1. Introduction

The United States has an extensive network of pipelines for transporting natural gas from supply areas to all of the lower 48 States. In 1996, this system delivered about 20 trillion cubic feet of natural gas to end users, an average increase of about 5 percent annually since 1990.[1] This trend is expected to continue, as Energy Information Administration (EIA) projections indicate that demand could be near an all-time high by the turn of the century.[2] These projections of increasing demand raise important issues for the U.S. pipeline transmission industry concerning the system's capability to move gas, the mechanisms for allocating capacity, and the best way to apportion costs among users to obtain efficient use of the system.

Report Purpose and Structure

This report primarily examines the capability of the interstate pipeline network to move natural gas to various markets within the United States. The examination evaluates these capabilities from supply areas to end-use markets, looking first at the productive capacity and assets of major production areas and the ability of the pipeline network to handle current and proposed levels of production. It then assesses the ability of the mainline pipeline network to transport and direct supplies to end-use markets and the capabilities of the trunklines and regional pipeline systems to deliver gas to the ultimate consumer. Throughout the report, the data are discussed and analyzed on a regional basis (see Figure ES1) to reflect the significantly different profiles of various production and market areas within North America that are linked by the pipeline network.

The main purposes of this study are to:

- Quantify the capacity levels and usage of capacity on the interstate pipeline network in 1996 between supply areas and major market areas.

- Examine the changes that have occurred on the pipeline network since 1990, including new pipeline systems and expansions to existing systems.

- Analyze how regulatory change and market forces since 1990 have created new market entities while altering the traditional role of a number of existing ones.

- Characterize and compare the various production and market areas in relationship to the interstate pipeline system.

- Assess shifts in market and end-use consumption patterns within the different markets between 1990 and 1996.[3]

- Identify and examine recent proposals for new pipeline routes and capacity expansions on existing lines, particularly their effects on capacity levels.

The report does not attempt to identify specific instances of excess pipeline capacity or system bottlenecks. Identification of specific existing capacity constraints or excesses would require modeling and simulation runs using actual daily operational data. Such an endeavor would require more detailed and specific data than were available for this study.

This chapter discusses some of the operational and regulatory features of the U.S. interstate pipeline system: the shipper requirements that affect the overall system design, the design process, the system utilization, and the regulatory procedures for capacity expansion. It also examines the differences between various types of pipeline companies and the importance of underground storage facilities in the design and operation of a pipeline system.

Chapter 2 looks at how the exploration, development, and production of natural gas within North America are linked to the national pipeline grid. The analysis includes a profile of current and, where possible, projected production levels within the major natural gas-producing areas in the United States and Canada. It also examines production levels relative to pipeline capacity on pipeline systems exiting these areas and entering the major natural gas transportation corridors serving markets in North America.

The capability of the interstate natural gas pipeline network to link production areas to market areas is examined in Chapter 3, based on capacity and usage levels along 10 corridors. Each corridor is profiled and analyzed relative

[1]Excludes gas used for pipeline fuel as well as lease (field) and plant processing. Also does not include Alaska and Hawaii. Energy Information Administration, *Natural Gas Annual 1996*, DOE/EIA-0131(96) (Washington, DC, September 1997), Table 1.

[2]Energy Information Administration, *Annual Energy Outlook 1996*, DOE/EIA-0383(96) (Washington, DC, January 1998).

[3]Unless otherwise specified, historical or general production and consumption data cited throughout this report are based on the publication, Energy Information Administration, *Natural Gas Annual 1996*, DOE/EIA-0131(96) (Washington, DC, September 1997).

to its combined pipeline capacity and usage levels, especially as to its receipt capability from supply areas and deliverability to market areas. The chapter also examines capacity expansions that have occurred since 1990 along each corridor and the potential impact of proposed new capacity.

Chapter 4 discusses the last step in the transportation chain, that is, deliverability to the ultimate end user. Flow patterns into and out of each market region are discussed, as well as the movement of natural gas between States in each region. The profile of the customer base is addressed to provide some insight into the current operation of pipeline and storage facilities in the market area. The potential impact of announced expansion projects is analyzed relative to current capacity levels and the regional demand profile.

