GAS DISTRIBUTION RATE DESIGN MANUAL

Prepared by the
NARUC Staff Subcommittee on Gas

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NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS

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NATURAL GAS ACRONYMS

BTU	British Thermal Unit (a measure of heat energy)
DTH	Dekatherm (equal to one million BTU's)
FERC	Federal Energy Regulatory Commission
LDC	Local Distribution Company
MCF	One thousand cubic feet
MFV	Modified Fixed Variable rate design
MMBTU	One million BTU's
NGA	Natural Gas Act of 1938
NGPA	Natural Gas Policy Act of 1978
PGA	Purchased Gas Adjustment
SNG	Synthetic Gas

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GAS DISTRIBUTION RATE DESIGN MANUAL

Chapter 1 - Historical Concepts

A. Brief History of the Natural Gas Industry

Productive use of natural gas in the United States first occurred during the early 1800's. However, difficulties in production and transportation of gas discouraged market growth. Manufactured gas (from coal), although more expensive, was used for illuminating streets and homes. When lighting became powered exclusively by electricity at the turn of the century, gas applications shifted to other markets, most notably heating and cooking.

Then, in the late 1920's, abundant supplies of natural gas were discovered in the new oil and gas fields in the Southwest. Additionally, improvements in pipeline construction technology made long-distance gas transmission practical. These two events, coupled with utilization of the manufactured gas distribution systems, heralded the emergence of natural gas as an important domestic energy source.

Throughout this time interstate sales and transmission of gas were unregulated. With the passage of the Natural Gas Act in 1938, regulation of interstate activities was introduced. This act initiated federal regulation by broadening the scope of the Federal Power Commission, now the Federal Energy Regulatory Commission (FERC).

While there was a reduction in pipeline construction during the Great Depression, construction increased with the end of World War II. Post-war technological advances initiated a period of dramatic growth in the national pipeline system that lasted until the mid-1960's.

During the 1970's the industry experienced significant change as the decline in proved reserves prompted acute shortages. Such decline necessitated supplementation of domestic natural gas supplies with oil and gas imports. In an attempt to deal with the energy crisis, Congress passed the Natural Gas Policy Act (1978) through which both price determination and the regulatory environment were changed.

By the early 1980's the crisis had abated with the emergence of a surplus of gas supply. Changes effected by the NGPA created the need for further regulation of gas transmission. In response to its interpretation of the NGPA and the evolving natural gas market, in 1985 the FERC issued Order No. 436 - a non-discriminatory open-access transportation program. Upon the D.C. Circuit Court's remand to the FERC of certain sections of Order No. 436, the FERC issued Order No. 500 (1987). Order No. 500 promulgated measures to remedy the perceived inequities in Order No. 436, with the intention of further facilitating a competitive natural gas market.

Prior to the current volatility at the interstate level, utilities viewed their participation in the national gas market as somewhat limited. Regulation of distribution originated within the jurisdiction of state and local authorities. However, the advent of increasingly dramatic consequences to utilities by federal promulgations has caused a shift in focus. Both utilities and their respective state commissions have been forced to significantly enlarge the scope of their participation in today's national gas market.

It should also be remembered that, in the federal arena of expanded competition, the concept of gas distribution as a natural monopoly still exists. That concept continues to exert significant influence on the industry.

B. Characteristics of the Natural Gas Industry

1. Natural Monopoly and Need for Regulation

The primary reason for regulation centers on the phenomenon of a natural monopoly. A natural monopoly exists when a single company can supply service at a lower cost than two companies with duplicate facilities and overlapping markets. An additional characteristic of a natural monopoly is the large capital investment required in order to serve customers on demand. The clearest case of a natural monopoly is in local distribution, where a single set of facilities can serve any given number of customers more efficiently than multiple sets of facilities. In such circumstances, unrestricted entry is considered wasteful and inefficient because of excessive investment and clutter of public property with service lines. Although, by definition, a monopoly is the most efficient means to provide utility service, control is needed in order to prevent exploitation of the public by the monopoly in terms of both price and quality of service.

Public utility regulation provides for adequate quality of service at reasonable prices and obligates monopoly companies to provide service to all interested parties without discrimination. Regulation attempts to obtain for the public the benefits gained through competition and the efficiency accomplished through a monopoly. Regulation can be provided by municipal bodies, state commissions, or federal commissions. The extent of jurisdiction varies and depends on a number of different factors.

One of the main reasons for the existence of regulatory agencies is rate regulation. Within rate regulation the cost-of-service principle exists. This principle maintains that a public utility can charge rates reflecting only the cost of providing the service plus a "reasonable" return to investors. Determining actual cost and "reasonable" return makes rate regulation one of the most difficult and controversial issues. Other areas of regulation include accounting, financing, service rules, safety and a variety of other functions.

Public utility regulation, as we know it today, is a product of long years of experimentation developing from the growth of the utility industry and the economy.

2. Industry Sectors

The natural gas industry is composed of four major industry sectors: producers, pipelines, distribution and marketers. Each of these sectors plays a role in the movement of natural gas from the wellhead to the burner tip.

a. Producers

The producers are responsible for locating, drilling, gathering, cleaning, and drying natural gas. Located in various parts of the United States, Canada, and the Outer Continental Shelf, producers have provided natural gas in the United States for over 100 years. Traditionally, producers sold gas only to pipeline companies. However, producers now sell gas to all sectors of the natural gas industry: pipelines, distribution utilities, and marketers.

b. Pipelines

Pipelines are the movers of natural gas. Nationwide, transmission pipelines, up to four feet in diameter, typically carry natural gas from Texas, Oklahoma, Louisiana, and offshore in the Gulf of Mexico to all parts of the United States.

Pipelines are regulated by the FERC under the authority of Section 1(b) of the Natural Gas Act. FERC has regulatory authority over facilities, services, and rates of interstate pipelines.

Traditionally, interstate pipeline companies have been the merchants of natural gas. Each interstate pipeline company bought, delivered, and sold natural gas to one or more local distributing companies. Ancillary to its sales service, the interstate pipeline company often provided storage of large quantities of natural gas to insure delivery as needed by its customers.

However, in today's natural gas industry, interstate pipeline companies have assumed a different role. While still maintaining their merchant function, transportation for interstate pipelines is becoming increasingly important in the restructured natural gas industry. Open access to the transportation facilities of the interstate pipeline by others, primarily distribution companies and marketers, is now changing the way pipelines do business.

c. Distribution Utilities

Across the nation over 1,600 local distribution companies (LDC's) provide gas service to residential, commercial, and industrial customers. These utilities provide the last link between the wellhead and the burner tip. Their rates, services and facilities are subject to the regulations of state and local regulatory commissions.

Traditionally, most local distribution companies have been customers of interstate pipeline companies. The utilities have paid pipeline companies for the gas supply they needed. However, in today's natural gas industry, utilities have the ability to secure system supply directly from gas producers or marketers.

d. Marketers

A new player in the natural gas industry is the gas marketer. This entrepreneur has emerged linking together willing sellers of natural gas to willing buyers of natural gas across the nation. The restructuring of the natural gas industry has opened a niche for this new market player. With increasing numbers of facilities supplying open-access transportation, the business opportunities for the gas marketer have greatly increased.

The gas marketer coordinates with producers, interstate pipelines, and LDCs, arranging marketable packages of gas for sale to end users. The marketer tailors the gas packages to meet the buyer's needs in terms of volume, delivery point, length of delivery, and quality of product. In the coming years, the gas marketer will likely play an increasing role in the national energy market. The marketer has enjoyed an environment relatively, if not totally, free from regulation.

3. General Natural Gas Market

Producers, natural gas pipelines, distribution utilities and marketers are involved in furnishing the commodity to the ultimate users of the product: the residential, commercial, and industrial customers who burn natural gas. Total U.S. natural gas consumption by these customers declined slowly during the 1984-87 period. This downturn in usage (especially in the residential and commercial sectors) is due in part to conservation efforts, energy efficient design, and the weather. But since natural gas is the cleanest, most efficient, and most readily available fuel for America's homes, factories, and electric generators, total natural gas consumption in the next five years is expected to grow.

a. Residential

Residential customers accounted for over twenty-five percent (25%) of total U.S. natural gas consumption in 1985. Approximately 45 million households now depend upon natural gas for part of their energy needs. The major residential applications for the commodity are space heating, water heating, and cooking although some residential space cooling units are also in service today. Since space heating during the winter months is the largest residential application of gas, residential usage is highly seasonal in nature. Due to continued efforts in conservation and the popularity of energy-efficient appliances, total residential natural gas usage is expected to show a slight net decline over the next decade, even though the number of customers is expected to grow.

b. Commercial

The commercial market sector normally includes businesses, hospitals, schools, and some government facilities. Commercial applications for natural gas include space heating and cooling, water heating, and electrical generation. Due to projected increases in commercial square footage and overall commercial energy use, this market sector is expected to have significantly greater natural gas usage during the next several years.

c. Industrial

Approximately forty percent (40%) of total U.S. natural gas consumption is in the industrial market, making this segment the largest consumer sector. Slow to modest growth in consumption is foreseen for this sector during the next several years. The largest portion of industrial natural gas use is for process heating, which refers to the combustion of fuels for the direct transfer of heat in applications such as furnaces, kilns, dryers and heaters. Other major uses of the commodity in the industrial sector include steam generation, space heating and cooling, and feedstock applications, where the fuel is used as a raw material in forming part of the product being processed or produced. In response to the energy shortages experienced during the last decade, many industrial users have installed equipment which allows access to alternative fuel sources and, thus, are often in a position to bargain for lower natural gas commodity rates.

Gas companies furnish service to the three classes of customers under varying circumstances of delivery and use. Most companies divide each of these customer classes into various subclasses (such as interruptible, seasonal and firm) which have specialized rate structures. The rationale behind such differentiation is that each customer in the subclass is deemed to have cost factors or other characteristics peculiar to the subclass. Because these variations result in differences in the cost of rendering service to the various classes, subclassification provides a basis for differences in the pricing.

C. Rate Types

Utility ratemaking has never been an exact science. The rate structure for a utility should normally be designed to recover the total allowed revenue requirement of the utility, including a fair rate of return. While cost is an important factor in ratemaking, actual rates are often designed to incorporate numerous other factors, including technological, economic, regulatory, political, promotional and social. This section includes a discussion of the various types of rates which have been historically used in the gas industry.

1. Unmetered Rate

The unmetered rate was the earliest type of rate used in the gas industry. Under an unmetered rate, a customer is billed a fixed sum for service during a stated period of time regardless of actual gas consumption (e.g. $30 per month). This method was used prior to the introduction of the gas meter and its use was dictated by the technological capabilities of the time. This rate structure was simple and easy to administer, but was not equitable since it meant that a customer who used his gas equipment fully had the same monthly bill as a customer with lesser use. With the advent of gas meters, this type of rate has almost died out, although it is still being used for some outdoor gas lighting because usage is constant.

2. Straight Line Meter or Flat Rate

A number of rate structures have been used since metering was introduced to remedy the inequity of the unmetered rate method. The first such rate structure was the straight line meter rate (now commonly referred to as a flat rate). Under this rate, a customer is billed based on a constant price per unit of gas consumed and registered by the meter (e.g. $3.00 per Mcf). This method is the simplest of all metered rate methods and with some modification is still in common use today.

The flat rate has the disadvantage of assigning costs at a uniform rate and in the same proportion to each volume of usage. For example, if a customer had no gas use in a month, he would have no charge. However, costs were incurred by the gas utility for fixed expenses such as meter reading, carrying cost on investment in facilities, etc. Therefore, each unit sold included an equal amount of the fixed cost, and a large customer would normally subsidize some of the costs of the smaller users. Variations on the flat rate were developed to alleviate this shortcoming, including use of a customer charge to recover some fixed costs and use of quantity discounts to encourage greater consumption and spread fewer fixed costs to the larger customers.

3. Step Meter Rate

A further solution was the introduction of the step meter rate. Under this method, the customer's entire consumption was billed at a certain unit rate. There were various unit rates and the one used depended upon the range into which consumption fell. The greater the consumption, the lower was the unit rate used, e.g. a customer using 100 Mcf or less would be charged $3.00 per Mcf, while one using more than 100 Mcf would be charged $2.50 per Mcf for all of the customer's consumption. This method had two advantages over previous methods: (1) Promotional incentive, and (2) Some cost justification.

However, this method had two shortfalls. First, bills for large use could actually be less than bills for lesser use. In the example above, a customer using 100 Mcf would have a bill of $300, but a customer consuming 101 Mcf would be billed only $252.50. Such a billing result would obviously be inequitable. Second, the system rewarded poor load factor customers who used little or no gas during most of the year, but who used a large amount of gas in sporadic or limited periods and, therefore, created a large investment in production and distribution plant to serve them. Conversely, it penalized good load factor customers who used gas at a steady rate and did not get the reduced unit rate for large users, even though the cost associated with the production and distribution facilities required to serve these customers was low in proportion to their total gas requirements.

4. Declining Block Rate

The step meter rate evolved into the declining block rate. This method provides a declining average unit cost to the customer as usage in a billing period increases. It employs two or more successive blocks with decreasing price, e.g. a rate of $3.00 per Mcf for the first 100 Mcf, and $2.50 for all consumption over 100 Mcf. This system avoids the sometimes inequitable pricing under the step meter rate. In the above example a customer using 100 Mcf would be billed $300, while one taking 101 Mcf would receive a bill for $302.50.

The declining block rate structure was intended to provide a method to equitably recover cost. The unit price for each block may include a portion of capacity costs as well as commodity costs. In other instances, the first blocks of the rate may be used to recover assigned costs while the later blocks are priced with a close relation to commodity costs. This rate structure was also intended to meet competitive situations and to promote the sale of gas by providing a lower marginal cost of gas to larger customers.

5. Inverted Rate

The inverted rate is simply the reverse of the declining block rate. Under the inverted rate structure the rate for successive blocks increases as consumption increases, e.g. a rate of $3.00 per Mcf for the first 100 Mcf, and $3.50 for all consumption over 100 Mcf.

Inverted rates were developed to achieve two goals. First, the gas shortages of the 1970's resulted in an increasing awareness of the value of conservation. Inverted rates were viewed as a method of promoting conservation by discouraging customers from using large quantities of gas. In this respect, the inverted rate was also viewed as being cost-based since the shortage of natural gas had caused it to be a commodity with increasing marginal costs.

The second objective of inverted rates was the desire to provide an affordable level of gas services to meet basic human needs, often referred to as lifeline rates. The natural gas shortage brought about a significant increase in prices. As a result, it was believed that some members of society were unable to afford natural gas to provide for minimal heating and other basic needs. Lifeline rates were designed to provide for these requirements at reduced rates while penalizing excess consumption.

6. Customer Charge

A customer charge is not a different type of rate, but rather is a specific type of charge which may be used with any of the other rate types. The customer charge is typically a monthly charge which is in addition to the volumetric charges, although in some cases it may contain an allowance for a small volume of gas. For example, a typical rate schedule might appear as follows:

Customer Charge: $5 per month
Commodity Charge: $3 per Mcf

The basis for the customer charge is that there are certain fixed costs that each customer should bear whether any gas is used at all. Examples of such costs are those associated with a service line, a regulator and a meter, recurring meter reading expenses and administrative costs of servicing the account.

7. Demand or Capacity Charges

Demand charges have commonly been used in the design of interstate pipeline rates for years, but are relatively uncommon for local distribution companies. A demand charge is designed to recover the fixed or capital costs associated with the customer's use of the transmission and distribution system. Like the customer charge, a demand charge can be used with any of the previous rate forms. It has the advantage of allowing the customer's bill to more closely reflect the actual costs incurred by the utility in providing service.

8. Minimum Bills

The term "minimum bill" is used to describe a tariff provision which can have the effect of requiring the customer to pay for a defined minimum level of service. It can take any number of forms, for example a provision where the customer is required to take a specified quantity of gas or pay for it anyway or a straight minimum bill, where the customer is required to pay a set minimum (for example, $1000 per month) when the customer's bill would otherwise be less.

