THE ECONOMICS OF NATURAL GAS PRODUCTION, TRANSPORTATION, STORAGE, AND DISTRIBUTION

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INTRODUCTION

The economics of the natural gas industry are largely influenced by the demands of a highly seasonal market. In meeting the demands of this market, the industry must operate within the confines of governmental regulatory bodies.

The increasing importance of natural gas in the overall energy picture of the United States is depicted in Fig. 1. Gas has increased its share of the total energy market from 18.0 percent in 1950 to 29.7 percent in 1963.[1] At the present rate of growth, the projected market for natural gas will be 17,880 trillion B.t.u. in 1975.[1] The large-scale movement of natural gas from established supply sources to existing and developing consumer markets entails a variety of operations: the production, purification, transportation, storage, and distribution of natural gas. The economics of the industry are characterized by the major differences in the costs of production and utilization. These differences are not due solely to the operations cited above but also to other factors such as varying rate structures and field contracts.

GAS PRODUCTION

In consideration of the risks involved, the exploration, development, and production of a natural gas field requires a tremendous investment. The major costs in production are the land, the rights, and the drilling of a potential field. Although no fixed values can be set on the first two items because they vary, well drilling costs are tabulated and are well known. Unfortunately, every well drilled is not productive. Thus in 1962, of a total of 43,944 oil and gas wells drilled in the U.S., 16,684 or 38 percent were dry holes (Table 1). These statistics include development wells. The success of wildcat wells is much lower.

Average well depths are increasing and, consequently, the cost per foot drilled. The sixth (1962) joint survey of the cost of drilling and equipping wells in the United States undertaken by the American Petroleum Institute, the Independent Association of America, and the Mid-Continent Oil and Gas Association reveals the following:[10]

Table 1.-SUMMARY OF 1962 DRILLING

	Oil	Gas	Dry	Total
Wells drilled	21,402	5,858	16,684	43,944
Footage drilled (thousands)	86,494	31,432	75,631	193,557
Expenditures ($ million)	1,161	569	847	2,576
Avg. depth per well, ft.	4,041	5,366	4,533	4,405
Avg. cost per well, $	54,223	97,093	50,793	58,635
Avg. cost per ft., $	13.41	18.10	11.20	13.31

Thus we see that by virtue of being 30 percent deeper, the cost of gas wells is almost 80 percent higher than oil wells, since costs increase very steeply with increased depth. Gas well costs per foot drilled increased from $17.65 in 1961 to $18.10 in 1962.

The most commonly accepted indicator of field gas prices is the average wellhead price compiled yearly by the U.S. Bureau of Mines.[12] The average wellhead price of natural gas has increased significantly over the past decade to 15.5¢/MCF in 1962 (Fig. 2). However, it should be cautioned that while this tabulation is useful in indicating trends it should not be construed as a measure of field prices. The U.S. Bureau of Mines data do not take into account the time delay in long-term supply contracts nor do they differentiate between low-value markets (such as carbon black manufacture) and high-value markets (such as interstate transportation).[8] A truer barometer of current wellhead prices are specific gas purchase contracts.

Gas Purification

Gas from the wellhead contains impurities that may be detrimental to the transmission pipeline. In order to reduce corrosion problems and improve gas quality, the gas has to be purified. Some wellhead gases also contain valuable heavy hydrocarbons which are removed and sold for greater value than fuel oil or gas.

The purification of natural gas varies with the type of gas produced. It may involve the removal of objectionable compounds such as carbon dioxide, sulfur compounds, and water. Some gases have to be scrubbed for light-hydrocarbon removal. The costs of such purification operations vary with the type of natural gas and the operations performed. To meet pipeline specifications natural gas is dried primarily by chemical means, wherein a desiccant or a hygroscopic liquid is used to absorb the water. Sulfur compounds are removed by standard techniques such as those using monoethanolamine and diethylene glycol solutions, and activated carbon boxes.