Chapter 5 examines how shippers reserve interstate pipeline capacity in the current transportation marketplace. It looks at how pipeline companies are handling the secondary market for short-term unused capacity that is placed on the market by shippers eager to lower their overall transportation costs. It also analyzes the level of this (capacity release) trading and what current trends might mean for firm and interruptible contract (reservation) levels on pipelines in the future. The report also includes four appendices that provide supporting data and additional detail on the methodology used to estimate capacity.

For the most part, the time series data used in this report cover the years 1990 through 1996. There are a few exceptions worth noting, however. Pipeline projects completed in 1997 are included in the analyses in chapters 3 and 4, although these projects were only in service for a part of the year. Since pipeline flow data for 1997 were not yet available, no attempt was made to integrate the 1997 projects into any discussion of pipeline utilization or specific State-to-State capacity profiles.

Another exception is the energy consumption data in Chapter 4 (and Appendix C, Table C1). As of March 1998, no comparative annual data for 1996 were available concerning total national energy consumption by fuel type. While this limited the data time series to the period 1990 through 1995, the use of average annual (percent) change in the accompanying profile analyses minimized the impact of the 1 year of missing data. It should also be noted that the analysis in Chapter 5 examines firm transportation contract data for the 1997 heating year (the 12 months ended March 31, 1997).

Analyses concerning out-year projections vary with the types of issues being addressed. Projections of pipeline capacity additions through the year 2000 presented in the report are based upon actual proposals currently under active consideration by the pipeline companies and regulatory authorities. Some of these projects may not survive the development process. Projections concerning production (Chapter 2) and future demand levels (Chapter 4), on the other hand, reflect estimates presented in EIA's *Annual Energy Outlook 1998 With Projections to 2020* as produced from the EIA's National Energy Modeling System (NEMS).

Defining Deliverability

"Deliverability" is defined for this report as the *maximum* volume (capacity) that can be received, delivered, or passed through a specific point during a specified period, e.g., 1 day. Pipeline deliverability, or capacity, can be measured in different ways, resulting in slightly different meanings. For example:

- **Systemwide peak-day capacity.** Major interstate pipeline companies file an annual capacity report (18 CFR §284.12) with the Federal Energy Regulatory Commission (FERC) that reports their daily system capacity based on a design estimate of how much their system can deliver for current shippers on a systemwide peak day, otherwise known as the coincidental peak day (Table 1).[4] The derivation of this figure differs among pipeline companies. Estimates of capacity on grid type (regional) systems (see "Pipeline Utilization" section) often are based upon the sum of system maximum deliverability when the system is in a balanced state (receipts match deliveries). Systemwide capacity on trunkline systems usually represents the sum of capacity at all delivery points.

- **Peak-day capacity of each individual receipt, delivery, or interconnection point.** This estimate represents the maximum amount of natural gas that can be delivered into or out of the system during a period based on an individual customer's peak needs, although no system is capable of reaching these maximums at all points on the same day. The sum of these capabilities is known as the "noncoincidental peak-day capacity." It is called noncoincidental because the days on which delivery points on a pipeline system experience their peak flow may not coincide.

- **Capacity at a specific (strategic) point along the pipeline system**, usually at a compressor station or hub interconnection (of several pipelines). Compressor

[4]A coincidental peak flow is a volume measured at a delivery, receipt, or interconnection point during a specified period (usually a day) when the entire pipeline system operated at its maximum (throughput) for a given year. Thus the day for this measure coincides for all shippers.

