be equal to the marginal costs corresponding to the new demand pattern. Of course, the magnitude of this shifting depends upon the own- and cross-price elasticity of the demands of the different periods. The analysis in chapter 4 will clearly demonstrate the importance of this shifting peak problem.

The above remarks do not negate the usefulness of marginal cost pricing principles but simply point out that their application is much more complicated than the simple prescriptions based on simple models. The purpose of the next section is to further the analysis of the applicability of marginal cost pricing principles in the case of gas distribution utilities.

Marginal Cost Pricing at the Gas Distribution Level: Introductory Considerations

The gas industry is made up of three major components: production, transmission, and distribution. Distributors may produce some of the gas they use, but generally they receive most of their gas from one or more interstate pipeline companies that in turn may purchase it from various producers or import it (Canada, Mexico, LNG). The relevant commodity costs, in the absence of any vertical integration of the gas industry, are, for the distributors, those they pay their suppliers. These costs are generally characterized by two-part rates: a commodity rate, related to the amount of gas actually purchased, and a demand rate, related to the contract demand, that is, the maximum daily deliveries that the supplier commits itself to deliver to the distributor. The demand rate provides for payment of the capacity (pipeline, compressors, storage, etc.) that the supplier has to install to offer the required quality of service. Also, most of the long-term contracts between distributors and interstate pipeline companies involve take-or-pay clauses, that is, the distributor commits itself to purchase a minimum quantity of gas at the specified commodity rate or to pay for this minimum quantity if it has not been actually taken.

The importance of the above features is obviously related to the variability of gas requirements that highly depend upon weather. Gas requirements peak in the winter season (generally January) and are at a low point in the summer season (generally July and August). Of course, the magnitude of the seasonal swing depends upon the market mix of the distributor, i.e., the number and characteristics of its space-heating customers. One way to attenuate the impact of the requirements variability on the supply variability is for the distributor to install and operate a storage (generally underground) system or to rent the storage pools of other companies (very often its own suppliers), and to use peak-shaving SNG (synthetic natural gas) plants or other short-term peak supplies.

In addition to an eventual storage system, the gas distribution system is made of transmission and distribution lines that deliver gas to the ultimate users. Transmission lines, of larger diameters, convey gas at higher pressure from the takeoff points, where gas is purchased from the suppliers, to the load centers, generally communities and metropolitan areas, where gas is then injected into the local distribution networks. The capacity of the distribution system must be such that the firm requirements corresponding to the coldest weather experienced in the service territory (or peak-day requirements) can be met. This capacity is therefore going to be underutilized most of the time, and under marginal cost pricing principles, the marginal capacity costs should then be paid by those consumers responsible for the peak requirements. Of course, note that the required marginal capacity also depends upon the existing excess capacity of the system.

The previous discussion of supply, storage, and distribution capacity costs clearly indicates that marginal variations in gas requirements at different periods have highly different impacts on these costs, and therefore marginal cost time-variable rates are clearly justified. Also, it appears that supply, storage, and distribution capacity decisions are highly interrelated. For instance, the economic feasibility of storage depends upon the costs of storage and the demand charge of the supplier. If the latter is very high, then storage may become an attractive alternative for reducing demand costs. Thus, the relevant marginal costs are those corresponding to the least-cost trade-off among supply, storage, and distribution decisions. They also depend upon additional supplies availability as well as upon such constraints as maximum incremental storage capacity, SNG production capacity, etc., and upon the possibility for the distributor to renegotiate long-term contracts with particular suppliers.

In addition to their temporal variability, gas distribution marginal costs are also characterized by a spatial variability.[4] Indeed, a gas distribution system is a spatialized system with complex technological interactions, and therefore increases in demands at different points of the network have different impacts in terms of the necessary additional capacity of the different pipeline links, storage pools, compressors, etc. To trace the impacts of increased gas requirements clearly implies the use of detailed gas distribution network models where the various flows are simulated and that account for the trade-offs between compressors size and pipeline diameters. The use of such models is discussed in the next section.

From the above discussion, it is clear that the approach envisioned here would encompass both short-term and long-term marginal costs. In

[4]The use of locational variations in rate design by distribution utilities has been minimal. However, the analysis in chapter 3 will demonstrate the importance of these locational variations.

other words, the capacity costs of distribution are not assumed to be sunk. A dynamic growing market is assumed to exist and to require capacity replacement and expansion.

Finally, it is necessary to conform revenues under marginal cost rates with the revenue requirements determined through the traditional rate base regulation. It has often been argued that setting prices equal to marginal costs would provide the utility revenues in excess of the authorized, regulated revenues. However, such a proposition has never been formally proven, and in fact, depends upon the specific characteristics of the utility, its suppliers, and its customers. These revenue considerations will be fully analyzed in chapter 4.

Calculating Gas Distribution Marginal Costs: A Conceptual Approach

Consider a hypothetical gas distribution utility as diagrammatically represented in figure 2.1.

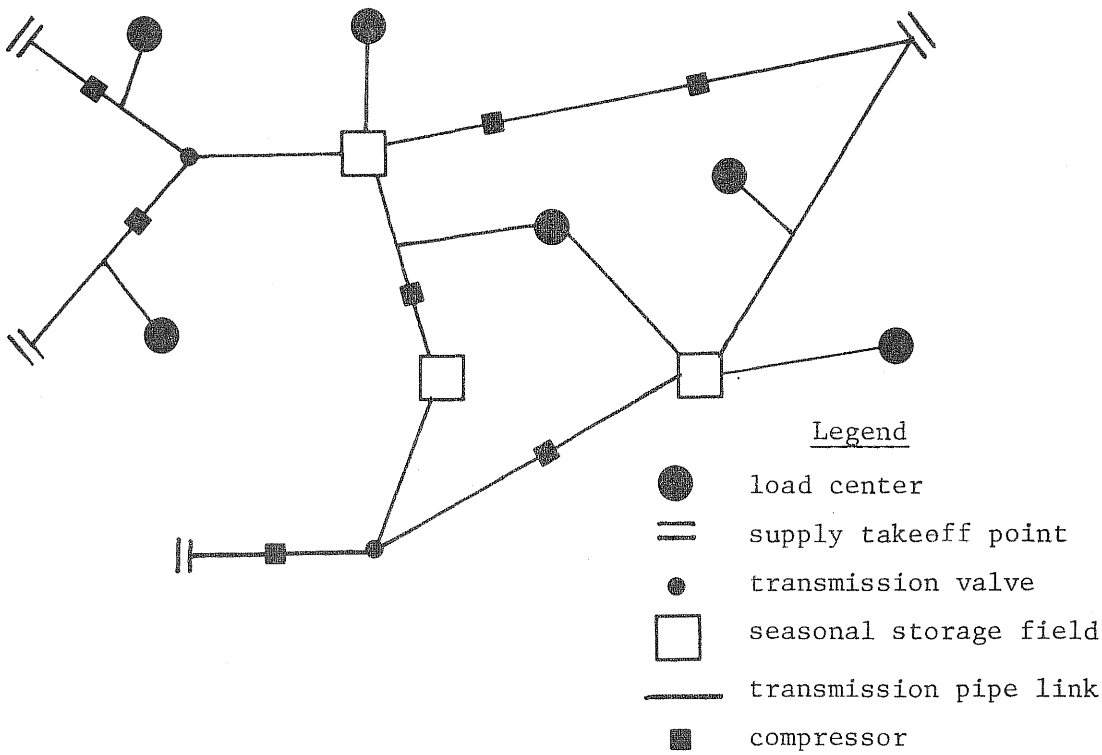

Figure 2.1 A Hypothetical Gas Distribution System

The system presented in figure 2.1 represents both existing and potential (i.e., which may eventually be added) components. The end-use customers are grouped into load centers (communities, urban areas, etc.) in which the distribution lines (and the related equipment such as regulators, gas holders) are located. The pipeline links on figure 2.1 are therefore only the transmission ones that convey gas from the supply takeoff points to the seasonal storage fields and to the load centers. Assume that there are L load centers ($\ell=1\to L$) and that the year can be subdivided into T periods ($t=1\to T$), each characterized by given levels of gas requirements. The gas requirements of load center ℓ during period t are then noted $D_{\ell t}$. The problem facing the utility planner is to determine the least-cost pattern of supply, operation, and capacity expansion decisions subject to various physical, technological, and other constraints, and to satisfying the gas requirements $D_{\ell t}$.

There are a large number of decision variables controlled by the uti ity planner, such as the following

- the amounts of gas purchased from each supplier at each takeoff point during each period t
- the maximum daily deliverability from each supplier
- the amounts of gas conveyed in each selected pipe link during each period
- the diameters of these pipes
- the location and power of the compressors
- the storage fields' capacity and the corresponding periodic inflows and outflows, etc.

There are, of course, constraints bearing on the above variables, such as the following

- maximum available supplies
- maximum pipe and compressor capacities
- maximum storage capacities and deliverability, etc.

Assume that there are K decision variables ($k=1\to K$) noted X_K and that the total cost associated with a given vector $\bar{X} = \{X_k\}$ is denoted $C(\bar{X})$. The constraints set is partitioned into two subsets:

- M_1 physical, technological, and resource availability constraints ($m=1 \rightarrow M_1$)
- M_2($=L \times T$) constraints expressing the satisfaction of the requirements $D_{\ell t}$

The planning problem can then be expressed as

$$\text{minimize } C(\bar{X}) \tag{2.10}$$

subject to the following constraints

$$F_m(\bar{X}) = 0 \qquad (m=1 \rightarrow M_1) \tag{2.11}$$

$$G_{\ell t}(\bar{X}) = D_{\ell t} \qquad (\ell=1 \rightarrow L;\ t=1 \rightarrow T) \tag{2.12}$$

The above model is a mathematical program that would turn out to be a linear program if the objective function $C(\bar{X})$ and the constraints were expressed linearly. In such a case, the marginal cost associated with a marginal variation of the requirements $D_{\ell t}$ is exactly equal to the shadow price, or dual value, of the corresponding constraint (2.12). These shadow prices are a natural part of the solution of any linear program. Such an approach to the calculation of space-time marginal costs has been applied by Scherer[5] in the case of electricity generation and distribution systems. When the system cannot be reduced to a linear format, a possible approach to the calculation of the marginal cost $MC(D_{\ell t})$ is to solve the above program while increasing the demand $D_{\ell t}$ by an increment $\Delta D_{\ell t}$ and to compute the cost increment ΔC. The marginal cost is then approximated by

$$MC(D_{\ell t}) = \frac{\Delta C}{\Delta D_{\ell t}} \tag{2.13}$$

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[5] C.R. Scherer, "Estimating Peak and Off-Peak Marginal Costs for an Electric Power System: An Ex Ante Approach," <u>The Bell Journal of Economics</u> 7, 2 (1976): 575-601.

Obviously, the above marginal cost would encompass supply, storage, and transmission marginal costs. However, providing for the increment $\Delta D_{\ell t}$ implies also additional distribution capacity costs within load center ℓ. Conceptually, then, the internal structure of each load center should also be formalized as a network serving all the individual customers (residential, commercial, industrial), and the marginal distribution cost corresponding to the marginal variation of the demand of any customer should be computed through a procedure similar to the one discussed for the larger network. Through such a hierarchical analysis, the total marginal cost corresponding to any marginal variation in demand could be calculated.

What are the practical prospects for the previous approach? Various planning models have been developed for gas utilities, mostly at the interstate transmission level,[6] but also at the distribution level.[7] The transmission models are all expressed as optimization models, whereas the distribution ones are cast into a simulation format. However, no model could be found that analyzes, comprehensively, the design and operation of a gas distribution network in an urban area (i.e., a load center). The review of the available literature shows that the design of a supply/storage/transmission optimization model is feasible, but that developing efficient solution algorithms may be quite difficult because of the highly nonlinear character of the model and the necessary inclusion

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[6] See, for instance: J.C. Heideman, "Optimal Development of a Natural Gas Transmission System," Society of Petroleum Engineers, SPE Preprint 3980, 1972; H.B. Martch and N.J. McCall, "Optimization of the Design and Operation of Natural Gas Pipeline Systems," SPE Preprint 4006, 1972; O. Flanigan, "Constrained Derivatives in Natural Gas Pipeline System Optimization," Journal of Petroleum Technology 24, 5 (1972); D.J. Fenton and J.H. Wilson, "Extending a Gas Pipeline Network," Journal of the Operational Research Society 29, 9 (1978).

[7] See, for instance: A.E. Yingling, D.L. Raphael, and G.E. Slater, "A Dynamic Linear Flow Model of a Gas Distribution System," SPE Preprint 4714, 1973; G.E. Slater, J.C. Erdle, D.L. Raphael, "Simulating the Operation of a Natural Gas Distribution System with Linear Flow Models," Journal of Canadian Petroleum Technology 16, 4 (1978).

of integer variables. The development of such models at the level of urban areas appears to be an even more difficult endeavor. The approach adopted in this study has been, therefore, to develop simplified models dealing with (a) supply, storage, and transmission costs on one side, and (b) distribution costs on the other side. The outline of this approach is presented in the next section.

Calculating Gas Distribution Marginal Costs: A Practical Approach

In view of the problems involved in calculating community-level distribution costs through a comprehensive network modeling approach, a statistical approach has been selected, wherein the actual distribution capacity costs of the various communities (or part of them) included in the utility's service territory are related to the size of their various submarkets, their population density, and their climatic characteristics, provided that the service territory is climatologically heterogeneous. The resulting econometric cost models can then be used to determine the marginal distribution plant costs incurred by a marginal increment of residential, commercial, or industrial demand (expressed in gas volume or number of customers). Clearly, these marginal costs represent average values for the whole community, encompassing higher or lower marginal costs for individual customers. This econometric approach is presented in chapter 3 and illustrated with the data provided by different gas distribution utilities in the U.S.

In view of the problems involved in solving a complete network model, a simplified, aggregate, and nonspatialized model has been developed to calculate the marginal supply, storage, and transmission costs. This model, cast into a linear programming format, yields time-linked marginal costs. In addition, it has been embedded into a larger simulation model designed to evaluate the implications of marginal cost pricing under alternative maximum supplies and demand elasticities assumptions. This general model - the Gas Utility Marginal Cost Pricing Model (GUMCPM) - has been applied to the East Ohio Gas Company, and the results of this application as well as the structure of the model are presented in chapter 4.

In order to establish a correspondence with the marginal capacity, energy, and customer costs customarily computed for electric utilities, the marginal costs computed in the above-mentioned approaches can be characterized as follows:

(1) The marginal distribution plant costs computed with the econometric models include both distribution and customer capacity costs

(2) The marginal costs computed by the cost-minimization model include (a) energy (supply) costs, (b) capacity (production, storage, and transmission costs, and (c) operating (production and storage) costs, closely related to the energy costs. These marginal costs are complemented, in the simulation model, by the distribution capacity marginal costs and by the other operating marginal costs (transmission, distribution, customer, and administration)

The optimization/simulation approach demonstrates that the various marginal costs cannot be easily separated because of multiple and complex cost trade-offs taking place in a gas distribution system. The econometric approach emphasizes the impacts of market size and mix, and urban structure on local distribution marginal costs. These impacts are not considered in the current optimization/simulation approach because of its aggregated, nonspatialized character but could be so in an extended model.

CHAPTER 3

ECONOMETRIC MODELING OF DISTRIBUTION PLANT COSTS

The purpose of this chapter is to present the principles and results of an econometric analysis of distribution plant costs, based on community-level data obtained from different distribution utilities. The resulting distribution plant cost functions can then be used to predict future costs as well as used for the calculation of marginal costs. In the first section, the general characteristics of the distribution plant, a review of the available data, and the general structure of the econometric models are presented. The next section deals with an analysis of the results obtained for four particular companies: Long Island Lighting Company, Columbia Gas of Ohio, Inc., Pacific Gas and Electric Company, and National Fuel Gas Distribution Corporation. The last section consists of a comparative analysis and synthesis of the results and outlines possible extensions of the approach.

General Considerations

Gas Distribution Utilities Plant Structure

The capital equipment of gas distribution utilities is generally classified according to the following categories:

(1) the intangible plant, generally very small, and including such items as "organization" and franchises and consents

(2) the production plant, including both manufactured gas production plant and natural gas production and gathering plant

(3) the natural gas storage plant, including both underground storage plant and other storage equipments, such as holders

(4) the transmission plant, made up essentially of mains and compressor station equipment

(5) the distribution plant, the major components of which are the mains, services, and meters

(6) the general plant, including transportation equipment, tools, shop and garage equipment, laboratory equipment, etc.

The distribution plant includes some or all of the following items:

- land and land rights
- structures and improvements
- mains
- compressor station equipment
- measuring and regulating station equipment
- services
- meters
- meter installations
- house regulators
- house regulating installations
- industrial measuring and regulating station equipment
- other property on customers premises
- other equipment

Mains, services, meters, and regulating equipment constitute most of the distribution plant. The mains comprise between 50% to 70% of the distribution plant value. They convey the gas taken from the transmission system to the final users and can be made of steel, cast iron, or plastic. Services comprise between 20% to 35% of the distribution plant. A gas service is the pipe between a distribution main and the customer's meter. Usually, it supplies a single building housing one or more customers. Both steel and plastic pipes are used for gas services. Meters are, of course, used to measure actual gas consumption by customers. Regulating equipment is used to control gas distribution pressures in both high-pressure and low-pressure systems. A gas pressure regulator automatically varies the rate of gas flow through a pipeline to maintain a preset outlet pressure.[8]

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[8] For more technical details about the various components of the distribution network, see the Gas Engineers Handbook, sec. 9 (New York: Industrial Press, 1966).

Estimating Gas Distribution Plant Costs

The original (or historical) cost balances of the different components of a utility's plant in service, at the beginning and end of each year, are generally available in the annual reports that the utility submits to the regulatory authorities. The end-of-year value is equal to the beginning-of-year value plus the value of the additions made during the year minus the original cost value of the plant retired during the same year. It is on the basis of these data that average plant costs per customer or per thousand cubic feet (MCF) delivered are estimated. Obviously, such an approach is ill fitted to deal with such considerations as joint, nonseparable costs, economies of scale, and population and land-use densities, inasmuch as they have an effect on plant costs.

The effects of market mix and density have been partially analyzed by some authors in the case of electrical distribution costs.[9] In the case of gas distribution, the available data are even scarcer. One study reporting some relationships between gas distribution capital costs and density has been carried out by Real Estate Research Corporation for the Council on Environmental Quality and other government agencies, with the broader goal of assessing the environmental and economic costs of alternate housing types and development patterns at the urban fringe.[10] Six neighborhood prototypes differing in housing type and density were analyzed. They are described in table 3.1.

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[9] See, for instance: F. J. Wells, "The Effects of Customer Density on Electrical Distribution Costs," in P. B. Downing, ed., Local Service Pricing Policies and Their Effect on Urban Spatial Structure (Vancouver, University of British Columbia Press, 1977); M. L. Baughman and D. J. Bottaro, Electric Power Transmission and Distribution Systems: Costs and Their Allocation, National Science Foundation PB-247189 (Springfield, VA: National Technical Information Service, 1975).

[10] Real Estate Research Corporation, The Costs of Sprawl: Detailed Cost Analysis (Washington, D.C.: U. S. Government Printing Office, 1974) Stock Number 4111-00023.

TABLE 3.1

NEIGHBORHOOD PROTOTYPES CHARACTERISTICS

Neighborhood Prototype	Population (Per 100 Acres)	Residential Density (Units per Acre)
A. Single Family Conventional	3,520	2.0
B. Single Family Clustered	3,520	2.5
C. Townhouse Clustered	3,330	3.3
D. Walk Up Apartments	3,330	5.0
E. High Rise Apartments	2,825	10.0
F. Housing Mix 20% of A,B,C,D,E	3,300	3.3

Source: The Costs of Sprawl: Detailed Cost Analysis, (Washington, D.C.: Government Printing Office, 1974).

The estimates for gas distribution capital costs are indicated in table 3.2 for each of the six neighborhood types. All figures are in 1973 dollars. It was assumed that all development prototypes would be typical of high-standard new suburban construction. Preexisting land uses and the relationships between the neighborhoods and the rest of the metropolitan area were not taken into account. Also, the study did not include the cost of debt servicing and replacement or upgrading costs for any facilities built within the development period. Thus, capital cost estimates are given only for pipelines and appurtenances within the neighborhood. The selected pipe materials were deemed to be typical of current practice in the U.S. (Use of other materials might alter cost estimates significantly.) Differences in costs due to differences in terrain, topography, and climate could not be considered. Also, 30% of the estimated costs of the pipelines were added to cover contractor's and subcontractor's profits and overhead plus engineering fees. The length of utility pipelines is close to street lengths. It was assumed that utility line length would be somewhat shorter than road length (10 to 15% less) to reflect sophisticated engineering and design practices.

TABLE 3.2

CAPITAL COSTS OF PROVIDING GAS TO THOUSAND HOUSING UNITS
IN SIX NEIGHBORHOODS

Variable	Neighborhood					
	A Single Family Conventional	B Single Family Clustered	C Townhouse Clustered	D Walk Up Apartments	E High Rise Apartments	F Housing Mix (20% A,B,C,D,E)
Total Pipeline Length	56,000'	35,800'	22,800'	13,604'	8,055'	25,500'
Percentage of Road Length	90%	80%	80%	80%	90%	85%
Cost per Linear Foot of Pipe	$2.30	$2.30	$2.30	$3.00	$3.00	In proportion to the Housing Mix
Total Pipeline Cost	$124,200	$82,340	$52,440	$40,812	$24,165	$64,791
Overhead and Profit	$37,260	$24,702	$15,732	$12,244	$7,249	$19,437
Total Capital Cost	$161,460	$107,062	$68,172	$53,056	$31,414	$84,228

Source: The Costs of Sprawl: Detailed Cost Analysis, (Washington, D.C.: U.S. Government Office, 1974).

Although the data in table 3.2 confirm, rather dramatically, the relationship between gas distribution capital costs and density, they remain too much prototype related to be of general use. Also, as noted earlier, they only refer to urban extensions and do not account for the cost implications of these extensions for the whole community or metropolitan area. For instance, such extensions may call for the reinforcement of the existing network to meet the increased loads through mains duplication or compressor stations installation, etc. Also, these new urban developments may be located at varying distances from the existing main lines, implying extensions of mains of varying lengths.

Next, it is important to remember that residential customers constitute only a part, important as it may be, of the gas market, and no specific cost data appear to be available for commercial and industrial customers that have consumption levels and load profiles significantly different from those of the residential customers. Hence, the distribution capital costs incurred to serve them can also be expected to be significantly different.

Finally, any given customer will consume more or less gas, depending upon the climate of the area where he is located, all other factors remaining the same, and it is necessary to account for the climatic factor in estimating and predicting distribution costs.

For all of the above-mentioned reasons, new approaches to the analysis of gas distribution capital costs are called for. The purpose of the next section is to outline the principles of such an approach.

An Econometric Approach to Distribution Plant Analysis

Most gas distribution utilities keep track of their capital investments at the community level. In some states, such as New York, they are required to do so for tax assessment purposes. They also keep track of their gas sales, numbers of customers, and revenues for market, revenue, and billing analyses. The communities located in the service territory of any utility display strong variations in terms of (1) the number of residential, commercial, and industrial customers and the corresponding unit-average and total gas loads; (2) the amount of distribution plant in service within the community boundaries; (3) the population and land acreage, and hence the density of the community; and (4) climatic factors if the service territory is spread over a climatologically heterogeneous region. Once such data are gathered, the natural next step is to try to explain, through regression analysis, the variations of the distribution plant in service - the dependent variable - by the variations of such independent variables as market size and mix, population density, winter-cold severity, etc. Both additive (linear) and multiplicative (logarithmic) models should be tested. Examples of such models are[11]

$$PS = a_0 + a_1*RMCF + a_2*CMCF + a_3*IMCF + a_4*TEDN \quad (3.1)$$

$$\ln(PS) = b_0 + b_1*\ln(RMCF) + b_2*\ln(CMCF) + b_3*\ln(IMCF) + b_4*\ln(TEDN) \quad (3.2)$$

where

- PS is the amount of distribution plant in service ($)
- RMCF is the amount of annual residential gas sales (MCF)
- CMCF is the amount of annual commercial gas sales (MCF)
- IMCF is the amount of annual industrial gas sales (MCF)
- TEDN is the population density (population per acre)

In equations (3.1) and (3.2), the coefficients a_1, a_2, a_3 and/or b_1, b_2, b_3 are expected to be positive, and the coefficients a_4 and/or b_4 negative. If, for instance, the linear model prevails, then the coefficients a_1, a_2, and a_3 represent the marginal plant costs incurred by serving one additional MCF to the residential, commercial, and industrial sectors, respectively. If, on the other side, the logarithmic model prevails, then the costs of service to the three sectors are nonseparable, and the marginal cost of serving, say, one MCF to the residential sector depends upon the current levels of sales to the three markets. Also, the latter case implies the existence of economies or diseconomies of scale, whereas the linear model implies constant costs to scale.

One obvious problem with the above approach is related to the use of the original cost balance for measuring the value of the plant in service,

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[11] From here on, the text contains a combination of algebraic and FORTRAN notations; e.g., multiplication is sometimes designated by an asterisk(*).

instead of its replacement cost that should be the correct reference for measuring total and marginal costs. However, if the various communities of the service territory have plants in service made up, percentage-wise, of equipment of similar vintages, then it can reasonably be assumed that the ratio between historical cost and replacement cost is approximately constant. Such an assumption turned out to be verified for the distribution plant of Pacific Gas and Electric Company (in 1979 the replacement cost was equal to 2.79 times the historical cost) and will be retained for the other companies analyzed in this study.

Other functional forms can be tested. For instance, the sectoral numbers of customers instead of the sectoral sales can be used as independent variables. However, both types of variables should not be used simultaneously, for there may be a strong to very strong correlation between them (i.e., the number of residential customers and the MCF level of residential sales are generally very strongly correlated). Also, the independent variables may be aggregated in various ways: total sales or total number of customers, commercial and industrial customers or sales, etc.

Cost functions such as those illustrated by equations (3.1) and (3.2) are indicative of long-term total costs and marginal costs. Indeed, as the whole community plant is taken into consideration in the analysis, the resulting marginal cost of serving, say, one additional residential MCF includes both the marginal cost corresponding to the localized main extension and service and meter, and the marginal cost corresponding to the necessary adjustments in the whole community plant. The latter may be incurred much after the extension has been made, as a result of reaching some threshold point in the operation of the whole network. The former, however, may be termed a "short-term" marginal cost, directly incurred at the time of new installation and service. Such a short-term cost could, in principle, be analyzed with time-series data on plant in service and market size and structure. In this case, however, only the numbers of customers should be used as independent variables because gas sales may change significantly from one year to the next as a result of climatic changes, even while the numbers and characteristics of the customers do not change.

Examples of short-term cost models are

$$DPS = a_0 + a_1*DRCUS + a_2*DCCUS + a_3*DICUS + a_4*TEDN \quad (3.3)$$

$$\ln(DPS) = b_0 + b_1*\ln(DRCUS) + b_2*\ln(DCCUS) + b_3*\ln(DICUS) + b_4*\ln(TEDN) \quad (3.4)$$

where

- DPS is the increase in the amount of distribution plant in service between two consecutive years, and
- DRCUS, DCCUS, and DICUS are the increases in the numbers of residential, commercial, and industrial customers during the same period, respectively

The feasibility of this short-term analysis depends upon (a) the availability of the corresponding data; and (b) the existence of actual market growth (i.e., DRCUS, DCCUS, DICUS > 0). As is well known, a ban on new customer hookups had been instituted in most states in the early 1970s because of steadily decreasing available gas supplies. However, because of wellhead gas pricing changes, supplies started to increase again in the late 1970s and the ban was removed. Utilities started to connect new customers, and the corresponding market growth has been particularly noticeable in 1978 and 1979. Some limited analyses of the "short-term" cost effect therefore turned out to be feasible within the framework of this study.

Based on the above principles and ideas, various analyses have been performed with data obtained from four different gas distribution utilities: Long Island Lighting Company, Columbia Gas of Ohio Company, Pacific Gas and Electric Company, and National Fuel Gas Distribution Corporation. The purpose of the next section is to describe the available data and the results of these analyses.

Applications of the Econometric Approach

Long Island Lighting Company (LILCO)

LILCO is a dual gas and electric, privately owned utility serving, in 1979, an estimated 2,884,601 people, including 97,343 persons residing on the Rockaway Peninsula of Queens, New York. Most of the served population is residing in communities located in the Long Island counties of Nassau and Suffolk.

The data in table 3.3 provide an overview of the gas plant in service at the end of 1978 and 1979, and those in table 3.4 present a summary of gas sales and average numbers of gas customers during the years 1978 and 1979.

Firm gas sales in 1979 totaled 39,400,000 MCF, down only 2.6% below 1978, despite much more moderate winter weather in 1979 (4,622 versus 5,441 annual heating degree-days; normal year average = 5,095 degree-days). Sales to interruptible commercial and industrial customers rose 170.5%. During 1979, the number of LILCO gas space-heating customers was increased by 5,600. However, the net balance of the average number of residential customers increased only by 297 because of a significant attrition of the existing market due to an overall population decline. Also, the existing firm customers were allowed to expand their firm gas requirements. Thus, LILCO was characterized by a dynamic market in 1978/1979 that will permit a limited "short-term" cost analysis.

The data in table 3.3 show that the distribution plant makes up for about 73% of the total plant. Mains and services, in turn, make up for about 59% and 29% of the distribution plant. In 1979, the changes in the distribution plant included (a) additions, valued at $8,238,075; and (b) retirements, valued at $609,177. The value of the additions corresponds to replacement costs, whereas the value of the retirements corresponds to historical (original) costs. A part of the additions is used to replace the retired plant, but most of it is likely to be related to new service, the exact amount depending upon the replacement costs.

TABLE 3.3

VALUE OF GAS PLANT IN SERVICE AT THE END OF 1978 AND 1979
LILCO

(In Dollars)

Plant Component	End of 1978	End of 1979
OVERVIEW		
Manufactured Gas Production	$ 5,833,120	$ 5,896,982
Storage	12,246,770	12,439,837
Transmission	48,127,301	48,506,446
Distribution	200,990,807	208,619,705
General	7,048,017	8,205,708
Total	$274,246,015	$283,668,678
DISTRIBUTION PLANT		
Land and Land Rights	$ 279,148	$ 280,014
Structures and Improvements	280,627	324,148
Mains	118,460,883	122,359,684
Compressor Station Equipment	9,585	9,585
Measuring and Regulating Station Equipment	2,294,563	2,453,773
Services	59,141,513	61,647,931
Meters	11,728,385	12,701,159
Meter Installation	6,791,098	6,826,330
House Regulators	2,005,005	2,017,081

Sources: Annual Reports of LILCO to the State of New York Public Service Commission - 1978 and 1979.

TABLE 3.4

VOLUME OF GAS SALES AND NUMBER OF CUSTOMERS
IN 1978 AND 1979 - LILCO

Sector	Year 1978	Year 1979
GAS SALES (MCF)		
Residential	27,470,883	26,369,644
Commercial & Industrial	14,549,342	17,241,741
Public Authorities	13,693	13,865
Interdepartmental	75,237	2,760,023
Total	42,109,155	46,385,272
NUMBER OF CUSTOMERS		
Residential	356,547	356,844
Commercial & Industrial	30,415	30,399
Public Authorities	60	58
Total	387,022	387,301

Sources: Annual Reports of LILCO to the State of New York Public Service Commission - 1978 and 1979.

On the basis of the data in tables 3.3 and 3.4, the 1978 distribution historical unit costs per MCF and customer are the following:

- 4.73 \$/MCF, and
- 519 \$/customer[12]

Included in the Annual Reports submitted by LILCO to the State of New York Public Service Commission (NYPSC) are community-level data on annual gas sales and average number of customers for the residential sector and for the combined commercial and industrial sectors, as well as on the value of the total gas plant in service by the end of the year. Unfortunately, the latter data are not further disaggregated, and therefore the amount of distribution plant is not known, and the application of the econometric analysis to the total plant is likely to introduce some bias because such items as gas production plant and transmission plant are very unlikely to be related to the structure of the local markets. This is less so for the storage plant, which includes mostly short-term gas holders, and for the general plant, which can be both related to local variables to some extent. Thus, the best that can be done in this case is to specify econometric models with the total plant in service variable, and then adjust the resulting equations by the ratio of the distribution to total plants (0.7329 in 1978 and 0.7354 in 1979).

A complete set of plant and market data was prepared for 101 communities for both 1978 and 1979. These data are presented in appendix A. LILCO's estimates of the 1978 population of these communities were also included in the data set. Land area data were partly drawn from a 1970 Census of Population report,[13] and from census tract acreage data provided by R. J. Panzarella, Forecast Analyst at LILCO. Complete acreage data were gathered for 89 communities.

The long-term, or static, analysis has been performed with the 1978 data. At the end of 1978, the total plant in service in the 101

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[12] LILCO's historical distribution unit costs are significantly larger than those of the other companies to be analyzed in this chapter. This is most likely due to the fact that LILCO's plant is made up of components of more recent vintages. However, this assumption could not be verified because the necessary data are lacking.

[13] 1970 Census of Population - Population of Places of 2500 or more - 1960 and 1970 Supplementary Report PC(S1)-26 (August 1972.)

communities amounted to $246,559,200, or 89.9% of the total LILCO plant in service. All the 387,022 LILCO 1978 customers were located in these 101 communities. The short-term, or dynamic, analysis has been performed by taking the difference between the 1979 and 1978 data on both plant and market variables.

a. The Static Analysis

The results presented in this section pertain to the 89 communities for which density figures could be prepared. The definitions and means and standard deviations of the various variables are presented in Table 3.5.

TABLE 3.5

DEFINITIONS, MEANS, AND STANDARD DEVIATIONS OF THE VARIABLES
LILCO STATIC ANALYSIS

Variable	Definition	Mean	Standard Deviation
PS	Plant in Service ($) - End of 1978	2,750,795	6,899,365
TMCF	Total Gas Sales (MCF) - 1978	468,923	1,111,092
RMCF	Residential Gas Sales (MCF) - 1978	305,941	722,895
CIMCF	Commercial & Industrial Gas Sales (MCF) - 1978	162,982	406,177
TCUS	Total Number of Customers - 1978	4,316	10,137
RCUS	Number of Residential Customers - 1978	3,977	9,362
CICUS	Number of Commercial & Industrial Customers - 1978	339	790
TEDN	Population Density (people per acre)	8.764	9.135

Source: Author's calculations.

In a first stage, the plant in service (PS) was regressed on the aggregate sales or number of customers, and on the population density, for both the additive and multiplicative forms. The multiplicative model is expressed in final (nonlogarithmic) multiplicative form. The t-statistics of the coefficients are indicated in parenthesis at the appropriate places. The following four models were obtained.

$$\begin{cases} PS = 238{,}641.4 + \underset{(37.13)^{14}}{6.03379} * TMCF - \underset{(1.83)}{36{,}196.96} * TEDN \quad (R^2 = 0.941) & (3.5) \\ \\ PS = 6.11658 * TMCF^{\underset{(32.02)}{1.0120}} * TEDN^{\underset{(3.35)}{-0.1514}} \quad (R^2 = 0.927) & (3.6) \end{cases}$$

$$\begin{cases} PS = 342{,}818.4 + \underset{(28.42)}{648.528} * TCUS - \underset{(1.76)}{44{,}667.47} * TEDN \quad (R^2 = 0.904) & (3.7) \\ \\ PS = 1983.9955 * TCUS^{\underset{(22.04)}{0.9141}} * TEDN^{\underset{(5.03)}{-0.3366}} \quad (R^2 = 0.858) & (3.8) \end{cases}$$

The performances of the four above models, as measured by their R^2, are overall quite good, with slightly higher R^2 in the linear case. However, the density coefficient is much more significant in the multiplicative case than in the linear one (where the confidence level is around 95% only). However, as is well known, R^2 for linear and log-linear models cannot be directly compared. For the same dependent variable and equivalent number of independent variables, the functional form that yields the minimum sum of squares of the residuals is generally to be selected.[15] A transformation of PS that permits such a comparison is $PS_1 = C.PS$, where C is the inverse of the geometric mean of PS. The sum of squares of the residuals in the linear model must then be multiplied by C^2, and the resulting value S_1 must be compared to the sum S_2 of squares of the residuals in the logarithmic case, the model with the smaller sum value being generally preferred. It is further possible to test whether the two functions are empirically equivalent by computing the d statistic

$$d = \frac{N}{2} \left| \ln \left(\frac{S_1}{S_2} \right) \right| \tag{3.9}$$

where N is the sample size. The larger of the two sums is placed in the numerator. If the two forms are equivalent, then d follows the chi-square

[14] The t-statistics, measuring the significance of the regression coefficients, are indicated in parenthesis below the corresponding coefficient. The level of significance, for a given t-value, depends upon the sample size and number of variables of the regression model.

[15] See: P. Rao, and R.L. Miller, Applied Econometrics (Belmont CA: Wadsworth Publishing Company, Inc.,1971),pp. 107-11.

distribution with one degree of freedom. (The critical value of the 90% level of confidence is 2.706).

On the basis of the previous criteria, the logarithmic models are clearly superior to the linear ones. For instance, the sum S_1 for equation (3.5) is equal to 138.83, whereas the sum S_2 for equation (3.6) is equal to 18.32. The multiplicative models are rewritten below to reflect only distribution costs by adjusting the total plant equations by the distribution to total plants ratio (0.7329)

$$PS = 4.48284 * TMCF^{1.0120} * TEDN^{-0.1514} \tag{3.10}$$

$$PS = 1{,}454.0703 * TCUS^{0.9141} * TEDN^{-0.3366} \tag{3.11}$$

The above cost functions imply nearly constant costs to scale (extremely slight diseconomies of scale) with respect to total sales and some economies of scale with respect to the total number of customers. The corresponding marginal distribution capacity cost[16] functions are

$$MC(TMCF) = \frac{\partial PS}{\partial TMCF} = 4.53663 * TMCF^{0.0120} * TEDN^{-0.1514} \tag{3.12}$$

$$MC(TCUS) = \frac{\partial PS}{\partial TCUS} = 1{,}329.1657 * TCUS^{-0.0859} * TEDN^{-0.3366} \tag{3.13}$$

The marginal costs for a hypothetical average community characterized by the average figures in table 3.5 are

$\overline{MC}(TMCF) = 3.82$ \$/MCF

$\overline{MC}(TCUS) = 311.897$ \$/customer

The next step of the analysis was to use sectoral sales and numbers of customers as independent variables. The results are

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[16] Hereafter in this chapter referred to as the marginal cost.

$$
\left\{
\begin{array}{l}
PS = 229{,}418.0 + \underset{(8.24)}{5.77470} * RMCF + \underset{(5.23)}{6.50241} * CIMCF - \underset{(1.72)}{34{,}814.58} * TEDN \\
\qquad\qquad\qquad\qquad\qquad\qquad (R^2 = 0.941) \qquad (3.14) \\
PS = 46.76794 * RMCF^{\underset{(15.00)}{0.7370}} * CIMCF^{\underset{(5.59)}{0.1545}} * TEDN^{\underset{(3.03)}{-0.1765}} \\
\qquad\qquad\qquad\qquad\qquad\qquad (R^2 = 0.883) \qquad (3.15)
\end{array}
\right.
$$

$$
\left\{
\begin{array}{l}
PS = 303{,}066.3 + \underset{(3.79)}{472.644} * RCUS + \underset{(1.88)}{2{,}765.305} * CICUS - \underset{(1.67)}{42{,}237.36} * TEDN \\
\qquad\qquad\qquad\qquad\qquad\qquad (R^2 = 0.906) \qquad (3.16) \\
PS = 5415.7519 * RCUS^{\underset{(7.83)}{0.6057}} * CICUS^{\underset{(4.19)}{0.2768}} * TEDN^{\underset{(4.81)}{-0.3106}} \\
\qquad\qquad\qquad\qquad\qquad\qquad (R^2 = 0.874) \qquad (3.17)
\end{array}
\right.
$$

The sums of the squares of the residuals are significantly smaller in the logarithmic cases, and therefore the multiplicative models are to be selected. It is also notable that the regression coefficients are much more significant in the multiplicative cases. Besides the previous statistical reasons for rejecting the linear models, there are also other substantive, logical reasons to do so. Indeed, the relative values of the coefficients of RMCF and CIMCF in equation (3.14) are highly questionable: it would appear that the distribution plant cost of one additional "commercial and industrial" MCF is higher than the corresponding residential one. This result is not consistent with the load profiles of these two sectors (the load factor of the residential sector being much lower) and the necessary relationship between distribution plant cost and peak load.

The multiplicative cost functions are characterized by significant economies of scale effects. The exponents can also be viewed as cost elasticities to sectoral sales or numbers of customers; that is, they indicate the percentage increase in plant cost due to 1% increase in the corresponding independent variables. As could be expected, the elasticities of the residential sector are larger than those of the commercial-industrial one.

The multiplicative models are rewritten below to reflect only distribution costs by using the distribution to total plants ratio (0.7329)

$$PS = 34.27622 * RMCF^{0.7370} * CIMCF^{0.1545} * TEDN^{-0.1765} \tag{3.18}$$

$$PS = 3969.2046 * RCUS^{0.6057} * CICUS^{0.2768} * TEDN^{-0.3106} \tag{3.19}$$

Focusing on the sales model (3.18), it is now possible to derive marginal cost functions with respect to residential and commercial-industrial sales, MC(RMCF) and MC(CIMCF), respectively, with

$$MC(RMCF) = \frac{\partial PS}{\partial RMCF} = 25.26055 * RMCF^{-0.2630} * CIMCF^{0.1545} * TEDN^{-0.1765} \tag{3.20}$$

$$MC(CIMCF) = \frac{\partial PS}{\partial CIMCF} = 5.29533 * RMCF^{0.7370} * CIMCF^{-0.8451} * TEDN^{-0.1765} \tag{3.21}$$

The marginal costs for the hypothetical average community characterized by the average sales and density figures presented in table 3.5 are then

$$\overline{MC}(RMCF) = 3.9661 \ \$/MCF$$

$$\overline{MC}(CIMCF) = 1.5606 \ \$/MCF$$

The above two values should be compared to the marginal cost of 3.82 \$/MCF when the total load is considered. (See equation 3.12.) Clearly the latter is not very helpful to discriminate between the two sectors and using it would heavily penalize the commercial-industrial sector while slightly advantaging the residential one. The customers-related marginal cost functions are derived similarly, with

$$MC(RCUS) = \frac{\partial PS}{\partial RCUS} = 2403.6471 * RCUS^{-0.3943} * CICUS^{0.2768} * TEDN^{-0.3106} \tag{3.22}$$

$$MC(CICUS) = \frac{\partial PS}{\partial CICUS} = 1098.8346 * RCUS^{0.6057} * CICUS^{-0.7232} * TEDN^{-0.3106} \quad (3.23)$$

The marginal customer-related costs for the average community depicted by the data in table 3.5 are then

$\overline{MC}(RCUS)$ = 234.08 \$/residential customer

$\overline{MC}(CICUS)$ = 1255.38 \$/commercial-industrial customer

To illustrate the variations of these marginal costs with market size, consider a much smaller community with 500 residential customers, 20 commercial-industrial customers, and a density of 4 people per acre. The marginal costs are then

MC(RCUS) = 308.99 \$/residential customer

MC(CICUS) = 3,531.41 \$/commercial-industrial customer

The above values should be compared to the marginal cost of 311.897 \$/customer when the total number of customers is considered. (See equation 3.13.) Basing a pricing policy on the latter cost would considerably advantage (in fact subsidize) the commercial-industrial sector at the slight expense of the residential one. Note, however, that all the above cost figures are based on historical costs data and are therefore smaller than the corresponding replacement cost figures. Naturally, any pricing policy incorporating distribution capacity marginal costs should use replacement cost figures.

b. The Dynamic Analysis

The numbers of communities characterized by an increase, decrease, or no change in the numbers of their residential (DRCUS) and commercial-industrial (DCICUS) customers are indicated in table 3.6.

TABLE 3.6

MARKET DYNAMICS IN LILCO COMMUNITIES
DURING THE PERIOD 1978-1979

Number of Residential Customers (DRCUS)	Number of Commercial-Industrial Customers (DCICUS)		
	Decrease (< 0)	No Change (= 0)	Increase (> 0)
Decrease (< 0)	12	7	6
No Change (= 0)	2	12	3
Increase (> 0)	22	19	18

Source: Author's calculations.

Three separate analyses were performed on the following groups of communities: (1) the 18 communities displaying growth in both sectors, (2) the 41 communities displaying growth in the residential sector only, and (3) the 9 communities displaying growth in the commercial-industrial sector only. A common feature of the three analyses is that the logarithmic model is, by far, superior to the linear one, and therefore only results pertaining to the former are presented. Also, the density variable turned out to be insignificant and was discarded. The definitions of the variables and their average values in the above three cases are presented in table 3.7.

TABLE 3.7

DEFINITIONS AND MEAN VALUES OF
THE DYNAMIC ANALYSIS VARIABLES - LILCO

Variable		Case 1 DRCUS>0 DCICUS>0	Case 2 DRCUS>0 DCICUS≤0	Case 3 DRCUS≤0 DCICUS>0
DPS	Increase in Plant in Service ($)	198,842	39,540	180,622
DRCUS	Increase in Residential Customers	16.89	7.71	-14.33
DCICUS	Increase in Commercial-Industrial Customers	1.72	-2.73	4.78

Source: Author's calculations.

Case 1: DRCUS > 0; DCICUS > 0; 18 communities

The model, adjusted to reflect distribution costs only, is

$$\text{DPS} = 1{,}375.9258 * \underset{(1.42)}{\text{DRCUS}^{0.7585}} * \underset{(1.58)}{\text{DCICUS}^{1.0904}} \qquad (R^2 = 0.486) \tag{3.24}$$

The coefficients of DRCUS and DCICUS are significant at the 10% level. The corresponding marginal cost functions are

$$\text{MC(DRCUS)} = \frac{\partial \text{DPS}}{\partial \text{DRCUS}} = 1{,}043.5852 * \text{DRCUS}^{-0.2415} * \text{DCICUS}^{1.0904} \tag{3.25}$$

$$\text{MC(DCICUS)} = \frac{\partial \text{DPS}}{\partial \text{DCICUS}} = 1{,}500.2806 * \text{DRCUS}^{0.7585} * \text{DCICUS}^{0.0904} \tag{3.26}$$

The marginal costs for the hypothetical community depicted by Case 1 growth data in table 3.7 (DRCUS = 16.89, DCICUS = 1.72) are

$\overline{\text{MC}}$(DRCUS) = 952.405 \$/new residential customer

$\overline{\text{MC}}$(DCICUS) = 13,445.216 \$/new commercial-industrial customer

The ratio between the above residential "dynamic" marginal cost (\$952.405) and the residential "static" marginal cost computed for the average community in the previous section (\$234.076) is equal to 4.07. This ratio may be viewed as a first, rough estimate of the ratio between replacement and historical costs. It is larger than the one obtained for Pacific Gas and Electric Company (2.78), and this may be due to the older age of LILCO's plant. The corresponding ratio for commercial-industrial customers is much larger, equal to 10.71 (\$13,445.216/\$1,255.38). However, this ratio does change rapidly with market size, and it does not seem possible to specify the characteristics of two equivalent static and dynamic communities for which costs could be meaningfully compared. (For instance, if the community of 500 residential customers and 20 commercial-industrial customers is selected for the static case, the previous ratio becomes equal to 3.807).

Case 2: DRCUS > 0; DCICUS $\leq$ 0; 42 communities

In this case, the plant increase is assumed to be solely related to residential growth. It is also assumed that there is no retirement of the plant in service related to the attrition of the commercial-industrial customers. The model, adjusted to reflect distribution costs only, is then

$$DPS = 1{,}748.723 * \underset{(3.85)}{DRCUS^{0.9996}} \qquad (R^2 = 0.276) \tag{3.27}$$

Although the correlation coefficient is lower than in the previous case, it is significantly different from zero (at the 0.1% level), and the regression coefficient is also highly significant. The above model can be viewed as an almost constant-cost-to-scale one, with a constant distribution plant marginal cost equal to

$$\overline{MC}(DRCUS) = 1{,}747 \text{ \$/new residential customer}$$

The above marginal cost appears to be larger (by \$795) than the one obtained in case 1. A reasonable explanation for this difference is that in the present case the residential sector does not benefit from the positive technological externalities related to the addition, in the distribution system, of commercial and industrial customers. In other words, the joint-cost effect does not take place here, and the cost difference of \$795 is a measure of the economic benefit derived from this externality by the residential sector.

Case 3: DRCUS $\leq$ 0; DCICUS > 0; 9 communities

In this case, it is assumed that the plant increase is solely related to commercial-industrial growth, and that there is no retirement of the plant in service related to the attrition of the residential customers. The model, adjusted to reflect distribution costs only, is then

$$DPS = 298.735 * \underset{(2.64)}{DCICUS^{2.9557}} \qquad (R^2 = 0.5) \tag{3.28}$$

The above model has significant correlation and regression coefficients. The cost function is characterized by diseconomies of scale, and so is the corresponding marginal cost function

$$MC(DCICUS) = 882.9791 * DCICUS^{1.9557} \tag{3.29}$$

A comparison of the results obtained with equations (3.29) and (3.26) shows that for a given commercial-industrial growth the corresponding marginal customer cost is going to be lower in presence of residential growth, as compared to the no-residential-growth case, only below a given threshhold of minimal residential growth. Assume, for instance, that DCICUS = 5 customers, then equation (3.29) would yield, in presence of no residential growth, a marginal cost of $20,556.3. With reference to equation (3.26), the residential growth leading to the same commercial-industrial marginal cost is equal to 26 residential customers. If DRCUS = 5, then MC(DCICUS) = $5,881, and if DRCUS = 40, then MC(DCICUS) = $28,474. To determine the technological circumstances (if any) producing these cost effects would require much more in-depth analyses of local factors, a study that could not be performed in the framework of this research.

Columbia Gas of Ohio Company (CGOC)

Columbia Gas of Ohio is a privately owned distribution utility providing service to 360 communities in central, northern, and southern Ohio. Its major supplier is the Columbia Transmission Corporation that also owns the underground storage fields used, at a cost, by CGOC. Therefore, the major part of the CGOC plant is its distribution plant, as demonstrated by the plant in service data for 1976 and 1977 presented in table 3.8.

The data in table 3.8 show that the distribution plant makes up for about 97% of the total plant. Mains and services, in turn, make up for about 59% and 21% of the distribution plant. Meter-related equipment and house-regulators-related equipment make up for another 11% and 2% of this plant.

The data in table 3.9 provide a summary of gas sales and average numbers of gas customers during the years 1976 and 1977. On the basis of

TABLE 3.8

VALUE OF GAS PLANT IN SERVICE AT THE END OF 1976 AND 1977
CGOC

(In Dollars)

Plant Component	End of 1976	End of 1977
DISTRIBUTION PLANT		
Land and Land Rights	$ 3,384,835	$ 3,452,563
Structures and Improvements	6,817,690	6,897,848
Mains	238,835,096	245,473,197
Measuring and Regulating Station Equipment	4,518,807	4,840,849
Measuring and Regulating Station Equipment - City Gate Check	2,491,710	2,529,750
Services	82,893,968	89,504,927
Meters	33,883,409	34,763,419
Meter Installation	10,794,359	11,126,744
House Regulators	4,236,932	4,245,608
House Regulator Installation	4,372,382	4,391,326
Industrial Measuring and Regulating Station Equipment	5,395,295	5,392,429
Other Property on Customers' Premises	877,333	877,333
Other Equipment	1,814,603	1,679,221
Total Distribution Plant	$400,316,419	$415,175,214
Total Utility Plant	$412,424,960	$428,715,064

Sources: Annual Reports of CGOC to the Public Utilities Commission of Ohio (PUCO).

TABLE 3.9

VOLUME OF GAS SALES AND NUMBER OF CUSTOMERS
IN 1976 AND 1977 - CGOC

Sector	Year 1976	Year 1977
GAS SALES (MCF)		
Residential	158,014,211	151,145,232
Commercial	64,601,949	56,232,729
Industrial	130,904,784	102,155,711
Total	353,520,944	309,533,672
NUMBER OF CUSTOMERS		
Residential	965,915	960,577
Commercial	78,219	77,380
Industrial	1,732	1,592
Total	1,045,866	1,039,549

Sources: Annual Reports of CGOC to the Public Utilities Commission of Ohio (PUCO).

these data, the 1976 distribution plant historical unit costs per MCF and customer are the following (using the 1977 sales figures could be misleading because of the heavy curtailments that took place in 1977)

- 1.132 \$/MCF, and
- 382.761 \$/customer

The home rule provision in Ohio's constitution and statutes permits a municipality to contract with a privately owned utility to obtain services by passage of a rate ordinance and its acceptance by the utility. On the basis of this provision, CGOC establishes gas rates separately with 360 Ohio communities. There are marked variations among these rates, related, according to CGOC, to variable costs of bringing gas to these communities.

At the request of the PUCO, data were collected by The National Regulatory Research Institute (NRRI) to find out whether there could be significant improvements in the ratemaking procedures adopted by the PUCO and by the various communities. Various data have been gathered for a sample of 52 communities included in the set of the 291 municipalities that had rate changes through either PUCO rate orders or ordinance rate negotiations during the period 1976-1979. The data retained for the purpose of the present study are

- the net plant in service, or rate base: RB
- the residential, commercial, and industrial gas sales (MCF): RMCF, CMCF, IMCF
- the numbers of residential, commercial, and industrial customers: RCUS, CCUS, ICUS

This data set was complemented, for 42 communities, with population and acreage data. In addition, the combined commercial-industrial sector was also considered (as in the case of LILCO's analysis), with the corresponding sales and number of customers noted CIMCF and CICUS. The means and standard deviations of the above plant and market variables are presented in table 3.10, and the detailed community-level data in appendix B. The rate base, or net plant in service, is equal to the total plant in service minus the accumulated provision for depreciation, amortization, and depletion. The latter was equal, at the end of 1977, to $145,155,000, while the total plant in service was equal, at the same period, to $428,715,064. (See table 3.8.) Thus, the ratio of total to net plants in service is equal to 1.512. It is assumed that this adjustment ratio can be uniformly applied to the rate bases of the 52 communities. Second, as was done in the case of LILCO, it is necessary to adjust the total plant figure to reflect only the distribution plant costs. The 1977 distribution to

TABLE 3.10

MEANS AND STANDARD DEVIATIONS OF THE VARIABLES
CGOC STATIC ANALYSIS

Variable	Mean	Standard Deviation
RB ($)	2,352,877	6,690,295
TMCF (total sales)	1,978,637	6,083,876
RMCF	1,441,581	4,332,637
CMCF	496,148	1,649,132
IMCF	40,907	121,460
CIMCF	537,055	1,765,766
TCUS (total customers)	9,505	29,016
RCUS	8,871	27,123
CCUS	599	1,721
ICUS	35	215
CICUS	634	1,900

Source: Author's calculations.

total plants ratio is selected, equal to 0.9684. Therefore, the rate base figures must be multiplied by 1.4642 to represent the distribution plant in service. Another problem is related to the fact that the data do not all pertain to the same year (28 communities refer to 1976 data, 12 to 1977 data, and the remainder equally to 1978 and 1979 data). Indeed, gas sales vary from one year to another because of weather changes, all other factors remaining equal (i.e., the numbers of customers). One way to eliminate this problem is to adjust gas sales with reference to an average-weather year (e.g., with an average number of degree-days). To perform this adjustment, the knowledge of the load equations of the different sectors is a prerequisite but could not be gathered in this study. Thus some bias is likely to exist in the resulting econometric models. However, in view of the excellent fits obtained, it is believed that this bias is probably negligible.

In a first stage, the distribution plant in service PS was regressed on the aggregate sales or number of customers, and on the population density, with both the additive and logarithmic forms. The density variable turned out to be highly insignificant and was therefore discarded. Thus, the analyses were performed with the 52 communities' data. The following four models were obtained

$$\begin{cases} PS = 385{,}565.5 + \underset{(138.53)}{1.60805} * TMCF \quad (R^2 = 0.997) & (3.30) \\[2ex] PS = 6.63155 * TMCF^{\underset{(42.54)}{0.9141}} \quad (R^2 = 0.973) & (3.31) \end{cases}$$

$$\begin{cases} PS = 248{,}023.6 + \underset{(81.95)}{438.848} * TCUS \quad (R^2 = 0.992) & (3.32) \\[2ex] PS = 810.691 * TCUS^{\underset{(36.31)}{0.9183}} \quad (R^2 = 0.963) & (3.33) \end{cases}$$

The sums of the squares of the residuals are significantly smaller in the logarithmic cases, and therefore the multiplicative models are to be selected. They imply economies of scale of similar magnitude with respect to both sales and total number of customers. The corresponding marginal cost functions are

$$MC(TMCF) = \frac{\partial PS}{\partial TMCF} = 6.0617 * TMCF^{-0.0859} \tag{3.34}$$

$$MC(TCUS) = \frac{\partial PS}{\partial TCUS} = 744.482 * TCUS^{-0.0817} \tag{3.35}$$

The marginal costs for a hypothetical average community characterized by the average figures in table 3.10 are

$\overline{MC}(TMCF) = 1.744$ \$/MCF

$\overline{MC}(TCUS) = 352.35$ \$/customer

It is interesting to compare the above marginal cost functions with the corresponding ones obtained in the LILCO analysis (equations 3.12 and 3.13). If equation (3.13) is adjusted for an average density of 8.764

people per acre, the resulting equation

$$MC(TCUS) = 640.126 * TCUS^{-0.0859} \tag{3.36}$$

is very similar to equation (3.35), both with respect to the multiplicative constant and the exponent, hence the similar customer-related marginal costs. On the other side, the sales-related marginal cost of LILCO (3.82 \$/MCF) is about twice as large as the corresponding cost for CGOC (1.744 \$/MCF). This apparent contradiction is resolved when it is noted that the average CGOC customer annual load is about twice the corresponding LILCO load. Thus, there are significant economies of scale associated with customer's size, and this observation points out the need for further econometric analyses involving customers' sizes in addition to the presently used variables. These analyses could not be performed in the framework of this study.

The next step in the analysis was to use sectoral sales and numbers of customers as independent variables. The industrial sector-related variables turned out to be insignificant or having the wrong sign. This result is probably related to the fact that most of the industrial customers are located in the large cities of Columbus (1,555) and Toledo (107), while most of the communities have very few such customers or none at all (24 communities in the latter case). The commercial and industrial sectors have therefore been pooled together. The subsequent analyses are therefore strictly similar to those performed on LILCO's data. The results are

$$\begin{cases} PS = 204{,}983.7 + \underset{(25.75)}{2.1053} * RMCF + \underset{(1.90)}{0.3821} * CIMCF \quad (R^2 = 0.998) & (3.37) \\ \\ PS = 16.5992 * RMCF^{\underset{(10.47)}{0.5835}} * CIMCF^{\underset{(5.93)}{0.3091}} \quad (R^2 = 0.974) & (3.38) \end{cases}$$

$$\begin{cases} PS = 235414.1 + \underset{(6.07)}{278.039} * RCUS + \underset{(1.79)}{1{,}171.871} * CICUS & (R^2 = 0.993) \quad (3.39) \\ PS = 1691.0924 * RCUS^{\underset{(8.32)}{0.5960}} * CICUS^{\underset{(4.50)}{0.3527}} & (R^2 = 0.971) \quad (3.40) \end{cases}$$

The sums of the squares of the residuals are significantly smaller in the logarithmic cases. Note also that the "commercial-industrial" regression coefficients are much more significant in the latter cases. Therefore, the multiplicative models (3.38) and (3.40) are to be selected.

The CGOC cost functions are characterized by significant economies of scale effects. Such a result clearly confirms the company's contention that the cost of service varies from one community to the other. The comparison of equations (3. and (3.40) with LILCO's equations (3.18) and (3.19) reveals a significant similarity when the customers variables are concerned. With respect to gas sales, the exponent of RMCF is larger in LILCO's case, probably because of diseconomies of scale at the customer level (the average LILCO residential customer consumption is 76.93 MCF, while for CGOC it is equal to 162.50 MCF). Surprisingly, the exponent of CIMCF is smaller in LILCO's case, although the corresponding average customer consumption is about half the corresponding one for CGOC. An explanation of this apparent contradiction clearly requires further data analyses.

The sales and customers marginal cost functions are then

$$MC(RMCF) = \frac{\partial PS}{\partial RMCF} = 9.6856 * RMCF^{-0.4165} * CIMCF^{0.3091} \qquad (3.41)$$

$$MC(CIMCF) = \frac{\partial PS}{\partial CIMCF} = 5.1315 * RMCF^{0.5835} * CIMCF^{-0.6908} \qquad (3.42)$$

$$MC(RCUS) = \frac{\partial PS}{\partial RCUS} = 1{,}007.8742 * RCUS^{-0.4040} * CICUS^{0.3527} \qquad (3.43)$$

$$MC(CICUS) = \frac{\partial PS}{\partial CICUS} = 596.4314 * RCUS^{0.5960} * CICUS^{-0.6473} \qquad (3.44)$$

The marginal costs for the average community depicted by the data in table 3.10 are

$$\overline{MC}(RMCF) = 1.557 \text{ \$/MCF}$$
$$\overline{MC}(CIMCF) = 2.214 \text{ \$/MCF}$$
$$\overline{MC}(RCUS) = 249.261 \text{ \$/residential customer}$$
$$\overline{MC}(CICUS) = 2{,}063.917 \text{ \$/commercial-industrial customer}$$

The striking feature in the above results is the fact that a marginal "commercial-industrial" MCF costs more than a marginal "residential" MCF. This counterintuitive result is here related to scale effects and to the relative sizes of the residential and commercial-industrial markets (the former is thrice as large as the latter). Consider now a community with equal-sized markets, each consuming 500,000 MCF (i.e., RMCF=CIMCF=500,000). In this case, the marginal sales costs are

$$MC(RMCF) = 2.367 \text{ \$/MCF}$$
$$MC(CIMCF) = 1.254 \text{ \$/MCF}$$

and the traditionally expected cost ranking is observed.

Pacific Gas and Electric Company (PG&E)

PG&E is a dual gas and electric, privately owned utility providing service to the central and northern parts of California. The data in table 3.11 provide a summary of gas sales and average numbers of gas customers during the years 1978 and 1979, and those in table 3.12 present an overview of the gas plant in service at the end of these two years.

The residential and commercial markets have been characterized by a significant growth during the period 1978-1979 (2.36% for residential customers and 3.66% for commercial customers). The industrial market has experienced, during the same period, a slight decrease, due to industrial customers switching to other energy sources. The average consumptions per customer in 1979 are as follows: 90.409 MCF per residential customer, 849.339 MCF per commercial customer, and 66,654.11 MCF per industrial customer. The growth dynamics of the PG&E market will therefore permit to

TABLE 3.11

VOLUME OF GAS SALES AND NUMBER OF CUSTOMERS
IN 1978 AND 1979 - PG&E

Sector	Year 1978	Year 1979
GAS SALES (MCF)		
Residential	220,076,421	234,294,712
Commercial	144,027,085	143,620,679
Industrial	138,975,191	186,164,937
Total	503,078,697	564,080,328
Public Authorities	1,339	1,356
Interdepartmental Sales	125,768,565	216,147,045
Sales for Resale	9,926,108	36,013,469
Total Gas Service	638,774,709	816,242,198
NUMBER OF CUSTOMERS		
Residential	2,531,755	2,591,507
Commercial	163,117	169,097
Industrial	2,853	2,793
Total	2,697,725	2,763,397
Public Authorities	1	1
Sales for Resale	5	5

Sources: Annual Reports of PG&E to the California Public Utilities Commission (CPUC) - 1978 and 1979.

TABLE 3.12

VALUE OF GAS PLANT IN SERVICE AT THE END OF 1978 AND 1979
PG&E

(In Dollars)

Plant Component	End of 1978	End of 1979
OVERVIEW		
Storage	$ 103,974,935	$ 107,715,240
Transmission	444,410,681	451,797,081
Distribution	1,088,674,784	1,157,367,950
General	12,736,349	13,241,884
Total (Excluding Production and Intangible Plant)	$1,649,796,749	$1,730,122,155
DISTRIBUTION PLANT		
Land and Land Rights	$ 3,551,839	$ 3,770,818
Structures and Improvements	453,164	456,962
Mains	522,350,801	551,964,541
Compressor Station Equipment	68,185	65,030
Measuring and Regulating Station Equipment	18,472,619	18,862,555
Services	375,948,482	404,008,003
Meters	129,106,410	136,917,955
House Regulators	32,483,993	34,827,752
Industrial Measuring and Regulating Station Equipment	5,071,754	5,330,965
Other Property on Customers' Premises	49,637	45,468
Other Equipment	1,117,900	1,117,901

Sources: Annual Reports of PG&E to the California Public Utilities Commission (CPUC) - 1978 and 1979.

perform a "short-term" dynamic cost analysis.