The recovery of liquid products (gasoline and light ends) from natural gas usually results in a credit to the purification operation. However, it may be uneconomical to remove the condensables, in certain cases, because their relative value is greater than the cost of their removal. The costs associated with purification are a negligible part of the overall gas costs. Reported purification costs at 15 major companies range from $0.000248 to $0.0173/MCF.[13] Average purification costs for major pipeline transmission costs run from $0.002 to $0.003/MCF treated.

TRANSPORTATION

The importance of natural gas pipelines is exemplified by the fact that as of 1963 about 200,000 miles of pipelines, not including field gathering and distribution lines, were in use to meet the demand for natural gas. The growth of the industry can be seen by the twofold increase in pipeline mileage (Fig. 3) over the past 15 years.[1] In 1964 it was estimated that over 11 trillion cu.ft. of gas would be transported and sold by natural gas pipelines, representing a movement of about 232 million tons of gas.[2]

Natural gas pipelines, because of their classification as public utilities engaged in the interstate transportation of natural gas, have been under federal regulation for many years. The Natural Gas Act of 1938 and its subsequent amendments places responsibility for this regulation with the Federal Power Commission (FPC). Therefore, prior to the construction of a new pipeline or the expansion or extension of present facilities, a certificate of public convenience and necessity must be obtained from the FPC. These certificates are usually granted only after extensive hearings and investigation on the adequacy of gas reserves dedicated to the project, competency of design, availability of market, and financing ability.

As compared to oil or product pipelines which act as interstate carriers, natural gas pipelines generally are not classified as common carriers; they own and sell most of the gas which flows through their lines. The growing market for which service is to be provided requires that the designer allow for increased future demands. He may do this by a number of means, e.g., the use of a lower line pressure during the early years of the project, provision for added compression capacity, and the installation of larger than necessary pipe. Assuming that the market and sufficient reserves exist, the utility must design and estimate the cost of the new facilities prior to obtaining FPC certification.

Pipe Costs

Many factors must be considered in evaluating the design parameters for any given pipeline project. The basic goal of any evaluation must be to optimize the design with respect to cost and capacity. The most influential factor in the design and cost of a pipeline for any given capacity is the pipe. Estimates for complete pipeline projects indicate that the cost of the pipe, including installation, is usually between 70 and 90 percent of the overall project cost. The basic factor in determining the cost of a pipeline is the type of pipe used. The designer's aim is to use the least amount of steel for a maximum delivery capacity, with the highest possible pressure and lowest possible installation costs.

Current F.O.B. mill prices for pipe (early 1964) range from about $175/ton for Grade B pipe (35,000 p.s.i. yield strength) to about $200/ton for X-60 pipe (60,000 p.s.i. yield strength). The balance of the installed cost of the pipe is for the coating and wrapping of the pipe and the actual installation charges. A summary of the three cost factors mentioned for various size pipe is presented in Table 2.

Table 2.-PIPELINE CAPITAL COST ESTIMATES[9]

Pipe Size, in.	Wall Thickness, in.	Yield Stress, p.s.i.	Pipe Cost, $/ton	Ton/ mile	Coating Materials, $/mile	Installation, $/ft.
4-1/2	0.188	35,000	208	22.6	310	2.40
8-5/8	0.219	35,000	179	51.8	585	2.95
12-3/4	0.250	46,000	190	88.2	863	3.50
16	0.250	52,000	210	110.9	1086	4.00
20	0.250	52,000	208	136.9	1340	4.60
26	0.312	52,000	200	208.6	1747	5.40
30	0.375	52,000	188	314.2	2007	5.90
36	0.438	52,000	193	438.2	2434	6.70
42	0.500	52,000	202	586.1	2840	7.50

The cost for various size transmission line projects reported to the FPC in fiscal 1964[9] are summarized in Fig. 4. The costs presented include the right-of-way, materials (pipe, coatings, etc.), labor, and miscellaneous charges. The high and low costs are also shown. Local conditions can cause as much as a threefold variation in the cost.