Chapter II - Rates Based on Cost of Service

A. Basic Concepts

1. Revenue Requirements

Traditionally utility rates have been set to permit the company to recover its reasonable cost of providing service plus the opportunity to earn a reasonable return on its investment which is used and useful in providing utility service. Typically the utility will file a rate increase request seeking authority to increase rates by a certain amount. Occasionally, a Commission may initiate a proceeding on its own motion to reduce a utility's rates. The basic objective in either case is to determine the rates necessary to recover the utility's cost of service. The specific method of determining that cost varies somewhat from state to state, but the various methods can be reduced to the following formula:

$$R = E + (B \times I)$$

where
E = Expenses
B = Rate Base
I = Overall Rate of Return
R = Revenue Requirement

The expenses are simply the utility's costs which are incurred in serving customers and are not capitalized. They include such items as operations and maintenance, administration, depreciation, taxes, uncollectibles, customer billing and, if not collected through a separate mechanism, cost of gas. It is not uncommon for some expense items to be disallowed because they are not reasonable or prudent, or because they are non-utility expenses. Such disallowed expenses are referred to as being "below the line" and hence not allowable for rate-making purposes. Allowable expenses are "above the line."

Rate base is a utility's plant, net of depreciation, plus working capital, which is used and useful in providing utility service. Most states use historical original cost to determine rate base but some use fair value, which is intended to provide a more up-to-date measure of replacement cost. There are also a variety of methods for dealing with construction work in progress, but this factor is not as significant for gas utilities as it is for electric. Finally, if the utility serves more than one state, it will be necessary to make a jurisdictional separation of rate base and expenses between the portion regulated by the Commission and others. This separation may also be necessary if the utility has affiliated operations which are not regulated.

The utility's overall rate of return represents its weighted average cost of financing through instruments such as common stock, preferred stock, long and short term debt. The purpose is to permit the utility the opportunity to earn a reasonable return on its capital invested in providing utility service. The allowed rate of return on common equity will often be highly controverted, but the other cost elements may not be controversial, especially if they are based on embedded costs.

The elements of expenses, rate base and overall rate of return are then utilized in keeping with the formula to produce the utility's rate case revenue requirement. This represents the total revenues which the rates designed in the case need to produce for the utility to have the opportunity to earn its authorized rate of return. The formula used in the case will often be designed to calculate a revenue deficiency (or excess) at present rates, but at some point this will need to be converted to a revenue requirement for rate design purposes.

2. Rate Class Determination

In order to design rates, it is first necessary to divide the utility's customers into various rate classes. This is done by defining rate classes according to certain characteristics which are common to all members of the class. The specific factors used to define rate classes will depend upon the characteristics of the customer population and the goals to be achieved. Factors which have been used to define rate classes include: (1) size, (2) customer type, (3) type of usage, (4) interruptible or firm service, (5) load factor, and (6) alternate fuel capability. Some of these, such as size, are relatively obvious, though others may require some elaboration.

Customer type basically refers to whether the customer is residential, commercial or industrial. These basic categories are often subdivided. For example, the residential class may be divided into space heating and non-heating, or separate rate classes may be created for senior citizens or low-income customers. These subclassifications are often related to other characteristics, such as size or load factors, but they need not be.

Classification by type of usage is similar to classification by customer type, but is more dependent upon the specifics of the utility's service territory. For example, if a utility is located in an agricultural area, it may be advantageous to design a special rate for grain dryers. These customers have relatively low load factors since they have high consumption during the drying season and little or none during the rest of the year, but they use large volumes of gas, generally are off peak and are price sensitive. A rate class limited to them can prove useful in designing rates to meet the utility's overall revenue requirement. Each utility will have its own unique mix of types of usage and the appropriate rate class determination should consider the particular consumption patterns on the utility's system.

Segmenting customers by load factor (or load consumption characteristics) can serve a purpose similar to dividing them into firm or interruptible categories. Demand for natural gas is seasonal, with northern states having a higher winter peak due to the heavy concentration of space heating. Usually it is desirable to have customers with load factors which reduce or at least don't accentuate the seasonality fluctuations.

In determining which factors to use in setting rate classes, it is necessary to consider the objectives to be achieved. In theory, utility rates could be designed for only a single rate class. However, an appropriate division of customers into rate classes can achieve a variety of goals, including economic efficiency, fairness and equity, reflection of costs, social needs, competitiveness, operating efficiency, business climate development, rate stability, conservation and political feasibility. The need for a reasonable division of rate classes to achieve these goals exists whether the rates are designed based on cost of service principles or some other means.

3. Rate Design Factors

Utility rate design is more art than science. Even within a seemingly objective standard, such as cost of service based rates, there remains considerable latitude for judgment and personal value systems to affect the final result. A leading reference manual on public utility rates goes so far as to state:

> "One of the reasons for the popularity of a cost-of-service standard of ratemaking no doubt lies in the flexibility of the standard itself. 'Cost,' like 'value,' is a word of many meanings, with the result that people who disagree, not just on minor details but on major principles of ratemaking policy, all may subscribe to some version of the principle of service at cost."[1]

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1 Principles of Public Utility Rates by James C. Bonbright, Albert L. Danielsen and David P. Kamerschen (1988), Pg. 109.

The flexibility of the cost of service standard is due to three factors: (1) Matters extraneous to the rate design system; (2) multiple costs to choose from, and (3) the need to allocate or assign costs.

First, it should be recognized that rate design does not occur in a vacuum. The utility likely has an existing rate design which must be considered. Although states prohibit undue discrimination in setting utility rates, the utility's product must compete with alternative energy sources in the marketplace. These and other similar factors will affect the viewpoint and potential results of the rate designer.

Second, there is more than one definition of cost which could be used. There are original costs and replacement costs; fixed costs and variable costs; direct costs and indirect costs; average costs and incremental costs; and short-run costs and long-run costs. Though many options are available, in practice the choice usually comes down to two: (1) allocated costs based upon the existing embedded accounting costs of providing service, and (2) marginal costs reflecting current costs for providing service to new or additional customers. These two approaches are completely antithetical in their philosophy, information used and results. The allocated embedded cost approach is more common, relies on existing accounting data and produces results which permit the utility to earn its authorized return. Marginal cost has a better theoretical foundation, but relies on data not readily available and is more likely to result in over or under-collection.

Once a definition of cost is decided upon, it is then necessary to assign costs to specific customer classes. Generally speaking, these costs can be divided into two broad categories: direct costs and common costs. Direct costs are those which are incurred only to provide service to a particular customer class. Common costs are incurred in providing service to more than one class. The assignment of direct costs is straight-forward and should not be subject to debate. Common costs are another matter. By definition, such costs are incurred for the benefit of several rate classes and their costs cannot be directly assigned. Instead, it is necessary to allocate these costs among the rate classes using some reasonable allocation method. There are a number of reasonable methods which means that the appropriate cost of service allocation is often a hotly contested issue. This is not to suggest that cost of service studies are arbitrary; some allocations are clearly more reasonable than others. However, there is no one correct cost of service, but rather a range of reasonable alternatives. The following two sections present an illustrative cost of study.

B. Historic or Embedded Cost of Service

Historic or embedded cost of service studies attempt to apportion total costs to the various customer classes in a manner consistent with the incurrence of those costs. This apportionment must be based on the fashion in which the utility's system, facilities and personnel operate to provide the service. Basic load and operating data are needed, in addition to the costs, to conduct a cost allocation study.

Embedded cost of service studies are generally conducted in the following steps: (1) functionalization of costs as either production, storage, transmission or distribution; (2) classification of costs into three basic categories -- customer, energy or commodity, and demand or capacity costs; and (3) the allocation of these costs to customer classes or to types of load. All items that can be directly attributed to a particular service (such as revenues from a specific service or the cost of a high pressure main constructed for a particular customer or group of customers) should be segregated and directly assigned to the appropriate customers. There is no scientifically correct method of making necessary allocations. A certain amount of judgment must be used in any cost of service study. Consequently, cost allocation studies should only be utilized as a general guide or as a starting point for rate design.

1. Functionalization of Costs

Functionalization is the arrangement of costs according to major functions, such as production, storage, transmission or distribution. This functional categorization of costs helps to facilitate a determination as to which customer groups are jointly responsible for such costs. Some costs, such as those associated with the general or common plant and administrative and general expenses, generally are not directly assigned to the established functional groups. These costs did not appear to have any direct relationship to the service characteristics employed for purposes of functionalization.

The primary operating functions to which costs can be broadly categorized are described as follows:

Production costs are the costs relating to producing, purchasing or manufacturing gas. Included are purchases of pipeline or producer gas and all costs associated with producing owned or peaking gas; i.e. the gas itself, feedstocks, capital costs, operations and maintenance expense.

Storage costs are the costs associated with storing gas normally during off-peak for use in times of cold weather. Also included are related operation and maintenance expenses.

Transmission costs are the costs incurred in transporting gas from interstate pipelines to the distribution system. Included are the capital costs of transmission mains, as well as city gas metering station costs and related operation and maintenance.

Distribution system costs are those costs incurred to deliver the gas to the customers. Included are capital and operating costs for distribution mains, compressors, customer services, meters, and regulators.

Other costs include those costs that do not fit the above functions, such as the cost associated with common plant and working capital, general and administrative costs, customer accounting, and advertising costs.

The functionalization of costs is generally the easiest step in a cost of service study, since utility investment and expense records are maintained in accordance with prescribed uniform accounting systems. These systems, such as the Uniform System of Accounts, classify costs according to primary operating functions. Thus, the functionalization of costs is already done for the cost of service analyst.

2. Classification of Costs

The functionalization of costs is of limited use in the allocation of costs. Therefore, it is necessary to further classify costs into customer, energy or commodity, and demand or capacity costs.

a. Customer Costs

Customer costs are those operating capital costs found to vary directly with the number of customers served rather than with the amount of utility service supplied. They include the expenses of metering, reading, billing, collecting, and accounting, as well as those costs associated with the capital investment in metering equipment and in customers' service connections.

A portion of the costs associated with the distribution system may be included as customer costs. However, the inclusion of such costs can be controversial. One argument for inclusion of distribution related items in the customer cost classification is the "zero or minimum size main theory." This theory assumes that there is a zero or minimum size main necessary to connect the customer to the system and thus affords the customer an opportunity to take service if he so desires.

Under the minimum size main theory, all distribution mains are priced out at the historic unit cost of the smallest main installed in the system, and assigned as customer costs. The remaining book cost of distribution mains is assigned to demand. The zero-inch main method would allocate the cost of a theoretical main of zero-inch diameter to the customer function, and allocate the remaining costs associated with mains to demand. A calculation of a minimum size main is shown in the illustrative cost allocation study. The contra argument to the inclusion of certain distribution costs as customer costs is that mains and services are installed to serve demands of the consumers and should be allocated to that function. Under this basic system theory, only those facilities, such as meters, regulators and service taps, are considered to be customer related, as they vary directly with the number of customers on the system.

Another controversial item is the inclusion of sales promotion expenses in the customer cost component. Analysts vary in their opinions as to the extent of the inclusion. Some would include all, some none, and some a portion of sales promotion expense in the customer category. With emphasis placed on conservation, many regulatory bodies have prohibited this type of activity, and in those cases, if cost were incurred, it should be deleted from the study based upon its being a "below the line" or a stockholder expense.

b. Energy or Commodity Costs

Energy or commodity costs are those which vary with the quantity of gas produced or purchased. They are largely made up of the commodity portion of purchased gas cost and the cost of feedstock, catalyst, fuel, and other variable expenses used in the production of gas from a manufactured or synthetic gas (SNG) plant. Energy or commodity costs increase or decrease as more or less gas is consumed.

c. Demand or Capacity Costs

Demand or capacity costs vary with the quantity or size of plant and equipment. They are related to maximum system requirements which the system is designed to serve during short intervals and do not directly vary with the number of customers or their annual usage. Included in these costs are: the capital costs associated with production, transmission and storage plant and their related expenses; the demand cost of gas; and most of the capital costs and expenses associated with that part of distribution plant not allocated to customer costs, such as the costs associated with distribution mains in excess of the minimum size.

3. Allocation of Costs to Customer Classes

After the assignment of costs to the customer, energy, and demand categories, each category must be allocated to the various service classifications or to their subdivisions.

a. Customer Costs

Customer costs may be distributed in proportion to the number of customers in a class, or a more detailed study may be made whereby certain components of the customer costs may be distributed on a per-customer basis, directly assigned or distributed on a weighted per-customer basis. The latter method permits recognition of known or ascertainable customer cost differences such as the frequency of meter readings, complexity in obtaining readings or integrating meter reading charts, and the individiual attention which may be given to large customers, such as separate meter reading schedules.

As discussed earlier, while there may be differences on whether certain items of plant should be assigned to customer costs, there are clearly certain expenses which are independent of whether a customer consumes gas or not. Since these costs will not be recouped if little or no gas is consumed, they are generally included in a minimum bill or customer service charge. One of the useful by-products of a detailed cost of service study is that the customer costs are broken out by service classification or class of customer. When these costs are divided by the number of customers within a particular subdivision, the analyst is provided with an indication of what the minimum or customer service charge should be.

b. Energy or Commodity Costs

Energy or commodity costs may be distributed to customer groups on the basis of the quantity of gas consumed during some historical or projected test period, with or without allowance for losses incurred in transporting the gas from the production plant or city gate station to the customer. If the historical test period were abnormally cold or warm, the sales and related cost should be normalized before allocation. The analyst in reviewing the operation of the system could find that certain classes of customers might appropriately be allocated a greater or lesser than average level of lost and unaccounted for gas. This determination will be affected by such factors as the degree of utilization of distribution facilities, quality of metering equipment and the timing of meter readings relative to purchases.

c. Demand or Capacity Costs

Demand or capacity costs are allocated to customer classes based upon an analysis of system load conditions and on how each customer class affects such costs. These are largely joint or common costs, and their allocation generates the largest controversy surrounding a cost of service study. This subject has been studied and argued for years without resolution, and often represents the largest item which can dramatically alter the result of a study.

d. Other Costs

Other costs, such as those associated with common plant, working capital and administrative and general expenses, cannot be readily categorized as either customer, energy or demand. Thus, they are not normally allocated on the basis of a single classification. These other costs are generally allocated on a composite basis of certain other cost categories. For example: common plant may be allocated on the composite allocation of all production, transmission, storage and distribution plant; and administrative and general expenses may be allocated in accordance with the composite allocation of all other operating and maintenance expense, excluding the cost of gas.

4. Methods of Allocation of Demand or Capacity Costs

a. Theory

There is a wide variety of alternative formulas for allocating and determining demand costs, each of which has received support from some rate experts. No method is universally accepted, although some definitely have more merit than others. The electric industry has produced more alternatives than the gas industry. For instance, in an early 1950 case before the Illinois Commerce Commission, an executive of Commonwealth Edison Company noted the existence of 29 different formulas for the apportionment of demand costs. The application of these formulas produced drastically different cost assignments to the several service classifications. As a result, the Illinois Commission refused to direct that the utility present such evidence. The NARUC published in 1955, through its Engineering Committee, a detailed discussion of 16 such methods.

The multiplicity of available methods (which in fact reflects the insoluble nature of the problem) has led many recognized experts to express grave doubts about the efficacy of cost of service analyses.

The most commonly used demand allocations for natural gas distribution utilities are the coincident demand method, the non-coincident demand method, the average and peak method, or some modification or combination of the three.

b. Coincident Demand Method

In the coincident demand (peak responsibility) method, allocation is based on the demands of the various classes of customers at the time of system peak. This method favors high load factor customers who take gas at a steady rate all year long by assigning the greater percentage of demand costs to lower load factor heating customers whose consumption is greatest at the time of the system peak. Generally, interruptible customers would receive no allocation of demand costs under this formula since they should be off the system during the peak period. The demand component of the cost of gas is generally allocated on a coincident demand method.

c. Noncoincident Demand Method

This method would result in all classes of customers being allocated a portion of system cost based upon their actual peak, regardless of the time of its occurrence. This method assigns cost to customer classes such as interruptibles, and thereby reduces the costs allocated to the heating customer under the peak demand method. The demand related portion of distribution mains and transmission mains are commonly allocated on a noncoincident demand method.

d. Average and Peak Demand Method

This method reflects a compromise between the coincident and noncoincident demand methods. Total demand costs are multiplied by the system's load factor to arrive at the capacity costs attributed to average use and are apportioned to the various customer classes on an annual volumetric basis. The remaining costs are considered to have been incurred to meet the individual peak demands of the various classes of service and are allocated on the basis of the coincident peak of each class. This method allocates cost to all classes of customers and tempers the apportionment of costs between the high and low load factor customers.

5. Use of Load Studies For Allocation of Demand Costs

a. Concepts

As previously mentioned, load data are necessary for a cost of service study. These data are the basis for any demand allocation and, if inaccurate, can give misleading results regardless of the case taken with the remainder of the analysis. The load characteristics of each utility's system and each customer class on a system are unique and must be separately surveyed in each case. The purpose of the survey is to determine for relatively homogenous customer groups such information as load pattern, amount and time of occurrence of maximum load, load factor, and diversity or coincidence factor.