The data in table 3.12 show that the distribution plant made up for about 66.89% of the total plant in 1979. Mains, services, and meters, in turn, made up for about 47.7%, 34.9%, and 11.8% of the distribution plant, respectively. In 1979, the changes in the distribution plant included (a) additions, valued at $73,552,557; and (b) retirements, valued at $4,859,391. The ratio of replacement to historical cost has been estimated by PG&E as equal to 2.79. Under the assumption that the whole retired plant is replaced, then the truly new distribution plant can be estimated at $59,994,856 (= 73,552,557 - 2.79 * 4,859,391). The average cost of the new distribution plant per new customer (residential, commercial, and industrial sectors combined) would then be $912.719. If the total 1979 distribution plant is considered, the historical unit costs per MCF and customer are

- 2.052 $/MCF
- 418.82 $/customer

If the replacement to historical costs ratio (= 2.79) is applied to the above customer cost, a figure of $1,168.5 is obtained, higher than the "dynamic" cost of $912.719. This result would confirm the hypothesis, presented in the first section of this chapter, that the "dynamic" costs are short-term, immediate costs (mains, services, meters) but do not include the longer term costs that the additions of new customers may call for later.

Included in the Annual Reports submitted by PG&E to the California Public Utilities Commission (CPUC) are community-level data on annual gas sales and average numbers of customers in the residential, commercial, and industrial sectors. These data are related to 94 communities with a population of 10,000 or more. These communities are regrouped into 13 geographical divisions. The gas sales and numbers of customers for those communities and for the years 1975 through 1979 are presented in appendix C. The Valuation Department of PG&E provided, for the same years, estimates of the historical and replacement costs of the distribution plant in these communities. The historical costs, i.e., the plant in service, at the end of 1978 and 1979 are also presented in appendix C, together with the mileage of distribution mains at the same periods. A complete set of population and acreage data could be prepared on the basis of the 1970 Census of Population documentation and is also presented in appendix C. Completely new parameters considered in this analysis are the total annual and peak-month average number of heating degree-days. Indeed, the service territory of PG&E is climatologically heterogeneous, and the same customer is likely to consume more or less gas annually as well as during the peak month, depending upon where he is located. The data used to prepare 30-year average figures for total annual and peak-month-heating degree-days are presented in appendix C. They refer to meteorological stations located in various divisions. When a division includes more than one station, the average value is selected. Then, the divisions total annual (DDT) and peak-month (DDM) figures are assigned to the communities located in the corresponding divisions.

The long-term, or static, econometric analysis has been performed with the 1979 data, and the short-term, dynamic analysis has been performed by taking the difference between the 1979 and 1978 data on both plant and market variables.

a. The Static Analysis

The definitions and means and standard deviations of the variables used in this analysis are presented in table 3.13.

In a first stage, the distribution plant in service was regressed on the aggregate sales or total number of customers, on the population density, and on the two degree-day measures alternatively. The variable DDT appeared with the wrong sign and also was highly insignificant. Therefore, only the specifications incorporating DDM were retained. In all cases, the multiplicative model appeared very superior to the additive one, and therefore only results pertaining to the former are presented. Also, in order to evaluate the impact of the introduction of the variable DDM on the

TABLE 3.13

DEFINITIONS, MEANS, AND STANDARD DEVIATIONS OF THE VARIABLES - PG&E STATIC ANALYSIS

Variable	Definition	Mean	Standard Deviation
PS	Distribution Plant in Service - End of 1979 ($)	7,384,459	10,184,724
TMCF	Total Gas Sales (MCF) - 1979	3,454,267	6,229,610
RMCF	Residential Gas Sales (MCF) - 1979	1,742,436	2,979,162
CMCF	Commercial Gas Sales (MCF) - 1979	969,256	2,586,112
IMCF	Industrial Gas Sales (MCF) - 1979	742,575	1,738,055
CIMCF	Commercial and Industrial Gas Sales (MCF) - 1979	1,711,831	4,205,098
TCUS	Total Number of Customers - 1979	21,139	36,008
RCUS	Number of Residential Customers - 1979	19,800	33,841
CCUS	Number of Commercial Customers - 1979	1,321	2,188
ICUS	Number of Industrial Customers - 1979	18	32
CICUS	Number of Commercial and Industrial Customers - 1979	1,339	2,218
TEDN	Population Density (people per acre)	5.96	3.64
DDM	Peak Month Average Number of Degree-Days	534.81	56.30
DDT	Annual Average Number of Degree-Days	2796.96	374.22

Source: Author's calculations.

models specifications and to permit a comparison with the corresponding models derived for the other companies (for which no meteorological variability is considered), the results with an without DDM are presented. They are

$$\begin{cases} PS = 229.1817 * \underset{(16.40)}{TMCF^{0.7072}} * \underset{(1.79)}{TEDN^{-0.1328}} \quad (R^2 = 0.751) & (3.45) \\ PS = 21.2111 * \underset{(16.40)}{TMCF^{0.7082}} * \underset{(1.48)}{TEDN^{-0.1143}} * \underset{(0.89)}{DDM^{0.3720}} \quad (R^2 = 0.753) & (3.46) \end{cases}$$

$$\begin{cases} PS = 1211.915 * \underset{(36.59)}{TCUS^{0.9289}} * \underset{(7.54)}{TEDN^{-0.2879}} \quad (R^2 = 0.937) & (3.47) \\ PS = 116.356 * \underset{(37.05)}{TCUS^{0.9299}} * \underset{(6.87)}{TEDN^{-0.2697}} * \underset{(1.78)}{DDM^{0.3671}} \quad (R^2 = 0.939) & (3.48) \end{cases}$$

All the coefficients are significant at, at least, the 5% level, with the exception of the coefficient of DDM in equation (3.46), the significance of which is in the 15-20% range. It is notable that the exponents of the density variable in equations (3.45) and (3.47) are very close to those obtained in the LILCO analysis (see equations 3.10 and 3.11), where they are equal to - 0.1514 and -0.3366. Also remarkable is the similarity of the exponents of TCUS in the cases of LILCO, CGOC, and PG&E. (See equations 3.11 and 3.33.) If the PG&E and LILCO customer-related cost functions (equations 3.47 and 3.11) are adjusted for the average PG&E population density (= 5.96), they become

<u>PG&E:</u> $PS = 724.92 * TCUS^{0.9289}$ (3.49)

<u>LILCO:</u> $PS = 797.33 * TCUS^{0.9141}$ (3.50)

The above equations, when compared with the corresponding CGOC equation (3.33)

<u>CGOC:</u> $PS = 810.69 * TCUS^{0.9183}$ (3.51)

show a considerable degree of similarity. Therefore, it can be concluded that distribution plant costs are uniformly characterized by the same level of economies of scale when market size is measured by the total number of customers. When market size is measured by total gas sales, it appears that PG&E is characterized by larger economies of scale than CGOC and LILCO.

The marginal cost functions derived from equations (3.46) and (3.48) are

$$MC(TMCF) = \frac{\partial PS}{\partial TMCF} = 15.0217 * TMCF^{-0.2918} * TEDN^{-0.1143} * DDM^{0.3720} \quad (3.52)$$

$$MC(TCUS) = \frac{\partial PS}{\partial TCUS} = 108.2036 * TCUS^{-0.0701} * TEDN^{-0.2697} * DDM^{0.3671} \quad (3.53)$$

The marginal costs for the hypothetical average community characterized by the average figures in table 3.13 are

$\overline{MC}(TMCF) = 1.567$ \$/MCF
$\overline{MC}(TCUS) = 333.97$ \$/customer

The next step of the analysis was to use sectoral sales and numbers of customers as independent variables. In order to permit comparisons with the LILCO and CGOC models, the commercial and industrial variables were pooled together in a first stage. In the second stage, the disaggregated data were used. Again, the models specifications with and without the degree-day variable DDM are presented (the variable DDT turned out to be insignificant and was discarded). The first-stage results are

$$\begin{cases} PS = 25.5817 * \underset{(21.32)}{RMCF^{0.8402}} * \underset{(2.96)}{CIMCF^{0.0696}} * \underset{(5.93)}{TEDN^{-0.2514}} \quad (R^2 = 0.925) & (3.54) \\ PS = 0.1926 * \underset{(22.72)}{RMCF^{0.8632}} * \underset{(2.50)}{CIMCF^{0.0565}} * \underset{(5.30)}{TEDN^{-0.2192}} * \underset{(3.34)}{DDM^{0.7474}} \quad (R^2 = 0.932) & (3.55) \end{cases}$$

$$\begin{cases} PS = 1700.1759 * RCUS^{0.8353} * CICUS^{0.0898} * TEDN^{-0.2844} \quad (R^2 = 0.937) & (3.56) \\ PS = \underset{}{181.1541} * \underset{(15.27)}{RCUS^{0.8492}} * \underset{(1.59)}{CICUS^{0.0772}} * \underset{(6.80)}{TEDN^{-0.2682}} * \underset{(1.64)}{DDM^{0.3451}} \quad (R^2 = 0.939) & (3.57) \end{cases}$$

All the regression coefficients in the above equations are significant at the 5% level. When the PG&E models are compared to the LILCO and CGOC models (see equations 3.18, 3.19, 3.38, and 3.40), it appears that they are characterized by lesser economies of scale with respect to the residential sales or number of customers, but by considerably larger economies of scale with respect to the commercial-industrial variables. The density elasticity is larger than LILCO's when sales are considered (-0.1765) and smaller when the variable is the number of customers (-0.3106). The significance of the density variable is here very high, and so is the significance of the degree-days variable DDM in the sales-related specification. (This variable is still significant at the 5% level in the customers-related specification.) The latter result clearly confirms the importance of the weather factor in the determination of the appropriate capacity of the distribution system.

The marginal cost functions derived from equations (3.55) and (3.57) are

$$MC(RMCF) = \frac{\partial PS}{\partial RMCF} = 0.1662 * RMCF^{-0.1368} * CIMCF^{0.0565} * TEDN^{-0.2192} * DDM^{0.7474} \tag{3.58}$$

$$MC(CIMCF) = \frac{\partial PS}{\partial CIMCF} = 0.0109 * RMCF^{0.8632} * CIMCF^{-0.9435} * TEDN^{-0.2192} * DDM^{0.7474} \tag{3.59}$$

$$MC(RCUS) = \frac{\partial PS}{\partial RCUS} = 153.837 * RCUS^{-0.1508} * CICUS^{0.0772} * TEDN^{-0.2682} * DDM^{0.3451} \tag{3.60}$$

$$MC(CICUS) = \frac{\partial PS}{\partial CICUS} = 13.9906 * RCUS^{0.8492} * CICUS^{-0.9228} * TEDN^{-0.2682} * DDM^{0.3451} \quad (3.61)$$

The marginal costs for the hypothetical average community characterized by the average figures in table 3.13 are

$\overline{MC}(RMCF) = 3.874$ \$/MCF

$\overline{MC}(CIMCF) = 0.258$ \$/MCF

$\overline{MC}(RCUS) = 326.751$ \$/residential customer

$\overline{MC}(CICUS) = 439.417$ \$/commercial-industrial customer

The above sectoral sales marginal costs should be compared to the total sales marginal cost, $\overline{MC}(TMCF) = 1.567$ \$/MCF. Using the latter in a pricing policy would lead to a considerable subsidization of the residential customers by the commercial-industrial ones. Whereas the residential marginal cost is in the same value range as those estimated for the average LILCO and CGOC communities, it should be noted that the commercial-industrial PG&E marginal cost is much smaller than those of LILCO and CGOC. As there are no major interutility differences as far as customer size is concerned, such a difference is probably due to (a) a higher load factor for PG&E customers, and (b) local circumstances, such as the location of these customers within the community. Clearly, additional research is necessary to provide more definite explanations about these differences.

When using the disaggregated commercial and industrial variables, the results turned out to be acceptable only with the sales variables. Indeed, whenever used, the number of industrial customers turned out to be statistically insignificant and with the wrong sign. The sales-related models, with and without the peak-month degree-day variable DDM, are

$$PS = 30.1581 * \underset{(21.35)}{RMCF^{0.8434}} * \underset{(1.37)}{CMCF^{0.0437}} * \underset{(2.05)}{IMCF^{0.0140}} * \underset{(5.96)}{TEDN^{-0.2494}} \qquad (R^2 = 0.926) \qquad (3.62)$$

$$PS = 0.2152 * \underset{(22.61)}{RMCF^{0.8575}} * \underset{(1.43)}{CMCF^{0.0432}} * \underset{(1.76)}{IMCF^{0.0115}} * \underset{(5.31)}{TEDN^{-0.2160}} * \underset{(3.45)}{DDM^{0.7530}} \qquad (R^2 = 0.935) \qquad (3.63)$$

All the regression coefficients are significant at the 5% level, with the exception of the commercial sales coefficient that is, nevertheless, significant at the 10% level. The exponents of RMCF, TEDN, and DDM are very close to those obtained when using the aggregate commercial-industrial sales variable. (See equation 3.55.) In the present model, the commercial sales elasticity (0.043) is about four times larger than the industrial one (0.011). This large difference can be explained by (a) the higher load factor of industrial customers, which are much less sensitive to weather than the commercial ones, and (b) customer-level economies of scale related to customer size. Indeed, the average commercial customer consumption, based on the data in table 3.13, is 734 MCF, whereas the corresponding industrial one is 41,254 MCF. Obviously, the above model might be further improved by introducing customer-size variables. Such an analysis is left for further research efforts.

The marginal cost functions derived from equation (3.63) are

$$MC(RMCF) = \frac{\partial PS}{\partial RMCF} = 0.1845 * RMCF^{-0.1425} * CMCF^{0.0432} * IMCF^{0.0115} * TEDN^{-0.2160} * DDM^{0.7530} \qquad (3.64)$$

$$MC(CMCF) = \frac{\partial PS}{\partial CMCF} = 0.0093 * RMCF^{0.8575} * CMCF^{-0.9568} * IMCF^{0.0115} * TEDN^{-0.2160} * DDM^{0.7530} \qquad (3.65)$$

$$MC(IMCF) = \frac{\partial PS}{\partial IMCF} = 0.0025 * RMCF^{0.8575} * CMCF^{0.0432} * IMCF^{-0.9885} * TEDN^{-0.2160} * DDM^{0.7530} \quad (3.66)$$

The marginal costs for the hypothetical average community characterized by the average figures in table 3.13 are then

$$\overline{MC}(RMCF) = 3.889 \text{ \$/MCF}$$
$$\overline{MC}(CMCF) = 0.352 \text{ \$/MCF}$$
$$\overline{MC}(IMCF) = 0.122 \text{ \$/MCF}$$

The above values should be compared to those obtained with the aggregate commercial-industrial sales ($\overline{MC}(RMCF) = 3.874$ \$/MCF, and $\overline{MC}(CIMCF) = 0.258$ \$/MCF). The residential marginal costs are nearly the same. However, the commercial marginal cost is about thrice the industrial one, and therefore basing a pricing policy on the aggregate commercial-industrial marginal cost would lead to a substantial subsidization of the commercial sector by the industrial one.

b. The Dynamic Analysis

Among the 94 communities analyzed in the previous section, 89 were characterized by a growth in both the residential sector and the combined commercial-industrial one, and 4 by a growth in the residential sector only. Because the sample in the latter case is too small, the following analysis only pertains to the 89 communities. The commercial and industrial sectors were combined because the results derived with the disaggregated data were not acceptable, basically because most of the growth has taken place in the commercial sector. This aggregation will also permit comparisons with the similar model derived for LILCO. Finally, note that the density and degree-day variables turned out to be insignificant and were discarded.

The definitions of the variables and their means and standard deviations are presented in table 3.14. These data imply an average new plant cost equal to \$864/customer.

TABLE 3.14

DEFINITIONS, MEANS, AND STANDARD DEVIATIONS OF THE DYNAMIC ANALYSIS VARIABLES - PG&E

Variable	Definition	Mean	Standard Deviation
DPS	Increase in the Distribution Plant in Service ($)	491,501	632,069
DTCUS	Increase in the Total Number of Customers	569	703
DRCUS	Increase in the Number of Residential Customers	518	651
DCICUS	Increase in the Number of Commercial-Industrial Customers	51	64

Source: Author's calculations.

In a first stage, the increase in plant in service DPS was regressed on the increase in the total number of customers. The linear and logarithmic specifications are

$$DPS = 82{,}120.87 + \underset{(12.41)}{718.636} * DTCUS \qquad (R^2 = 0.639) \tag{3.67}$$

$$DPS = 9{,}790.874 * DTCUS^{\underset{(9.73)}{0.6004}} \qquad (R^2 = 0.521) \tag{3.68}$$

The sums of the squares of the residuals are equal to 140.53 for equation (3.67) and to 44.44 for equation (3.68). The logarithmic model (3.68) is therefore to be selected. It is characterized by stronger economies of scale than in the case of the static approach. (See equation 3.47.) The corresponding marginal cost function is

$$MC(DTCUS) = \frac{\partial DPS}{\partial DTCUS} = 5879.0125 * DTCUS^{-0.3995} \tag{3.69}$$

The marginal cost for the average growth community characterized by the figures in table 3.14 (DTCUS = 569) is

$$\overline{MC}(DTCUS) = 466.146 \text{ \$/customer.}$$

The static marginal cost computed in the static analysis was equal to 333.97 $/customer. Using the replacement to historical costs ratio of 2.79, this static marginal cost is then equal to $931.78 at current 1979 costs. As expected, the short-term, dynamic marginal cost is significantly smaller than the long-term one.

The next step in the analysis was to regress DPS on both residential and commercial-industrial customers increases (DRCUS and DCICUS). The linear and logarithmic specifications are

$$DPS = 69{,}756.53 + \underset{(6.17)}{614.579} * DRCUS + \underset{(1.99)}{2007.349} * DCICUS \qquad (R^2 = 0.629) \tag{3.70}$$

$$DPS = 16{,}650.291 * DRCUS^{\underset{(5.91)}{0.4088}} * DCICUS^{\underset{(2.32)}{0.1917}} \qquad (R^2 = 0.495) \tag{3.71}$$

The sums of the squares of the residuals are equal to 137.89 for equation (3.70) and to 46.79 for equation (3.71). Thus the multiplicative model is to be selected. It is characterized by stronger economies of scale effects in the residential sector as compared to the corresponding static model. (See equation 3.57.) However, the opposite feature characterizes the commercial-industrial sector. The marginal cost functions derived from equation (3.71) are

$$MC(DRCUS) = 6{,}806.334 * DRCUS^{-0.5912} * DCICUS^{0.1917} \tag{3.72}$$

$$MC(DCICUS) = 3{,}192.187 * DRCUS^{0.4088} * DCICUS^{-0.8083} \tag{3.73}$$

The marginal costs for the average growth community characterized by the figures in table 3.14 (DRCUS = 518; DCICUS = 51) are then

$$\overline{MC}(DRCUS) = 359.357 \text{ \$/residential customer}$$

$$\overline{MC}(DCICUS) = 1711.832 \text{ \$/commercial-industrial customer}$$

National Fuel Gas Distribution Corporation (NFGDC)

National Fuel Gas Distribution Corporation is a privately owned gas distribution utility providing service to 471 communities in western New York, northwestern Pennsylvania, and a small portion of eastern Ohio. These communities have an aggregate population estimated, in 1979, at 2,400,000. The principal ones are Buffalo, Niagara Falls, and Jamestown, New York; and Erie and Sharon, Pennsylvania.

NFGDC is a subsidiary of the National Fuel Gas Company, a public holding company that owns 100% of NFGDC capital stock, as well as 100% of the stock of the National Fuel Gas Supply Corporation, which deals with storage and transmission, of the Seneca Resources Corporation, which deals with gas production and gasoline extraction, and of the National Gas Storage Corporation, which deals exclusively with storage. The National Fuel Gas Supply Corporation purchases about 81.5% of the gas requirements from five major interstate pipeline suppliers (see the system map in figure 3.1) and resells this gas to NFGDC. The supply balance is obtained from the purchase of synthetic gas, natural gas produced in the Appalachian area, and manufactured gas.

NFGDC is partitioned into three divisions: New York, Pennsylvania, and Ohio. The latter is extremely small. The New York division is about twice as large as the Pennsylvania one with respect to the residential and commercial markets, and slightly larger with respect to the industrial market. The New York division covers more than 5,100 square miles and has a population (1970 census) of over 1.6 million persons. As the community-level data used in the following analysis pertain to communities in the New York division, summary statistics are provided for both NFGDC and its New York division. The data in table 3.15 provide a summary of end-use gas sales and average numbers of customers in 1979, and those in table 3.16 present an overview of the gas plant in service at the end of 1979.

The data in table 3.16 show that the distribution plant makes up for about 85% of the total plant for both the total corporation and the New York division. Mains, services, and meter-related equipment, in turn, make up for about 65%, 21%, and 7.5% of the distribution plant. The

National Fuel Gas Company

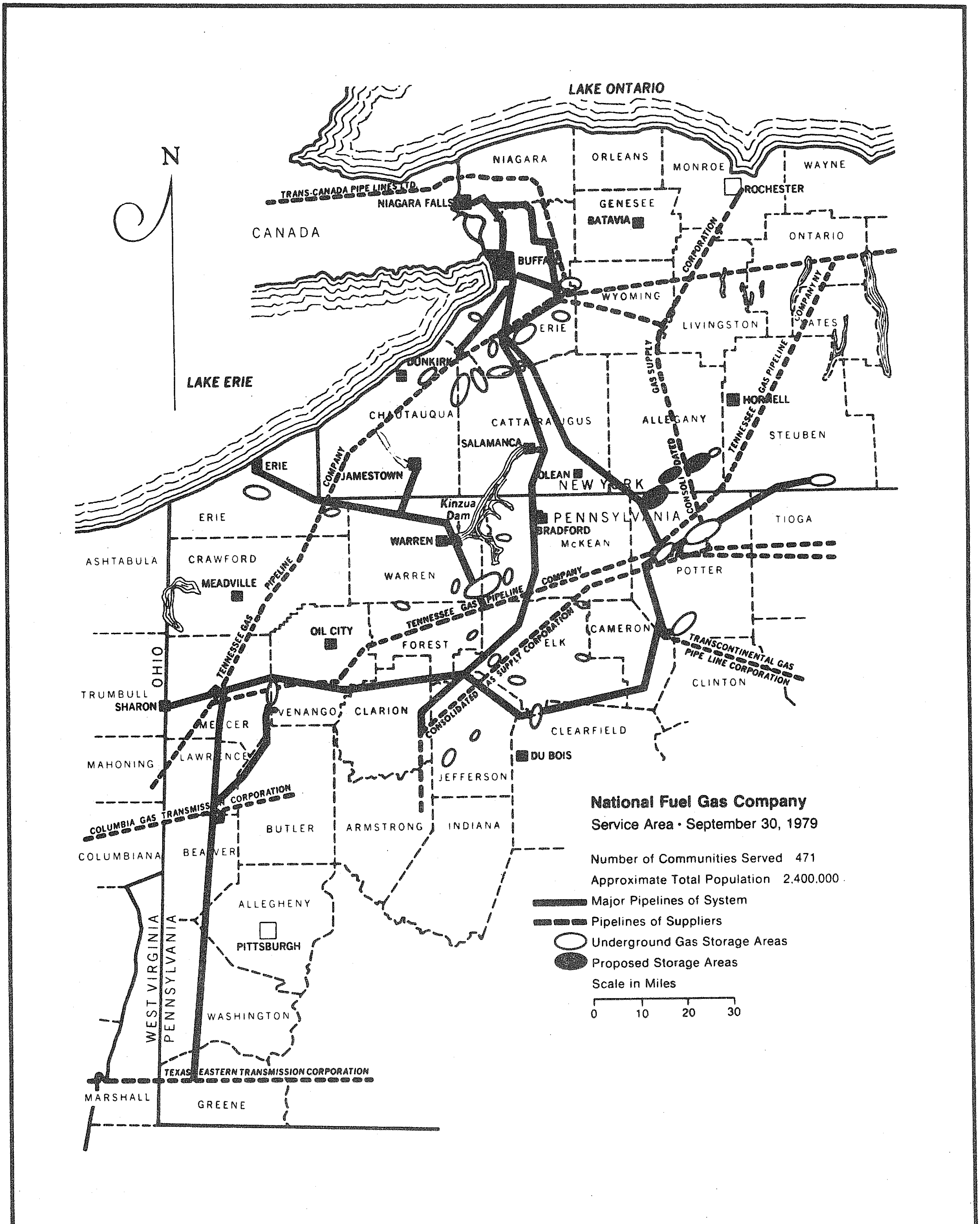

Figure 3.1 National Fuel Gas Company System

Source: 1979 Financial and Statistical Report - National Fuel Gas Company

TABLE 3.15

VOLUME OF GAS SALES AND NUMBER OF CUSTOMERS
IN 1979 - NFGDC AND ITS NEW YORK DIVISION

	TOTAL CORPORATION		NEW YORK DIVISION	
	Gas Sales (MCF)	Number of Customers	Gas Sales (MCF)	Number of Customers
Residential	104,287,562	637,821	72,403,511	451,223
Commercial	35,419,094	36,309	23,310,374	22,295
Industrial	67,187,351	1,470	34,286,874	805
Total	206,894,007	675,600	130,000,759	474,323

Sources: Annual Reports of NFGDC to the Federal Energy Regulatory Commission (FERC) and to the New York State Public Service Commission (NYPSC) - 1979.

New York division total plant represents about 72% of the total corporation plant.

The total average number of accounts has been virtually static in the past few years in the New York division, in part because of the high-saturation percentage in the residential market and the depressed economic climate of western New York. In 1979, installations of new main extensions and service lines were due principally to conversions of existing homes from oil to gas, but the largest segment of expenditures was for the replacement of mains and service lines because of obsolescence. Such a situation therefore precluded a dynamic analysis of the distribution plant.

On the basis of the data in tables 3.15 and 3.16, the distribution historical unit costs per MCF and customer for the New York division are

- 1.774 $/MCF
- 486.23 $/customer

As mentioned before, the community-level data used in the NFGDC static analysis pertain to communities located in the New York division. This is

TABLE 3.16

VALUE OF GAS PLANT IN SERVICE AT THE END OF 1979 - NFGDC AND ITS NEW YORK DIVISION

(In Dollars)

	Total Corporation	New York Division
OVERVIEW		
Intangible	$ 318,882	$ 195,236
Production	13,832,717	12,719,581
Transmission	27,268,184	16,511,380
Distribution	321,151,271	230,629,864
General	14,281,077	12,167,618
Total	$376,852,131	$272,223,679
DISTRIBUTION PLANT		
Land and Land Rights	$ 2,919,718	$ 1,831,204
Structures and Improvements	4,012,172	1,244,623
Mains	208,788,832	151,891,791
Measuring and Regulating Station Equipment	5,914,523	4,235,788
Services	69,216,169	51,300,074
Meters	19,870,029	13,842,716
Meter Installation	4,366,716	2,548,016
House Regulators	1,014,866	563,465
House Regulators Installation	1,024,251	727,054
Industrial Measuring and Regulating Station Equipment	3,213,289	2,329,333
Other Equipment	799,499	115,800

Sources: Annual Reports of NFGDC to the Federal Energy Regulatory Commission (FERC) and to the New York State Public Service Commission (NYPSC) - 1979.

so because plant data are specifically prepared for these communities for submission to the New York State Board of Equalization and Assessment. Two different documents have been provided by NFGDC and used to prepare the data file: Form EA5.3 and Form EA4.3EG.

Form EA5.3 includes the following aggregate data for each community (or tax district):

- the total plant in service;
- the "personal" plant in service, including essentially meters, as well as other measuring devices and house regulators;
- the "highway" plant in service, which includes mains, regulator stations, and other equipment located on the street side of the curbs;
- the "private" plant in service, which includes mainly pipelines and regulators on the house side of the street.

Only the "personal" plant in service variable, PC, is used in the following analysis, and it is assumed that PC closely represents the investment in meters, meter installation, house regulators, and house regulator installation.

Form EA4.3EG includes, for each community, disaggregated account-level data for the production, transmission, distribution, and general plants. The distribution plant accounts do not refer to meters and house regulators, hence the use of the "personal" plant in service variable PC discussed above. Each account data are further disaggregated into "highway" and "private" plants. However, in the present analysis such differentiation has not been accounted for, and the total values only are considered. The following plant components have been included in the file:

- LAR: land and land rights;
- STI: structures and improvements;
- MAI: mains;
- MRS: measuring and regulating stations;
- SER: services.

A minor component, "Other Equipment," has been merged with the "personal" plant in service, and the resulting variable is defined as

MER: meters and house regulators

Finally, the total distribution plant PS has been defined as the sum of the above variables

$$PS = LAR + STI + MAI + MRS + SER + MER \tag{3.74}$$

Sales and numbers of customers data have been prepared by NFGDC staff for the specific purposes of this study. These data are related, for each community, to the residential, commercial, and industrial sectors and to a fourth category, Public Authorities, which refer to municipal, state, and federal buildings, as well as, in a very minor way, to some street lighting. In the data presented in table 3.15, the Public Authorities (P.A.) sector is combined with the commercial sector, as P.A.s display very much the same load characteristics as commercial customers (space heating is the dominant use of gas).

A complete set of plant and market data was prepared for 173 communities. These data are presented in appendix D. Population and land acreage data, however, could be prepared for 33 communities only (those with a population of 2,500 or more), on the basis of the 1970 Census of Population documentation. This smaller sample is referred to as S_2, while the larger one is referred to as S_1.

The means of the different variables to be used in the static NFGDC statistical analysis are presented in table 3.17 for the two samples S_1 and S_2 separately. The sample S_1 represents about 85% of the New York division distribution plant, and about 95% of the corresponding total sales and number of customers. The average distribution plant in sample S_2 is about 1.95 times larger than the corresponding plant in sample S_1. The ratios of average sales and average numbers of customers between samples S_2 and S_1 are equal to 3.27 and 2.83, respectively. The latter figures indicate that the average gas consumption per customer is about 15% larger for sample S_2

TABLE 3.17

DEFINITIONS AND MEANS OF THE VARIABLES FOR THE TWO SAMPLES
S_1 AND S_2 - NFGDC STATIC ANALYSIS

Variable	Definition	Sample S_1 (173)	Sample S_2 (33)
	DISTRIBUTION PLANT ($) - END OF 1979		
PS	Total Distribution Plant	1,134,931	2,213,307
LAR	Land and Land Rights	3,267	7,963
STI	Structures and Improvements	5,836	18,811
MAI	Mains	815,216	1,597,039
MRS	Measuring and Regulating Stations	18,025	43,113
SER	Services	166,546	335,746
MER	Meters and House Regulators	126,041	210,634
	MARKET DURING 1979		
TMCF	Total Gas Sales (MCF)	714,926	2,338,234
RMCF	Residential Gas Sales (MCF)	396,903	1,177,212
CMCF	Commercial Gas Sales (MCF)	92,818	299,775
IMCF	Industrial Gas Sales (MCF)	190,636	755,969
PMCF	Public Authorities Gas Sales (MCF)	34,568	105,278
CIPMCF	Total Nonresidential Gas Sales (MCF)	318,023	1,161,022
CPMCF	Total Commercial and Public Authorities Gas Sales (MCF)	127,386	405,053
TCUS	Total Number of Customers	2,618	7,419
RCUS	Number of Residential Customers	2,492	7,045
CCUS	Number of Commercial Customers	110	332
ICUS	Number of Industrial Customers	4	12
PCUS	Number of Public Authorities Customers	12	29
CIPCUS	Number of Nonresidential Customers	126	373
CPCUS	Number of Commercial and Public Authorities Customers	122	361
TEDN	Population Density (people per acre)	-	6.053

Source: Author's calculations.

as compared to sample S_1.

The major advantage of the NFGDC data is their disaggregated character. Indeed, it is now possible to develop econometric models not only for the total distribution plant, as was done for LILCO, CGOC, and PG&E, but also for the various components of this plant. The various plant variables have been regressed on aggregated and disaggregated sales and customers variables. The analyses have been carried out separately for samples S_1 and S_2, with the intent to identify size effects eventually. (Sample S_2 refers to much larger communities.) This is, of course, only a first step in the segmentation of the market to get better models, and such a segmentation should be further considered in subsequent research efforts.

In the following, the total distribution plant and its various components are analyzed separately, and a synthesis of the results is then presented.

a. Total Distribution Plant

1. <u>Sales-Related Analysis</u>

Sample S_1

The multiplicative model turns out to be superior to the additive one in all cases. The results are acceptable only for (a) total sales, and (b) the two-sector market disaggregation (i.e., residential sales RMCF and nonresidential sales CIPMCF, with

$$PS = 30.3703 * \underset{(27.83)}{TMCF^{0.7934}} \qquad (R^2 = 0.819) \qquad (3.75)$$

$$PS = 56.1046 * \underset{(15.51)}{RMCF^{0.6920}} * \underset{(2.82)}{CIPMCF^{0.0883}} \qquad (R^2 = 0.858) \qquad (3.76)$$

All the coefficients are highly significant (at least at the 1% level) and display the expected relative values. As in the other companies analyzed previously, economies of scale characterize distribution plant costs. The marginal cost functions derived from equations (3.75) and (3.76) are

$$MC(TMCF) = 24.0965 * TMCF^{-0.2066} \tag{3.77}$$

$$MC(RMCF) = 38.8227 * RMCF^{-0.3080} * CIPMCF^{0.0883} \tag{3.78}$$

$$MC(CIPMCF) = 4.9550 * RMCF^{0.6920} * CIPMCF^{-0.9117} \tag{3.79}$$

The marginal costs for the average community characterized by sample S_1 figures in table 3.17 are then

$\overline{MC}(TMCF) = 1.488$ \$/MCF
$\overline{MC}(RMCF) = 2.241$ \$/MCF
$\overline{MC}(CIPMCF) = 0.357$ \$/MCF

The marginal total distribution cost per additional MCF is about six times larger in the residential sector, as compared to the nonresidential one, and using the total sales marginal cost would lead to a substantial subsidization of the residential customers by the commercial-industrial ones.

Sample S_2

The multiplicative model here also turns out to be the best one. The significance of the density variable is rather low. The results are therefore presented with and without this variable. As for sample S_1, it is not possible to obtain satisfactory models beyond a two-sector market disaggregation. The results are

$$\left\{\begin{array}{ll} PS = 28.1441 * \underset{(10.61)}{TMCF^{0.7775}} \quad (R^2 = 0.784) & (3.80) \\ PS = 26.1733 * \underset{(8.63)}{TMCF^{0.7865}} * \underset{(0.17)}{TEDN^{-0.0303}} \quad (R^2 = 0.784) & (3.81) \end{array}\right.$$

$$\left\{\begin{array}{ll} PS = 9.5978 * \underset{(6.46)}{RMCF^{0.8028}} * \underset{(1.08)}{CIPMCF^{0.0965}} \quad (R^2 = 0.854) & (3.82) \\ PS = 6.5054 * \underset{(6.31)}{RMCF^{0.8495}} * \underset{(1.08)}{CIPMCF^{0.0969}} * \underset{(0.91)}{TEDN^{-0.1357}} \quad (R^2 = 0.858) & (3.83) \end{array}\right.$$

The density variable is totally insignificant in equation (3.81), and its significance level is about 20% in equation (3.83). Considering equations (3.75), (3.76), (3.80), and (3.82), one can notice that the rates of economies of scale are quite similar for both samples in the cases of TMCF and CIPMCF, while in the residential case, the rate of economies of scale is slightly smaller for S_2. Whether the previous result is an indication that lesser economies of scale are achieved in the larger communities is a somehow premature conclusion, and additional analyses are needed to confirm or invalidate this proposition.

Comparison with the Other Companies

NFGDC equations (3.75) and (3.76) should be compared with the corresponding equations for LILCO (3.10 and 3.15), for CGOC (3.31 and 3.38), and for PG&E (3.45 and 3.54). Although substantial differences exist, NFGDC equations compare best with PG&E equations, where the exponents of TMCF, RMCF, and CIMCF are equal to 0.707, 0.840, and 0.056. LILCO and CGOC display larger economies of scale in the residential sector and substantially smaller ones in the commercial-industrial sector.

2. Customers-Related Analysis

Sample S_1

The multiplicative model turns out to be superior to the additive one in the case of the variable TCUS. No disaggregated model is acceptable (the sign of the variable CIPCUS is negative). The model is

$$PS = 1287.3305 * \underset{(32.96)}{TCUS^{0.8771}} \qquad (R^2 = 0.864) \tag{3.84}$$

The marginal cost function derived from equation (3.84) is

$$MC(TCUS) = 1129.1047 * TCUS^{-0.1229} \tag{3.85}$$

The marginal cost for the average community characterized by sample S_1 figures in table 3.17 is then

$\overline{MC}(TCUS) = 429.172$ \$/customer

Sample S_2

The multiplicative models, which again turn out to be the superior ones, are specified for both aggregated and disaggregated variables. In addition, the density variable appears to have much higher significance levels than when used with the sales variables. The results are

$$PS = 478.7315 * \underset{(12.05)}{TCUS^{1.0080}} * \underset{(1.46)}{TEDN^{-0.2078}} \quad (R^2 = 0.871) \tag{3.86}$$

$$PS = 767.1275 \ \& \ \underset{(4.19)}{RCUS^{0.8092}} * \underset{(1.05)}{CIPCUS^{0.2183}} * \underset{(1.27)}{TEDN^{-0.1843}} \quad (R^2 = 0.873) \tag{3.87}$$

If equation (3.86) is compared to equation (3.84), it would appear that lesser economies of scale are achieved with the larger communities (sample S_2), which supports the preliminary conclusion derived in the sales models case. The density variable is significant at the 10% level, and its elasticity compares most closely with PG&E density elasticity. The marginal cost functions derived from equations (3.86) and (3.87) are

$$MC(TCUS) = 482.5829 * TCUS^{0.0080} * TEDN^{-0.2078} \tag{3.88}$$

$$MC(RCUS) = 620.7375 * RCUS^{-0.1908} * CIPCUS^{0.2183} * TEDN^{-0.1844} \tag{3.89}$$

$$MC(CIPCUS) = 167.4708 * RCUS^{0.8092} * CIPCUS^{-0.7817} * TEDN^{-0.1843} \tag{3.90}$$

The above functions are then used to compute the marginal costs for the average community characterized by sample S_2 figures in table 3.17, with

$\overline{MC}(TCUS) = 356.64$ \$/customer
$\overline{MC}(RCUS) = 299.15$ \$/residential customer
$\overline{MC}(CIPCUS) = 1{,}524.37$ \$/non-residential customer

b. Land and Land Rights

1. Sales-Related Analysis

Sample S_1

The multiplicative models are again the superior ones. They are presented below for three cases: (1) total market, (2) two-sector market, and (3) three-sector market, with

$$LAR = 0.0000244 * \underset{(10.86)}{TMCF^{1.2445}} \quad (R^2 = 0.408) \tag{3.91}$$

$$LAR = 0.0001709 * \underset{(4.43)}{RMCF^{0.9085}} * \underset{(1.64)}{CIPMCF^{0.2364}} \quad (R^2 = 0.393) \tag{3.92}$$

$$LAR = 0.0002893 * \underset{(3.83)}{RMCF^{0.8219}} * \underset{(1.60)}{CPMCF^{0.2602}} * \underset{(1.11)}{IMCF^{0.0558}} \quad (R^2 = 0.400) \tag{3.93}$$

All the coefficients are significant at the 5% level, but the exponent of IMCF in equation (3.93) with a significance level at about 15%. The land and land rights component is characterized by economies of scale effects with respect to sectoral sales, and the relative values of the different elasticities are as expected. However, LAR is characterized by diseconomies of scale when total sales are considered, and there is no clear explanation for this phenomenon. The marginal cost functions derived from equations (3.91) and (3.92) are

$$MC(TMCF) = 0.0000304 * TMCF^{0.2445} \tag{3.94}$$

$$MC(RMCF) = 0.0001553 * RMCF^{-0.0915} * CIPMCF^{0.2364} \tag{3.95}$$

$$MC(CIPMCF) = 0.0000404 * RMCF^{0.8219} * CIPMCF^{-0.7635} \tag{3.96}$$

The marginal land and land rights costs for the average community characterized by sample S_1 figures in table 3.17 are then

$\overline{MC}(TMCF) = 0.00082$ \$/MCF

$\overline{MC}(RMCF) = 0.00095$ \$/MCF

$\overline{MC}(CIPMCF) = 0.00010$ \$/MCF

Sample S_2

Interestingly, the additive models turn out to be superior in this case. However, the density variable is never significant. The acceptable models are

$$LAR = -513.6472 + \underset{(20.96)}{0.0036} * TMCF \qquad (R^2 = 0.934) \tag{3.97}$$

$$LAR = 443.4687 + \underset{(23.64)}{0.0061} * RMCF + \underset{(0.84)}{0.00028} * CIPMCF \qquad (R^2 = 0.985) \tag{3.98}$$

The significance of CIPMCF is low, at the 20% level. However, the marginal costs, which are here read directly from the equations as the coefficients of the sales variables, display the expected relative values and are about four to six times larger than those obtained with sample S_1. This would confirm the hypothesis that lesser economies of scale are achieved in the larger communities.

2. Customers-Related Analysis

Sample S_1

The following multiplicative models are selected as both acceptable and superior to the corresponding additive ones

$$LAR = 0.0090414 * TCUS^{\underset{(11.29)}{1.3696}} \qquad (R^2 = 0.427) \tag{3.99}$$

$$LAR = 0.0285463 * RCUS^{\underset{(2.78)}{0.8532}} * CIPCUS^{\underset{(1.78)}{0.6113}} \qquad (R^2 = 0.436) \tag{3.100}$$

$$LAR = 0.0379849 * RCUS^{\underset{(2.34)}{0.7347}} * CPCUS^{\underset{(2.02)}{0.7392}} * ICUS^{\underset{(0.13)}{0.0068}} \qquad (R^2 = 0.441) \tag{3.101}$$

The significance of the exponent of ICUS in equation (3.101) is very low, which would imply that the number of industrial customers has very little impact on the necessary land and land rights. Equation (3.101) implies that residential and commercial customers have a similar impact on this component. Finally, note that the pattern of economies and diseconomies of scale when using aggregated and disaggregated variables is strictly similar to the pattern characterizing the sales-related models.

Sample S_2

As for the sales-related models, the additive models are the superior ones, and the density variable is not significant. The acceptable models are

$$LAR = -137.4929 + \underset{(57.55)}{1.0919} * TCUS \qquad (R^2 = 0.991) \tag{3.102}$$

$$LAR = -357.2541 + \underset{(3.70)}{0.8796} * RCUS + \underset{(1.12)}{5.7123} * CIPCUS \qquad (R^2 = 0.991) \tag{3.103}$$

$$LAR = -814.32124 + \underset{(3.05)}{0.6288} * RCUS + \underset{(1.18)}{4.9923} * CPCUS + \underset{(3.99)}{202.8004} * ICUS \qquad (R^2 = 0.994) \tag{3.104}$$

c. Structures and Improvements

1. <u>Sales-Related Analysis</u>

Sample S_1

The following multiplicative models are both acceptable and superior to the corresponding additive ones

$$STI = 0.0000564 * TMCF^{\underset{(9.42)}{1.2214}} \qquad (R^2 = 0.342) \tag{3.105}$$

$$STI = 0.000321 * RMCF^{\underset{(4.00)}{0.9217}} * CIPMCF^{\underset{(1.33)}{0.2159}} \qquad (R^2 = 0.334) \tag{3.106}$$

$$STI = 0.0003955 * \underset{(3.68)}{RMCF^{0.8922}} * \underset{(1.20)}{CPMCF^{0.2207}} * \underset{(0.52)}{IMCF^{0.0293}} \quad (R^2 = 0.335) \tag{3.107}$$

All the coefficients are significant at the 10% level except the coefficient of IMCF in equation (3.107). The patterns of economies of scale with respect to sectoral sales and of diseconomies of scale with respect to total sales are strikingly similar to those pointed out for the land and land rights variable LAR. (See equations 3.91 through 3.93.) The marginal cost functions derived from equations (3.105) and (3.106) are

$$MC(TMCF) = 0.0000689 * TMCF^{0.2214} \tag{3.108}$$

$$MC(RMCF) = 0.0002959 * RMCF^{-0.0783} * CIPMCF^{0.2159} \tag{3.109}$$

$$MC(CIPMCF) = 0.0000854 * RMCF^{0.9217} * CIPMCF^{-0.7841} \tag{3.110}$$

The marginal structures and improvements costs for the average community characterized by sample S_1 figures in table 3.17 are then

$\overline{MC}(TMCF) = 0.00136$ \$/MCF
$\overline{MC}(RMCF) = 0.00166$ \$/MCF
$\overline{MC}(CIPMCF) = 0.00060$ \$/MCF

Sample S_2

In this case, the additive specification turns out to be the superior one. The density variable is totally insignificant when the total sales are considered and weakly significant in the two-sector case. The results are

$$STI = -1176.93 + \underset{(21.31)}{0.0085} * TMCF \quad (R^2 = 0.936) \tag{3.111}$$

$$STI = 2272.228 + \underset{(31.89)}{0.0148} * RMCF + \underset{(0.60)}{0.0003} * CIPMCF - \underset{(0.84)}{206.0199} * TEDN \quad (R^2 = 0.992) \tag{3.112}$$

The residential and nonresidential marginal costs, read directly from the equations, are about nine times larger and two times smaller than the corresponding costs in the case of sample S_1, with the total marginal cost being about six times larger than in the case of sample S_1. Overall, these results continue to support the hypothesis that lesser economies of scale are achieved in the larger communities.

2. Customers-Related Analysis

Sample S_1

The following multiplicative models are selected as both acceptable and superior to the corresponding additive ones

$$STI = 0.01713 * \underset{(9.91)}{TCUS^{1.3585}} \qquad (R^2 = 0.365) \qquad (3.113)$$

$$STI = 0.08913 * \underset{(1.70)}{RCUS^{0.5854}} * \underset{(2.39)}{CIPCUS^{0.9221}} \qquad (R^2 = 0.383) \qquad (3.114)$$

It can be noted that the pattern of economies of scale with the sectoral variables and of diseconomies of scale with the aggregated variable is similar to those found out in the case of the sales models. (See equations 3.105 and 3.106.)

Sample S_2

As for the sales-related models, the additive specifications are the superior ones. In addition, the density variable turns out to be significant. The selected models are

$$STI = 2226.698 + \underset{(60.47)}{2.6239} * TCUS - \underset{(2.20)}{475.9217} * TEDN \qquad (R^2 = 0.993) \qquad (3.115)$$

$$STI = 2074.321 + \underset{(5.26)}{2.5026} * RCUS + \underset{(0.51)}{5.2304} * CIPCUS - \underset{(2.13)}{470.554} * TEDN$$

$$(R^2 = 0.994) \qquad (3.116)$$

$$STI = \underset{}{786.6148} + \underset{(4.54)}{2.0919} * RCUS + \underset{(0.49)}{4.6038} * CPCUS + \underset{(2.67)}{304.2455} * ICUS$$

$$- \underset{(1.76)}{362.1987} * TEDN \qquad (3.117)$$

The significance of the commercial customers variable is very low, and it may be inferred from the above that in the nonresidential sector, the major impact on STI is related to industrial customers.

d. Mains

1. <u>Sales-Related Analysis</u>

Sample S_1

The multiplicative specification is again the superior one. The selected models are

$$MAI = 1.0707 * TMCF^{\underset{(16.51)}{1.0296}} \qquad (R^2 = 0.615) \qquad (3.118)$$

$$MAI = 1.84172 * RMCF^{\underset{(9.14)}{0.9211}} * CIPMCF^{\underset{(1.66)}{0.1175}} \qquad (R^2 = 0.677) \qquad (3.119)$$

All the coefficients are significant at the 5% level. The relative values of the residential and nonresidential sales elasticities are as expected and imply economies of scale with respect to sectoral sales. However, mains are characterized by very slight diseconomies of scale when total sales are considered, as was the case with the variables LAR and STI. The marginal cost functions derived from equations (3.118) and (3.119) are

$$MC(TMCF) = 1.1398 * TMCF^{0.0296} \qquad (3.120)$$

$$MC(RMCF) = 1.6964 * RMCF^{-0.0789} * CIPMCF^{0.1175} \qquad (3.121)$$

$$MC(CIPMCF) = 0.2165 * RMCF^{0.9211} * CIPMCF^{-0.8824} \qquad (3.122)$$

The marginal mains costs for the average community characterized by sample S_1 figures in table 3.17 are then

$$\overline{MC}(TMCF) = 1.69868 \text{ \$/MCF}$$
$$\overline{MC}(RMCF) = 2.71985 \text{ \$/MCF}$$
$$\overline{MC}(CIPMCF) = 0.43319 \text{ \$/MCF}$$

Sample S_2

The multiplicative specification is the superior one. The significance of the density variable is low in the case of the aggregate sales model, and therefore results are given with and without this variable. In the case of the two-sector model, the density variable has a significance level of 15%. The results are

$$\begin{cases} MAI = 17.9452 * \underset{(9.88)}{TMCF^{0.7836}} & (R^2 = 0.759) \quad (3.123) \\ MAI = 15.1248 * \underset{(8.17)}{TMCF^{0.8048}} * \underset{(0.37)}{TEDN^{-0.0714}} & (R^2 = 0.760) \quad (3.124) \end{cases}$$

$$MAI = 3.7767 * \underset{(5.73)}{RMCF^{0.8613}} * \underset{(1.04)}{CIPMCF^{0.1041}} * \underset{(1.06)}{TEDN^{-0.1770}} \quad (R^2 = 0.831) \quad (3.125)$$

The comparison of equations (3.125) and (3.119) indicates that a higher rate of economies of scale with respect to residential sales characterizes the larger communities, while this feature is reversed in the case of nonresidential sales. With respect to total sales, the rate of economies of scale is significantly larger in the present case. Therefore, the present results would tend to support the hypothesis that larger economies of scale can be achieved in the larger communities.

2. Customers-Related Analysis

Sample S_1

The only acceptable model is the multiplicative one with the aggregate number of customers

$$MAI = 134.426 * \underset{(18.21)}{TCUS^{1.1483}} \quad (R^2 = 0.660) \tag{3.126}$$

The above model displays the same slight diseconomies of scale as the sales-related model. (See equation 3.118.)

Sample S_2

The acceptable models are

$$MAI = 298.3278 * \underset{(10.97)}{TCUS^{1.0302}} * \underset{(1.57)}{TEDN^{-0.2516}} \quad (R^2 = 0.845) \tag{3.127}$$

$$MAI = 456.8266 * \underset{(3.95)}{RCUS^{0.8628}} * \underset{(0.77)}{CIPCUS^{0.1807}} * \underset{(1.42)}{TEDN^{-0.2322}} \quad (R^2 = 0.846) \tag{3.128}$$

The significance of the variable CIPCUS in equation (3.128) is rather low (about 20%). The significance of the density variable TEDN is higher (less than 10%). The sectoral elasticities are in the same ranges as those of the sales-related model. (See equation 3.125.)

e. Measuring and Regulating Stations

1. <u>Sales-Related Analysis</u>

Sample S_1

The multiplicative specification is the superior one, and the selected models are

$$MRS = 0.0000946 * \underset{(11.17)}{TMCF^{1.3809}} \quad (R^2 = 0.422) \tag{3.129}$$

$$MRS = 0.0011062 * \underset{(4.02)}{RMCF^{0.8799}} * \underset{(2.43)}{CIPMCF^{0.3745}} \quad (R^2 = 0.419) \tag{3.130}$$

$$MRS = 0.0019346 * \underset{(3.62)}{RMCF^{0.8316}} * \underset{(1.97)}{CPMCF^{0.3435}} * \underset{(1.47)}{IMCF^{0.0789}} \quad (R^2 = 0.423) \tag{3.131}$$

All the coefficients are significant at, at least, the 10% level. The relative values of the sectoral elasticities are as expected, and all imply economies of scale with respect to sectoral sales. However, the pattern of diseconomies of scale with respect to total sales, noticed for the previous components, is also present here. The marginal cost functions derived from equations (3.129) and (3.130) are

$$MC(TMCF) = 0.0001306 * TMCF^{0.3809} \tag{3.132}$$

$$MC(RMCF) = 0.0009734 * RMCF^{-0.1201} * CIPMCF^{0.3745} \tag{3.133}$$

$$MC(CIPMCF) = 0.0004143 * RMCF^{0.8316} * CIPMCF^{-0.6255} \tag{3.134}$$

The marginal measuring and regulating stations costs for the average community characterized by sample S_1 figures in table 3.17 are then

$$\overline{MC}(TMCF) = 0.02219 \ \$/MCF$$
$$\overline{MC}(RMCF) = 0.02381 \ \$/MCF$$
$$\overline{MC}(CIPMCF) = 0.00678 \ \$/MCF$$

Sample S_2

Again the multiplicative specification is the superior one. The density variable is significant at the 15% level in the total sales model, and at the 2.5% level in the two-sector sales model. The selected models are

$$MRS = 0.63398 * \underset{(8.62)}{TMCF^{0.7880}} * \underset{(0.99)}{TEDN^{-0.1768}} \quad (R^2 = 0.765) \tag{3.135}$$

$$MRS = 0.13818 * \underset{(6.71)}{RMCF^{0.8696}} * \underset{(1.04)}{CIPMCF^{0.0895}} * \underset{(2.04)}{TEDN^{-0.2925}} \quad (R^2 = 0.858) \tag{3.136}$$

The comparison of equations (3.136) and (3.130) points out a much higher rate of economies of scale with nonresidential sales in the larger communities, whereas this rate does not change significantly with respect to residential sales. These sectoral effects lead to overall higher economies of scale in the larger communities when total sales are considered. Similar to the main-related analysis in the previous section, these results tend to support the hypothesis that larger economies of scale can be achieved in the larger communities.

2. Customers-Related Analysis

Sample S_1

The acceptable models are

$$MRS = 0.0597 * \underset{(11.87)}{TCUS^{1.5384}} \quad (R^2 = 0.452) \tag{3.137}$$

$$MRS = 0.3644 * \underset{(2.16)}{RCUS^{0.7032}} * \underset{(2.72)}{CIPCUS^{0.9899}} \quad (R^2 = 0.469) \tag{3.138}$$

$$MRS = 0.3980 * \underset{(2.11)}{RCUS^{0.7053}} * \underset{(2.41)}{CPCUS^{0.9411}} * \underset{(0.39)}{ICUS^{0.0210}} \quad (R^2 = 0.468) \tag{3.139}$$

The significance of the coefficient of ICUS in equation (3.139) is very low, and it therefore appears that in the nonresidential sector, the major impact on MRS is related to commercial customers.

Sample S_2

The acceptable models are

$$MRS = 11.8009 * \underset{(11.90)}{TCUS^{1.0081}} * \underset{(2.45)}{TEDN^{-0.3526}} \quad (R^2 = 0.857) \tag{3.140}$$

$$MRS = 21.4219 * \underset{(3.79)}{RCUS^{0.7300}} * \underset{(1.50)}{CIPCUS^{0.3118}} * \underset{(2.20)}{TEDN^{-0.3190}} \quad (R^2 = 0.863) \tag{3.141}$$

The significance of the density variable is quite high (2.5% level), as it was the case in the sales-related model (3.136). Larger economies of scale are achieved in the larger communities with respect to nonresidential customers, and this confirms the pattern noticed in the sales-related models.

f. Services

1. <u>Sales-Related Analysis</u>

Sample S_1

The acceptable models are

$$SER = 0.4871 * \underset{(27.26)}{TMCF^{0.9670}} \quad (R^2 = 0.813) \tag{3.142}$$

$$SER = 1.6691 * \underset{(12.20)}{RMCF^{0.7195}} * \underset{(4.74)}{CIPMCF^{0.1966}} \quad (R^2 = 0.834) \tag{3.143}$$

All the coefficients are highly significant (at the 0.01% level) and imply economies of scale. The relative values of the residential and non-residential elasticities are as expected. The comparison of equation (3.143) with the similar equation for mains (3.119) shows that the services components are characterized by higher economies of scale in the residential sector and lesser ones in the commercial-industrial sector. The marginal cost functions derived from equations (3.142) and (3.143) are

$$MC(TMCF) = 0.4710 * TMCF^{-0.0330} \tag{3.144}$$

$$MC(RMCF) = 1.2010 * RMCF^{-0.2805} * CIPMCF^{0.1966} \tag{3.145}$$

$$MC(CIPMCF) = 0.3281 * RMCF^{0.7195} * CIPMCF^{-0.8034} \tag{3.146}$$

The marginal services costs for the average community characterized by sample S_1 figures in table 3.17 are then

$\overline{MC}(TMCF) = 0.30176$ \$/MCF

$\overline{MC}(RMCF) = 0.38985$ \$/MCF

$\overline{MC}(CIPMCF) = 0.13291$ \$/MCF

Sample S_2

The density variable turns out to be insignificant. The acceptable models are

$$SER = 6.1161 * \underset{(8.31)}{TMCF^{0.7532}} \quad (R^2 = 0.690) \tag{3.147}$$

$$SER = 2.0774 * \underset{(4.72)}{RMCF^{0.7846}} * \underset{(0.74)}{CIPMCF^{0.0894}} \quad (R^2 = 0.755) \tag{3.148}$$

The significance of the coefficient of CIPMCF in equation (3.148) is rather low (at about the 20% level). The comparison of equations (3.147) and (3.142) indicates that a higher rate of economies of scale is achieved in the larger communities. However, the comparison of the sectoral models (3.148) and (3.143) shows that this is only true for the commercial-industrial sector, whereas slightly less economies of scale are achieved with respect to residential sales in the larger communities.

2. Customers-Related Analysis

Sample S_1

The only acceptable model is the multiplicative one with the aggregate number of customers

$$SER = 49.3229 * \underset{(30.45)}{TCUS^{1.0607}} \quad (R^2 = 0.844) \tag{3.149}$$

Sample S_2

Here also the only acceptable model is the aggregate multiplicative one

$$SER = 122.7594 * \underset{(9.89)}{TCUS^{0.9038}} \quad (R^2 = 0.759) \tag{3.150}$$

The comparison of equations (3.149) and (3.150) confirms the hypothesis that higher economies of scale for services are achieved in the larger communities.

g. Meters and House Regulators

1. Sales-Related Analysis

Sample S_1

The acceptable models are

$$MER = 9.5988 * \underset{(21.31)}{TMCF^{0.7079}} \quad (R^2 = 0.726) \tag{3.151}$$

$$MER = 17.9205 * \underset{(10.80)}{RMCF^{0.6138}} * \underset{(1.88)}{CIPMCF^{0.0751}} \quad (R^2 = 0.744) \tag{3.152}$$

All the coefficients are significant at, at least, the 5% level, and imply significant economies of scale, in particular in the nonresidential sector. The resulting marginal cost functions are

$$MC(TMCF) = 6.7946 * TMCF^{-0.2921} \tag{3.153}$$

$$MC(RMCF) = 10.9994 * RMCF^{-0.3862} * CIPMCF^{0.0751} \tag{3.154}$$

$$MC(CIPMCF) = 1.3460 * RMCF^{0.6138} * CIPMCF^{-0.9249} \tag{3.155}$$

The marginal meters and house regulators costs for the average community characterized by sample S_1 figures in table 3.17 are then

$\overline{MC}(TMCF) = 0.13240$ \$/MCF

$\overline{MC}(RMCF) = 0.19606$ \$/MCF

$\overline{MC}(CIPMCF) = 0.02994$ \$/MCF

Sample S_2

The acceptable models are

$$MER = 2.0173 * \underset{(8.33)}{TMCF^{0.8160}} * \underset{(0.72)}{TEDN^{-0.1370}} \quad (R^2 = 0.759) \tag{3.156}$$

$$MER = 0.6852 * \underset{(5.14)}{RMCF^{0.8053}} * \underset{(1.41)}{CIPMCF^{0.1471}} * \underset{(1.29)}{TEDN^{-0.2236}} \quad (R^2 = 0.814) \tag{3.157}$$

The significance of the density variable is at the 20% level in equation (3.156) and at the 10% level in equation (3.157). The comparison of these equations with equations (3.151) and (3.152) indicates that lesser economies of scale are achieved in the larger communities.

2. Customers-Related Analysis

Sample S_1

The only acceptable model is the multiplicative one with the aggregate number of customers

$$MER = 275.0448 * \underset{(23.42)}{TCUS^{0.7805}} \quad (R^2 = 0.762) \tag{3.158}$$

Sample S_2

In this case, both the aggregate and two-sector multiplicative models are acceptable

$$MER = 45.9453 * \underset{(10.45)}{TCUS^{1.0282}} * \underset{(1.81)}{TEDN^{-0.3024}} \quad (R^2 = 0.828) \tag{3.159}$$

$$MER = 113.1802 * \underset{(2.61)}{RCUS^{0.5602}} * \underset{(2.31)}{CIPCUS^{0.5349}} * \underset{(1.51)}{TEDN^{-0.2440}} \quad (R^2 = 0.848) \tag{3.160}$$

The comparison of equations (3.158) and (3.159) confirms the hypothesis that as far as meters and regulators are concerned, lesser economies of scale are achieved in the larger communities. Also, note that the density variable is significant at, at least, the 10% level.

h. Synthesis of the NFGDC Analysis

Some general conclusions emerge from the previous analysis.

(1) The cost variations of the different components of the distribution plant are best explained by the multiplicative model, as was the case for the other companies. Note that the additive model, which implies constant marginal costs, is superior for two minor components (land and land rights, and structures and improvements) when sample S_2 (i.e., the larger communities) is used. It can therefore be concluded that in most instances, the cost effects of the different market sectors are nonseparable.

(2) All the cost functions are characterized by economies of scale with respect to sectoral sales. The residential sales elasticity varies between 0.614 (meters and house regulators) and 0.922 (structures and improvements). The nonresidential sales elasticity varies between 0.075 (meters and house regulators) and 0.374 (measuring and regulating stations).

(3) The significance of the density variable is generally low. It scores best in the cases of measuring and regulating stations, meters and house regulators, and mains. Such a disappointing result calls for further investigation. It is possible that sample S_2 is too small and not enough diversified as far as population density is concerned, and further data gathering may prove a beneficial investment.

(4) The comparison of the results for samples S_1 and S_2 would imply that higher rates of economies of scale with respect to sectoral sales are achievable in the larger communities for mains and measuring and regulating stations. The opposite conclusion would be true for the

other distribution plant components. These results cannot be viewed as definitive but indicate that a segmentation of the communities by size and the specification of econometric models for different market segments might better account for size effects and lead to better, more accurate models.

In order to get an overview of the various models' performances the total and two-sector sales models derived with sample S_1 have been used to compute the plant components corresponding to the average figures in table 3.17 (TMCF = 714,926 MCF; RMCF = 396,903 MCF; CIPMCF = 318,023 MCF). The results are presented in Table 3.18.

TABLE 3.18

COMPARISON OF MODEL-CALCULATED AND AVERAGE PLANT VALUES FOR THE AVERAGE NFGDC COMMUNITY (In Dollars)

Plant Component	Total Sales Models	Two-Sector Sales Models	Sample S_1 Actual Average Values
LAR	$ 471	$ 417	$ 3,267
STI	797	715	5,836
MAI	1,179,518	1,171,998	815,216
MRS	11,488	10,742	18,025
SER	223,105	215,045	166,546
MER	133,727	126,781	126,041
TOTAL	$1,549,106	$1,525,698	$1,134,931
PS	$1,340,764	$1,285,537	$1,134,931

Source: Author's calculations.

The results obtained with the total and two-sector sales models are very similar, very slightly lower in the case of the two-sector sales models. The most significant differences between the model-calculated and the actual average values pertain to the mains and services costs that the models overestimate by 44% and 29%, respectively. Although the results only characterize the average community, they are indicative of the need to improve the analysis and obtain more accurate models. Another important comparison is between the sums of the values of the individual plant components ("Total" in table 3.18) and the values obtained by using the models calibrated while using directly the total distribution plant variable PS. (See equations 3.75 and 3.76.) The sum of the individual components is about 15% to 18% larger than the value derived from the PS model. Such a result is not surprising. Indeed, a single-equation estimation procedure has been used for variables that are not independent, i.e., the sum of the individual plant components must be equal to PS. (See equation 3.74.) It is possible that the use of simultaneous-equations estimation procedures might reduce the observed discrepancies, although such a conclusion cannot be a priori taken for granted.[17]

Finally, the sectoral and total sales marginal costs computed in the previous sections for the average community of sample S_1 are presented in table 3.19, together with the average total sales costs computed on the basis of the data in table 3.17.