Compressor Stations

After the pipe and its associated costs, the expenditure due to compression of the gas is the second major component of transmission investment. The number of compressor stations that should be utilized on a pipeline are a function of the distance, pipeline operating pressure, and delivery required, as well as the economic restraints such as operating costs (fuel, labor, maintenance, and materials), and fixed or owning costs normally encountered (insurance, taxes, and return on investment). It may be advantageous to allow a large pressure-drop between stations, which will increase compression costs at each station but will reduce the number of stations.

The basic investment cost factors in the installation of a compressor station are the compressor, prime mover, land and improvements, the structures, and the miscellaneous equipment. The average cost per horsepower for nine new mainline compressor stations reported to the FPC in 1964 was $380.[9] The total installed capacity was 60,000 h.p. The cost varied from $169/h.p. for 10,500 h.p. in Louisiana to $518/h.p. for 6000 h.p. in New Jersey. Table 3 lists the average cost/h.p. reported from 1959 through 1964 for new mainline stations and additions. Compressor stations vary somewhat with line size; Table 4 shows the estimated cost for compressor stations as a function of nominal pipe size. These costs include land, engineering, equipment, purchasing, and inspection.

Procurement of right-of-way is often a major problem and can considerably increase the cost of a pipeline project. The type of land, the population density in the area, and the number of road, water, and rail crossings affect the economic decisions of alternate routes. Right-of-way costs range from $2000 to $4000 per mile. In actual experience as reported to the FPC for 30- and 36-in. pipelines the cost/mile averaged $3650. These costs reflect construction in both mountainous and relatively flat terrain.

Table 3.-COMPRESSOR STATION COSTS[9]

Fiscal Year	New Mainline: Total Capacity, h.p.	New Mainline: Cost, $/h.p.	New Additions: Total Capacity, h.p.	New Additions: Cost, $/h.p.
1959	123,980	325	79,770	271
1960	242,850	208	396,115	233
1961	36,750	326	85,560	266
1962	109,080	340	101,840	251
1963	45,000	338	90,800	222
1964	60,000	380	100,200	233

Table 4.-COMPRESSOR STATION COSTS[9]

Nominal Pipe Size, in.	Fixed Station Cost, $	Variable Station Cost, $/installed h.p.
12	250,000	250
16	250,000	250
20	300,000	250
26	500,000	225
30	500,000	225
36	650,000	225
42	650,000	225

A pipeline must also have communications facilities, maintenance facilities, meter stations, and sales and regulator facilities at delivery points.

Pipeline Construction and Transmission Costs

A large new pipeline proposal presented to the FPC in 1963 was the 1545-mile Gulf-Pacific Pipeline Company system designed to transport gas from south of Houston, Texas to the Los Angeles area. The application and the figures supporting it effectively summarize pipeline construction costs. The estimated cost of the project is $314 million or about $203,200/mile.[11] The line would require 15 compressor stations costing approximately $51 million or about $273/h.p. The mainline system would use 36-in. X-60 pipe for the major portion and would cost over $209 million or an average of almost $150,000/mile. The project investment costs are summarized in Table 5.

Table 5.-GULF-PACIFIC PIPELINE CO. COST ESTIMATE[11]

	Unit Cost, $	Total Cost, $
Mainline (1397.8 miles)	149,849/mile	209,458,900
Gathering line (45.0 miles)	72,162/mile	3,247,300
California Laterals (102.4 miles)	108,476/mile	11,108,000
Sales Regulator Facilities		1,550,000
Compressor Stations, (15,000-188,000 h.p.)	273/h.p.	51,381,500
Miscellaneous		2,733,300
Total Direct Cost		279,479,000
Overhead, 3.86%		10,787,000
Interest During Construction, 3%		8,708,000
Contingencies, 5%		14,949,000
Total Project Cost	203,200/mile	313,923,000

The total operating cost of a pipeline is composed of the actual cost of operations, maintenance, general services, and fixed charges. The greatest contributor, excluding gas purchase cost, to the total cost is the fixed cost (Table 6).