Arriving at load patterns is not an easy task. Most of the necessary information is not readily available from the normal record keeping of a utility. To secure the information requires a systematic activity known as load research. It embraces a whole gamut of engineering, statistical, and mathematical methods and procedures, ranging from the simple application of judgments to available data to refined mathematical probes into the significance of sampling techniques. The gas industry generally has not devoted the same resources to this area in the past as the electric industry on the whole has, so in most cases more reliance will have to be placed on use of existing records than would be preferred. However, since system peaks in the gas industry are highly weather sensitive, a fairly reliable correlation between temperature versus gas consumption can be developed from utility records. By applying a least square fit to "average degree day" and "use per day" data for each customer group, one can calculate with reasonable accuracy the demands to be placed on the system. A relatively unsophisticated estimate of system peaks is included in the illustrative cost of service study.

More attention is now being devoted to this important phase of input data needed for not only studies of this sort, but in understanding customer load profiles in general. The following briefly summarizes the steps which can be taken to develop load curves.

b. Determination of Load Curves By Billing Records

Load curves can be determined for some classes from the billing records of customers who are equipped with standard recording instruments. This is feasible for classes in which all, or nearly all, the customers are so equipped. Normally, this is the case for interruptible and large industrial customers, a tiny fraction of all customers served by a utility.

c. Determination of Load Curves By Load Surveys

The load curves for residential and small commercial and industrial classes must be developed from data for sample groups of these classes, obtained from field surveys, and expanded to include the entire energy use of these classes. The particular procedure adopted will be dictated largely by the economic considerations of conducting such tests and by the availability of manpower and test-metering equipment. However, test groups of sample customers must be carefully selected in accordance with sound statistical principles. The sample customers should be chosen at random so as to properly reflect the specific energy use characteristics of all substantially homogenous customer groups within a service classification.

There may be difficulty in getting customers to accept test meters, since their premises must be available for meter printout sheet or tape replacement where necessary so that the test data will be continuous for the period involved. This complicates the selection procedure.

The selection process must result in a valid statistical sample. Ultimately, there must be selected a representative cross-section of customers willing to cooperate in the test-metering program, sufficiently large in number to be statistically significant. About three times the number of customers for which tests are needed must be initially selected. Factors such as examination of the types of customers produced by the random selection to assure that they are representative; field inspection of premises to determine type of premises; connected load and number of people who live or work on the premises; and unwillingness or inability of a customer to cooperate, all must eventually be tested. A considerable expenditure of time and manpower is needed to complete the process.

C. Illustrative Embedded Cost of Service Study

A cost of service study is a series of choices regarding potentially controversial methods of identifying and allocating costs incurred by a utility. This illustrative study represents one possible means of computing class cost of service. There are many other equally correct methods. For illustrative purposes, the following example demonstrates how the factors discussed above are utilized in a fully allocated cost of service study.

The first step in preparation of the study is a separation of all plant and expense items incurred during the test period into the functional categories of production, storage, transmission, distribution and general. This functionalization is shown throughout the study on Schedules 3, 4 and 5, according to Monopolytown's accounting system. Where possible, functional costs are directly assigned to the classes of service based upon details from the utility's books or by special analysis or studies. This is illustrated in Schedule No. 2 where Rate Revenues are directly assigned to the classes which produce them.

The costs not directly assignable were allocated among the customer classifications according to factors developed from the basic statistical data. The derivation of the allocation factors is illustrated on Schedules 10 and 11. The following is an explanation of the major allocation factors used in this study.

The Peak Day Demand (Allocation Factor 100) is the computed quantity of gas which would be supplied on a day when the mean temperature of the utility's service territory is 5 degrees Fahrenheit (the coldest day in 20 years for this particular system), which equates to a 60 degree-day deficiency. Schedule No. 12 provides the details of the peak day calculations. There are two predominant Commodity allocation factors which consist of normalized and curtailed gas sales during the test period. Factor No. 110 is comprised of sales without transportation volumes. Factor No. 120 is the total throughput quantity which includes gas sales and transportation. The primary Customer allocation factor, No. 160, consists of the number of bills rendered during the test period.

Once the allocation factors are prepared, they should be applied to the functionalized costs in relation to how those costs are incurred by the utility. Expenses and plant are classified or considered to be fixed, variable, customer, or revenue related. Classification is an integral part of the allocation process and once costs are classified, the appropriate allocation factors are applied to these costs as shown in the last column in each of Schedules 2 through 9. Fixed costs are normally allocated on the basis of demand, while variable costs are allocated on the basis of commodity sales. Costs incurred as a result of a customers' connection to the utility system are allocated on the basis of a customer factor, and costs related to revenues are allocated on the basis of a revenue factor. Costs which cannot be related to one of the four basic classifications are allocated on the basis of a composite factor, reflecting two or more elements of the expense or plant accounts. This is illustrated on Schedule No. 4 where account 374 (land and land rights) is allocated on the basis of allocation Factor No. 13, which reflects a composite of the allocation of all other distribution plant.

As a more detailed explanation of the allocation process, consider the allocation of utility plant which is shown on Schedule No. 4. Production plant, which includes a propane-air facility, was designed and constructed by the utility to meet peak load requirements. Consequently, production plant has been allocated on the basis of peak day demand (Allocation Factor No. 100).

The distribution plant investment in mains may be classified as both demand and customer related. The customer component was determine as the amount of investment that would be required it all mains were comprised of a theoretical minimum size. Monopolytown's smallest mains (1.5 inch diameter) were installed at an average unit cost of $0.61 per foot. The customer component of mains is computed by multiplying the total length of mains (6,385,860 feet) by the unit cost of the smallest mains. The resulting amount ($3,988,733) represents approximately 20 percent of the total investment in mains. The remaining 80 percent is considered to be demand related. Therefore, the investment and expenses associated with mains are allocated on the basis of composite allocation Factor No. 150. Factor No. 150 is a weighted average of allocation Factor No. 160 (20 percent weight) and Factor No. 100 (80 percent weight).

Plant facilities such as gas services and meters are allocated to the rate schedules by using allocation factors designed to reflect the various cost differentials among classes. To accomplish this weighted computation for gas services, the typical current cost to construct gas services for each customer class is determined. The class gas service costs are then divided by the typical residential gas service cost. The resulting ratio is a weighting factor which is then multiplied by the number of customers in each class. The product of this calculation then becomes the basis of the gas service Allocation Factor No. 200. The meter allocation factor is determined in a similar manner and the weighting factors utilizied for both meters and gas services are the following:

WEIGHTING FACTORS

Class	Services	Meters
Residential	1	1
*Commercial	5	5
*Industrial	50	40
Interruptible	50	40
Transportation	50	40

* The Commercial and Industrial classes are combined in the study under "GENERAL SERVICE"

Once the allocation of plant is accomplished, depreciation and working capital are the next steps which ultimately lead to the determination of rate base. The allocation of depreciation is illustrated on Schedule No. 5 and the allocation of working capital is demonstrated on Schedule No. 6. The allocation of rate base is illustrated on Schedule No. 7, where figures from previous schedules are assembled to determine customer class rate base for ratemaking purposes.

The allocation of operating expenses is illustrated in Schedule No. 3. Expenses which are demand related, such as pipeline demand charges and gas production expenses, are allocated on the basis of peak day demand, Allocation Factor No. 100. Expenses which are commodity related, such as commodity gas purchases, are allocated on the basis of sales excluding transmission, Allocation Factor No. 110. Customer oriented expenses, such as customer accounting, meter reading and advertising expenses are allocated on the basis of the number of customers on the system or the number of meters, Allocation Factor No. 160 or 180.

Many expenses, such as supervision and engineering, administration and general costs, taxes, and depreciation, are allocated on the same basis as the related plant investment. These are composite allocation factors developed as a line item summary of various elements in the cost of service study as it progresses. For example, Allocation Factor No. 13 is the respective customer class percentage of total distribution plant costs. Therefore, the allocation of any costs which are allocated on the basis of Factor No. 13 would have to proceed after total distribution plant by class is computed on Schedule No. 4. The composite allocation factors are illustrated on Schedule No. 11, with the appropriate reference to their development in the cost of service study.

Following the allocation of all plant and expenses, a summary is developed in Schedule No. 1. The relevent totals from each schedule previously explained are brought forward to Schedule No. 1 as a summary of the cost of service study and to examine the rate of return generated by the entire system as well as each class of service.

MONOPOLYTOWN GAS SERVICES
Summary of Class Cost Study

Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
Total Operating Revenue	62,804,086	30,193,577	21,312,089	11,152,860	145,560	Schedule 2
Operation & Maintenance Exp.	54,131,100	25,396,295	18,595,697	10,070,004	69,104	Schedule 3
Depreciation Expense	1,101,152	716,319	367,692	12,562	4,578	Schedule 5
Federal Income Taxes	1,662,145	800,080	499,938	335,752	26,375	Schedule 9
Taxes Other	2,437,051	1,307,609	795,366	325,151	8,926	Schedule 8
Total Operating Expense	59,331,449	28,220,303	20,258,693	10,743,469	108,983	
Net Operating Income	3,472,637	1,973,274	1,053,396	409,390	36,577	
Charitible Donations	14,080	12,874	1,193	10	3	Factor 170
Interest on Deposits	151,961	139,340	12,621	0	0	Factor 16
Adjusted Net Operating Income	3,306,596	1,821,060	1,039,581	409,380	36,574	
Total Rate Base	24,776,459	14,841,077	8,755,675	1,087,522	92,184	
Return on Rate Base	13.3457%	12.2704%	11.8732%	37.6434%	39.6755%	

MONOPOLYTOWN GAS SERVICES
Allocation of Revenues

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
	Rate Revenues	62,378,875	29,939,507	21,287,396	11,151,972	0	Direct
487	Forfeited Discounts	235,316	215,166	19,939	167	43	Factor 160
488	Miscellaneous Service Revenue	40,515	37,046	3,433	29	7	Factor 160
489	Transportation Gas	145,510	0	0	0	145,510	Direct
495	Other Revenue	3,870	1,857	1,321	692	0	Factor 17
	Total	62,804,086	30,193,577	21,312,089	11,152,860	145,560	

MONOPOLYTOWN GAS SERVICES
Allocation of Operating & Maintenance Expense

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
	Gas Production Expense	71,759	45,665	26,094	0	0	Factor 100
	Other Gas Supply Expense						
804	Natural Gas Purchases:						
	Demand	7,713,504	4,908,627	2,804,878	0	0	Factor 100
	Commodity	40,424,560	15,870,195	14,369,269	10,185,095	0	Factor 110
805	Synthetic Natural Gas	133,571	85,001	48,571	0	0	Factor 100
805	Propane	59,371	37,782	21,589	0	0	Factor 100
807	Purchased Gas Adjustment	(940,211)	(369,116)	(334,206)	(236,889)	0	Factor 110
809	Gas delivered from storage	50,527	32,154	18,373	0	0	Factor 100
812	Gas used other	(41,664)	(16,357)	(14,810)	(10,497)	0	Factor 100
813	Other expense	13,913	5,462	4,946	3,506	0	Factor 110
	Total Other Gas Supply Exp	47,413,572	20,553,748	16,918,609	9,941,215	0	
	Total Gas Supply Expense	47,485,331	20,599,413	16,944,703	9,941,215	0	
	Distribution Expense:						
	Operation:						
870	Operations super. & engineer.	107,937	80,001	23,149	2,836	1,951	Factor 10
871	Load dispatching	84,742	27,569	24,962	17,693	14,519	Factor 120
873	Compression station fuel	1,111	362	327	232	190	Factor 120
874	Mains	120,979	81,663	39,301	12	3	Factor 150
875	Measuring & regulating general	36,895	23,479	13,416	0	0	Factor 100
876	Measuring & regulating indust.	13,761	0	3,237	5,781	4,743	Factor 140
878	Meter & house regulators	369,766	234,693	125,915	7,289	1,869	Factor 180
879	Customer installation	552,732	506,824	45,908	0	0	Factor 170
880	Other distribution expense	287,109	212,801	61,575	7,544	5,189	Factor 10
881	Rents	5,248	3,890	1,126	138	95	Factor 10
	Total Operating Expense	1,580,280	1,171,282	338,916	41,525	28,558	

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MONOPOLYTOWN GAS SERVICES
Allocation of Operating & Maintenance Expense

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
	Maintenance Expense:						
885	Supervision & engineering	24,228	15,115	8,078	627	409	Factor 11
886	Structures & improvements	36,408	11,844	10,724	7,601	6,238	Factor 120
887	Mains	231,598	156,333	75,237	23	6	Factor 150
888	Compressor station equipment	17	6	5	4	3	Factor 120
889	Measuring & regulating general	81,770	52,036	29,734	0	0	Factor 100
890	Measuring & regulating indust.	7,177	0	1,688	3,015	2,474	Factor 140
892	Services	107,644	68,322	36,656	2,122	544	Factor 180
893	Meters	120,421	76,432	41,007	2,374	609	Factor 180
894	Other	1,341	837	447	35	23	Factor 11
	Total Maintenance Expense	610,604	380,925	203,575	15,800	10,304	
	Total Distribution Expense	2,190,885	1,552,206	542,491	57,324	38,863	
	Customer Accounting Expense:						
901	Supervision	58,268	53,279	4,937	41	11	Factor 160
902	Meter reading expense	255,409	162,110	86,974	5,034	1,291	Factor 180
903	Customer records	1,171,530	743,578	398,938	23,092	5,921	Factor 180
904	Uncollectible expense	248,489	227,212	21,056	176	45	Factor 160
905	Miscellaneous expense	29,838	27,283	2,528	21	5	Factor 160
	Total	1,763,535	1,213,463	514,433	28,366	7,273	
	Customer Services Expense:						
909	Miscellaneous expense	768	702	65	1	0	Factor 160
909	Advertising expense	2,740	2,537	201	2	0	Factor 160
	Total Customer Service Expense	3,508	3,239	266	2	1	

MONOPOLYTOWN GAS SERVICES
Allocation of Operating & Maintenance Expense

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
	Sales:						
915	Supervision	153,026	139,923	12,967	109	28	Factor 160
916	Selling	178,241	162,979	15,103	127	32	Factor 160
917	Advertising	112,431	102,804	9,527	80	20	Factor 160
918	Miscellaneous	24,556	22,453	2,081	17	4	Factor 160
	Total	468,253	428,158	39,677	332	85	
	Administrative & General Exp.:						
920	Administrative & gen'l salary	722,334	521,748	179,004	14,039	7,543	Factor 12
921	Office supplies	271,907	196,401	67,382	5,285	2,839	Factor 12
922	Administrative expense	(49,554)	(35,793)	(12,280)	(963)	(517)	Factor 12
923	Outside services	444,917	321,368	110,257	8,647	4,646	Factor 12
924	Property insurance	14,353	9,340	4,786	166	61	Factor 13
925	Injuries & damages	65,744	47,487	16,292	1,278	687	Factor 12
926	Employee pension & benefits	675,923	488,225	167,503	13,137	7,059	Factor 12
928	Regulatory commission expense	4,431	3,201	1,098	86	46	Factor 12
930	Miscellaneous general expense	36,214	26,157	8,974	704	378	Factor 12
931	Rents	33,319	21,682	11,111	386	141	Factor 13
	Total Administrative & General	2,219,588	1,599,815	554,127	42,764	22,882	
	Total Operating & Maintenance	54,131,100	25,396,295	18,595,697	10,070,004	69,104	

MONOPOLYTOWN GAS SERVICES
Allocation of Plant in Service

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
	Intangible:						
301	Organization	52,036	33,862	17,352	603	220	Factor 13
302	Franchises	47,068	30,628	15,695	545	199	Factor 13
	Total	99,104	64,490	33,047	1,148	418	
	Manufactured Production:						
304	Land & land rights	26,375	16,784	9,591	0	0	Factor 100
305	Structures & improvements	65,825	41,889	23,936	0	0	Factor 100
311	Liquefied petroleum	387,373	246,512	140,861	0	0	Factor 100
320	Other equipment	429	273	156	0	0	Factor 100
	Total	480,001	305,457	174,544	0	0	
	Distribution Plant:						
374	Land & land rights	94,527	61,512	31,521	1,095	399	Factor 13
375	Structures & improvements	213,046	138,636	71,043	2,468	899	Factor 13
376	Mains	19,326,453	13,045,703	6,278,354	1,907	489	Factor 150
377	Compressor station equipment	66,327	42,208	24,118	0	0	Factor 100
378	Measuring & regulating general	724,502	461,050	263,452	0	0	Factor 100
385	Measuring & regulating indust.	181,941	0	42,797	76,428	62,715	Factor 140
380	Services	9,361,448	5,828,366	3,248,811	226,256	58,014	Factor 200
381	Meters	2,621,018	1,663,579	892,528	51,664	13,247	Factor 180
382	Meter installations	1,215,649	771,581	413,961	23,962	6,144	Factor 180
383	House regulators	638,684	405,377	217,489	12,589	3,228	Factor 180
384	House regulator installations	320,403	203,362	109,106	6,316	1,619	Factor 180
386	Other property	2,799	2,559	237	2	1	Factor 160
387	Other equipment	23,304	15,165	7,771	270	98	Factor 13
	Total	34,790,101	22,639,100	11,601,189	402,957	146,855	
	Total General Plant	1,423,053	926,029	474,535	16,483	6,007	Factor 13
	Total Plant in Service	36,792,259	23,935,076	12,283,315	420,588	153,280	