Table 1. Forty Largest Interstate Pipeline Companies by Level of Deliverability, 1996

Company Name	Type of System[1]	Number of Receipt Points[2]	Number of Delivery Points[2]	Number of Interconnect Points[3]	Systemwide Peak-Day Capacity[4] (MMcf/d)	Coincidental Peak-Day System Flow[5] (MMcf)
Columbia Gas Transmission Co.	Grid	86	464	44	7,445	7,309
Transcontinental Gas Pipeline Co.	Trunk	52	246	18	6,376	6,448
CNG Transmission Co.	Grid	42	125	30	6,275	6,899
Tennessee Gas Pipeline Co.	Trunk	701	386	112	5,981	6,887
ANR Pipeline Co.	Trunk	92	355	35	5,923	6,311
Texas Eastern Transmission Corp.	Trunk	158	178	62	5,761	5,414
Natural Gas Pipeline Co of America	Trunk	203	322	43	5,208	5,957
El Paso Natural Gas Co.	Trunk	54	618	8	4,744	4,075
Northern Natural Gas Co.	Grid/Trunk	135	393	13	3,800	4,290
Koch Gateway Pipeline Co.	Grid/Trunk	937	1,273	18	3,598	3,741
Northwest Pipeline Corp.	Trunk/Grid	39	328	11	3,300	2,907
Texas Gas Transmission Corp.	Trunk	197	377	49	2,950	3,621
Panhandle Eastern Pipeline Co.	Trunk	7	117	7	2,917	2,744
Noram Gas Transmission Co.	Trunk/Grid	736	754	33	2,811	2,335
Great Lakes Gas Transmission Co.	Trunk	126	206	16	2,712	3,767
PG&E Gas Transmission Co. - Northwest	Trunk	1	190	3	2,619	2,756
Transwestern Gas Pipeline Co.	Trunk	80	40	10	2,615	1,292
Southern Natural Gas Co. (SONAT)	Grid/Trunk	259	341	17	2,411	2,848
National Fuel Gas Supply Corp.	Grid/Trunk	27	98	34	2,222	2,159
Columbia Gulf Transmission Co.	Trunk	89	15	14	2,063	2,845
Colorado Interstate Gas Co	Grid/Trunk	99	131	24	2,000	2,162
Northern Border Pipeline Co.	Trunk	3	14	5	1,760	1,791
Trunkline Gas Co.	Trunk	227	107	25	1,987	1,896
Williams Natural Gas Co.	Grid/Trunk	298	897	31	1,820	--
Mississippi River Gas Transmission Co.	Trunk	23	66	17	1,724	1,703
Algonquin Gas Transmission Co.	Trunk/Grid	1	97	9	1,645	1,513
Florida Gas Transmission Co.	Trunk	62	209	19	1,497	1,611
Questar Pipeline Co.	Grid/Trunk	136	15	13	1,380	1,167
Sabine Gas Pipeline Co.	Trunk	10	15	11	1,304	1,211
Equitrans Inc.	Grid	2	132	10	843	737
Iroquois Gas Pipeline Co.	Trunk	11	10	4	826	1,017
Midwestern Gas Transmission Co.	Trunk	4	21	7	785	935
Kern River Gas Transmission Co.	Trunk	5	39	3	714	848
East Tennessee Natural Gas Co.	Grid/Trunk	0	147	6	634	726
KN Interstate Gas Co.	Grid/Trunk	67	388	19	575	508
Wyoming Interstate Gas Co.	Trunk	0	0	4	500	579
Viking Gas Transmission Co.	Trunk	1	42	4	490	517
Williston Basin Interstate Pipeline Co.	Grid/Trunk	62	271	4	458	490
Trailblazer Pipeline Co.	Trunk	1	3	4	422	588
Mojave Pipeline Co.	Trunk	0	17	2	407	577
				Total	**103,502**	

[1]"Trunk" systems are long-distance trunklines that generally tie supply areas to market areas. "Grid" systems are usually a network of many interconnection and delivery points that operate in and serve major market areas. Some systems are a combination of the two. Where two are shown, the first represents the predominant system design.

[2]Pipelines with zero receipt and/or delivery points transfer volume via interconnections with other interstate pipelines.

[3]Represents a receipt, delivery, or emergency interconnect with one or more of the other pipeline companies listed in this table.