Table 6.-AVERAGE 1962 U.S. GAS TRANSMISSION COST[13]
(Including Return)

	Cost, ¢/MCF
Purchase and Production	20.6
Operating Maintenance	2.7
General Services	1.4
Fixed Costs	11.5
Average Delivered Cost	36.2

The overall cost of transmission generally averages about 1.5¢/MCF for each 100 miles. The average operating costs, as reported to the FPC,[13] for the transmission facilities of 15 pipeline companies is 10.1¢/MCF of gas delivered.[13]

Since transportation is a major component of the cost of gas, the industry has directed continuing efforts in the area of transmission and pipeline research with a view to improved and more economical techniques. Examples of this are the development of high-strength steel and the entry of gas turbines as prime movers. In addition, the A.G.A. has sponsored research on line pipe properties, multiphase flow mechanics and transient flow systems which will permit the design of optimized and economical transmission systems.

STORAGE

Distributing companies faced with seasonal variations in daily sendout normally control the average cost of purchased gas by peak-shaving and the sales of interruptible gas. Interruptible gas is that which is sold with the understanding that in times of excessive demand it will be delivered to other customers. However, when a distributing company is unable to sell interruptible gas at satisfactory rates, it will store summer gas to meet future winter firm gas sales. Therefore, one of the important components that influence the final delivered gas cost is storage. These large volumes of gas can be most economically stored underground in depleted oil or gas reservoirs and in porous water-bearing formations, or aquifers. Any storage system must be close to the point of use but, unfortunately, underground geological formations suitable for this type of storage are not available in all parts of the United States. Depleted oil or gas reservoirs are confined to areas where favorable conditions for the formation of oil and gas deposits once existed – areas that can be developed with much less expense and effort than would be required for aquifers. Because of the high developmental costs, aquifer storage costs more than storage in depleted oil or gas fields.

Economics

Before an economic evaluation can be made of a potential underground storage, certain engineering considerations have to be met.

Most important of these are:

1. Site location relative to transmission lines and market
2. Reservoir size in relation to gas turnover
3. Structural integrity, porosity, and permeability
4. Rate of deliverability.

These considerations also have an economic significance on the cost of storage. Obviously, the location of a prospective underground storage site as near to transmission lines and markets as possible is vital for decreased expenditures. The size of the reservoir is dictated by the maximum seasonal demand which has to be met and also increased demand in the future. High porosity is conducive to storage of a larger volume of gas for a given structure. Good permeability is desirable since it permits the storage structure to receive gas readily on injection and deliver it at high withdrawal rates when needed. In addition, the legal and economic problems of site, cost of the land, and the cost of development and operation of the storage field are decisive factors. The volume of cushion gas which will remain in the reservoir for the life of the project and provide the pressure for the working gas withdrawal rates should not be excessive since this will represent a major investment. Normally, the working inventory averages 50 percent of total inventory. Fig. 5 shows the growth of underground storage pools and the ultimate reservoir capacity since 1950.[1] Although total reservoir capacity has increased an average of 10 percent over the past 8 years, the rate of growth has slowed to an increase of only 2.8 percent in the past year.

In Fig. 5 we see that by the end of 1963, 278 underground pools were being used by 72 companies in 23 states with an estimated ultimate storage capacity of 3.7 trillion cu.ft. In 1963, $106 million were spent in new facilities; an estimated $140 million was spent on new facilities in 1964.

Cost

Individual components of the storage cost vary with company and location. Thus, although storage plant fixed investment, including cushion gas, may average $0.98/MCF of working storage capacity, the actual reported costs vary from $0.34 to $2.05/MCF. An idea of the relative contributory factors can be obtained from Table 7.