MONOPOLYTOWN GAS SERVICES
Depreciation

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
	Accumulated Depreciation:						
108	Production	9,383	5,971	3,412	0	0	Factor 100
108	Distribution	8,299,182	5,400,559	2,767,465	96,126	35,032	Factor 13
108	General	791,723	515,201	264,010	9,170	3,342	Factor 13
108	Total	9,100,288	5,921,731	3,034,886	105,296	38,374	
	Depreciation Expense:						
403	Production	16,552	10,533	6,019	0	0	Factor 100
403	Distribution	989,011	643,583	329,798	11,455	4,175	Factor 13
403	General	95,589	62,203	31,875	1,107	403	Factor 13
403	Total	1,101,152	716,319	367,692	12,562	4,578	

MONOPOLYTOWN GAS SERVICES
Allocation of Working Capital

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
165	Gas inventory	867,715	552,186	315,529	0	0	Factor 100
151	Synthetic feedstock	95,249	60,613	34,636	0	0	Factor 100
154	Materials & supplies	438,742	285,504	146,304	5,082	1,852	Factor 13
131	Cash	4,572,355	2,145,179	1,570,745	850,595	5,837	Factor 19
168	Cost free capital	(3,686,585)	(2,398,086)	(1,231,228)	(41,974)	(15,297)	Factor 16
	Total Working Capital	2,287,476	645,396	835,986	813,702	(7,608)	

MONOPOLYTOWN GAS SERVICES
Allocation of Rate Base

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
	Net Plant:						
	Total gas plant	36,792,259	23,935,076	12,283,315	420,588	153,280	Schedule 4
	Total accumulated depreciation	9,100,288	5,921,731	3,034,886	105,296	38,374	Schedule 5
	Net plant	27,691,971	18,013,345	9,248,428	315,292	114,906	
	Working Capital	2,287,476	645,396	835,986	813,702	(7,608)	Schedule 6
	Net Plant	27,691,971	18,013,345	9,248,428	315,292	114,906	
282	Deferred taxes	(3,580,574)	(2,330,001)	(1,193,986)	(41,472)	(15,114)	Factor 13
235	Customer Deposits	(1,622,415)	(1,487,663)	(134,752)	0	0	Factor 170
	Rate Base	24,776,459	14,841,077	8,755,675	1,087,522	92,184	

MONOPOLYTOWN GAS SERVICES

Allocation of Taxes Other Than Federal Income Tax

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
408	Federal unemployment insurance	9,955	7,191	2,467	193	104	Factor 12
408	FICA & miscellaneous tax	307,736	222,280	76,261	5,981	3,214	Factor 12
408	State unemployment insurance	6,031	4,356	1,495	117	63	Factor 12
408	Property tax	339,937	221,209	113,356	3,937	1,435	Factor 13
408	Gross receipts tax	1,512,583	727,187	513,284	268,607	3,506	Factor 14
408	Franchise tax	96	46	33	17	0	Factor 14
408	Business & occupation	260,712	125,339	88,471	46,298	604	Factor 14
	Total Taxes Other	2,437,051	1,307,609	795,366	325,151	8,926	

MONOPOLYTOWN GAS SERVICES
Allocation of Federal Income Tax

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
	Total Operating Revenue	62,804,086	30,193,577	21,312,089	11,152,860	145,560	Schedule 2
	Operation & maintenance exp.	54,131,100	25,396,295	18,595,697	10,070,004	69,104	Schedule 3
	Depreciation expense	1,101,152	716,319	367,692	12,562	4,578	Schedule 5
408	Taxes other	2,437,051	1,307,609	795,366	325,151	8,926	Schedule 8
729	Charitable deductions	14,080	12,874	1,193	10	3	Factor 160
730	Interest on deposits	151,961	139,340	12,621	0	0	Factor 170
731	Interest expense	1,087,043	707,110	363,045	12,377	4,511	Factor 16
	Miscellaneous deductions	269,364	175,218	89,961	3,067	1,118	Factor 16
	Total Expense	59,191,751	28,454,765	20,225,576	10,423,171	88,239	
	Taxable Income	3,612,335	1,738,812	1,086,513	729,689	57,321	
	Total Federal Income Tax	1,662,145	800,080	499,938	335,752	26,375	Factor 20

MONOPOLYTOWN GAS SERVICES
Allocation Factors

Fact	Description	System	Residential	General	Interrupt	Transport
100	Peak Day	85,053	54,125	30,928	0	0
		100%	63.64%	36.36%	0.00%	0.00%
110	Sales without Transporation	10,228,227	4,015,479	3,635,714	2,577,034	0
		100%	39.26%	35.55%	25.20%	0.00%
120	Sales with Transportation	12,342,893	4,015,479	3,635,714	2,577,034	2,114,666
		100%	32.53%	29.46%	20.88%	17.13%
130	Residential & Commercial Sales	6,208,137	4,015,479	2,192,658	0	0
		100%	64.68%	35.32%	0.00%	0.00%
140	Sales without Residential &	6,134,756	0	1,443,056	2,577,034	2,114,666
	Commercial	100%	0.00%	23.52%	42.01%	34.47%
160	Customers	54,936	50,232	4,655	39	10
		100%	91.44%	8.47%	0.07%	0.02%
170	Number of Residential &	54,782	50,232	4,550	0	0
	Commercial Customers	100%	91.69%	8.31%	0.00%	0.00%
180	Meters	79,142	50,232	26,950	1,560	400
		100%	63.47%	34.05%	1.97%	0.51%
200	Services	82,415	50,232	28,000	1,950	500
		100%	60.95%	33.97%	2.37%	0.61%
150	Mains 20% on Customers, 80% on	79,030	53,346	25,673	8	2
	Demand	100%	67.50%	32.49%	0.01%	0.00%

MONOPOLYTOWN GAS SERVICES
Derivation of Composite Allocators

Factor 10 - Composite of Accounts 871 through 879

Factor 11 - Composite of Accounts 886 through 893

Factor 12 - Composite of Total Production & Distribution O&M Expense less Gas Costs

Factor 13 - Total Distribution Plant

Factor 14 - Total Revenue

Factor 16 - Composite of Net Plant

Factor 17 - Rate Revenue

Factor 19 - Total Operating & Maintenance Expense

Factor 20 - Total Taxable Income

MONOPOLYTOWN GAS SERVICES
Derivation of Peak Day Demand

	Residential	Commercial	Industrial
January Usage	14.13 Mcf/Cust	76.07 Mcf/Cust	1504.11 Mcf/Cust
Non-Heating Load a_/	1.94 Mcf/Cust	14.61 Mcf/Cust	991.84 Mcf/Cust
Heating Load (line 8 - line 9)	12.19 Mcf/Cust	61.46 Mcf/Cust	512.27 Mcf/Cust
January Degree Day Deficiences (DDD) b_/	707	724	979
Peak Day DDD	60	60	60
Heating Use Per Degree Day c_/	0.0172 Mcf/Cust	0.0849 Mcf/Cust	0.5233 Mcf/Cust
Peak Day Heating Use (line 15 * line 13)	1.0346 Mcf/Cust	5.0934 Mcf/Cust	31.3956 Mcf/Cust
Peak Day NonHeat Use (line 9 / 30.4)	0.0639 Mcf/Cust	0.4807 Mcf/Cust	32.6264 Mcf/Cust
Peak Day Use (line 17 + line 18)	1.0985 Mcf/Cust	5.5741 Mcf/Cust	64.0220 Mcf/Cust
Number of Customers	49,273	4,331	106
Peak Day Usage (line 19 * line 21)	54,125 Mcf	24,141 Mcf	6,786 Mcf
Calculated Peak Day Demand (Sum line 23)	85,053 Mcf		

a_/ Assumes non-heating load equals average daily usage during the summer.

b_/ Monthly DDD varies for each class as a result of cycle billing.

c_/ Peak month heating usage divided by total peak month degree day deficiencies (DDD).

Note : The Commercial and Industrial peak day usages are used to determine the peak day allocation factor for the General rate class.

E. Rate Design

1. Firm Rates

Most of a utility's customers will be firm customers; that is, they have no alternate fuel or energy source readily available. The fact that they are firm customers indicates that the utility has an obligation to serve them and the utility plans its gas supply acquisition program and its system capacity with the goal of maintaining service to these cutomers.

Firm rates could be designed using any of the rate forms discussed in Chapter I, but most commonly use a flat rate or a declining block rate.

When flat rates are used, they normally consist of two components, a customer charge (or minimum bill) and a flat commodity rate. Even though the cost of service study indicates how to allocate costs to classes, it still must be decided how much of this cost to recover with each of these two rate components. First, customer charges should be billed as an explicit, separate, monthly charge. Ideally, the customer charge should recover all customer costs. However, to the extent that customer costs are not fully recovered in the customer charge or that capacity costs are included, the customer charge will be above or below customer costs. In some jurisdictions, an explicit customer charge will be unacceptable. In this case, a minimum bill, extending over a few units of gas, is an alternative. The commodity costs allocated to the class divided by normalized sales will yield the commodity component of the rate.

The most controversial issue is deciding where capacity costs belong in the rate. Because they are fixed costs, it is sometimes argued that they should be part of the customer charge. On the other hand, it can be argued that gas not customer backup, is the fundamental product being sold, and that those common fixed costs should be recovered evenly from all units of commodity sold. It is even occasionally proposed that these costs be spread between customer and commodity charges. On an embedded cost basis, once the decision is made as to what revenues should be collected through the customer charge, that amount is subtracted from the revenue requirement. All other revenues needed to meet the total revenue requirement must then be recovered through the commodity portion of the rate.

If instead of fixed customer charges and flat commodity rates, declining block rates are used, the initial high-priced blocks usually reflect the fixed costs of customer service as accurately as possible. Also, since gas sales are generally temperature sensitive, the tail blocks normally contain only a small amount of fixed costs. This provides revenue stability during abnormal weather.

2. Inverted/Lifeline/Baseline Rates

Lifeline and inverted rates are many times thought of interchangeably but there can be major differences between them. For instance, lifeline rate structures are almost always inverted but an inverted rate structure may not be a lifeline rate. The difference arises because of philosophical reasons and value judgments which pervade the entire rate design process.

The lifeline rate is a social rate design which has as its goal the furnishing of a quantity of gas sufficient to meet the basic energy needs of certain residential customers at a subsidized rate. The quantity of gas in the initial block could vary according to geographical location and season of the year, if it is intended to cover space heating needs. Winter volumes would have to be sufficient to cover space heating, water heating and cooking loads, while summer basic gas requirements would include only the latter two.

The rate charged for the initial block should not be less than the variable system cost, principally the commodity cost of gas, and depending upon the amount of subsidy, may or may not pick up some of the system's fixed cost. The cost not picked up in the initial residential block is spread to larger residential customers in higher usage blocks (an inverted rate) and to all commercial and industrial customers. Because of the subsidization, legislation may be needed before lifeline rates can be implemented to avoid claims of undue discrimination.

Another approach sometimes used to eliminate concerns with undue discrimination is to make a baseline rate available to all residential customers and have no cost shifted to commercial and industrial customers. Unlike the concept of lifeline rates wherein eligibility depends upon social or economic factors, a baseline rate would be universally applicable to all residential customers' essential needs service.

Inverted rate designs generally were advocated to encourage conservation and utilize marginal cost principles to foster that goal. Thus, lower rates per unit of gas are charged in the initial, nonelastic blocks and progressively higher rates per unit of gas are charged in the more elastic end blocks.

Under lifeline, baseline or inverted rate structures, the ability of a utility to earn its revenue requirement is riskier than with a declining block rate structure. This is because rates are designed to recover a large amount of fixed costs through the tail block rates which depend upon usage that is more sensitive to conservation and weather.

3. Interruptible Rates

Interruptible rates are designed with the primary purpose of controlling load factor. Interruptible service is offered by a gas utility to an industrial or commercial customer without an obligation to deliver any specific volume. The volume of gas available is determined by supply or dispatching considerations. Interruptible sales fill the summer valleys created by the heating load.

Traditionally, interruptible rates have been designed for customers with alternate fuel capability. With the onset of gas transportation, many of these customers have converted from sales to transportation. Consequently, with respect to the recovery of gas costs, the impact of interruptible customers on a utility's load factor is no longer as significant as it once was.

4. Seasonal Rates

Prior to the early 1970s, utilities attempted to maintain high system load factors to reduce unit gas costs. This was typically accomplished by means of either underground storage or interruptible sales (including some service just provided during the off-peak season) or a combination of both.

Subsequent to the early 1970s, curtailments became an important feature of the national supply picture. Utilities no longer received all the pipeline gas contracted for, and service to some types of firm customers was interrupted or permanently abandoned. Utilities began to acquire high cost supplemental gas and increased storage and peaking capabilities to ensure that winter demand was met. These activities so altered the economic cost relationship between summer and winter gas that much more significant cost differentials existed.

FERC Order 436 and the subsequent opening up of the natural gas market to competitive market forces have done two things to place renewed emphasis on seasonal rates. First, Order 436 requires that open access pipelines have transportation rates with seasonal differentiation. Second, the spot market for natural gas has shown a strong seasonal differentiation in price. While the long-term effects of this open gas market are not now known with any clarity, it is reasonable to expect that these differentials in well-head gas costs and transportation costs may ultimately result in seasonal distribution rates which reflect these cost differentials.

5. Demand or Standby Rates

A customer may wish to use some fuel source other than system supply gas as his primary fuel and use that gas only as a backup. This is convenient for the customer because he can easily shift to system supply gas on short notice if the service line and delivery equipment are in place. However, the utility may be required to provide the same delivery services that it would for its other customers, as well as maintain an available gas supply for a customer who will seldom, if ever, use it.

The service being provided here is not so much gas supply as it is the availability of a backup fuel source. Charging rates based on traditional rate design would be unreasonable in these instances. The customer would generate very little commodity revenue. Accordingly, the rate should be designed to recover, through a demand or standby charge, the costs associated with maintaining that backup, including the costs of the delivery system and the cost of maintaining a gas supply to provide backup.

6. Flexible Rates

Traditionally, utility rates have been set at a fixed amount which cannot be varied by the utility absent a rate order from the Commission. This system worked fine as long as natural gas prices were substantially below those of oil.

However, about 1983, gas prices rose and oil prices fell to the point at which significant gas sales began to be lost to oil through price competition. When this happened it became clear that the inflexibility of gas prices allowed oil dealers to reduce their prices to just below the fixed gas price and gain a competitive advantage. The solution to this problem was to set flexible rates allowing the utility to vary its price between a floor and a ceiling. The use of flexible rates results in three main issues which must be addressed.

First, the rate must be designed to avoid undue discrimination. Fixed rates provide that all customers within a given rate class will be charged the same rate and hence do not provide a discrimination problem. However, with flexible rates, different customers in the same rate class can be charged different rates. Whether this would be undue discrimination will depend upon the specific law in a given state. If there are discrimination concerns, they can be alleviated by a number of methods, including: (1) requiring that all customers in the rate class receive the same rate; (2) grouping customers in a rate class by some characateristic (such as existence or type of alternate fuel) and requiring that all customers in the group be charged the same; and (3) setting the rate for each customer at the price at which the customer could obtain an alternate fuel.

The second issue involves the method of setting the floor and the ceiling. Sometimes a floor is not used if the utility is responsible for absorbing all losses caused by downward reduction in the rates. Where a floor is used it should not be set below the short-run variable cost of providing service, because there is no valid economic theory to support a rate below this level; moreover, such a floor guards against challenges based upon predatory pricing and anti-trust considerations. The setting of a ceiling rate is much more difficult than deciding on a floor. Often times the ceiling is set at the fully allocated cost of service as determined by the cost of service study. However, this has the disadvantage of causing the average rate to be below the fully allocated cost unless all sales are at the ceiling. Another common approach is to set the ceiling such that the expected average cost equals the fully allocated cost. A third alternative is to set the ceiling as far above the fully allocated cost as the floor is below that cost. Whatever approach is used, it is quite likely to draw attention simply because there is no wholly satisfactory method for setting the ceiling.