TABLE 3.19

SUMMARY OF MARGINAL AND AVERAGE COSTS
FOR THE AVERAGE NFGDC COMMUNITY
(In Dollars per MCF)

Plant Component	Sectoral Sales Marginal Costs: Residential Sector(1)	Sectoral Sales Marginal Costs: Nonresidential Sector(2)	(1)/(2)	Total Sales Marginal Costs	Total Sales Average Costs
LAR	0.00095	0.00010	9.50	0.00082	0.00457
STI	0.00166	0.00060	2.77	0.00136	0.00816
MAI	2.71985	0.43319	6.28	1.69868	1.14028
MRS	0.02381	0.00678	3.51	0.02219	0.02521
SER	0.38985	0.13291	2.93	0.30176	0.23295
MER	0.19606	0.02994	6.55	0.13240	0.17630
TOTAL	3.33218	0.60352	5.52	2.15721	1.58747
PS	2.24123	0.37500	6.28	1.48798	1.58747

Source: Author's calculations.

[17]See, for instance: P. Rao and R.L. Miller, "Simultaneous Equations Model", in Applied Econometrics (Belmont CA: Wadsworth Publishing Company, Inc.), chap. 8, p. 185.

As could be expected, the sums of the marginal costs computed for each plant component are larger than the marginal costs computed with the total plant (PS) equations. The ratio between residential and nonresidential marginal costs varies between 2.77 and 9.50. However, a ratio of 6 is probably best representative of this relationship when the total distribution plant is considered. When total sales are considered, marginal costs appear larger than average costs when the individual components are considered. However, this conclusion is reversed when using the total plant (PS) equation. Thus, additional analyses are called for to ascertain the relationship between marginal and average costs for the average (or any other) community.

Synthesis of the Econometric Analyses and Possible Extensions

Some major commonalities emerge from the previous analyses. Probably the most important one is the nonseparability of the distribution plant costs incurred to serve the different sectoral markets of the utility. Such a result is not surprising in view of the complex and nonseparable linkages that exist among the different customers served by the same pipeline network. The second most important commonality is related to the economies of scale achieved with respect to both residential and nonresidential gas sales. The two previous results imply that the sectoral sales marginal costs are (1) decreasing with the sector's size, and (2) depending upon the size of the other sector(s). Third, the density variable turns out to be highly significant for two companies (LILCO and PG&E), weakly so for NFGDC, and not at all for CGOC. The disappointing results for the two last companies call for additional investigations and may be related to poor quality data or to too small variations of the density variable. Finally, the PG&E analysis has demonstrated the usefulness of accounting for weather parameters when the utility's service territory is climatologically heterogeneous.

The elasticities of residential sales, nonresidential sales, and density for the four companies are presented in table 3.20. (The values for NFGDC correspond to sample S_2 analysis, where the density variable is considered.)

TABLE 3.20

SUMMARY OF SALES AND DENSITY ELASTICITIES

Utility	Residential Sales Elasticity	Non-Residential Sales Elasticity	Density Elasticity
Long Island Lighting Company	0.737	0.154	-0.176
Columbia Gas of Ohio Company	0.583	0.309	NA
Pacific Gas & Electric Company	0.840	0.069	-0.251
National Fuel Gas Distribution Corporation	0.849	0.096	-0.136

Source: Author's calculations.

The data in table 3.20 point out a considerable similarity between PG&E and NFGDC with respect to the sales elasticities. LILCO and CGOC display higher economies of scale in the residential sector and lesser ones in the nonresidential sector. These interutility variations constitute an interesting and important area for further analysis and research. The variations of the sales elasticities are most likely due, in part, to variations in customers' sizes, and the introduction of these variables into the models should be tested. Another source of variations may be related to variable load characteristics (load factor, peak load) for a given sector among the different communities of the service area. These load characteristics can be determined on the basis of historical monthly consumptions and degree-days data. Such a determination for each community may be quite time consuming. However, this analysis is much more feasible at the level of company division and may permit a preliminary test of the importance of these variables.

CHAPTER 4

UTILITY COST MINIMIZATION AND MARGINAL COST PRICING EVALUATION - APPLICATION TO THE EAST OHIO GAS COMPANY

The purpose of this chapter is to present the structure of the Gas Utility Marginal Cost Pricing Model (GUMCPM) and the results of its application to the East Ohio Gas Company. In the first section, after an overview of the model's organization and logic, its different submodels are described in detail. In the next section, the assumptions used in applying the model to the East Ohio Gas Company (EOGC) are specified, the results thoroughly analyzed, and the feasibility and worth of a marginal cost pricing policy assessed. In the final section, some possible extensions of the model are outlined.

Structure of the Gas Utility Marginal Cost Pricing Model (GUMCPM)

An Overview of the Model

A general flow diagram of the model is presented in figure 4.1. The model consists of three major, interlinked blocks: (1) Exogenous data and assumptions, (2) Average cost pricing policy, and (3) Marginal cost pricing policy. The computer program of the model, a listing of which is presented in appendix E, is organized into a main program, where the basic data and assumptions are specified, and various subprograms - LOAD, MARCOS, DIST, REVREQ, EVAL1, EVAL2 - also indicated in figure 4.1.

The exogenous data and assumptions include (1) market-related parameters such as sectoral market growth, base and space-heating load coefficients, and price elasticities of monthly gas demands; (2) supply-related parameters such as maximum supplies and rates for the different available suppliers; and (3) utility-related parameters such as operating

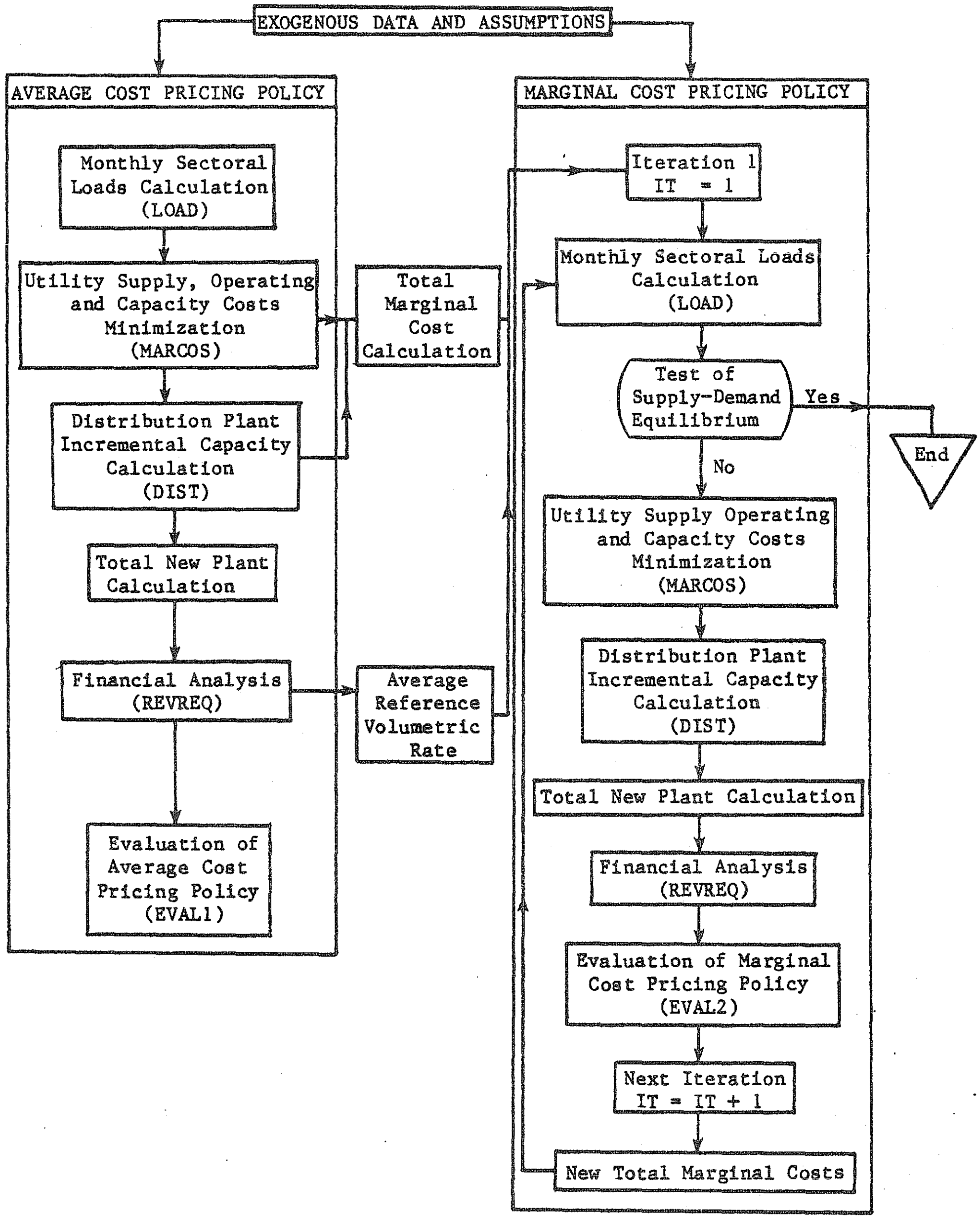

Figure 4.1 Structure of the Gas Utility Marginal Cost Pricing Model (GUMCPM)

and capacity costs, maximum capacity expansions, the allowed rate of return, and other financial parameters (taxes, etc.).

The above data and assumptions are first used in the Average cost pricing policy block, where the monthly loads of the residential, commercial, and industrial sectors are calculated while using historically determined base and space-heating load coefficients and neglecting the price-effect component of the monthly load (demand) functions. These loads are then inputs to the utility supply, operating, and capacity costs minimization submodel that determines the optimal trade-off between supply mix and own production, storage and transmission operations, and capacity expansion decisions, subject to satisfying the above-mentioned loads and various utility-related technological constraints. The format of this cost minimization model is a linear program that yields automatically as an important by-product shadow prices for the monthly load constraints (satisfaction of demand), and these shadow prices are precisely the marginal costs incurred by marginal increases in demand. Note, however, that these marginal costs are defined only with respect to the costs considered in the linear program. Therefore, these marginal costs will have to be complemented by other marginal costs such as the distribution capacity marginal costs computed in the next step, together with the total new distribution plant. The total new plant (production, storage, transmission, distribution) is then calculated and serves as an input to the financial analysis submodel that very much replicates the financial analysis typically made in the context of rate cases. The utility's rate base is first calculated, and then so is the revenue from gas sales necessary to provide the allowed rate of return on this rate base. This revenue, divided by the total annual gas load, yields the appropriate average volumetric rate. This rate will be used as the reference rate when price effects are considered in load calculations within the Marginal cost pricing policy block. In other words, it is assumed that the price-effect components of the monthly load equations are equal to one when the monthly rates are set equal to the above average volumetric rate. (An alternative equilibrating procedure is outlined in the last section.) Finally, the average cost pricing policy is evaluated with respect to criteria such as

(1) total gas consumption, (2) peak monthly load, (3) load factor, and (4) consumers' and producer's surpluses (two measures of the overall economic efficiency of the pricing policy).

The Marginal cost pricing policy block consists of a repetition of a calculation cycle until an equilibrium between monthly gas supplies and demands is eventually reached, wherein the demands are determined by prices set equal to the total marginal costs of these demands. If this equilibrium is not reached, the calculations are terminated after a specified number of iterations. At the first iteration, the monthly sectoral loads are calculated while setting monthly rates equal to the total marginal costs derived from the Average cost pricing policy block. The resulting loads, necessarily different from those used in the Average cost pricing policy block, are then inputs to, and constraints for, the utility supply, operating, and capacity costs minimization submodel. The subsequent calculations are similar to those of the Average cost pricing policy block, up to the evaluation of the marginal cost pricing policy. The new total marginal costs corresponding to the sectoral loads are then computed and become inputs, in the next iteration, to the monthly load equations. If the new loads are equal to the loads computed in the previous iteration, it is then clear that the equilibrium has been reached. If this is not the case, the previous cycle of calculations is repeated.

The following subsections describe the structure of the different submodels and their adaptation to the specific features of the East Ohio Gas Company (EOGC) that serves the northeastern part of Ohio, including the cities of Cleveland, Akron, Canton, Warren, and Youngstown. It is the largest gas distribution utility in Ohio with respect to the number of customers: in 1977, the EOGC had 908,758 residential customers, 52,867 commercial customers, and 1,108 industrial customers. The data used have been drawn from the annual reports of the EOGC to the Federal Power Commission[18] and to the Public Utilities Commission of Ohio for the period 1970-1977 or have been obtained directly from the EOGC.

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[18]Now the Federal Energy Regulatory Commission.

The Load Analysis Submodel

The monthly gas requirements depend upon the specific characteristics and mix of the end-use customers, upon weather severity measured in degree-days, and in the longer term, upon gas prices. The EOGC's customers have been aggregated into three categories: residential, commercial, and industrial. Their observed monthly requirements (or loads) for the year 1972 have been regressed on the corresponding monthly degree-day values. This year has been selected because it was the most recent one (as from 1977) without curtailments, and therefore actual industrial usage closely approximated potential industrial requirements. The following regression models were obtained, with $DGMRO_m$, $DGMCO_m$, and $DGMIO_m$ being defined as the residential, commercial, and industrial requirements during month m, and DD_m as the corresponding number of degree-days

$$DGMRO_m = 3{,}203.742 + 23.912 * DD_m \text{ (MMCF)} \quad (R^2 = 0.989) \tag{4.1}$$

$$DGMCO_m = 1{,}516.625 + 9.104 * DD_m \text{ (MMCF)} \quad (R^2 = 0.989) \tag{4.2}$$

$$DGMIO_m = 10{,}179.264 + 3.567 * DD_m \text{ (MMCF)} \quad (R^2 = 0.920) \tag{4.3}$$

The corresponding total gas requirements $DGMTO_m$ are then

$$DGMTO_m = DGMRO_m + DGMCO_m + DGMIO_m = 14{,}899.621 + 36.583 * DD_m \tag{4.4}$$

Equations (4.1) through (4.4) are assumed to characterize the base or existing gas market throughout the following analysis. In equations (4.1) through (4.4), the first coefficient represents the base load, independent of weather, and the second one represents the space-heating load per degree-day. For an average annual number of degree-days equal to 6258, the residential, commercial, and industrial base loads correspond to 20.5%, 24.2%, and 84.5% of the total sectoral load, respectively. For example, the residential base and space-heating loads represent 20.5% and 79.5% of the total residential load. Throughout the following analysis, 30-year average values of the monthly degree-days are used. These values, together with the corresponding base market sectoral and total loads, are presented in table 4.1.

TABLE 4.1

AVERAGE MONTHLY DEGREE-DAYS AND SECTORAL AND TOTAL LOADS (MMCF)

Month	Average Degree-Days	Residential Load DGMRO	Commercial Load DGMCO	Industrial Load DGMIO	Total Load DGMTO
1. April	506.6	15,317.56	6,128.71	11,986.31	33,432.59
2. May	248.2	9,138.70	3,776.24	11,064.60	23,979.53
3. June	50.5	4,411.30	1,976.38	10,359.40	16,747.07
4. July	11.0	3,466.77	1,616.77	10,218.50	15,302.05
5. August	18.9	3,655.68	1,688.69	10,246.68	15,591.05
6. September	120.5	6,085.14	2,613.66	10,609.09	19,307.88
7. October	371.6	12,089.44	4,899.67	11,504.76	28,493.88
8. November	712.6	20,243.44	8,004.14	12,721.11	40,968.68
9. December	1,071.6	28,827.85	11,272.47	14,001.66	54,101.98
10. January	1,207.7	32,082.27	12,511.53	14,487.13	59,080.92
11. February	1,046.3	28,222.87	11,042.14	13,911.42	53,176.43
12. March	892.5	24,545.20	9,641.95	13,362.81	47,549.96
Total	6,258.0	188,086.22	75,172.34	144,473.48	407,732.04

Source: Author's calculations.

The next step is to introduce price effects in the monthly sectoral load functions. It is assumed that these effects interact multiplicatively with the weather-related components as described by equations (4.1) through (4.3) and are characterized by constant price elasticities. The constant elasticity assumption has been found to be appropriate at the <u>annual level</u>.

Nelson,[19] for instance, estimated an elasticity of -0.280, and derived, through regression analysis, a predictive model for total annual energy demand of the multiplicative form, where the price and weather effects constitute two of the most significant factors. However, it seems that very little information is available on demand elasticities at the intraannual level, such as the month. In view of the resulting uncertainty, sensitivity analyses are necessary to assess the impacts of alternate elasticity values within reasonable ranges. If EL_m is the elasticity for month m, and P_m the corresponding price, the price effect PE_m is assumed to be measured by the quantity

$$PE_m = \left(\frac{P_m}{PAVG}\right)^{EL_m} \quad (EL_m < o) \tag{4.5}$$

where PAVG is a reference price for which the price effect is equal to one. This reference price is, in the present approach, set equal to the average volumetric rate, enabling the utility to earn its allowed operating income exactly. (PAVG is determined in the financial analysis submodel of the Average cost pricing policy block.) The sectoral monthly elasticities are noted ELR_m, ELC_m, and ELI_m for the residential, commercial, and industrial sectors, respectively.

It is finally necessary to account for the change in demand due to market growth. If RMR, RMC, and RMI represent the residential, commercial, and industrial sectors growth rates, then the complete monthly sectoral load functions can be specified as

$$DGMR_m = DGMRO_m * (1 + RMR) * \left(\frac{P_m}{PAVG}\right)^{ELR_m} \tag{4.6}$$

$$DGMC_m = DGMCO_m * (1 + RMC) * \left(\frac{P_m}{PAVG}\right)^{ELC_m} \tag{4.7}$$

$$DGMI_m = DGMIO_m * (1 + RMI) * \left(\frac{P_m}{PAVG}\right)^{ELI_m} \tag{4.8}$$

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[19] J. P. Nelson, "The Demand for Space Heating Energy," The Review of Economics and Statistics, 1975, pp. 508-12.

In the application of the model, the three market growth rates are taken equal to 0.5 (50%). As mentioned in the overview of the model, the price effects are neglected in the Average cost pricing policy block. This is simply done by setting initially the P_m's ($m = 1 \rightarrow 12$) and PAVG equal to 1. In the Marginal cost pricing policy block, the P_m's are set equal to the corresponding monthly total marginal costs, and PAVG is taken as the average volumetric rate determined by the financial analysis submodel at the end of the Average cost pricing policy block.

The Utility Supply, Operating, and Capacity Costs Minimization Submodel

There are noticeable variations in the structure of gas distribution utilities in terms of the characteristics of their suppliers (number, maximum supplies, rate structure, take-or-pay clauses, etc.), of their own gas production, of their own storage system or of the storage they rent, and of the importance of their transmission system. It is therefore necessary to adapt the costs minimization submodel to the specific features of the utility dealt with. In the following subsections, the supply, production, storage, and transmission components of the EOGC are described, and the corresponding mathematical relationships and constraints are formulated. In the final subsection, the submodel is summarized and the objective function - the total system cost - formulated.

a. EOGC Gas Supply

From 1970 to 1977, the EOGC has purchased between 87% and 91% of its annual supply from two interstate pipeline companies: The Consolidated Gas Supply Corporation (71% to 74%) and Panhandle Eastern Pipeline Company (13.5% to 18.4%). The remainder was obtained from wellhead and field-line purchases in Ohio, as well as, to a small extent, from production by EOGC itself. The latter will be discussed in the next subsection.

In the model, the monthly purchases from Consolidated and Panhandle are noted $SUP1_m$ and $SUP2_m$ for month m, respectively. In order to keep up with seasonal definitions and constraints, the year is defined as the period extending from April 1 to March 31 (with months numbered accordingly). It is assumed that there are limits to the total annual supplies purchasable from these two companies. These limits are noted SUP1T and SUP2T for Consolidated and Panhandle, respectively. These constraints are expressed mathematically as

$$\sum_{m=1}^{12} \mathrm{SUP1}_m \leq \mathrm{SUP1T}: \quad \text{Consolidated's annual supply} \tag{4.9}$$

$$\sum_{m=1}^{12} \mathrm{SUP2}_m \leq \mathrm{SUP2T}: \quad \text{Panhandle's annual supply} \tag{4.10}$$

The rate structure of Consolidated includes a commodity charge, CC1, related to the amount actually purchased, a demand charge, DC1, related to the maximum allowable daily purchase DAYMX1, and a winter requirement charge, WRC, related to the total winter gas purchases (from November 1 to March 31). The rate structure of Panhandle, in addition to a commodity charge, CC2, and a demand charge, DC2, includes a take-or-pay clause stating that the minimum monthly bill must include a minimum commodity charge based upon 75% use of the demand contract DAYMX2. The demand contracts DAYMX1 and DAYMX2 are taken, in this analysis, as decision variables of the model. Assuming that the monthly purchases $\mathrm{SUP1}_m$ and $\mathrm{SUP2}_m$ are uniformly spread over the month, the following maximum monthly purchases constraints must hold for each month m (where N_m is the number of days in month m)

$$\mathrm{SUP1}_m - N_m\,\mathrm{DAYMX1} \leq 0 \quad (m = 1 \rightarrow 12): \quad \text{Consolidated} \tag{4.11}$$

$$\mathrm{SUP2}_m - N_m\,\mathrm{DAYMX2} \leq 0 \quad (m = 1 \rightarrow 12): \quad \text{Panhandle} \tag{4.12}$$

The take-or-pay clause of Panhandle makes it necessary to introduce into the model a new monthly variable, SUPV_m, equal to the highest of (1) the actual monthly supply $\mathrm{SUP2}_m$ and (2) 75% of the monthly equivalent of the daily demand contract. The following constraints ensure the endogenous determination of $SUPV_m$

$$SUPV_m - SUP2_m \geq 0 \quad (m = 1 \rightarrow 12) \tag{4.13}$$

$$SUPV_m - 0.75 * N_m * DAYMX2 \geq 0 \quad (m = 1 \rightarrow 12) \tag{4.14}$$

The total annual cost of supply from Consolidated, CTS1, includes commodity, winter requirement, and demand costs, with

$$CTS1 = [\sum_{m=1}^{12} CC1 * SUP1_m] + 12 * [\sum_{m=8}^{12} WRC * SUP1_m] + 12 * DC1 * DAYMX1 \tag{4.15}$$

The total annual cost of supply from Panhandle, CTS2, includes commodity and demand costs, with

$$CTS2 = [\sum_{m=1}^{12} CC2 * SUPV_m] + 12 * DC2 * DAYMX2 \tag{4.16}$$

The intrastate wellhead and field-line purchases are assumed constant over time. The monthly wellhead and field-line purchases, SUPWH and SUPFL, are limited by maximum production capacities SUPWHT and SUPFLT, hence the constraints

$$SUPWH \leq SUPWHT: \text{ maximum wellhead purchases} \tag{4.17}$$

$$SUPFL \leq SUPFLT: \text{ maximum field-line purchases} \tag{4.18}$$

The above purchases are assumed subject to commodity charges only, noted CWH and CFL. The total annual cost of wellhead and field-line purchases, CTWF, is then

$$CTWF = 12 * [CWH * SUPWH + CFL * SUPFL] \tag{4.19}$$

The actual rate values used in the model are those which were in effect in 1977, with

$$CC1 = 1{,}202.4 \ \$/MMCF$$
$$DC1 = 980.0 \ \$/MMCF$$
$$WRC = 8.075 \ \$/MMCF$$
$$CC2 = 1{,}009.2 \ \$/MMCF$$
$$DC2 = 1{,}860.0 \ \$/MMCF$$

The wellhead and field-line purchase costs were taken equal to the average 1977 corresponding costs, with

$$CWH = 787.0 \ \$/MMCF$$
$$CFL = 1{,}481.0 \ \$/MMCF$$

Alternate assumptions with respect to Consolidated's and Panhandle's maximum annual supplies, SUP1T and SUP2T, will be considered in the application of the model in the next section. The assumptions with respect to maximum wellhead and field-line purchases are

$$SUPWHT = 2000 \ MMCF/month$$
$$SUPFLT = 2500 \ MMCF/month$$

b. EOGC Gas Production

The actual annual amounts of gas produced by the EOGC for the period 1972-1977 are indicated in table 4.2.

Taken on a monthly basis, this capacity is then

$$PROC = \frac{11{,}372}{12} = 947.667 \ MMCF/month$$

TABLE 4.2
EOGC OWN GAS PRODUCTION

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

Source: EOGC's Annual Reports to the Public Utilities Commission of Ohio.

The total operating cost for production in 1977 amounted to \$5,711,000. The average 1977 unit operating cost was selected in this model, with

$$\text{COMP} = \frac{5,711,000}{6,200} = 921.129 \ \$/\text{MMCF}$$

The 1977 historical (or book) value of the production plant amounted to \$73,299,000. In view of the fact that the production plant has been constructed quite recently, it was assumed that its 1977 replacement value would be equal to 1.5 times its historical value, or \$109,948,500. The replacement cost per unit of monthly production capacity is then equal to 116,020.22 \$/(MMCF/month). It is, however, necessary to use annualized investment cost figures in the model. These annualized figures were computed while assuming (1) an investment lifetime of 30 years, and (2) an interest rate of 12%. The ratio of the annualized cost to the total present cost is then equal to

$$\text{CRF} = 1/\left\{\frac{1}{0.12}\left[1 - \frac{1}{(1 + 0.12)^{30}}\right]\right\} = 0.1241$$

The annualized production capacity investment cost is then

$$\text{CIP} = 14{,}398.11 \ \$/(\text{MMCF/month})$$

The production-related decision variables are

- the monthly production levels PR_m, and
- the additional monthly production capacity DPRO

The total annual production cost is then

$$\text{CTP} = \text{CIP} * \text{DPRO} + \sum_{m=1}^{12} \text{COMP} * PR_m \tag{4.20}$$

It is assumed that there is an upper limit, DPROM, to the incremental production capacity, with

$$\text{DPROM} = 3{,}000 \ \text{MMCF/month}$$

In addition, it is assumed that the utility is constrained by the regulatory authorities to supply a certain share, SHP, of new customers with its own gas. Such a constraint was actually imposed on the EOGC by the Public Utilities Commission of Ohio (PUCO) in 1978, when the EOGC applied for a relief order from the then existing moratorium on new hookups. In the present analysis, this share is taken equal to 10% of the new total annual load DDGT. The production-related constraints are then written as

$\text{DPRO} \leq \text{DPROM}$: maximum incremental production capacity (4.21)

$\sum_{m=1}^{12} PR_m \geq \text{SHP} * \text{DDGT}$: minimum total production (4.22)

$PR_m - \text{DPRO} \leq \text{PROC} \ (m = 1 \rightarrow 12)$: the monthly production levels are limited by the production capacity (4.23)

c. EOGC Gas Storage

The EOGC storage system includes five storage fields, with a total certified storage capacity of 147,594.1 MMCF. From 1970 to 1977, the average annual total deliveries and withdrawals were equal to 54,125.348 MMCF and 53,614.929 MMCF, respectively, with an average gas loss of 306.947 MMCF. The total amount of cushion gas was equal to 90,937.838 MMCF at the end of 1977 (i.e., 61.6% of the certified capacity). This cushion gas must be maintained in storage at all times to ensure effective utilization of the reservoir. Additional volumes must also be injected and maintained above the cushion gas volume to establish reservoir volume and pressure conditions necessary to provide minimum withdrawal rates: in the case of the EOGC, these additional volumes correspond to 15.4% of the certified capacity.

Although the different storage fields have different capacities and porosities, only the aggregate storage capacity is considered. This simplification is acceptable inasmuch as one field makes up for 88.3% of the total capacity. The major difference between a gas storage system and a water storage system is that both injection and withdrawal maximal rates depend, at any time, upon the amount of gas stored, i.e., the reservoir pressure. The main technological difference between gas withdrawal and delivery is that compressors are required for delivery, whereas natural storage pressure is used to transfer gas out of storage into the mains. Monthly constraints on storage deliveries and withdrawals have been determined on the basis of historical data. Using monthly storage flows, the level of gas in storage at the beginning of each month m, $GSTOR_m$, has been determined, and a storage saturation rate, $RSTOR_m$, taken as a proxy for storage pressure, has been defined as

$$RSTOR_m = GSTOR_m/STCO \qquad (4.24)$$

where STCO is the existing certified storage capacity. The monthly deliveries and withdrawals for the period 1971-1976 were plotted against the corresponding saturation rates, and the maximum flows were approximated by straight-line segments, as presented in figures 4.2 and 4.3. It appears that storage was active when the saturation rate was comprised between a minimum and a maximum saturation rate, R_{min}(= .77) and R_{max}(=1.18), respectively. The maximum deliveries and withdrawals during any month m are noted by $MAXINS_m$ and $MAXOUS_m$ and are defined functionally as

$$MAXINS_m = A_1 * RSTOR_m + B_1 \quad \text{(MMCF)} \tag{4.25}$$

$$MAXOUS_m = A_2 * RSTOR_m + B_2 \quad \text{(MMCF)} \tag{4.26}$$

with A_1 = -11,463.415, B_1 = 20,726.83, A_2 = 22,500, B_2 = -9,825.
If $GINST_m$ and $GOUST_m$ are the actual deliveries and withdrawals during month m, if $GSTOR_o$ is the cushion and operational (nonwithdrawable) gas, and if it is assumed that there is no usable gas in storage at the beginning of the first month, it follows that

$$RSTOR_m = GSTOR_m/STCO = [GSTOR_o + \sum_{\mu=1}^{m-1} (GINST_\mu - GOUST_\mu)]/STCO \tag{4.27}$$

The above coefficients A_1, B_1, A_2, B_2 characterize the existing storage system (STCO = 147,594.1 MMCF). To extend the applicability of equations (4.25) through (4.27), it is assumed that these coefficients are linear functions of the total storage capacity, STCAP, whatever the incremental storage capacity DSTC added to STCO. The coefficients A_{10}, B_{10}, A_{20}, B_{20} of these functions are specified on the basis of the existing storage characteristics. For instance

$$A_{10} = \frac{A_1}{STCO} = - \frac{11,463.415}{147,594.1} = -0.07766852$$

and the coefficient A_1 is redefined as

$$A_1 = A_{10} * (STCO + DSTC) \tag{4.28}$$

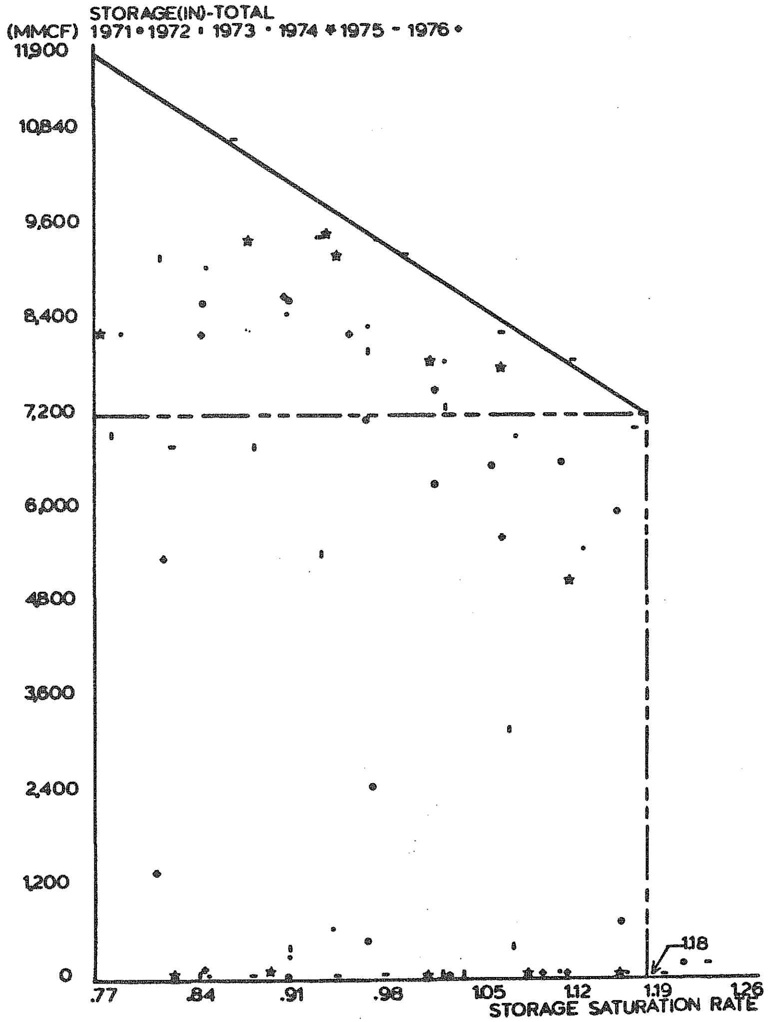


Figure 4.2 Maximum Gas Deliveries to Storage

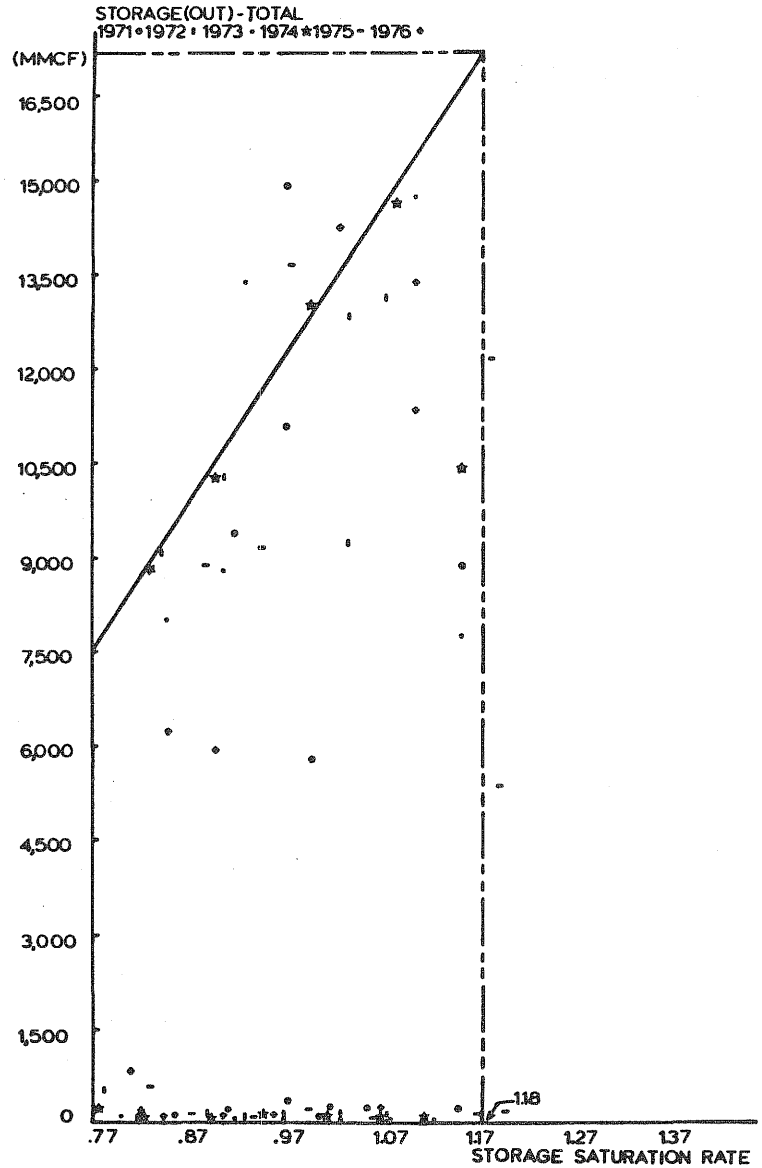


Figure 4.3 Maximum Gas Withdrawals from Storage

The other coefficients are then

$$B_{10} = 0.14043129$$
$$A_{20} = 0.15244512$$
$$B_{20} = -0.06656770$$

In addition, it is assumed that the minimum and maximum storage saturation rates, R_{min} and R_{max}, remain constant whatever the storage capacity.
The maximum monthly storage deliveries and withdrawals constraints, and the maximum and minimum storage saturation constraints

$$GINST_m \leq MAXINS_m \qquad (m = 1 \rightarrow 12) \tag{4.29}$$

$$GOUST_m \leq MAXOUS_m \qquad (m = 1 \rightarrow 12) \tag{4.30}$$

$$R_{min} \leq RSTOR_m \leq R_{max} \quad (m = 1 \rightarrow 12) \tag{4.31}$$

are then rewritten as follows

$$GINST_m - A_{10} * \sum_{\mu=1}^{m-1} (GINST_\mu - GOUST_\mu) - (A_{10} * R_{min} + B_{10}) * DSTC \leq (A_{10} * R_{min} + B_{10}) * STCO \; (m = 1 \rightarrow 12): \text{ maximum delivery} \tag{4.32}$$

$$GOUST_m - A_{20} * \sum_{\mu=1}^{m-1} (GINST_\mu - GOUST_\mu) - (A_{20} * R_{min} + B_{20}) * DSTC \leq (A_{20} * R_{min} + B_{20}) * STCO \; (m = 1 \rightarrow 12): \text{ maximum withdrawal} \tag{4.33}$$

$$\sum_{\mu=1}^{m} (GINST_\mu - GOUST_\mu) - (R_{max} - R_{min}) * DSTC \leq (R_{max} - R_{min}) * STCO \; (m = 1 \rightarrow 12): \text{ maximum saturation rate} \tag{4.34}$$

$$\sum_{\mu=1}^{m} (GINST_\mu - GOUST_\mu) \geq 0 \; (m = 1 \rightarrow 12): \text{ minimum saturation rate} \tag{4.35}$$

Constraints (4.32) through (4.35) are derived from constraints (4.29) through (4.31) while accounting for the fact that in equation (4.27)

$$GSTOR_o = R_{min} * (STCO + DSTC) \tag{4.36}$$

In addition to the previous storage operations constraints, it is assumed that there is a limit, DSTCM, to the incremental storage capacity, hence the constraint

$$DSTC \leq DSTCM \tag{4.37}$$

In the present analysis, DSTCM is taken equal to 100,000 MMCF.

Gas storage costs include initial capital costs, mostly related to wells, gathering lines, compressors, regulating equipment, land, etc., and annual operation and maintenance costs, mostly related to wells maintenance, compressor fuel, gas losses, storage well royalties, supervision, etc. There is much uncertainty in the estimation of new storage capital costs, which depend on an annualized basis, upon the project lifetime, discount rate, and amount of cushion and operational gas necessary to maintain adequate pressure conditions. On the basis of various data, an annual capital cost range of 32.0 \$/MMCF to 77.1 \$/MMCF was obtained, consistent with the Federal Power Commission National Gas Survey 1975 average estimate of 57.0 \$/MMCF of storage capacity. The figure selected in this study is

$$CIST = 50 \ \$/MMCF$$

The EOGC average annual operation and maintenance expense per MMCF of gas delivered to storage is equal to \$66.46. This cost figure, apportioned equally among deliveries and withdrawals, is used in the present study, with

$$CS = 33.23 \ \$/MMCF$$

The total storage investment and operation and maintenance cost, CTS, is finally

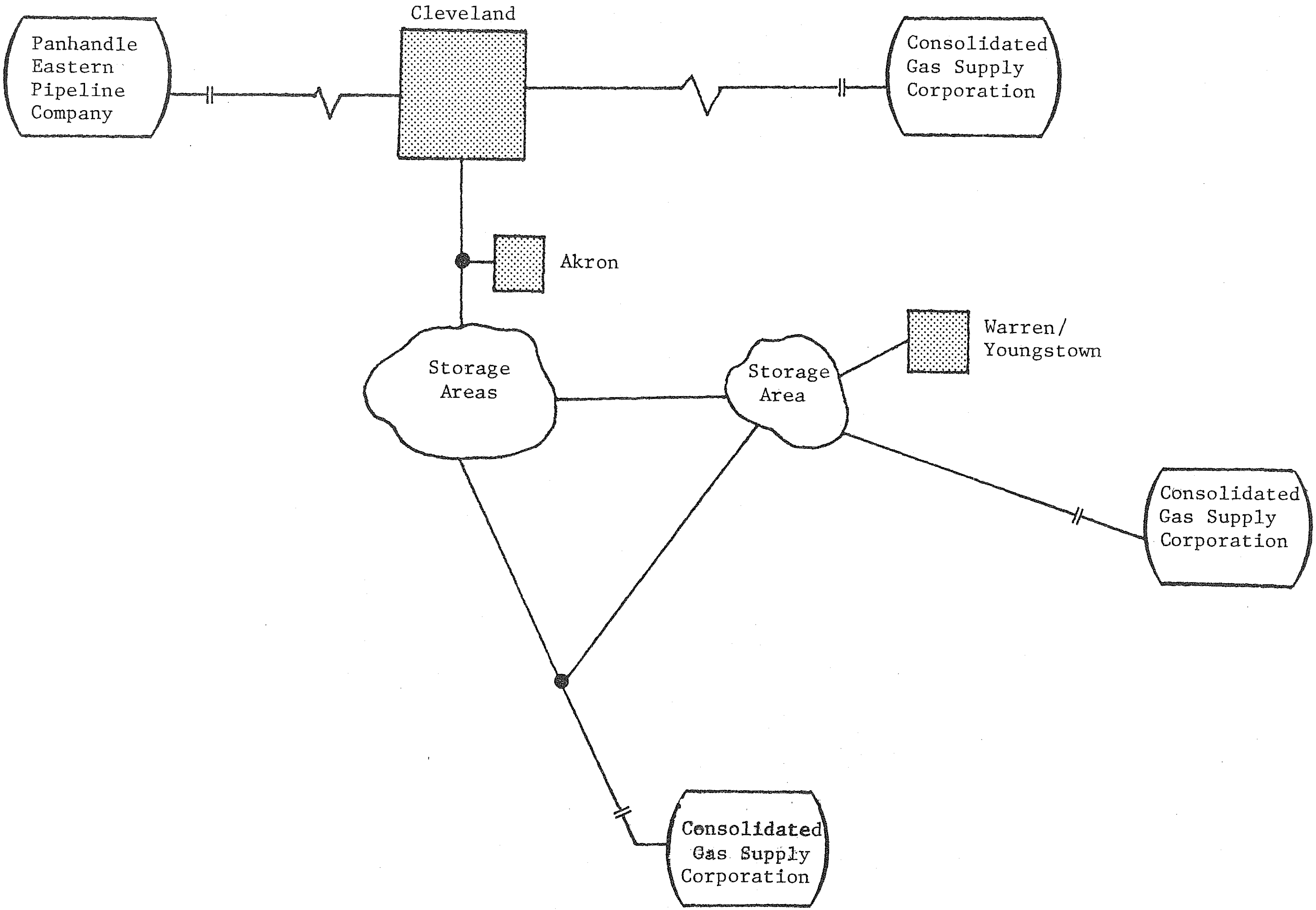
$$CTS = CIST * DSTC + CS * \sum_{m=1}^{12} (GINST_m + GOUST_m) \qquad (4.38)$$

d. EOGC Gas Transmission

The EOGC tranmission mains convey gas from the points of connection with its suppliers to the distribution networks of the various communities and metropolitan areas served by the company. Many important transmission mains do so while passing through the EOGC storage system, as illustrated in figure 4.4. Abstracting from the spatial complexities of the system's network, it is assumed that the transmission system may be decomposed into two components: (1) T_1, conveying gas from the suppliers to storage as well as directly to the end-use customers; and (2) T_2, conveying gas from storage and from the suppliers to the end-use customers. This simplification of the system is illustrated in figure 4.5. Clearly, then, the capacity of T_1 is determined by the peak purchases, while the capacity of T_2 is determined by the peak sales to the end-use customers. The peak sales are, on a monthly basis, exogenously specified for the utility costs minimization model and only vary in the iterative simulation of the Marginal cost pricing policy block, where rates are iteratively readjusted equal to the total marginal costs. On the other side, the peak monthly purchases are endogenously determined by the costs minimization model and may be reduced by increasing the available storage capacity. Obviously, there is a cost trade-off between the incremental transmission and storage capacities that must be accounted for in the model.

By the end of 1977, the maximum daily sales had taken place on January 8, 1970, with an amount of 2,853.1 MMCF. At such a constant daily rate, the monthly sales would have been equal to 88,446.1 MMCF. In the following, the existing monthly capacity of T_2 is assumed to be

$$PT2_0 = 88,500 \text{ MMCF}$$


Cleveland
Panhandle Eastern Pipeline Company
Consolidated Gas Supply Corporation
Akron
Warren/ Youngstown
Storage Areas
Storage Area
Consolidated Gas Supply Corporation
Consolidated Gas Supply Corporation

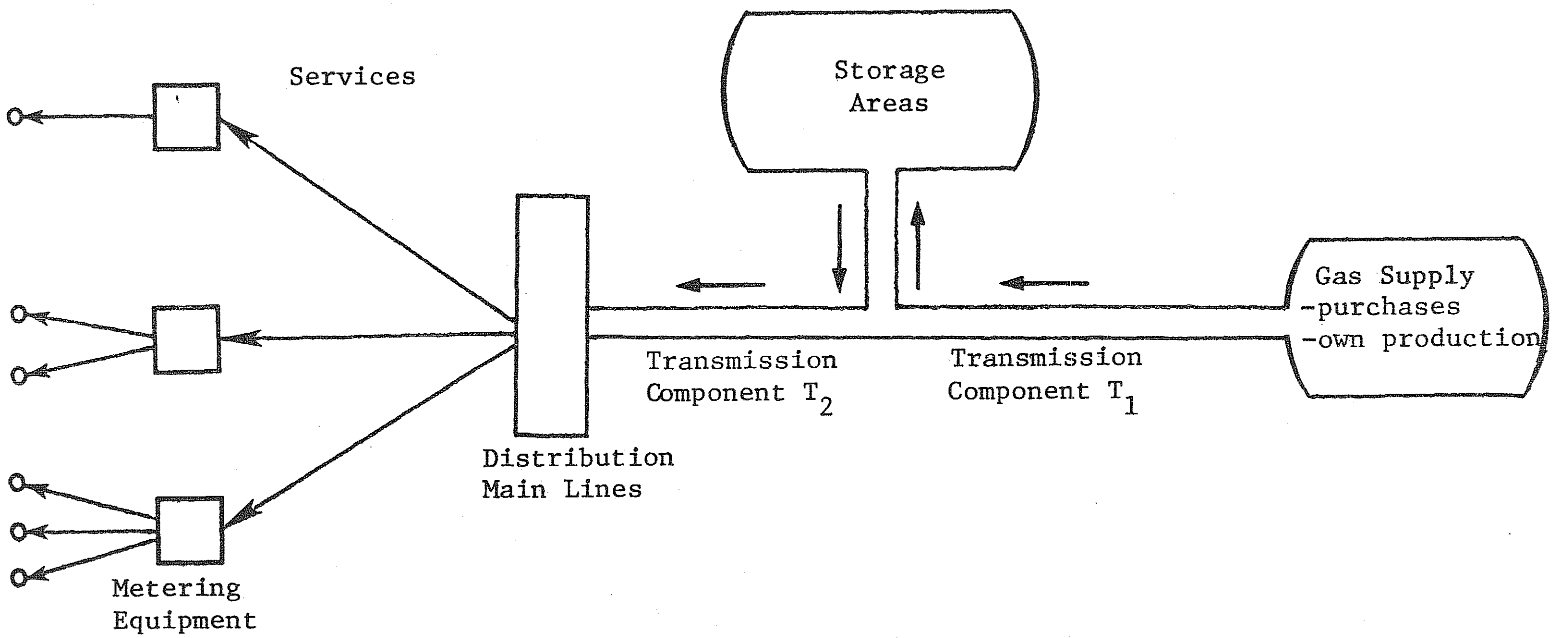


Figure 4.5 EOGC System Approximation

The peak daily purchases have taken place on February 1, 1971, when the balance between sales and storage withdrawal/delivery was at a maximum. The sales were equal, on that day, to 2,796.0 MMCF and the withdrawal from storage to 1,025.9 MMCF. The corresponding daily purchase rate of 1,770.1 MMCF would lead to a monthly purchase rate of 54,873.1 MMCF. In the following, the existing monthly capacity of T_1 is assumed to be

$$PT1_0 = 55{,}000 \text{ MMCF}$$

The 1977 historical (or book) value of the transmission plant amounted to $102,837,912. In view of the age of the system, it was assumed that the 1977 replacement value of this plant would be equal to 2.5 times its historical value, or $257,094,785. In addition, it was assumed that (1) component T_1 represents 40% of this investment and component T_2 the remainder, (2) the lifetime of a transmission investment is 30 years, and (3) the discount rate is 12%. The annualized unit expansion costs of the transmission components T_1 and T_2 are then computed as

$$CIPT_1 = \frac{0.4 * 0.1241 * 257{,}094{,}785}{55{,}000} = 232.0397 \text{ \$/(MMCF/month)}$$

$$CIPT_2 = \frac{0.6 * 0.1241 * 257{,}094{,}785}{88{,}500} = 216.30822 \text{ \$/(MMCF/month)}$$

Calculations related to component T_2 are described in the distribution plant analysis section. With respect to component T_1, the decision variable is the incremental monthly transmission capacity DPT_1. The augmented capacity is the upper limit to monthly transmission flows, hence the constraint

$$SUP1_m + SUP2_m + SUPWH + SUPFL + PR_m - DPT_1 \leq PT1_0 \quad (m = 1 \rightarrow 12) \qquad (4.39)$$

Finally, the annualized transmission capacity expansion cost is defined as

$$CTPT_1 = CIPT_1 * DPT_1 \tag{4.40}$$

The transmission operating costs are considered later, together with the distribution and other operating costs, and are taken as proportional to the end-use sales.

e. EOGC Gas Requirements

The monthly total loads computed in the load analysis submodel, $DGMT_m$, must always be satisfied, hence the supply-demand equality constraints

$$SUP1_m + SUP2_m + SUPWH + SUPFL + PR_m - GINST_m + GOUST_m = DGMT_m \qquad (m = 1 \rightarrow 12) \tag{4.41}$$

The shadow prices of these constraints are noted MC_m. They are precisely equal to the marginal costs incurred by an increase of one unit of demand during any month m. Note, however, that these marginal costs refer only to the costs considered in this linear program (supply, production operations and investment, storage operations and investment, and transmission investment). Therefore, they do not constitute the total marginal costs relevant to marginal cost pricing policy and will be complemented by other investment and operations marginal costs later.

f. Summary of the Utility Costs Minimization Submodel

The linear program described in the previous subsections is made of

- 79 decision variables: $SUP1_m$ ($m = 1 \rightarrow 12$); $SUP2_m$ ($m = 1 \rightarrow 12$); $SUPV_m$ ($m = 1 \rightarrow 12$); DAYMX1; DAYMX2; SUPWH; SUPFL; DPRO; PR_m ($m = 1 \rightarrow 12$); $GINST_m$ ($m = 1 \rightarrow 12$); $GOUST_m$ ($m = 1 \rightarrow 12$); DSTC; DPT_1

- 139 constraints: maximum monthly and annual purchases from Consolidated and Panhandle; maximum wellhead and field-line purchases; maximum production capacity expansion; minimum total annual production; maximum monthly production rate; maximum storage capacity expansion; maximum monthly storage deliveries and withdrawals; maximum monthly transmission flows; and monthly gas loads provision.

The objective function of the program is the sum of all the costs considered, i.e., purchases, production, storage, and transmission costs, with

$$CT = CTS1 + CTS2 + CTWF + CTP + CTS + CTPT_1 \qquad (4.42)$$

The linear program has been solved by the code LPCODE developed by Professor C. H. Martin, Department of Industrial and Systems Engineering, The Ohio State University.

The Distribution Plant Capacity Submodel

This submodel determines the incremental capacities necessary to accommodate the peak sales to the end-use customers. As such, it deals with (1) the component T_2 of the transmission system, as described in the costs minimization submodel; and (2) the distribution system. For both cases, it is first necessary to determine the peak sales month m_p. (This peak month is initially January ($m_p = 10$) but is likely to change with changes in the rate structure.)

a. Case of the Transmission Component T_2

If the peak sales $DGMT_{m_p}$ are smaller than the existing transmission capacity PT_{20} (= 88,500 MMCF/month), then there is no need for expanding component T_2, and the corresponding marginal capacity cost, $CMPT_2$, and present value of the incremental plant, NPT_2, are both equal to zero. In the other case, it follows that

$$\text{CMPT}_2 = \begin{cases} \text{CIPT}_2 = 216.30822 \text{ \$/MMCF during month } m_p \\ 0 \text{ during all the other months} \end{cases} \tag{4.43}$$

and

$$\text{NPT}_2 \;=\; \text{CIPT}_2 * (\text{DGMT}_{m_p} - \text{PT}_{20})/\text{CRF} \tag{4.44}$$

b. Case of the Distribution Plant

The existing capacity of the distribution network has been assumed equal to the January peak sales of the base gas market (see table 4.1), with

PD_0 = 59,081 MMCF/month

The above figure is significantly lower than the capacity of transmission component T_2 (PT_{20} = 88,500 MMCF). This is so because it can be reasonably assumed that with the increased use of compressors, the capacity of the transmission system can be easily increased, and this is much less the case for smaller distribution mains. In addition, note that, even if there was some excess capacity in some distribution mains, the taking of new customers necessarily requires such new investments as meters and services. Obviously, the above assumption is an approximation and should be submitted to a sensitivity analysis.

The 1977 historical (or book) value of the EOGC's distribution plant amounted to $372,284,403. The breakdown of this plant into various components is indicated in table 4.3. In view of the age of the system, it was assumed that the 1977 replacement value of this plant is equal to 2.5 times

TABLE 4.3

EOGC DISTRIBUTION PLANT

Plant Category	Historical Value $
Land and Land Rights	2,105,000
Structures	11,755,000
Mains	264,543,000
Regulators	9,935,000
Services	50,723,000
Meters	28,618,000
Other	4,604,000

Source: EOGC's 1977 Annual Report to the PUCO.

its historical value, or \$930,711,000. Under the assumptions that (1) the lifetime of a distribution investment is 30 years and (2) the discount rate is 12%, the annualized unit expansion cost of the distribution system is then computed as

$$\text{CIPD} = \frac{0.1241 * 930{,}711{,}000}{59{,}081} = 1954.964 \ \$/(\text{MMCF/month})$$

If the peak sales DGMT_{m_p} are smaller than the existing distribution capacity PD_0 (= 59,081 MMCF/month), then there is no need for expanding the distribution system, and the corresponding marginal capacity cost, CMPD, and the present value of the incremental plant, NPD, are both equal to zero. In the other case, it follows that

$$\text{CMPD} = \begin{cases} \text{CIPD} = 1954.964 \ \$/\text{MMCF during month } m_p \\ 0 \text{ during all the other months} \end{cases} \tag{4.45}$$

and

$$NPD = CIPD * (DGMT_{m_p} - PD_0)/CRF \tag{4.46}$$

Total New Plant and Marginal Costs Calculations

The total cost CT (see equation 4.42) minimized in the utility supply, operating, and capacity costs minimization submodel includes both operating and annualized investment costs, noted OMC_1 and PIS_1, respectively. The investment costs PIS_1 include the production, storage, and transmission capacity costs, with

$$PIS_1 = CIP * DPRO + CIST * DSTC + CIPT_1 * DPT_1 \tag{4.47}$$

The present value of this plant is then

$$NEWPIS_1 = PIS_1/CRF \tag{4.48}$$

The operating costs OMC_1 include the supply and the production and storage operating costs, with

$$OMC_1 = CT - PIS_1 \tag{4.49}$$

The next step is to compute the present value of the total new plant, NEWPIS, including the transmission component T_2 and the distribution system, with

$$NEWPIS = NEWPIS_1 + NPT_2 + NPD \tag{4.50}$$

The total new plant NEWPIS constitutes then a major input to the financial analysis submodel described in the next section.

The total marginal costs include (1) the marginal costs MC_m corresponding to the costs considered in the costs minimization submodel, (2) the transmission component T_2 and the distribution system capacity marginal costs, $CMPT_2$ and CMPD, which must be exclusively assigned to the peak sales month m_p, and (3) other operating marginal costs, COM_2, corresponding to costs proportional to sales and not considered previously (i.e. transmission and distribution operating costs, customers services, administration, etc.). The value of COM_2 was estimated as

$$COM_2 = 209.48495 \text{ \$/MMCF}$$

The total monthly marginal costs, TMC_m, are then computed as

$$TMC_m = \begin{cases} MC_m + COM_2 + CMPT_2 + CMPD, \text{ if } m = m_p, \\ \\ MC_m + COM_2, \text{ if } m \neq m_p \end{cases} \tag{4.51}$$

The above monthly marginal costs then serve as monthly prices in the load analysis submodel within the Marginal cost pricing policy block.

The Financial Analysis Submodel

This submodel very much replicates the main calculations typically performed prior to rate case proceedings that take place when the utility requests a change in its retail prices in order to be able to achieve the allowed rate of return on the net value of the utility's plant in service (or rate base), as determined by the state regulatory authorities. The equations and procedures used in this analysis are based on a former study applied to the East Ohio Gas Company, and are not, therefore, discussed in great detail here. For more information, the reader is referred to the corresponding published materials.[20]

The first part of the analysis consists in determining the net plant in service (or rate base) and the depreciation expense. It is assumed that the whole new plant is put in service in the same single period (i.e., within a year's time), and that the market growth takes place in a similar way. Of course, this is an approximation of reality, wherein the growth in

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[20]See for instance: J.M. Guldmann and D.Z. Czamanski, "A Simulation Model of Market Expansion Policies for Natural Gas Distribution Utilities," Energy 5, 10 (1980): 1013-43; D.Z. Czamanski and J.M. Guldmann, The Allocation of Increasing Gas Supplies in Ohio (Columbus, Ohio: The National Regulatory Research Institute, 1978).

both plant and market takes place progressively. However, such an approximation should be acceptable in view of the stated purpose of the model, i.e., a general evaluation of marginal cost pricing policy. The total plant in service, TOTPIS, is equal to the sum of

(1) the initial total plant in service, PISBEG (= $617,338,511)

(2) the replacement plant, REPPIS, which is to replace those parts of PISBEG normally retired, with

$$\text{REPPIS} = 0.03625 * \text{PISBEG} \tag{4.52}$$

(3) the new plant in service, NEWPIS, the calculation of which has been described in previous sections

It follows that

$$\text{TOTPIS} = \text{PISBEG} + \text{REPPIS} + \text{NEWPIS} \tag{4.53}$$

A single average depreciation rate, estimated with historical data, is used to compute the depreciation expense DEPEXP for the three plant types, with

$$\text{DEPEXP} = 0.02939 * \text{TOTPIS} \tag{4.54}$$

The total accumulated provision for depreciation, TAPD, is credited for amounts recovered during the year, such as insurance and salvage value of plant, by adjusting the depreciation expenses with an accumulated provision factor also estimated with historical data, so that

$$\text{TAPD} = \text{TAPDO} + 0.82528 * \text{DEPEXP} \tag{4.55}$$

where TAPDO (= $224,690,519) is the initial accumulated provision for depreciation before the replacement and new plants are put in service. The net plant in service (or rate base), NETPIS, is finally calculated as the difference between the total plant in service and the total accumulated provision for depreciation, with

$$NETPIS = TOTPIS - TAPD \quad (4.56)$$

The second part of the analysis consists in determining the revenue from gas sales, X, that enables the utility to earn the allowed rate of return, ALLROR, on its rate base. It is assumed that this rate of return is equal to 12.06% (1978 value prescribed by the Public Utilities Commission of Ohio). The allowed operating income, AOPINC, is then

$$AOPINC = 0.1206 * NETPIS \quad (4.57)$$

The actual operating expenses of the utility, ACOPEX, are the sum of the operating and depreciation expenses. The operating expenses include

(a) the operating costs OMC_1, determined in the costs minimization submodel (see equation 4.49), and

(b) the other operating costs OMC_2 include the transmission, distribution, customer, and administrative operating costs; they are assumed proportional to the total gas sales DGT, with unit cost COM_2 (= 209.48495 \$/MMCF), so that

$$OMC_2 = 209.48495 * DGT \quad (4.58)$$

It follows that

$$ACOPEX = OMC_1 + OMC_2 + DEPEXP \quad (4.59)$$

The total operating revenues, OPREVS, are the sum of the revenues from gas sales, X, and of other revenues derived from the transportation of gas of others and from nonutility operations such as building rentals. These other revenues are empirically related to the total plant in service, TOTPIS. The total operating revenues are then

$$OPREVS = X + 0.005263 * TOTPIS \quad (4.60)$$

In order to determine the net operating income, it is necessary to account for various taxes and deductions. The income before federal income taxes, INCBFT, is calculated while accounting for revenues taxes, REVTAX, property taxes, PRPTAX, and payroll taxes, PAYTAX, with

$$REVTAX = 0.041454 * OPREVS \tag{4.61}$$

$$PRPTAX = 0.021 * NETPIS \tag{4.62}$$

$$PAYTAX = 0.03 * OMC_2 \tag{4.63}$$

The income before federal income taxes is then

$$INCBFT = OPREVS - ACOPEX - REVTAX - PRPTAX - PAYTAX \tag{4.64}$$

or

$$INCBFT = 0.958546 * X + 0.00504483 * TOPIS - ACOPEX - PRPTAX - PAYTAX \tag{4.65}$$

In order to simplify later calculations, the following notations are used

$$X_1 = 0.00504483 * TOTPIS - ACOPEX - PRPTAX - PAYTAX \tag{4.66}$$

and

$$INCBFT = 0.958546 * X + X_1 \tag{4.67}$$

The federally taxable income, TAXINC, and the federal income tax, INCTAX, are then computed while accounting for liberalized depreciation, LIBDEP, interest charges, INTCHG, and investment tax credits, INVTXC, with

$$LIBDEP = 0.3 * DEPEXP \tag{4.68}$$

$$INTCHG = 0.01759 * TOTPIS \tag{4.69}$$

$$INVTXC = 0.1 * (NEWPIS + REPPIS) \tag{4.70}$$

and

$$TAXINC = INCBFT - LIBDEP - INTCHG \tag{4.71}$$

$$INCTAX = 0.46 * TAXINC - INVTXC \tag{4.72}$$

The net operating income, NOPINC, is finally determined as

$$NOPINC = INCBFT - INCTAX \tag{4.73}$$

and must be equal to the allowed operating income, hence

$$NOPINC = AOPINC \tag{4.74}$$

Equation 4.74 includes, implicitly, the unknown X - the revenues from gas sales. In order to simplify the resolution of this equation, the following quantity is defined

$$X_2 = 0.46 * LIBDEP + 0.46 * INTCHG + INVTXC \tag{4.75}$$

The necessary revenues from gas sales are then

$$X = (AOPINC - X_2 - 0.54 * X_1)/(0.51761484) \tag{4.76}$$

and the corresponding average volumetric rate is

$$PAVG = X/DGT \tag{4.77}$$

The Pricing Policy Evaluation Submodel

This submodel is implemented through two computer subprograms - EVAL1 and EVAL2 - that are essentially identical with the exception of the way they deal with gas sales revenues surpluses or deficits. Indeed, in the Average cost pricing policy block (case of EVAL1), there are neither deficits nor surpluses, for gas revenues are determined to yield exactly the allowed operating income, whereas in the Marginal cost pricing policy block these revenues depend upon (1) the monthly rates taken equal to the total marginal costs, and (2) the corresponding monthly gas demands.

The submodel first computes the load factor of the end-use customers sales. If m_p is the peak sales month, this load factor is defined as

$$LF = DGT/(12 * DGMT_{m_p}) \tag{4.78}$$

The next step consists in estimating the sectoral consumers' surpluses, taken as consumers' measures of the economic efficiency of the pricing policy. Such surpluses are computed for each month separately. Consider the typical demand curve in figure 4.6. The consumers' surplus at price P_o is measured by the shaded area S_o. If the functional relationship between price P and demand D is known, this area can be estimated as

$$CS_o = \int_{P_o}^{\infty} D(P)dP \tag{4.79}$$

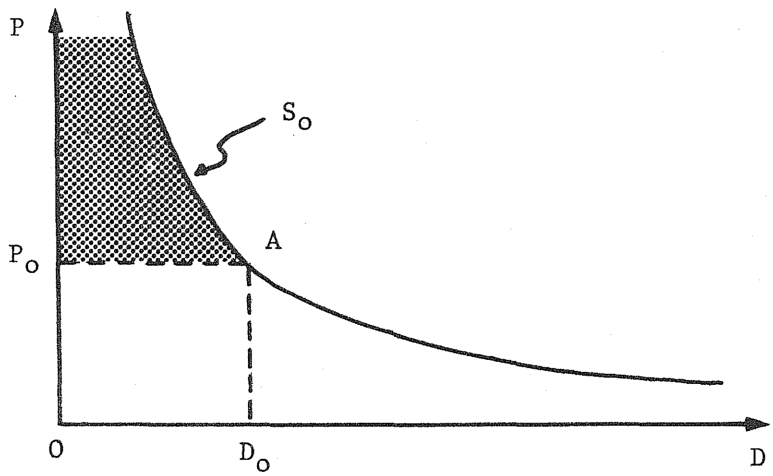

Figure 4.6 Typical Demand Curve and Consumers' Surplus

In the present study, the monthly demand functions are of the constant price elasticity type. (See equations 4.6 through 4.8.) In such a case, it is impossible to integrate the demand function up to an infinite price, and for practical purposes, the upper bound of the integral (4.79) has been set equal to 10,000 \$/MMCF. The residential consumers' surplus for month m is then expressed as

$$CSR_m = DGMRO_m * \left[\frac{PAVG^{-ELR_m}}{1 + ELR_m}\right] * \left[10{,}000^{(1+ELR_m)} - P_m^{(1+ELR_m)}\right] \tag{4.80}$$

Similar functional relationships are derived for the commercial and industrial sectors by replacing the weather component $DGMRO_m$ and the elasticity ELR_m by the corresponding sectors' values. The total annual sectoral surpluses are obtained as the sum of the corresponding monthly surpluses.