Table 7.-VARIATION OF UNDERGROUND STORAGE COST[5]

	Average, $/MCF	Range, $/MCF
Storage Plant Investment	0.98	0.34 - 2.05
Cost of Storage Gas		
Fixed Charges, 15%	0.15	0.051 - 0.308
Operating and Maintenance Expense	0.031	0.016 - 0.115
Inventory Value of Gas Withdrawn	0.279	0.097 - 0.433
Total Gas Cost/MCF	0.460	

Although the estimated ultimate capacity of underground storage has increased, the increasing gas demand and lack of suitable underground storage locations have spurred the industry into investigating alternate means of storage for peakshaving.

One of the newly developed methods is the storage of gas as a liquid. Liquid natural gas can be stored at atmospheric pressure and −259°F., where it has the advantage of containing 630 volumes of gas as 1 volume of liquid. At present, three methods of LNG storage are available to the gas industry:

1. Aboveground metal tanks
2. Cryogenic inground storage
3. Belowground prestressed-concrete tanks.

The storage of LNG at cryogenic temperatures involves special problems and materials; techniques have been developed which permit the storage container to withstand the extremely low temperatures. The costs of LNG storage vary with capacity as shown in Fig. 6 for aboveground metal tanks ($1.80/MCF for 1 million MCF) and in Fig. 7 for belowground prestressed-concrete containers ($1.50/MCF for 1 million MCF).[7] The prestressed-concrete tank storage technique was successfully demonstrated at IGT under sponsorship of the American Gas Association. Present efforts at IGT are directed towards the storage of large volumes of LNG in underground caverns. The acceptance of the LNG storage technique has resulted in construction of three major installations in recent months. Double-walled metal LNG storage tanks are being installed at Birmingham, Alabama and San Diego, California, and a cryogenic inground storage pit is being constructed at Hackensack, New Jersey. Once the gas has been delivered to the city gate, perhaps having been stored at some intermediate point, it must still be distributed to the individual customers.

DISTRIBUTION

In 1963, 434,000 miles of distribution piping was used to supply 35.5 million customers. The dominant economic factor in gas distribution is the character of the demand which varies with each of the four types of customer application:

1. Residential and small commercial — non-spaceheating
2. Residential — spaceheating
3. Small-volume commercial and industrial — spaceheating
4. Large-volume commercial and industrial

In addition to these classifications a distribution company may also sell gas to the interruptible customers. As public utilities gas distribution companies have an implicit contract with their firm customers to satisfy their demands at all times. Since a high percentage of firm customers use gas for spaceheating, such demand is very responsive to weather conditions.

This widely fluctuating demand precipitates a problem of supply that is felt all the way back to the producer. However, we will confine ourselves to its effects on the distribution company, felt most keenly by the northern utilities who experience the widest temperature variations. The southern gas companies have the same problem, but to a lesser extent. The structure of gas rates stresses the necessity to maintain high load factors. The cost of gas to most companies is computed from a two-part rate. The first part, the demand charge, or fixed cost, is payable monthly and is based on the maximum, daily contracted (with the pipeline) quantity; the second part, the commodity

cost or variable cost, is the direct cost for each 1000 cu. ft. of gas purchased. Table 8 typifies the problem faced by some distribution companies in the Northeast. In this instance, the demand charge is $65/MCF of daily capacity contracted and the commodity cost is $0.31/MCF of gas actually delivered.

Table 8.-PIPELINE GAS COST

Usage, days	Cost, $/MCF
1	65.31
5	13.34
10	6.81
50	1.61
100	0.96
200	0.64
300	0.53
365	0.49

It is readily apparent that management will attempt to optimize the purchase pattern of gas. Many methods are used to obtain a higher load factor than would be obtained through exclusive pipeline purchase. Fig. 8 shows a hypothetical sendout curve for a northern utility. It can be seen that a large "valley" exists during the summer months. Many gas companies attempt to fill this valley by selling interruptible gas to industrial and/or commercial customers, or through the use of storage systems which was discussed previously. Among the other techniques for peakshaving are the use of propane-air mixtures, manufactured gases, and special purchases of peakload pipeline gas.

Design

The distribution system must be designed to meet instantaneous peaks, as well as daily and seasonal demands. Distribution systems are generally designed to be able to serve the maximum rate of gas demanded over a 15-30 minute period.