[4]Some pipeline companies reported their system levels in decaterms per day (Dth/d) rather than in million cubic feet per day (MMcf/d). In those instances, a factor of 1.027 was used for the conversion.

[5]Total volume reported as delivered off the entire pipeline system on its peak-day during the heating year extending from April 1, 1996, through March 31, 1997. All volumes reported in Dth/d and converted to MMcf/d using a 1.027 conversion factor.

MMcf/d = Million cubic feet per day.

Source: Federal Energy Regulatory Commission (FERC). **Receipt/Delivery/Interconnects:** FERC 567 Capacity Report, "System Flow Diagram." **Systemwide Peak-Day Capacity:** FERC Annual Capacity Report (18 CFR §284.12). **Peak-Day Flow:** FERC Form 2, "Annual Report of Major Natural Gas Companies."

stations can be viewed as choke points along a system because they are designed to move a limited amount of gas through their location over a period of time. Capacity measures for individual pipelines at a hub are dependent upon the capabilities of the hub itself and operational aspects of other pipelines using the hub during a peak period.

This report primarily uses the "specific point" measure of deliverability, based on an estimated design throughput capability of a pipeline as it crosses State borders. This design capacity estimates the flow that could be obtained along a pipeline segment on a sustained basis under a specific set of conditions and thus provides a measure of comparability across all pipeline systems.

It should be emphasized that the capacity numbers derived for this report are merely "reasonable" estimates based upon design or contractual conditions. Actual capacity at a particular point or system wide is rarely one stable figure. Weather conditions, ambient temperature, elevation, and operational variables, such as short-term line packing[5] and line pressure shifts, can affect stated capacity levels. In some cases, line packing can increase operational capacity by as much as 20 to 30 percent. Some of this increase is reflected in the differences between system capacity and peak-day flows shown in Table 1. In a number of cases, the peak-day flow is well above the reported overall system capacity.

The pipeline capacity estimates in this report are based primarily upon compressor station data in the Federal Energy Regulatory Commission Format 567, "System Flow Diagrams," filed annually by the major interstate pipeline companies. (See Appendix C for a detailed discussion of how capacity levels were derived and refined.) Systemwide capacity levels, when used, are based upon data reported to FERC by the major interstate pipeline companies in their annual capacity reports that accompany Format 567 (18 CFR §284.12) or constructed from pipeline delivery data reported on FERC Form 11, "Natural Gas Pipeline Company Monthly Statement."[6]

Shipper Requirements

Ultimately, the shippers' requirements determine the design capacity of pipeline system facilities. Pipeline companies seek to obtain a mix of shippers and contract types in order to maximize system throughput. Firm service requirements may be expressed as a reservation on system capacity for the receipt and delivery of a maximum daily quantity of gas at specific points along the network. Under firm transportation contracts, the pipeline company agrees to reserve capacity on its system to provide a shipper, such as a local distribution company (LDC), industrial user, or electric utility, with up to a specified quantity on any given day. Pipeline companies must stand ready to provide service up to the volume level specified under firm contracts even though their shippers may not need or actually request transport of that gas. (However, in certain instances, pipeline companies have the authority to impose restrictions on the level of service they are obligated to provide (see Box, "Operational Flow Orders")).

LDCs are still the principal providers of supply to the ultimate end user, accounting for about 42 percent of the natural gas sold to end users in 1996 (down from 46 percent in 1993) and 25 percent of the gas transported on their behalf (up from 20 percent in 1993). They typically contract with pipeline companies for firm transportation and storage services to meet the requirements of their high-priority customers and for interruptible service to meet the needs of their lower priority customers. However, in some States where open-access transportation and deregulation are being tested, LDCs are slowly becoming merely deliverers for other sellers. In 1996, nonsales deliveries represented 37 percent (4.9 trillion cubic feet) of total LDC deliveries, up from 30 percent in 1993.