The third issue to be considered is the method for pricing sales on flexible rate for the purpose of meeting the revenue requirement. With fixed rates, this process is normally straight-foward as the revenues are simply the rate times the sales volume. With flexible rates, the exact rate itself is unknown. The problem is compounded by the fact that the sales units may be a function of the rate actually charged, with lower rates producing higher sales and vice-versa. One approach is to use the ceiling rate on the theory that the utility will only discount from the ceiling when it is in the utility's best interest to do so and the utility should be responsible for any revenue loss caused by discounting. Another approach is simply to assign a target revenue that the utility should be expected to achieve. Mathematically this has the same effect as allocating a certain level of costs to the class. Finally, if the functional relationship between sales and rates is known, sales can be priced at the rate which maximizes revenues.

7. Incentive Rates

Another rate form that has been used is related to circumstances where a utility is attempting to either capture a new load or recapture a load previously serviced with natural gas. The basis for this rate is the relationship of current consumption to a selected base year where the load was not serviced by the gas utility. All consumption in excess of the base volume would receive a discount from the normal tariff rate. The discount, or incentive, could take the form of a percentage of full tariff, possibly with step discounts for increased consumption or it could take the form of a stated flat rate. In either instance, the customer would continue to purchase base volumes at the full stated tariff rate, and all incremental consumption would receive the discount. Implementing such a rate does present potential discrimination problems. Depending upon the magnitude of the discount the utility could be providing service to customers with similar characteristics at widely divergent rates. Such a situation, particularly if the customers were competitors and energy was a significant element of their cost of goods sold, could be unduly discriminatory.

F. Other Factors

1. Historical Rates

The utility's currently existing rate structure and the history of changes in that structure should be considered when a new rate design is contemplated. If the existing structure works reasonably well, there will likely be considerable reluctance to change it. Even when there is convincing evidence that major changes are needed, Commissions will often utilize the concept of gradualism to make a series of small incremental changes rather than a large revolutionary change. Rate design changes which can be postured as improvements on the existing system are more likely to find acceptance because they maintain continuity and minimize problems due to misunderstanding.

2. Social and Political Factors

By its very nature, the ratemaking process is subject to considerable public and political scrutiny. Commissioners are either appointed by elected officials or are elected themselves. The Commission itself is typically a creature of the Legislature -- created for a specific purpose and existing until dissolved by the Legislature. While the ratemaking process is designed to be somewhat insulated from direct political pressure, nevertheless political influence does affect the process. Broad governmental policy goals, such as business climate development, can have a significant impact. While such policies may not directly determine the final result, it would probably be undesirable to set rates which directly controvert such a policy.

Consideration also needs to be given to designing rates which are responsive to the social needs of our society. Like political factors, social factors are nebulous and ill-defined, but not unimportant. In practice, it is often difficult to distinguish between social and political factors.

It is probably impossible to give any hard and fast rules for incorporating social and political factors into utility rate design, and no attempt will be made here. Suffice to say that rate designers should be aware of the social and political implications of their work. Gas rate design is not an abstract application of economic principles, but rather a practical exercise which affects customers in their daily lives. The rate designer should be aware that people need affordable gas to heat their homes and businesses need energy supplies which enable them to remain competitive. The rate designer should be sympathetic to these concerns while continuing to follow the basic rate design principles.

Chapter III - Rate Based on Value of Service

A. Basic Concepts

1. Alternate Fuel Competition

Up until this point, rates have been considered to be based on the principle of cost, giving recognitition to the fact that there is no one definition of cost, and that other factors (social, political, historical) may have some effect. At this point we set aside cost-of-service to the customer as a standard and consider a totally different one--value of service to the customer.

There is even less agreement on the definition of value of service than there is on cost of service. Obviously the value referred to is the value to the customer. From this, one might infer that value of service pricing is tantamount to deregulation of a monopoly, wherein the utility raises its price to the highest level that the customer will pay. However, this concept of value of service has seldom, if ever, been used.

Most commonly, value of service in the natural gas industry has been determined by reference to the cost of alternate fuels available to the customer. Although large industrial customers have a wide variety of alternate fuels available to them, the marginal alternative is generally taken to be No. 6 residual fuel oil. While coal may be cheaper in the long-run, a choice to use it involves a substantial capital investment and thus it is not the type of short-term alternative with which gas competes. Other alternatives are generally more expensive, and thus the Btu-equivalent price of residual oil is normally taken to be the measure of the value of service for a large industrial customer.

Surprisingly, value of service pricing has been used as a standard for industrial customers during periods of shortage and surplus, although the reasons for doing so were different. During the natural gas shortage of the 1970's, prices were escalating at a rapid pace as efforts were made to raise well-head prices in order to provide additional supplies of natural gas. By the late 1970's and early 1980's residential prices had risen to the point that many customers were having difficulty paying their bills. At the same time, indus-dustrial gas prices were low relative to the cost of residual fuel oil, which had an inflated price caused by the actions of the OPEC oil cartel. Consequently, many Commissions raised industrial rates based on the cost of alternative fuels and used the additional revenues to lower residential rates and soften the "rate shock" hitting those customers. This was a case of value of service pricing being used to foster a social ratemaking goal.

By the middle of the 1980's, things had changed dramatically. Oil prices had fallen due to the world-wide glut while natural gas prices had generally continued upward. For industrial customers, gas prices set on a cost of service basis exceeded the alternate fuel price, and utilities began to lose industrial load. In this environment, Commissions once again turned to value of service pricing, in this case to maintain markets that would otherwise be lost.

2. Competition Due to Bypass

Natural gas utilities have long been considered to be natural monopolies. This concept forms the basis of utility regulation. Gas utilities have their rates and conditions of service regulated and in turn they receive protection from competition. In many states, this protection comes in the form of exclusive franchises, where the utility has the right (and the obligation) to provide service and other utility competition is prohibited.

Even though the states have the right to regulate entry of other local gas distributors, this does not necessarily mean that an individual state commission can restrict market entry of an interstate pipeline performing transportation service. Each Commission's authority depends upon the specific laws under which it operates. If a state does not have an exclusive franchise system or there is bypass by a pipeline, there may be no alternative method of dealing with bypass other than rate design.

An important step in dealing with a potential bypass situation is to make a decision as to whether the customer is worth keeping. Distribution utilities and interstate pipelines have different characteristics, with different strengths and weaknesses. Utilities may have an obligation to serve and hold themselves out to all applicants for service. They also maintain large distribution networks to serve a wide area. An interstate pipeline may only have a short service extension to serve an individual industrial customer. Because of these differences, it may not be possible for the utility to continue serving the customer at rates competitive with the pipeline, and still cover the utility's variable cost and make a contribution to fixed cost.

If rate design is to be used in an effort to prevent bypass, then it will be necessary to determine why bypass is attractive to the customer. Utility rates are normally set based on the average cost to serve all similarly situated customers. This means that customers' rates are based on average costs for many types of items, such as average distribution main, average uncollectibles, average lost and unaccounted for, etc. An interstate pipeline may be able to take advantage of a customer's specific situation. For example, if the customer is located adjacent to an interstate pipeline's main transmission line, the pipeline may be able to serve the customer at a cost below that of the distributor. In such cases, devising a special rate for the distributor which takes into account the unique characteristics of the customer may be the only way to compete. If a special rate is not adequate, then this may be a case of economic bypass which should be allowed to occur.

In dealing with the threat of bypass, non-price factors can be important elements to consider. The customer may have had a long-term relationship with the utility, which could be the source of goodwill. There may be some price security in staying with the utility since its rates are regulated by the state commission. On the other hand, the pipeline's direct industrial sales rates are not regulated by FERC. In the case of interstate transportation, FERC regulates the transportation rates and service but not the sales price. Finally, if the utility receives supplies from more than one pipeline, it may be able to offer greater supply reliability to the customer.

As with most rate design issues, in dealing with bypass, it is important to keep in mind the objectives to be achieved. Bypass may be undesirable because the loss of large industrial customers means that the remaining customers will bear a greater share of the utility's fixed costs. It is reasonable to make pragmatic rate design decisions to offer reduced rates to potential bypass customers, provided that the customer maintains a reasonable contribution to the system fixed costs. If this cannot be done, then such economic bypass situations should probably be allowed to proceed.

B. Competitive Rates

1. Rate Determination

Setting rates based on value of service bears little relationship to setting them based on cost of service. When the cost of service system is used, the rate is built up from the various cost elements incurred by the utility. The rate becomes the sum of those costs which are assigned to the customer's rate class.

When using value of service principles, we normally look not to the cost of the utility providing the service, but rather to the cost of alternatives available to the customer. This can be the Btu-equivalent cost of an alternative fuel or the cost of a competing gas source, but it can also represent non-fuel alternatives. For example, if a firm is in danger of going bankrupt and gas represents a significant cost to the company, then it may be desirable to design rates with a goal of keeping the firm operating. Similarly, if industrial customers have the option of producing at different locations, it would be prudent to consider setting gas rates at a level which would encourage maintaining production locally. This is especially true when a new business is considering moving into the area. It is increasingly common to offer reduced rates to such customers to induce them to choose to locate in the utility's service territory.

2. Maximum - Minimum or Flexible Rates

Maximum - Minimum or Flexible rates have already been discussed in Chapter II, where they were considered as a development of rates based on cost of service. That discussion applies equally well to their use in setting rates based on value of service, except that some additional matters should be discussesd.

Flexible rates are more common and more properly suited to use with value of service principles. Rate setting is not simply a matter to be determined by calculation from formula, but rather there is a zone of reasonableness within which utility rates may fall. Rates below that zone are confiscatory and do not give the utility an opportunity to earn its authorized return. Rates above the zone are monopolistic. Any rate within the zone is generally considered to be just and reasonable, so long as it is not applied in an unduly discriminatory fashion.

The use of a zone of rates with a ceiling and floor often comports well with the objectives of value of service pricing. Value of service is most commonly used when there is a need to meet competition from a substitute fuel. Determining the appropriate competitive price can be difficult for two reasons. First, it is not always easy to determine the equivalent price of an alternate fuel. One must take into account not only the Btu equivalency, but other costs associated with the alternative such as installation and maintenance of equipment, fuel storage, payment upon delivery, inventory maintenance and costs associated with burning a less clean fuel. Second, the costs of alternative supplies can change quickly and unpredictably. Consequently, even if the competitive rate were well-known at any point in time, it could change so rapidly that such a price would be ineffective for meeting competition.

Flexible rates alleviate both of these concerns. Obviously if the prices of alternate fuels change, flexible rates permit rapid adjustment to meet these changing circumstances. Less obviously, flexible rates reduce the need to precisely measure the equivalent cost of an alternate fuel. If sales are lost due to failure to properly consider some factor in converting costs from the alternate fuel to gas, then this is readily correctable with flexible rates. Traditional rates would remain in place until the Commission could act to change them. Flexible rates provide the opportunity to utilize feedback received from the market to move towards the appropriate competitive rate. Some protection against abuse may be necessary because such rates also provide the opportunity for the end-user to utilize the rate system and threat of competition to obtain a lower rate than they otherwise would pay.

3. Contribution to Fixed Costs

Although value of service is an alternative to setting rates based on cost of service, the decision to use value of service as the basis for designing rates does not mean that costs can or should be ignored. Costs must still be considered when using value of service, but the nature of the analysis changes.

Costs for a utility (or any other corporation) can be divided into two categories: fixed and variable. Fixed costs do not materially change with the volume of output (units of gas sold or number of customers). Variable costs do change with the volume. In actual practice, the dividing line between fixed and variable costs is not sharp and clearly defined. However, in the short run, which is normally the period of concern for the rate designer, most costs can reasonably be categorized as either fixed or variable. Generally, a reasonable classification can be made by looking to see if a given cost would be avoidable in the near future (say two or three years) if output were to decline significantly.

When using a cost of service approach to design rates, the distinction between fixed and variable costs may not be significant. Under this approach, the objective is to allocate costs among rate classes, without regard to whether the costs are fixed or variable. When using value of service pricing, the distinction between fixed and variable costs becomes crucial.

Fixed costs are going to be incurred regardless of whether a given sale is made or not. They must be recovered either from the utility's customers or from its shareholders. Variable costs are going to be incurred only if a given sale occurs. This sets a floor on value of service pricing. That is, the rate should be set to recover the utility's variable cost of service at a minimum. The rate has some positive benefit if it recovers the variable cost and provides some contribution to the recovery of the utility's fixed cost. This raises two important questions: (1) How much contribution is appropriate; and (2) what happens if that amount is not recovered?

The first question is easier to deal with. Generally value of service pricing is used when competitive market conditions do not permit charging a rate which recovers the fully allocated cost of service. From this it follows that the rate should at least be designed to recover as much of the fully allocated fixed cost as possible. Although in theory the rate would be beneficial with any amount of fixed cost coverage, it is common to set some minimum amount that would be considered reasonable.

Because markets are competitive, the ability to recover any level of fixed costs is problematic. Since there is risk associated with the failure to recover a given level of fixed costs, absent a Commission policy the rate designer must deal with the issue of how to allocate this risk. There are two choices: the other ratepayers and the shareholders. The answer is not easy and is primarily a value judgment. On the one hand, it is argued it is reasonable that shareholders bear the risk because the utility has an obligation to control its costs and remain competitive. On the other hand, the argument is that the utility is a regulated entity which must be given a reasonable opportunity to earn its authorized rate of return. Both arguments have merit, and the rate analyst must make a judgment between them in setting rates if the Commission does not already have an existing policy on this issue.

C. <u>Market Segmentation</u>

1. <u>Ability to Maximize Revenues</u>

The use of market segmentation to maximize net revenues is a common one in many industries. To be able to segment the market efficiently, two conditions must be met: (1) the customers are divisable into two or more classes which have different elasticities of demand, and (2) the product can be sold separately to each class without an effective means for one class to resell the product to another.

Market segmentation can best be explained by example. Consider a local movie theater which has 200 potential customers. Of these, 100 are adults who would be willing to pay up to $4 per ticket, while 100 are children who will only pay $2 each. The movie theater could set its price at $4 and generate $400 in revenue ($4 x 100 customers), or it could set the price at $2 and receive $400 ($2 x 200 customers). What the theater will probably attempt to do is segment the market by offering a matinee priced at $2 to attract the children and an evening show at $4 for the adults. If successful, this strategy will generate revenues of $600 ($2 x 100 children plus $4 x 100 adults).

The gas industry provides many opportunities to use market segmentation. There is little chance that one customer will be able to resell his service to another. There are a wide variety of customers with differing characteristics and demand. The traditional method of dividing customers into rate classes is one example of market segmentation, although its goal is not necessarily revenue maximization when rates are based on cost of service.

When value of service concepts are used, market segmentation can be a valuable tool to maxmimize revenues and the fixed cost contribution from such customers. Under these circumstances, the customers will normally have differing competitive price levels depending upon their type of alternate fuel, and possible other factors. By classifying customers into different groups according to their cost of alternatives, the rate design can reduce the proportion of fixed costs which will be borne by other customers.

2. Discrimination and Price Differentiation

Although the specific laws vary from state to state, the general rule is that gas rates be free from undue discrimination. The requirement that rates shall be free from undue discrimination does not mean that the rates be the same for all services and customers. What it does mean is that differing rates for differing customer groups must reasonably reflect differences in their conditions of service. Generally, there are two such differences: (1) differences in cost, and (2) differences in competition. Obviously, when value of service pricing is being used, the first matters not. With respect to the second, the rate designer should ensure that the classification of customers reflects differing competitive conditions and that the differences in rates reasonably reflect those differing conditions. For example, if the cost of propane and distillate fuel oil were approximately the same it would probably be discrimination to charge significantly different rates to customers with one or the other of these alternate fuel capabilities.

Another concern regarding discrimination is the need to ensure that the rates set for customer classes, that have little or no alternate fuel source available, are fair. The value of service to that captive customer class is very high. Protection from monopolistic pricing becomes a function of regulation, not competition.

D. Special Rates

Special rates may be developed to recognize unique customer circumstances, promote economic development and provide incentives for the development of certain natural gas usages. These rates are often subject to allegations of discrimination and represent a departure from traditional ratemaking. Special rates may be prohibited by certain regulatory commissions or state law. Customer specific rates, economic development rates and incentive rates are examples of special rates.