The production efficiency of the utility can be measured by its net income, NETINC. In the Average cost pricing policy block, this net income is, by definition, equal to the allowed operating income

$$NETINC = AOPINC \tag{4.81}$$

When the marginal cost pricing policy is applied, the net income may be higher or lower than the allowed operating income. The difference can be found by comparing the gas sales revenues XE necessary to earn the allowed operating income and computed in the financial analysis submodel at the end of the computations cycle, with the actual gas sales XA computed as

$$XA = \sum_{m=1}^{12} P_m * DGMT_m \tag{4.82}$$

The revenue deficit ($DF < 0$) or surplus ($DF > 0$) is then

$$DF = XA - XE \tag{4.83}$$

and the net income is adjusted for DF while accounting for tax effects

$$NETINC = AOPINC + 0.5176 * DF \tag{4.84}$$

The aggregate efficiency of the pricing policy is finally measured by the sum of (1) all the consumers' surpluses, and (2) the utility's net income.

Application of the Gas Utility Marginal Cost Pricing Model (GUMCPM)

The Assumptions

As stated several times in the description of the model, there is some uncertainty about the exact value of different parameters, either because of forecasting difficulties or because of approximations made while formulating the model. Therefore, sensitivity analyses are called for on such items as (1) demand functions parameters, (2) market growth rates, (3) operating and capacity unit costs, (4) operating and capacity expansion technological constraints, (5) supply costs and constraints, and (6) financial parameters and allowed rate of return.

Obviously, all the above sensitivity analyses could not be performed in the framework of this study. In order to illustrate the potentialities and usefulness of the model, a limited sensitivity analysis was conducted, focusing on the maximum annual supplies available from Consolidated (SUP1T) and Panhandle (SUP2T), and on the monthly price elasticities of demand that were assumed to be equal for all the months and sectors. More specifically, the following values were considered

1. Supply cases

S_1 : SUP1T = 500,000 MMCF; SUP2T = 200,000 MMCF

S_2 : SUP1T = 200,000 MMCF; SUP2T = 500,000 MMCF

2. Elasticity cases

E_1 : $ELR_m = ELC_m = ELI_m = -0.1 \quad (m = 1 \rightarrow 12)$

E_2 : $ELR_m = ELC_m = ELI_m = -0.5 \quad (m = 1 \rightarrow 12)$

The model was then applied under the following four combinations of assumptions: S_1E_1, S_1E_2, S_2E_1, S_2E_2. The results of these applications are described and discussed in the following section.

The Results

a. Case of the Average Cost Pricing Policy

As the price elasticities of demand are not accounted for in the Average cost pricing policy block, the monthly load patterns are the same for all the four combinations (S_1E_1, S_1E_2, S_2E_1, S_2E_2), and therefore the results differ only with respect to the supply assumptions S_1 and S_2.

The sectoral monthly loads, corresponding to residential, commercial, and industrial rates of growth all equal to 50%, are indicated in table 4.4. These loads are part of the constraints of the costs minimization submodel run under both supply assumptions. The corresponding minimum

TABLE 4.4

SECTORAL MONTHLY LOADS (MMCF) WITH MARKET GROWTH RATES EQUAL TO 50%
AVERAGE COST PRICING POLICY

	Month	Residential Load DGMR	Commercial Load DGMC	Industrial Load DGMI	Total Load DGMT
1.	April	22,976.35	9,193.07	17,979.46	50,148.88
2.	May	13,708.05	5,664.36	16,596.89	35,969.30
3.	June	6,616.95	2,964.57	15,539.10	25,120.61
4.	July	5,200.16	2,425.15	15,327.75	22,953.07
5.	August	5,483.52	2,533.04	15,370.02	23,386.58
6.	September	9,127.71	3,920.49	15,913.63	28,961.83
7.	October	18,134.17	7,349.51	17,257.14	42,740.82
8.	November	30,365.16	12,006.20	19,081.67	61,453.03
9.	December	43,241.77	16,908.71	21,002.50	81,152.97
10.	January	48,123.40	18,767.29	21,730.70	88,621.39
11.	February	42,334.31	16,563.21	20,867.13	79,764.65
12.	March	36,817.81	14,462.92	20,044.22	71,324.94
	Total	282,129.34	112,758.50	216,710.22	611,598.06

Source: Author's calculations.

costs CT and their breakdown into various components are presented in table 4.5. The lower cost of case S_2 is related to the much higher availability of gas from Panhandle (500,000 MMCF) in case S_2 than in case S_1 (200,000 MMCF), and to the significantly lower commodity cost for

Panhandle's gas (1,009.2 \$/MMCF versus 1,202.4 \$/MMCF for Consolidated's gas), hence the difference of \$57,959,986 in total commodity charge. This decrease is compensated, to a smaller extent, by an increase of \$10,274,363 in the total demand charge, as Panhandle's charge (1,860 \$/MMCF) is about double that of Consolidated's charge (980 \$/MMCF). When shifting from case S_1 to case S_2, the total winter requirement charge decreases by \$12,683,008 because of considerably lower winter gas purchases from Consolidated. All the other cost components have the same values under both cases.

TABLE 4.5

COSTS STRUCTURE OF THE OPTIMUM SOLUTIONS
UNDER SUPPLY CASES S_1 and S_2
AVERAGE COST PRICING POLICY
(In Dollars)

Cost Component	Supply Case S_1	Supply Case S_2
Total Cost CT	\$ 754,632,290	\$ 693,263,101
Total Commodity Charge	\$ 643,375,002	\$ 585,415,016
Total Demand Charge	32,057,349	42,331,712
Total Winter Requirement Charge	15,964,072	3,281,064
Wellhead Purchases	18,888,000	18,888,000
Field-line Purchases	0	0
Production Operations	18,778,652	18,778,652
Storage Operations	6,746,598	5,746,038
Total of Above Operating Costs OMC_1	\$ 735,809,718	\$ 674,440,529
Total Annualized Investment Costs PIS	\$ 18,822,572	\$ 18,822,572
Total Discounted Investment Costs NEWPIS	\$ 151,672,576	\$ 151,672,576

Source: Author's calculations.

The previous results are further illustrated and clarified by the optimal values of the model's decision variables, as presented in tables

TABLE 4.6

OPTIMAL MONTHLY PURCHASES FROM CONSOLIDATED AND PANHANDLE
AND STORAGE DELIVERIES AND WITHDRAWALS (MMCF)
AVERAGE COST PRICING POLICY

Month	Supply Case S_1			Supply Case S_2		
	Consolidated SUP_1	Panhandle SUP_2	Storage Deliveries (-) and Withdrawals (+)	Consolidated SUP_1	Panhandle SUP_2	Storage Deliveries (-) and Withdrawals (+)
April	44,745.61	14,634.15	-12,929.76	12,542.19	36,525.55	- 2,617.75
May	28,747.76	14,634.15	-11,111.49	0.00	36,525.55	- 4,255.13
June	24,882.98	14,634.15	-18,095.40	0.00	36,525.55	-15,103.82
July	21,309.99	14,634.15	-16,689.96	984.39	36,525.55	-18,255.75
August	20,447.22	14,634.15	-15,393.67	0.00	36,525.55	-16,837.85
September	24,826.86	14,634.15	-14,198.07	4,267.48	36,525.55	-15,530.08
October	37,503.11	14,634.15	-13,095.32	15,557.07	37,343.08	-13,858.22
November	10,185.18	19,512.20	+28,056.77	0.00	48,700.73	+ 9,053.41
December	37,508.63	19,512.20	+20,433.26	4,371.81	48,700.73	+24,381.55
January	44,745.61	19,512.20	+20,664.70	15,557.07	48,700.73	+20,664.70
February	39,039.10	19,512.20	+17,514.47	9,850.57	48,700.73	+17,514.47
March	33,269.39	19,512.20	+14,844.47	4,080.86	48,700.73	+14,844.47
Total	367,211.44	200,000.00	0.00	67,211.44	500,000.00	0.00

Source: Author's calculations.

4.6 and 4.7. As previously noted, all the available supplies from Panhandle are purchased, and in such a way that the take-or-pay clause (75% of the contract demand) is never implemented. All the available wellhead gas is purchased because of its low cost (787 \$/MMCF), whereas field-line gas is never purchased because of its high cost (1481 \$/MMCF). Production is not a cost-attractive alternative, and the production capacity is expanded by 751.22 MMCF/month, just enough to provide for a constant monthly production of 1698.88 MMCF, or 20,386.56 MMCF for the whole year. This amount simply covers 10% of the total demand increment of 203,866 MMCF, as stipulated in the constraint set. In both cases, the maximum incremental storage capacity (100,000 MMCF) is developed. However, it is fully used only in case S_1 (total storage deliveries equal to 101,513.67 MMCF). Finally, the peak purchases in month 10 (January) determine the level of incremental transmission capacity (12,956.69 MMCF/month).

The results of the analyses performed in the distribution and financial submodels are presented in table 4.8. The lower revenue requirement and average volumetric rate in case S_2 are attributable to the corresponding lower operating expenses (\$975,488,359 versus \$1,039,511,566, and 1,594.98 \$/MMCF versus 1,699.66 \$/MMCF).

The evaluation criteria are presented in table 4.9. The gas consumption/conservation criteria have the same values under both cases, simply because the sales patterns are the same. The economic efficiency criteria with respect to consumers depend both upon the reference average volumetric rate (1,699.66 \$/MMCF for case S_1 and 1,594.98 \$/MMCF for case S_2) and upon the assumed price elasticities. Four different cases must therefore be considered, and the results pertaining to each of them are also indicated in table 4.9. Note that the highest aggregate efficiency is obtained under case S_2E_1 (\$4,692,805,148), because of both the lowest reference volumetric rate and the highest demand curve (see figure 4.6). However, it is important to remember that the four sets of values are not comparable among themselves because they each refer to different demand curves but will constitute benchmarks for the evaluation of the marginal cost pricing policy as described in the next section.

TABLE 4.7

OPTIMAL MAXIMUM SUPPLIES FROM CONSOLIDATED AND PANHANDLE, WELLHEAD AND FIELD-LINE MONTHLY PURCHASES, INCREMENTAL PRODUCTION CAPACITY AND CONSTANT MONTHLY PRODUCTION, INCREMENTAL STORAGE CAPACITY AND TOTAL STORAGE DELIVERIES, AND INCREMENTAL TRANSMISSION CAPACITY AVERAGE COST PRICING POLICY

Variable	Supply Case S_1	Supply Case S_2
Consolidated's Maximum Supply:		
- Daily (MMCF)	1,491.52	518.57
- Monthly (MMCF)	44,745.61	15,557.07
Panhandle's Maximum Supply:		
- Daily (MMCF)	650.41	1,623.36
- Monthly (MMCF)	19,512.20	48,700.73
Monthly Wellhead Purchases (MMCF)	2,000.00	2,000.00
Monthly Field-line Purchases (MMCF)	0.00	0.00
Incremental Production Capacity (MMCF/month)	751.22	751.22
Monthly Production (MMCF)	1,698.88	1,698.88
Incremental Storage Capacity (MMCF)	100,000.00	100,000.00
Total Storage Deliveries (MMCF)	101,513.67	86,458.60
Transmission Component T_1 Incremental Capacity (MMCF/month)	12,956.69	12,956.69

Source: Author's calculations.

TABLE 4.8

DISTRIBUTION PLANT, FINANCIAL VARIABLES, AND AVERAGE VOLUMETRIC RATES AVERAGE COST PRICING POLICY

Variable	Supply Case S_1	Supply Case S_2
New Transmission Plant T_2 ($)	211,576	211,576
New Distribution Plant ($)	465,353,472	465,353,472
Total New Plant ($)	617,237,504	617,237,504
Net Plant in Service ($)	1,001,776,640	1,001,776,640
Allowed Operating Income ($)	120,814,248	120,814,248
Actual Operating Expenses ($)	900,872,207	839,503,017
Revenue Requirement ($)	1,039,511,566	975,488,359
Average Volumetric Rate ($/MMCF)	1,699.66	1,594.98

Source: Author's calculations.

TABLE 4.9

EVALUATION CRITERIA FOR THE AVERAGE COST PRICING POLICY

Variable	Supply Case S_1	Supply Case S_2
Gas Consumption/Conservation		
Peak Sales Month	January	January
Peak Sales (MMCF)	88,621.39	88,621.39
Sales Load Factor	0.5751	0.5751
Total Gas Consumption (MMCF)	611,598.06	611,598.06
Economic Efficiency		
E_1. Price Elasticity = -0.1		
Total Residential Surplus ($)	2,092,875,719	2,109,053,072
Total Commercial Surplus ($)	836,458,689	842,924,285
Total Industrial Surplus ($)	1,607,587,336	1,620,013,544
Total Consumers' Surplus ($)	4,536,921,745	4,571,990,900
Net Utility Income ($)	120,814,248	120,814,248
Aggregate Efficiency ($)	4,657,735,992	4,692,805,148
E_2. Price Elasticity = -0.5		
Total Residential Surplus ($)	1,367,218,105	1,353,510,283
Total Commercial Surplus ($)	546,435,440	540,956,841
Total Industrial Surplus ($)	1,050,192,561	1,039,663,259
Total Consumers' Surplus ($)	2,963,846,106	2,934,130,383
Net Utility Income ($)	120,814,248	120,814,248
Aggregate Efficiency ($)	3,084,660,354	3,054,944,631

Source: Author's calculations.

Finally, it is interesting to analyze the implications of a marginal cost pricing policy with monthly demands such as those indicated in table 4.4, that is, totally price-inelastic demands. The marginal costs produced by the cost minimization model, MC_m, and the total marginal costs, TMC_m, are presented in table 4.10 for the two supply cases.

Under a marginal cost pricing policy, the utility's revenues from gas sales, RGS, are

$$RGS = \sum_{m=1}^{12} TCM_m * DGMT_m \qquad (4.85)$$

with

TABLE 4.10

MONTHLY MARGINAL COSTS
AVERAGE COST PRICING POLICY ANALYSIS
(In Dollars)

Month	Supply Case S_1		Supply Case S_2	
	Cost Minimization Model Marginal Costs MC_m	Total Marginal Costs TMC_m	Cost Minimization Model Marginal Costs MC_m	Total Marginal Costs TMC_m
April	1202.40	1411.88	1202.40	1411.88
May	1202.40	1411.88	1202.40	1411.88
June	1202.40	1411.88	1202.40	1411.88
July	1202.40	1411.88	1202.40	1411.88
August	1202.40	1411.88	1139.30	1348.78
September	1202.40	1411.88	1202.40	1411.88
October	1202.40	1411.88	1208.16	1417.65
November	1299.30	1508.78	1274.62	1484.11
December	1299.30	1508.78	1299.30	1508.78
January	1923.34	4304.10	1917.58	4298.34
February	1299.30	1508.78	1299.30	1508.78
March	1299.30	1508.78	1299.30	1508.78

Source: Author's calculations.

- Case S_1: RGS = $1,148,274,700 or a revenue above the "normal" revenue by $108,763,200

- Case S_2: RGS = $1,145,019,200 or a revenue above the "normal" revenue by $169,530,850

The above results would therefore confirm the widespread view that marginal cost pricing is likely to bring to the utility revenues higher than those it is entitled to by regulation. However, these results constitute extreme cases because it is assumed that there is no change in the demand pattern as a consequence of the marginal cost pricing pattern. It is the purpose of the next section to analyze the implications for marginal cost pricing policy of price-dependent demands for gas.

b. Case of the Marginal Cost Pricing Policy

The major feature of the four applications (S_1E_1, S_1E_2, S_2E_1, S_2E_2) is that no equilibrium of supply and demand can be reached, at least through the iterative procedure implemented here, because of constantly shifting peaks. This "negative" result is in itself significant, for it gives additional strength to the widespread assertion that time-differentiated marginal cost based rates are likely to induce customers to shift their peak consumption, with a new peak load eventually higher than the one under the existing rate structure, and therefore implying more peaking capacity for the system.

In each application, the disequilibrium is characterized by a shift between two different demand-supply patterns, each providing price inputs to the other; that is, the total marginal costs of one solution constitute the price pattern used in the determination of the other solution. The two alternating price-demand patterns are noted A and B for each of the four cases and are presented in tables 4.11 through 4.14. In all cases, the peak-rate month is alternatively January or December, and the peak-sales month alternatively December or January, respectively. One pattern (A for cases S_1E_1 and S_1E_2, and B for cases S_2E_1 and S_2E_2) is characterized by a unique major peak rate in January, while the other pattern includes a major and a minor peak rate (3,463.75 \$/MMCF in December and 2,132.82 \$/MMCF in February). The latter rate pattern always implies higher peak sales, but not higher annual sales, with the exception of case S_2E_2 (679,557 MMCF versus 601,327 MMCF). The characteristics of the optimal solutions for each pattern and case, as well as their evaluations, are presented in tables 4.15 through 4.18. As indicated earlier, the four cases - S_1E_1, S_1E_2, S_2E_1, S_2E_2, - cannot be compared among themselves, because they refer to different demand functions assumptions, and instead must be compared to the corresponding average cost pricing solutions described in tables 4.5 through 4.9. For instance, the outputs of the cost minimization, distribution, and financial submodels for patterns A and B in case S_1E_1 must be compared to the corresponding variables for supply case S_1 in tables 4.5 through 4.9, whereas the economic efficiency criteria (surpluses, aggregate efficiency) must be compared with those of the supply case S_1 and the price elasticity case E_1 ($E = -0.1$) in table 4.9. To illustrate the previous remark, the aggregate efficiency of pattern A/S_1E_1, equal to \$4,593,440,450, must be compared to the reference aggregate efficiency of

TABLE 4.11

PRICE-DEMAND PATTERNS IN CASE S_1E_1

Month	Pattern A		Pattern B	
	Price ($/MMCF)	Total Demand (MMCF)	Price ($/MMCF)	Total Demand (MMCF)
April	1411.88	51,087.85	1411.88	51,087.86
May	1411.88	36,642.78	1411.88	36,642.78
June	1411.88	25,590.96	1411.88	25,590.96
July	1411.88	23,382.83	1411.88	23,382.83
August	1411.88	23,824.46	1411.88	23,824.46
September	1411.88	29,504.10	1411.88	29,504.10
October	1411.88	43,541.09	1411.88	43,541.09
November	1508.78	62,189.47	1508.78	62,189.47
December	1508.78	82,125.50	3463.75	75,576.38
January	4304.10	80,758.20	1508.78	89,683.41
February	1508.78	80,720.54	2132.82	77,974.26
March	1508.78	72,179.69	1508.78	72,179.69
Total	—	611,547.47	—	611,177.29

Source: Author's calculations.

TABLE 4.12

PRICE-DEMAND PATTERNS IN CASE S_1E_2

Month	Pattern A		Pattern B	
	Price ($/MMCF)	Total Demand (MMCF)	Price ($/MMCF)	Total Demand (MMCF)
April	1411.88	55,022.86	1411.88	55,022.86
May	1411.88	39,465.17	1411.88	39,465.17
June	1411.88	27,562.09	1411.88	27,562.09
July	1411.88	25,183.88	1411.88	25,183.88
August	1411.88	25,659.53	1411.88	25,659.53
September	1411.88	31,776.64	1411.88	31,776.64
October	1411.88	46,894.81	1411.88	46,894.81
November	1508.78	65,224.57	1508.78	65,224.57
December	1508.78	86,133.56	3463.75	56,847.69
January	4304.10	55,690.25	1508.78	94,060.33
February	1508.78	84,660.03	2132.82	71,205.66
March	1508.78	75,702.36	1508.78	75,702.36
Total	—	618,975.75	—	614,605.59

Source: Author's calculations.

TABLE 4.13

PRICE-DEMAND PATTERNS IN CASE S_2E_1

Month	Pattern A		Pattern B	
	Price ($/MMCF)	Total Demand (MMCF)	Price ($/MMCF)	Total Demand (MMCF)
April	1411.88	50,764.12	1411.88	50,764.12
May	1240.52	36,884.79	1321.04	36,653.54
June	1218.68	25,805.76	311.84	29,574.16
July	218.91	27,995.63	1321.04	23,389.70
August	209.48	28,650.16	1321.04	23,831.46
September	1218.68	29,751.74	1321.04	29,512.76
October	1411.88	43,265.18	1411.88	43,265.18
November	1508.78	61,795.40	1497.28	61,842.70
December	3463.75	75,097.48	1508.78	81,605.10
January	1508.78	89,115.12	4304.10	80,246.47
February	2132.82	77,480.16	1508.78	80,209.04
March	1508.78	71,722.32	1508.78	71,722.32
Total	--	618,327.86	--	612,616.55

Source: Author's calculations.

TABLE 4.14

PRICE-DEMAND PATTERNS IN CASE S_2E_2

Month	Pattern A		Pattern B	
	Price ($/MMCF)	Total Demand (MMCF)	Price ($/MMCF)	Total Demand (MMCF)
April	1411.88	53,301.52	1411.88	53,301.52
May	1240.52	40,785.75	1411.88	38,230.53
June	1218.68	28,738.39	1362.74	27,177.03
July	218.91	61,956.67	1416.02	24,360.35
August	209.48	64,530.98	1416.02	24,820.44
September	1218.68	33,132.81	1411.88	30,782.53
October	1411.88	45,427.75	1411.88	45,427.75
November	1508.78	63,184.07	1483.21	63,726.49
December	3463.75	55,069.26	1483.21	84,155.24
January	1508.78	91,117.73	4295.82	53,999.97
February	2132.82	68,978.04	1508.78	82,011.50
March	1508.78	73,334.07	1508.78	73,334.07
Total	--	679,557.04	--	601,327.42

Source: Author's calculations.

TABLE 4.15

SOLUTIONS CHARACTERISTICS AND EVALUATION IN CASE S_1E_1

Variable	Pattern A	Pattern B
OUTPUT OF THE COST MINIMIZATION SUBMODEL		
Total Cost CT ($)	751,846,983	755,776,881
Total Commodity Charge ($)	643,316,202	642,885,930
Total Demand Charge ($)	32,968,116	35,745,832
Total Winter Requirement Charge ($)	19,516,151	19,480,778
Total Operating Costs OMC_1 ($)	737,487,349	739,788,055
Annualized Investment Costs ($)	14,359,634	15,988,826
Discounted Investment Costs ($)	115,710,144	128,838,208
Maximum Monthly Supply: Consolidated (MMCF)	47,069	54,155
Maximum Monthly Supply: Panhandle (MMCF)	19,512	19,512
Annual Purchases from Consolidated (MMCF)	367,163	366,805
Annual Purchases from Panhandle (MMCF)	200,000	200,000
Monthly Wellhead Purchases (MMCF)	2,000	2,000
Incremental Production Capacity (MMCF)	751	750
Monthly Production Rate (MMCF)	1,698	1,697
Storage Incremental Capacity (MMCF)	0	0
Annual Storage Deliveries (MMCF)	60,513	60,513
Transmission Plant T_1 Incremental Capacity (MMCF)	15,279	22,365
OUTPUTS OF THE DISTRIBUTION AND FINANCIAL SUBMODELS		
New Transmission Plant T_2 ($)	0	2,062,706
New Distribution Plant T_2 ($)	363,022,848	482,083,840
Total New Plant ($)	478,732,800	612,984,576
Net Plant in Service ($)	866,631,424	997,626,880
Actual Operating Expenses ($)	898,468,587	904,637,404
Equilibrium Revenue ($)	1,033,292,770	1,043,322,900
Equilibrium Volumetric Rate ($/MMCF)	1,689.64	1,707.07
OUTPUT OF THE EVALUATION SUBMODEL		
Peak Sales (MMCF) - Month	82,125.60 - December	89,683.41 - January
Sales Load Factor	0.6205	0.5679
Total Gas Consumption (MMCF)	611,547.47	611,177.29
Total Residential Surplus ($)	2,026,957,733	2,047,161,873
Total Commercial Surplus ($)	811,509,256	819,270,035
Total Industrial Surplus ($)	1,602,573,597	1,607,825,070
Total Consumers' Surplus ($)	4,441,040,587	4,474,256,978
Revenue Surplus (+) or Deficit (-) ($)	+ 92,511,836	+ 52,586,954
Aggregate Efficiency ($)	4,593,440,450	4,621,789,773

Source: Author's calculations.

TABLE 4.16

SOLUTIONS CHARACTERISTICS AND EVALUATION IN CASE S_1E_2

Variable	Pattern A	Pattern B
OUTPUT OF THE COST MINIMIZATION SUBMODEL		
Total Cost CT ($)	762,422,982	761,315,954
Total Commodity Charge ($)	651,950,236	646,870,720
Total Demand Charge ($)	34,504,308	37,457,850
Total Winter Requirement Charge ($)	18,482,633	18,065,047
Total Operating Costs OMC_1 ($)	746,852,138	744,174,395
Annualized Investment Costs ($)	15,570,844	17,141,558
Discounted Investment Costs ($)	125,470,096	138,126,944
Maximum Monthly Supply: Consolidated (MMCF)	50,988	58,522
Maximum Monthly Supply: Panhandle (MMCF)	19,512	19,512
Annual Purchases from Consolidated (MMCF)	374,343	370,119
Annual Purchases from Panhandle (MMCF)	200,000	200,000
Monthly Wellhead Purchases (MMCF)	2,000	2,000
Incremental Production Capacity (MMCF)	772	759
Storage Incremental Capacity (MMCF)	0	0
Annual Storage Deliveries (MMCF)	60,513	60,513
Transmission Plant T_1 Incremental Capacity (MMCF)	19,219	26,742
OUTPUTS OF THE DISTRIBUTION AND FINANCIAL SUBMODELS		
New Transmission Plant T_2 ($)	0	9,691,736
New Distribution Plant T_2 ($)	426,162,432	551,033,856
Total New Plant ($)	551,632,384	698,852,352
Net Plant in Service ($)	937,762,816	1,081,411,840
Actual Operating Expenses ($)	911,532,006	912,265,578
Equilibrium Revenue ($)	1,048,923,004	1,053,604,046
Equilibrium Volumetric Rate ($/MMCF)	1,694.61	1,714.28
OUTPUT OF THE EVALUATION SUBMODEL		
Peak Sales (MMCF) - Month	86,133.56 - December	94,060.33 - January
Sales Load Factor	0.5989	0.5445
Total Gas Consumption (MMCF)	618,975.75	614,605.59
Total Residential Surplus ($)	1,324,976,057	1,334,202,912
Total Commercial Surplus ($)	530,746,277	534,237,643
Total Industrial Surplus ($)	1,056,754,515	1,057,426,049
Total Consumers' Surplus ($)	2,912,476,849	2,925,866,603
Revenue Surplus (+) or Deficit (-) ($)	+ 16,273,191	+ 4,897,271
Aggregate Efficiency ($)	3,033,994,034	3,058,819,683

Source: Author's calculations.

TABLE 4.17

SOLUTIONS CHARACTERISTICS AND EVALUATION IN CASE S_2E_1

Variable	Pattern A	Pattern B
OUTPUT OF THE COST MINIMIZATION SUBMODEL		
Total Cost CT ($)	703,713,329	701,439,979
Total Commodity Charge ($)	594,313,620	595,979,109
Total Demand Charge ($)	44,677,088	40,046,196
Total Winter Requirement Charge ($)	6,806,471	9,725,772
Total Operating Costs OMC_1 ($)	687,570,384	687,156,275
Annualized Investment Costs ($)	16,142,945	14,283,704
Discounted Investment Costs ($)	130,080,096	115,098,304
Maximum Monthly Supply: Consolidated (MMCF)	27,539	25,873
Maximum Monthly Supply: Panhandle (MMCF)	45,540	40,193
Annual Purchases from Consolidated (MMCF)	73,717	114,813
Annual Purchases from Panhandle (MMCF)	500,000	453,883
Monthly Wellhead Purchases (MMCF)	2,000	2,000
Incremental Production Capacity (MMCF)	770	754
Monthly Production Rate (MMCF)	1,718	1,702
Storage Incremental Capacity (MMCF)	0	0
Annual Storage Deliveries (MMCF)	58,680	55,781
Transmission Plant T_1 Incremental Capacity (MMCF)	21,797	14,768
OUTPUTS OF THE DISTRIBUTION AND FINANCIAL SUBMODELS		
New Transmission Plant T_2 ($)	1,072,165	0
New Distribution Plant T_2 ($)	473,131,264	354,824,960
Total New Plant ($)	604,283,392	469,923,072
Net Plant in Service ($)	989,136,640	858,035,200
Actual Operating Expenses ($)	853,661,944	848,102,551
Equilibrium Revenue ($)	989,956,661	980,519,500
Equilibrium Volumetric Rate ($/MMCF)	1,601.02	1,600.54
OUTPUT OF THE EVALUATION SUBMODEL		
Peak Sales (MMCF) - Month	89,115.12 - January	81,605.10 - December
Sales Load Factor	0.5782	0.6256
Total Gas Consumption (MMCF)	618,327.86	612,616.55
Total Residential Surplus ($)	2,053,543,610	2,025,366,022
Total Commercial Surplus ($)	822,855,564	811,346,108
Total Industrial Surplus ($)	1,646,548,121	1,616,808,550
Total Consumers' Surplus ($)	4,522,947,295	4,453,520,680
Revenue Surplus (+) or Deficit (-) ($)	+ 29,670,941	+ 101,592,054
Aggregate Efficiency ($)	4,657,594,838	4,609,583,759

Source: Author's calculations.

TABLE 4.18

SOLUTIONS CHARACTERISTICS AND EVALUATION IN CASE S_2E_2

Variable	Pattern A	Pattern B
OUTPUT OF THE COST MINIMIZATION SUBMODEL		
Total Cost CT ($)	776,976,123	684,397,599
Total Commodity Charge ($)	664,405,084	580,540,481
Total Demand Charge ($)	46,437,113	41,243,689
Total Winter Requirement Charge ($)	4,327,615	7,315,443
Total Operating Costs OMC_1 ($)	757,919,648	670,147,158
Annualized Investment Costs ($)	19,056,475	14,250,441
Discounted Investment Costs ($)	153,557,360	114,830,272
Maximum Monthly Supply: Consolidated (MMCF)	26,412	26,347
Maximum Monthly Supply: Panhandle (MMCF)	48,499	41,553
Annual Purchases from Consolidated (MMCF)	132,905	91,996
Annual Purchases from Panhandle (MMCF)	500,000	465,287
Monthly Wellhead Purchases (MMCF)	2,000	2,000
Incremental Production Capacity (MMCF)	940	723
Monthly Production Rate (MMCF)	1,888	1,670
Storage Incremental Capacity (MMCF)	0	0
Annual Storage Deliveries (MMCF)	45,087	55,615
Transmission Plant T_1 Incremental Capacity (MMCF)	23,799	16,571
OUTPUTS OF THE DISTRIBUTION AND FINANCIAL SUBMODELS		
New Transmission Plant T_2 ($)	4,562,736	0
New Distribution Plant T_2 ($)	504,678,656	394,997,504
Total New Plant ($)	662,798,592	509,827,584
Net Plant in Service ($)	1,046,232,580	896,972,032
Actual Operating Expenses ($)	938,557,560	829,901,323
Equilibrium Revenue ($)	1,080,492,967	962,526,324
Equilibrium Volumetric Rate ($/MMCF)	1,589.99	1,600.67
OUTPUT OF THE EVALUATION SUBMODEL		
Peak Sales (MMCF) - Month	91,117.73 - January	84,155.24 - December
Sales Load Factor	0.6215	0.5955
Total Gas Consumption (MMCF)	679,557.03	601,327.41
Total Residential Surplus ($)	1,317,972,930	1,286,013,382
Total Commercial Surplus ($)	529,141,889	515,134,929
Total Industrial Surplus ($)	1,090,412,118	1,025,546,839
Total Consumers' Surplus ($)	2,937,526,937	2,826,695,150
Revenue Surplus (+) or Deficit (-) ($)	- 106,702,886	+ 66,679,651
Aggregate Efficiency ($)	3,008,473,157	2,969,383,351

Source: Author's calculations.

$4,657,735,992. An ordinal comparison of the values of a selected number of variables, for the two patterns A and B and the reference one R, is presented in table 4.19 for the four cases.

Case S_1E_1 - The average cost pricing policy (R) dominates the two marginal cost related pricing patterns A and B with respect to the economic efficiency criteria. The consumers would be the losers in patterns A and B while the utility would, in both cases, earn high excess revenues ($92 million and $52 million). This is so although pattern R implies very slightly higher annual gas consumption, and a new plant significantly higher than in case A ($478,732,800), and is second ranked with respect to peak sales, load factor, and the equilibrium volumetric rate.

Case S_1E_2 - From the economic efficiency viewpoint, the reference average cost pricing pattern R dominates the two others. Note that the utility achieves excess revenues much smaller than in case S_1E_1. Pattern R is also the optimal one with respect to total annual gas consumption and remains second ranked for the other variables.

Case S_2E_1 - From the economic efficiency viewpoint, pattern R again dominates the two others. Note that the utility achieves its overall highest excess revenues in case B ($101,592,054). Pattern R is also the optimum one with respect to the total annual gas consumption and the equilibrium volumetric rate but turns out to be the least desirable with respect to load factor and amount of new plant in service.

Case S_2E_2 - Although here again pattern R dominates the two others with respect to aggregate efficiency, this is no longer so when the consumers and the utility are considered separately. Indeed, the total consumers' surplus in pattern A is, by a small margin, the highest one, mainly because of its industrial component. On the other side, it is under pattern A that the utility, for the first time, has a revenue deficit of quite a substantial magnitude ($106,702,886). Pattern R achieves the lowest load factor and is second ranked with respect to the other variables.

TABLE 4.19

SOLUTIONS RANKING

Variable	CASE			
	S_1E_1	S_1E_2	S_2E_1	S_2E_2
ECONOMIC EFFICIENCY				
Aggregate Efficiency	A<B<R	A<B<R	B<A<R	B<A<R
Residential Surplus	A<B<R	A<B<R	B<A<R	B<A<R
Commercial Surplus	A<B<R	A<B<R	B<A<R	B<A<R
Industrial Surplus	A<R<B	R<A<B	B<R<A	B<R<A
Total Consumers' Surplus	A<B<R	A<B<R	B<A<R	B<R<A
Utility's Revenue Surplus	R<B<A	R<B<A	R<A<B	A<R<B
GAS CONSUMPTION/CONSERVATION				
Total Gas Consumption	B<A<R	R<B<A	R<B<A	B<R<A
Peak Monthly Sales	A<R<B	A<R<B	B<R<A	B<R<A
Load Factor	B<R<A	B<R<A	R<A<B	R<B<A
OTHER VARIABLES				
Total New Plant	A<B<R	A<R<B	B<A<R	B<R<A
Equilibrium Volumetric Rate	A<R<B	A<R<B	R<B<A	A<R<B

Source: Author's calculations.

It would be unwise to draw from the previous analysis a definite conclusion about the feasibility and economic efficiency of marginal cost pricing for gas distribution utilities because of both the uncertainties bearing upon the values of various parameters and the failure to achieve an equilibrium. To reach such a conclusion (or its opposite), additional research and analyses are necessary. They are summarily outlined in the next section.

Possible Extensions of the Modeling Approach

The model presented in this chapter could be improved in at least two ways. First, the average cost pricing policy analysis could include a supply-demand equilibrium procedure similar to that used in the marginal cost pricing policy analysis. Under such an approach, it could be possible to analyze the implications of various assumptions with a given set of demand functions. Second, marginal cost based pricing policies should be tested. Such pricing patterns should imply a lesser difference between peak and nonpeak prices, for instance through spreading the distribution capacity marginal cost over the winter months. In such a case, an equilibrium between supply and demand is more likely to be reached. Also, some theoretical research is called for with respect to the existence or conditions for the existence of a supply-demand equilibrium when prices are set equal to the marginal costs as computed in the present model.

Finally, it is obvious that the implications of marginal cost pricing for gas utilities should be analyzed while applying the model to other utilities. The data base for such applications is currently being prepared for the National Fuel Gas Company, which serves western parts of the states of New York and Pennsylvania, and for Pacific Gas and Electric Company, which serves northern and central California, and it is expected that the results of these applications will be reported in a future research report.

CHAPTER 5

SUMMARY

The purpose of this research effort was to develop methods for the calculation of the marginal costs of gas distribution utilities, and for the evaluation of gas pricing policies based on marginal costs. Two different approaches have been followed: (1) the distribution plant costs have been analyzed statistically with community-level data, and econometric models predicting these costs on the basis of such variables as market size and mix, population density, and weather have been specified; (2) an aggregate, nonspatialized optimization model has been developed to calculate monthly supply, storage, and transmission marginal costs, and this model has been embedded into a larger simulation model analyzing the implications of marginal cost pricing policies.

The major results of the econometric analysis are that (1) the total distribution plant costs incurred to serve different sectoral markets are nonseparable; (2) economies of scale are achieved with respect to both residential and nonresidential gas sales; (3) the community's population density is generally an important determinant of distribution plant costs, and so is the weather pattern if the service territory is climatologically heterogeneous. The above results imply that the marginal plant costs with respect to sectoral sales decrease with the sector's size and depend upon the size of the other sector(s).

The major results of the optimization/simulation analysis are that (1) marginal costs highly depend upon supply conditions (maximum availability, charges, contracts, etc.) and upon various technological constraints; (2) peak-shifting problems are very likely to occur if distribution capacity marginal costs are wholly assigned to the peak period (month); (3) the excess revenue problem does not necessarily always occur, and its occurrence depends upon supply conditions, costs, technological constraints, financial parameters, and the price elasticities of the monthly demands. It would be premature to draw final conclusions from this partial analysis, but it should be noted that the results do not clearly demonstrate the superiority of this marginal cost pricing method.

The previous analyses can of course be improved and further developed in a number of ways. The econometric models could probably be improved by including such variables as sectoral load factors and average customer sizes. An important endeavor would be to explain fully the interutility differences in the estimated parameters. The optimization/simulation model should be used to test marginal cost based pricing policies, wherein peak-capacity marginal costs could be spread over longer periods. Such policies might help to avoid the peak-shifting problem and turn out to be preferable to a pure marginal cost pricing policy. Finally, this optimization/-simulation model might be spatialized through a complete network representation of the system (as outlined in chapter 2) in order to compute time- and space-related marginal costs. This spatialization would be the appropriate way to integrate the econometric and optimization/simulation approaches presented in this study.

APPENDIX A

LONG ISLAND LIGHTING COMPANY DATA

The purpose of this appendix is to present the community-level data used in the econometric analysis of the Long Island Lighting Company, as reported in chapter 3. The data are indicated for 101 different villages, towns, and cities, and for two years - 1978 and 1979. The plant in service and the residential and commercial/-industrial gas sales are presented in table A-1. The residential and commercial/industrial numbers of customers, the 1978 population, and the corresponding total and residential acreage are presented in table A-2.

TABLE A-1

PLANT IN SERVICE AND GAS SALES - LONG ISLAND LIGHTING COMPANY

		Plant In Service ($)		Gas Sales (MCF) - 1979			Gas Sales (MCF) - 1978		
Case	Municipality	End of 1979	End of 1978	Total	Residential	Comm./Ind.	Total	Residential	Comm./Ind.
1	Town of Hempstead	46,980,146	45,435,491	7,382,642.5	4,475,445.1	2,907,197.4	6,962,310.4	4,598,579.0	2,363,731.4
	Village of:								
2	Atlantic Beach	264,698	262,219	87,032.4	76,045.9	10,986.5	91,436.4	77,904.7	13,531.7
3	Bellerose	111,262	110,668	27,914.6	25,421.4	2,493.2	28,375.1	26,027.2	2,347.9
4	Cedarhurst	528,631	508,407	146,444.0	98,210.6	48,233.4	149,163.4	100,397.4	48,766.0
5	East Rockway	754,654	746,384	193,355.6	124,645.2	68,710.4	180,735.6	128,915.6	51,820.0
6	Floral Park	1,045,572	987,715	270,438.8	232,954.2	37,484.6	268,441.2	236,401.0	32,040.2
7	Freeport	3,491,923	3,287,353	639,616.6	340,004.7	299,611.9	615,635.2	345,217.0	270,418.2
8	Garden City	4,066,477	4,043,941	581,456.3	397,691.2	183,765.1	557,572.6	406,813.7	150,758.9
9	Hempstead	3,932,371	3,881,974	761,152.0	462,577.5	298,574.5	775,942.2	477,430.7	298,511.5
10	Hewlett Bay Park	145,727	139,947	28,272.8	27,666.9	605.9	29,077.4	28,337.6	739.8
11	Hewlett Harbor	315,672	305,003	52,566.1	51,354.3	1,211.8	53,414.0	52,138.5	1,275.5
12	Hewlett Neck	80,833	78,969	17,252.6	17,252.6		17,838.5	17,838.5	
13	Island Park	1,914,524	1,911,004	115,263.1	86,472.3	28,790.8	116,323.8	87,440.8	28,883.0
14	Lawrence	809,159	779,088	239,459.9	206,015.8	33,444.1	253,406.2	214,263.8	39,142.4
15	City of Long Beach	7,268,240	7,250,461	612,912.6	346,826.2	266,086.4	626,477.7	354,588.8	271,888.9
	Village of:								
16	Lynbrook	1,785,069	1,756,340	384,302.3	241,902.9	142,399.4	392,465.0	243,012.6	149,452.4
17	Malverne	578,674	568,026	153,273.0	141,859.8	11,413.5	155,982.1	145,032.9	10,949.2
18	New Hyde Park	239,645	224,053	73,344.9	50,416.3	22,928.6	69,043.2	50,249.1	18,794.1
19	Rockville Centre	3,225,988	3,177,206	479,375.0	239,917.2	239,457.8	434,456.0	240,669.9	193,786.1
20	South Floral Park	181,429	169,697	19,442.6	19,439.3	3.3	19,567.3	19,563.8	3.5

TABLE A-1

PLANT IN SERVICE AND GAS SALES - LONG ISLAND LIGHTING COMPANY (Continued)

		Plant In Service ($)		Gas Sales (MCF) - 1979			Gas Sales (MCF) - 1978		
Case	Municipality	End of 1979	End of 1978	Total	Residential	Comm./Ind.	Total	Residential	Comm./Ind.
	Village of:								
21	Stewart Manor	173,930	168,883	41,510.9	37,677.3	3,833.6	42,483.3	38,520.3	3,963.0
22	Valley Stream	2,865,374	2,742,910	715,290.5	543,374.6	171,915.9	732,533.6	555,356.7	177,176.9
23	Woodsburgh	102,715	93,256	27,082.6	25,536.5	1,546.1	29,498.1	27,705.0	1,793.1
24	Town of N. Hempstead	8,812,002	8,616,141	2,344,402.8	1,381,263.7	963,139.1	2,340,527.3	1,425,974.1	914,553.2
	Village of								
25	Baxter Estates	78,486	76,358	16,356.3	10,032.4	6,323.9	16,241.4	10,164.0	6,077.4
26	East Hills	409,224	396,526	81,588.3	51,488.7	30,099.6	87,066.5	55,503.5	31,563.0
27	East Williston	275,521	253,448	36,676.4	35,546.7	1,129.7	37,626.4	36,357.2	1,269.2
28	Floral Park	183,221	178,534	40,180.3	30,451.5	9,728.8	41,949.3	31,539.8	10,409.5
29	Flower Hill	500,309	495,373	76,690.8	59,994.7	16,696.1	80,791.6	62,599.5	18,192.1
30	Great Neck	872,134	839,705	174,773.7	142,964.9	31,808.8	179,139.9	146,833.0	32,306.9
31	Great Neck Estates	263,374	253,618	76,096.2	65,627.9	10,468.3	80,265.6	69,559.6	10,706.0
32	Great Neck Plaza	263,421	251,086	133,723.2	14,515.6	119,207.6	119,686.6	15,745.1	103,941.5
33	Kensington	81,153	81,692	34,851.0	26,057.9	8,793.1	34,376.0	26,671.2	7,704.8
34	Kings Point	697,278	645,583	139,764.5	114,665.5	25,099.0	209,176.2	123,469.5	85,706.7
35	Lake Success	691,283	709,362	234,894.6	49,237.2	185,657.4	114,397.5	51,500.4	62,897.1
36	Manorhaven	361,401	351,420	67,230.1	42,143.7	25,086.4	68,562.8	43,164.4	25,398.4
37	Mineola	1,306,279	1,254,710	499,668.7	209,265.6	290,403.1	420,881.6	211,540.5	209,341.1
38	Munsey Park	195,292	189,123	42,737.2	40,947.5	1,789.7	44,708.4	42,734.4	1,974.0
39	New Hyde Park	388,062	376,891	93,095.3	75,494.2	17,601.1	93,532.9	75,832.5	17,700.4
40	North Hills	429,374	413,061	18,260.2	1,313.2	16,947.0	28,173.3	9,149.6	19,023.7

TABLE A-1

PLANT IN SERVICE AND GAS SALES - LONG ISLAND LIGHTING COMPANY (Continued)

		Plant In Service ($)		Gas Sales (MCF) - 1979			Gas Sales (MCF) - 1978		
Case	Municipality	End of 1979	End of 1978	Total	Residential	Comm./Ind.	Total	Residential	Comm./Ind.
	Village of:								
41	Old Westbury	529,566	534,343	86,303.7	22,640.6	63,663.1	47,707.7	21,563.8	26,143.9
42	Plandome	100,872	84,284	27,976.1	27,832.9	143.2	29,006.7	28,845.8	160.9
43	Plandome Heights	74,672	69,212	18,903.6	18,903.6		19,541.1	19,541.1	—
44	Plandome Manor	79,228	77,386	16,982.6	15,201.0	1,781.6	18,190.1	16,572.5	1,617.6
45	Port Washington N.	329,446	328,929	137,033.6	88,857.6	48,176.0	134,191.4	89,500.9	44,690.5
46	Roslyn	554,355	547,619	77,281.1	12,626.5	64,654.6	75,508.7	13,783.3	61,725.4
47	Roslyn Estates	122,099	119,570	29,141.4	24,713.7	4,427.7	29,527.6	26,048.4	3,479.2
48	Roslyn Harbor	362,748	361,265	17,503.3	15,367.9	2,135.4	19,628.8	17,577.4	2,051.4
49	Russell Gardens	95,248	95,506	25,828.7	14,919.1	10,909.6	25,493.5	16,705.5	8,788.0
50	Saddle Rock	40,495	46,608	5,724.6	4,989.6	735.0	6,410.1	5,618.4	791.7
51	Sands Point	88,223	89,678	15,457.0	13,466.2	1,990.8	15,436.9	13,220.2	2,216.7
52	Thomaston	541,583	541,527	54,723.2	43,608.1	11,115.1	57,377.3	44,879.4	12,497.9
53	Westbury	1,559,449	1,347,889	232,105.5	163,936.6	68,168.9	236,219.5	165,912.2	70,307.3
54	Williston Park	431,152	408,462	146,347.4	123,381.5	22,965.9	149,867.8	124,141.1	25,726.7
55	Town of Oyster Bay	28,140,961	26,964,148	4,537,342.2	1,903,364.6	2,633,977.6	4,095,979.7	1,978,531.9	2,117,447.8
	Village of:								
56	Bayville	478,867	458,814	131,058.3	113,755.3	17,303.0	130,945.7	114,756.9	16,188.8
57	Brookville	371,003	358,567	94,237.6	13,144.7	81,092.9	46,440.8	14,361.9	32,078.9
58	Farmingdale	936,281	734,474	78,736.7	35,594.5	43,142.2	80,398.1	35,840.4	44,557.7
59	City of Glen Cove	2,501,348	2,474,959	564,490.3	253,457.4	311,032.9	460,020.6	265,413.7	194,606.9
60	Village of Lattingtown	85,175	73,634	11,604.5	10,147.6	1,456.9	12,754.1	10,900.3	1,853.8

TABLE A-1

PLANT IN SERVICE AND GAS SALES - LONG ISLAND LIGHTING COMPANY (Continued)

		Plant In Service ($)		Gas Sales (MCF) - 1979			Gas Sales (MCF) - 1978		
Case	Municipality	End of 1979	End of 1978	Total	Residential	Comm./Ind.	Total	Residential	Comm./Ind.
	Village of:								
61	Laurel Hollow	8,972	8,972	1,556.0	(4.7)	1,560.7	1,504.8	24.4	1,480.4
62	Massapequa Park	1,060,091	947,593	137,403.5	107,509.6	29,893.9	133,262.0	109,216.9	24,045.1
63	Matinecock	93,122	96,166	18,983.5	13,019.7	5,963.8	17,882.4	13,336.4	4,546.0
64	Mill Neck	108,276	106,827	6,242.7	6,242.7		5,853.3	5,853.3	24,761.3
65	Muttontown	414,143	409,128	71,201.8	48,688.9	22,512.9	77,390.0	52,628.7	11,107.9
66	Old Brookville	87,380	87,768	25,194.2	13,643.4	11,550.8	25,501.4	14,393.5	—
67	Oyster Bay Cove	143,116	143,660	22,038.4	22,038.4		23,100.0	23,100.0	—
68	Roslyn Harbor	167,088	163,564	13,056.5	13,056.5		13,369.4	13,369.4	—
69	Sea Cliff	969,885	934,454	104,494.8	94,553.4	9,941.4	108,268.3	98,178.6	10,089.7
70	Upper Brookville	50,742	49,401	5,872.0	4,478.7	1,393.3	5,593.4	4,287.2	1,306.2
71	Town of Babylon	13,634,907	13,140,246	2,511,961.4	1,302,246.4	1,209,715.0	2,456,395.8	1,373,302.1	1,083,093.7
	Village of:								
72	Amityville	1,164,722	1,096,064	186,306.1	101,035.2	85,270.9	172,461.6	103,706.0	68,755.6
73	Babylon	1,735,463	1,609,857	130,913.0	102,836.7	28,076.3	134,137.6	105,758.0	28,379.6
74	Lindenhurst	2,615,850	2,559,887	288,314.8	196,766.3	91,548.5	298,229.6	202,744.1	95,485.5
75	Town of Brookhaven	28,662,610	28,474,846	3,057,570.4	2,074,118.1	983,452.3	3,063,332.5	2,221,412.1	841,920.4
	Village of:								
76	Belle Terre	30,644	30,644	2,443.9	2,410.2	33.7	2,699.7	2,633.4	66.3
77	Bellport	93,327	91,212	10,832.2	8,500.8	2,331.4	11,868.7	9,167.2	2,701.5
78	Old Field	41,568	37,201	5,596.6	5,596.6		6,165.6	6,165.6	—
79	Patchogue	926,307	875,718	177,986.5	62,782.4	115,204.1	170,100.7	66,374.8	103,725.9
80	Poquott	5,093	5,093	1,958.1	1,958.1		1,902.1	1,902.1	—

TABLE A-1

PLANT IN SERVICE AND GAS SALES - LONG ISLAND LIGHTING COMPANY (Continued)

Case	Municipality	Plant In Service ($) End of 1979	Plant In Service ($) End of 1978	Gas Sales (MCF) - 1979 Total	Gas Sales (MCF) - 1979 Residential	Gas Sales (MCF) - 1979 Comm./Ind.	Gas Sales (MCF) - 1978 Total	Gas Sales (MCF) - 1978 Residential	Gas Sales (MCF) - 1978 Comm./Ind.
	Village of:								
81	Port Jefferson	482,526	459,112	98,583.4	53,174.4	45,409.0	105,849.5	56,282.6	49,566.9
82	Lake Grove	469,750	470,550	127,548.1	75,285.6	52,262.5	123,666.8	81,427.9	42,238.9
83	Town of East Hampton	349,463	332,952	31,440.7	21,398.4	10,042.3	33,483.9	22,874.7	10,609.2
	Village of:								
84	East Hampton	731,615	714,225	127,958.6	104,792.3	23,166.3	134,256.5	108,521.2	25,735.3
85	Sag Habor	149,591	148,192	15,497.9	14,726.7	771.2	14,540.6	13,895.0	645.6
86	Town of Huntington	17,232,837	16,763,582	3,601,048.3	2,505,424.0	1,095,624.3	3,592,536.5	2,662,009.1	930,527.4
	Village of:								
87	Asharoken	18,235	16,912	9,346.8	9,274.0	72.8	9,909.5	9,836.7	72.8
88	Huntington Bay	137,151	130,715	37,850.5	36,355.9	1,494.6	39,970.5	38,483.8	1,486.7
89	Lloyd Harbor	26,053	26,053	5,935.9	4,590.2	1,345.7	6,287.0	4,766.5	1,520.5
90	Northport	562,781	562,932	136,929.5	88,167.4	48,762.1	119,277.7	91,288.0	27,989.7
91	Town of Islip	21,774,198	20,776,994	4,643,850.1	2,696,224.0	1,947,626.1	4,302,760.5	2,850,006.0	1,452,754.5
	Village of:								
92	Brightwaters	565,747	532,958	60,906.5	50,858.1	10,048.4	60,941.2	50,812.5	10,128.7
93	Town of Riverhead	3,599,077	3,474,546	203,746.7	87,292.4	116,454.3	200,198.6	91,125.6	109,073.0
94	Town of Smithtown	8,716,555	8,598,667	1,917,720.1	1,451,195.8	466,524.3	1,985,300.1	1,559,929.4	425,370.7
	Village of:								
95	Head of the Harbor	21,219	21,219	4,360.1	3,128.2	1,231.9	4,084.3	3,195.5	888.8
96	The Branch	79,985	75,028	27,525.6	3,265.4	24,260.2	26,441.6	3,393.9	23,047.7
97	Town of Southampton	3,356,573	3,343,291	194,196.9	120,865.4	73,331.5	200,232.6	126,802.1	73,430.5
	Village of:								
98	Sag Harbor	323,867	319,300	38,262.8	28,432.3	9,830.5	39,062.9	29,303.7	9,759.2
99	Southampton	1,062,846	1,042,636	182,061.5	137,019.9	45,041.6	181,930.4	135,111.9	46,818.5
100	Town of Southold	1,092,078	1,070,275	155,251.6	115,662.2	39,589.4	161,359.1	119,108.7	42,250.4
101	City of New York	6,946,156	7,082,285	1,729,420.9	1,018,890.4	696,665.7	1,681,734.3	1,059,414.9	608,626.4

Source: Annual Reports fo the New Public Service Commission, 1978-1979, Long Island Lighting Company

TABLE A-2

NUMBER OF CUSTOMERS, POPULATION AND ACREAGE - LONG ISLAND LIGHTING COMPANY

		Number of Customers - 1979			Number of Customers - 1978					
Case	Municipality	Total	Residential	Comm./Ind.				Population 1978	Total Acreage	Residential Acreage
1	Town of Hempstead	76,334	70,886	5,448	76,218	70,795	5,423	542,402	83,200	0
	Village of:									
2	Atlantic Beach	754	715	39	756	717	39	1,624	388	270
3	Bellerose	362	345	17	360	345	15	1,090	114	91
4	Cedarhurst	2,108	1,877	231	2,106	1,877	229	6,928	456	383
5	East Rockway	2,528	2,363	165	2,520	2,358	162	11,461	831	496
6	Floral Park	4,577	4,405	172	4,545	4,375	170	16,107	896	0
7	Freeport	7,449	6,872	577	7,443	6,866	577	40,997	3,219	2,544
8	Garden City	5,319	5,129	190	5,294	5,096	198	24,914	3,505	2,404
9	Hempstead	9,635	8,878	757	9,649	8,864	785	40,365	2,360	1,773
10	Hewlett Bay Park	134	130	4	133	129	4	601	213	174
11	Hewlett Harbor	231	229	2	229	227	2	1,501	534	436
12	Hewlett Neck	120	120		119	119	—	541	192	157
13	Island Park	1,283	1,163	120	1,285	1,161	124	5,578	269	234
14	Lawrence	1,941	1,854	87	1,954	1,861	93	6,425	3,007	1,991
15	City of Long Beach	8,837	8,022	815	8,795	7,975	820	34,546	1,564	1,364
	Village of:									
16	Lynbrook	5,700	5,193	507	5,693	5,187	506	22,853	1,280	0
17	Malverne	2,602	2,509	93	2,595	2,500	95	10,024	308	273
18	New Hyde Park	1,126	1,088	38	1,129	1,089	40	4,263	299	198
19	Rockville Centre	5,637	5,222	415	5,644	5,233	411	28,535	2,148	1,607
20	South Floral Park	296	295	1	293	292	1	1,105	83	58

TABLE A-2

NUMBER OF CUSTOMERS, POPULATION AND ACREAGE - LONG ISLAND LIGHTING COMPANY (Continued)

		Number of Customers - 1979			Number of Customers - 1978					
Case	Municipality	Total	Residential	Comm./Ind.				Population 1978	Total Acreage	Residential Acreage
	Village of:									
21	Stewart Manor	607	580	27	609	582	27	2,147	127	105
22	Valley Stream	10,462	9,833	629	10,473	9,842	631	40,200	4,215	2,079
23	Woodsburgh	248	243	5	247	242	5	806	284	232
24	Town of N. Hempstead	22,154	20,510	1,644	22,158	20,494	1,664	103,742	35,840	0
	Village of									
25	Baxter Estates	231	198	33	227	196	31	1,036	0	0
26	East Hills	437	367	70	439	366	73	8,708	1,408	0
27	East Williston	514	509	5	509	504	5	2,805	370	292
28	Floral Park	734	693	41	732	689	43	1,936	118	118
29	Flower Hill	563	528	35	561	525	36	4,610	1,055	885
30	Great Neck	2,569	2,425	144	2,565	2,421	144	10,661	904	852
31	Great Neck Estates	803	763	40	800	761	39	3,082	327	278
32	Great Neck Plaza	1,987	1,765	222	1,984	1,759	225	6,113	203	95
33	Kensington	244	241	3	244	241	3	1,605	168	147
34	Kings Point	648	628	20	640	623	17	5,799	2,559	2,483
35	Lake Success	383	336	47	385	337	48	3,434	1,045	692
36	Manorhaven	514	442	72	510	440	70	5,911	256	0
37	Mineola	5,351	4,909	442	5,342	4,894	448	20,497	1,190	821
38	Munsey Park	530	519	11	528	518	10	3,004	333	333
39	New Hyde Park	1,700	1,596	104	1,696	1,587	109	5,907	299	198
40	North Hills	38	25	13	40	26	14	1,329	563	248

TABLE A-2

NUMBER OF CUSTOMERS, POPULATION AND ACREAGE - LONG ISLAND LIGHTING COMPANY (Continued)

Case	Municipality	Number of Customers - 1979			Number of Customers - 1978			Population 1978	Total Acreage	Residential Acreage
		Total	Residential	Comm./Ind.						
	Village of:									
41	Old Westbury	101	88	13	99	87	12	2,389	3,637	3,407
42	Plandome	287	283	4	286	282	4	1,604	375	292
43	Plandome Heights	246	246		244	133	--	1,056	247	192
44	Plandome Manor	111	107	4	110	106	4	820	192	149
45	Port Washington N.	606	538	68	608	540	68	3,009	330	211
46	Roslyn	631	537	94	628	532	96	2,621	717	503
47	Roslyn Estates	202	195	7	203	195	8	1,438	394	276
48	Roslyn Harbor	93	89	4	92	88	4	848	232	163
49	Russell Gardens	315	302	13	314	301	13	1,103	117	98
50	Saddle Rock	35	30	5	35	30	5	885	330	290
51	Sands Point	76	74	2	77	75	2	3,112	2,302	1,429
52	Thomaston	704	679	25	700	675	25	2,648	281	244
53	Westbury	3,106	2,872	234	3,087	2,853	234	15,924	1,525	1,525
54	Williston Park	2,190	2,056	134	2,183	2,043	140	8,923	751	497
55	Town of Oyster Bay	33,723	30,258	3,465	33,642	30,219	3,423	282,159	72,960	0
	Village of:									
56	Bayville	1,459	1,396	63	1,452	1,392	60	6,981	896	0
57	Brookville	67	51	16	64	49	15	3,435	4,266	2,683
58	Farmingdale	1,310	1,092	218	1,307	1,091	216	9,568	722	624
59	City of Glen Cove	4,920	4,577	343	4,931	4,589	342	27,684	4,460	3,572
60	Village of Lattingtown	88	83	5	88	82	6	1,912	3,076	1,177

TABLE A-2

NUMBER OF CUSTOMERS, POPULATION AND ACREAGE - LONG ISLAND LIGHTING COMPANY (Continued)

		Number of Customers - 1979			Number of Customers - 1978					
Case	Municipality	Total	Residential	Comm./Ind.				Population 1978	Total Acreage	Residential Acreage
	Village of:									
61	Laurel Hollow	10	1	9	10	2	8	1,560	2,897	3,188
62	Massapequa Park	2,419	2,314	105	2,398	2,303	95	22,200	1,393	1,341
63	Matinecock	80	63	17	80	63	17	886	1,425	544
64	Mill Neck	34	34	--	32	32	15	1,039	1,671	640
65	Muttontown	200	185	15	200	185	13	2,753	485	386
66	Old Brookville	84	71	13	84	71	—	2,084	367	292
67	Oyster Bay Cove	76	76	--	76	76	--	1,717	2,982	2,823
68	Roslyn Harbor	75	75	--	73	73	--	305	0	0
69	Sea Cliff	1,605	1,511	94	1,594	1,504	90	6,123	704	0
70	Upper Brookville	33	27	6	33	27	6	1,331	235	186
71	Town of Babylon	17,559	15,457	2,102	17,547	15,461	2,086	165,651	33,920	0
	Village of:									
72	Amityville	1,892	1,684	208	1,894	1,683	211	10,776	1,344	0
73	Babylon	2,012	1,873	139	2,019	1,877	142	13,499	1,600	0
74	Lindenhurst	4,082	3,791	291	4,090	3,796	294	30,457	2,368	0
75	Town of Brookhaven	19,075	17,845	1,230	18,980	17,754	1,226	321,322	166,400	0
	Village of:							877	0	0
76	Belle Terre	15	14	1	15	14	1			
77	Bellport	252	232	20	254	234	20	2,978	896	0
78	Old Field	43	43	--	44	44	--	872	0	0
79	Patchogue	1,825	1,618	207	1,842	1,632	210	11,299	1,472	0
80	Poquott	31	31	--	31	31	—	521	0	0

TABLE A-2

NUMBER OF CUSTOMERS, POPULATION AND ACREAGE - LONG ISLAND LIGHTING COMPANY (Continued)

		Number of Customers - 1979			Number of Customers - 1978					
Case	Municipality	Total	Residential	Comm./Ind.				Population 1978	Total Acreage	Residential Acreage
	Village of:									
81	Port Jefferson	997	836	161	993	829	164	6,315	1,280	0
82	Lake Grove	630	557	73	632	558	74	9,445	1,856	0
83	Town of East Hampton	410	371	39	410	371	39	12,013	44,800	0
	Village of:									
84	East Hampton	1,025	932	93	1,023	928	95	2,044	0	0
85	Sag Habor	311	298	13	311	298	13	946	0	0
86	Town of Huntington	23,336	21,474	1,862	23,299	21,434	1,865	203,028	60,160	0
	Village of:									
87	Asharoken	65	64	1	64	63	1	644	0	0
88	Huntington Bay	265	261	4	262	258	4	1,925	0	0
89	Lloyd Harbor	33	31	2	33	31	2	3,930	5,888	0
90	Northport	1,451	1,331	120	1,462	1,338	124	8,212	1,600	0
91	Town of Islip	31,772	29,438	2,334	31,858	29,536	2,322	309,016	65,280	0
	Village of:									
92	Brightwaters	672	628	44	670	628	42	3,808	576	0
93	Town of Riverhead	1,851	1,590	261	1,869	1,603	266	23,921	49,920	0
94	Town of Smithtown	12,197	11,376	821	12,181	11,372	809	121,723	1,952	0
	Village of:									
95	Head of the Harbor	68	62	6	69	63	6	1,093	0	0
96	The Branch	148	80	68	148	83	65	1,856	0	0
97	Town of Southampton	1,909	1,693	216	1,899	1,682	217	38,355	92,800	0
	Village of:									
98	Sag Harbor	576	507	69	577	507	70	1,860	0	0
99	Southampton	1,579	1,418	161	1,575	1,411	164	5,541	4,096	0
100	Town of Southold	2,109	1,941	168	2,102	1,933	169	17,067	33,920	0
101	City of New York	16,535	15,053	1,482	16,690	15,173	1,457	97,343	3,455	0

Source: Annual Reports to the New York Public Service Commission, 1978-1979, Long Island Lighting Company

APPENDIX B

COLUMBIA GAS OF OHIO COMPANY DATA

The purpose of this appendix is to present the community-level data used in the econometric analysis of the Columbia Gas of Ohio Company, as reported in chapter 3. The residential, commercial, and industrial gas sales and numbers of customers, the net plant in service, and the population and acreage of 52 communities included in the company's service territory are indicated in Table B-1.