Consumers are generally classified into four categories: (1) residential, (2) commercial, (3) industrial, and (4) electric utility. Residential and commercial gas consumers usually have no other alternative for fuel except through the LDCs and thus are considered high-priority users. In contrast, many industrial users and electric utilities do not require firm service because they often have the capability to switch to other fuels. Some electric utility and industrial consumers contract for service on an interruptible basis. Under interruptible contracts, deliveries are subject to curtailments by the pipeline company or local distribution company when necessary to meet the requirements for service under firm contracts. Rates for interruptible service are generally less expensive than for firm service. Service to interruptible shippers is extremely important to the pipeline companies in their efforts to maintain a high level of throughput.

The demand for natural gas is quite diverse regionally. For example, in the northern regions of the country where a high proportion of residential and commercial consumers use natural gas for heating, deliveries under firm service contracts are highly seasonal because of the extreme weather variation. Other more temperate regions, such as the Southwest, may be very dependent on natural gas used in the generation of electricity to meet summer cooling loads. The use of natural gas for industrial purposes also varies substantially from

[5]Line packing is temporary storage of pipeline gas through the use of increased compression.

[6]The FERC Form 11 data used are only through 1995. The form was revised in 1996 and now is filed only on a quarterly basis.

Operational Flow Orders

When FERC Order 636 was instituted in 1993 and open access became the norm, the Federal Energy Regulatory Commission recognized that pipeline operators needed a mechanism in place that would still allow them to maintain the operational integrity of their system during periods of potential flux and when the system is under stress. Conditions such as extreme weather, unscheduled downtime on critical parts of the system, and extreme imbalance situations are some of the reasons pipeline companies cite as the need for such short-term control.

Operational flow orders (OFOs) (also called system emergency orders or critical period measures) are the mechanisms put in place to permit this control. In effect, these orders permit the pipeline operator during emergency situations to restrain shipper activities and to curtail services that could result in imbalances and service interruptions. For instance, OFOs allow the operator to reduce or eliminate flow tolerances and require shippers to maintain a strict daily balance between receipt and delivery volumes. The OFO also may restrict or eliminate such services as intraday nominations, the use of secondary receipt and delivery points, firm storage withdrawals, and interruptible storage services. As an enforcement measure, pipeline companies can exact penalties for violations (pipeline companies do not bear any costs incurred as a result of service restrictions and they get to keep any penalty revenues).

Despite their utility, OFOs are controversial. The direct consequence of measures taken under OFOs is to lessen short-term trading and shipping flexibility on the part of customers. Some maintain that pipeline operators are given too much discretion regarding what constitutes an OFO situation and that operators have incentives for maintaining the OFO for longer than is needed. Critics also argue that the fact that the pipeline company can retain any penalty revenues and place restrictions on nonfirm services and secondary receipt/delivery points is a disincentive to shippers who want these lower-cost services but are unwilling to risk possible interruption of their operational flows during peak periods.

While operating contingencies must be addressed and some form of pipeline system control during stress periods and emergencies will continue to be required, the criteria for OFO implementation may be changed as more experience is gained with emergency situations under open-access conditions. For instance, it has been suggested that the restrictions be imposed in a ratcheted manner, implementing more severe restrictions only if the lesser ones fail to alleviate the situation. Among the other possibilities: limit restrictions only to those parts of the system that are under stress; give shippers more advance notice before issuing the OFO; remove any financial incentives to pipeline companies under the OFO; and clearly define within the pipeline company's tariff the conditions for imposing an OFO and what operational conditions constitute an end to an OFO.

region to region. Some applications use natural gas for feedstocks and require a secure, dedicated supply of natural gas. Other uses are for boiler fuel where the user typically has the capability to burn other fuels in the event that natural gas is not available or is less economic than the alternatives.