1. Customer Specific Rates

Customers whose load characteristics differ significantly from any other customer groups or customers whose physical connection to the utility is unique may require special rates. Examples of these unusual circumstances are: extremely large customers with loads that represent a significant percentage of their respective distribution utility's load; customers served directly from a transmission main; or customers who have made a significant contribution in aid of construction. Typical customer groupings or rate schedules may not recognize these unique situations and may result in inequitable treatments. In these instances it may be necessary to develop a separate rate schedule or rate blocks within a rate schedule to recognize the special customer.

2. Economic Development Rates

Economic development rates are designed to promote growth within a gas distribution utility's service area. These rates seek to attract new customers through discounts from the otherwise applicable tariff rate. These discounts may be eliminated over time. For example: an economic development tariff may provide new customers with a 15 percent discount during the first year; a 10 percent discount during the second year; a 5 percent discount during the third year; and no discount thereafter. Economic development may also be promoted by liberal line extension policies and customer connection requirements.

Another, more controversial, example of an economic development rate is one that reflects the incremental cost of providing the new service with no contribution toward the costs associated with the utility's existing system. These incremental costs are limited to the investment and expenses associated directly with the new service. This type of economic development rate is generally limited to very large customers and usually result in a customer specific rate. Pre-existing customers often argue that these incrementally based rates are preferential and should be made available to all customers.

3. Incentive Rates

Incentive rates are designed to promote specific types of usages which provide operational or economic benefits. One such rate, gas-fired air conditioning, provides a discount for summer usage. Increased summer usage is often beneficial as a result of increased utilization of purchased demand volumes and improved cash flow. Natural gas distribution utilities typically have excess capacity during the summer months since their loads are primarily heat sensitive.

Many gas utilities are actively promoting incentive rates for gas-fired cogeneration. Cogenerators may provide significant economic benefits to the utility as a result of their large natural gas usage and high load factor. The economies of scale associated with these large users and the potential operational benefits allow gas utilities to offer attractive cogeneration rates for both sales and transportation services.

Chapter IV Cost of Gas Adjustments

A. Importance of Gas Costs and Effect on Cost of Service

The marketing of natural gas as a consumer commodity is accomplished in a regulatory environment that inhibits the marketer's freedom to use competitive skills and pricing factors. This regulatory environment exists at both the federal and state level. Marketers must offer their product at an inflexible tariff rate set and approved by regulatory agencies.

For the distributor, commodity cost makes up fifty to eighty percent of the sales tariff. The obvious need for some flexibility to adjust to swings in their gas purchase cost has mandated the approval and adoption of a "Purchase Gas Adjustment" (PGA) rider to their approved tariffs.

At the federal level, currently, interstate pipelines are encouraged to act primarily as transporters of gas for distribution systems and end-users that have been, or are currently, purchasers under inflexible tariffs. The various components of transportation tariffs are all cost of service items, with the commodity cost the concern of the distributors and end-users. As this transformation progresses, the cost of gas will become of lesser importance to interstate pipelines. Total replacement of marketing services will never occur, however, since a number of distribution systems and end-users will, through their own choice, continue reliance on the pipeline as a supplier of natural gas. For these remaining purchasers, the pipeline must get approval of a set tariff, and, like the distribution system which must gain regulatory approval of sales tariffs, must contend with the monthly swings of their weighted average cost of gas.

B. <u>Pipeline Rates</u>

1. <u>Natural Gas Act, Natural Gas Policy Act, and FERC</u>

Prior to the mid-1980's, local gas distribution companies (LDCs) generally purchased most of their needed gas from interstate gas pipelines "system supply gas." Stated differently, the interstate pipelines functioned primarily as merchants, buying gas from a large number of producers and reselling the aggregated gas supply to LDCs as well as other customers. The role of most interstate pipelines is changing (more rapidly for some than others) from that of being primarily a gas merchant to becoming more of a gas transporter, offering sales and other services on a "unbundled" basis.

The changing role of interstate gas pipelines and changes in the regulations affecting those pipelines have a direct impact on the types of services available to LDCs and the charges for those services. To best appreciate the reasons for and implications of some of the changes, a brief overview of some essential points of interstate gas pipeline rates is appropriate.

All rates and charges related to the transportation of natural gas in interstate commerce and the sale for resale of natural gas in interstate commerce are regulated by the Federal Energy Regulatory Commission (FERC). The FERC's authority in this regard derives principally from its administration of the Natural Gas Act of 1938 (NGA). This statute continues to be the "cornerstone" of the Federal Government's regulation of interstate natural gas facilities and activities.

Another Federal statute affecting natural gas activities (including some intrastate, as well as interstate activities) is the Natural Gas Policy Act of 1978 (NGPA). Among other things, all "first sales" of natural gas, such as sales by a gas producer to an interstate or intrastate gas pipeline or to a local distribution company (LDC), are controlled by the operation of this statute. While the NGPA gradually deregulated many types of first sales, some such sales are still subject to either or both price controls under the NGPA or certificate jurisdiction under the NGA. Some transportation of gas is also subject to rate jurisdiction under the NGPA, as is discussed later.

The NGPA, like the NGA, is administered by the FERC. However, the implementation of certain functions under the NGPA requires assistance from state and other regulatory agencies.

For example, "well category determinations," which involve decisions as to whether a particular well qualifies for a specific pricing category under the NGPA, are made by state and other "jurisdictional agencies." Such determinations are subject to review by the FERC; but the reviews are limited, essentially, to the adequacy of the record on which the determinations were made.

Also, certain transportation rates by an intrastate pipeline for transporting gas on behalf of an interstate pipeline or an LDC served by an interstate pipeline are authorized by the FERC if the rates have been previously approved by and are on file with a state regulatory agency. The NGPA requires FERC's approval of such rates because the nature of the transportation services involved, by definition, causes the gas to become involved in interstate commerce.

The above noted types of transportation services by intrastate pipelines were provided for under the NGPA as a means of integrating intrastate pipelines and gas supplies with interstate markets. In this way, a truly integrated, national pipeline grid system was created, which allows for more efficient use of facilities and more efficient allocation of natural gas resources. The NGPA is clear, however, that Federal regulation under the NGA does not extend to intrastate activities conducted under the NGPA.

2. Standards for Reviewing Pipeline Rates

The standards employed by the FERC for reviewing rates differ depending on the "type" of rate involved. The standards also differ somewhat depending on whether the service involved is related to activities authorized by the FERC in administering the NGA or activities conducted under the NGPA.

For example, when an interstate pipeline receives authority from the FERC to perform a "new service" or to change an existing service, such authorization derives from section 7 of the NGA. This part of the NGA deals with the issuance of certificates of "public convenience and necessity."

Rates approved under section 7 of the NGA are called "initial rates." Typically, such rates cannot be based upon any historical cost and operation experience, because none exists. Therefore, such rates are based more on projections of future costs and operations.

The FERC uses its "conditioning authority" under section 7 of the NGA to attach any conditions it deems necessary to assure that an "initial rate" will remain consistent with the overall public interest until it is subsequently reviewed under section 4 or section 5 of the NGA. An applicant has to notify the FERC within 30 days from the date a certificate is issued whether the applicant accepts the certificate. This notification is required, irrespective of whether the FERC imposes a "rate condition' or any other condition in issuing the certificate.

An interstate pipeline is, of course, free to propose changes to its existing rates. Section 4 of the NGA establishes the essential authority for the FERC's review of such rate changes. Section 4(a) and (b) state:

> (a) All rates and charges made, demanded, or received by any natural-gas company for or in connection with the transportation or sale of natural gas subject to the jurisdiction of the [FERC], and all rules and regulations affecting or pertaining to such rates or charges, shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.
>
> (b) No natural-gas company shall, with respect to any transportaiton or sale of natural gas subject to the jurisdiction of the [FERC], (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

Section 5 of the NGA allows the FERC to review an interstate pipeline's existing rates, even where those rates were found to be appropriate during a previous review process (under, for example, either section 7 or section 4) and the pipeline proposes to continue the effectiveness of those rates. In pertinent part, section 5(a) states:

> (a) Whenever the [FERC], after a hearing had upon its own motion or upon complaint of any State, municipality, State commission, or gas distributing company, shall find that any rate, charge, or classification demanded, observed, charged, or collected by any natural-gas company in connection with any transportation or sale of natural gas, subject to the jurisdiction of the [FERC], or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory, or preferential, the [FERC] shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order: ...

Although the NGA does not define the term "just and reasonable," the FERC and the reviewing courts have generally held that actual cost-of-service has to be viewed at least as the point of departure in determining whether the "just and reasonable" standard is satisfied. Any departure from cost-of-service must be justified by demonstrating a "public interest purpose." The courts have made clear, however, that the FERC is permitted to select any rate which is within a "zone of reasonableness."

The courts have also held that the FERC is not bound to the use of any single formula or combination of formulae in determining rates. And the courts have recognized that ratemaking involves the making of pragmatic adjustments. At the bottom line, it is the result reached -- and not the ratemaking method employed -- that is controlling in determining whether the "just and reasonable" standard is satisfied. (Ref: FPC v. Hope Natural Gas Co., 320 U.S. 591, 600-01(1944)).

The NGPA required some modifications to certain of FERC's ratemaking approaches used under the NGA. For example, section 601(c) of the NGPA prohibits the FERC from denying an interstate pipeline from recovering the costs of gas purchased at prices established by the NGPA -- except to the extent the FERC determines that the amounts paid were "excessive due to fraud, abuse, or similar grounds." Thus, the FERC's ability to deny the flow-through in a pipeline's rates of the prices paid for gas purchased by the pipeline is somewhat limited by the NGPA.

The FERC can, however, examine a pipeline's overall gas purchasing practices as a part of its "prudence review process" under the NGA. Thus, although the NGPA intentionally "shields" the well-head prices that the

U.S. Congress determined to be consistent with the national interests, the pipeline remains accountable for its contracting practices and its management of gas supplies.

A pipeline is also accountable for its contracting practices and prices paid for gas that is price-deregulated under the NGPA. Although the test can be somewhat subjective, the "bottom line" is whether the pipeline's overall gas contracting and purchasing practices are "prudent."

The standards for reviewing transportation rates also differ somewhat under the NGPA, as compared to the NGA. As explained earlier, the essential review standard under the NGA is a determination of whether the overall effect of a rate is "just and reasonable." Also as noted, the courts and a long history of FERC orders (including orders issued by its predecessor agency, the Federal Power Commission) have constructed a strong nexus between rates referenced to "rate-base cost-of-service" and the "just and reasonable" standard.

Section 311 of the NGPA adopts the NGA's "just and reasonable" standard for rates applicable to NGPA-related transportation by interstate pipelines. This approach maintains consistency in the manner in which rates are determined for transportation conducted by interstate pipelines, irrespective of whether the transportation is related to the NGA or the NGPA.

By contrast, the NGPA employs a "fair and equitable" standard for rates applicable to transportation by intrastate pipelines. This standard, among other things, permits the FERC to authorize the use of intrastate pipeline rates which have been approved by a variety of state regulatory agencies, possibly using somewhat differing approaches to setting rates.

Therefore, the FERC could determine that a rate approved by a state regulatory agency satisfied the "fair and equitable" standard under the NGPA, even where the method used to compute the rate would not totally conform to the original cost-of-service methodologies used to set a "just and reasonable" rate under the NGA for an interstate pipeline. However, section 311 of the NGPA also makes clear that any charges by an intrastate pipeline "may not exceed an amount which is reasonably comparable to the rates and charges which interstate pipelines would be permitted to charge for providing similar transportation service."

As is set out in detail in the FERC's regulations, rate authorization for transportation performed by an intrastate pipeline can be obtained in several ways. The FERC's authorization is, essentially, automatic if the transportation rate is equal to "the cost of gathering, treatment, processing, transportation, delivery or similar service (including storage service) included in one of [the intrastate pipeline's] then effective firm rate schedules for city-gate service on file with the appropriate state regulatory agency." Authorization is also, essentially, automatic if the transportation rate is equal to the allowance permitted by an "appropriate state regulatory agency" to be included in an LDC's rates for city-gate service.

Rate authorization may also be obtained if the intrastate pipeline uses a transportation rate which is on file and in effect with the "appropriate state regulatory agency." However, the intrastate pipeline has to demonstrate to the FERC that such a rate covers service comparable to the service to be performed under section 311 of the NGPA.

In authorizing such a rate, the FERC exercises its authority under section 502(c) of the NGPA. Under this authority, the FERC grants "adjustments, consistent with other purposes of the [NGPA], as may be necessary to prevent special hardship, inequity, or an unfair distribution of burdens." An essential ingredient of the FERC's rate authorization under this procedure is based on a showing of comparability of services.

The first two of the above procedures of authorizing rates look, respectively, to the methodology used to determine either specific cost elements or allowances included in a rate for citygate sales service approved by an "appropriate state regulatory agency." The third procedure looks to the "comparability of services" in regard to a rate for transportation service approved by an "appropriate state regulatory agency."

The term "appropriate state regulatory agency" is defined by the FERC's regulations to mean a state agency that: (1) regulates intrastate pipelines and LDCs within the state, and (2) sets rates and charges on a cost basis.

A final rate-authorization procedure available to an intrastate pipeline is for the pipeline to seek approval of its transportation rate by the FERC. Under this procedure, the pipeline files with the FERC its proposed rates and charges, together with "information showing the proposed rates and charges are fair and equitable."

In reviewing rates and charges filed under this procedure, the FERC applies many of the same ratemaking concepts and criteria that it would use to review a transportation rate for an interstate pipeline. This approach is intended to assure that an intrastate pipeline's rate would not be in excess of the rates and charges that an interstate pipeline would be permitted to charge for similar transportation service.

It is important to note, however, that the FERC does not have jurisdiction under the NGPA to examine the planned construction and operation of an intrastate pipeline before it commences operation, or to unilaterally investigate a previously-approved rate. Therefore, certain ratemaking features may take on added concern when the FERC addresses an intrastate pipeline's rate filed under the last-noted procedure.

As discussed earlier, the FERC sets "initial rates" for a newly-constructed interstate pipeline or a new service provided by an interstate pipeline. The FERC can assure that such rates remain acceptable by attaching "conditions" to certificates issued under Section 7 of the NGA, which are needed prior to construction of new facilities or initiation of new services. Also as noted, the FERC can use its NGA Section 5 authority to unilaterally investigate and change an interstate pipeline's existing rates.

Because the FERC does not have comparable jurisdiction over an intrastate pipeline, the degree of capacity utilization inherent in an intrastate pipeline's proposed rates often becomes of particular concern. The FERC generally resolves this concern in several ways: (1) by requiring that the rate be a 100 percent volumetric charge (i.e., no demand component); (2) by imputing a sufficiently high use of capacity in determining the rate (e.g., 80-90 percent); and (3) by requiring that the intrastate pipeline seek authorization from the FERC within no more than three years to continue the use of the previously approved rate or to use a different rate.

The above concerns with intrastate pipelines' rates are especially important because of the limits that the NGPA places on the FERC's authority to prohibit the flow-through of the charges by an interstate pipeline. The NGPA states that the amounts paid by an interstate pipeline to an intrastate pipeline for any transportation authorized by the FERC under Section 311(a) of the NGPA are deemed just and reasonable (for purposes of setting the interstate pipeline's rates) if such amounts do not exceed that approved by the FERC.

Taken together, the above concerns and ratemaking approaches are intended to provide safeguards against shifting the cost effects of any underutilized facilities and inefficient operations to interstate gas customers. At the same time, however, rate certainty remains in place (after rates are approved under these procedures) for the intrastate pipeline providing the NGPA Section 311 transportation service and for the interstate pipeline purchasing this service.

As developed above, and terminology aside, the same essential public interest considerations are inherent to both the "just and reasonable" standard under the NGA and the "fair and equitable" standard under the NGPA. And, as noted earlier, the guiding ratemaking precept involved is the propriety of the result reached -- and not the methodology employed -- in determining whether the overall public interests are sufficiently accounted for.

3. <u>Interstate Pipelines' PGA Rates</u>

Before the 1980s, an interstate pipeline's costs of purchasing gas increased generally in proportion to increases in regulated well-head prices. After the NGPA initially came into play this feature generally continued, although the NGPA gradually eliminated many of the well-head price controls.

Pipelines were able to reasonably forecast their gas cost increases, based upon known increases in well-head ceiling prices and estimates of the mix of various "pricing categories" of gas and price-deregulated gas available to the pipeline. Thus, pipelines were permitted to adjust the "gas supply" component of their rates, generally every six months, to accomodate these cost changes.

The above procedures, generally referred to as "PGA filings," were permissable and not mandatory. In a sense, the PGA procedures provided administrative conveniences -- for the regulators and the pipelines' customers, as well as for the pipelines.