TABLE B-1

GAS SALES, NUMBERS OF CUSTOMERS, NET PLANT IN SERVICE, POPULATION AND ACREAGE - COLUMBIA GAS OF OHIO COMPANY

Case	Community	Gas Sales (MCF)				Number of Customers				Net Plant In Service ($)	Population	Acreage
		Residential Sector	Commercial Sector	Industrial Sector	All Sectors	Residential Sector	Commercial Sector	Industrial Sector	All Sectors			
1	Toledo	18921600	5834240	595056	25350896	105789	7398	107	113294	29121200	383818	51968
2	Lorain	3678430	1201380	86090	4965900	20851	1469	5	22325	6493670	78185	14272
3	New Riegel	16557	13220	7483	37260	103	26	1	130	47796	--	--
4	Mansfield	3034030	1253110	156290	4443430	16891	1791	22	18704	5039310	55047	15424
5	Parma	4801800	1079030	17740	5898570	29119	1350	3	30472	7182480	100216	13312
6	Westlake	876060	384577	29313	1289950	4298	272	4	4574	1648710	15689	9984
7	Dublin	21767	109011	0	130778	143	33	0	176	257064	5000	11520
8	Bexley	913233	117658	0	1030890	4606	151	0	4757	919970	14888	1536
9	Brice	8109	6001	0	14109	48	8	0	56	56160	250	64
10	Canal Winchester	99570	51673	1363	152605	628	73	1	702	173420	3200	6400
11	Columbus	25089392	10502700	643108	36235200	166263	9999	1555	177817	38948896	539677	86144
12	Gahanna	573314	156232	0	729546	3938	174	0	4112	1138880	12400	4288
13	Grove City	643216	143203	14310	800729	4669	197	2	4868	1321340	13911	2880
14	Groveport	135525	40600	0	176124	1012	68	0	1080	319436	4000	4480
15	Hilliard	327003	83408	44317	454733	2435	123	4	2562	747516	8369	2752
16	Marble Cliff	40101	40053	0	80154	267	25	0	292	102601	680	192
17	Minerva	84134	8272	0	92406	463	28	0	491	132142	1600	1920
18	New Albany	22698	18114	0	40812	149	31	0	180	70959	530	4480
19	New Rome	5465	6297	0	11762	38	16	0	54	33023	110	640
20	Obetz	104418	41444	30245	176107	709	31	2	742	238919	3500	1920
21	Reynoldsburg	600557	153428	0	753980	4803	216	0	5019	1249880	13921	3008
22	Upper Arlington	2249180	385746	0	2634930	12013	357	0	12370	3234450	38630	6144
23	Urbancrest	28271	3764	0	32035	173	7	0	180	76474	--	--
24	Valleyview	40632	860	0	41492	265	3	0	268	29922	1000	3200
25	Westerville	610072	192861	56299	859232	4282	309	5	4596	1762330	12530	5440
26	Whitehall	923728	345809	13123	1282660	8196	523	1	8720	1815520	25263	3712
27	Worthington	717015	253311	30254	1000580	4565	309	4	4878	1426700	15326	3264
28	Ashville	85484	23294	4882	113660	573	64	1	638	256988	2309	640
29	Mount Sterling	86954	30670	0	117623	528	77	0	605	217049	--	--
30	Waldo	19027	9644	9126	37797	126	31	1	158	44432	437	256
31	Baltimore	117863	26736	176	144774	822	78	1	901	397805	3150	2560
32	Centerburg	72004	23868	10523	106394	397	65	2	464	121475	--	--
33	Granville	141405	59180	4473	205058	713	122	3	838	229058	3963	448
34	Magnetic Springs	17466	3713	0	21179	108	11	0	119	25393	--	--
35	Springfield	4023530	1212120	147110	5382760	24709	2120	26	26855	5811170	81926	10688

TABLE B-1

GAS SALES, NUMBERS OF CUSTOMERS, NET PLANT IN SERVICE, POPULATION AND ACREAGE - COLUMBIA GAS OF OHIO COMPANY (Continued)

		Gas Sales (MCF)				Number of Customers						
Case	Community	Residential Sector	Commercial Sector	Industrial Sector	All Sectors	Residential Sector	Commercial Sector	Industrial Sector	All Sectors	Net Plant In Service ($)	Population	Acreage
36	Tremont City	17912	2617	0	20528	117	11	0	128	19693	--	--
37	Columbiana	240345	106271	59393	406009	1598	162	6	1766	486780	4959	1920
38	Martins Ferry	534975	179553	31953	746481	3171	267	3	3441	998015	10757	1344
39	Shadyside	212723	33110	868	246701	1528	78	1	1607	367350	5070	512
40	Mingo Junction	203308	30532	6837	240677	1318	88	3	1409	407877	5278	1408
41	Steubenville	1539250	675665	30525	2245440	8641	776	14	9431	2480390	27105	4800
42	Jewett	47076	9983	0	57059	255	27	0	282	86611	--	--
43	Quaker City	33585	10493	0	44078	206	29	0	235	88118	--	--
44	Frazeysburg	53826	12582	0	66408	342	39	0	381	94825	--	--
45	Lower Salem	5913	1111	0	7024	46	8	0	54	27526	102	320
46	Hemlock	9462	390	0	9852	63	2	0	65	25232	199	256
47	Shawnee	40183	9137	0	49319	267	35	0	302	129723	914	448
48	Chillicothe	1206150	315401	35569	1557120	8082	770	9	8861	2532240	24842	5312
49	Cheshire	9348	1986	0	11334	74	12	0	86	30480	--	--
50	Middleport	143105	36443	10515	190063	988	125	4	1117	369244	2784	704
51	New Boston	152239	38217	0	190456	1023	129	0	1152	354208	3325	640
52	Portsmouth	1383200	520979	50311	1954490	8871	1064	13	9948	3159150	27633	7808

Source: Public Utilities Commission of Ohio

APPENDIX C

PACIFIC GAS AND ELECTRIC COMPANY DATA

The purpose of this appendix is to present the community-level data used in the econometric analysis of the Pacific Gas and Electric Company, as reported in chapter 3. The numbers of residential, commercial, and industrial gas customers and the corresponding sales for the years 1975 through 1979 and for 94 communities of 10,000 population or more are indicated in tables C-1 through C-8. The 1970 population and acreage, and the 1978 and 1979 distribution plant and main mileage of these communities are indicated in table C-9. Finally, average degree-day data are indicated in table C-10.

TABLE C-1

Average Number of Residential, Commercial, and Industrial Gas Customers -
Communities of 10,000 Population or More
Pacific Gas and Electric Company

Year	1975	1976	1977	1978	1979
Community					
Coast Valleys					
Monterey	9,288	9,455	9,545	9,583	9,644
Pacific Grove	6,666	6,705	6,717	6,766	6,893
Salinas	22,609	23,255	23,975	24,445	25,038
Seaside	6,855	6,905†	6,955	6,931	6,963
Colgate					
Yuba City	5,785	5,986	6,320	7,160	7,558
De Sabla					
Chico	8,278	8,576	9,075	9,378	9,770
Drum					
Roseville	7,465	7,693	7,994	8,280	8,552
East Bay					
Alameda	20,554	20,678	20,680	20,675	20,827
Albany	5,757	5,764†	5,772	5,781	5,780
Antioch	11,712	12,093	12,774	13,742	14,609
Berkeley	41,788	41,913	41,912	41,958	42,199
Concord	30,817	31,747	32,962	33,943	35,027
El Cerrito	9,631	9,675	9,707	9,768	9,807
Fremont	35,507	36,441	37,605	38,835	40,645
Hayward	29,665	30,186	30,556	30,984	31,462
Lafayette	7,182	7,276	7,349	7,430	7,535
Livermore	15,409	15,699	15,879	16,033	16,140
Martinez	6,770	7,038	7,444	7,849	8,297
Moraga	--	--	4,103	4,188	4,317
Newark	8,105	8,455†	8,806	9,012	9,198
Oakland	126,639	126,913	127,219	127,223	128,497

TABLE C-1

Average Number of Residential, Commercial, and Industrial Gas Customers
Communities of 10,000 Population or More
Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
East Bay (cont.)					
Piedmont	3,797	3,808	3,822	3,828	3,848
Pinhole	4,739	4,836	4,858	4,868	4,910
Pittsburg	8,673	9,111	9,529	9,938	10,433
Pleasant Hill	7,868	7,944	7,991	8,117	8,560
Pleasanton	9,477	10,086	10,502	10,734	10,999
Richmond	26,543	26,776	26,962	27,054	27,289
San Leandro	23,696	23,893	23,937	24,027	24,312
San Pablo	7,229	7,221	7,241	7,243	7,258
Union City	9,473	10,220	10,743	11,102	11,515
Walnut Creek	16,634	17,032	17,533	17,986	18,800
Humboldt					
Arcata	3,762	3,842	4,037	4,238	4,385
Eureka	10,393	10,464	10,589	10,702	10,810
North Bay					
Benicia	--	--	4,372	4,634	5,058
Larkspur	4,265	4,313	4,329	4,375	4,418
Mill Valley	4,915	5,005	5,107	5,119	5,133
Napa	17,187	17,660	18,051	18,463	18,973
Novato	10,020	10,548	11,061	11,455	12,330
Petaluma	10,577	10,857	10,995	11,266	11,551
Rohnert Park	--	--	4,296	4,895	5,468
San Anselmo	4,978	4,988	4,985	5,006	5,024
San Rafael	15,913	16,597	16,853	16,958	17,024
Santa Rosa	25,982	27,247	28,739	30,008	30,966
Ukiah	3,228	3,496	3,718	3,881	4,156
Vallejo	23,602	24,184	24,472	25,247	26,228
Sacramento					
Davis	10,038	10,459	10,942	11,527	12,052
Fairfield	12,466	12,979	13,704	14,198	14,911
Sacramento	96,944	97,796	98,123	98,711	100,155

TABLE C-1

Average Number of Residential, Commercial, and Industrial Gas Customers
Communities of 10,000 Population or More
Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
Sacramento (cont.)					
Vacaville	9,358	10,288	11,295	12,360	13,275
Woodland	8,933	9,201	9,557	10,005	10,311
San Francisco					
Daly City	23,945	24,157	24,403	24,539	24,702
Millbrae	7,126	7,157	7,220	7,280	7,301
Pacifica	11,344	11,421	11,424	11,452	11,525
San Bruno	11,790	11,793	11,825	11,835	11,863
San Francisco	256,230	256,674	257,136	259,013	260,507
South San Francisco	15,946	16,201	16,277	16,384	16,624
San Joaquin					
Atwater	3,568	3,706	3,854	4,052	4,390
Bakersfield	28,698	29,828	31,412	33,224	34,826
Clovis	7,311	8,355	9,484	10,273	11,254
Fresno	67,238	70,025	73,825	76,852	79,905
Los Banos	3,238	3,275	3,296	3,343	3,427
Madera	6,344	6,477	6,681	6,932	7,323
Merced	10,413	10,875	11,396	11,928	12,298
Ridgecrest	4,273	4,062	4,170	4,404	4,686
Sanger	3,462	3,566	3,607	3,710	3,896
San Jose					
Belmont	8,460	8,601	8,802	8,939	9,054
Burlingame	11,151	11,158	11,136	11,172	11,190
Campbell	9,189	9,360	9,335	9,530	9,792
Cupertino	7,336	7,629	7,851	8,098	9,917
Foster City	4,943	5,272	5,616	6,150	6,369
Gilroy	4,826	5,071	5,387	5,814	6,286
Los Altos	9,130	9,265	9,436†	9,608	9,650
Los Gatos	8,665	8,910	9,217	9,584	9,811
Menlo Park	11,472	11,603	11,683	11,783	11,819
Milpitas	8,858	8,951	9,258	9,738	10,391

TABLE C-1

Average Number of Residential, Commercial, and Industrial Gas Customers
Communities of 10,000 Population or More
Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
San Jose (cont.)					
Mountain View	19,236	19,596	20,246	20,615	21,092
Morgan Hill	--	--	3,364	3,904	4,306
Redwood City	20,030	20,147	20,208	20,429	20,708
San Carlos	10,273	10,382	10,453	10,540	10,598
San Jose	167,500	172,938	179,362	184,728	188,598
San Mateo	27,871	28,034	28,106	28,382	28,704
Santa Clara	27,321	27,642	28,228	28,473	29,250
Santa Cruz	13,428	13,677	13,965	14,335	14,641
Saratoga	8,465	8,651	8,799	8,832	9,142
Sunnyvale	32,083	32,708	33,207	34,169	34,439
Watsonville	5,998	6,417	6,702	6,938	7,104
Shasta					
Redding	3,714	3,811	3,950	7,419	9,893
Stockton					
Ceres	--	--	3,682	3,947	4,232
Lodi	12,455	12,768	13,040	13,421	13,797
Manteca	6,147	6,470	6,993	7,796	8,550
Modesto	30,125	31,551	33,191	34,963	36,721
Stockton	42,463	44,401	46,723	49,369	52,266
Tracy	5,888	5,979	6,130	6,325	6,499
Turlock	6,538	6,802	7,500	8,012	8,805
Customers in Communities of 10,000 Population and Over	1,795,687	2,112,814	1,883,132	1,936,143	1,990,815
Customers in Communities of Less Than 10,000 Population	724,092	462,057	752,108	761,582	772,582

† See Table C-2

TABLE C-1

Average Number of Residential, Commercial, and Industrial Gas Customers
Communities of 10,000 Population or More
Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Other Sales to Public Authorities	1	1	1	1	1
Sales for Resale	4	4	4	6	8
Interdepartmental Sales	--	--	--	--	--
Total	2,519,784	2,574,876	2,635,245	2,697,732	2,763,406

Source: Annual Reports to the California Public Utilities Commission, 1975-1979, Pacific Gas and Electric Company.

TABLE C-2

Average Number of Residential Gas Customers - Communities of 10,000 Population or More - Pacific Gas and Electric Company

Year	1975	1976	1977	1978	1979
Community					
Coast Valleys					
Monterey	8,293	8,435	8,524	8,557	8,589
Pacific Grove	6,347	6,368	6,383	6,424	6,539
Salinas	20,924	21,531	22,233	22,634	23,161
Seaside	6,426	6,475†	6,524	6,502	6,532
Colgate					
Yuba City	5,187	5,355	5,688	6,428	6,767
De Sabla					
Chico	7,352	7,645	8,144	8,439	8,763
Drum					
Roseville	6,925	7,140	7,429	7,722	7,959
East Bay					
Alameda	19,723	19,805	19,786	19,776	19,915
Albany	5,449	5,444†	5,439	5,443	5,441
Antioch	11,181	11,551	12,213	13,159	14,002
Berkeley	39,093	39,154	39,183	39,205	39,439
Concord	29,315	30,209	31,344	32,233	33,223
El Cerrito	9,233	9,254	9,295	9,351	9,387
Fremont	34,101	34,969	36,067	37,257	38,959
Hayward	27,395	27,856	28,153	28,506	28,919
Lafayette	6,701	6,781	6,862	6,935	7,003
Livermore	14,798	15,070	15,241	15,340	15,418
Martinez	6,417	6,682	7,084	7,492	7,928
Moraga	--††	--	3,976	4,063	4,189
Newark	7,787	8,124†	8,461	8,644	8,814
Oakland	118,503	118,633	119,169	119,229	120,421

TABLE C-2

Average Number of Residential Gas Customers - Communities of 10,000 Population or More - Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
East Bay (cont.)					
Piedmont	3,760	3,768	3,785	3,794	3,815
Pinhole	4,573	4,663	4,685	4,688	4,721
Pittsburg	8,219	8,651	9,072	9,461	9,939
Pleasant Hill	7,472	7,537	7,575	7,684	8,094
Pleasanton	9,121	9,702	10,080	10,278	10,509
Richmond	25,042	25,259	25,451	25,550	25,750
San Leandro	21,801	21,966	21,997	22,089	22,358
San Pablo	6,791	6,782	6,826	6,838	6,859
Union City	9,118	9,838	10,356	10,698	11,104
Walnut Creek	15,650	16,022	16,505	16,927	17,638
Humboldt					
Arcata	3,340	3,404	3,600	3,797	3,928
Eureka	9,264	9,280	9,390	9,475	9,570
North Bay					
Benicia	--	--	4,101	4,350	4,755
Larkspur	4,054	4,103	4,113	4,145	4,165
Mill Valley	4,630	4,699	4,787	4,794	4,797
Napa	16,124	16,564	16,936	17,290	17,750
Novato	9,586	10,098	10,595	10,978	11,758
Petaluma	9,897	10,145	10,269	10,529	10,777
Rohnert Park	--	--	4,137	4,698	5,254
San Anselmo	4,683	4,687	4,684	4,704	4,713
San Rafael	14,383	15,041	15,269	15,333	15,345
Santa Rosa	24,063	25,303	26,803	28,042	28,887
Ukiah	2,811	3,056	3,269	3,402	3,623
Vallejo	22,171	22,783	23,071	23,827	24,792
Sacramento					
Davis	9,652	10,069	10,559	11,142	11,616
Fairfield	11,852	12,314	13,005	13,473	14,129
Sacramento	91,255	92,059	92,374	92,885	94,209

TABLE C-2

Average Number of Residential Gas Customers - Communities of 10,000 Population or More - Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
Sacramento (cont.)					
Vacaville	8,949	9,864	10,857	11,899	12,772
Woodland	8,330	8,584	8,939	9,343	9,591
San Francisco					
Daly City	23,247	23,474	23,720	23,860	24,027
Millbrae	6,822	6,856	6,919	6,976	6,998
Pacifica	11,062	11,113	11,124	11,162	11,219
San Bruno	11,212	11,201	11,230	11,238	11,262
San Francisco	239,190	239,021	239,965	241,808	243,298
South San Francisco	14,747	14,987	15,052	15,139	15,342
San Joaquin					
Atwater	3,328	3,468	3,619	3,803	4,126
Bakersfield	25,873	26,971	28,537	30,221	31,727
Clovis	6,934	7,939	9,036	9,768	10,658
Fresno	62,054	64,641	68,299	71,157	73,879
Los Banos	2,924	2,956	2,982	3,026	3,108
Madera	5,824	5,952	6,167	6,428	6,755
Merced	9,480	9,924	10,438	10,964	11,287
Ridgecrest	3,970	3,740	3,851	4,069	4,328
Sanger	3,172	3,266	3,312	3,420	3,596
San Jose					
Belmont	8,065	8,192	8,396	8,525	8,632
Burlingame	10,153	10,148	10,129	10,149	10,159
Campbell	8,215	8,325	8,258	8,429	8,624
Cupertino	6,923	7,201	7,399	7,617	9,387
Foster City	4,832	5,156	5,486	6,001	6,185
Gilroy	4,327	4,574	4,885	5,295	5,709
Los Altos	8,579	8,699	8,867†	9,036	9,064
Los Gatos	8,000	8,230	8,532	8,870	9,059
Menlo Park	10,758	10,876	10,962	11,046	11,077
Milpitas	8,529	8,622	8,927	9,394	10,005

TABLE C-2

Average Number of Residential Gas Customers - Communities of 10,000 Population or More - Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
San Jose (cont.)					
Mountain View	17,538	17,870	18,481	18,760	19,156
Morgan Hill	--	--	3,103	3,633	3,949
Redwood City	18,692	18,792	18,859	19,062	19,338
San Carlos	9,346	9,446	9,511	9,575	9,627
San Jose	159,884	165,080	171,269	176,404	179,886
San Mateo	26,128	26,252	26,328	26,574	26,887
Santa Clara	25,167	25,433	25,884	26,002	26,616
Santa Cruz	12,178	12,390	12,666	13,015	13,314
Saratoga	8,139	8,309	8,451	8,476	8,769
Sunnyvale	30,413	30,956	31,385	32,263	32,327
Watsonville	5,305	5,703	5,969	6,193	6,347
Shasta					
Redding	2,902	2,945	3,079	6,316	8,596
Stockton					
Ceres	--	--	3,437	3,700	3,972
Lodi	11,497	11,806	12,078	12,434	12,776
Manteca	5,729	6,041	6,542	7,303	8,030
Modesto	28,246	29,631	31,220	32,895	34,493
Stockton	39,533	41,403	43,666	46,195	48,938
Tracy	5,487	5,551	5,710	5,903	6,052
Turlock	5,882	6,147	6,851	7,338	8,075
Customers in Communities of 10,000 Population and Over	1,681,474	1,977,114	1,764,986	1,814,894	1,864,845
Customers in Communities of Less Than 10,000 Population	680,737	436,479	707,916	716,861	726,662
Total	2,362,211	2,413,593	2,472,902	2,531,755	2,591,507

Source: Annual Reports to the California Public Utilities Commission, 1975-1979, Pacific Gas and Electric Company.

† : value linearly interpolated (original data inconsistent)
†† : See Table C-3

TABLE C-3

Average Number of Commercial Gas Customers - Communities of 10,000 Population or More - Pacific Gas and Electric Company

Year	1975	1976	1977	1978	1979
Community					
Coast Valleys					
Monterey	983	1,009	1,012	1,017	1,046
Pacific Grove	316	334	331	339	351
Salinas	1,665	1,705	1,727	1,796	1,861
Seaside	428	429†	430	428	430
Colgate					
Yuba City	590	622	623	724	783
De Sabla					
Chico	914	919	920	928	996
Drum					
Roseville	528	542	557	550	586
East Bay					
Alameda	811	855	876	882	895
Albany	303	315†	328	333	334
Antioch	522	533	554	578	602
Berkeley	2,623	2,690	2,675	2,734	2,741
Concord	1,494	1,530	1,609	1,701	1,795
El Cerrito	397	420	411	416	419
Fremont	1,381	1,448	1,518	1,558	1,665
Hayward	2,221	2,282	2,359	2,433	2,498
Lafayette	481	495	487	495	532
Livermore	605	623	634	689	719
Martinez	345	348	352	349	361
Moraga	--††	--	124	124	127
Newark	290	306†	322	346	362
Oakland	7,911	8,076	7,869	7,819	7,904

TABLE C-3

Average Number of Commercial Gas Customers - Communities of 10,000 Population or More - Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
East Bay (cont.)					
Piedmont	37	40	37	34	33
Pinhole	166	173	173	180	189
Pittsburg	445	451	449	469	486
Pleasant Hill	396	407	416	433	466
Pleasanton	348	378	417	451	485
Richmond	1,425	1,443	1,444	1,439	1,475
San Leandro	1,801	1,837	1,860	1,858	1,878
San Pablo	435	436	412	402	396
Union City	317	344	352	370	378
Walnut Creek	981	1,007	1,026	1,057	1,160
Humboldt					
Arcata	414	433	435	439	455
Eureka	1,108	1,166	1,184	1,212	1,227
North Bay					
Benicia	--	--	267	280	299
Larkspur	206	206	213	227	250
Mill Valley	285	306	320	325	336
Napa	1,054	1,088	1,110	1,168	1,218
Novato	433	450	466	477	572
Petaluma	665	697	712	723	761
Rohnert Park	--	--	159	197	214
San Anselmo	295	301	301	302	311
San Rafael	1,520	1,545	1,573	1,615	1,669
Santa Rosa	1,908	1,933	1,926	1,956	2,069
Ukiah	415	438	447	477	531
Vallejo	1,419	1,390	1,395	1,414	1,430
Sacramento					
Davis	383	387	380	382	433
Fairfield	611	661	697	723	780
Sacramento	5,585	5,642	5,666	5,743	5,864

TABLE C-3

Average Number of Commercial Gas Customers - Communities of 10,000 Population or More - Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
Sacramento (cont.)					
Vacaville	404	419	434	457	500
Woodland	594	608	611	655	713
San Francisco					
Daly City	690	676	676	673	669
Millbrae	303	300	301	304	303
Pacifica	279	306	299	289	305
San Bruno	573	587	592	594	598
San Francisco	16,739	17,415	16,971	17,014	17,026
South San Francisco	1,121	1,141	1,161	1,183	1,222
San Joaquin					
Atwater	239	237	234	248	263
Bakersfield	2,790	2,824	2,844	2,972	3,068
Clovis	376	415	447	504	595
Fresno	5,082	5,291	5,443	5,612	5,944
Los Banos	308	313	309	314	317
Madera	514	518	509	499	563
Merced	921	939	948	954	1,001
Ridgecrest	302	321	318	334	357
Sanger	279	289	285	280	290
San Jose					
Belmont	394	408	405	413	422
Burlingame	992	1,004	1,001	1,017	1,029
Campbell	971	1,032	1,074	1,099	1,166
Cupertino	405	419	442	469	518
Foster City	111	116	130	149	184
Gilroy	491	489	495	511	569
Los Altos	550	565	568†	571	585
Los Gatos	660	675	681	710	748
Menlo Park	704	718	712	728	734
Milpitas	307	308	312	326	367

TABLE C-3

Average Number of Commercial Gas Customers - Communities of 10,000 Population or More - Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
San Jose (cont.)					
Mountain View	1,660	1,688	1,727	1,817	1,900
Morgan Hill	--	--	257	268	354
Redwood City	1,309	1,328	1,324	1,345	1,349
San Carlos	909	918	925	948	955
San Jose	7,476	7,723	7,963	8,190	8,576
San Mateo	1,728	1,769	1,767	1,798	1,808
Santa Clara	2,108	2,165	2,303	2,434	2,598
Santa Cruz	1,227	1,265	1,280	1,301	1,308
Saratoga	324	340	346	354	371
Sunnyvale	1,631	1,713	1,789	1,875	2,082
Watsonville	674	697	716	728	740
Shasta					
Redding	799	854	864	1,091	1,284
Stockton					
Ceres	--	--	244	246	259
Lodi	937	941	941	966	1,001
Manteca	415	426	448	490	517
Modesto	1,842	1,885	1,938	2,035	2,197
Stockton	2,868	2,939	2,999	3,116	3,270
Tracy	394	422	415	417	442
Turlock	633	631	627	654	711
Customers in Communities of 10,000 Population and Over	112,066	133,292	116,371	119,544	124,303
Customers in Communities of Less Than 10,000 Population	41,939	24,638	43,030	43,573	44,794
Total	154,005	157,930	159,401	163,117	169,097

Source: Annual Reports to the California Public Utilities Commission, 1975-1979, Pacific Gas and Electric Company.

† See Table C-2

†† data not indicated (community with less than 10,000 population at that time)

TABLE C-4

Average Number of Industrial Gas Customers - Communities of 10,000 Population or More - Pacific Gas and Electric Company

Year	1975	1976	1977	1978	1979
Community					
Coast Valleys					
Monterey	12	11	9	9	9
Pacific Grove	3	3	3	3	3
Salinas	20	19	15	15	16
Seaside	1	1†	1	1	1
Colgate					
Yuba City	8	9	9	8	8
De Sabla					
Chico	12	12	11	11	11
Drum					
Roseville	12	11	8	8	7
East Bay					
Alameda	20	18	18	17	17
Albany	5	5†	5	5	5
Antioch	9	9	7	5	5
Berkeley	72	69	54	19	19
Concord	8	8	9	9	9
El Cerrito	1	1	1	1	1
Fremont	25	24	20	20	21
Hayward	49	48	44	45	45
Lafayette	0	0	0	0	0
Livermore	6	6	4	4	3
Martinez	8	8	8	8	8
Moraga	0	0	1	1	1
Newark	28	25†	23	22	22
Oakland	225	204	181	175	172

TABLE C-4

Average Number of Industrial Gas Customers - Communities of 10,000 Population or More - Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
East Bay (cont.)					
Piedmont	0	0	0	0	0
Pinhole	0	0	0	0	0
Pittsburg	9	9	8	8	8
Pleasant Hill	0	0	0	0	0
Pleasanton	8	6	5	5	5
Richmond	76	74	67	65	64
San Leandro	94	90	80	80	76
San Pablo	3	3	3	3	3
Union City	38	38	35	34	33
Walnut Creek	3	3	2	2	2
Humboldt					
Arcata	8	5	2	2	2
Eureka	21	18	15	15	13
North Bay					
Benicia	0	0	4	4	4
Larkspur	5	4	3	3	3
Mill Valley	0	0	0	0	0
Napa	9	8	5	5	5
Novato	1	0	0	0	0
Petaluma	15	15	14	14	13
Rohnert Park	0	0	0	0	0
San Anselmo	0	0	0	0	0
San Rafael	10	11	11	10	10
Santa Rosa	11	11	10	10	10
Ukiah	2	2	2	2	2
Vallejo	12	11	6	6	6
Sacramento					
Davis	3	3	3	3	3
Fairfield	3	4	2	2	2
Sacramento	104	95	83	83	82

TABLE C-4

Average Number of Industrial Gas Customers - Communities of 10,000 Population or More - Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
Sacramento (cont.)					
Vacaville	5	5	4	4	3
Woodland	9	9	7	7	7
San Francisco					
Daly City	8	7	7	6	6
Millbrae	1	1	0	0	0
Pacifica	3	2	1	1	1
San Bruno	5	5	3	3	3
San Francisco	301	238	200	191	183
South San Francisco	78	73	64	62	60
San Joaquin					
Atwater	1	1	1	1	1
Bakersfield	35	33	31	31	31
Clovis	1	1	1	1	1
Fresno	102	93	83	83	82
Los Banos	6	6	5	3	2
Madera	6	7	5	5	5
Merced	12	12	10	10	10
Ridgecrest	1	1	1	1	1
Sanger	11	11	10	10	10
San Jose					
Belmont	1	1	1	1	0
Burlingame	6	6	6	6	2
Campbell	3	3	3	2	2
Cupertino	8	9	10	12	12
Foster City	0	0	0	0	0
Gilroy	8	8	7	8	8
Los Altos	1	1	1†	1	1
Los Gatos	5	5	4	4	4
Menlo Park	10	9	9	9	8
Milpitas	22	21	19	18	19

TABLE C-4

Average Number of Industrial Gas Customers - Communities of 10,000 Population or More - Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
San Jose (cont.)					
Mountain View	38	38	38	38	36
Morgan Hill	0	0	4	3	3
Redwood City	29	27	25	22	21
San Carlos	18	18	17	17	16
San Jose	140	135	130	134	136
San Mateo	15	13	11	10	9
Santa Clara	46	44	41	37	36
Santa Cruz	23	22	19	19	19
Saratoga	2	2	2	2	2
Sunnyvale	39	39	33	31	30
Watsonville	19	18	17	17	17
Shasta					
Redding	13	12	7	12	13
Stockton					
Ceres	0	0	1	1	1
Lodi	21	21	21	21	20
Manteca	3	3	3	3	3
Modesto	37	35	33	33	31
Stockton	62	59	58	58	58
Tracy	7	6	5	5	5
Turlock	23	24	22	20	19
Customers in Communities of 10,000 Population and Over	2,147	2,408	1,775	1,705	1,667
Customers in Communities of Less Than 10,000 Population	1,416	940	1,162	1,148	1,126
Total	3,563	3,348	2,937	2,853	2,793

Source: Annual Reports to the California Public Utilities Commission, 1975-1979, Pacific Gas and Electric Company.

TABLE C-5

Total Residential, Commercial, and Industrial Gas Sales (MCF)
Communities of 10,000 Population or More
Pacific Gas and Electric Company

Year	1975	1976	1977	1978	1979
Community					
Coast Valleys					
Monterey	1,877,721	1,702,422	1,502,737	1,546,457	1,611,966
Pacific Grove	833,733	752,351	665,553	659,489	682,675
Salinas	3,655,150	3,366,499	3,175,063	2,992,291	3,051,111
Seaside	1,003,854	921,335	836,335	797,061	816,355
Colgate					
Yuba City	965,774	981,723	979,611	1,020,505	1,074,526
De Sabla					
Chico	1,396,994	1,243,349	1,173,591	1,172,709	1,219,075
Drum					
Roseville	1,333,668	1,197,468	1,096,588	1,119,684	1,192,469
East Bay					
Alameda	3,869,983	8,539,378	3,016,016	3,240,332	3,373,209
Albany	916,673	783,969	740,174	724,132	746,765
Antioch	1,803,985	1,540,515	1,208,426	1,164,128	1,310,911
Berkeley	8,081,846	7,096,082	6,371,396	6,263,691	6,774,647
Concord	3,889,735	3,630,623	3,224,044	3,182,167	3,474,423
El Cerrito	1,118,488	967,266	860,443	844,402	896,743
Fremont	6,367,067	6,640,732	6,369,574	6,360,047	6,385,544
Hayward	6,411,453	5,834,443	5,441,285	5,085,216	5,314,905
Lafayette	1,200,410	1,087,509	884,165	923,342	966,592
Livermore	2,015,434	1,932,895	1,767,623	1,738,383	1,855,264
Martinez	1,253,438	1,196,100	1,064,888	1,092,961	1,156,164
Moraga	--†	--	627,179	651,437	675,885
Newark	3,265,622	3,512,503	3,371,592	3,433,326	3,597,987
Oakland	24,669,933	22,976,464	21,198,287	20,626,399	20,560,562

TABLE C-5

Total Residential, Commercial, and Industrial Gas Sales (MCF)
Communities of 10,000 Population or More
Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
East Bay (cont.)					
Piedmont	689,097	603,652	517,789	525,085	541,126
Pinhole	660,494	577,306	486,309	474,587	500,696
Pittsburg	1,580,584	1,504,286	1,393,551	1,181,382	1,265,576
Pleasant Hill	1,100,694	1,002,124	855,757	833,715	958,614
Pleasanton	1,608,356	1,532,728	1,342,160	1,320,816	1,405,069
Richmond	37,779,623	39,288,828	38,157,081	33,725,841	37,749,652
San Leandro	6,432,310	6,142,142	5,371,415	5,129,881	5,308,937
San Pablo	920,150	852,023	789,955	762,108	818,421
Union City	3,780,590	3,862,223	3,847,246	3,359,126	1,825,373
Walnut Creek	2,510,115	2,323,741	1,977,903	2,045,057	2,230,412
Humboldt					
Arcata	669,559	684,280	611,187	611,893	640,147
Eureka	1,753,302	1,689,825	1,488,633	1,392,447	1,335,709
North Bay					
Benicia	--	--	6,968,118	6,241,088	8,691,701
Larkspur	636,197	547,419	455,417	471,369	495,107
Mill Valley	721,607	636,107	553,225	554,845	594,768
Napa	2,293,803	2,144,129	1,944,668	1,854,164	2,011,234
Novato	1,781,294	1,647,691	1,440,789	1,427,362	1,574,491
Petaluma	1,754,898	1,608,681	1,446,915	1,397,985	1,552,879
Rohnert Park	--	--	546,918	581,688	675,710
San Anselmo	647,176	578,999	489,621	485,137	527,377
San Rafael	2,638,724	2,394,386	2,011,923	2,004,087	2,177,882
Santa Rosa	3,643,899	3,435,754	3,162,562	3,191,788	3,466,752
Ukiah	379,809	373,551	363,863	367,414	409,608
Vallejo	4,828,587	4,296,100	3,721,535	3,590,773	3,824,548
Sacramento					
Davis	1,890,382	1,563,556	1,467,487	1,373,552	1,741,012
Fairfield	2,515,316	2,434,110	2,866,868	2,759,021	3,147,235
Sacramento	17,797,055	15,643,733	14,281,043	13,727,446	14,675,218

TABLE C-5

Total Residential, Commercial, and Industrial Gas Sales (MCF)
Communities of 10,000 Population or More
Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
Sacramento (cont.)					
Vacaville	2,010,436	1,663,972	1,813,798	1,644,492	1,855,923
Woodland	2,113,720	1,733,024	1,564,876	1,481,938	1,686,809
San Francisco					
Daly City	3,340,203	2,941,924	2,724,055	2,568,475	2,659,802
Millbrae	1,041,351	965,827	847,290	816,937	846,997
Pacifica	1,520,756	1,432,371	1,267,778	1,189,224	1,222,686
San Bruno	1,538,000	1,408,365	1,273,442	1,197,805	1,256,700
San Francisco	43,373,592	39,401,383	36,050,171	34,172,294	34,949,780
South San Francisco	4,435,984	4,113,417	3,871,814	3,511,151	3,687,949
San Joaquin					
Atwater	838,152	702,575	690,103	657,298	645,048
Bakersfield	4,106,024	3,706,383	3,589,258	3,456,051	3,755,702
Clovis	769,461	766,624	782,166	792,844	901,363
Fresno	9,470,263	9,094,627	8,538,188	8,311,411	8,746,587
Los Banos	625,509	619,310	599,945	540,861	543,387
Madera	752,412	712,931	673,759	652,027	715,232
Merced	1,988,054	1,663,913	1,739,652	1,556,981	1,775,263
Ridgecrest	892,707	799,415	750,341	668,690	775,121
Sanger	508,364	487,210	462,342	419,229	460,342
San Jose					
Belmont	1,151,063	1,057,767	939,031	913,834	979,115
Burlingame	1,879,993	1,744,457	1,535,851	1,439,529	1,531,932
Campbell	1,203,173	1,135,268	997,953	981,730	1,059,984
Cupertino	1,288,263	1,231,831	1,165,809	1,203,947	1,397,050
Foster City	822,187	780,809	692,296	706,754	782,274
Gilroy	2,431,266	1,866,065	1,963,178	1,952,207	2,226,136
Los Altos	1,473,978	1,385,311	1,390,082†	1,199,359	1,199,693
Los Gatos	1,344,856	1,311,744	1,180,082	1,213,727	1,250,052
Menlo Park	2,031,234	1,905,437	1,615,186	1,577,077	1,603,887
Milpitas	1,884,370	1,817,967	1,763,434	1,718,793	1,933,144

TABLE C-5

Total Residential, Commercial, and Industrial Gas Sales (MCF)
Communities of 10,000 Population or More
Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
San Jose (cont.)					
Mountain View	3,253,993	3,088,847	2,778,691	2,737,996	2,865,935
Morgan Hill	--	--	433,545	465,214	529,074
Redwood City	3,075,480	2,935,215	2,609,250	2,527,263	2,664,320
San Carlos	1,486,902	1,393,617	1,215,296	1,153,331	1,251,155
San Jose	28,807,313	26,942,260	25,745,168	24,887,438	26,208,402
San Mateo	4,013,489	3,762,436	3,287,607	3,134,361	3,329,022
Santa Clara	7,388,178	7,468,244	7,214,952	7,246,007	7,842,281
Santa Cruz	2,326,062	2,106,514	1,877,738	1,844,627	1,918,862
Saratoga	1,705,397	1,664,581	1,414,374	1,399,227	1,397,975
Sunnyvale	7,070,918	6,412,670	5,984,184	5,897,853	6,141,255
Watsonville	1,106,149	1,093,686	1,120,089	1,073,951	1,087,247
Shasta					
Redding	739,644	661,856	653,788	874,899	1,209,403
Stockton					
Ceres	--	--	383,537	384,216	416,545
Lodi	2,263,772	1,928,928	1,978,887	1,840,563	2,071,888
Manteca	687,505	653,325	661,578	708,207	779,622
Modesto	5,481,992	5,140,000	5,281,631	5,228,792	5,680,889
Stockton	10,140,602	9,383,709	8,370,091	7,493,400	8,971,866
Tracy	1,661,645	1,598,753	1,627,626	1,683,575	1,789,874
Turlock	1,264,154	1,052,911	1,034,665	1,113,997	1,214,500
Total Sales in Communities of 10,000 Population and Over	354,975,928	333,006,041	317,498,993	304,267,398	325,120,401
Sales in Communities of Less Than 10,000 Population	306,435,048	269,114,358	232,492,042	198,811,299	238,959,927

TABLE C-5

Total Residential, Commercial, and Industrial Gas Sales (MCF)
Communities of 10,000 Population or More
Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Other Sales to Public Authorities	6,447	3,056	1,683	1,339	1,356
Sales for Resale	9,458,672	8,715,861	7,810,276	9,926,108	36,013,469
Interdepartmental Sales	159,223,561	195,063,458	217,368,151	125,768,565	216,147,045
Total	829,999,656	805,902,774	775,171,145	638,774,709	816,242,198

Source: Annual Reports to the California Public Utilities Commission, 1975-1979, Pacific Gas and Electric Company.

† : See Table C-3
†† : See Table C-2

TABLE C-6

Total Residential Gas Sales (MCF) - Communities of 10,000 Population or More
Pacific Gas and Electric Company

Year	1975	1976	1977	1978	1979
Community					
Coast Valleys					
Monterey	869,015	840,933	795,610	797,806	823,245
Pacific Grove	626,673	582,432	523,835	526,698	545,668
Salinas	2,157,332	2,028,124	1,915,264	1,815,034	1,861,519
Seaside	700,579	684,080	692,595	667,698	674,521
Colgate					
Yuba City	553,569	510,970	478,916	498,731	562,436
De Sabla					
Chico	763,992	680,163	652,586	662,895	682,021
Drum					
Roseville	778,268	682,128	637,052	658,093	714,503
East Bay					
Alameda	2,139,111	1,924,907	1,691,719	1,634,630	1,748,534
Albany	479,356	469,035	430,336	407,733	432,689
Antioch	1,093,148	989,945	905,287	962,414	1,075,233
Berkeley	3,890,451	3,416,774	3,073,915	2,966,999	3,139,785
Concord	3,137,965	2,960,868	2,615,114	2,607,092	2,832,474
El Cerrito	960,094	826,827	736,244	733,550	768,599
Fremont	3,907,581	3,672,330	3,221,078	3,198,767	3,411,058
Hayward	2,865,249	2,773,671	2,474,486	2,435,219	2,570,195
Lafayette	1,079,792	972,254	782,289	827,391	862,246
Livermore	1,694,658	1,580,801	1,403,516	1,356,636	1,438,202
Martinez	680,858	623,427	570,377	584,446	655,058
Moraga	--††	--	516,811	546,203	571,066
Newark	905,260	859,813	757,160	732,533	777,332
Oakland	12,214,946	11,009,179	10,245,149	9,920,488	10,567,025

TABLE C-6

Total Residential Gas Sales (MCF) - Communities of 10,000 Population or More
Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
East Bay (cont.)					
Piedmont	664,901	582,156	499,219	505,645	522,121
Pinhole	584,500	514,713	431,091	422,662	446,883
Pittsburg	852,725	796,673	749,397	760,778	842,130
Pleasant Hill	871,185	788,272	664,258	656,726	721,599
Pleasanton	1,204,412	1,167,978	1,051,496	1,034,885	1,079,611
Richmond	2,239,908	2,394,774	2,213,632	2,128,694	2,279,539
San Leandro	2,137,116	2,012,360	1,758,923	1,697,389	1,810,176
San Pablo	594,407	539,587	532,279	515,315	545,571
Union City	924,764	947,526	885,450	845,953	935,110
Walnut Creek	1,868,032	1,728,199	1,451,322	1,509,420	1,658,778
Humboldt					
Arcata	348,414	347,827	312,570	301,987	317,660
Eureka	1,040,022	978,177	858,231	821,016	835,895
North Bay					
Benicia	--	--	361,226	366,847	425,006
Larkspur	451,516	424,057	362,739	379,782	396,620
Mill Valley	625,768	539,353	466,094	467,779	501,216
Napa	1,677,803	1,568,430	1,424,567	1,385,821	1,522,013
Novato	1,279,345	1,288,921	1,147,650	1,145,392	1,252,352
Petaluma	1,184,837	1,101,651	976,989	949,145	1,049,115
Rohnert Park	--	--	475,756	512,744	589,954
San Anselmo	554,921	489,363	412,265	412,179	449,332
San Rafael	1,952,415	1,745,383	1,433,583	1,466,119	1,575,828
Santa Rosa	2,544,234	2,461,734	2,281,636	2,320,576	2,529,231
Ukiah	245,764	241,228	233,327	236,893	261,776
Vallejo	2,276,122	2,115,647	1,976,475	1,887,515	2,143,014
Sacramento					
Davis	1,017,941	934,608	870,328	869,833	929,105
Fairfield	1,306,828	1,256,033	1,269,744	1,262,660	1,407,056
Sacramento	10,484,470	9,185,083	8,411,887	8,070,455	8,666,892

TABLE C-6

Total Residential Gas Sales (MCF) - Communities of 10,000 Population or More
Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
Sacramento (cont.)					
Vacaville	931,703	921,945	921,198	984,500	1,101,254
Woodland	951,786	853,670	797,249	785,214	839,853
San Francisco					
Daly City	2,722,094	2,437,040	2,241,245	2,124,042	2,189,948
Millbrae	864,312	799,388	692,931	673,155	701,509
Pacifica	1,394,441	1,269,338	1,127,636	1,075,577	1,100,742
San Bruno	1,295,462	1,184,002	1,057,249	1,001,764	1,049,695
San Francisco	25,369,811	22,955,461	21,504,945	20,481,213	21,337,976
South San Francisco	1,630,653	1,499,912	1,350,052	1,284,290	1,346,685
San Joaquin					
Atwater	326,179	305,922	370,829	369,617	388,047
Bakersfield	2,504,914	2,302,950	2,295,435	2,277,852	2,440,822
Clovis	624,194	653,898	664,766	672,836	754,886
Fresno	5,859,503	5,483,399	5,263,631	5,160,075	5,439,752
Los Banos	289,846	270,159	250,890	243,255	252,148
Madera	547,578	513,224	488,127	476,645	517,574
Merced	949,117	885,722	850,599	829,667	880,058
Ridgecrest	335,777	281,952	282,850	294,158	337,048
Sanger	277,036	262,503	246,597	232,268	256,500
San Jose					
Belmont	946,193	874,747	775,625	772,957	834,182
Burlingame	1,164,578	1,075,634	933,876	897,354	945,835
Campbell	840,288	800,860	702,752	693,726	739,657
Cupertino	865,120	812,687	731,187	726,081	865,854
Foster City	760,501	728,938	644,332	660,750	725,218
Gilroy	441,289	430,826	433,608	432,124	474,617
Los Altos	1,274,907	1,194,131	1,113,660†	1,033,190	1,031,288
Los Gatos	965,928	932,450	838,888	872,344	896,707
Menlo Park	1,145,507	1,080,680	932,235	919,820	956,357
Milpitas	965,493	934,851	798,132	785,280	903,247

TABLE C-6

Total Residential Gas Sales (MCF) - Communities of 10,000 Population or More
Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
San Jose (cont.)					
Mountain View	1,818,780	1,793,185	1,592,456	1,583,405	1,682,799
Morgan Hill	--	--	330,610	370,877	410,844
Redwood City	1,855,800	1,763,346	1,526,452	1,499,345	1,584,665
San Carlos	1,071,892	990,452	848,075	824,824	887,614
San Jose	18,082,088	17,296,897	16,107,682	15,679,755	16,298,261
San Mateo	2,964,846	2,746,856	2,401,025	2,328,236	2,494,957
Santa Clara	2,642,167	2,487,194	2,187,779	2,156,501	2,324,099
Santa Cruz	1,246,024	1,121,192	994,168	1,005,762	1,061,224
Saratoga	1,487,346	1,419,818	1,212,817	1,209,108	1,200,158
Sunnyvale	3,477,768	3,381,453	3,085,050	3,018,703	3,116,413
Watsonville	473,266	458,089	444,009	448,604	471,708
Shasta					
Redding	277,479	233,935	233,396	391,695	653,724
Stockton					
Ceres	--	--	288,716	297,837	324,118
Lodi	1,136,378	1,019,757	979,966	966,244	1,038,718
Manteca	535,253	509,091	507,381	545,383	605,905
Modesto	2,938,952	2,782,117	2,750,027	2,761,110	2,987,979
Stockton	3,826,435	3,480,984	3,421,042	3,530,681	3,874,219
Tracy	488,430	438,835	419,955	411,883	445,499
Turlock	553,167	525,610	514,877	543,625	611,629
Total Sales in Communities of 10,000 Population and Over	181,936,348	169,163,622	155,924,710	153,808,598	164,149,998
Sales in Communities of Less Than 10,000 Population	80,426,464	74,094,258	67,806,827	66,267,823	70,144,714
Total	262,362,812	243,257,880	233,731,537	220,076,421	234,294,712

Source: Annual Reports to the California Public Utilities Commission, 1975-1979, Pacific Gas and Electric Company.

† : See Table C-2

†† : See Table C-3

TABLE C-7

Total Commercial Gas Sales (MCF) - Communities of 10,000 Population or More - Pacific Gas and Electric Company

Year	1975	1976	1977	1978	1979
Community					
Coast Valleys					
Monterey	725,093	608,906	507,310	508,617	549,736
Pacific Grove	196,138	158,445	130,429	123,005	129,118
Salinas	995,535	899,140	927,824	864,641	899,595
Seaside	300,099	233,851	140,397	126,095	138,742
Colgate					
Yuba City	222,403	189,503	171,428	182,435	204,659
De Sabla					
Chico	462,481	410,243	391,815	387,868	408,897
Drum					
Roseville	220,434	205,786	253,902	266,315	286,145
East Bay					
Alameda	503,549	472,678	426,556	408,297	438,808
Albany	186,535	121,322	152,341	160,117	156,199
Antioch	202,917	183,875	183,675	179,453	205,392
Berkeley	1,231,508	1,163,789	1,149,592	1,267,498	1,387,022
Concord	698,318	578,116	520,657	497,199	563,140
El Cerrito	155,891	137,988	122,121	109,237	126,116
Fremont	656,150	643,658	1,833,520	2,232,282	2,110,599
Hayward	1,202,075	1,075,203	1,350,338	1,200,090	1,282,788
Lafayette	120,618	115,255	101,876	95,951	104,346
Livermore	217,112	205,138	231,905	217,319	244,649
Martinez	222,155	203,618	197,286	174,283	187,573
Moraga	-- †	--	54,076	48,438	50,060
Newark	120,821	128,955	1,156,361	1,084,094	1,131,966
Oakland	4,152,076	3,875,599	5,636,380	4,438,228	4,513,713

TABLE C-7

Total Commercial Gas Sales (MCF) - Communities of 10,000 Population or More - Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
East Bay (cont.)					
Piedmont	24,196	21,496	18,570	19,440	19,005
Pinhole	75,994	62,593	55,218	51,925	53,813
Pittsburg	224,925	191,089	206,064	220,724	237,366
Pleasant Hill	229,509	213,852	191,499	176,989	237,015
Pleasanton	194,154	180,343	218,428	183,810	183,427
Richmond	670,657	617,815	30,850,461	29,743,789	22,345,971
San Leandro	906,860	802,506	1,101,693	1,032,320	1,103,443
San Pablo	258,264	243,197	189,638	170,741	176,506
Union City	148,737	140,482	180,907	194,468	179,863
Walnut Creek	548,079	512,682	451,890	456,867	489,488
Humboldt					
Arcata	254,811	286,087	294,860	306,967	319,797
Eureka	490,923	497,228	485,950	451,244	453,568
North Bay					
Benicia	--	--	4,681,235	5,239,132	7,414,686
Larkspur	103,233	83,724	57,566	56,883	66,632
Mill Valley	95,839	96,754	87,131	87,066	93,552
Napa	442,076	388,825	398,695	361,691	387,947
Novato	499,517	358,359	293,139	281,970	322,139
Petaluma	301,768	270,071	239,204	220,785	252,265
Rohnert Park	--	--	71,162	68,944	85,756
San Anselmo	92,255	89,636	77,356	72,958	78,045
San Rafael	575,646	538,658	484,178	454,552	512,091
Santa Rosa	882,493	749,054	691,086	674,827	746,264
Ukiah	124,249	127,208	126,130	126,975	144,395
Vallejo	725,729	657,772	644,762	620,315	663,204
Sacramento					
Davis	246,813	189,539	159,670	145,422	154,669
Fairfield	1,037,248	903,367	819,964	801,896	856,771
Sacramento	3,285,563	2,787,686	3,059,851	2,706,905	2,912,056

TABLE C-7

Total Commercial Gas Sales (MCF) - Communities of 10,000 Population or More - Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
Sacramento (cont.)					
Vacaville	238,985	175,389	705,690	502,864	585,617
Woodland	355,938	316,152	293,179	353,017	397,267
San Francisco					
Daly City	539,614	437,901	416,749	383,098	403,210
Millbrae	157,696	151,606	154,359	143,782	145,488
Pacifica	105,180	155,018	136,211	109,760	117,896
San Bruno	179,868	169,425	189,324	172,325	172,233
San Francisco	10,245,135	9,688,528	8,892,647	8,370,113	8,529,606
South San Francisco	731,512	804,739	1,408,751	1,417,045	1,469,596
San Joaquin					
Atwater	216,664	186,855	90,355	73,834	75,219
Bakersfield	1,199,707	1,072,653	1,028,108	936,678	1,043,138
Clovis	142,070	109,067	113,437	115,670	141,986
Fresno	2,097,452	2,011,785	2,050,016	1,997,497	2,117,089
Los Banos	116,302	100,082	274,729	253,447	202,526
Madera	185,820	167,420	172,947	163,225	179,451
Merced	419,410	406,961	419,647	403,575	468,404
Ridgecrest	422,395	380,119	373,167	346,455	326,948
Sanger	81,790	80,988	98,343	93,211	104,006
San Jose					
Belmont	183,865	166,174	148,751	130,904	144,933
Burlingame	617,196	574,604	515,872	457,393	506,741
Campbell	344,916	307,208	271,712	268,381	301,845
Cupertino	285,372	284,776	286,575	290,885	324,834
Foster City	61,686	51,871	47,964	46,004	57,056
Gilroy	198,683	161,297	1,150,644	1,139,327	1,259,816
Los Altos	196,901	189,237	274,729	164,135	166,542
Los Gatos	308,956	306,134	265,910	270,624	288,813
Menlo Park	378,254	358,142	329,458	300,547	327,248
Milpitas	234,988	186,374	542,014	725,399	802,304

TABLE C-7

Total Commercial Gas Sales (MCF) - Communities of 10,000 Population or More - Pacific Gas and Electric (Continued)

Year	1975	1976	1977	1978	1979
Community					
San Jose (cont.)					
Mountain View	739,153	663,867	597,911	596,972	654,421
Morgan Hill	--	--	84,071	86,675	106,819
Redwood City	616,008	560,377	493,067	464,420	508,477
San Carlos	236,538	228,959	212,786	183,177	215,939
San Jose	4,022,086	3,412,825	3,515,566	3,337,699	3,522,211
San Mateo	777,294	753,954	693,647	638,407	662,486
Santa Clara	1,161,076	1,106,621	2,228,929	2,120,901	2,444,283
Santa Cruz	516,166	477,970	435,348	442,449	487,037
Saratoga	180,132	209,400	164,561	156,964	162,538
Sunnyvale	1,250,392	1,064,827	1,451,337	1,443,682	1,559,127
Watsonville	235,511	245,323	252,047	243,166	234,651
Shasta					
Redding	350,138	332,757	354,573	384,135	448,523
Stockton					
Ceres	--	--	83,690	79,297	83,053
Lodi	364,540	316,836	421,820	350,463	367,407
Manteca	137,086	123,654	132,451	130,638	135,239
Modesto	907,538	855,492	1,041,505	1,127,016	1,224,623
Stockton	1,634,999	1,476,281	1,440,761	1,472,378	1,567,339
Tracy	145,464	165,720	182,442	187,863	200,457
Turlock	267,734	246,181	312,165	264,259	256,648
Total Sales in Communities of 10,000 Population and Over	59,237,512	54,101,832	96,526,061	92,840,823	91,157,216
Sales in Communities of Less Than 10,000 Population	23,911,228	20,499,556	67,204,285	51,186,262	52,463,463
Total	83,148,740	74,601,388	163,730,346	144,027,085	143,620,679

Source: Annual Reports to the California Public Utilities Commission, 1975-1979, Pacific Gas and Electric Company.

† : See Table C-3

TABLE C-8

Total Industrial Gas Sales (MCF) - Communities of 10,000 Population or More - Pacific Gas and Electric Company

Year	1975	1976	1977	1978	1979
Community					
Coast Valleys					
Monterey	283,613	252,583	199,817	240,034	238,985
Pacific Grove	10,922	11,474	11,289	9,786	7,889
Salinas	502,283	439,235	331,975	312,616	289,997
Seaside	3,176	3,404	3,343	3,268	3,092
Colgate					
Yuba City	189,802	281,250	329,267	339,339	307,431
De Sabla					
Chico	170,521	152,943	129,190	121,946	128,157
Drum					
Roseville	334,966	309,554	205,634	195,276	191,821
East Bay					
Alameda	1,227,323	1,141,793	897,786	1,197,405	1,185,867
Albany	250,782	193,612	157,497	156,282	157,877
Antioch	507,920	366,695	119,464	22,261	30,286
Berkeley	2,959,887	2,515,519	2,147,889	2,029,194	2,247,840
Concord	53,452	91,639	88,273	77,876	78,809
El Cerrito	2,503	2,451	2,078	1,615	2,028
Fremont	1,803,336	2,324,744	1,314,976	928,998	863,887
Hayward	2,344,129	1,985,569	1,616,461	1,449,907	1,461,922
Lafayette	0	0	0	0	0
Livermore	103,664	146,956	132,202	164,428	172,413
Martinez	350,425	369,055	297,225	334,232	313,533
Moraga	0	0	56,292	56,796	54,759
Newark	2,239,541	2,523,735	1,458,071	1,616,699	1,688,689
Oakland	8,302,911	8,091,686	5,316,758	6,267,683	5,479,824

TABLE C-8

Total Industrial Gas Sales (MCF) - Communities of 10,000 Population or More - Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
East Bay (cont.)					
Piedmont	0	0	0	0	0
Pinhole	0	0	0	0	0
Pittsburg	502,934	516,524	438,090	199,880	186,080
Pleasant Hill	0	0	0	0	0
Pleasanton	209,790	184,407	72,236	102,121	142,031
Richmond	34,869,058	36,276,240	5,092,988†	1,853,358	13,124,142
San Leandro	3,388,334	3,327,276	2,510,799	2,400,172	2,395,318
San Pablo	67,479	69,239	68,038	76,052	96,344
Union City	2,707,089	2,774,215	2,780,889	2,318,705	710,400
Walnut Creek	94,004	82,860	74,691	78,770	82,146
Humboldt					
Arcata	66,334	50,366	3,757	2,939	2,690
Eureka	222,357	214,420	144,452	120,187	46,246
North Bay					
Benicia	0	0	1,925,657	635,109	852,009
Larkspur	81,448	39,638	35,112	34,704	31,855
Mill Valley	0	0	0	0	0
Napa	173,924	186,874	121,406	106,652	101,274
Novato	2,432	411	0	0	0
Petaluma	268,293	236,959	230,722	228,055	251,499
Rohnert Park	0	0	0	0	0
San Anselmo	0	0	0	0	0
San Rafael	110,663	110,345	94,162	83,416	89,963
Santa Rosa	217,172	224,966	189,840	196,385	191,257
Ukiah	9,796	5,115	4,406	3,546	3,437
Vallejo	1,826,736	1,522,681	1,100,298	1,082,943	1,018,330
Sacramento					
Davis	625,628	439,409	437,489	358,297	657,238
Fairfield	171,240	274,710	777,160	694,465	883,408
Sacramento	4,027,022	3,670,964	2,809,305	2,950,086	3,096,270

TABLE C-8

Total Industrial Gas Sales (MCF) - Communities of 10,000 Population or More - Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
Sacramento (cont.)					
Vacaville	839,748	566,637	186,910	157,128	169,052
Woodland	805,996	563,202	474,448	343,707	449,689
San Francisco					
Daly City	78,495	66,983	66,061	61,335	66,644
Millbrae	19,343	14,833	0	0	0
Pacifica	21,135	8,015	3,931	3,887	4,048
San Bruno	62,670	54,938	26,869	23,716	34,772
San Francisco	7,758,646	6,757,394	5,652,579	5,320,968	5,082,198
South San Francisco	2,073,819	1,808,766	1,113,011	809,816	871,668
San Joaquin					
Atwater	295,309	209,798	228,919	213,847	181,782
Bakersfield	401,403	330,780	265,715	241,521	271,742
Clovis	3,197	3,659	3,963	4,338	4,491
Fresno	1,513,308	1,599,443	1,224,541	1,153,839	1,189,746
Los Banos	219,361	249,069	74,326	44,159	88,713
Madera	19,014	32,287	12,685	12,157	18,207
Merced	619,527	371,231	469,406	323,739	426,801
Ridgecrest	134,535	137,344	94,324	28,077	111,125
Sanger	149,538	143,719	117,402	93,750	99,836
San Jose					
Belmont	21,005	16,846	14,655	9,973	0
Burlingame	98,219	94,219	86,103	84,782	79,356
Campbell	17,969	27,200	23,489	19,623	18,482
Cupertino	137,771	134,368	148,047	186,981	206,362
Foster City	0	0	0	0	0
Gilroy	1,791,294	1,273,942	378,926	380,756	491,703
Los Altos	2,170	1,943	1,693††	2,034	1,863
Los Gatos	69,972	73,160	75,284	70,759	64,532
Menlo Park	507,473	466,615	353,493	356,710	320,282
Milpitas	683,889	696,742	423,288	208,114	227,593

TABLE C-8

Total Industrial Gas Sales (MCF) - Communities of 10,000 Population or More - Pacific Gas and Electric Company (Continued)

Year	1975	1976	1977	1978	1979
Community					
San Jose (cont.)					
Mountain View	696,060	631,795	588,324	557,619	528,715
Morgan Hill	0	0	18,864	7,662	11,411
Redwood City	603,672	611,492	589,731	563,498	571,178
San Carlos	178,472	174,206	154,435	145,330	147,602
San Jose	6,703,139	6,232,538	6,121,920	5,869,984	6,387,930
San Mateo	271,349	261,626	192,935	167,718	171,579
Santa Clara	3,584,935	3,874,429	2,798,244	2,968,605	3,073,899
Santa Cruz	563,872	507,352	448,222	396,416	370,601
Saratoga	37,919	35,363	36,996	33,155	35,279
Sunnyvale	2,342,758	1,966,390	1,447,797	1,435,468	1,465,715
Watsonville	397,372	390,274	424,033	382,181	380,888
Shasta					
Redding	112,027	95,164	65,819	99,069	107,156
Stockton					
Ceres	0	0	11,131	7,082	9,374
Lodi	762,854	592,335	577,101	523,856	665,763
Manteca	15,166	20,580	21,746	32,186	38,478
Modesto	1,635,502	1,502,391	1,490,099	1,340,666	1,468,287
Stockton	4,679,168	4,426,444	3,508,288	2,490,341	3,530,308
Tracy	1,027,751	994,198	1,025,229	1,083,829	1,143,918
Turlock	443,253	281,120	207,623	306,113	346,223
Total Sales in Communities of 10,000 Population and Over	113,702,068	109,740,587	65,048,222	57,617,977	69,813,186
Sales in Communities of Less Than 10,000 Population	202,097,356	74,520,540	97,480,930	81,357,214	116,351,750
Total	315,799,424	284,261,131	162,529,152	138,975,191	186,164,937

Source: Annual Reports to the California Public Utilities Commission, 1975-1979, Pacific Gas and Electric Company.

† : The sharp decrease in industrial sales from 1976 to 1977 is due to a reclassification of industrial establishments into the commercial sector.