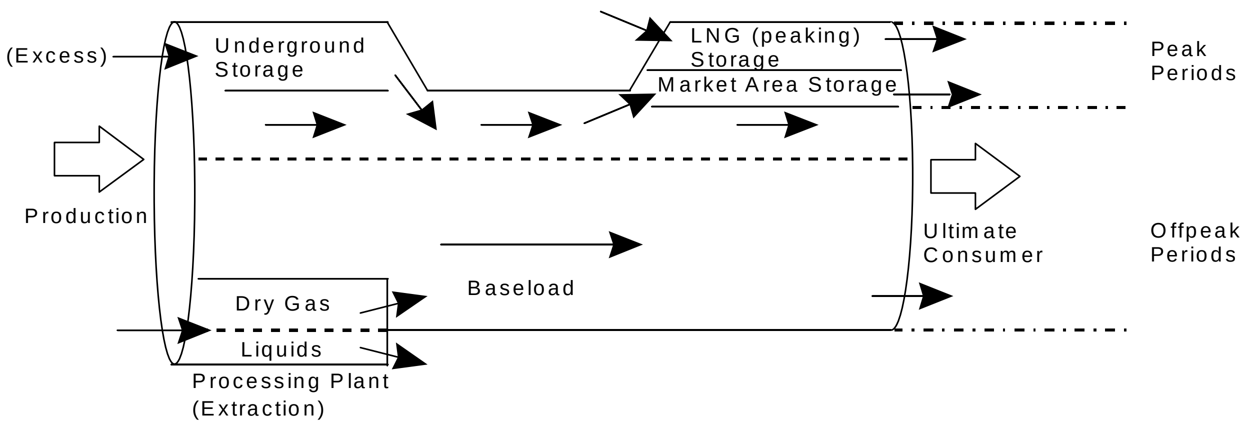
Transmission System Design

The principal requirement of the natural gas transmission system is that it be capable of meeting the peak-day demand of its shippers who have contracts for firm service. To meet this requirement, the principal facilities developed by the natural gas industry are a combination of transmission lines to bring the gas to the market areas and of underground storage and liquefied natural gas (LNG) facilities closer to the market areas to meet surges in demand (Figure 1).

The design of the transmission lines and integrated storage sites represents a balance of the most efficient and economical mix of delivery techniques given the operational requirements facing pipeline companies. The mix varies widely depending on the number and types of shippers and access to supplies, either from production areas or underground storage. Many pipeline systems are configured principally for the long-distance transmission of supplies from production regions to market areas and are characterized as "trunklines" (Table 1). At the other extreme are the "grid" systems, which generally operate in and serve major market areas. Many of the grid systems can be categorized as regional distribution systems. For the most part, they receive their supplies from major trunklines or directly from local production areas and transport gas to local distribution companies and other consumers in more than one State.

Underground storage is an essential component of an efficient and reliable interstate natural gas transmission and

Figure 1. Generalized Schematic of Natural Gas Pipeline Transmission



Note: Areas shown are not proportional to actual operational volumes or capacity.
Source: Energy Information Administration, Office of Oil and Gas.

distribution network. The size of the transmission line often depends in large part on the availability of storage. Rather than size a line to meet peak-day volumes, the line need satisfy only the difference between total shipper peak requirements and maximum withdrawal from storage as it enters the market area. In off-peak periods, the line must be able to provide shippers' off-peak needs plus injection to storage. In addition, some storage sites may require that system flow be reversible and that the main transmission line in the vicinity be able to accommodate this capability. The resulting pipeline configuration, including storage, may result in a comparatively low usage level in the off-peak season and a much higher, albeit shorter term, usage level during the peak-demand season.

During the nonheating season, for instance, when shippers do not use all the capacity contracted for, natural gas can be transported and injected into storage at a fairly constant rate. By the beginning of the heating season (November 1), inventory levels are generally at their annual peak. Working gas, that is, the portion of natural gas in storage sites ordinarily available for withdrawal and delivery to markets,[7] is then withdrawn during periods of peak demand.

In addition, the pipeline company itself can avoid the need to expand transmission capacity from production areas by using existing, or establishing new, storage facilities in market areas where there is a strong seasonal variation to demand and where the system may be subjected to some operational imbalances.