Changes in gas markets, caused primarily by interfuel competition and gas-to-gas competition, made the past PGA procedures inefficient. This inefficiency arose because the normal operation of FERC's PGA regulations did not permit pipelines to make timely rate adjustments to meet competition their markets.

However, where justification was shown, the FERC waived the PGA regulations to permit pipelines to make "out-of-cycle" PGA filings. Generally, this procedure permitted pipelines to make PGA filings more frequently or on dates other than those prescribed by FERC's regulations.

Also, downwardly flexible PGA procedures were approved by the FERC for specific pipelines that requested them as a means of addressing competition. Under the flexible PGA procedures, the pipeline could (after a one-day notice) reduce its rates below its last-approved "base PGA gas rate."

Downwardly flexible PGA procedures were approved by the FERC as a means of permitting timely adjustments to be made to the gas component of a pipeline's rates. Approval was based on the belief that these procedures offered the opportunity for benefits for both the pipeline and its customers. However, the FERC made clear that flexible PGAs were not to be used as a "marketing tool," to the disadvantage of certain of a pipeline's customers.

In particular, the FERC was concerned that flexible PGAs not be used by a pipeline to defer recovery of a substantial amount of its purchased gas costs to a subsequent period, or to allocate "unrecovered" costs to a customer or class of customers not benefitting from these procedures. To guard against these possibilities, pipelines were not permitted to recover any "deferred" gas costs in excess of 3 percent of their projected gas costs, absent a specific showing that such costs should be recovered.

To permit pipelines to better deal with the growing competition in natural gas markets, the FERC established new PGA regulations, which became effective on May 1, 1988. These new regulations provided for one comprehensive annual PGA filing and for three quarterly filings, which shortened by one-half the normal prescribed time between filings under the previous PGA regulations.

Shortening of the interval between PGA filings was intended to offer more rate flexibility for the pipeline. It was also intended to reduce the dollar amounts by which a pipeline could under-recover its purchased gas costs between consecutive PGA filings and, in turn, reduce the amount of carrying charges (interest) that would be imputed to such imbalances.

The new PGA regulations carried forward the requirement that a pipeline separately state the level of purchased gas costs (i.e., its "base PGA gas rate") incorporated in its overall charges. This feature better informs the pipeline's existing customers and potential customers of the effects of their decisions in dealing with the pipeline. The new PGA regulations also permitted on a generic basis the "flexible PGA procedures" noted above.

In essence, the new PGA regulations recognized the growing competition in natural gas markets and the need to provide for greater rate flexibility to deal with this increased competition.

4. Demand-Commodity Rates

The PGA rate changes described above generally occur more frequently than other types of pipeline rate changes. Therefore, they are probably the most familiar type of rate changes made by interstate pipelines. However, rate changes related to the non-gas component of pipelines' charges are equally important.

As was noted in regard to FERC's policies affecting the gas component of pipeline charges, FERC's policies affecting the non-gas component of interstate pipelines' charges also significantly changed during the mid and late 1980s. The need for these changes was due to the growing competition in natural gas markets, as was noted earlier. Some of the changes relate to generally familiar ratemaking features; other changes were more profound.

Most interstate gas pipelines have two-part rate structures, composed of a demand charge and a commodity charge. The demand charge may be split between a peak or daily component and an annual component, as is the case under the Modified Fixed Variable rate design noted later.

Generally, the demand charge applies to the level of "firm" service that the LDC (or other customer) has contracted for. In a sense, the LDC has reserved the right to "demand" service up to this level of service -- on a daily, seasonal, or annual basis, as the case may be.

The pipeline's commodity charge applies only to the actual quantities of service purchased by the LDC. That is, the LDC is not assessed commodity charges for quantities not purchased; neither is the LDC required to purchase a minimum quantity of gas. Although "minimum commodity bills" were typically a part of gas pipeline tariffs in the past, they are no-longer permitted under the FERC's regulations.

Moreover, "fixed-cost minimum commodity bills" (which would, essentially, assure the pipeline's recovery of fixed costs classified to its commodity charges) are also generally disallowed by the FERC under the currently employed rate procedures, for reasons noted in the following discussion.

Generally there has been agreement that all of a pipeline's variable costs should be recovered by its "usage" (commodity) rates; however, the method of classifying a pipeline's fixed costs has been somewhat controversial and has changed over time.

During the mid-1980s, the FERC's use of the Modified Fixed Variable (MFV) rate design approach was fairly well established. However, this rate design replaced the earlier used Seaboard and United rate designs. The differences in these several rate design methodologies relate primarily to the relative proportions of a pipeline's "fixed costs" that would be classified between its usage (commodity) and demand rates under each method.

By definition, fixed costs remain essentially constant (at least over the short term); also, they are not materially affected by changes in facilities utilization or gas throughput. Fixed costs include labor expenses, overhead costs, and capital-related costs -- such as plant investment, depreciation accrual, debt expense, return on equity capital, and associated income taxes.

Capital-related costs (depreciation, debt expense, equity return, and income taxes) normally make up the preponderance of a pipeline's fixed costs.

These costs are often referred to as being "capacity-related," or as "capacity" costs. This association exists because of the obvious direct relationship between these costs and a pipeline's physical capacity to provide services.

Because a regulated pipeline must have a reasonable opportunity to recover its full cost-of-service, including a reasonable return on its investment, the rate design employed can, among other things, affect the degree to which a pipeline's recovery of fixed costs (and especially capacity-related costs) are exposed to pipeline performance. Of course, this feature is not the only goal, nor necessarily the most important goal, of ratemaking; however, it's particulary relevant to gas pipeline ratemaking in an evolving more competitive environment.

The Seaboard formula, commonly used for designing pipeline rates until the early-1970s, made an equal division in classifying storage and transmission fixed costs between demand and commodity. That is, 50 percent of these fixed costs were recovered by the pipeline's demand charges and 50 percent were recovered by its commodity charges.

By the mid-1970s, the United formula replaced the Seaboard formula for designing rates for most pipelines. Under the United formula, 25 percent of a pipeline's storage and transmission fixed costs were classified to demand and 75 percent were classified to commodity.

Under both the Seaboard and United formulas, all of a pipeline's fixed "production" costs (e.g., gathering facilities costs) would be classified to the commodity charges. Costs related to services purchased from another interstate gas pipeline would be classified between the purchasing pipeline's demand and commodity charges in the same proportions that the charges were billed to the purchasing pipeline. That is, they would be treated on an "as-billed" basis.

The MFV rate design formula employs most of the same cost classification principles embodied in the Seaboard and United formulas. There are, however, major differences: Under the MFV formula, all of a pipeline's return on equity capital and associated income taxes are classified to the commodity component of the pipeline's rates. All other fixed "capacity costs" (such as depreciation and debt expense), as well as other fixed costs, are classified in their entirety to demand. One-half of these fixed costs is recovered through a demand charge applicable to the customers' daily entitlements; the other half is recovered through a demand charge applicable to their annual entitlements (or "seasonal" entitlements in the case of fixed storage costs).

Under the MFV formula, the pipeline's "profit" (i.e., return on equity capital) and the related income taxes are at risk because they are in the commodity and not demand component of the pipeline's rates. Thus, the profitability of a pipeline's operations would be a function of how well the pipeline actually performed in relation to the performance levels inherent in its approved rates. If a pipeline performed well, its profitability would be enhanced.

But, in order for a pipeline to perform well, its rates would have to remain competitive. As such, the pipeline's customers benefit -- not only because of competitive charges by the pipeline, but also because of greater utilization of the pipeline's facilities and services.

The MFV formula also classifies all of the pipeline's "non-equity" fixed costs (exclusive of fixed costs related to the pipeline's production and gathering functions) to the pipeline's demand charges. As such, any need for a "fixed-cost minimum commodity bill" is eliminated.

Thus, whereas in the past a "fixed-cost minimum commodity bill" may have been justified because, for example, it was necessary to protect the pipeline's ability to service its debt, that same justification would not apply when the MFV formula is used. This is true because the pipeline's debt coverage would be secured through its demand charges.

Regardless of the rate design method method (e.g., Seaboard, United, MFV, etc.), the "non-gas" component of a pipeline's charges is usually subject to review and change at a frequency not in excess of 36 months. This review occurs because, as a condition to a pipeline being authorized to use the PGA procedures to adjust the "gas supply" component of rates over relatively short intervals, the pipeline has to agree to "restate" its last-approved "base tariff rate" (i.e., the non-gas component of its charges) within 36 months.

Because of this rate-restatement requirement, all elements of a pipeline's cost-of-service are subject to full scrutiny at least every three years. This approach assures that the pipeline's rates would not generate revenues excessively above the pipeline's justified cost-of-service.

Moreover, a pipeline also has to agree that its restated base tariff rate would automatically be subject to refund until that rate or some other (possibly lower) rate is approved by the FERC. These mandatory rate review requirements are a part of the FERC's "new" PGA regulations, noted earlier, as well as the regulations that they replaced.

In addition to the above required 36-month base tariff review filings, an interstate pipeline is free to unilaterally make "general rate change filings" with the FERC. Such filings were especially common during past periods of major pipeline expansions or during periods of declining markets. However, with increasing stability in the extent and configuration of pipeline systems, the need for these types of rate filings is less now than in earlier periods.

With changes in natural gas markets, brought about primarily by a clear Congressional intent to phase out the wellhead regulation of natural gas and to eliminate the separate interstate and intrastate markets, the frequency and nature of rate change filings by interstate pipelines should continue to change in the furture. Some of these changes are briefly discussed next.

5. Seasonal/Storage Rates

With the growth in competition in natural gas markets during the 1980s, the FERC undertook significant changes in the regulation of an interstate pipeline's services and charges. These various changes, and other changes in regulatory policies, were espoused particularly in FERC's Order No. 436 and Order No. 500. Some of these changes are briefly discussed below; these changes and other features of Order Nos. 436 and 500 are discussed more fully in Chapter V.

Order Nos. 436 and 500 had several principal purposes. One purpose was to "unbundle"pipeline services, and especially transportation from other services. Another purpose was to provide more rate flexibility to the pipeline so it could remain competitive, while at the same time making the pipeline more accountable for its decisions and actions.

The essential public interest purpose of these orders was that with the unbundling of pipeline services, LDCs and other gas purchasers would be offered a wider variety of gas suppliers and gas services. Thus, they would be freer to purchase gas directly from producers, marketers, and other suppliers and contract separately with pipelines for transportion and other needed services. In this way, a variety of suppliers and pipelines could compete for various portions or all of the purchasers' needs.

Order Nos. 436 and 500 do not, however, preclude an LDC from continuing to purchase all of its needed gas supplies and services from its historic pipeline supplier. Rather, they permit the LDC to select a portfolio of suppliers and services that best suits its short-term and longer-term requirements.

If a pipeline were to offer its basic services on a completely "unbundled" basis (in addition to continuing to offer some "bundled" services), the LDC could make better informed decisions regarding the most economic and reliable means of meeting its needs for natural gas services. The LDC would have some indication of the pricing and other terms of each service. As such, the LDC would know the full cost of the menu of services (e.g., gathering, storage, transportation, gas supply, etc.) chosen to bring various gas supplies to its markets, as well as the probable reliability of these services.

These changes could, however, cause the LDC to make choices it did not have to make in the past. For example, some (but not all) gas pipelines have offered or proposed "seasonal sales services." Such services allow an LDC to contract for a higher level of service during its peak-demand period than for other periods. Generally, the charge for seasonal sales service would be expected to equate to the pipeline's costs for off-peak service plus an incremental component to compensate the pipeline for storage and other costs attributable to service.

Also, some pipelines have offered "contract storage services," which generally are contracted for by LDCs having significant flucuations between peak and off-peak requirements. Normally, contract storage service is available in only specific storage fields or specified portions of the storage capacity in certain fields. As such, the costs of this service can be separated from a pipeline's overall cost-of-service and directly assigned to those customers which have contracted for specific levels of storage service.

Generally, the pipeline's contract storage service incorporates maximum limits on the quantities of gas a customer can place into and withdraw from storage. These limits are usually defined on both a daily basis and a seasonal basis; and, in effect, these quantities establish the extent of the customer's contractual right to "demand" storage capacity.

Like charges for transportation capacity, charges for storage capacity are assessed through the pipeline's demand rates. Separate charges (similar to a commodity charge) are also normally assessed for the actual quantities of gas injected into and withdrawn from storage for the account of a customer. Generally, these charges are composed of 100 percent variable costs and do not recover any fixed costs.

The cost classification and rate design procedures used to develop a pipeline's contract storage demand rates generally followed the same procedures used to develope that pipeline's transportation rates when the Seaboard and United rate designs have been employed. However, as the MFV formula is normally implemented, a slight variation exists.

Under the MFV rate design approach, all fixed storage costs (including return on equity and associated income taxes) are classified as demand costs. These demand costs are then divided equally between a storage "deliverability" charge and a storage "space" charge.

The storage deliverability charge is assessed on the basis of a customer's daily storage entitlement, and the storage space charge is assessed on the basis of the customer's seasonal entitlement to receive this service. This treatment more closely accounts for the relative costs responsibilities attributable to and among contract storage service customers (versus customers that have not contracted for this specific service) than would result from the same MFV procedures used to design the pipeline's transportation rates.

Some or all of the storage capability on some pipeline systems has not traditionally been offered as a distinct "contract storage service." Rather, it has been viewed as being integral to the pipeline's transportation facilities, services, and charges.

As currently implemented, Order Nos. 436 and 500 would require that an interstate pipeline segregate its transportation and storage charges. Any storage-related costs included in a pipeline's transportation charges would be permitted only on the basis that the storage facilities that engendered the costs were: (1) integral to the pipeline's gas transportation system, (2) provided a benefit to the transportation service, and (3) were available to customers contracting for gas transportation service.

Under past ratemaking approaches, storage costs have generally been included in the non-gas component of most pipelines' rates. Typically, such treatment was based on the view that the existence and use of storage facilities resulted in more efficient transportation, lower costs of transportation facilities (because of smaller size pipe or less compression, or both), and lower charges for transportation services.

The propriety of continuing the past treatment of storage costs will likely be challenged for many pipelines. Such challenges -- as well as challenges to the inclusion of gathering costs in transportation rates and to some of the other more traditional ratemaking approaches -- are likely to continue during the transition from the past periods of rigid regulatory approaches to ratemaking to the more flexible, unbundled ratemaking provided by the FERC's Order Nos. 436 and 500.

C. Adjustment Clauses

1. Historical Costs

Prospective tariffs of necessity require an assumption of prospective gas costs. Like hindsight, historical cost is suggested to be the most reliable source of data from which this assumption can be made. Use of "zero-basing" in tariff design would not require any such assumption.

2. Formulistic Methods

Using an historical cost as the base cost in tariffs allows for a billing amount to which can be added or subtracted a calculated difference per Mcf sales unit that adjusts to latest known costs.

The calculations are made through use of a PGA formula that, in simplest form, dictates A - B = PGA, where "A" is the current (latest known) cost per Mcf, "B" is the embedded tariff (base) cost, and the difference is the PGA factor as applied to sales volume.

This simple formula obviously does not recover the cost of unaccounted for volumes, unless the cost-of-service element of the tariff contains line loss recovery of a determined percentage at base cost. In this case, the assuming line loss is constant, i.e. experienced the same as the tariff provision, the simple formula corrects base cost to actual cost only on the sales volumes. The tariff recovery is set, and does not change. Monetary gain or loss is minimal to the extent gas cost swings are not abnormally great.

This formula does not, however, recover the base cost of the unaccounted for gas whenever the tariff element of cost-of-service does not contain provision for line loss. The formula may be adjusted as various regulatory agencies authorize full recovery of gas costs or, to encourage greater maintenance and deliveries, authorize recovery of only portions of total gas cost attributable to line loss. On the other hand, there is a PGA formula which can deal with recovery for unaccounted for volumes. This formula is A - B divided by 1 - x, where the component x is the line loss experienced.

Some regulatory agencies also authorize a surcharge to "true-up" the PGA revenues collected, since the PGA factor is based on purchase volumes and then is applied to sales volumes. This surcharge methodology, known as "Deferred Fuel Cost Accounting," establishes the dollar amount of PGA recovery authorized, nets this to amount collected, and charges the difference into a balance sheet deferred account. Periodic accumulations (normally one to twelve months) are then divided by the estimated or forecasted sales volumes for the recovery period (again, one to twelve months), to arrive at the surcharge to be used.

End-of-period remaining balances are brought forward into the next recovery period.