†† : See Table C-2

TABLE C-9

Population, Acreage, Distribution Plant, and Main Mileage
Pacific Gas and Electric Company

Community	Population	Total Acreage	Plant in Service ($) End of 1979	Plant in Service ($) End of 1978	Miles of Distribution End of 1979	Miles of Distribution End of 197
Coast Valleys						
Monterey	26,302	5,056	4,175,024	4,020,736	104.05	104.10
Pacific Grove	13,505	1,728	2,202,007	2,200,086	55.38	55.38
Salinas	58,896	8,512	7,965,727	7,453,037	203.54	200.26
Seaside	35,935	5,760	2,460,646	2,367,341	71.26	71.26
Colgate						
Yuba City	13,986	2,240	2,731,675	2,548,083	58.90	55.83
De Sabla						
Chico	19,580	7,040	4,510,462	4,286,338	88.96	86.47
Drum						
Roseville	17,895	17,856	4,202,708	3,658,965	95.65	89.72
East Bay						
Alameda	70,968	6,400	5,671,343	5,218,047	141.34	140.88
Albany	14,674	1,088	1,423,307	1,372,221	36.63	36.64
Antioch	28,060	4,736	4,896,329	4,485,517	123.90	114.69
Berkeley	116,716	6,784	11,008,896	10,720,852	289.30	291.09
Concord	85,164	16,512	12,666,516	11,755,759	305.75	296.83
El Cerrito	25,190	2,944	3,089,513	2,934,513	75.91	75.83
Fremont	100,869	53,952	15,957,133	14,727,645	345.91	325.89
Hayward	93,058	24,256	10,891,569	10,074,061	271.70	264.60
Lafayette	20,484	7,936	4,526,570	4,307,325	107.49	103.64
Livermore	37,703	7,616	6,670,122	6,518,475	160.22	159.98
Martinez	16,506	4,544	3,468,822	3,165,176	84.17	77.37
Moraga	14,205	4,864	2,358,782	2,254,939	58.61	58.01
Newark	27,153	5,376	4,293,728	4,008,813	80.61	78.13
Oakland	361,561	34,176	39,045,685	37,855,251	1,010.07	1,012.78

TABLE C-9

Population, Acreage, Distribution Plant, and Main Mileage
Pacific Gas and Electric Company (Continued)

Community	Population	Total Acreage	Plant in Service ($) End of 1979	Plant in Service ($) End of 1978	Miles of Distribution Main End of 1979	Miles of Distribution Main End of 1978
East Bay (cont.)						
Piedmont	10,917	1,280	1,761,128	1,721,702	47.01	47.26
Pinhole	15,850	2,240	1,882,259	1,811,980	41.50	41.30
Pittsburg	20,651	5,376	4,470,213	4,034,047	102.99	96.57
Pleasant Hill	24,610	3,712	3,989,000	3,724,217	94.59	91.27
Pleasanton	18,328	8,128	4,531,821	4,294,458	115.39	114.38
Richmond	79,043	20,544	9,747,754	9,304,423	235.25	233.02
San Leandro	68,698	8,128	8,330,034	7,938,850	199.57	197.22
San Pablo	21,461	1,600	1,872,542	1,797,660	42.94	42.91
Union City	14,724	9,408	4,430,570	4,233,963	97.93	95.13
Walnut Creek	39,844	9,408	7,337,723	6,735,424	148.32	140.31
Humboldt						
Arcata	8,985	4,416	1,946,950	1,847,531	46.31	45.41
Eureka	24,337	5,248	4,851,487	4,659,587	120.03	120.27
North Bay						
Benicia	8,783	1,984	2,459,054	2,217,344	56.08	54.18
Larkspur	10,487	2,112	1,450,364	1,376,825	36.12	35.00
Mill Valley	12,942	3,008	2,543,235	2,452,401	58.46	58.36
Napa	35,978	8,384	7,441,942	7,031,282	187.95	183.93
Novato	31,006	13,120	5,259,909	4,603,482	123.63	118.48
Petaluma	24,870	4,800	4,537,520	4,220,877	108.45	102.39
Rohnert Park	6,133	3,584	2,017,777	1,737,814	51.59	44.89
San Anselmo	13,031	1,728	1,871,746	1,803,798	46.45	46.55
San Rafael	38,977	9,152	6,727,702	6,454,637	173.64	173.45
Santa Rosa	50,006	12,736	12,675,490	11,646,974	300.09	279.77
Ukiah	10,095	2,432	1,850,657	1,747,789	42.49	39.83
Vallejo	66,733	9,728	9,392,154	8,465,803	228.85	217.46
Sacramento						
Davis	23,488	3,648	4,025,947	3,726,489	96.04	94.07
Fairfield	44,146	9,856	6,866,836	6,172,392	154.00	144.18
Sacramento	254,413	60,032	42,988,841	39,249,469	969.70	935.07

TABLE C-9

Population, Acreage, Distribution Plant, and Main Mileage
Pacific Gas and Electric Company (Continued)

Community	Population	Total Acreage	Plant in Service ($) End of 1979	Plant in Service ($) End of 1978	Miles of Distribution M[ains] End of 1979	Miles of Distribution M[ains] End of 1978
Sacramento (cont.)						
Vacaville	21,690	5,824	5,831,640	5,256,693	134.73	126.35
Woodland	20,677	3,200	4,109,167	3,926,003	99.31	98.48
San Francisco						
Daly City	66,922	4,416	6,038,305	5,775,647	141.39	141.14
Millbrae	20,781	2,112	2,182,510	2,067,347	53.61	53.61
Pacifica	36,020	8,064	3,690,571	3,553,121	95.29	95.26
San Bruno	36,254	3,584	3,916,183	3,768,717	98.19	98.16
San Francisco	715,674	29,056	47,871,683	46,203,472	1,194.53	1,194.00
South San Francisco	46,646	6,080	5,078,464	4,841,329	120.57	120.01
San Joaquin						
Atwater	11,640	2,048	2,192,541	1,983,689	46.81	42.93
Bakersfield	69,515	16,576	14,185,068	12,645,350	331.09	313.56
Clovis	13,856	2,240	4,513,111	3,602,693	88.73	77.55
Fresno	165,972	26,752	32,377,960	29,261,120	787.42	762.62
Los Banos	9,188	3,456	1,721,398	1,580,220	41.32	39.27
Madera	16,044	4,160	3,269,199	2,999,765	77.47	72.87
Merced	22,670	4,800	5,109,513	4,802,144	123.25	120.87
Ridgecrest	7,629	4,992	2,457,771	2,304,763	63.87	59.76
Sanger	10,008	1,664	1,770,763	1,580,025	38.86	37.99
San Jose						
Belmont	23,667	2,944	2,855,766	2,746,744	68.68	67.85
Burlingame	27,320	2,944	3,134,299	3,020,651	79.72	79.62
Campbell	24,770	2,176	3,064,268	2,911,702	73.18	72.13
Cupertino	18,216	4,864	4,451,365	3,142,260	77.37	75.11
Foster City	9,327	2,368	2,313,421	2,243,814	57.08	56.08
Gilroy	12,665	3,136	3,004,437	2,732,420	62.12	56.93
Los Altos	24,956	3,648	4,637,585	4,449,265	112.03	111.47
Los Gatos	23,735	5,632	4,478,477	3,909,206	101.19	99.82
Menlo Park	26,734	7,744	3,788,853	3,523,198	74.91	74.84
Milpitas	27,149	5,952	3,618,948	3,241,235	87.08	83.42

TABLE C-9

Population, Acreage, Distribution Plant, and Main Mileage
Pacific Gas and Electric Company (Continued)

Community	Population	Total Acreage	Plant in Service ($)		Miles of Distribution Main	
			End of 1979	End of 1978	End of 1979	End of 1978
San Jose (cont.)						
Mountain View	51,092	6,976	2,942,741	2,764,623	160.87	157.92
Morgan Hill	6,485	5,120	6,283,321	5,943,479	64.50	62.95
Redwood City	55,686	13,120	6,118,190	5,867,521	147.83	145.84
San Carlos	25,924	2,944	3,685,398	3,522,431	84.10	83.54
San Jose	445,779	87,168	67,035,089	64,021,151	1,677.72	1,642.77
San Mateo	78.991	7,232	9,023,296	8,676,796	223.99	223.79
Santa Clara	87,717	10,560	10,105,598	9,529,975	250.71	248.02
Santa Cruz	32,076	7,808	5,762,667	5,484,102	160.14	158.15
Saratoga	27,110	7,808	5,733,416	5,497,325	133.59	132.59
Sunnyvale	95,408	13,696	11,031,126	10,546,577	275.51	273.58
Watsonville	14,569	2,624	2,669,546	2,505,061	64.58	63.14
Shasta						
Redding	16,659	9,728	6,964,861	6,600,799	171.59	166.58
Stockton						
Ceres	6,029	1,920	2,401,358	2,033,588	50.49	43.39
Lodi	28,691	4,544	5,461,647	5,203,469	141.05	135.05
Manteca	13,845	1,920	3,301,411	2,985,790	80.06	74.14
Modesta	61,712	6,080	16,265,111	15,222,248	370.49	355.43
Stockton	107,644	19,136	19,271,810	18,007,242	478.80	458.38
Tracy	14,724	3,712	2,626,873	2,413,790	65.84	63.58
Turlock	13,992	2,944	4,315,208	4,009,390	95.61	90.25

Source: Pacific Gas and Electric Company.

Table C-10

Average Degree-Days for the Period 1941-1970 - Meteorological Stations in the Pacific Gas and Electric Company's Service Area

Meter. Station	Jan.	Feb.	Mar.	Apr.	May.	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total Annual	Peak Month	Load Factor
COAST VALLEYS DIVISION															
Salinas	465	364	372	296	214	139	102	96	72	136	275	428	2959	465	0.53
Santa Maria	450	364	378	303	245	167	112	102	94	159	270	409	3053	450	0.56
Average	457	364	375	300	229	153	107	99	83	148	272	419	3006	457	0.55
COLGATE DIVISION															
Marysville	605	406	335	186	58	9	0	0	0	76	333	577	2585	605	0.35
DE SABLA DIVISION															
Red Bluff	614	420	366	218	64	8	0	0	0	82	339	577	2688	614	0.36
Marysville	605	406	335	186	58	9	0	0	0	76	333	577	2585	605	0.35
Average	609	413	351	202	61	8	0	0	0	79	336	577	2636	609	0.36
DRUM DIVISION															
Sacramento	617	426	372	227	120	20	0	0	5	101	360	595	2843	617	0.38
EAST BAY DIVISION															
Oakland	508	367	350	270	193	114	80	74	59	135	291	468	2909	508	0.48
HUMBOLDT DIVISION															
Eureka	549	465	518	459	388	294	270	248	252	329	399	508	4679	549	0.71
NORTH BAY DIVISION															
Santa Rosa	586	420	406	289	171	78	20	22	33	134	354	552	3065	586	0.43
Ukiah	589	426	412	285	141	47	0	7	12	131	369	558	2977	589	0.42
Average	587	423	409	287	156	63	10	14	23	132	362	555	3021	587	0.43
SACRAMENTO DIVISION															
Sacramento	617	426	372	227	120	20	0	0	5	101	360	595	2843	617	0.38
SAN FRANCISCO DIVISION															
S/F City	437	325	332	291	257	194	202	177	102	127	233	403	3080	437	0.59
S/F Airport	518	386	372	291	210	120	93	84	66	137	291	474	3042	518	0.49
Average	477	356	352	291	233	157	148	130	84	132	262	439	3061	477	0.53
SAN JOAQUIN DIVISION															
Fresno	611	423	344	182	51	9	0	0	0	90	345	595	2650	611	0.36
Bakersfield	543	353	266	140	22	0	0	0	0	55	276	530	2185	543	0.33
Average	577	388	305	161	36	5	0	0	0	72	311	562	2417	577	0.35
SAN JOSE DIVISION															
San Jose	481	350	322	228	123	50	12	15	13	90	276	456	2416	481	0.42
SHASTA DIVISION															
Red Bluff	614	420	366	218	64	8	0	0	0	82	339	577	2688	614	0.36
STOCKTON DIVISION															
Stockton	632	445	381	214	67	15	0	0	0	88	363	601	2806	632	0.37

Source: Monthly Normals of Temperature, Precipitation, and Heating and Cooling Degree-Days 1941-1970 Climatography of the United States No. 81-California. U.S. Department of Commerce, National Oceanic and Atmospheric Administration, Environmental Data Service.

APPENDIX D

NATIONAL FUEL GAS DISTRIBUTION CORPORATION DATA

The purpose of this appendix is to present the community-level data used in the econometric analysis of the National Fuel Gas Distribution Corporation, as reported in chapter 3. These data correspond to the year 1979 and cover 173 communities. The residential, commercial, industrial, and public authorities gas sales and numbers of customers are presented in table D-1. The distribution plant in service, disaggregated into various categories, the total plant in service, and the population and acreage are indicated in table D-2.

Table D-1: Gas Sales and Average Numbers of Customers - 1979 - National Fuel Gas Distribution Corporation

Community	Gas Sales (MCF)					Average Number of Customers				
	Residential	Commercial	Industrial	Public Authorities	Total	Residential	Commercial	Industrial	Public Authorities	Total
1. Alfred, T.	43995	12337	5028	4591	65951	287	27	8	5	327
2. Alfred, V.	63749	113694	0	169089	346532	381	44	0	20	445
3. Alma, T.	30309	747	7314	3820	42190	242	7	13	7	269
4. Almond T.	27511	780	0	21399	49690	218	8	0	4	230
5. Almond, V.	30932	4443	0	386	35761	200	12	0	2	214
6. Amity, T.	17863	11422	0	380	29665	151	6	0	2	159
7. Andover, T.	90410	6947	954	12902	111213	45	33	1	9	637
8. Angelica, T.	5684	639	0	0	6323	327	5	0	0	50
9. Angellica, V.	47658	8258	0	6882	62798	324	23	0	8	358
10. Belfast, T.	49353	6485	0	8579	64417	381	31	0	7	362
11. Belmont, V.	61250	11531	0	21203	93984	803	45	0	16	442
12. Bolivar, T.	124874	16215	4815	9744	155648	256	62	9	11	885
13. Caneadea, T.	54720	33577	0	2960	91257	51	12	0	5	273
14. Centerville, T.	7307	440	0	113	8860	227	3	0	2	56
15. Cura, T.	33292	4193	192814	228	230527	623	6	2	2	237
16. Cuba, V.	103752	16760	57269	29803	207584	190	53	7	10	693
17. Friendship, T.	25985	12364	0	147	38496	386	5	0	1	196
18. Friendship, V.	67478	6323	50739	14834	139374	261	23	1	15	425
19. Genesee, T.	32749	4778	1967	815	40309	276	11	4	6	282
20. Independence, T.	34998	2553	2305	5372	45228	532	17	3	7	303
21. Scio, T.	77930	4738	5528	8410	96606	982	26	6	5	569
22. Wellsville, T.	134871	33822	154279	16632	339604	1913	60	6	6	1054
23. Wellsville, V.	321432	79066	25824	44886	471208	427	180	7	18	2118
24. Willing, T.	56095	1920	1	681	58697	241	14	2	3	446
25. Wirt, T.	38420	464	300	7427	46611	0	3	21	8	273
26. Carrollton, T.	0	430	0	0	430	4	2	0	0	2
27. Dayton, T.	486	0	0	0	486	405	0	0	0	4
28. Delevan, V.	60852	6199	0	14458	81509	141	20	0	9	434
29. East Otto, T.	20010	1255	0	1426	22691	642	5	0	4	150
30. Ellicottville, R.	95368	24326	31808	11022	162524	13	53	4	8	707
31. Farmersville, T.	1842	1392	20	1095	4349	211	2	0	1	16
32. Franksville, T.	30711	966	95	52	31824	160	5	1	1	218

Table D-1: Gas Sales and Average Numbers of Customers - 1979 - National Fuel Gas Distribution Corporation (Continued)

Community	Gas Sales (MCF)					Average Number of Customers				
	Residential	Commercial	Industrial	Public Authorities	Total	Residential	Commercial	Industrial	Public Authorities	Total
33. Freedon, T.	22310	325	0	481	23116	160	1	-20	1	142
34. Govanda, V.	120373	42091	19906	11623	193993	804	78	4	8	894
35. Great Valley, T.	54672	3535	23557	9263	91027	420	13	3	4	440
36. Little Valley, T.	92208	12715	20796	22060	147779	593	37	4	24	658
37. Machias T.	72181	7756	0	14048	93985	643	22	0	6	671
38. Mansfield, T.	3061	0	0	848	3909	18	0	0	1	19
39. New Albion, T.	92360	9937	35793	14152	152242	588	36	3	12	639
40. Olean, C.	266434	82588	209372	14590	572984	1653	74	2	15	1744
41. Olean, T.	38325	16829	24505	7157	86816	263	27	1	1	292
42. Otto, T.	21134	2326	2562	1013	27035	126	9	2	2	139
43. Perrysburg, V.	21486	797	0	51291	73574	143	4	0	4	151
44. Perrysburg, T.	42441	1308	0	14380	58129	288	6	0	2	296
45. Persia, T.	11125	777	0	968	12870	83	3	0	2	88
46. Portville, T.	91457	37172	0	22894	151523	622	43	0	3	668
47. Portville, V.	63364	16247	55672	3610	138893	369	35	1	9	414
48. Salam Anca, C.	397434	88971	38416	46761	571582	2412	145	6	15	2578
49. Salam Anca, T.	27025	8	0	6430	33463	192	0	0	2	194
50. Yorkshire, T.	53674	12910	265	290	67139	418	28	1	3	450
51. Dunkirk, T.	83583	27750	310583	28307	450223	511	49	5	5	570
52. Arkwright, T.	8980	92	0	755	9827	64	1	0	2	67
53. Brocton, V.	80817	17424	42061	25631	165933	512	32	1	5	550
54. Cassadaga, V.	56627	8750	1511	3747	70635	361	26	1	5	393
55. Chautaliquat, T.	88766	9534	0	20376	118676	764	26	0	1	791
56. Dunkirk, C.	881268	193756	1710336	87354	2872714	5454	342	16	39	5851
57. Forestville, V.	48445	5654	953	14760	69812	305	22	2	4	333
58. Fredonia, V.	473722	80751	156423	272723	983619	2905	163	2	16	3086
59. Hanover, T.	156842	36219	-3600	19023	208484	1263	54	0	9	1326
60. Mayville, V.	96243	24811	9623	35849	166526	583	52	1	11	647
61. Pomfret, T.	139309	44496	572	34637	219014	939	51	1	7	998
62. Portland, T.	87544	3981	0	1332	92857	690	12	0	4	706
63. Ripley, T.	86257	14434	11495	10166	122352	522	26	2	5	555
64. Sheridan, T.	127164	21948	0	1697	150809	794	49	0	4	847
65. Sherman, T.	46970	10286	0	10954	68210	250	29	0	7	286
66. Silvercreek, V.	182368	49520	23246	7438	262572	1150	109	2	8	1269
67. Stockton, T.	23280	622	0	3183	27085	145	6	0	5	156
68. Villenova, T.	194	0	0	0	194	3	0	0	0	3
69. Westfield, T.	35849	9441	676	0	45966	281	21	1	0	303

Table D-1: Gas Sales and Average Numbers of Customers - 1979 - National Fuel Gas Distribution Corporation (Continued)

Community	Gas Sales (MCF)					Average Number of Customers				
	Residential	Commercial	Industrial	Public Authorities	Total	Residential	Commercial	Industrial	Public Authorities	Total
70. Westfield, V.	220369	45465	191087	17009	473930	1278	101	6	12	1397
71. Akron, V.	165129	26326	23119	9216	223790	1099	70	5	14	1188
72. Alden, T.	254511	17162	2974	11655	286302	1630	34	-1	11	1674
73. Alden, V.	114602	15283	2181	1835	133901	751	40	1	2	794
74. Amherst, T.	4938904	903203	15334	267305	6124746	31132	974	7	64	32177
75. Angola, V.	127335	13178	35133	4015	179661	814	47	1	9	871
76. Aurora, T.	386342	30733	0	28509	445584	2198	51	0	13	2262
77. Blasdell, V.	162121	39162	213405	16860	431548	1126	49	2	8	1185
78. Boston, T.	328513	21532	3149	5929	359123	2122	57	1	7	2187
79. Brant, T.	89331	10109	0	4591	104031	596	28	0	10	634
80. Buffalo, C.	22747232	6125422	6273705	1895977	37042336	125398	5273	179	367	131217
81. Cheektomiaga,T.	4444263	1358704	495461	236198	6534626	30772	1040	43	68	31923
82. Clarence, T.	886749	265538	63593	63134	1279014	5146	365	3	25	5539
83. Colden, T.	118232	16571	-200	5818	140421	779	32	0	9	820
84. Collins, T.	155050	13450	97825	16321	282646	993	40	2	12	1047
85. Concord, T.	92473	10828	0	7348	110649	624	36	0	5	665
86. Depew, V.	923469	124012	705217	43938	1796636	6347	192	21	22	6582
87. E. Aurdra, V.	391445	106427	27893	46162	571927	2261	210	2	22	2495
88. Eden, T.	297467	60856	1924	25181	385428	1996	100	4	8	2108
89. Elma, T.	566754	47978	14115	30775	659622	3211	100	3	16	3330
90. Evans, T.	655329	60798	0	46114	762241	4779	143	0	21	4943
91. Farmham,V.	25724	1287	0	5043	32054	144	1	3	6	154
92. Gowanda, V.	55167	15011	3718	4796	78692	363	33	1	5	402
93. GrandIsland,T.	555679	130879	73065	44074	803697	4004	99	4	13	4120
94. Hamburg, T.	1693620	383674	440151	148114	2665559	11244	448	7	52	11751
95. Hamburg, V.	457529	97598	535	35681	591343	2743	216	1	20	2980
96. Holland, T.	142348	11980	30409	18153	202890	910	33	3	7	953
97. Kenmore, V.	859107	124724	0	15769	999600	6546	265	0	19	6830
98. Lackawanna, V.	1146913	276269	9059655	59411	10542248	8098	251	7	26	8382
99. Lancaster, V.	673546	75472	77491	51084	877593	4330	115	10	19	4474
100. Lancaster, T.	516654	63185	73178	45100	698117	3239	83	3	15	3340
101. Marilla, T.	166418	2589	0	5172	174179	1145	10	0	5	1160
102. Newstead, T.	59444	15501	48576	0	123521	368	38	3	0	409
103. Northcollins,T.	53730	6370	-2140	7223	65183	333	23	0	3	359
104. Northcollins,V.	76623	19079	6224	2180	104106	490	39	1	5	535
105. OrchardPark, V.	226065	38694	0	28178	292937	1198	78	0	9	1285
106. OrchardPark, T.	923661	118403	0	62355	1104419	5529	173	0	27	5729

Table D-1: Gas Sales and Average Numbers of Customers - 1979 - National Fuel Gas Distribution Corporation (Continued)

Community	Gas Sales (MCF)					Average Number of Customers				
	Residential	Commercial	Industrial	Public Authorities	Total	Residential	Commercial	Industrial	Public Authorities	Total
107. Sardinia, T.	71351	9950	102313	3835	187449	441	30	2	7	480
108. Sldan, V.	257722	85687	50	9981	353440	1759	36	0	5	1800
109. Springville, V.	219925	70782	32572	32926	356205	1351	119	4	16	1490
110. Tonawanda, C.	768577	188784	902775	54336	1914472	5709	222	27	29	5987
111. Tonawanda, T.	3015905	726010	3245150	152891	7139956	23166	845	49	64	24124
112. Wales, T.	73274	8684	0	5889	87847	527	19	0	6	552
113. West Seneca, T.	2361327	318729	89856	146178	2916090	15156	465	4	57	15682
114. Williamsville, V.	333025	87513	0	6160	426698	2206	126	0	6	2338
115. Alexander, T.	52068	5746	11093	24183	93090	321	18	1	6	346
116. Batavia, C.	871612	255245	415142	142997	1684996	5191	311	20	38	5560
117. Batavia, T.	167624	67119	0	6821	241564	1121	102	10	5	1238
118. Bethany, T.	23449	1726	-60	0	25115	145	4	0	0	149
119. Corfu, V.	30472	11825	0	345	42642	177	25	0	2	204
120. Darien, T.	50021	7865	0	2098	59984	320	21	0	3	344
121. Elba, T.	32453	5538	0	9853	47844	231	23	0	6	260
122. Pavilion, T.	17104	910	0	0	18014	110	5	0	0	115
123. Pembroke, T.	85360	9613	19173	6719	120865	576	28	1	7	612
124. Oakfield, T.	118110	23789	0	3345	145244	743	43	20	5	811
125. Stafford, T.	3136	809	0	0	3945	25	3	0	0	28
126. Avon, T.	141	0	0	0	141	1	0	0	0	1
127. Lima, T.	98759	40771	138290	6142	283962	556	64	2	9	631
128. Honeoye Falls,V.	121344	39911	20466	3659	185380	725	74	4	7	810
129. Mendon, T.	1686	0	0	0	1686	9	0	0	0	9
130. Lewiston, T.	394315	215732	31256	97706	739009	2548	59	2	11	2620
131. Cambria, T.	36761	4744	0	39545	81050	271	8	0	1	280
132. Lewiston, V.	94762	49857	0	6049	150668	768	93	0	3	864
133. NiagraFalls,V.	2714015	830291	4184084	129100	7857490	19343	1177	32	80	20632
134. Niagra, T.	303398	131113	866670	125063	1426244	2227	249	5	9	2490
135. North TonawandaC.	1410784	192793	493464	100402	2197443	10004	348	42	42	10436
136. Dorter, T.	80489	6016	0	18082	104587	535	16	0	12	563
137. Wilson, T.	16730	1391	7134	13206	38461	143	4	1	2	150
138. Wilson, V.	34407	8021	0	8577	51005	270	24	0	6	300
139. Youngstown,V.	67668	11716	0	1202	80586	552	26	0	2	580
140. Wheatfield,T.	324198	62217	158818	10456	555689	2453	120	4	7	2584
141. Bristol, T.	27773	2395	0	962	31130	170	6	0	4	180

Table D-1: Gas Sales and Average Numbers of Customers - 1979 - National Fuel Gas Distribution Corporation (Continued)

Community	Gas Sales (MCF)					Average Number of Customers				
	Residential	Commercial	Industrial	Public Authorities	Total	Residential	Commercial	Industrial	Public Authorities	Total
142. EastBloomfield,T.	60846	6775	7837	12251	87709	299	17	1	6	323
143. EastBloomfield,V.	36690	12231	0	7643	56564	212	30	0	4	246
144. WestBloomfield,T.	63147	3811	619704	1898	688560	4450	180	0	30	4660
145. Richmond,T.	2986	32525	7717	4288	47516	20	4	2	2	28
146. Arcade,V.	71651	31322	146828	2614	252415	491	61	6	5	563
147. Arcade,T.	60606	4886	21535	1284	88311	446	7	4	4	461
148. Attica,V.	152933	31240	0	9243	193416	853	65	0	[illegible]	927
149. Attica,T.	13735	11467	61491	39688	126381	78	3	3	6	90
150. Bennington,T.	56342	2121	1189	1177	60829	339	8	1	2	350
151. Castile,V.	73232	13399	0	5615	92246	401	33	0	7	441
152. Castile,T.	5863	0	0	953	6816	30	1	1	0	32
153. Eagle,T.	25823	2637	0	3444	31904	157	9	0	4	170
154. Gainsville,T.	27747	2108	440	19554	49849	157	9	0	4	170
155. GeneseeFalls,T.	476	0	0	0	476	2	0	0	0	2
156. Java,T.	48246	6507	0	1000	55753	302	28	0	4	334
157. Middlebury,T.	13106	2768	0	800	16674	145	9	1	4	159
158. Orangeville,T.	10351	126	0	0	10477	80	1	0	0	89
159. Pike,T.	6829	93	404	0	7326	40	1	0	0	41
160. Sheldon,T.	794910	109080	4140	29590	937720	710	10	0	10	730
161. SilverSprings,V.	46430	4402	47807	3405	102044	498	35	1	9	543
162. Wyoming,V.	29661	5288	0	3944	38893	278	15	2	4	299
163. Covington,T.	5863	0	0	0	5863	36	0	0	0	36
164. Canisted,T.	15092	843	0	0	15935	107	3	0	0	110
165. Canisted,V.	149641	16080	2161	16279	184161	921	70	1	12	1004
166. Fremont,T.	11857	130	0	1142	13129	79	2	0	2	83
167. Greenwood,T.	29207	1736	0	6316	37259	200	16	1	6	223
168. Hornell,C.	655899	184993	121860	61915	1024667	3716	259	10	19	4004
169. Hornellsville,T.	134897	47447	6252	17101	205697	942	93	3	12	1050
170. Holiard,T.	11063	702	-80	419	12104	62	5	0	1	68
171. NorthHornell,V.	52610	20215	0	2202	75027	309	8	0	5	322
172. WestUnion,T.	6265	305	0	426	6996	39	2	0	2	43
173. Clarksville,T.	25502	745	0	1066	27313	183	1	0	2	186

Source: National Fuel Gas Distribution Corporation.

Table D-2: Distribution Plant in Service, Total Plant in Service, Population and Land Area - 1979 - National Fuel Gas Distribution Corporation

	Community	Land & Land Rights	Structures and Improvements	Mains	Measuring and Regulating Stations	Services	Total	Total Plant in Service ($)	Population	Land Area (acres)
1.	Alfred, T.	0	0	125451	332	37279	163062	634809	--	--
2.	Alfred, V.	0	256	255811	5727	58414	320208	389534	3804	768
3.	Alma, T.	0	13	106677	26	24175	130891	216610	--	--
4.	Almond T.	0	0	110147	0	16211	126358	295753	--	--
5.	Almond, V.	100	755	38233	1652	12909	53650	69795	--	--
6.	Amity, T.	168	3583	89864	4018	23541	121174	142507	--	--
7.	Andover, T.	0	0	172937	889	24414	198240	577491	--	--
8.	Angelica, T.	0	374	140902	197	8076	149549	162227	--	--
9.	Angellica, V.	202	1201	137624	3055	42466	184548	222885	--	--
10.	Belfast, T.	654	631	84103	8140	30523	124051	132139	--	--
11.	Belmont, V.	1095	3526	143068	11952	52324	211964	219062	--	--
12.	Bolivar, T.	0	0	175006	183	52585	227774	338130	--	--
13.	Caneadea, T.	0	0	176769	0	23549	200319	243517	--	--
14.	Centerville, T.	0	0	25850	0	6095	31945	35216	--	--
15.	Cura, T.	0	0	44106	0	24753	68859	152875	--	--
16.	Cuba, V.	1032	1041	119309	6847	76154	204383	290405	--	--
17.	Friendship, T.	464	3489	400474	11883	64339	480649	507747	--	--
18.	Friendship, V.	0	0	0	0	64339	43443	69031	--	--
19.	Genesee, T.	0	512	237381	8518	3865	250277	362856	--	--
20.	Independence, T.	0	299	220514	0	51722	272535	364952	--	--
21.	Scio, T.	0	359	365278	4708	76163	446508	616002	--	--
22.	Wellsville, T.	0	1144	641997	4168	128982	776290	1503070	--	--
23.	Wellsville, V.	505	1899	499675	20693	202296	725068	1022977	--	1408
24.	Willing, T.	0	0	264224	0	49235	313459	372061	5815	--
25.	Wirt, T.	0	27	188246	8339	70642	267253	407134	--	--
26.	Carrollton, T.	0	0	0	0	96	96	311	--	--
27.	Dayton, T.	0	0	0	0	76	76	360	--	--
28.	Delevan, V.	307	887	99025	6035	19281	125535	168588	--	--
29.	East Otto, T.	244	563	99104	1093	10626	111630	116333	--	--
30.	Ellicottville, R.	386	782	186026	4825	25464	217484	317936	--	--
31.	Farmersville, T.	0	0	16432	2313	3436	22181	34050	--	--
32.	Franksville, T.	0	0	91902	1399	19207	112508	199634	--	--

Table D-2: Distribution Plant in Service, Total Plant in Service, Population and Land Area - 1979 - National Fuel Gas Distribution Corporation (Continued)

Community	Land & Land Rights	Structures and Improvements	Mains	Measuring and Regulating Stations	Services	Total	Total Plant in Service ($)	Population	Land Area (acres)
33. Freedon, T.	0	0	53514	0	13182	66696	77499	--	--
34. Govanda, V.	0	0	116507	3661	28688	148856	205375	3110	1024
35. Great Valley, T.	432	865	228364	3362	35767	268790	289428	--	--
36. Little Valley, T.	0	0	125655	0	11515	137170	169323	--	--
37. Machias T.	321	876	191853	21084	53352	267487	367747	--	--
38. Mansfield, T.	0	0	17129	0	2503	19632	49239	--	--
39. New Albion, T.	0	709	133044	1980	12946	148679	161386	--	--
40. Olean, C.	1623	14777	441010	39560	136617	633586	870345	19169	3968
41. Olean, T.	0	0	228843	9288	43562	281692	301023	--	--
42. Otto, T.	395	1399	32684	1455	9158	45090	93330	--	--
43. Perrysburg, V.	111	1376	48451	6068	9633	65638	413989	--	--
44. Perrysburg, T.	963	2711	225642	8494	29286	267097	79870	--	--
45. Persia, T.	0	0	28138	0	6090	34228	38418	--	--
46. Portville, T.	2836	1660	410544	28977	108981	552998	596324	--	--
47. Portville, V.	648	1330	86310	9634	38280	136200	145323	--	--
48. Salam Anca, C.	1844	8605	773674	22381	102130	908633	1110103	7877	1920
49. Salam Anca, T.	273	0	100551	0	19512	120336	139316	--	--
50. Yorkshire, T.	347	808	222206	7608	29035	260005	383295	--	--
51. Dunkirk, T.	350	1292	419630	8968	124390	554631	918404	--	--
52. Arkwright, T.	0	0	58627	0	5638	64265	2002692	--	--
53. Brocton, V.	789	3305	128540	9839	57055	199527	226821	--	--
54. Cassadaga, V.	0	0	141790	2934	42312	187037	201078	--	--
55. Chautaliquat, T.	0	103	464383	8934	135905	609325	1886405	--	--
56. Dunkirk, C.	4242	27003	863577	46259	331435	272516	1727435	16855	2944
57. Forestville, V.	203	0	75346	2559	30643	108751	120182	--	--
58. Fredonia, V.	3741	7051	702778	31004	206294	950867	1238412	10326	3584
59. Hanover, T.	830	125	504137	21980	173010	700081	1992613	--	--
60. Mayville, V.	787	77	221903	5366	41022	269154	302361	--	--
61. Pomfret, T.	0	76	705147	8979	125933	840136	2173149	--	--
62. Portland, T.	0	14955	364760	38155	81332	499203	1580543	--	--
63. Ripley, T.	0	0	356890	6457	55685	419032	1524724	--	--
64. Sheridan, T.	0	0	514148	5392	87668	607208	1043885	--	--
65. Sherman, T.	0	0	21532	0	2475	24007	434923	--	--
66. Silvercreek, V.	2265	2811	211330	10615	76436	303457	346782	3182	768
67. Stockton, T.	0	0	50716	2020	11379	64116	1496115	--	--
68. Villenova, T.	0	0	2524	0	0	2524	2662	--	--
69. Westfield, T.	0	14663	248421	33562	33844	330450	659590	--	--

Table D-2: Distribution Plant in Service, Total Plant in Service, Population and Land Area - 1979 - National Fuel Gas Distribution Corporation (Continued)

Community	Land & Land Rights	Structures and	Mains	Measuring and Regulating Stations	Services	Total	Total Plant in Service ($)	Population	Land Area (acres)
70. Westfield, V.	5046	2862	258637	18946	74262	359753	423313	3651	2432
71. Akron, V.	2123	5052	361374	12960	79251	460761	497071	2863	1152
72. Alden, T.	1292	0	770129	3469	186227	962017	1507019	--	--
73. Alden, V.	49	171	283941	5888	33179	323228	350445	2651	1728
74. Amherst, T.	32108	61964	12884804	219758	2131351	387507	17631152	--	--
75. Angola, V.	0	340	261019	2982	55520	319861	401149	2676	768
76. Aurora, T.	876	3995	1363211	20117	210764	598963	1927217	--	--
77. Blasdell, V.	559	1950	279417	5586	69889	357401	494340	3910	704
78. Boston, T.	1191	2351	1161453	20158	214850	403197	1682971	--	--
79. Brant, T.	50	0	360113	5588	59714	425466	563524	--	--
80. Buffalo, C.	142009	337823	19703168	625097	4224131	032256	29599312	462768	26432
81. Cheektomiaga,T.	33889	54602	10299659	155315	1687741	253925	13714349	--	--
82. Clarence, T.	3103	2574	2555144	26435	572942	161992	3799657	--	--
83. Colden, T.	4754	160	603550	14987	87148	710598	959340	--	--
84. Collins, T.	0	435	537193	13426	75202	626256	1723857	--	--
85. Concord, T.	355	5546	396140	23184	62232	319832	704487	--	--
86. Depew, V.	7320	10826	2465058	48981	405589	937774	3196719	22158	3264
87. E. Aurdra, V.	2187	5591	697982	18679	114674	839114	1061313	7033	1536
88. Eden, T.	270	0	1046712	27970	232420	307371	2364314	2962	2688
89. Elma, T.	3044	10484	1863065	42604	395202	314398	2572219	--	--
90. Evans, T.	7451	9890	2367283	47204	609516	041345	3668229	--	--
91. Farmham,V.	50	741	88764	3308	16354	109216	120917	--	--
92. Gowanda, V.	718	3337	120995	5301	22374	152725	169516	--	--
93. GrandIsland,T.	15819	0	2472358	11994	556340	3060288	3586423	--	--
94. Hamburg, T.	11582	38751	4844954	105923	1110081	6111292	7340337	--	--
95. Hamburg, V.	2423	12610	895612	27265	176947.	1115962	1374238	10215	1280
96. Holland, T.	328	4696	454871	39809	127378	627082	841170	--	--
97. Kenmore, V.	6059	5651	906602	24225	375055	1317592	1484836	20980	896
98. Lackawanna, V.	6912	15891	1564953	31562	376797	1996115	2569408	28657	3904
99. Lancaster, V.	6360	11468	1287297	24326	266464	1795735	1733517	13365	1728
100. Lancaster, T.	8938	5817	1957656	29969	483555	2485935	2809664	--	--
101. Marilla, T.	305	823	872604	3580	154080	1022392	1320275	--	--
102. Newstead, T.	0	0	512459	3792	51910	602160	735655	--	--
103. Northcollins,T.	50	777	268883	13412	49585	332707	893568	--	--
104. Northcollins,V.	1296	3608	177007	5343	27352	214605	241953	--	--
105. OrchardPark, V.	0	2331	467635	6944	62176	539915	607811	3732	1216
106. OrchardPark, T.	4462	8997	3474523	59045	628963	4175691	4798128	--	--

Table D-2: Distribution Plant in Service, Total Plant in Service, Population and Land Area - 1979 - National Fuel Gas Distribution Corporation (Continued)

Community	Land & Land Rights	Structures and Improvements	Mains	Measuring and Regulating Stations	Services	Total	Total Plant in Service ($)	Population	Land Area (acres)
107. Sardinia, T.	317	2712	233901	3149	35704	275783	438377	--	--
108. Sldan, V.	265	2516	228052	8457	55346	294437	317630	5216	512
109. Springville, V	501	4171	448519	10102	85993	549287	617591	4350	1856
110. Tonawanda, C.	5660	17750	2095867	36288	580832	2736698	3139413	21898	2368
111. Tonawanda, T.	48341	45065	6895106	146531	2265571	9402196	14369034	--	--
112. Wales, T.	330	2123	261295	2690	30732	297172	399675	--	--
113. West Seneca, T.	18957	34719	5812266	116379	1214780	7215106	10585303	--	--
114. Williamsville,	701	2201	361434	12551	305481	682369	612711	6835	704
115. Alexander, T.	426	0	360783	0	27847	389056	414206	--	--
116. Batavia, C.	7841	19587	1887823	55140	397005	2367397	2667457	17338	3648
117. Batavia, T.	75	0	759111	3736	114653	877575	1966051	--	--
118. Bethany, T.	0	0	76638	511	72373	89552	294560	--	--
119. Corfu, V.	0	0	133705	8857	31538	174100	330743	--	--
120. Darien, T.	0	0	257517	0	35986	293504	357172	--	--
121. Elba, T.	3404	0	154748	0	4913	163065	181029	--	--
122. Pavilion, T.	0	0	153052	0	15757	168810	261398	--	--
123. Pembroke, T.	0	0	322124	1075	60083	383281	754212	--	--
124. Oakfield, T.	0	0	78697	0	17321	96018	110995	--	--
125. Stafford, T.	0	0	10421	0	2679	13101	16056	--	--
126. Avon, T.	0	0	0	0	0	0	321812	--	--
127. Lima, T.	0	0	252642	1987	15385	270014	356731	--	--
128. Honeoye Falls,V	3710	3710	257891	14173	49225	328710	362445	--	--
129. Mendon, T.	0	0	19940	0	861	20801	22967	--	--
130. Lewiston, T.	6298	0	2234155	26377	410050	2676881	3303210	--	--
131. Cambria, T.	0	0	330593	0	28456	359049	436497	--	--
132. Lewiston, V.	490	3272	498563	9196	81059	592580	646864	3292	640
133. NiagraFalls,V.	27337	48374	7368586	120606	292513	7857417	10520194	85615	8576
134. Niagra, T.	9804	3771	1600396	50114	293426	1957512	2644928	--	--
135. North Tonawanda	20857	37766	4143348	76042	1160071	5438086	6076841	36012	6400
136. Dorter, T.	0	0	415833	0	57864	474020	585544	--	--
137. Wilson, T.	3727	0	249597	0	13440	266765	316509	--	--
138. Wilson, V.	0	0	190282	0	12013	202296	282130	--	--
139. Youngstown,V.	0	0	287302	758	72465	360525	462319	--	--
140. Wheatfield,T.	54854	0	1939863	28437	357520	1264675	2801921	--	--
141. Bristol, T.	0	0	192794	7473	16902	217169	232278	--	--

Table D-2: Distribution Plant in Service, Total Plant in Service, Population and Land Area - 1979 - National Fuel Gas Distribution Corporation (Continued)

	Land & Land Rights	Structures and Improvements	Mains	Measuring and Regulating Stations	Services	Total	Total Plant in Service ($)	Population	Land Area (acres)
142. EastBloomfield,T.	10	0	214555	0	14161	228725	246643	--	--
143. East Bloomfiled,V.	40	0	130456	3128	30488	164112	176104	--	--
144. West Bloomfield,T.	0	0	543572	4654	44221	592447	645106	--	--
145. Richmond,T.	0	0	89118	3779	1482	94379	109444	--	--
146. Arcade,V.	4977	1969	177860	18884	32024	235714	359295	--	--
147. Arcade,T.	0	0	167522	8210	20961	196693	404678	--	--
148. Attica,V.	1235	4141	366323	14125	103172	488995	543475	2911	896
149. Attica,T.	0	0	31864	0	7097	38961	43667	--	--
150. Bennington,T.	0	0	317304	2445	23372	343120	404137	--	--
151. Castile,V.	342	2131	126634	4181	23813	157100	164856	--	--
152. Castile,T.	0	0	33767	0	4747	38514	46643	--	--
153. Eagle,T.	319	809	32970	5788	9119	49005	106552	--	--
154. Gainsville,T.	0	0	42957	0	8245	51202	102492	--	--
155. GeneseeFalls,T.	0	0	0	0	219	219	47068	--	--
156. Java,T.	0	0	229355	0	26163	255518	307390	--	--
157. Middlebury,T.	0	0	93099	0	8977	102075	163965	--	--
158. Orangeville,T.	0	0	51327	0	3035	54362	62081	--	--
159. Pike,T.	0	0	14694	2397	4839	21930	93397	--	--
160. Sheldon,T.	0	0	399372	0	36201	435573	518172	--	--
161. SilverSprings,V.	434	1267	66248	1201	12277	81426	116917	--	--
162. Wyoming,V.	151	4009	45504	4704	11175	65543	73337	--	--
163. Covington,T.	0	0	13727	0	3088	16814	19168	--	--
164. Canisted,T.	285	563	58197	2575	8366	69986	102102	--	--
165. Canisted,V.	1700	1772	69178	5023	8366	238200	310255	2772	640
166. Fremont,T.	0	0	68051	0	3468	71520	79658	--	--
167. Greenwood,T.	0	351	102278	273	24864	127766	248466	--	--
168. Hornell,C.	666	4257	890836	13902	321130	1230790	1824712	12144	1664
169. Hornellsville,T.	0	530	290749	2565	63246	357090	717273	--	--
170. Holiard,T.	0	0	38210	0	1638	39848	66716	--	--
171. NorthHornell,V.	0	0	56492	0	19884	76376	102543	--	--
172. WestUnion,T.	0	0	29656	0	7926	37582	40176	--	--
173. Clarksville,T.	0	42	64985	1252	25713	91992	204110	--	--

Source: National Fuel Gas Distribution Corporation.