Distribution system pressure is the first design parameter that must be defined after the load is known. The system pressure directly influences the cost of a system because the major investment (80 percent)[6] of a gas distribution company is in its mains and services. (Services are the pipes from the street mains to the customer's meter.) Pipe costs are directly related to volume of gas delivered and operating pressure. Maximum design pressure for distribution systems rarely exceeds 60 p.s.i.g.; many companies operate their systems below 25 p.s.i.g.

Because of the high proportion of investment in mains and services and their direct effect on the distribution cost, it is imperative that new distribution system investments be optimized. Future loads for expanding communities must be accurately estimated to optimize costs. The cost of mains varies considerably across various sections of the country because of the great variability of labor costs and its large effect on installed main costs. Generally, the only predictable costs are those of the pipe itself. However, some general estimates have been made. For example, the cost of installing 1000 ft. of a 6-in. steel main in a suburban area was estimated as $5150; the cost of installing a 50 ft., 1-in. service would be $175.[3]

The cost of new distribution facilities also includes the cost of meters and pressure regulators, which account for about 14 percent of total distribution system investment. The cost varies from about $45-$50 for residential meters to almost $5000 for the large-volume meters. The average investment for distribution facilities is about $325/customer.[4]

The total costs for gas distribution include fixed charges on the distribution system investment, and the operating, maintenance, and customer accounts expenses. The fixed charges, averaging about $42.60/yr. per customer exceed all other costs combined, which have an average total of about $19/yr. per customer.[6] The implication of these costs is that the design and operation of mains and services is of paramount importance and must not be left to chance. The distribution expenses contribute 9.3 percent of the total operating costs in a distribution company. Table 9 details the other items of expense. Note that purchase and production of gas are by far the largest contributor, 77 percent, to the total operating expenses.

Table 9.-TOTAL DISTRIBUTION COMPANY OPERATING COSTS IN 1962[1]

	Cost Distribution, %
Purchase and Production	77.0
Transmission and Storage	5.5
Distribution and Customer Accounts	9.3
Sales, Administration, and General	8.2
	100.0

While the cost of gas purchases offer the largest target for cost reduction through improved storage and transportation methods, the other costs offer many opportunities through advances in technology and improved methods. Such efforts are being extended by the industry through industrywide research by the A.G.A. and through individual company efforts. Activities include development of new methods of leak detection and studies of nonwelding techniques of joining pipe at IGT, and studies in the use of plastic pipe at Battelle Memorial Institute. A number of projects are also being conducted at the A.G.A. laboratories in areas associated with domestic gas usage.

CONCLUSION

We have traced the route of our supply of gas from the wellhead to the consumer and discussed the problems and role that each step plays in the overall economics. Although consumer gas prices vary, an average for all classes of service showing the contribution of each step can be calculated:

Table 10.-AVERAGE GAS PRICE[1,13]

	Price Factor, ¢/MCF	Contribution, %
Production	20.4	32.4
Purification	0.2	0.3
Transmission	15.6	24.8
Storage	0.7	1.1
Distribution	26.0	41.4
	62.9	100.0

Storage and distribution account for 42.5 percent of the average consumer price for 1 MMBtu (1 MCF) of energy. Following is the average price paid in 1963 for 1 MCF of gas in each of the three major classes of service:

Table 11.-AVERAGE PRICE PAID FOR GAS IN 1963[1]

	$/MCF
Residential	0.99
Commercial	0.77
Industrial	0.34

The large price variation among the different types of service is due primarily to the volume purchased and the allocation of the entire system's fixed charges on investment. The residential, most commercial, and a few industrial consumers, pay for and receive a guarantee of continuous service. Payment for this guarantee comprises a major portion of the fixed investment. Despite rising prices at the wellhead and in the nation's overall economy, the continuing advances in research and development in the gas industry have provided the consumer with relatively stable gas prices and have greatly increased the market demand for gas.

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