3. Forecasted Gas Costs

Actual gas cost for any given billing period is not known, except in smaller distribution systems where that information is available from the supplier at the same time the end-user meters are read. The latest known cost per Mcf is accepted by most regulatory agencies for PGA purposes. Forcasted gas cost may in some states be used for tariff development (base cost), but a general policy or pattern for such use in the PGA is not discernable from contacts with other state regulatory agencies.

4. Allocation of Gas Costs

The revenue collection from a utility's PGA surcharge may be allocated based on at least two considerations. First, such revenue may be allocated according to customer class. In this instance, such allocation may be equivalent for all such classes, or some classes may be paying more PGA revenue than others. Unequal PGA charges may result from factors such as: (1) special sales programs for industrial end users; (2) off-system sales and/or transportation revenue credits; (3) serving large capacity end users as transporter for their gas rather than as a utility supplier of gas to the end user; (4) end users choosing to operate with the utility on an interruptable basis where only changes in the commodity component of a pipeline's rate structure might be reflected; and (5) class load factor differences. Second, PGA revenue may be allocated according to regulatory areas of jurisdiction. Some utilities, for example, operate in more than one state and thus utilize two or more PGA clauses, based on the requirements of each jurisdiction. Since these PGA clauses may vary in both form and content, their impact in terms of cost on customers' bills may also vary.

D. Gas Purchasing Practice Reviews

The industry and regulation have allowed gas utilities to expand their involvement into the nontraditional method of acquiring gas supplies and thereby establishing a portfolio approach to gas purchasing. As a result, state regulatory agencies have become more concerned about the lengths of contracts, price of gas, reliability of supply, mix of supply and other issues not previously reviewed in depth by many state regulatory bodies.

Some states chose to incorporate this expanded review into the rate case proceeding, other states chose to expand the Purchase Gas Adjustment (PGA) review and others established separate reviews.

While some states chose to establish formal rules on information the utilities should provide the state agencies and what criteria will be considered in determining if their purchasing practice are acceptable, other states decided to wait.

Forecasting requirements is one of the areas many states are reviewing. The typical time covered in the forecasting requirements are five to ten years but many range from one to twenty years. Some states require that not only the volumes of gas to be used but expected prices, sources, storage use and other applicable information be provided for review.

Procurement plans and practices are also being reviewed by some states. These states require the utilities to provide the gas contracts and the review of the contracts may range from informal to full blown examinations.

The procurement plans of the utilities are required by some states and these may be reviewed in rate case proceedings or separate formal proceedings.

Chapter V - Transportation Rates

A. Nature of Transportation Versus Sales

Traditionally, natural gas utilities and their supplying pipelines have bought and sold gas supplies for their own account - commonly referred to as the merchant function. Under this function, the utility performs the following operations: (1) contract for natural gas supplies from a pipeline or producer, (2) take delivery of the supplies into the utility's system, (3) transmit the gas through the utility's integrated transmission, distribution and storage system, and (4) deliver the gas to the customer upon demand. These four operations occurred without the need for the customer to do anything other than turn on the customer's gas-burning equipment when it was needed.

In recent years, many customers have begun to conduct the first operation themselves (contracting for their own gas supplies), while relying on the utility for operations 2 through 4. This approach -- commonly referred to as transportation -- became a viable option during the middle 1980's when customers were able to negotiate for gas at prices lower than available from the local utility. As a result, customers who were capable of negotiating their own gas supply contracts, found transportation to be an economically attractive option.

From an operating point of view, transportation differs very little from traditional sales for a utility. The most important difference is that the utility need not contract for gas supplies for the transportation customer. It is not clear whether this is an advantage or a disadvantage, since the transportation option complicates the planning for gas supplies by the utility. The only other substantial difference is that transportation complicates the billing procedure due to the need to track individual supplies for individual customers from the wellhead to the burner-tip.

B. FERC Order 436/500

Federal regulation of interstate transportation can be conveniently divided into three types: (1) traditional transportation under the Natural Gas Act, (2) transportation under Section 311 of the Natural Gas Policy Act, and (3) open access transportation under FERC Order 436/500.

The Natural Gas Act (NGA) of 1938 provided for regulation by the Federal Power Commission (now Federal Energy Regulatory Commission) over the interstate transportation and sales of natural gas. Under this act, FERC has broad rate-making powers with respect to interstate gas sales-for-resale and transportation, as well as certificate authority. Any natural gas company seeking to engage in the transportation of gas in interstate commerce must first obtain a certificate of public convenience and necessity from FERC. To obtain this certificate, the pipeline has to demonstrate that it is able and willing to perform the service and to conform to FERC's rules and regulations, and that the proposed service is or will be required by the present or future public convenience and necessity. Otherwise the application is denied. These certification provisions effectively function to restrict access to transportation services. When a pipeline files for a certificate to serve an area with an existing competing pipeline, the competitor will normally file a protest alleging that the service is unneeded. When this happens, the matter is set for hearing, which may eventually result in the pipeline being permitted to provide transportation service, but only afater completing a long and tedious certification process.

This process fit in well with the regulatory scheme of the NGA, which was premised on the assumption that pipelines were natural monopolies. It was thought in 1938 that the pipelines were not subject to workable competition and thus should be restricted in the exercise of their monopoly power. As a quid pro quo, new entry into the market was restricted by the certificate process.

By the middle 1980's the natural monopoly assumption was no longer universally valid. Pipelines were subject to competition from a variety of sources, including other pipelines, locally produced gas, alternate fuels and conservation. Rather than being able to use their monopoly powers to coerce customers, pipelines often found themselves in situations where regulation tied their hands and prevented them from competing effectively.

FERC Order 436 was an effort to respond to these changed circumstances by permitting pipelines the freedom to compete within the framework of the NGA, that had been altered in some important aspects by the Natural Gas Policy Act of 1978 (NGPA). In essence, the NGPA eliminated or placed into effect a phase-out of most Federal regulation of gas at the well-head. It provided impetus for the transportation of natural gas. Order 436 allowed a pipeline to choose between continuing to provide service under the traditional NGA certification procedure, or to become an open access transporter, which provides for more flexibility but puts the pipeline at risk if it fails to compete successfully. Pipelines, who become open access transporters, are required to provide non-discriminatory access to all shippers. The pipeline must offer both firm and interruptible service, and within each category must provide service on a "first come -- first served" basis.

Order 436 also contained certain contract reduction rights for local distribution companies. The reviewing court found that FERC had not adequately dealt with the take-or-pay problems being experienced by the pipelines and that the contract reduction provision in Order 436 could exacerbate the problem. Consequently the court remanded the proceeding to FERC. The court did, however, generally uphold the basic concept embodied in Order 436. In response, FERC issued Order 500 which left the basic transportation provisions intact.

The main difference between sales rates and transportation rates is that transportation rates are "unbundled" while sales rates are not. A sales customer pays a rate which includes all services provided by the utility. By definition, a transportation customer does not use all of those services, since the custmer contracts for its own gas supplies, and therefore transportation rates should be unbundled to pay for only those services provided to the transportation customer directly or indirectly.

The first issue to be decided is what qualifications should be met for a customer to go on transportion. There can be serious problems associated with allowing essential needs customers (such as hospitals) to become transportation customers without backup supply. Transportation customers normally have a limited number of suppliers (often only one) and run the risk of supply shortage if their supplier is unable to deliver. It may be unacceptable public policy to allow essential needs customers to be without an adequate gas supply. There are many methods for dealing with this concern. One possibility is to allow only interruptible customers with alternate fuel capability to go on transportation. Some states divide customers into an esssential needs or core group which must remain on sales, and a non-core group which has an option to switch to transportation. Others use a monthly administrative fee as a fence to keep smaller customers off transportation. Some states require transportation customers to execute an affidavit certifying their gas procurement plans. While a variety of methods are available, the important point is that the particular method chosen should be selected with the utility's supply plan in mind.

Once the qualifications for transportation have been determined, the next step is to design rates. Four methods have been developed for setting transportation rates: (1) Net margin, (2) Gross margin, (3) Allocated cost of service, and (4) Value of service.

Net margin is a method of deriving transportation rates from a utility's existing sales rates. Under this method, the utility's total gas supply cost is subtracted from its commodity rate, and the resulting distribution margin is used as the transportation rate. Gross margin is similar except that only the pipeline's gas commodity cost is subtracted from the commodity rate. For example, consider a utility with a commodity charge of $5.00 per Mcf that pays its suppliers $3.50 per Mcf for its gas supply. Of this $3.50 per Mcf, $2.50 is the pipeline's gas cost and $1.00 represents demand charges of the pipeline. In this example, the net margin would be $1.50 ($5.00 commodity charge - $3.50 total gas cost), while the gross margin would be $2.50 ($5.00 commodity charge - $2.50 pipeline gas cost).

Net and gross margin are based on the concept that sales and transportation are essentially the same except for the gas acquisition function. Consequently, both types of customers will pay the same costs from the point where the utility takes delivery of the gas to the point where it is delivered to the customer. The difference between gross and net margin is in the treatment of pipeline demand charges. These are fixed charges associated with making the facilities available to deliver gas to the utility. The argument for using net margin is that transportation customers pay the pipeline directly for transporting the customer's gas to the utility's territory, and demand charges are simply part of the utility's gas bill which should be paid by sales customers. Gross margin advocates counter that transportation customers had formerly been sales customers and the demand charge is intended to pay for making available the facilities to serve all customers. There is unfortunately no universally correct answer to this question as the facts and circumstances vary from case to case. Many utilities have contract demands far in excess of those needed by their sales customers. Gradually this problem will diminish through the expiration of contracts and by contract reductions associated with pipeline open access settlements.

The concept of basing transportation rates on the allocated cost of service is in principle no different from using that approach to set sales rates. Consequently the principles espoused in Chapter II can be applied equally well to transportation. However, one should be cautious about designing transportation rates on a different cost allocation basis than is used for sales. Sales and transportation are inextricably interlinked on the utility's system. The customers are the same; the physical facilities are the same; the utility employees dealing with the customers are the same. To attempt to create different cost of service studies for two such coadunate services would only magnify the inherently subjective element in the allocation of common costs. If transportation and sales rates are designed on dfferent bases, then customers will be inclined to use whichever service is undervalued, which could result in a revenue shortfall to be made up by other uninvolved customers (i.e. cross subsidization).

The fourth approach used to set transportation rates has been value of service. In many cases, transportation customers have alternate fuel capability and have voluntarily chosen to leave sales for transportation. Under these circumstances, it is reasonable to expect that competitive market forces will maintain competing prices at reasonable levels without the need for traditional regulatory controls. Under this approach, sales rates to core markets continue to be regulated because the utility maintains its monopoly power over these customers, while transportation rates are essentially deregulated (within rather broad limits set by the Commission), because it is believed that market forces are adequate to maintain prices at reasonable levels.

Finally, it should be noted that the distinction between firm and interruptible transportation service is not the same as for sales customers. The risk of interruption for a sales customer is due to three factors: (1) insufficient gas supply (2) insufficient pipeline capacity, and (3) insufficient utility distribution capacity. A transportation customer directly assumes the risk of insufficient gas supply and pipeline capacity. This would suggest that the rate differential between firm and interruptible transportation customers may be different than for sales customers. Additionally, if the utility's distribution system is adequate to serve its peak load, there might not be any reason to maintain the firm/interruptible distinction for transportation customers.

2. Storage/Load Balancing

The availability of load balancing and storage is another potential area in which a difference could exist between transportation and sales. If the utility has storage capability, then its purchases will not normally equal its sales in any give month. The utility will generally balance its load by purchasing additional supplies in the summer months and storing these for use in the winter. Sales customers automatically pay for this storage through their rates, and any transportation rates taken directly from such sales rates would automatically include a charge for storage. However, transportation customers can structure their purchases so as to match deliveries of the customer's gas to the utility assuming that adequate capacity is available. In this event, the transportation customer would not be using the storage and load balancing services of the utility.

This difference in service characteristics can be dealt with in two ways. The most common method is to allow the customer to carry a certain amount of excess deliveries in a "bank" which can be used up over time. The second approach is to unbundle storage costs. Under this method, the transportation charge would be reduced by the average storage cost on the utility's system. A corresponding storage charge would then be made based on the cumulative amount of excess deliveries made on the customer's behalf. Under this approach, a transportation customer could avoid paying storage costs by matching takes with deliveries, while a customer who did not do a good job of matching would pay for the storage used.

3. <u>Supply Commitment Fees/Backup Charges</u>

The prior section dealt with the situation where a transportation customer had more gas delivered than the customer was taking. Of greater concern is the opposite situation where the transportation customer needs more gas than is delivered by its supplier. The utility may still have an obligation to serve depending on the jurisdiction, and if so, there is normally little concern if the utility has an excess supply to sell the customer. Many transportation arrangements provide that if deliveries into the utility's system are less than the customer uses, any excess takes will automatically be billed at the utility's sales rate.

The difficulty arises when the customer relies upon the utility to provide backup supplies in the event of a shortage from its supplier or intervening pipeline capacity constraints. For the utility to stand ready to provide backup sales service, it must make a substantial long-term commitment for gas supplies, which involves the incurrence of fixed costs for these supplies. A common approach is to require that transportation customers who wish to retain the right to return to sales service pay a supply commitment fee (or back up charge) to do so. The actual calculation of this charge will depend upon the specific details of a utility's supply arrangements, but a good general rule is that the commitment fee for a transportation customer should equal the cost being paid by a sales customer to maintain the utility's supply contracts. The costs would include such items as gas supply demand charges, fixed cost minimum bills and gas inventory charges.

While most people are likely to agree with the concept that a backup charge is appropriate where the customer wishes to return to sales, there is likely to be considerable disagreement over exactly who is to pay the charge. Basically there are three approaches: (1) Make it optional, (2) Require all customers to pay, and (3) Require some customers to pay.

At first blush giving the customer the option to pay a backup charge to return to the system seems to be the most reasonable approach. The customer would thus make a choice based on the amount of risk which the customer wishes to bear. Customers who wish to have a secure source of supply would chose to pay the backup charge, while those who did not have as much to lose due to shortage would not pay the charge. Each customer would evaluate the potential adverse consequences and probability of its gas supplies not being available compared with the additional costs of the backup charge, and would chose the most economically beneficial. Utilities would obtain gas supply commitments only for sales and backup services for transportation customers, and would thus not incur any unneeded gas inventory costs.

In theory, this approach should be the best. Each customer would make a rational decision as to which option is most beneficial and the overall benefits to all customers would be maximized. However, this system has not been tested in practice and there is concern that it may not always work satisfactorily. For example, if a hospital or major industrial employer indicates that it will have to shut down due to a lack of gas supplies, it is likely that there will be a great deal of pressure to serve that customer irrespective of whether the customer paid a backup charge or not. If this happens, or is expected to happen, then the whole system may break down. Utilities may have to plan for gas supplies not only to serve sales customers and backup for transportation customers, but also for transportation customers who do not pay the backup charge. These additional supply commitments may result in additional costs which would be borne by sales and backup transportation customers, and which may thus cause additional customers to opt not to pay for backup. If this scenario occurs transportation customers who have options could be getting a free ride paid for by captive sales customers who lack options. But, there may be ways to address this concern.

One way would be to require all transportation customers to pay for backup supplies. This approach eliminates the "free lunch" problem but has little else to recommend it. Many customers would argue, quite legitimately, that they have alternative fuels available, do not need backup supplies, and that it would be economically wasteful to require them to pay for a service they do not need.

Another way would be to require customers who would be expected to need backup service to pay for it. The method for deciding which customers must take backup service should be based on some rational criterion, such as whether the customer has alternate fuel capability installed. This approach should help to reduce but probably not eliminate the "free lunch" problem.

But, it has the problem of choosing an appropriate criterion and it can appear unfair that certain customers are required to take backup service while others are not. It may also encourage the customer to seek bypass.

There is probably no universally correct answer to this concern. Each option has certain disadvantages and none appear totally satisfactory. The rate designer should work in cooperation with the gas supply planners to ensure that the approach chosen reasonably meets the needs of the utility and all customers.

4. Capacity Reservation Charges

Most pipelines carrying gas from the producing to the consuming regions were primarily built to provide service to the local distribution utilities and their customers. For the most part, the utilities have been and still are paying the fixed costs associated with these pipelines. Accordingly these customers have the right to claim capacity entitlements on these lines. If transportation customers wish to contract for firm capacity previously used by the utility (rather than contract for unused firm capacity or for interruptible capacity), then it is reasonable to expect such customers to make appropriate compensation for the use of that capacity. When and how this may best be done is an active topic at both the state and federal level. The rate designer should be aware that the entitlement to capacity on an interstate pipeline could be a valuable asset for some utilities.