APPENDIX E

COMPUTER PROGRAM OF THE GUMCP MODEL

The purpose of this appendix is to present the listing of the GUMCP model developed in chapter 4. This listing depicts the MAIN program and the following subroutines: MARCOS, EVAL1, DIST, REVREQ, EVAL1, and EVAL2. The listing of the linear programming code LPCODE used in MARCOS is not presented here.

```
              C      MAIN PROGRAM
0001                 IMPLICIT REAL*8(A-H,O-Z)
0002                 COMMON /MAIN1/ A(150,200),BINV(150,150),TAB(150,200),SOL(150),
                    1  TOP(200),B(150),C(200),BOUND(200),ROW(200),COL(150),S(150),
                    2  X(200),SLACK(150),TOL(8),DUAL(150),BIG,SMALL,DETERM,OBJ
              C
0003                 COMMON /MAIN2/ LABCOL(200),LABROW(150),LABTEM(200),INFEAS,
                    1  NINTO,NOUTOF,ISTATE,MNOW,M,NCOL,N,NUMEQU,ISFEAS,ISDEGN,
                    2  ITYPE,ITERS,ITRMAX,IPRINT,ISBND,IRMAX,IRCNT,MAXM,MAXN
              C
0004                 DIMENSION DDM(12),PR(12),PC(12),PI(12),ELR(12),ELC(12),ELI(12)
0005                 DIMENSION DGMR(12),DGMC(12),DGMI(12),DGMT(12)
0006                 DIMENSION PRMCV(12,50),PCMCV(12,50),PIMCV(12,50)
0007                 DIMENSION DGMRV(12,50),DGMCV(12,50),DGMIV(12,50)
0008                 DIMENSION PRO(12),PCO(12),PIO(12)
0009                 REAL KMIN
0010                 REAL NEWPIS,NPT2,NPD
0011                 NM=12
0012                 ICASE=1
0013                 ICASE=0
0014                 PAVGM=1699.665
              C
              C      BASIC DATA
              C      *******************************************
              C
              C
              C      RMR,RMC,RMI=REIDENTIAL,COMMERCIAL,AND INDUSTRIAL GROWTH RATES
              C      ELR,ELC,ELI=RESIDENTIAL,COMMERCIAL,AND INDUSTRIAL ELASTICITIES
              C      BL,SL=BASE AND SPACE HEATING LOAD COEFFICIENTS
              C      DDM(IM) = HISTORIC AVERAGE DEGREE DAY DATA - YEAR STARTS IN APRIL
              C
              C      SUPT1=MAXIMUM ANNUAL SUPPLY OF CONSOLIDATED (MMCF)
              C      SUP2T=MAXIMUM ANNUAL SUPPLY OF PANHANDLE (MMCF)
              C      SUPWHT=MAXIMUM MONTHLY WELLHEAD SUPPLY (MMCF)
              C      SUPFLT=MAXIMUM MONTHLY FIELD LINES SUPPLY (MMCF)
              C      CC = COMMODITY CHARGE $/MMCF-1=CONSOLIDATED- 2=PANHANDLE
              C      DC = DEMAND CHARGE $/MMCF - 1=CONSOLIDATED- 2=PANHANDLE
              C      WRC = WINTER REQUIREMENT CHARGE- CONSOLIDATED
              C      KMIN=TAKE-OR-PAY PROPORTION - CASE OF PANHANDLE
              C      CWH=COST OF WELL-HEAD PURCHASES ($/MMCF)
              C      CFL=COST OF FIELD-LINE PURCHASES  ($/MMCF)
              C
              C      DPROM=MAXIMUM MONTHLY INCREMENTAL PRODUCTION CAPACITY (MMCF)
              C      COMP=GAS PRODUCTION OPERATING COST ($/MMCF)
              C      CIP=GAS PRODUCTION INVESTMENT COST ($/MMCF)
              C      SHP=MARKET GROWTH SHARE SUPPLIED BY OWN PRODUCTION
              C
              C      DSTCM=MAXIMUM INCREMENTAL STORAGE CAPACITY (MMCF)
              C      CS = STORAGE COST (O.M.R.) $/MMCF DELIVERED/WITHDRAWN
              C      CIST=STORAGE EXPANSION INVESTMENT COST ($/MMCF)
              C
              C      CIPT1=TRANSMISSION EXPANSION INVESTMENT COST ($/MMCF)
              C      COM2=OTHER OPERATING COSTS ($/MMCF)
              C      ALLROR=RATE OF RETURN
              C
              C
              C
0015                 RMR=0.5
```

```
      RMC=0.5
      RMI=0.5
C
      DO 2 IM=1,NM
      ELR(IM)=-0.5
      ELC(IM)=-0.5
      ELI(IM)=-0.5
    2 CONTINUE
      BLR=3203.742
      SLR=23.912
      BLC=1516.625
      SLC=9.104
      BLI=10179.264
      SLI=3.567
C
      DDM(1)=506.6
      DDM(2)= 248.2
      DDM(3)=  50.5
      DDM(4)=  11.0
      DDM(5)= 18.9
      DDM(6)=  120.5
      DDM(7)= 371.6
      DDM(8)= 712.6
      DDM(9)= 1071.6
      DDM(10)=1207.7
      DDM(11)=1046.3
      DDM(12)= 892.5
C
      SUP1T=200000.
      SUP2T=500000.
      SUPWHT=2000.
      SUPFLT=2500.
      CC1 = 1202.4
      DC1 =  980.
      WRC = 8.075
      CC2 = 1009.2
      DC2 = 1860.0
      KMIN = 0.75
      CWH=787.
      CFL=1481.
C
      DPROM=3000.
      COMP=921.12903
      CIP=14398.11
      SHP=0.1
C
      DSTCM=100000.
      CS=33.23
      CIST=50.
C
      CIPT1=232.0397
      COM2=209.48495
      ALLROR=0.1206
C
C
      WRITE(6,4)
    4 FORMAT(1H1,40X,'SUMMARY OF BASIC DATA ASSUMPTIONS'/5X,100(1H*)/5X,
     1100(1H*)///)
```

```
0065          WRITE(6,3) RMR,RMC,RMI
0066        3 FORMAT(////10X,'RATES OF MARKET GROWTH'/20X,'RESIDENTIAL=',F6.2/
             120X,'COMMERCIAL =',F6.2/20X,'INDUSTRIAL =',F6.2//)
0067          WRITE(6,5) (ELR(IM),IM=1,NM),(ELC(IM),IM=1,NM),(ELI(IM),IM=1,NM)
0068        5 FORMAT(///10X,'MONTHLY DEMAND ELASTICITIES'//20X,'RESIDENTIAL',3X,
             112F6.2/20X,'COMMERCIAL ',3X,12F6.2/20X,'INDUSTRIAL ',3X,12F6.2///)
0069          WRITE(6,6) BLR,SLR,BLC,SLC,BLI,SLI
0070        6 FORMAT(///10X,'BASE- AND SPACE-HEATING LOAD COEFFICIENTS'//20X,'RE
             1SIDENTIAL',3X,2F12.3/20X,'COMMERCIAL ',3X,2F12.3/20X,'INDUSTRIAL '
             2,3X,2F12.3///)
0071          WRITE(6,41)
0072       41 FORMAT(////10X,' MEAN DEGREE DAYS DATA'//)
0073          DDT=0.
0074          DO 35 IM=1,NM
0075          DDT=DDT+DDM(IM)
0076       35 CONTINUE
0077          WRITE(6,36) DDT,(DDM(IM),IM=1,NM)
0078       36 FORMAT(5X,'AVG. ANNUAL TOTAL DEGREE DAYS=',F9.1//5X,'MONTHLY DEGRE
             1E DAYS=',12F8.1)
0079          WRITE(6,7) SUP1T,SUP2T,SUPWHT,SUPFLT,CC1,DC1,WRC,CC2,DC2,KMIN,CWH,
             1CFL
0080        7 FORMAT(////10X,'SUPPLY CHARACTERISTICS'//20X,'SUP1T=',F12.0/20X,'S
             1UP2T=',F12.0/20X,'SUPWHT=',F12.0/20X,'SUPFLT=',F12.0/20X,'CC1=',F1
             22.3/20X,'DC1=',F12.3/20X,'WRC=',F12.3/20X,'CC2=',F12.3/20X,'DC2=',
             3F12.3/20X,'KMIN=',F12.3/20X,'CWH=',F12.3/20X,'CFL=',F12.3///)
0081          WRITE(6,8)  DPROM,COMP,CIP,SHP
0082        8 FORMAT(////10X,'PRODUCTION CHARACTERISTICS'//20X,'DPROM=',F12.0/20
             1X,'COMP=',F12.3/20X,'CIP=',F12.3/20X,'SHP=',F12.3///)
0083          WRITE(6,9) DSTCM,CS,CIST
0084        9 FORMAT(////10X,'STORAGE CHARACTERISTICS'//20X,'DSTCM=',F12.0/20X,
             1'CS=',F12.3/20X,'CIST=',F12.3///)
0085          WRITE(6,10) CIPT1,ALLROR
0086       10 FORMAT(///10X,'TRANSMISSION INVESTMENT CIPT1=',F12.3////10X,'RATE
             1 OF RETURN ALLROR=',F12.3////)
        C
        C
        C     AVERAGE COST ANALYSIS
        C
        C
0087          WRITE(6,300)
0088      300 FORMAT(///40X,'BASE AND AVERAGE COST PRICING ANALYSIS'/5X,100(1H*)
             1/5X,100(1H*)///)
0089          PAVG=1.
0090          DO 1 IM=1,NM
0091          PR(IM)=1.
0092          PC(IM)=1.
0093          PI(IM)=1.
0094        1 CONTINUE
0095          CALL             LOAD(BLR,BLC,BLI,SLR,SLC,SLI,RMR,RMC,RMI,DDM,PAVG,
             1PR,PC,PI,ELR,ELC,ELI,DGMR,DGMC,DGMI,DGMT,DDGT)
0096          CALL         MARCOS(CC1,CC2,DC1,DC2,KMIN,WRC,CWH,CFL,COMP,CIP,CS,CIS
             1T,CIPT1,SUP1T,SUP2T,SUPWHT,SUPFLT,DPROM,DSTCM,SHP,DGMT,DDGT,OMC1,
             2NEWPIS,DGT,PR,PC,PI)
0097          CALL         DIST(DGMT,IMP,PEAK,CMPT2,NPT2,CMPD,NPD)
0098          NEWPIS=NEWPIS+NPT2+NPD
0099          CALL         REVREQ(ALLROR,NEWPIS,DGT,OMC1,X,PAVG,NETPIS)
0100          CALL         EVAL1(IMP,PEAK,DGMT,ELR,ELC,ELI,DGMR,DGMC,DGMI,PAVG,
             1DGT,X,NETPIS,ALLROR,CRS,CCS,CIS,CRST,CCST,CIST,CST,PS,TS)
```

```
C
C      START OF THE ITERATIVE EQUILIBRATION PROCEDURE
C
       WRITE(6,11)
    11 FORMAT(1H1,40X,'ITERATIVE EQUILIBRIUM PROCEDURE'/5X,100(1H*)/5X,
      1100(1H*)///)
C
       IF(ICASE.EQ.1) PAVG=PAVGM
       NTMAX=50
       NTMAX=10
       NTMAX=5
       WRITE(6,203) NTMAX
   203 FORMAT(//30X,'MAXIMAL NUMBER OF ITERATIONS NTMAX=',I5/30X,34(1H=)/
      1/)
       IT=1
       DO 50 IM=1,NM
       PK=0.
       IF(IM.EQ.IMP) PK=1.
       PRMCV(IM,IT)=PR(IM)+PK*(CMPT2+CMPD)+COM2
       PCMCV(IM,IT)=PC(IM)+PK*(CMPT2+CMPD)+COM2
       PIMCV(IM,IT)=PI(IM)+PK*(CMPT2+CMPD)+COM2
    50 CONTINUE
       DO 100 IT=1,NTMAX
       WRITE(6,108) IT
   108 FORMAT(1H1,20X,'ITERATION NUMBER',I5/21X,16(1H*)//)
       WRITE(6,12)
    12 FORMAT(5X,'MONTHLY MARGINAL COSTS'//)
       DO 101 IM=1,NM
       PRO(IM)=PRMCV(IM,IT)
       PCO(IM)=PCMCV(IM,IT)
       PIO(IM)=PIMCV(IM,IT)
       WRITE(6,13) IM,PRO(IM)
    13 FORMAT(3X,'MONTH=',I4,3X,'COST=',F12.3)
   101 CONTINUE
       CALL            LOAD(BLR,BLC,BLI,SLR,SLC,SLI,RMR,RMC,RMI,DDM,PAVG,
      1PRO,PCO,PIO,ELR,ELC,ELI,DGMR,DGMC,DGMI,DGMT,DDGT)
       DO 102 IM=1,NM
       DGMRV(IM,IT)=DGMR(IM)
       DGMCV(IM,IT)=DGMC(IM)
       DGMIV(IM,IT)=DGMI(IM)
   102 CONTINUE
       IF(IT.EQ.1) GO TO 106
C      TEST OF DEMAND-SUPPLY EQUILIBRIUM
       WRITE(6,14)
    14 FORMAT(///5X,'TEST OF DEMAND-SUPPLY EQUILIBRIUM'//)
       ID=0
       DO 104 IM=1,NM
       DR=DGMRV(IM,IT)-DGMRV(IM,IT-1)
       DC=DGMCV(IM,IT)-DGMCV(IM,IT-1)
       DI=DGMIV(IM,IT)-DGMIV(IM,IT-1)
       DRA=DABS(DR)
       DCA=DABS(DC)
       DIA=DABS(DI)
       WRITE(6,15) IM,DR,DC,DI
    15 FORMAT(3X,'MONTH=',I4,3X,'DR=',F12.3,3X,'DC=',F12.3,3X,'DI=',F12.3
      1)
       EPS=10.
       IF((DRA.GT.EPS).OR.(DCA.GT.EPS).OR.(DIA.GT.EPS))  ID=1
```

```
            104 CONTINUE
                IF(ID.EQ.1) GO TO 106
                WRITE(6,105) IT
            105 FORMAT(///5X,'EQUILIBRIUM OF SUPPLY AND DEMAND REACHED AT ITERATIO
               1N',I5///)
                GO TO 200
            106 CALL      MARCOS(CC1,CC2,DC1,DC2,KMIN,WRC,CWH,CFL,COMP,CIP,CS,CIS
               1T,CIPT1,SUP1T,SUP2T,SUPWHT,SUPFLT,DPROM,DSTCM,SHP,DGMT,DDGT,OMC1,
               2NEWPIS,DGT,PR,PC,PI)
                CALL      DIST(DGMT,IMP,PEAK,CMPT2,NPT2,CMPD,NPD)
                NEWPIS=NEWPIS+NPT2+NPD
                CALL      REVREQ(ALLROR,NEWPIS,DGT,OMC1,XE,PAVGE,NETPIS)
                CALL      EVAL2(IMP,PEAK,BLR,BLC,BLI,SLR,SLC,SLI,DDM,DGMR,DGMC,
               1DGMI,DGMT,DGT,PRO,PCO,PIO,ELR,ELC,ELI,PAVGE,XE,NETPIS,ALLROR,CRS,
               2CCS,CIS,CRST,CCST,CIST,CST,PS,TS,PAVG,RMR,RMC,RMI)
                IT1=IT+1
                DO 107 IM=1,NM
                PK=0.
                IF(IM.EQ.IMP) PK=1.
                PRMCV(IM,IT1)=PR(IM)+(CMPT2+CMPD)*PK+COM2
                PCMCV(IM,IT1)=PC(IM)+(CMPT2+CMPD)*PK+COM2
                PIMCV(IM,IT1)=PI(IM)+(CMPT2+CMPD)*PK+COM2
            107 CONTINUE
            100 CONTINUE
            200 STOP
                END
```

```
0001                SUBROUTINE MARCOS(CC1,CC2,DC1,DC2,KMIN,WRC,CWH,CFL,COMP,CIP,CS,CIS
                   1T,CIPT1,SUP1T,SUP2T,SUPWHT,SUPFLT,DPROM,DSTCM,SHP,DGMT,DDGT,OMC1,
                   2NEWPIS,DGT,PR,PC,PI)
            C      MAIN PROGRAM LINPRO                                              1576
            C      LINEAR PROGRAMMING CODE                                          1577
            C                                                                       1582
0002                IMPLICIT REAL*8(A-H,O-Z)                                        0008
0003                COMMON /MAIN1/ A(150,200),BINV(150,150),TAB(150,200),SOL(150),
                   1  TOP(200),B(150),C(200),BOUND(200),ROW(200),COL(150),S(150),
                   2  X(200),SLACK(150),TOL(8),DUAL(150),BIG,SMALL,DETERM,OBJ
            C                                                                       0012
0004                COMMON /MAIN2/ LABCOL(200),LABROW(150),LABTEM(200),INFEAS,
                   1  NINTO,NOUTOF,ISTATE,MNOW,M,NCOL,N,NUMEQU,ISFEAS,ISDEGN,       0014
                   2  ITYPE,ITERS,ITRMAX,IPRINT,ISBND,IRMAX,IRCNT,MAXM,MAXN         0015
            C                                                                       0016
0005                REAL KMIN
0006                REAL NEWPIS
0007                DIMENSION DGMT(12),PR(12),PC(12),PI(12),
                   1GINST(12),GOUST(12),SUP1(12),SUP2(12),SUPV(12),PROD(12)
0008                DIMENSION CSTOR(12),FSN(12)
0009                DIMENSION GOMAX(12),GIMAX(12),RSTOR(12)
0010                DIMENSION    VGINS(12),VGOUS(12),VSMAX(12),VSMIN(12)
0011                DIMENSION V1X(12),V2X(12),VVV(12),VSUV(12),VDGMT(12)
0012                DIMENSION VPRO(12),VTRAN(12)
0013                DIMENSION RHS(139)
0014                NM=12
            C
            C       ALL GAS FLOWS ARE EXPRESSED IN MMCF
            C       PROC=EXISTING PRODUCTION CAPACITY (MMCF)
            C       PT10=EXISTING TRANSMISSION CAPACITY (MMCF)
            C       A10,B10 = UNIT SLOPE AND INTERCEPT OF MAX. DELIVERIES TO STORAGE
            C       A20,B20=UNIT SLOPE AND INTERCEPT OF MAX. WITHDRAWALS FROM STORAGE
            C       RMIN AND RMAX = MINIMAL AND MAXIMAL SATURATION RATES
            C       STCO=EXISTING CERTIFIED STORAGE CAPACITY (MMCF)
            C
            C
0015                WTOT = 12.*WRC
0016                PROC=947.66667
0017                PT10=55000.
0018                A10=-0.07766852
0019                A20=0.15244512
0020                B10=0.14043129
0021                B20=-0.0665677
0022                RMAX=1.18
0023                RMIN=0.77
0024                STCO=147594.1
            C
            C
0025                WRITE(6,42) PROC,PT10
0026             42 FORMAT(1H1,40X,'OUTPUT FROM SUBROUTINE MARCOS'/40X,39(1H=)////10X,
                   1'EXISTING MONTHLY PRODUCTION CAPACITY PROC=',F12.3//10X,'EXISTING
                   2MONTHLY TRANSMISSION CAPACITY PT10=',F12.3///)
0027             52 FORMAT(//10X,'EXISTING STORAGE CHARACTERISTICS'//5X,'A10=',F10.5,
                   13X,'B10=',F10.5,3X,'A20=',F10.5,3X,'B20=',F10.5/5X,'STCO=',F10.1/)
            C
            C       START OF LP MODEL SET-UP
            C
            C       START MAKE UP OF C VECTOR
```

```
0028          N=6*NM+7
0029          M=11*NM+7
0030          DO 54 I=1,NM
0031          I1=I+NM
0032          I2=I+2*NM
0033          I3=I+3*NM
0034          I4=I+4*NM
0035          C(I)=-CS
0036          C(I1)=-CS
0037          C(I2)=-CC1
0038          IF(I.GE.8) C(I2)=-CC1-WTOT
0039          C(I3)=0.
0040          C(I4)=-CC2
0041       54 CONTINUE
0042          I1=5*NM+1
0043          I2=I1+1
0044          I3=I2+1
0045          I4=I3+1
0046          C(I3)=-CWH*12.
0047          C(I4)=-CFL*12.
0048          C(I1)=-0.4*DC1
0049          C(I2)=-0.4*DC2
0050          DO 57 IM=1,NM
0051          I=64+IM
0052          C(I)=-COMP
0053       57 CONTINUE
0054          I1=77
0055          I2=78
0056          I3=79
0057          C(I1)=-CIP
0058          C(I2)=-CIST
0059          C(I3)=-CIPT1
        C
        C
        C     INITIALIZE A & B TO BE ALL ZEROES
0060          DO 5 I=1,M
0061          B(I)=0.
0062          DO 5 J=1,N
0063          A(I,J)=0.
0064          BOUND(J)=-1.
0065        5 CONTINUE
        C
        C     WRITING OF CONSTRAINTS (1) AND (2)     GINST,GOUST
        C
0066          F1=A10*RMIN+B10
0067          F2=A20*RMIN+B20
0068          DO 7 I=1,NM
0069          I1=I
0070          I2=NM+I
0071          B(I1)=F1*STCO
0072          B(I2)=F2*STCO
0073          S(I1)=1.
0074          S(I2)=1.
0075          J1=I
0076          J2=I+NM
0077          J3=78
0078          A(I1,J1)=1.
0079          A(I1,J3)=-F1
```

```
0080              A(I2,J2)=1.
0081              A(I2,J3)=-F2
0082              NM1=I-1
0083              IF(NM1.EQ.0) GO TO 7
0084              DO 8 J=1,NM1
0085              J1=J
0086              J2=J+NM
0087              A(I1,J1)=-A10
0088              A(I1,J2)=A10
0089              A(I2,J1)=-A20
0090              A(I2,J2)=A20
0091            8 CONTINUE
0092            7 CONTINUE
            C
            C     WRITING OF CONSTRAINTS (3) AND (4)     GINST,GOUST
            C
0093              DO 56 I=1,NM
0094              I1=2*NM+I
0095              I2=3*NM+I
0096              B(I1)=(RMAX-RMIN)*STCO
0097              B(I2)=0.
0098              S(I1)=1.
0099              S(I2)=1.
0100              J3=78
0101              A(I1,J3)=-(RMAX-RMIN)
0102              IMAX=I
0103              DO 10 J=1,IMAX
0104              J1=J
0105              J2=J+NM
0106              A(I1,J1)=1.
0107              A(I2,J2)=1.
0108              A(I1,J2)=-1.
0109              A(I2,J1)=-1.
0110           10 CONTINUE
0111           56 CONTINUE
            C
            C     CONTRACT DEMAND CONSTRAINTS
            C     WRITING OF CONSTRAINTS (5)AND (6)    SUP1,SUPMX1,SUP2,SUPMX2
0112              DO 55 I=1,NM
0113              I1=4*NM+I
0114              I2=5*NM+I
0115              S(I1)=1.
0116              S(I2)=1.
0117              J1=2*NM+I
0118              J2=5*NM+1
0119              J3=3*NM+I
0120              J4=5*NM+2
0121              A(I1,J1)=1.0
0122              A(I1,J2)=-1.0
0123              A(I2,J3)=1.0
0124              A(I2,J4)=-1.0
0125           55 CONTINUE
            C     WRITING OF CONSTRAINTS (7)
            C     TAKE-OR-PAY CONSTRAINTS  (7) AND (8)
0126              DO 6 I=1,NM
0127              I1=6*NM+I
0128              I2=7*NM+I
0129              S(I1)=1.
```

```
0130                  S(I2)=1.
0131                  J1=4*NM+I
0132                  J2=3*NM+I
0133                  J3=5*NM+2
0134                  A(I1,J1)=-1.0
0135                  A(I1,J3)=KMIN
0136                  A(I2,J2)=1.0
0137                  A(I2,J1)=-1.0
0138                6 CONTINUE
            C
            C         MAXIMUM ANNUAL SUPPLIES
            C            CONSTRAINTS (9) AND (10)
0139                  I1=8*NM+1
0140                  I2=8*NM+2
0141                  B(I1)=SUP1T
0142                  B(I2)=SUP2T
0143                  S(I1)=1.
0144                  S(I2)=1.
0145                  DO 30 I=1,NM
0146                  J1=2*NM+I
0147                  J2=3*NM+I
0148                  A(I1,J1)=1.0
0149                  A(I2,J2)=1.0
0150               30 CONTINUE
            C
            C         CONSTRAINTS ON WELL-HEAD AND FIELD-LINE PURCHASES
0151                  I1=99
0152                  I2=100
0153                  J1=63
0154                  J2=64
0155                  B(I1)=SUPWHT
0156                  B(I2)=SUPFLT
0157                  S(I1)=1.
0158                  S(I2)=1.
0159                  A(I1,J1)=1.
0160                  A(I2,J2)=1.
            C         CONSTRAINTS ON PRODUCTION
0161                  DO 58 IM=1,NM
0162                  I=100 + IM
0163                  B(I)=PROC
0164                  S(I)=1.
0165                  J1=64 + IM
0166                  J2=77
0167                  A(I,J1)=1.
0168                  A(I,J2)=-1.
0169               58 CONTINUE
0170                  I=113
0171                  J=77
0172                  B(I)=DPROM
0173                  S(I)=1.
0174                  A(I,J)=1.
0175                  I=114
0176                  B(I)=-DDGT*SHP
0177                  S(I)=1.
0178                  DO 59 IM=1,NM
0179                  J=64 + IM
0180                  A(I,J)=-1.
0181               59 CONTINUE
```

```
C     CONTRAINT ON STORAGE EXPANSION
      I=115
      J=78
      B(I)=DSTCM
      S(I)=1.
      A(I,J)=1.
C     CONTRAINT ON TRANSMISSION EXPANSION
      DO 60 IM=1,NM
      I=115 + IM
      B(I)=PT10
      S(I)=1.
      J1=24 + IM
      J2=36 + IM
      J3=63
      J4=64
      J5=64 + IM
      J6=79
      A(I,J1)=1.
      A(I,J2)=1.
      A(I,J3)=1.
      A(I,J4)=1.
      A(I,J5)=1.
      A(I,J6)=-1.
   60 CONTINUE
C     DEMAND REQUIREMENTS
      DO 62 IM=1,NM
      I=127 + IM
      B(I)=DGMT(IM)
      S(I)=0.
      J1=IM
      J2=NM + IM
      J3=2*NM + IM
      J4=3*NM + IM
      J5=63
      J6=64
      J7=64 + IM
      A(I,J1)=-1.
      A(I,J2)=1.
      A(I,J3)=1.
      A(I,J4)=1.
      A(I,J5)=1.
      A(I,J6)=1.
      A(I,J7)=1.
   62 CONTINUE
C     ******************************************************************
C
      NEQ=M
      MAXM=150
      MAXN=200
      MAXNOD=225
      MAXSUR=8
      IFLXBT=1
      IROUND=3
      ILOGIC=1
      IGOMRY=1
      ISBND=1
      ITRMAX=300
      IPRINT=0
```

```
          IRMAX=1
          NUMEQU=0
          DO 135 I=1,M
          IF(S(I).EQ.0) NUMEQU=NUMEQU+1
      135 CONTINUE
          ISTATE=0
          ISFEAS=0
          BIG=1.0E11
          SMALL=1.0E-9
          TOL(1)=1.0E-6
          TOL(2)=1.0E-5
          TOL(3)=1.0E-5
          TOL(4)=1.0E-6
          TOL(5)=1.0E-5
          TOL(6)=1.0E-5
          TOL(7)=1.0E-5
          TOL(8)=1.0E-3
          DETERM=1.0
          CALL FIRSTS
          CALL LPCODE
          IF(MNOW .NE. M) GO TO 9
          IF(ISTATE .NE. 4) GO TO 9
          DO 1 I=1,M
          IF(S(I) .EQ. 1.0) GO TO 1
          GO TO 2
        1 CONTINUE
          GO TO 9
        2 CALL INVERT
          CALL FULTAB
          DO 4 I=1,M
          HOLD=0.0
          DO 3 K=1,M
        3 HOLD=HOLD+COL(K)*BINV(K,I)
        4 DUAL(I)=HOLD
          ISTATE=4
        9 CALL OUTPUT
C****************************************************************************
C****************************************************
          WRITE(6,17)
       17 FORMAT(//5X,'CONSTRAINTS VALUES AND DUAL PRICES'///)
          DO 14 I=1,NEQ
          RHS(I)=0.
          DO 15 J=1,N
          RHS(I)=RHS(I)+A(I,J)*X(J)
       15 CONTINUE
          WRITE(6,16) I,RHS(I),B(I),DUAL(I)
       16 FORMAT(2X,'I=',I4,3X,'RHS=',F20.5,3X,'B=',F20.5,3X,'DUAL=',F20.5)
       14 CONTINUE
          DO 43 IM=1,NM
          I2=NM+IM
          I3=2*NM+IM
          I4=3*NM+IM
          I5=4*NM+IM
          I6=5*NM+IM
          I7=6*NM+IM
          I8=7*NM+IM
          I9=100+IM
          VPRO(IM)=DUAL(I9)
```

```
      I10=115+IM
      VTRAN(IM)=DUAL(I10)
      I11=127+IM
      VDGMT(IM)=DUAL(I11)
      VGINS(IM)=DUAL(IM)
      VGOUS(IM)=DUAL(I2)
      VSMAX(IM)=DUAL(I3)
      VSMIN(IM)=DUAL(I4)
      V1X(IM) = DUAL(I5)
      V2X(IM) = DUAL(I6)
      VVV(IM) = DUAL(I7)
      VSUV(IM)= DUAL(I8)
      PR(IM)=-VDGMT(IM)
      PC(IM)=-VDGMT(IM)
      PI(IM)=-VDGMT(IM)
   43 CONTINUE
      I1=8*NM+1
      I2=8*NM+2
      VS1T=DUAL(I1)
      VS2T=DUAL(I2)
      I3=99
      I4=100
      VSWH=DUAL(I3)
      VSFL=DUAL(I4)
      I5=113
      I6=114
      VPRMX=DUAL(I5)
      VPRMN=DUAL(I6)
      I7=115
      VSTC=DUAL(I7)
      WRITE(6,20)
   20 FORMAT(1H1,40X,'OPTIMAL SOLUTION CHARACTERISTICS'/40X,32(1H*)///)
      DO 18 IM=1,NM
      I1=IM
      I2=NM+IM
      I3=2*NM+IM
      I4=3*NM+IM
      GINST(IM)=X(I1)
      GOUST(IM)=X(I2)
      FSN(IM)=GOUST(IM)-GINST(IM)
      SUP1(IM)=X(I3)
      SUP2(IM)=X(I4)
   18 CONTINUE
      I5=5*NM+1
      I6=5*NM+2
      SUPMX1=X(I5)
      SUPMX2=X(I6)
      DAYMX1 = SUPMX1/30.
      DAYMX2 = SUPMX2/30.
      WRITE(6,6999)
      WRITE(6,21) SUPMX1,DAYMX1
      WRITE(6,7000)
      WRITE(6,21) SUPMX2,DAYMX2
 6999 FORMAT(//'      CONSOLIDATED ' /  )
 7000 FORMAT('       PANHANDLE' / )
   21 FORMAT(//5X,'MAXIMAL MONTHLY SUPPLY=',F10.2/,5X,'MAXIMAL DAILY SUP
     1PLY=',F10.2//)
      DO 63 IM=1,NM
```

```
0348                I1=48 + IM
0349                I2=64 + IM
0350                SUPV(IM)=X(I1)
0351                PROD(IM)=X(I2)
0352             63 CONTINUE
0353                DO 19 IM=1,NM
0354                WRITE(6,65) IM,FSN(IM),SUP1(IM),SUP2(IM),SUPV(IM),PROD(IM),DGMT(IM
               1)
0355             65 FORMAT(1X,'IM=',I3,2X,'FSN=',F9.2,2X,'SUP1=',F9.2,2X,'SUP2=',F9.2,
               12X,'SUPV=',F9.2,2X,'PROD=',F8.2,3X,'DGMT=',F9.2)
0356             19 CONTINUE
0357                I1=63
0358                I2=64
0359                I3=77
0360                I4=78
0361                I5=79
0362                SUPWH=X(I1)
0363                SUPFL=X(I2)
0364                DPRO=X(I3)
0365                DSTC=X(I4)
0366                DPT1=X(I5)
0367                WRITE(6,66) SUPWH,SUPFL,DPRO,DSTC,DPT1
0368             66 FORMAT(////10X,'SUPWH=',F10.3/10X,'SUPFL=',F10.3/10X,'DPRO=',F10.3
               1/10X,'DSTC=',F10.3/10X,'DPT1=',F10.3//)
0369                DCHT =(DC1*SUPMX1 + DC2*SUPMX2)*0.4
0370                CCHT=0.
0371                CST=0.
0372                WCST=0.
0373                DO 22 IM=1,NM
0374                CCHT=CCHT+SUP1(IM)*CC1 + SUPV(IM)*CC2
0375                CST= CST+(GINST(IM)+GOUST(IM))*CS
0376                IF(IM.GE.8) WCST=WCST+WTOT*SUP1(IM)
0377             22 CONTINUE
0378                DCHTS=-DCHT/OBJ
0379                CCHTS=-CCHT/OBJ
0380                CSTS=-CST/OBJ
0381                WCSTS=-WCST/OBJ
0382                WRITE(6,23) DCHT,DCHTS,CCHT,CCHTS,CST,CSTS,WCST,WCSTS
0383             23 FORMAT(//10X,'TOTAL DEMAND CHARGE=',3X,F15.2,5X,'OR',F10.5,3X,'OF M
               1MINIMUM COST'/10X,'TOTAL COMMODITY CHARGE=',F15.2,5X,'OR',F10.5,3X,'OF
               2,'OF MINIMUM COST'/10X,'TOTAL STORAGE COST=',4X,F15.2,5X,'OR',F10.
               35,3X,'OF MINIMUM COST'/10X,'TOTAL WINTER CHARGE=',3X,F15.2,5X,'OR'
               4,F10.5,3X,'OF MINIMUM COST'///)
0384                STCAP=STCO+DSTC
0385                A1=A10*STCAP*RMIN
0386                A2=A20*STCAP*RMIN
0387                B1=B10*STCAP
0388                B2=B20*STCAP
0389                GSTOR(1)=0.
0390                DO 24 IM=2,NM
0391                GSTOR(IM)=GSTOR(IM-1)+GINST(IM-1)-GOUST(IM-1)
0392                RSTOR(IM)=(GSTOR(IM)/STCAP)+RMIN
0393             24 CONTINUE
0394                WRITE(6,25)
0395             25 FORMAT(//10X,'SUMMARY OF MONTHLY STORAGE GAS FLOWS AND STOCKS'//)
0396                GINTT=0.
0397                GOUTT=0.
0398                DO 26 IM=1,NM
```

```
      GINTT=GINTT+GINST(IM)
      GOUTT=GOUTT+ GOUST(IM)
      GIMAX(IM)=A10*GSTOR(IM) + A1 + B1
      GOMAX(IM)=A20*GSTOR(IM) + A2 + B2
      WRITE(6,27) IM,GSTOR(IM),RSTOR(IM),GINST(IM),GIMAX(IM),GOUST(IM),
     1GOMAX(IM)
   27 FORMAT(1X,'IM=',I3,2X,'GSTOR=',F10.2,2X,'RSTOR=',F10.2,2X,'GINST='
     1,F10.2,2X,'GIMAX=',F10.2,2X,'GOUST=',F10.2,2X,'GOMAX=',F10.2)
   26 CONTINUE
      WRITE(6,49) GINTT,GOUTT
   49 FORMAT(/10X,'YEARLY FLOW INTO STORAGE=',F12.2/10X,'YEARLY FLOW OUT
     1 OF STORAGE=',F12.2)
      WRITE(6,44)
   44 FORMAT(///40X,'DUAL VALUES SUMMARY'/40X,20(1H*)////)
      DO 45 IM=1,NM
      WRITE(6,46) IM,VGINS(IM),VGOUS(IM),VSMAX(IM),VSMIN(IM)
   46 FORMAT(1X,'IM=',I2,2X,'VGINS=',F10.3,2X,'VGOUS='
     1,F13.5,2X,'VSMAX=',F11.3,2X,'VSMIN=',F11.3)
   45 CONTINUE
      WRITE(6,48)
   48 FORMAT(//10X,80(1H*)//)
      DO 47 IM=1,NM
      WRITE(6,51) IM,V1X(IM),V2X(IM),VVV(IM),VSUV(IM),VDGMT(IM)
   51 FORMAT(1X,'IM=',I2,2X,'V1X=',F10.3,2X,'V2X=',F10.3,2X,'VVV=',F10.3
     1,2X,'VSUV=',F10.3,2X,'VDGMT=',F10.3)
   47 CONTINUE
      WRITE(6,50) VS1T,VS2T
   50 FORMAT(///10X,'VS1T=',F15.5/10X,'VS2T=',F15.5//)
      WRITE(6,48)
      DO 67 IM=1,NM
      WRITE(6,68) IM,VPRO(IM),VTRAN(IM)
   68 FORMAT(15X,'IM=',I3,3X,'VPRO=',F15.5,5X,'VTRAN=',F15.5)
   67 CONTINUE
      WRITE(6,48)
      WRITE(6,69) VSWH,VSFL,VPRMX,VPRMN,VSTC
   69 FORMAT(///1X,'VSWH=',F10.3,3X,'VSFL=',F10.3,3X,'VPRMX=',F10.3,
     13X,'VPRMN=',F10.3,3X,'VSTC=',F10.3//)
      CRF=0.1241
      PIS=DPRO*CIP + DSTC*CIST + DPT1*CIPT1
      OMC1=-OBJ-PIS
      NEWPIS=PIS/CRF
      DGT=0.
      DO 501 IM=1,NM
      DGT=DGT+DGMT(IM)
  501 CONTINUE
      WRITE(6,500) PIS,NEWPIS,OMC1,DGT
  500 FORMAT(//80(1H*)//5X,'TOTAL INVESTMENT IN PRODUCTION,STORAGE AND T
     1RANSMISSION CAPACITY'//15X,'ANNUALIZED COST PIS=',F15.2/15X,'TOTAL
     2 DISCOUNTED COST NEWPIS=',F15.2///5X,'PURCHASES, PRODUCTION AND ST
     3ORAGE OPERATING COSTS OMC1=',F15.2//5X,'TOTAL ANNUAL GAS DEMAND (M
     4MCF) DGT=',F15.2//80(1H*)///)
      RETURN
      END
```

```
      SUBROUTINE       LOAD(BLR,BLC,BLI,SLR,SLC,SLI,RMR,RMC,RMI,DDM,PAVG,
     1PR,PC,PI,ELR,ELC,ELI,DGMR,DGMC,DGMI,DGMT,DDCT)
      IMPLICIT REAL*8(A-H,O-Z)
      DIMENSION DDM(12),PR(12),PC(12),PI(12),ELR(12),ELC(12),ELI(12)
      DIMENSION DGMRO(12),DGMCO(12),DGMIO(12),DGMTO(12)
      DIMENSION DGMR(12),DGMC(12),DGMI(12),DGMT(12)
      NM=12
      WRITE(6,1)
    1 FORMAT(//20X,'SUBROUTINE LOAD--GAS MARKET CHARACTERISTICS'/20X,45(
     11H=)//)
      WRITE(6,37)
   37 FORMAT(////10X,'GAS DEMAND PATTERNS'//)
      WRITE(6,40)
   40 FORMAT(///2X,'BASE DEMAND (MMCF) '//)
      DGMRTO=0.
      DGMCTO=0.
      DGMITO=0.
      DGMTTO=0.
      DO 33 IM=1,NM
      DGMRO(IM)=(BLR+SLR*DDM(IM))*((PAVG/PR(IM))**(-ELR(IM)))
      DGMCO(IM)=(BLC+SLC*DDM(IM))*((PAVG/PC(IM))**(-ELC(IM)))
      DGMIO(IM)=(BLI+SLI*DDM(IM))*((PAVG/PI(IM))**(-ELI(IM)))
      DGMTO(IM)=DGMRO(IM)+DGMCO(IM)+DGMIO(IM)
      DGMRTO=DGMRTO+DGMRO(IM)
      DGMCTO=DGMCTO+DGMCO(IM)
      DGMITO=DGMITO+DGMIO(IM)
      DGMTTO=DGMTTO+DGMTO(IM)
      WRITE(6,38) IM,DGMRO(IM),DGMCO(IM),DGMIO(IM),DGMTO(IM)
   38 FORMAT('    MONTH=',I4,'    DGMRO=',F10.2,'    DGMCO=',F10.2,'    DGMI
     1O=',F10.2,4X,'DGMTO=',F10.2)
   33 CONTINUE
      WRITE(6,39) DGMRTO,DGMCTO,DGMITO,DGMTTO
   39 FORMAT(//3X,'TOTAL',    7X,'DGMRTO=',F11.2,'    DGMCTO=',F9.2,2X,'DG
     1MITO=',F10.2,'    DGMTTO' ,F11.2//)
      WRITE(6,34)
   34 FORMAT(/////2X,'FORECASTED DEMAND (MMCF)'//)
      DGMRT=0.
      DGMCT=0.
      DGMIT=0.
      DGMTT=0.
      DO 64 IM=1,NM
      DGMR(IM)=(1.+RMR)*DGMRO(IM)
      DGMC(IM)=(1.+RMC)*DGMCO(IM)
      DGMI(IM)=(1.+RMI)*DGMIO(IM)
      DGMT(IM)=DGMR(IM)+DGMC(IM)+DGMI(IM)
      DGMRT=DGMRT+DGMR(IM)
      DGMCT=DGMCT+DGMC(IM)
      DGMIT=DGMIT+DGMI(IM)
      DGMTT=DGMTT+DGMT(IM)
      WRITE(6,32) IM,DGMR(IM),DGMC(IM),DGMI(IM),DGMT(IM)
   32 FORMAT('    MONTH=',I4,'    DGMR =',F10.2,'    DGMC =',F10.2,'    DGMI
     1 =',F10.2,4X,'DGMT =',F10.2)
   64 CONTINUE
      WRITE(6,42) DGMRT,DGMCT,DGMIT,DGMTT
   42 FORMAT(//3X,'TOTAL',    7X,'DGMRT =',F11.2,'    DGMCT =',F9.2,2X,'DG
     1MIT =',F10.2,'    DGMTT ' ,F11.2//)
      DDCT=RMR*DGMRTO+RMC*DGMCTO+RMI*DGMITO
      WRITE(6,31) DDCT
```

```
0053                31 FORMAT(//10X,'TOTAL DEMAND INCREMENT (MMCF)',F10.2///)
0054                   RETURN
0055                   END
```

```
0001                SUBROUTINE DIST(DGMT,IMP,PEAK,CMPT2,NPT2,CMPD,NPD)
0002                IMPLICIT REAL*8(A-H,O-Z)
0003                DIMENSION DGMT(12)
0004                REAL NPT2,NPD
0005                WRITE(6,7)
0006              7 FORMAT(1H1,40X,'OUTPUT OF SUBROUTINE DIST'/40X,25(1H=)////)
0007                CRF=0.1241
            C       DETERMINATION OF THE PEAK MONTH (IMP)
0008                PEAK=0.
0009                DO 1 IM=1,12
0010                IF(PEAK.GT.DGMT(IM)) GO TO 1
0011                PEAK=DGMT(IM)
0012                IMP=IM
0013              1 CONTINUE
            C       CALCULATION OF FINAL LOAD-RELATED TRANSMISSION PLANT PT2
0014                PT20=88500.
0015                IF(PEAK.GT.PT20) GO TO 2
0016                CMPT2=0.
0017                NPT2=0.
0018                GO TO 3
0019              2 CMPT2=216.30822
0020                NPT2=216.30822*(PEAK-PT20)/CRF
            C       CALCULATION OF FINAL LOAD-RELATED DISTRIBUTION PLANT PD
0021              3 PDO=59081.
0022                IF(PEAK.GT.PDO) GO TO 4
0023                CMPD=0.
0024                NPD=0.
0025                GO TO 5
0026              4 CMPD=1954.964
0027                NPD=1954.964*(PEAK-PDO)/CRF
0028              5 WRITE(6,6) IMP,PEAK,CMPT2,NPT2,CMPD,NPD
0029              6 FORMAT(/10X,'PEAK MONTH=',
                 1I4,3X,'PEAK LOAD=',F10.2//10X,'TRANSMISSION MARGINAL COST=',F12.3,
                 25X,'NEW TRANSMISSION PLANT=',F15.2//10X,'DISTRIBUTION MARGINAL COS
                 3T=',F12.3,5X,'NEW DISTRIBUTION PLANT=',F15.2/////)
0030                RETURN
0031                END
```

```
      SUBROUTINE EVAL1(IMP,PEAK,DGMT,ELR,ELC,ELI,DGMR,DGMC,DGMI,PAVG,
     1DGT,X,NETPIS,ALLROR,CRS,CCS,CIS,CRST,CCST,CIST,CST,PS,TS)
      IMPLICIT REAL*8(A-H,O-Z)
      DIMENSION DGMR(12),DGMC(12),DGMI(12),DGMT(12),ELR(12),ELC(12),
     1ELI(12),CRS(12),CCS(12),CIS(12)
      REAL NETPIS
      NM=12
      FL=DGT/(12.*PEAK)
      WRITE(6,10)
   10 FORMAT(1H1,40X,'OUTPUT OF SUBROUTINE EVAL1'/40X,26(1H=)////)
      WRITE(6,1) IMP,PEAK,FL,DGT
    1 FORMAT(////10X,'GAS CONSUMPTION EVALUATION CRITERIA'/10X,35(1H*)//
     1/20X,'PEAK MONTH=',I3/20X,'PEAK LOAD (MMCF)=',F10.2/20X,'LOAD FACT
     2OR=',F8.4/20X,'TOTAL GAS CONSUMPTION=',F12.2////)
      WRITE(6,2) PAVG,X
    2 FORMAT(20X,'AVERAGE VOLUMETRIC RATE=',F10.3/20X,'ACHIEVED GAS SALE
     1S REVENUE=',F15.2///)
      WRITE(6,3)
    3 FORMAT(///10X,'EFFICIENCY CRITERIA'/10X,19(1H*)///)
      CRST=0.
      CCST=0.
      CIST=0.
      DO 5 IM=1,NM
      E1=1./(1.+ELR(IM))
      E2=1./(1.+ELC(IM))
      E3=1./(1.+ELI(IM))
      F1=1./E1
      F2=1./E2
      F3=1./E3
      CRS(IM)=DGMR(IM)*(PAVG**(-ELR(IM)))*E1*((10000.**F1)-(PAVG**F1))
      CCS(IM)=DGMC(IM)*(PAVG**(-ELC(IM)))*E2*((10000.**F2)-(PAVG**F2))
      CIS(IM)=DGMI(IM)*(PAVG**(-ELI(IM)))*E3*((10000.**F3)-(PAVG**F3))
      CRST=CRST+CRS(IM)
      CCST=CCST+CCS(IM)
      CIST=CIST+CIS(IM)
      WRITE(6,4) IM,CRS(IM),CCS(IM),CIS(IM)
    4 FORMAT(3X,'MONTH=',I3,3X,'RESIDENTIAL SURPLUS=',F15.0,3X,'COMMERCI
     1AL SURPLUS=',F15.0,3X,'INDUSTRIAL SURPLUS=',F15.0)
    5 CONTINUE
      CST=CRST+CCST+CIST
      PS=ALLROR*NETPIS
      TS=CST+PS
      WRITE(6,6) CRST,CCST,CIST,CST
    6 FORMAT(///3X,'TOTAL RESIDENTIAL SURPLUS',F15.0/3X,'TOTAL COMMERCIA
     1L SURPLUS',F15.0/3X,'TOTAL INDUSTRIAL SURPLUS',F15.0/3X,'TOTAL CON
     2SUMER SURPLUS',F15.0//)
      WRITE(6,7) PS,TS
    7 FORMAT(///3X,'PRODUCER SURPLUS',F15.0//3X,'TOTAL SURPLUS',F15.0//)
      RETURN
      END
```

```
0001           SUBROUTINE EVAL2(IMP,PEAK,BLR,BLC,BLI,SLR,SLC,SLI,DDM,DGMR,DGMC,
              1DGMI,DGMT,DGT,PR,PC,PI,ELR,ELC,ELI,PAVGE,XE,NETPIS,ALLROR,CRS,
              2CCS,CIS,CRST,CCST,CIST,CST,PS,TS,PAVG,RMR,RMC,RMI)
0002           IMPLICIT REAL*8(A-H,O-Z)
0003           DIMENSION DDM(12),DGMR(12),DGMC(12),DGMI(12),DGMT(12),PR(12),PC(12
              1),PI(12),ELR(12),ELC(12),ELI(12),CRS(12),CCS(12),CIS(12)
0004           REAL NETPIS
0005           NM=12
0006           FL=DGT/(12.*PEAK)
0007           WRITE(6,10)
0008        10 FORMAT(1H1,40X,'OUTPUT OF SUBROUTINE EVAL2'/40X,26(1H=)////)
0009           WRITE(6,1) IMP,PEAK,FL,DGT
0010         1 FORMAT(////10X,'GAS CONSUMPTION EVALUATION CRITERIA'/10X,35(1H*)//
              1/20X,'PEAK MONTH=',I3/20X,'PEAK LOAD (MMCF)=',F10.2/20X,'LOAD FACT
              2OR=',F8.4/20X,'TOTAL GAS CONSUMPTION=',F12.2////)
0011           WRITE(6,2) PAVGE,XE
0012         2 FORMAT(20X,'THEORETICAL EQUILIBRIUM VOLUMETRIC RATES=',F10.3/
              120X,'EQUILIBRIUM GAS SALES REVENUE REQUIREMENT=',F15.2////)
0013           WRITE(6,3)
0014         3 FORMAT(///10X,'EFFICIENCY CRITERIA'/10X,19(1H*)///)
0015           CRST=0.
0016           CCST=0.
0017           CIST=0.
0018           DO 5 IM=1,NM
0019           E1=1./(1.+ELR(IM))
0020           E2=1./(1.+ELC(IM))
0021           E3=1./(1.+ELI(IM))
0022           F1=1./E1
0023           F2=1./E2
0024           F3=1./E3
0025           CRS(IM)=(BLR+SLR*DDM(IM))*(PAVG**(-ELR(IM)))*E1*((10000.**F1)-
              1(PR(IM)**F1))*(1.+RMR)
0026           CCS(IM)=(BLC+SLC*DDM(IM))*(PAVG**(-ELC(IM)))*E2*((10000.**F2)-
              1(PC(IM)**F2))*(1.+RMC)
0027           CIS(IM)=(BLI+SLI*DDM(IM))*(PAVG**(-ELI(IM)))*E3*((10000.**F3)-
              1(PI(IM)**F3))*(1.+RMI)
0028           CRST=CRST+CRS(IM)
0029           CCST=CCST+CCS(IM)
0030           CIST=CIST+CIS(IM)
0031           WRITE(6,4) IM,CRS(IM),CCS(IM),CIS(IM)
0032         4 FORMAT(3X,'MONTH=',I3,3X,'RESIDENTIAL SURPLUS=',F15.0,3X,'COMMERCI
              1AL SURPLUS=',F15.0,3X,'INDUSTRIAL SURPLUS=',F15.0)
0033         5 CONTINUE
0034           CST=CRST+CCST+CIST
         C     CALCULATION OF ACTUAL GAS SALES REVENUES--XA
0035           XA=0.
0036           DO 8 IM=1,NM
0037           XA=XA+DGMR(IM)*PR(IM)+DGMC(IM)*PC(IM)+DGMI(IM)*PI(IM)
0038         8 CONTINUE
0039           DF=XA-XE
0040           WRITE(6,9) XA,DF
0041         9 FORMAT(/5X,'ACTUAL GAS SALES REVENUES=',F15.2//5X,'GAS SALES REVEN
              1UE SURPLUS (+) OR DEFICIT (-)=',F15.2///)
0042           PS=ALLROR*NETPIS+DF*0.5176
0043           TS=CST+PS
0044           WRITE(6,6) CRST,CCST,CIST,CST
0045         6 FORMAT(///5X,'TOTAL RESIDENTIAL SURPLUS',F15.0/5X,'TOTAL COMMERCIA
              1L SURPLUS',F15.0/5X,'TOTAL INDUSTRIAL SURPLUS',F15.0/5X,'TOTAL CON
```

```
                 2SUMER SURPLUS',F15.0//)
                  WRITE(6,7) PS,TS
                7 FORMAT(///5X,'PRODUCER SURPLUS',F15.0//5X,'TOTAL SURPLUS',F15.0//)
                  RETURN
                  END
```

```
0001              SUBROUTINE REVREQ(ALLROR,NEWPIS,DGT,OMC1,X,PAVG,NETPIS)
0002              IMPLICIT REAL*8(A-H,O-Z)
0003              REAL NEWPIS,NETPIS,INVTXC
0004              WRITE(6,2)
0005            2 FORMAT(////40X,'OUTPUT OF SUBROUTINE REVREQ'/40X,27(1H=)////)
0006              ATPIS=0.03625
0007              PISBEG=617338511.
0008              DEPAVG=0.02939
0009              TAPD0=224690519.
0010              APDF=0.82528
0011              REPPIS=ATPIS*PISBEG
0012              TOTPIS=PISBEG+REPPIS+NEWPIS
0013              DEPEXP=DEPAVG*TOTPIS
0014              TAPD=TAPD0+APDF*DEPEXP
0015              NETPIS=TOTPIS-TAPD
0016              WRITE(6,3) REPPIS,TOTPIS,DEPEXP,TAPD,NETPIS
0017            3 FORMAT(//10X,'REPPIS=',F15.3/10X,'TOTPIS=',F15.3/10X,'DEPEXP=',F15
                 1.3/10X,'TAPD=',F15.3/10X,'NETPIS=',F15.3///)
0018              REVTXR=0.041454
0019              A3=0.002288
0020              A4=0.002975
0021              COM2=209.48495
0022              PRPTXR=0.021
0023              PAYTXR=0.03
0024              FEDITR=0.46
0025              A5=0.3
0026              A6=0.01759
0027              A7=0.1
0028              OOPREV=A3*TOTPIS
0029              ONUINC=A4*TOTPIS
0030              OMC2=DGT*COM2
0031              ACOPEX=OMC1+OMC2+DEPEXP
0032              PRPTAX=PRPTXR*NETPIS
0033              PAYTAX=PAYTXR*OMC2
0034              INVTXC=A7*(NEWPIS+REPPIS)
0035              WRITE(6,4) OOPREV,ONUINC,OMC2,ACOPEX,PRPTAX,PAYTAX,INVTXC
0036            4 FORMAT(//10X,'OOPREV=',F15.3/10X,'ONUINC=',F15.3/10X,'OMC2=',F15.3
                 1/10X,'ACOPEX=',F15.3/10X,'PRPTAX=',F15.3/10X,'PAYTAX=',F15.3/10X,
                 2'INVTXC=',F15.3//)
0037              X0=A5*DEPEXP+A6*TOTPIS
0038              X1=ALLROR*NETPIS
0039              X2=FEDITR*X0+INVTXC
0040              X3=(X1-X2)/(1.-FEDITR)
0041              X4=ACOPEX+PRPTAX+PAYTAX
0042              X5=(X3+X4)/(1.-REVTXR)
0043              X6=OOPREV+ONUINC
0044              WRITE(6,5) X0,X1,X2,X3,X4,X5,X6
0045            5 FORMAT(10X,'X0=',F15.3/10X,'X1=',F15.3/10X,'X2=',F15.3/
                 110X,'X3=',F15.3/10X,'X4=',F15.3/10X,'X5=',F15.3/10X,'X6=',F15.3//)
0046              X=X5-X6
            C     X IS THE GAS REVENUE REQUIREMENT
0047              PAVG=X/DGT
            C     PAVG IS THE AVERAGE VOLUMETRIC GAS RATE
0048              WRITE(6,1) NEWPIS,DGT,OMC1,X,PAVG
0049            1 FORMAT(//10X,'NEWPIS=',F15.3/10X,'DGT=',F15.3/10X,'OMC1=',F15.3/10
                 1X,'X=',F15.3/10X,'PAVG=',F10.3///)
0050              RETURN
0051              END
```

APPENDIX F

SAMPLE OUTPUT OF THE GUMCP MODEL

The purpose of this appendix is to present a sample output of the GUMCP model developed and applied in chapter 4. This output includes (1) the basic data assumptions, (2) the results of the average cost pricing policy, and (3) the results of the first iteration of the marginal cost pricing equilibrating procedure.

SUMMARY OF BASIC DATA ASSUMPTIONS

****
****

RATES OF MARKET GROWTH

RESIDENTIAL=	0.50
COMMERCIAL =	0.50
INDUSTRIAL =	0.50

MONTHLY DEMAND ELASTICITIES

RESIDENTIAL	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50
COMMERCIAL	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50
INDUSTRIAL	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50

BASE- AND SPACE-HEATING LOAD COEFFICIENTS

RESIDENTIAL	3203.742	23.912
COMMERCIAL	1516.625	9.104
INDUSTRIAL	10179.266	3.567

MEAN DEGREE DAYS DATA

AVG. ANNUAL TOTAL DEGREE DAYS= 6258.0

MONTHLY DEGREE DAYS=	506.6	248.2	50.5	11.0	18.9	120.5	371.6	712.6	1071.6	1207.7	1046.3	892.5

SUPPLY CHARACTERISTICS

SUP1T=	200000.
SUP2T=	500000.
SUPWHT=	2000.
SUPFLT=	2500.
CC1=	1202.400
DC1=	980.000
WRC=	8.075
CC2=	1009.200
DC2=	1860.000
KMIN=	0.750
CWH=	787.000
CFL=	1481.000

PRODUCTION CHARACTERISTICS

DPROM= 3000.
COMP= 921.129
CIP= 14398.109
SHP= 0.100

STORAGE CHARACTERISTICS

DSTCM= 100000.
CS= 33.230
CIST= 50.000

TRANSMISSION INVESTMENT CIPT1= 232.040

RATE OF RETURN ALLROR= 0.121

BASE AND AVERAGE COST PRICING ANALYSIS

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SUBROUTINE LOAD--GAS MARKET CHARACTERISTICS

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GAS DEMAND PATTERNS

BASE DEMAND (MMCF)

MONTH=	1	DGMRO=	15317.56	DGMCO=	6128.71	DGMIO=	11986.31	DGMTO=	33432.59
MONTH=	2	DGMRO=	9138.70	DGMCO=	3776.24	DGMIO=	11064.60	DGMTO=	23979.53

MONTH=	3	DGMRO=	4411.30	DGMCO=	1976.38	DGMIO=	10359.40	DGMTO=	16747.07
MONTH=	4	DGMRO=	3466.77	DGMCO=	1616.77	DGMIO=	10218.50	DGMTO=	15302.05
MONTH=	5	DGMRO=	3655.68	DGMCO=	1688.69	DGMIO=	10246.68	DGMTO=	15591.05
MONTH=	6	DGMRO=	6085.14	DGMCO=	2613.66	DGMIO=	10609.09	DGMTO=	19307.88
MONTH=	7	DGMRO=	12089.44	DGMCO=	4899.67	DGMIO=	11504.76	DGMTO=	28493.88
MONTH=	8	DGMRO=	20243.44	DGMCO=	8004.14	DGMIO=	12721.11	DGMTO=	40968.68
MONTH=	9	DGMRO=	28827.85	DGMCO=	11272.47	DGMIO=	14001.66	DGMTO=	54101.98
MONTH=	10	DGMRO=	32082.27	DGMCO=	12511.53	DGMIO=	14487.13	DGMTO=	59080.92
MONTH=	11	DGMRO=	28222.87	DGMCO=	11042.14	DGMIO=	13911.42	DGMTO=	53176.43
MONTH=	12	DGMRO=	24545.20	DGMCO=	9641.95	DGMIO=	13362.81	DGMTO=	47549.96
TOTAL		DGMRTO=	188086.22	DGMCTO=	75172.34	DGMITO=	144473.48	DGMTTO	407732.04

FORECASTED DEMAND (MMCF)

MONTH=	1	DGMR =	22976.35	DGMC =	9193.07	DGMI =	17979.46	DGMT =	50148.88
MONTH=	2	DGMR =	13708.05	DGMC =	5664.36	DGMI =	16596.89	DGMT =	35969.30
MONTH=	3	DGMR =	6616.95	DGMC =	2964.57	DGMI =	15539.10	DGMT =	25120.61
MONTH=	4	DGMR =	5200.16	DGMC =	2425.15	DGMI =	15327.75	DGMT =	22953.07
MONTH=	5	DGMR =	5483.52	DGMC =	2533.04	DGMI =	15370.02	DGMT =	23386.58
MONTH=	6	DGMR =	9127.71	DGMC =	3920.49	DGMI =	15913.63	DGMT =	28961.83
MONTH=	7	DGMR =	18134.17	DGMC =	7349.51	DGMI =	17257.14	DGMT =	42740.82
MONTH=	8	DGMR =	30365.16	DGMC =	12006.20	DGMI =	19081.67	DGMT =	61453.03
MONTH=	9	DGMR =	43241.77	DGMC =	16908.71	DGMI =	21002.50	DGMT =	81152.97
MONTH=	10	DGMR =	48123.40	DGMC =	18767.29	DGMI =	21730.70	DGMT =	88621.39
MONTH=	11	DGMR =	42334.31	DGMC =	16563.21	DGMI =	20867.13	DGMT =	79764.65
MONTH=	12	DGMR =	36817.81	DGMC =	14462.92	DGMI =	20044.22	DGMT =	71324.94
TOTAL		DGMRT =	282129.34	DGMCT =	112758.50	DGMIT =	216710.22	DGMTT	611598.06

TOTAL DEMAND INCREMENT (MMCF) 203866.02

OUTPUT FROM SUBROUTINE MARCOS

EXISTING MONTHLY PRODUCTION CAPACITY PROC= 947.667

EXISTING MONTHLY TRANSMISSION CAPACITY PT1O= 55000.000

OPTIMAL SOLUTION

```
OBJ   -693263100.7   ISTATE   4  ITERATIONS  96  DETERMINANT          -7.85810  INFEAS   0  NINTO   0  NOUTOF   0

N  79  NCOL  67  M 139  MNOW 139  ISFEAS   1 IRCNT   1

X VECTOR
         2617.74557  4255.12929 15103.81867 18255.75102 16837.85335 15530.08174 13858.22011       0.0         0.0         0.0
            0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0      9053.41412
        24381.54804 20664.69960 17514.46663 14844.47135 12542.19379       0.0         0.0      984.38942      0.0      4267.47838
        15557.07370      0.0      4371.81322 15557.07370  9850.56699  4080.86078 36525.54611 36525.54611 36525.54611 36525.54611
        36525.54611 36525.54611 37343.08263 48700.72814 48700.72814 48700.72814 48700.72814 48700.72814 36525.54611 36525.54611
        36525.54611 36525.54611 36525.54611 36525.54611 37343.08263 48700.72814 48700.72814 48700.72814 48700.72814 48700.72814
        15557.07370 48700.72814 [illegible]000.00000  0.0     1698.88390  1698.88390  1698.88390  1698.88390  1698.88390  1698.88390
         1698.88390  1698.88390  1698.88390  1698.88390  1698.88390  1698.88390   751.21715100000.00000 12956.68574

SLACK VECTOR
        17344.90332 15504.20310  4325.02401      0.0         0.0         0.0       465.66273 13247.53501 13950.70054 15844.37996
        17449.37717 18809.70036 12581.50388 12980.56646 13629.24023 15931.74394 18714.74442 21281.59329 23649.07873 16708.28288
            0.0         0.0         0.0         0.0     98895.92597 94640.79668 79536.97801 61281.22699 44443.37364 28913.29190
        15055.07179 24108.48591 48490.03396 69154.73355 86669.200181015l3.67153  2617.74557  6872.87485 21976.69352 40232.44454
        57070.29789 72600.37963 86458.59974 77405.18562 53023.63758 32358.93798 14844.47135      0.0      3014.87991 15557.07370
        15557.07370 14572.68428 15557.07370 11289.59532      0.0     15557.07370 11185.26048      0.0      5705.50671 11476.21292
        12175.18204 12175.18204 12175.18204 12175.18204 12175.18204 12175.18204 11357.64552      0.0         0.0         0.0
            0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0       817.53652 12175.18204
        12175.18204 12175.18204 12175.18204 12175.18204      0.0         0.0         0.0         0.0         0.0         0.0
            0.0         0.0         0.0         0.0         0.0         0.0    132788.55001      0.0         0.0      2500.00000
            0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0
            0.0         0.0      2248.78285      0.0         0.0     15190.06195 27732.25574 27732.25574 26747.86632 27732.25574
        23464.77735 11357.64552 15557.07370 11185.26048      0.0      5706.50671 11476.21292      0.0         0.0         0.0
            0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0

DUAL VECTOR
            0.0         0.0         0.0         0.00000    68.41705     5.76133      0.0         0.0         0.0         0.0
            0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0
           29.11750   763.83947   171.74241   202.63279      0.0         0.0         0.0         0.0         0.0         0.0
            0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0
            0.0         0.0         0.0         0.0         0.0         0.0         0.0      1063.43711      0.0         0.0
            0.0         0.0         0.0         0.0         5.76133      0.0         0.0       386.23865      0.0         0.0
            0.0         0.0         0.0         0.0         0.0         0.0         0.0        66.45999    91.13867   477.37732
           91.13867    91.13867     5.76133     5.76133     5.76133     5.76133    68.86452     5.76133      0.0         0.0
            0.0         0.0         0.0         0.0      1003.43862  1003.43862  1003.43862  1003.43862   940.33543  1003.43862
         1009.19995  1009.19995  1009.19995  1009.19995  1009.19995  1009.19995      0.0       198.96128  5773.51692      0.0
         1134.11594  1134.11594  1134.11594  1134.11594  1071.01274  1134.11594  1139.87727  1206.33726  1231.01594  1617.25459
         1231.01594  1231.01594      0.0       852.84519    15.29877      0.0         0.0         0.0         0.0         0.0
            0.0         0.0         0.0         0.0       232.03970      0.0         0.0     -1202.39990 -1202.39990 -1202.39990
        -1202.39990 -1139.29670 -1202.39990 -1208.16123 -1274.62122 -1299.29990 -1917.57825 -1299.29990 -1299.29990

COST VECTOR
          -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000
          -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000
          -33.23000   -33.23000   -33.23000   -33.23000 -1202.39990 -1202.39990 -1202.39990 -1202.39990 -1202.39990 -1202.39990
        -1202.39990 -1299.29990 -1299.29990 -1299.29990 -1299.29990 -1299.29990      0.0         0.0         0.0         0.0
            0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0     -1009.19995 -1009.19995
        -1009.19995 -1009.19995 -1009.19995 -1009.19995 -1009.19995 -1009.19995 -1009.19995 -1009.19995 -1009.19995 -1009.19995
         -391.99998  -743.99996 -9444.00000-17772.00000  -921.12915  -921.12915  -921.12915  -921.12915  -921.12915  -921.12915
         -921.12915  -921.12915  -921.12915  -921.12915  -921.12915  -921.12915-14398.10937   -50.00000  -232.03970

BOUND VECTOR
          -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000
          -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000
          -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000
          -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000
          -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000
          -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000
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     -1.00000     -1.00000     -1.00000     -1.00000     -1.00000     -1.00000     -1.00000     -1.00000     -1.00000     -1.00000
     -1.00000     -1.00000     -1.00000     -1.00000     -1.00000     -1.00000     -1.00000     -1.00000     -1.00000

B VECTOR
   11899.99841  11899.99841  11899.99841  11899.99841  11899.99841  11899.99841  11899.99841  11899.99841  11899.99841  11899.99841
   11899.99841  11899.99841   7500.00048   7500.00048   7500.00048   7500.00048   7500.00048   7500.00048   7500.00048   7500.00048
    7500.00048   7500.00048   7500.00048   7500.00048  60513.63911  60513.63911  60513.63911  60513.63911  60513.63911  60513.63911
   60513.63911  60513.63911  60513.63911  60513.63911  60513.63911  60513.63911      0.0          0.0          0.0          0.0
       0.0          0.0          0.0          0.0          0.0          0.0          0.0          0.0          0.0          0.0
       0.0          0.0          0.0          0.0          0.0          0.0          0.0          0.0          0.0          0.0
       0.0          0.0          0.0          0.0          0.0          0.0          0.0          0.0          0.0          0.0
       0.0          0.0          0.0          0.0          0.0          0.0          0.0          0.0          0.0          0.0
       0.0          0.0          0.0          0.0          0.0          0.0          0.0          0.0          0.0          0.0
       0.0          0.0          0.0          0.0          0.0          0.0     200000.00000500000.00000   2000.00000   2500.00000
     947.66675    947.66675    947.66675    947.66675    947.66675    947.66675    947.66675    947.66675    947.66675    947.66675
     947.66675    947.66675   3000.00000-20386.60675100000.00000  55000.00000  55000.00000  55000.00000  55000.00000  55000.00000
   55000.00000  55000.00000  55000.00000  55000.00000  55000.00000  55000.00000  55000.00000  50148.87822  35969.30072  25120.61133
   22953.06840  23386.57665  28961.82665  42740.82011  61453.02617  81152.97330  88621.38334  79764.64566  71324.94418

SIGN VECTOR
       1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000
       1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000
       1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000
       1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000
       1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000
       1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000
       1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000
       1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000
       1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000
       1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000
       1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000
       1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000
       1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      1.00000      0.0          0.0          0.0
       0.0          0.0          0.0          0.0          0.0          0.0          0.0          0.0          0.0

   CONSTRAINTS VALUES AND DUAL PRICES


 I=   1   RHS=       -5444.90490   B=       11899.99841   DUAL=          0.0
 I=   2   RHS=       -3604.20469   B=       11899.99841   DUAL=          0.0
 I=   3   RHS=        7574.97441   B=       11899.99841   DUAL=          0.0
 I=   4   RHS=       11899.99841   B=       11899.99841   DUAL=          0.00000
 I=   5   RHS=       11899.99841   B=       11899.99841   DUAL=         68.41705
 I=   6   RHS=       11899.99841   B=       11899.99841   DUAL=          5.76133
 I=   7   RHS=       11434.33569   B=       11899.99841   DUAL=          0.0
 I=   8   RHS=       -1347.53660   B=       11899.99841   DUAL=          0.0
 I=   9   RHS=       -2050.70213   B=       11899.99841   DUAL=          0.0
 I=  10   RHS=       -3944.38155   B=       11899.99841   DUAL=          0.0
 I=  11   RHS=       -5549.37876   B=       11899.99841   DUAL=          0.0
 I=  12   RHS=       -6909.70194   B=       11899.99841   DUAL=          0.0
 I=  13   RHS=       -5081.50340   B=        7500.00048   DUAL=          0.0
 I=  14   RHS=       -5480.56598   B=        7500.00048   DUAL=          0.0
 I=  15   RHS=       -6129.23975   B=        7500.00048   DUAL=          0.0
 I=  16   RHS=       -8431.74346   B=        7500.00048   DUAL=          0.0
 I=  17   RHS=      -11214.74394   B=        7500.00048   DUAL=          0.0
 I=  18   RHS=      -13781.59281   B=        7500.00048   DUAL=          0.0
 I=  19   RHS=      -16149.07825   B=        7500.00048   DUAL=          0.0
 I=  20   RHS=       -9208.28240   B=        7500.00048   DUAL=          0.0
 I=  21   RHS=        7500.00048   B=        7500.00048   DUAL=         29.11750
 I=  22   RHS=        7500.00048   B=        7500.00048   DUAL=        763.83947
 I=  23   RHS=        7500.00048   B=        7500.00048   DUAL=        171.74241
 I=  24   RHS=        7500.00048   B=        7500.00048   DUAL=        202.63279
 I=  25   RHS=      -38382.28686   B=       60513.63911   DUAL=          0.0
 I=  26   RHS=      -34127.15757   B=       60513.63911   DUAL=          0.0
 I=  27   RHS=      -19023.33890   B=       60513.63911   DUAL=          0.0
 I=  28   RHS=        -767.58788   B=       60513.63911   DUAL=          0.0
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I=	29	RHS=	16070.26547	B=	60513.63911	DUAL=	0.0
I=	30	RHS=	31600.34720	B=	60513.63911	DUAL=	0.0
I=	31	RHS=	45458.56732	B=	60513.63911	DUAL=	0.0
I=	32	RHS=	36405.15319	B=	60513.63911	DUAL=	0.0
I=	33	RHS=	12023.60515	B=	60513.63911	DUAL=	0.0
I=	34	RHS=	-8641.09445	B=	60513.63911	DUAL=	0.0
I=	35	RHS=	-26155.56107	B=	60513.63911	DUAL=	0.0
I=	36	RHS=	-41000.03242	B=	60513.63911	DUAL=	0.0
I=	37	RHS=	-2617.74557	B=	0.0	DUAL=	0.0
I=	38	RHS=	-6872.87485	B=	0.0	DUAL=	0.0
I=	39	RHS=	-21976.69352	B=	0.0	DUAL=	0.0
I=	40	RHS=	-40232.44454	B=	0.0	DUAL=	0.0
I=	41	RHS=	-57070.29789	B=	0.0	DUAL=	0.0
I=	42	RHS=	-72600.37963	B=	0.0	DUAL=	0.0
I=	43	RHS=	-86458.59974	B=	0.0	DUAL=	0.0
I=	44	RHS=	-77405.18562	B=	0.0	DUAL=	0.0
I=	45	RHS=	-53023.63758	B=	0.0	DUAL=	0.0
I=	46	RHS=	-32358.93798	B=	0.0	DUAL=	0.0
I=	47	RHS=	-14844.47135	B=	0.0	DUAL=	0.0
I=	48	RHS=	0.00000	B=	0.0	DUAL=	1063.43711
I=	49	RHS=	-3014.87991	B=	0.0	DUAL=	0.0
I=	50	RHS=	-15557.07370	B=	0.0	DUAL=	0.0
I=	51	RHS=	-15557.07370	B=	0.0	DUAL=	0.0
I=	52	RHS=	-14572.68428	B=	0.0	DUAL=	0.0
I=	53	RHS=	-15557.07370	B=	0.0	DUAL=	0.0
I=	54	RHS=	-11289.59532	B=	0.0	DUAL=	0.0
I=	55	RHS=	0.00000	B=	0.0	DUAL=	5.76133
I=	56	RHS=	-15557.07370	B=	0.0	DUAL=	0.0
I=	57	RHS=	-11185.26048	B=	0.0	DUAL=	0.0
I=	58	RHS=	0.00000	B=	0.0	DUAL=	386.23865
I=	59	RHS=	-5706.50671	B=	0.0	DUAL=	0.0
I=	60	RHS=	-11476.21292	B=	0.0	DUAL=	0.0
I=	61	RHS=	-12175.18204	B=	0.0	DUAL=	0.0
I=	62	RHS=	-12175.18204	B=	0.0	DUAL=	0.0
I=	63	RHS=	-12175.18204	B=	0.0	DUAL=	0.0
I=	64	RHS=	-12175.18204	B=	0.0	DUAL=	0.0
I=	65	RHS=	-12175.18204	B=	0.0	DUAL=	0.0
I=	66	RHS=	-12175.18204	B=	0.0	DUAL=	0.0
I=	67	RHS=	-11357.64552	B=	0.0	DUAL=	0.0
I=	68	RHS=	0.00000	B=	0.0	DUAL=	66.45999
I=	69	RHS=	0.00000	B=	0.0	DUAL=	91.13867
I=	70	RHS=	0.0	B=	0.0	DUAL=	477.37732
I=	71	RHS=	-0.00000	B=	0.0	DUAL=	91.13867
I=	72	RHS=	0.00000	B=	0.0	DUAL=	91.13867
I=	73	RHS=	-0.00000	B=	0.0	DUAL=	5.76133
I=	74	RHS=	-0.00000	B=	0.0	DUAL=	5.76133
I=	75	RHS=	-0.00000	B=	0.0	DUAL=	5.76133
I=	76	RHS=	-0.00000	B=	0.0	DUAL=	5.76133
I=	77	RHS=	-0.00000	B=	0.0	DUAL=	68.86452
I=	78	RHS=	-0.00000	B=	0.0	DUAL=	5.76133
I=	79	RHS=	-817.53652	B=	0.0	DUAL=	0.0
I=	80	RHS=	-12175.18204	B=	0.0	DUAL=	0.0
I=	81	RHS=	-12175.18204	B=	0.0	DUAL=	0.0
I=	82	RHS=	-12175.18204	B=	0.0	DUAL=	0.0
I=	83	RHS=	-12175.18204	B=	0.0	DUAL=	0.0
I=	84	RHS=	-12175.18204	B=	0.0	DUAL=	0.0
I=	85	RHS=	-0.00000	B=	0.0	DUAL=	1003.43862
I=	86	RHS=	0.00000	B=	0.0	DUAL=	1003.43862
I=	87	RHS=	0.00000	B=	0.0	DUAL=	1003.43862
I=	88	RHS=	-0.00000	B=	0.0	DUAL=	1003.43862
I=	89	RHS=	-0.00000	B=	0.0	DUAL=	940.33543
I=	90	RHS=	-0.00000	B=	0.0	DUAL=	1003.43862
I=	91	RHS=	-0.00000	B=	0.0	DUAL=	1009.19995
I=	92	RHS=	0.00000	B=	0.0	DUAL=	1009.19995
I=	93	RHS=	0.0	B=	0.0	DUAL=	1009.19995
I=	94	RHS=	-0.00000	B=	0.0	DUAL=	1009.19995
I=	95	RHS=	0.0	B=	0.0	DUAL=	1009.19995
I=	96	RHS=	0.00000	B=	0.0	DUAL=	1009.19995

I=	97	RHS=	67211.44999	B=	200000.00000	DUAL=	0.0
I=	98	RHS=	500000.00000	B=	500000.00000	DUAL=	198.96128
I=	99	RHS=	2000.00000	B=	2000.00000	DUAL=	5773.51692
I=	100	RHS=	0.0	B=	2500.00000	DUAL=	0.0
I=	101	RHS=	947.66675	B=	947.66675	DUAL=	1134.11594
I=	102	RHS=	947.66675	B=	947.66675	DUAL=	1134.11594
I=	103	RHS=	947.66675	B=	947.66675	DUAL=	1134.11594
I=	104	RHS=	947.66675	B=	947.66675	DUAL=	1134.11594
I=	105	RHS=	947.66675	B=	947.66675	DUAL=	1071.01274
I=	106	RHS=	947.66675	B=	947.66675	DUAL=	1134.11594
I=	107	RHS=	947.66675	B=	947.66675	DUAL=	1139.87727
I=	108	RHS=	947.66675	B=	947.66675	DUAL=	1206.33726
I=	109	RHS=	947.66675	B=	947.66675	DUAL=	1231.01594
I=	110	RHS=	947.66675	B=	947.66675	DUAL=	1617.25459
I=	111	RHS=	947.66675	B=	947.66675	DUAL=	1231.01594
I=	112	RHS=	947.66675	B=	947.66675	DUAL=	1231.01594
I=	113	RHS=	751.21715	B=	3000.00000	DUAL=	0.0
I=	114	RHS=	-20386.60675	B=	-20386.60675	DUAL=	852.84519
I=	115	RHS=	100000.00000	B=	100000.00000	DUAL=	15.29877
I=	116	RHS=	39809.93805	B=	55000.00000	DUAL=	0.0
I=	117	RHS=	27267.74426	B=	55000.00000	DUAL=	0.0
I=	118	RHS=	27267.74426	B=	55000.00000	DUAL=	0.0
I=	119	RHS=	28252.13368	B=	55000.00000	DUAL=	0.0
I=	120	RHS=	27267.74426	B=	55000.00000	DUAL=	0.0
I=	121	RHS=	31535.22265	B=	55000.00000	DUAL=	0.0
I=	122	RHS=	43642.35448	B=	55000.00000	DUAL=	0.0
I=	123	RHS=	39442.92630	B=	55000.00000	DUAL=	0.0
I=	124	RHS=	43814.73952	B=	55000.00000	DUAL=	0.0
I=	125	RHS=	55000.00000	B=	55000.00000	DUAL=	232.03970
I=	126	RHS=	49293.49329	B=	55000.00000	DUAL=	0.0
I=	127	RHS=	43523.78708	B=	55000.00000	DUAL=	0.0
I=	128	RHS=	50148.87822	B=	50148.87822	DUAL=	-1202.39990
I=	129	RHS=	35969.30072	B=	35969.30072	DUAL=	-1202.39990
I=	130	RHS=	25120.61133	B=	25120.61133	DUAL=	-1202.39990
I=	131	RHS=	22953.06840	B=	22953.06840	DUAL=	-1202.39990
I=	132	RHS=	23386.57665	B=	23386.57665	DUAL=	-1139.29670
I=	133	RHS=	28961.82665	B=	28961.82665	DUAL=	-1202.39990
I=	134	RHS=	42740.82011	B=	42740.82011	DUAL=	-1208.16123
I=	135	RHS=	61453.02617	B=	61453.02617	DUAL=	-1274.62122
I=	136	RHS=	81152.97330	B=	81152.97330	DUAL=	-1299.29990
I=	137	RHS=	88621.38534	B=	88621.38534	DUAL=	-1917.57825
I=	138	RHS=	79764.64566	B=	79764.64566	DUAL=	-1299.29990
I=	139	RHS=	71324.94418	B=	71324.94418	DUAL=	-1299.29990

OPTIMAL SOLUTION CHARACTERISTICS

****

CONSOLIDATED

MAXIMAL MONTHLY SUPPLY= 15557.07
MAXIMAL DAILY SUPPLY= 518.57

PANHANDLE

MAXIMAL MONTHLY SUPPLY= 48700.73
MAXIMAL DAILY SUPPLY= 1623.36

IM= 1	FSN= -2617.75	SUP1= 12542.19	SUP2= 36525.55	SUPV= 36525.55	PROD= 1698.88	DGMT= 50148.88
IM= 2	FSN= -4255.13	SUP1= 0.0	SUP2= 36525.55	SUPV= 36525.55	PROD= 1698.88	DGMT= 35969.39
IM= 3	FSN=-15103.82	SUP1= 0.0	SUP2= 36525.55	SUPV= 36525.55	PROD= 1698.88	DGMT= 25120.61
IM= 4	FSN=-18255.75	SUP1= 984.39	SUP2= 36525.55	SUPV= 36525.55	PROD= 1698.88	DGMT= 22953.07
IM= 5	FSN=-16837.85	SUP1= 0.0	SUP2= 36525.55	SUPV= 36525.55	PROD= 1698.88	DGMT= 23386.58
IM= 6	FSN=-15530.08	SUP1= 4267.48	SUP2= 36525.55	SUPV= 36525.55	PROD= 1698.88	DGMT= 28961.83
IM= 7	FSN=-13858.22	SUP1= 15557.07	SUP2= 37343.08	SUPV= 37343.08	PROD= 1698.88	DGMT= 42740.82
IM= 8	FSN= 9053.41	SUP1= 0.0	SUP2= 48700.73	SUPV= 48700.73	PROD= 1698.88	DGMT= 61453.03
IM= 9	FSN= 24381.55	SUP1= 4371.61	SUP2= 48700.73	SUPV= 48700.73	PROD= 1698.88	DGMT= 81152.97
IM= 10	FSN= 20664.70	SUP1= 15557.07	SUP2= 48700.73	SUPV= 48700.73	PROD= 1698.88	DGMT= 88621.39
IM= 11	FSN= 17514.47	SUP1= 9850.57	SUP2= 48700.73	SUPV= 48700.73	PROD= 1698.88	DGMT= 79764.65
IM= 12	FSN= 14844.47	SUP1= 4080.66	SUP2= 48700.73	SUPV= 48700.73	PROD= 1698.88	DGMT= 71324.94

SUPWH= 2000.000
SUPFL= 0.0
DPRO= 751.217
DSTC= 100000.000
DPT1= 12956.686

TOTAL DEMAND CHARGE=	42331712.11	OR	0.06106	OF MINIMUM COST
TOTAL COMMODITY CHARGE=	585415016.49	OR	0.84443	OF MINIMUM COST
TOTAL STORAGE COST=	5746037.80	OR	0.00829	OF MINIMUM COST
TOTAL WINTER CHARGE=	3281064.42	OR	0.00473	OF MINIMUM COST

SUMMARY OF MONTHLY STORAGE GAS FLOWS AND STOCKS

IM= 1	GSTOR= 0.0	RSTOR= 0.0	GINST= 2617.75	GIMAX= 19962.65	GOUST= 0.0	GOMAX= 12581.50
IM= 2	GSTOR= 2617.75	RSTOR= 0.78	GINST= 4255.13	GIMAX= 19759.33	GOUST= 0.0	GOMAX= 12980.57
IM= 3	GSTOR= 6872.87	RSTOR= 0.80	GINST= 15103.82	GIMAX= 19428.84	GOUST= 0.0	GOMAX= 13629.24
IM= 4	GSTOR= 21976.69	RSTOR= 0.86	GINST= 18255.75	GIMAX= 18255.75	GOUST= 0.0	GOMAX= 15931.74
IM= 5	GSTOR= 40232.44	RSTOR= 0.93	GINST= 16837.85	GIMAX= 16837.85	GOUST= 0.0	GOMAX= 18714.74
IM= 6	GSTOR= 57070.30	RSTOR= 1.00	GINST= 15530.08	GIMAX= 15530.08	GOUST= 0.0	GOMAX= 21281.59
IM= 7	GSTOR= 72600.38	RSTOR= 1.06	GINST= 13858.22	GIMAX= 14323.88	GOUST= 0.0	GOMAX= 23649.08
IM= 8	GSTOR= 86458.60	RSTOR= 1.12	GINST= 0.0	GIMAX= 13247.54	GOUST= 9053.41	GOMAX= 25761.70

```
IM=  9  CSTOR=  77405.19  RSTOR=       1.08  GINST=       0.0  GIMAX=  13950.70  COUST=  24381.55  COMAX=  24381.55
IM= 10  CSTOR=  53023.64  RSTOR=       0.98  GINST=       0.0  GIMAX=  15844.38  COUST=  20664.70  COMAX=  20664.70
IM= 11  CSTOR=  32358.94  RSTOR=       0.90  GINST=       0.0  GIMAX=  17449.38  COUST=  17514.47  COMAX=  17514.47
IM= 12  CSTOR=  14844.47  RSTOR=       0.83  GINST=       0.0  GIMAX=  18809.70  COUST=  14844.47  COMAX=  14844.47

        YEARLY FLOW INTO STORAGE=     86458.60
        YEARLY FLOW OUT OF STORAGE=     86458.60
```

DUAL VALUES SUMMARY
****

```
IM= 1  VGINS=     0.0    VCOUS=      0.0      VSMAX=     0.0    VSMIN=       0.0
IM= 2  VGINS=     0.0    VCOUS=      0.0      VSMAX=     0.0    VSMIN=       0.0
IM= 3  VGINS=     0.0    VCOUS=      0.0      VSMAX=     0.0    VSMIN=       0.0
IM= 4  VGINS=     0.000  VCOUS=      0.0      VSMAX=     0.0    VSMIN=       0.0
IM= 5  VGINS=    68.417  VCOUS=      0.0      VSMAX=     0.0    VSMIN=       0.0
IM= 6  VGINS=     5.761  VCOUS=      0.0      VSMAX=     0.0    VSMIN=       0.0
IM= 7  VGINS=     0.0    VCOUS=      0.0      VSMAX=     0.0    VSMIN=       0.0
IM= 8  VGINS=     0.0    VCOUS=      0.0      VSMAX=     0.0    VSMIN=       0.0
IM= 9  VGINS=     0.0    VCOUS=     29.11750  VSMAX=     0.0    VSMIN=       0.0
IM=10  VGINS=     0.0    VCOUS=    763.83947  VSMAX=     0.0    VSMIN=       0.0
IM=11  VGINS=     0.0    VCOUS=    171.74241  VSMAX=     0.0    VSMIN=       0.0
IM=12  VGINS=     0.0    VCOUS=    202.63279  VSMAX=     0.0    VSMIN=    1063.437

        ********************************************************************************

IM= 1  V1X=     0.0    V2X=     0.0    VVV=     5.761  VSUV=  1003.439  VDCMT= -1202.400
IM= 2  V1X=     0.0    V2X=     0.0    VVV=     5.761  VSUV=  1003.439  VDCMT= -1202.400
IM= 3  V1X=     0.0    V2X=     0.0    VVV=     5.761  VSUV=  1003.439  VDCMT= -1202.400
IM= 4  V1X=     0.0    V2X=     0.0    VVV=     5.761  VSUV=  1003.439  VDCMT= -1202.400
IM= 5  V1X=     0.0    V2X=     0.0    VVV=    68.865  VSUV=   940.335  VDCMT= -1139.297
IM= 6  V1X=     0.0    V2X=     0.0    VVV=     5.761  VSUV=  1003.439  VDCMT= -1202.400
IM= 7  V1X=     5.761  V2X=     0.0    VVV=     0.0    VSUV=  1009.200  VDCMT= -1208.161
IM= 8  V1X=     0.0    V2X=    66.460  VVV=     0.0    VSUV=  1009.200  VDCMT= -1274.621
IM= 9  V1X=     0.0    V2X=    91.139  VVV=     0.0    VSUV=  1009.200  VDCMT= -1299.300
IM=10  V1X=   386.239  V2X=   477.377  VVV=     0.0    VSUV=  1009.200  VDCMT= -1917.578
IM=11  V1X=     0.0    V2X=    91.139  VVV=     0.0    VSUV=  1009.200  VDCMT= -1299.300
IM=12  V1X=     0.0    V2X=    91.139  VVV=     0.0    VSUV=  1009.200  VDCMT= -1299.300

        VS1T=          0.0
        VS2T=        198.96128

        ********************************************************************************

             IM=  1    VPRO=     1134.11594     VTRAN=        0.0
             IM=  2    VPRO=     1134.11594     VTRAN=        0.0
             IM=  3    VPRO=     1134.11594     VTRAN=        0.0
             IM=  4    VPRO=     1134.11594     VTRAN=        0.0
             IM=  5    VPRO=     1071.01274     VTRAN=        0.0
             IM=  6    VPRO=     1134.11594     VTRAN=        0.0
             IM=  7    VPRO=     1139.87727     VTRAN=        0.0
             IM=  8    VPRO=     1206.33726     VTRAN=        0.0
             IM=  9    VPRO=     1231.01594     VTRAN=        0.0
             IM= 10    VPRO=     1617.25459     VTRAN=      232.03970
             IM= 11    VPRO=     1231.01594     VTRAN=        0.0
```

```
        IM= 12   VPRO=     1231.01594     VTRAN=         0.0

     *****************************************************************************

VSWH=  5773.517   VSFL=     0.0     VPRMX=     0.0     VPRMN=  852.845   VSTC=    15.299

*****************************************************************************
   TOTAL INVESTMENT IN PRODUCTION,STORAGE AND TRANSMISSION CAPACITY

           ANNUALIZED COST PIS=     18822572.18
           TOTAL DISCOUNTED COST NEWPIS=   151672576.