The daily deliverability from storage can also be factored into the design needs of a new pipeline or the expansion needs of an existing one. Some underground storage facilities are located in production areas at the terminus of the pipeline corridor and, in contrast to storage near local markets, can be used to store gas that may not be economically marketable at the time of production.[8] These sites can be used by shippers to store short-term excess supplies that exceed their reserve capacity on the pipeline system and the reverse when supplies fall below reserved capacity. Thus, the pipeline is relieved of additional demands for capacity brought on by temporary swings in transportation demands.

Often new systems are initially designed to handle volumes beyond the minimum requirement. A number of factors are involved in calculating how much gas a pipeline can carry, the most important being the diameter of the pipe and the pressure pushing the gas along the pipe.[9] Because of flow dynamics, doubling the diameter of the pipe will increase the

[7]In addition to working (top storage) gas, underground storage reservoirs also contain base (cushion) gas and, in the case of depleted oil and/or gas field reservoirs, native gas. Native gas is gas that remains after economic production ceases and before conversion to use as a storage site. Native gas and base gas typically are not withdrawn from the storage facility, as these volumes are necessary to ensure sufficient pressure for the withdrawal of the working gas.

[8]For instance, natural gas produced in association with oil production is a function of oil market decisions, which may not coincide with natural gas demand or available pipeline capacity to transport the gas to end-use markets. Another example is the storage of gas from low-pressure wells, where the gas can be injected during the off-peak season and delivered, at high pressure, to the mainline during the peak season.

[9]Standard design codes require that all pipelines passing though populated areas have their maximum operating pressures reduced for safety reasons. It became common practice to maintain nominal diameter but increase wall thickness where a line had to be derated for its surroundings in order to keep the working pressure rating more constant along the line.

capacity more than sixfold at approximately twice the cost. Increasing the pipe wall thickness or strength of the pipe will enable the pipe to withstand a greater pressure. The pressure pushing the gas is usually provided by mechanical compression.

The design process itself includes the development of cost estimates for various possible combinations of pipe size, compression equipment, and interstation distances to find the combination that minimizes transportation cost given the desired flexibility and expandability goals. New trunklines are typically built with larger diameter pipe than needed initially, but only with the currently required compression capacity. Compression can then be added, either in existing or new, intermediate stations, to increase capacity as growth in load occurs.

Pipeline Utilization

Pipeline companies prefer to operate as close to capacity as possible, thus maximizing revenue; however, the *average* annual utilization rate usually does not reach 100 percent even in cases of full utilization. Several factors contribute to these lower rates, including the outages resulting from pipeline maintenance. During the summer months, when pipeline capacity demands are lowest, most pipeline companies schedule needed maintenance. As a result, some pipeline segments or compressor facilities may be placed out of service and transportation service suspended temporarily, for a day, a week, or even as long as a month.

Thus, average utilization rates below 100 percent do not necessarily imply that additional capacity is available. A pipeline company that serves primarily a seasonal market may have a relatively low average utilization rate even if there is no unreserved capacity on its system. Yet because of the difficulty in balancing unused commitments for firm service with interruptible service and transportation for others, it may be unable to provide further interruptible service to complement the high level of deliveries required during the peak consumption periods.

Integration of storage capacity into the pipeline network design can increase average-day utilization rates. Storage used for seasonal demand-swings effectively moves demand from one season of the year to another. Trunklines, which are generally upstream of the market storage areas, can be designed for a more constant load than the pipelines on the downstream side of the storage fields. Storage is usually integrated into or available to the system at the production and/or the market end as a means of balancing flow levels throughout the year. Therefore, trunklines serving markets with significant storage capacity have a much greater potential for obtaining a high utilization rate because the load moving on these pipelines can be levelized. Furthermore, to the extent these pipelines serve multiple markets, they can also achieve higher utilization rates because of load diversity across the markets they serve.