   PURCHASES, PRODUCTION AND STORAGE OPERATING COSTS OMC1=   674440528.57

   TOTAL ANNUAL GAS DEMAND (MMCF) DCT=      611598.06
*****************************************************************************
```

OUTPUT OF SUBROUTINE DIST

```
PEAK MONTH=  10   PEAK LOAD=  88621.39
TRANSMISSION MARGINAL COST=     216.308     NEW TRANSMISSION PLANT=       211576.44
DISTRIBUTION MARGINAL COST=    1954.964     NEW DISTRIBUTION PLANT=    465353472.
```

OUTPUT OF SUBROUTINE REVREQ

```
REPPIS=    22378524.476
TOTPIS=  1256954652.476
DEPEXP=    36941896.994
TAPD=   255177921.146
NETPIS=  1001776640.

OOPREV=      2875912.194
ONUINC=      3739440.177
OMC2=   128120591.292
ACOPEX=   839503016.853
PRPTAX=    21037311.022
PAYTAX=     3843617.892
INVTXC=    63961616.0

X0=     33192403.416
X1=    120814247.880
X2=     79230120.859
X3=     77007639.572
X4=    864383945.767
X5=    982103711.142
X6=      6615352.371

NEWPIS=   617237504.
DGT=      611598.057
OMC1=   674440528.567
X=  975488358.771
PAVG=  1594.983
```

OUTPUT OF SUBROUTINE EVALI

GAS CONSUMPTION EVALUATION CRITERIA

PEAK MONTH= 10
PEAK LOAD (MMCF)= 88621.39
LOAD FACTOR= 0.5751
TOTAL GAS CONSUMPTION= 611598.06

AVERAGE VOLUMETRIC RATE= 1594.983
ACHIEVED GAS SALES REVENUE= 975488358.77

EFFICIENCY CRITERIA

MONTH=	1	RESIDENTIAL SURPLUS=	110228601.	COMMERCIAL SURPLUS=	44103576.	INDUSTRIAL SURPLUS=	86256140.
MONTH=	2	RESIDENTIAL SURPLUS=	65764123.	COMMERCIAL SURPLUS=	27174647.	INDUSTRIAL SURPLUS=	79623286.
MONTH=	3	RESIDENTIAL SURPLUS=	31744682.	COMMERCIAL SURPLUS=	14222448.	INDUSTRIAL SURPLUS=	74548539.
MONTH=	4	RESIDENTIAL SURPLUS=	24947676.	COMMERCIAL SURPLUS=	11634629.	INDUSTRIAL SURPLUS=	73534616.
MONTH=	5	RESIDENTIAL SURPLUS=	26307076.	COMMERCIAL SURPLUS=	12152193.	INDUSTRIAL SURPLUS=	73737401.
MONTH=	6	RESIDENTIAL SURPLUS=	43790008.	COMMERCIAL SURPLUS=	18808457.	INDUSTRIAL SURPLUS=	76345364.
MONTH=	7	RESIDENTIAL SURPLUS=	86998330.	COMMERCIAL SURPLUS=	35259131.	INDUSTRIAL SURPLUS=	82790834.
MONTH=	8	RESIDENTIAL SURPLUS=	145676275.	COMMERCIAL SURPLUS=	57599545.	INDUSTRIAL SURPLUS=	91543939.
MONTH=	9	RESIDENTIAL SURPLUS=	207451590.	COMMERCIAL SURPLUS=	81119217.	INDUSTRIAL SURPLUS=	100759084.
MONTH=	10	RESIDENTIAL SURPLUS=	230871120.	COMMERCIAL SURPLUS=	90035719.	INDUSTRIAL SURPLUS=	104252621.
MONTH=	11	RESIDENTIAL SURPLUS=	203098056.	COMMERCIAL SURPLUS=	79461699.	INDUSTRIAL SURPLUS=	100109659.
MONTH=	12	RESIDENTIAL SURPLUS=	176632746.	COMMERCIAL SURPLUS=	69385580.	INDUSTRIAL SURPLUS=	96161776.

TOTAL RESIDENTIAL SURPLUS 1353510283.
TOTAL COMMERCIAL SURPLUS 540956841.
TOTAL INDUSTRIAL SURPLUS 1039663259.
TOTAL CONSUMER SURPLUS 2934130383.

PRODUCER SURPLUS 120814248.

TOTAL SURPLUS 3054944631.

ITERATIVE EQUILIBRIUM PROCEDURE

ITERATION NUMBER 1
****

MONTHLY MARGINAL COSTS

MONTH=	1	COST=	1411.885
MONTH=	2	COST=	1411.885
MONTH=	3	COST=	1411.885
MONTH=	4	COST=	1411.885
MONTH=	5	COST=	1348.782
MONTH=	6	COST=	1411.885
MONTH=	7	COST=	1417.646
MONTH=	8	COST=	1484.106
MONTH=	9	COST=	1508.785
MONTH=	10	COST=	4298.336
MONTH=	11	COST=	1508.785
MONTH=	12	COST=	1508.785

SUBROUTINE LOAD--GAS MARKET CHARACTERISTICS
===

GAS DEMAND PATTERNS

BASE DEMAND (MMCF)

MONTH=	1	DGMRO=	16280.51	DGMCO=	6514.00	DGMIO=	12739.84	DGMTO=	35534.35
MONTH=	2	DGMRO=	9713.21	DGMCO=	4013.63	DGMIO=	11760.18	DGMTO=	25487.02
MONTH=	3	DGMRO=	4688.62	DGMCO=	2100.62	DGMIO=	11010.65	DGMTO=	17799.89
MONTH=	4	DGMRO=	3684.71	DGMCO=	1718.41	DGMIO=	10860.90	DGMTO=	16264.02
MONTH=	5	DGMRO=	3975.35	DGMCO=	1836.36	DGMIO=	11142.70	DGMTO=	16954.41
MONTH=	6	DGMRO=	6467.68	DGMCO=	2777.97	DGMIO=	11276.04	DGMTO=	20521.69
MONTH=	7	DGMRO=	12823.32	DGMCO=	5197.10	DGMIO=	12203.14	DGMTO=	30223.56
MONTH=	8	DGMRO=	20986.00	DGMCO=	8297.74	DGMIO=	13187.74	DGMTO=	42471.49
MONTH=	9	DGMRO=	29639.89	DGMCO=	11590.00	DGMIO=	14396.07	DGMTO=	55625.96
MONTH=	10	DGMRO=	19543.07	DGMCO=	7621.46	DGMIO=	8824.91	DGMTO=	35989.44
MONTH=	11	DGMRO=	29017.87	DGMCO=	11353.18	DGMIO=	14303.28	DGMTO=	54674.34
MONTH=	12	DGMRO=	25236.61	DGMCO=	9913.55	DGMIO=	13739.23	DGMTO=	48889.38
TOTAL		DGMRTO=	182056.85	DGMCTO=	72934.02	DGMITO=	145444.67	DGMTTO	400435.54

FORECASTED DEMAND (MMCF)

MONTH=	1	DGMR =	24420.77	DGMC =	9771.00	DGMI =	19109.75	DGMT =	53301.52
MONTH=	2	DGMR =	14569.82	DGMC =	6020.45	DGMI =	17640.27	DGMT =	38230.53
MONTH=	3	DGMR =	7032.93	DGMC =	3150.93	DGMI =	16515.97	DGMT =	26699.83
MONTH=	4	DGMR =	5527.07	DGMC =	2577.61	DGMI =	16291.34	DGMT =	24396.03
MONTH=	5	DGMR =	5963.02	DGMC =	2754.54	DGMI =	16714.05	DGMT =	25431.61

MONTH=	6	DGMR	=	9701.53	DGMC	=	4166.95	DGMI	=	16914.05	DGMT =	30782.53
MONTH=	7	DGMR	=	19234.98	DGMC	=	7795.65	DGMI	=	18304.72	DGMT =	45335.34
MONTH=	8	DGMR	=	31479.01	DGMC	=	12446.61	DGMI	=	19781.62	DGMT =	63707.24
MONTH=	9	DGMR	=	44459.83	DGMC	=	17385.00	DGMI	=	21594.11	DGMT =	83438.94
MONTH=	10	DGMR	=	29314.61	DGMC	=	11432.19	DGMI	=	13237.36	DGMT =	53984.16
MONTH=	11	DGMR	=	43526.81	DGMC	=	17029.77	DGMI	=	21454.93	DGMT =	82011.50
MONTH=	12	DGMR	=	37854.91	DGMC	=	14870.32	DGMI	=	20608.84	DGMT =	73334.07
TOTAL		DGMRT	=	273085.28	DGMCT	=	109401.03	DGMIT	=	218167.01	DGMTT	600653.31

TOTAL DEMAND INCREMENT (MMCF) 200217.77

OUTPUT FROM SUBROUTINE MARCOS

EXISTING MONTHLY PRODUCTION CAPACITY PROC= 947.667

EXISTING MONTHLY TRANSMISSION CAPACITY PT10= 55000.000

```
OPTIMAL SOLUTION

OBJ   -682006594.8  ISTATE   4  ITERATIONS  94  DETERMINANT          -7.03470  INFEAS   0  NINTO   0  NOUTOF   0

N  79  NCOL  67  M 139  MNOW 139  ISFEAS   1 IRCNT   1

X VECTOR
        0.0       7309.23128 11332.30104 10452.13767  9640.33532  8891.58448  8200.98803     0.0         0.0         0.0
        0.0          0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0     16010.49081
  13569.76934  6956.72775 10440.60467  8848.98525  7761.75407     0.0         0.0         0.0         0.0         0.0
   7996.56850  2156.98421 24[illegible]29.40594  1487.67130 26031.13571 18945.31902 41871.28236 41871.28236 34363.65321 31179.68300
  31403.46177 36005.63233 41871.28236 41871.28236 41871.28236 41871.28236 41871.28236 41871.28236 41871.28236 41871.28236
  34363.65321 31403.46177 31403.46177 36005.63233 41871.28236 41871.28236 41871.28236 41871.28236 41871.28236 41871.28236
  26031.13571 41871.28236  2000.00000     0.0      1668.48181  1668.48181  1668.48181  1668.48181  1668.48181  1668.48181
   1668.48181  1668.48181  1668.48181  1668.48181  1668.48181  1668.48181   720.81507     0.0     16570.89988

SLACK VECTOR
  11899.99841  4590.76714     0.0         0.0         0.0         0.0         0.0      7564.02920  8807.54076  9861.48504
  10401.80398 11212.71058  7500.00048  7500.00048  8614.25725 10341.81143 11935.18900 13404.81124 14760.29006     0.0
        0.0     4544.39623     0.0         0.0     60513.63911 53204.40783 41872.10679 31419.96912 21779.63380 12888.04932
   4687.06129 20697.55210 34267.32144 41224.04919 51664.65386 60513.63911     0.0      7309.23128 18641.53231 29093.66999
  38734.00531 47625.58979 55126.57781 39816.08700 26246.31767 19289.58992  8848.98525     0.0     18269.38164 26031.13571
  26031.13571 26031.13571 26031.13571 26031.13571 18034.56722 23874.15151  1701.72977 24543.46441     0.0      7085.81669
        0.0         0.0      7507.62915 10691.59936 10467.82059  5865.65002     0.0         0.0         0.0         0.0
        0.0         0.0     10467.82059 10467.82059  2960.19144     0.0         0.0      4602.17056 10467.82059 10467.82059
  10467.82059 10467.82059 10467.82059 10467.82059     0.0         0.0         0.0       223.77877     0.0         0.0
        0.0         0.0         0.0         0.0         0.0         0.0    111291.16125 32077.31083     0.0      2500.00000
        0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0
        0.0         0.0      2279.18493     0.0    100000.00000 18269.38164 26031.13571 33538.76486 36722.73507 36498.95630
  31896.78574 18034.56722 23874.15151  1701.72977 24543.46441     0.0      7085.81669     0.0         0.0         0.0
        0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0

DUAL VECTOR
        0.0         0.0        23.61937  1119.79193  1203.80235   221.27573    30.44001     0.0         0.0         0.0
        0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.00000
       -0.00000     0.0       736.28234   132.43115     0.0         0.0         0.0         0.0         0.0         0.0
        0.0         0.0         0.0         0.0         0.0         0.0       104.95507     0.0         0.0         0.0
        0.0         0.0         0.0         0.0         0.0         0.0         0.0      1133.63876     0.0         0.0
        0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0       391.99998     0.0
      193.19995    21.78489     0.0         0.0         0.0         0.0       193.19995   290.09995   290.09995   290.09995
      682.09993   290.09995     0.0         0.0         0.0      1009.19995   999.71279     0.0         0.0         0.0
        0.0         0.0         0.0         0.0      1009.19995  1009.19995  1009.19995     0.0         9.48716  1009.19995
     1009.19995  1009.19995  1009.19995  1009.19995  1009.19995  1009.19995     0.0         0.0      2908.17118     0.0
     1372.89475  1201.47969  1179.69480   170.49485   179.98201  1179.69480  1372.89475  1469.79475  1469.79475  1469.79475
     1861.79473  1469.79475     0.0      1091.62400     0.0         0.0         0.0         0.0         0.0         0.0
        0.0         0.0         0.0         0.0         0.0       232.03970     0.0     -1202.39990 -1030.98484 -1009.19995
        0.0        -9.48716 -1009.19995 -1202.39990 -1299.29990 -1299.29990 -1299.29990 -1923.33958 -1299.29990

COST VECTOR
      -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000
      -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000   -33.23000
      -33.23000   -33.23000   -33.23000   -33.23000 -1202.39990 -1202.39990 -1202.39990 -1202.39990 -1202.39990 -1202.39990
    -1202.39990 -1299.29990 -1299.29990 -1299.29990 -1299.29990 -1299.29990     0.0         0.0         0.0         0.0
        0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0     -1009.19995 -1009.19995
    -1009.19995 -1009.19995 -1009.19995 -1009.19995 -1009.19995 -1009.19995 -1009.19995 -1009.19995 -1009.19995 -1009.19995
     -391.99998  -743.99996 -9444.00000-17772.00000  -921.12915  -921.12915  -921.12915  -921.12915  -921.12915  -921.12915
     -921.12915  -921.12915  -921.12915  -921.12915  -921.12915  -921.12915-14398.10937************  -232.03970

BOUND VECTOR
     -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000
     -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000
     -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000
     -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000
     -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000
     -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000
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        -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000
        -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000    -1.00000

B VECTOR
     11899.99841 11899.99841 11899.99841 11899.99841 11899.99841 11899.99841 11899.99841 11899.99841 11899.99841 11899.99841
     11899.99841 11899.99841  7500.00048  7500.00048  7500.00048  7500.00048  7500.00048  7500.00048  7500.00048  7500.00048
      7500.00048  7500.00048  7500.00048  7500.00048 60513.63911 60513.63911 60513.63911 60513.63911 60513.63911 60513.63911
     60513.63911 60513.63911 60513.63911 60513.63911 60513.63911 60513.63911     0.0         0.0         0.0         0.0
         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0
         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0
         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0
         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0
         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0
         0.0         0.0         0.0         0.0         0.0         0.0   200000.00000500000.00000  2000.00000  2500.00000
       947.66675   947.66675   947.66675   947.66675   947.66675   947.66675   947.66675   947.66675   947.66675   947.66675
       947.66675   947.66675  3000.00000-20021.78176100000.00000 55000.00000 55000.00000 55000.00000 55000.00000 55000.00000
     55000.00000 55000.00000 55000.00000 55000.00000 55000.00000 55000.00000 55000.00000 53301.51825 38230.53289 26699.83399
     24396.02714 25431.60826 30782.52967 45335.34464 63707.23919 83438.93945 53984.16323 82011.50455 73334.06844

SIGN VECTOR
         1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000
         1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000
         1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000
         1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000
         1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000
         1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000
         1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000
         1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000
         1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000
         1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000
         1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000
         1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000
         1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     1.00000     0.0         0.0         0.0
         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0         0.0
```


CONSTRAINTS VALUES AND DUAL PRICES

I=	1	RHS=	0.0	B=	11899.99841	DUAL=	0.0
I=	2	RHS=	7309.23128	B=	11899.99841	DUAL=	0.0
I=	3	RHS=	11899.99841	B=	11899.99841	DUAL=	23.61937
I=	4	RHS=	11899.99841	B=	11899.99841	DUAL=	1119.79193
I=	5	RHS=	11899.99841	B=	11899.99841	DUAL=	1203.80235
I=	6	RHS=	11899.99841	B=	11899.99841	DUAL=	221.27573
I=	7	RHS=	11899.99841	B=	11899.99841	DUAL=	30.44001
I=	8	RHS=	4335.96922	B=	11899.99841	DUAL=	0.0
I=	9	RHS=	3092.45765	B=	11899.99841	DUAL=	0.0
I=	10	RHS=	2038.51337	B=	11899.99841	DUAL=	0.0
I=	11	RHS=	1498.19443	B=	11899.99841	DUAL=	0.0
I=	12	RHS=	687.28783	B=	11899.99841	DUAL=	0.0
I=	13	RHS=	0.0	B=	7500.00048	DUAL=	0.0
I=	14	RHS=	0.0	B=	7500.00048	DUAL=	0.0
I=	15	RHS=	-1114.25677	B=	7500.00048	DUAL=	0.0
I=	16	RHS=	-2841.81096	B=	7500.00048	DUAL=	0.0
I=	17	RHS=	-4435.18852	B=	7500.00048	DUAL=	0.0
I=	18	RHS=	-5904.81077	B=	7500.00048	DUAL=	0.0
I=	19	RHS=	-7260.28958	B=	7500.00048	DUAL=	0.0
I=	20	RHS=	7500.00048	B=	7500.00048	DUAL=	0.00000
I=	21	RHS=	7500.00048	B=	7500.00048	DUAL=	-0.00000
I=	22	RHS=	2955.60425	B=	7500.00048	DUAL=	0.0
I=	23	RHS=	7500.00048	B=	7500.00048	DUAL=	736.28234
I=	24	RHS=	7500.00048	B=	7500.00048	DUAL=	132.43115
I=	25	RHS=	0.0	B=	60513.63911	DUAL=	0.0
I=	26	RHS=	7309.23128	B=	60513.63911	DUAL=	0.0
I=	27	RHS=	18641.53231	B=	60513.63911	DUAL=	0.0
I=	28	RHS=	29093.66999	B=	60513.63911	DUAL=	0.0

I=	29	RHS=	38734.00531	B=	60513.63911	DUAL=	0.0
I=	30	RHS=	47625.58979	B=	60513.63911	DUAL=	0.0
I=	31	RHS=	55826.57781	B=	60513.63911	DUAL=	0.0
I=	32	RHS=	39816.08700	B=	60513.63911	DUAL=	0.0
I=	33	RHS=	26246.31767	B=	60513.63911	DUAL=	0.0
I=	34	RHS=	19289.58992	B=	60513.63911	DUAL=	0.0
I=	35	RHS=	8848.98525	B=	60513.63911	DUAL=	0.0
I=	36	RHS=	0.00000	B=	60513.63911	DUAL=	0.0
I=	37	RHS=	0.0	B=	0.0	DUAL=	104.95507
I=	38	RHS=	-7309.23128	B=	0.0	DUAL=	0.0
I=	39	RHS=	-18641.53231	B=	0.0	DUAL=	0.0
I=	40	RHS=	-29093.66999	B=	0.0	DUAL=	0.0
I=	41	RHS=	-38734.00531	B=	0.0	DUAL=	0.0
I=	42	RHS=	-47625.58979	B=	0.0	DUAL=	0.0
I=	43	RHS=	-55826.57781	B=	0.0	DUAL=	0.0
I=	44	RHS=	-39816.08700	B=	0.0	DUAL=	0.0
I=	45	RHS=	-26246.31767	B=	0.0	DUAL=	0.0
I=	46	RHS=	-19289.58992	B=	0.0	DUAL=	0.0
I=	47	RHS=	-8848.98525	B=	0.0	DUAL=	0.0
I=	48	RHS=	-0.00000	B=	0.0	DUAL=	1133.63876
I=	49	RHS=	-18269.38164	B=	0.0	DUAL=	0.0
I=	50	RHS=	-26031.13571	B=	0.0	DUAL=	0.0
I=	51	RHS=	-26031.13571	B=	0.0	DUAL=	0.0
I=	52	RHS=	-26031.13571	B=	0.0	DUAL=	0.0
I=	53	RHS=	-26031.13571	B=	0.0	DUAL=	0.0
I=	54	RHS=	-26031.13571	B=	0.0	DUAL=	0.0
I=	55	RHS=	-18034.56722	B=	0.0	DUAL=	0.0
I=	56	RHS=	-23874.15151	B=	0.0	DUAL=	0.0
I=	57	RHS=	-1701.72977	B=	0.0	DUAL=	0.0
I=	58	RHS=	-24543.46441	B=	0.0	DUAL=	0.0
I=	59	RHS=	-0.00000	B=	0.0	DUAL=	391.99998
I=	60	RHS=	-7085.81669	B=	0.0	DUAL=	0.0
I=	61	RHS=	0.00000	B=	0.0	DUAL=	193.19995
I=	62	RHS=	0.00000	B=	0.0	DUAL=	21.78489
I=	63	RHS=	-7507.62915	B=	0.0	DUAL=	0.0
I=	64	RHS=	-10691.59936	B=	0.0	DUAL=	0.0
I=	65	RHS=	-10467.82059	B=	0.0	DUAL=	0.0
I=	66	RHS=	-5865.65002	B=	0.0	DUAL=	0.0
I=	67	RHS=	0.00000	B=	0.0	DUAL=	193.19995
I=	68	RHS=	0.00000	B=	0.0	DUAL=	290.09995
I=	69	RHS=	0.0	B=	0.0	DUAL=	290.09995
I=	70	RHS=	0.00000	B=	0.0	DUAL=	290.09995
I=	71	RHS=	0.0	B=	0.0	DUAL=	682.09993
I=	72	RHS=	0.00000	B=	0.0	DUAL=	290.09995
I=	73	RHS=	-10467.82059	B=	0.0	DUAL=	0.0
I=	74	RHS=	-10467.82059	B=	0.0	DUAL=	0.0
I=	75	RHS=	-2960.19144	B=	0.0	DUAL=	0.0
I=	76	RHS=	-0.00000	B=	0.0	DUAL=	1009.19995
I=	77	RHS=	-0.00000	B=	0.0	DUAL=	999.71279
I=	78	RHS=	-4602.17056	B=	0.0	DUAL=	0.0
I=	79	RHS=	-10467.82059	B=	0.0	DUAL=	0.0
I=	80	RHS=	-10467.82059	B=	0.0	DUAL=	0.0
I=	81	RHS=	-10467.82059	B=	0.0	DUAL=	0.0
I=	82	RHS=	-10467.82059	B=	0.0	DUAL=	0.0
I=	83	RHS=	-10467.82059	B=	0.0	DUAL=	0.0
I=	84	RHS=	-10467.82059	B=	0.0	DUAL=	0.0
I=	85	RHS=	0.00000	B=	0.0	DUAL=	1009.19995
I=	86	RHS=	0.00000	B=	0.0	DUAL=	1009.19995
I=	87	RHS=	0.00000	B=	0.0	DUAL=	1009.19995
I=	88	RHS=	-223.77877	B=	0.0	DUAL=	0.0
I=	89	RHS=	0.00000	B=	0.0	DUAL=	9.48716
I=	90	RHS=	0.00000	B=	0.0	DUAL=	1009.19995
I=	91	RHS=	-0.00000	B=	0.0	DUAL=	1009.19995
I=	92	RHS=	-0.00000	B=	0.0	DUAL=	1009.19995
I=	93	RHS=	-0.00000	B=	0.0	DUAL=	1009.19995
I=	94	RHS=	0.00000	B=	0.0	DUAL=	1009.19995
I=	95	RHS=	0.0	B=	0.0	DUAL=	1009.19995
I=	96	RHS=	0.0	B=	0.0	DUAL=	1009.19995

I=	97	RHS=	88708.83875	B=	200000.00000	DUAL=	0.0
I=	98	RHS=	467922.68917	B=	500000.00000	DUAL=	0.0
I=	99	RHS=	2000.00000	B=	2000.00000	DUAL=	2908.17118
I=	100	RHS=	0.0	B=	2500.00000	DUAL=	0.0
I=	101	RHS=	947.66675	B=	947.66675	DUAL=	1372.89475
I=	102	RHS=	947.66675	B=	947.66675	DUAL=	1201.47969
I=	103	RHS=	947.66675	B=	947.66675	DUAL=	1179.69480
I=	104	RHS=	947.66675	B=	947.66675	DUAL=	170.49485
I=	105	RHS=	947.66675	B=	947.66675	DUAL=	179.98201
I=	106	RHS=	947.66675	B=	947.66675	DUAL=	1179.69480
I=	107	RHS=	947.66675	B=	947.66675	DUAL=	1372.89475
I=	108	RHS=	947.66675	B=	947.66675	DUAL=	1469.79475
I=	109	RHS=	947.66675	B=	947.66675	DUAL=	1469.79475
I=	110	RHS=	947.66675	B=	947.66675	DUAL=	1469.79475
I=	111	RHS=	947.66675	B=	947.66675	DUAL=	1861.79473
I=	112	RHS=	947.66675	B=	947.66675	DUAL=	1469.79475
I=	113	RHS=	720.81507	B=	3000.00000	DUAL=	0.0
I=	114	RHS=	-20021.78176	B=	-20021.78176	DUAL=	1091.62400
I=	115	RHS=	0.0	B=	100000.00000	DUAL=	0.0
I=	116	RHS=	36730.61836	B=	55000.00000	DUAL=	0.0
I=	117	RHS=	28968.86429	B=	55000.00000	DUAL=	0.0
I=	118	RHS=	21461.23514	B=	55000.00000	DUAL=	0.0
I=	119	RHS=	18277.26493	B=	55000.00000	DUAL=	0.0
I=	120	RHS=	18501.04370	B=	55000.00000	DUAL=	0.0
I=	121	RHS=	23103.21426	B=	55000.00000	DUAL=	0.0
I=	122	RHS=	36965.43278	B=	55000.00000	DUAL=	0.0
I=	123	RHS=	31125.84849	B=	55000.00000	DUAL=	0.0
I=	124	RHS=	53298.27023	B=	55000.00000	DUAL=	0.0
I=	125	RHS=	30456.53559	B=	55000.00000	DUAL=	0.0
I=	126	RHS=	55000.00000	B=	55000.00000	DUAL=	232.03970
I=	127	RHS=	47914.18331	B=	55000.00000	DUAL=	0.0
I=	128	RHS=	53301.51825	B=	53301.51825	DUAL=	-1202.39990
I=	129	RHS=	38230.53289	B=	38230.53289	DUAL=	-1030.98484
I=	130	RHS=	26699.83399	B=	26699.83399	DUAL=	-1009.19995
I=	131	RHS=	24396.02714	B=	24396.02714	DUAL=	0.0
I=	132	RHS=	25431.60826	B=	25431.60826	DUAL=	-9.48716
I=	133	RHS=	30782.52967	B=	30782.52967	DUAL=	-1009.19995
I=	134	RHS=	45335.34464	B=	45335.34464	DUAL=	-1202.39990
I=	135	RHS=	63707.23919	B=	63707.23919	DUAL=	-1299.29990
I=	136	RHS=	83438.93945	B=	83438.93945	DUAL=	-1299.29990
I=	137	RHS=	53984.16323	B=	53984.16323	DUAL=	-1299.29990
I=	138	RHS=	82011.50455	B=	82011.50455	DUAL=	-1923.33958
I=	139	RHS=	73334.06844	B=	73334.06844	DUAL=	-1299.29990

OPTIMAL SOLUTION CHARACTERISTICS
****

CONSOLIDATED

MAXIMAL MONTHLY SUPPLY= 26031.14
MAXIMAL DAILY SUPPLY= 867.70

PANHANDLE

MAXIMAL MONTHLY SUPPLY= 41871.28
MAXIMAL DAILY SUPPLY= 1395.71

IM= 1	FSN= 0.0	SUP1= 7761.75	SUP2= 41871.28	SUPV= 41871.28	PROD= 1668.48	DGMT= 53301.52
IM= 2	FSN= -7309.23	SUP1= 0.0	SUP2= 41871.28	SUPV= 41871.28	PROD= 1668.48	DGMT= 38230.53
IM= 3	FSN=-11332.30	SUP1= 0.0	SUP2= 34363.65	SUPV= 34363.65	PROD= 1668.48	DGMT= 26699.83
IM= 4	FSN=-10452.14	SUP1= 0.0	SUP2= 31179.68	SUPV= 31403.46	PROD= 1668.48	DGMT= 24396.03
IM= 5	FSN= -9640.34	SUP1= 0.0	SUP2= 31403.46	SUPV= 31403.46	PROD= 1668.48	DGMT= 25431.61
IM= 6	FSN= -8891.58	SUP1= 0.0	SUP2= 36005.63	SUPV= 36005.63	PROD= 1668.48	DGMT= 30782.53
IM= 7	FSN= -8200.99	SUP1= 7996.57	SUP2= 41871.28	SUPV= 41871.28	PROD= 1668.48	DGMT= 45335.34
IM= 8	FSN= 16010.49	SUP1= 2156.98	SUP2= 41871.28	SUPV= 41871.28	PROD= 1668.48	DGMT= 63707.24
IM= 9	FSN= 13569.77	SUP1= 24329.41	SUP2= 41871.28	SUPV= 41871.28	PROD= 1668.48	DGMT= 83438.94
IM= 10	FSN= 6956.73	SUP1= 1487.67	SUP2= 41871.28	SUPV= 41871.28	PROD= 1668.48	DGMT= 53984.16
IM= 11	FSN= 10440.60	SUP1= 26031.14	SUP2= 41871.28	SUPV= 41871.28	PROD= 1668.48	DGMT= 82011.50
IM= 12	FSN= 8848.99	SUP1= 18945.32	SUP2= 41871.28	SUPV= 41871.28	PROD= 1668.48	DGMT= 73334.07

SUPWH= 2000.000
SUPFL= 0.0
DPRO= 720.815
DSTC= 0.0
DPT1= 16570.900

TOTAL DEMAND CHARGE=	41356436.81	OR	0.06057	OF MINIMUM COST
TOTAL COMMODITY CHARGE=	579116891.64	OR	0.84814	OF MINIMUM COST
TOTAL STORAGE COST=	3710233.88	OR	0.00543	OF MINIMUM COST
TOTAL WINTER CHARGE=	7068904.85	OR	0.01035	OF MINIMUM COST

SUMMARY OF MONTHLY STORAGE GAS FLOWS AND STOCKS

IM= 1	GSTOR= 0.0	RSTOR= 0.0	GINST= 0.0	GIMAX= 11900.00	GOUST= 0.0	GOMAX= 7500.00
IM= 2	GSTOR= 0.0	RSTOR= 0.77	GINST= 7309.23	GIMAX= 11900.00	GOUST= 0.0	GOMAX= 7500.00
IM= 3	GSTOR= 7309.23	RSTOR= 0.82	GINST= 11332.30	GIMAX= 11332.30	GOUST= 0.0	GOMAX= 8614.26
IM= 4	GSTOR= 18641.53	RSTOR= 0.90	GINST= 10452.14	GIMAX= 10452.14	GOUST= 0.0	GOMAX= 10341.81
IM= 5	GSTOR= 29093.67	RSTOR= 0.97	GINST= 9640.34	GIMAX= 9640.34	GOUST= 0.0	GOMAX= 11935.19
IM= 6	GSTOR= 38734.01	RSTOR= 1.03	GINST= 8891.58	GIMAX= 8891.58	GOUST= 0.0	GOMAX= 13404.81
IM= 7	GSTOR= 47625.59	RSTOR= 1.09	GINST= 8200.99	GIMAX= 8200.99	GOUST= 0.0	GOMAX= 14760.29
IM= 8	GSTOR= 55826.58	RSTOR= 1.15	GINST= 0.0	GIMAX= 7564.03	GOUST= 16010.49	GOMAX= 16010.49

IM=	9	CSTOR=	39816.09	RSTOR=	1.04	CINST=	0.0	CIMAX=	8807.54	COUST=	13569.77	COMAX=	13569.77
IM=	10	CSTOR=	26246.32	RSTOR=	0.95	CINST=	0.0	CIMAX=	9861.49	COUST=	6956.73	COMAX=	11501.12
IM=	11	CSTOR=	19289.59	RSTOR=	0.90	CINST=	0.0	CIMAX=	10191.80	COUST=	10440.60	COMAX=	10440.60
IM=	12	CSTOR=	8848.99	RSTOR=	0.83	CINST=	0.0	CIMAX=	11212.71	COUST=	8848.99	COMAX=	8848.99

YEARLY FLOW INTO STORAGE= 55826.58
YEARLY FLOW OUT OF STORAGE= 55826.58

DUAL VALUES SUMMARY

****

IM= 1	VGINS= 0.0	VGOUS= 0.0	VSMAX= 0.0	VSMIN= 104.955
IM= 2	VGINS= 0.0	VGOUS= 0.0	VSMAX= 0.0	VSMIN= 0.0
IM= 3	VGINS= 23.619	VGOUS= 0.0	VSMAX= 0.0	VSMIN= 0.0
IM= 4	VGINS= 1119.792	VGOUS= 0.0	VSMAX= 0.0	VSMIN= 0.0
IM= 5	VGINS= 1203.802	VGOUS= 0.0	VSMAX= 0.0	VSMIN= 0.0
IM= 6	VGINS= 221.276	VGOUS= 0.0	VSMAX= 0.0	VSMIN= 0.0
IM= 7	VGINS= 30.440	VGOUS= 0.0	VSMAX= 0.0	VSMIN= 0.0
IM= 8	VGINS= 0.0	VGOUS= 0.00000	VSMAX= 0.0	VSMIN= 0.0
IM= 9	VGINS= 0.0	VGOUS= -0.00000	VSMAX= 0.0	VSMIN= 0.0
IM=10	VGINS= 0.0	VGOUS= 0.0	VSMAX= 0.0	VSMIN= 0.0
IM=11	VGINS= 0.0	VGOUS= 735.28234	VSMAX= 0.0	VSMIN= 0.0
IM=12	VGINS= 0.0	VGOUS= 132.43115	VSMAX= 0.0	VSMIN= 1133.639

****

IM= 1	V1X= 0.0	V2X= 193.200	VVV= 0.0	VSUV= 1009.200	VDGNT= -1202.400
IM= 2	V1X= 0.0	V2X= 21.785	VVV= 0.0	VSUV= 1009.200	VDGNT= -1030.985
IM= 3	V1X= 0.0	V2X= 0.0	VVV= 0.0	VSUV= 1009.200	VDGNT= -1009.200
IM= 4	V1X= 0.0	V2X= 0.0	VVV= 1009.200	VSUV= 0.0	VDGNT= 0.0
IM= 5	V1X= 0.0	V2X= 0.0	VVV= 999.713	VSUV= 9.487	VDGNT= -9.487
IM= 6	V1X= 0.0	V2X= 0.0	VVV= 0.0	VSUV= 1009.200	VDGNT= -1009.200
IM= 7	V1X= 0.0	V2X= 193.200	VVV= 0.0	VSUV= 1009.200	VDGNT= -1202.400
IM= 8	V1X= 0.0	V2X= 290.100	VVV= 0.0	VSUV= 1009.200	VDGNT= -1299.300
IM= 9	V1X= 0.0	V2X= 290.100	VVV= 0.0	VSUV= 1009.200	VDGNT= -1299.300
IM=10	V1X= 0.0	V2X= 290.100	VVV= 0.0	VSUV= 1009.200	VDGNT= -1299.300
IM=11	V1X= 392.000	V2X= 682.100	VVV= 0.0	VSUV= 1009.200	VDGNT= -1923.340
IM=12	V1X= 0.0	V2X= 290.100	VVV= 0.0	VSUV= 1009.200	VDGNT= -1299.300

VS1T= 0.0
VS2T= 0.0

****

IM= 1	VPRO= 1372.89475	VTRAN= 0.0
IM= 2	VPRO= 1201.47969	VTRAN= 0.0
IM= 3	VPRO= 1179.69489	VTRAN= 0.0
IM= 4	VPRO= 170.49485	VTRAN= 0.0
IM= 5	VPRO= 179.98201	VTRAN= 0.0
IM= 6	VPRO= 1179.69489	VTRAN= 0.0
IM= 7	VPRO= 1372.89475	VTRAN= 0.0
IM= 8	VPRO= 1469.79475	VTRAN= 0.0
IM= 9	VPRO= 1469.79475	VTRAN= 0.0
IM= 10	VPRO= 1469.79475	VTRAN= 0.0
IM= 11	VPRO= 1861.79473	VTRAN= 232.03970

```
                    OUTPUT OF SUBROUTINE DIST
                    ========================

PEAK MONTH=   9   PEAK LOAD=  83438.94
TRANSMISSION MARGINAL COST=       0.0      NEW TRANSMISSION PLANT=           0.0
DISTRIBUTION MARGINAL COST=    1954.964    NEW DISTRIBUTION PLANT=   383713792.


                    OUTPUT OF SUBROUTINE REVREQ
                    ==========================

REPPIS=    22378524.476
TOTPIS=  1138043932.476
DEPEXP=    33447110.956
TAPD=   252293744.087
NETPIS=   885750016.

OOPREV=     2603844.472
ONUINC=     3385680.777
OMC2=   125827831.450
ACOPEX=   827858056.409
PRPTAX=    18600751.735
PAYTAX=     3774835.094
INVTXC=    52070528.0

X0=    30052327.852
X1=   106821438.752
X2=    65894598.167
X3=    75790442.516
X4=   850233643.237
X5=   966071617.156
X6=     5989525.249

NEWPIS=  498326784.
DCT=       600653.310
OMC1=  668583114.003
X=  960082091.908
PAVG=  1598.396
```

OUTPUT OF SUBROUTINE EVAL2

========================

GAS CONSUMPTION EVALUATION CRITERIA

****

PEAK MONTH= 9
PEAK LOAD (MMCF)= 83438.94
LOAD FACTOR= 0.5999
TOTAL GAS CONSUMPTION= 600653.31

THEORETICAL EQUILIBRIUM VOLUMETRIC RATES= 1598.396
EQUILIBRIUM GAS SALES REVENUE REQUIREMENT= 960082091.91

EFFICIENCY CRITERIA

****

MONTH= 1	RESIDENTIAL SURPLUS=	114563728.	COMMERCIAL SURPLUS=	45838104.	INDUSTRIAL SURPLUS=	89648465.
MONTH= 2	RESIDENTIAL SURPLUS=	68350528.	COMMERCIAL SURPLUS=	28243385.	INDUSTRIAL SURPLUS=	82754751.
MONTH= 3	RESIDENTIAL SURPLUS=	32993153.	COMMERCIAL SURPLUS=	14781796.	INDUSTRIAL SURPLUS=	77480422.
MONTH= 4	RESIDENTIAL SURPLUS=	25928831.	COMMERCIAL SURPLUS=	12092202.	INDUSTRIAL SURPLUS=	76426623.
MONTH= 5	RESIDENTIAL SURPLUS=	27713679.	COMMERCIAL SURPLUS=	12801953.	INDUSTRIAL SURPLUS=	77680037.
MONTH= 6	RESIDENTIAL SURPLUS=	45512203.	COMMERCIAL SURPLUS=	19548165.	INDUSTRIAL SURPLUS=	79347913.
MONTH= 7	RESIDENTIAL SURPLUS=	90308912.	COMMERCIAL SURPLUS=	36600861.	INDUSTRIAL SURPLUS=	85941308.
MONTH= 8	RESIDENTIAL SURPLUS=	149103698.	COMMERCIAL SURPLUS=	58954727.	INDUSTRIAL SURPLUS=	93697754.
MONTH= 9	RESIDENTIAL SURPLUS=	211230708.	COMMERCIAL SURPLUS=	82596955.	INDUSTRIAL SURPLUS=	102594599.
MONTH= 10	RESIDENTIAL SURPLUS=	132375035.	COMMERCIAL SURPLUS=	51623960.	INDUSTRIAL SURPLUS=	59775534.
MONTH= 11	RESIDENTIAL SURPLUS=	206797867.	COMMERCIAL SURPLUS=	80909243.	INDUSTRIAL SURPLUS=	101933343.
MONTH= 12	RESIDENTIAL SURPLUS=	179850441.	COMMERCIAL SURPLUS=	70649568.	INDUSTRIAL SURPLUS=	97913543.

ACTUAL GAS SALES REVENUES= 1030271552.99

GAS SALES REVENUE SURPLUS (+) OR DEFICIT (-)= 70189461.08

TOTAL RESIDENTIAL SURPLUS 1284728783.
TOTAL COMMERCIAL SURPLUS 514640920.
TOTAL INDUSTRIAL SURPLUS 1025194291.
TOTAL CONSUMER SURPLUS 2824563995.

PRODUCER SURPLUS 143151504.

TOTAL SURPLUS 2967715498.

APPENDIX G

COMMENTS OF FIRST DRAFT REVIEWERS

This appendix contains the comments of reviewers of an early draft of this report: Walter J. Cavagnaro, California Public Utilities Commission; Stephen P. Reynolds and other staff, Pacific Gas and Electric Company; and John R. Yurtchuk, National Fuel Gas Distribution Corporation.

ADDRESS ALL COMMUNICATIONS
TO THE COMMISSION
CALIFORNIA STATE BUILDING
SAN FRANCISCO, CALIFORNIA 94102
TELEPHONE: (415) 557- 0507

Public Utilities Commission

STATE OF CALIFORNIA

January 7, 1981

FILE NO.

Dr. Jean-Michel Guldman
Senior Faculty Associate
The National Regulatory Research Institute
The Ohio State University
2130 Neil Avenue
Columbus, Ohio 43210

Dear Dr. Guldman

Thank you for the opportunity to comment on the draft of your Gas Capacity Cost Study. NRRI is to be commended for initiating studies in this area and it is hoped that such studies will continue. I would like to stress that California's interest mainly focuses on Gas Supply Cost including storage and transmission facilities. In California, we have experienced rapidly escalating Canadian gas prices which together with the phased deregulation of domestic gas is presenting us with marginal supply cost substantially in excess of average cost. I am enclosing for your information, a copy of a paper presented by Irwin M. Stelzer at a seminar on August 6, 1980. His view on the marginal cost of gas (Page 6) is quite interesting.

Through my association with other state commissions and NARUC, as well as our experience in California, I feel there is a need to develop a simplified marginal cost methodology and recommendations for reconciliation between marginal cost and the revenue requirement in meeting the PURPA goals of conservation, efficiency and equity. I hope that NRRI will provide the states with such a report as soon as possible. I would also encourage you to develop the link between your model and the utilities resource planning models. I am sure that PG&E will continue to cooperate with you in your further studies.

Very truly yours

Walter Cavagnaro

Walter J. Cavagnaro
Energy Policy Staff
Policy and Planning Division

WJC:asa
cc Steve Reynolds, PG&E
att

PACIFIC GAS AND ELECTRIC COMPANY

PGandE

77 BEALE STREET • SAN FRANCISCO, CALIFORNIA 94106 • (415) 781-4211 • TWX 910-372-6587

S. P. REYNOLDS
MANAGER
RATE DEPARTMENT

December 19, 1980

Dr. J. M. Guldmann
Senior Faculty Associate
The National Regulatory Research Institute
The Ohio State University
2130 Neil Avenue
Columbus, Ohio 43210

Dear Dr. Guldmann:

Thank you for the opportunity to comment on Chapter 3 of the final draft of your gas capacity cost study. Although Pacific Gas and Electric Company is not generally supportive of either an econometric or a historical approach to estimating marginal costs, we read your study with interest. The draft has been circulated within PGandE, and many of our staff have had a chance to review it. Attached please find a summary of their comments. Should you require additional information, please do not hesitate to contact either Mr. T. C. Long (Ext. 4743) or Ms. L. G. Baldwin (Ext. 2998).

You may also have our approval to release the study to Mr. Walter Cavagnero of the California Public Utilities Commission. We might suggest, however, that you send him a copy of PGandE's comments along with the report.

Sincerely,

Steph P. Reynolds

Attachment

PGandE Comments on Chapter 3 - Gas Capacity Cost Study

PGandE agrees with you that research in the area of gas distribution costs has been limited, and, thus, applauds the objectives of your study. You cite several weaknesses with the analysis performed by previous researchers (the Real Estate Research Corporation): designation of prototype neighborhoods too general to be of much use; failure to reflect costs due to differences in terrain, topography, and climate; no investigation of costs for commercial and industrial customers; and, neglect of the situations that may cause different types of investment, such as reinforcement, pressurizing, or extension. Your approach makes some good progress towards addressing these shortcomings in its recognition of the importance of localized conditions in evaluating gas distribution costs.

PGandE would, however, like to offer comments on your study along two veins. The first section of our comments deals with the conceptual economic basis for evaluating marginal costs. This is followed by a discussion of more specific topics: the econometric model specification, the data supporting the analysis, the interpretation of results, and areas for further work.

I. Conceptual Basis for Marginal Costing

Your stated objective (p. 15) is to perform an econometric analysis of distribution plant costs, and to use the resulting distribution plant cost functions to predict future costs and marginal costs. Your use of cross-sectional regression analysis and of historic accounting cost data to support that analysis, however, make us skeptical that your model has the capability of predicting future costs (if what you mean is next year's costs as opposed to the costs of a 95th PGandE community). Verification of the predictive ability of your model would be a desirable addition to the analysis. We also have reservations about the applicability of your model to gas marginal costing. It would be helpful to the reader for you to define what you mean by marginal costs early on in Chapter 3.

PGandE defines the marginal cost of gas service as "the change in the total cost of supplying gas as a result of a change in the quantity supplied." Gas service involves the process of hooking up customers, acquiring gas supplies, and then providing a gas system that delivers the supplies to the customers. Accordingly, we view the marginal cost of gas service as having three components: a marginal customer cost; a marginal commodity cost; and a marginal capacity cost. The marginal customer cost is associated with providing service to an additional customer. The marginal commodity cost is the variable cost of providing the last unit of gas supplied. The marginal capacity cost is related to constructing and maintaining a system with sufficient capacity to meet the last unit of peak day gas demand. Therefore, your designation of marginal distribution costs overlaps with two of our identified marginal cost components - the marginal customer cost and the distribution portion of the marginal capacity cost - one of which varies with a change in customers, and the other with a change in demand. Your specifications, however, attempt to explain all distribution investment with either customers or sales and do not attempt to break down the cost of distribution plant investment by cost causation.

PGandE is suspicious of the use of historic accounting data to calculate marginal costs. Marginal costs, by their nature, are prospective, forward-looking costs, not historic costs. Only those costs which result from investing in resources to supply and deliver additional increments of gas or to hook-up additional customers, should be counted as marginal costs. Sunk costs, or costs which are presently on the books, are not considered costs in an economic sense. Thus, the use of historic accounting costs (which in PGandE's case include investments made back as early as 1910), coupled with the limitations of the data described below and your assumptions concerning vintaging, make us skeptical that your approach will produce marginal costs that are grounded in economic theory.

II. Discussion of Specific Topics

The Appropriate Use of Cross-Section Regression Analysis

In principal, cross-section regression is appropriate for analysis of long-run cost determinants but is not suitable for analysis of short-run adjustment to changes in cost determinants. This distinction follows from recognition that the information isolated by cross-section analysis is consistent only with the economic concept of the long-run, i.e. the period of time in which all factors are fully variable.

Ideally, cross-section data represent a wide and independent variation of the factors that determine the cost of distribution capacity. Moreover, each cross-section is held to be in full adjustment to the local determinants of cost. Regression analysis on cross-section data therefore focuses on the relationship that independently varying cost determinants have to total plant cost under conditions of full adjustment, in particular, adjustment to long-run equilibrium.

Data Limitations

You state on page 20 of your study that "most gas distribution utilities keep track of their capital investments at the community level." As you know, PGandE does not maintain statistics on distribution plant for individual communities. Therefore, as we agreed, the PGandE data on distribution cost for service by communities was developed as the product of the miles of distribution gas mains in each community and the system historical unit cost per mile of distribution main.

This approach to allocation of system historical costs between individual communities obscures many of the factors that cause real variation of plant costs between communities. For example, the local differences in distribution costs due to differences in technology, pre-existing land uses, and local terrain can not be discerned. Furthermore, it may be that the mileage of gas mains is not a suitable basis for allocation of total system costs between communities with varying proportions of residential, commercial and industrial customers.

PGandE acknowledges that your model makes some intuitive sense: the cost of distribution capacity _is_ a function of weather, density, and composition of customer population. However, because of data limitations, the interpretation of the model results are less clear. For example, since the unit cost per mile of distribution main does not vary by community, isn't the dependent variable really the miles of gas main per community?

An effect of the method by which historical data was generated for community level distribution plant is to impose the assumption that the vintage composition of local plant is constant across all communities. PGandE _does not_ verify the assumption of similar vintages of plant across communities as you claim (page 22). Indeed, we are certain that the vintage of distribution plant varies substantially across PGandE service communities.

As noted (page 21) one obvious problem with your approach is "related to the use of the original cost balance for measuring the value of plant in service, instead of its replacement costs, which should be the correct reference for measuring total and marginal costs." The fact that the vintage of distribution plant varies substantially between PGandE communities compounds this problem. As a result, the estimated model cannot be used to predict historical plant costs for any given community.

Dynamic Analysis

PGandE has two comments concerning your dynamic analysis of distribution costs. First, analysis of the change in capacity cost should be adjusted by the initial conditions of local capacity utilization: for instance, is the current situation one of overcapacity or undercapacity? Second, the historical cost method of plant accounting may misrepresent the cost for addition of _incremental_ capacity.

First, the dynamic analysis must be qualified with respect to the level of PGandE's capacity utilization in 1979. Under normal conditions investments in transmission and major distribution facilities have lead times and life times longer than one year, so that the planner typically prebuilds for anticipated growth. However, the significant dislocations in the energy market over the last decade have caused the system to diverge from normal levels of capacity utilization because of a substantially lower average use per customer than estimated earlier for planning purposes. Because of this reason, the use of a single period analysis under the recent conditions of excess capacity may have yielded costs that are lower than will be required on average in the future.

Second, the dynamic analysis focuses on the change in the distribution plant cost for one year and relates this change in cost to the change in customers. A problem exists with this approach in that the procedures of historical cost accounting may introduce an upward bias on the cost of additional plant. Load growth may be by upgrading an existing pipeline with a larger diameter pipeline. In the instance of pipeline replacement the book investment in the larger pipeline is based on current cost. Meanwhile, the smaller pipeline that is replaced, is retired from plant based on its historical cost. As a result, historical cost accounting will tend to overstate the year to year increase in plant.

Interpretation of Regression Estimates

PGandE has several comments that relate to the general results of the regression analysis:

Plausibility of Cost Estimates: PGandE finds your "short-run" residential marginal cost to be low, while the "long-run" residential marginal cost are difficult to judge. The Gas System Planning Department provided the following estimate of the total cost for a typical sub-division customer:

Service:	$340.00	
Meter & regulator:	65.00	
Total (without main):	405.00	(1980 dollars)
Local main:	182.28	
Total (with main):	587.28	(1980 dollars)

This cost estimate includes an allowance of $182.28 for a local distribution main. This cost added to the "customer costs" would be $587.28 which is higher than your derived costs of $359.357 per residential customer. Your estimate of "long-run" residential cost of $326.75 on page 54 would need to be translated to current cost. However, the replacement cost multiple of 2.79 (which, if applied to $326.75 would yield $911.64), is not applicable to residential cost estimates because the multiple pertains only to the historical system technology and customer composition. Consequently the estimate of long-run residential costs is difficult to put into perspective.

The Specification of Heating-Degree-Day's Variable: PGandE designs the distribution system to have the capacity necessary to meet demand on an abnormal peak day. Therefore, the finding that the peak-month heating-degree-day measure (DDM) was clearly more significant than the annual heating degree-day measure (DDT) is consistent with planning criteria for capacity of the gas distribution system. However, since peak day is the critical influence, an even better explanatory variable would be peak day demand.

The Test for a Separable Cost Structure: By use of the regression analysis the hypothesis that the distribution system is characterized by joint, non-separable costs is tested. This hypothesis is tested by determining whether the additive (separable and linear) or multiplicative (non-separable and log-linear) form of the regression estimator achieves a significantly better fit. The results indicate that distribution costs are not separable between customer classes. PGandE finds the result that distribution costs are non-separable plausible.

The results for residential and commercial/industrial customers further indicate that total distribution costs exhibit economies of scale. This seems realistic. However, the implied marginal cost function for residential customers indicates that costs for additional residential customers are positively influenced by the presence of commercial/industrial customers, which seems less realistic. Historically, major extensions of the gas system were more desirable when there was a simultaneous hook-up of residential and commercial/industrial customers. PGandE has typically made an analysis in order to certify that the costs of the prospective additions to gas distribution plant would be recovered from commercial/industrial customers. Thus it seems the residential sector benefited from an externality (technological and pecuniary) related to the presence of commercial and industrial customers.

Problems In Interpretation: You note that the ratio between replacement and historical costs for PGandE's gas distribution plant is 2.79 and proceed to use this value at various points. PGandE thinks that the meaning of the system ratio of 2.79 must be clarified because at numerous points certain inferences are based on questionable application of this ratio.

The ratio of replacement to historical costs represents a system average and is specific to the historical technology and equipment composition of system-wide distribution facilities. One problem with your analysis occurs on page 48, line 9. Obviously, one would expect the vintage of plant being retired to differ significantly from the system average vintage. Therefore the estimate for "truly new distribution plant" should be substantially less than $59,944,556, because the factor 2.79 is too low to be appropriate for retired capital.

Another instance of questionable inference occurs on page 58, line 3. At this point you have estimated a 'dynamic' cost of $466.46 per customer. It must be noted that this value is supposed to reflect the costs for plant added in 1979 and implies use of current technology. You then compare this 1979 investment against the 'static' estimate of historical distribution costs, adjusted by the 2.79 ratio of replacement cost to historical cost. The problem is that the numbers are not comparable. Technology is certain to have changed, so that the difference in your estimates could be due to technological change or other influences, and not specifically to the disparity of short-run and long-run costs.

Areas For Further Work: It would be instructive for you to more carefully align your definitions of short-run and long-run costs with economic theory. The economic definition of long-run is the period over which all factors of production are variable, while the short-run simply refers to any lesser time. Your distribution costs seem to be comprised of two parts: (1) the cost of hooking up new customers, such as the cost of meter, regulator and service; and (2) the distribution costs incurred to serve additional volumes of gas demand. It appears that you implicitly designate a one year period as the short-run, categorize the former costs as short-run costs, and use the dynamic model to estimate them. The latter remaining costs therefore, fall into the long-run category and are (in addition to the former) analyzed with your static model. This would be a very neat approach to estimating the two components in which PGandE is interested - marginal customer costs and the distribution portion of marginal capacity costs - if your construct can be verified.

If as is suggested (page 15) the results are to be the basis for projection of future costs, there is a problem of translating the model's predictions based on historical cost into values relevant today or in the future. PGandE suggests that if the model is to be practically useful for cost forecasting, further research must address the translation of historical costs into replacement costs with allowance for technological change. Also, to the extent that costs of additional plant vary between locations within the PGandE gas distribution network, use of the present model for forecasting may misrepresent additional costs. For example, communities may differ by terrain, state of development, and the type of investment required to meet growth.

PGandE requests that any future work be accompanied by more information related to sample design, correlation analysis of independent variables, and error analysis. Furthermore, experimentation with plausible alternative formulations of the model and introduction of other explanatory variables such as terrain, zoning, income, etc. would be interesting.

Corrections to Tables

PGandE would like to bring to your attention several figures that need to be changed in Tables 3.11 and 3.12. The suggested corrections are shown on the attached tables. Also, the total gas plant in service that you quote in Table 3.12 is exclusive of production and intangible plant; this should be noted.[21]

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[21] Author's note: These corrections have been made.

National Fuel

January 7, 1981

Dr. J. M. Guldman
The National Regulatory Research Institute
The Ohio State University
2130 Neil Avenue
Columbus, Ohio 43210

Dear Dr. Guldman:

I have enclosed my comments regarding your marginal cost study. Your direct approach in estimating total cost functions is theoretically appealing, yet I feel requires some fine-tuning with respect to its econometrics. Since you plan to address these problems, that would certainly alleviate any of the concern I might have in utilizing the results.

I look forward to receiving any further work you may undertake on this project, and should you require any additional information, please feel free to contact me.

Sincerely,

John R. Yurtchuk

John R. Yurtchuk
Economist

JRY: ms
Enc.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION/10 LAFAYETTE SQUARE/BUFFALO NY 14203

Comments of John R. Yurtchuk, Economist - National Fuel Gas Distribution

The study attempts to identify various total cost functions in aggregate and disaggregate form so that estimates of marginal costs and scale economics can be made. The three types of independent variables used were: number of customers, MCF sales, and a density variable. The performance of the estimating equations utilizing the stated regressors either jointly or separately generally superior when a multiplicative-type function was used.

The methodology exhibited in this study rests upon sound microeconomic principles and offers a tractable approach to identifying certain characteristics of a utility's operations. However, in reviewing the empirical component it appears that certain econometric difficulties may exist.

The first problem lies in the values for the coefficients of determination. Certainly some of the R-squares are "acceptable" in that a significant portion of the variation in the dependent variable is being explained. However, there do exist a number of equations whose R-square value is simply too low, indicating that the regression equation lacks significant explanatory power. Specifically, the following equations have R-square values below .50 with some even less than .40: 3.91, 3.92, 3.93, 3.99, 3.100, 3.101, 3.105, 3.106, 3.113, 3.114, 3.129, 3.130, 3.131, 3.137, 3.138, and 3.139. Statistical theory would suggest that something is missing from these relations. Since results from these equations are discussed and economically interpreted, it is assumed that the R-square levels are regarded as acceptable in this stage of the study.

In the following equation, TMCF and CIPMCF are the two included independent variables.

$$\text{(Equation 3.82)} \quad PS = 9.5978 * TMCF^{0.8028} * CIPMCF^{0.0965}$$

where PS - Total Distribution Plant

These two right hand side variables are linearly related to one another in the following way:

$$TMCF = RMCF + CIPMCF$$

where TMCF - Total Gas Sales (MCF)
RMCF - Residential Gas Sales (MCF)
CIPMCF - Total Non-Residential Gas Sales (MCF)

Clearly, since CIPMCF is a component of TMCF, their respective effects on the dependent variable, PS, are inseparable. Thus the problem of multicollinearity with a consequencial loss of precision becomes a distinct possibility.[22]

Lastly, it appears highly probable that simultaneous equation bias exists in many of the regressions in light of the accounting relationships that are present among the independent variables. Further work is thus called for to account for these identities.

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[22] Author's note: Thanks are due to Mr. Yurtchuk for pointing out a typographical error in equation 3.82 in the first draft (TMCF must be replaced by RMCF). This error has been corrected.