In fact, some trunkline systems, especially those reaching high-demand markets, often exhibit peak daily utilization rates greater than 100 percent. For example, the Iroquois Pipeline system, which transports Canadian gas to the U.S. Northeast, showed a peak-period usage rate above 100 percent in 1996, as did the Trailblazer Pipeline system out of the Rocky Mountains area. Several factors contribute to this situation.[10] First, some trunkline systems are capable of handling much larger volumes than indicated by the operational design level certificated by FERC, which is the level that is used as the denominator when calculating usage rates (based on an annual throughput volume divided by 365 days). Second, as the line can handle more than the certificated capacity and shipper demand is high, maximum usage is made of the pipeline by its owners. In many instances of high demand, pipeline companies also use line packing and/or secondary compression to increase throughput, which was a tactic used by both Iroquois and Trailblazer this past year. When average daily utilization rates exceed stated capacity, it is more appropriate to use the peak-day volume as the actual capacity, or capability, of the system.

Utilization on the grid systems operating closer to the market areas and downstream of the storage fields is more likely to reflect the seasonal load profile of the market being served than utilization on upstream trunklines. The grid-type systems usually operate at lower average utilization levels than the trunklines, although during peak periods, usage levels are generally also at much higher rates. Grid systems usually show a marked variation between high and low flow levels, reflecting their seasonal service and local market characteristics. Storage services are usually highly integrated into the grid network to meet varying local market demands. Because grid systems have numerous interconnections within the network, their overall usage levels depend upon what happens in the various parts of the system. Pipeline segments that show a high degree of utilization are either serving a

[10]It should also be noted that in some instances the sum of individual transportation transactions may exceed pipeline capacity even though physically the pipeline may be full. For example, suppose a segment from points A to D (with points B and C between A and D) has a capacity of 200 million cubic feet (MMcf) per day. Suppose further that this segment handles a 100 MMcf per day transaction from A to B, a second of 100 MMcf per day from B to C, and a third of 100 MMcf per day from C to D. The pipeline company will report transportation volumes of 300 MMcf per day, even though its capacity is 200 MMcf per day but is only 50 percent utilized on any one segment.

shipper (or group of shippers) with relatively constant demand or have a significant interruptible service market.

The primary measure of pipeline utilization used in this analysis is an estimate of average-day natural gas throughput relative to estimates of system capacity at State and regional boundaries. Another measure used is systemwide pipeline flow rates, which highlight variations in monthly system usage relative to an estimated system peak throughput level (see Box, "Pipeline Utilization Measures"). In some instances, where data were available, pipeline peak-day utilization rates are referenced in this report. System peak-day usage rates, although only a reflection of peak system deliveries versus estimated system capacity, come the closest to showing how well the design of the system matches current shipper peak-day needs. For example, when a pipeline shows a comparatively low average usage rate (based on annual or monthly data) yet shows a usage rate approaching 100 percent on its peak day, it indicates that the system is still called upon and is capable of meeting its shipper's maximum daily needs. Nevertheless, a large spread between average usage rates and peak-day usage rates can indicate a need to find better ways to utilize off-peak unused capacity.

Capacity Expansion

Although pipeline systems have some flexibility in handling changes in demand, sometimes system expansion and new pipeline routes are needed. There was substantial interest in expansion of the national pipeline network during the late 1980's and early 1990's and that interest continues today. Two of the largest proposals of the late 1980's to be implemented during the early 1990's were the Iroquois project, built to bring Canadian natural gas into the Northeast, and the Kern River project, which now transports natural gas from supply sources in Wyoming to California. These new lines began service in 1991 and 1992, respectively. A large number of other new systems and expansions are planned or under construction that will bring additional supplies from Canada, as well as from the Rocky Mountains area and the Southwest, to the U.S. Midwest and Northeast regions.

In most cases, interstate pipeline companies are required under Section 7(c) of the Natural Gas Act of 1938 to obtain a certificate of public convenience and necessity before constructing pipeline facilities. Besides review of operational aspects of the system, other legislation requires extensive review of the environmental aspects of the projects.[11] These requirements have resulted in a very time-consuming, complex, and sometimes controversial process.

Once a project is approved and constructed under a Section 7(c) certificate, the costs of the facilities are eligible for inclusion in the pipeline company rate base (when the company files its next general rate case).[12] Other options are also available to pipeline companies for capacity expansion, depending on the size of the project and the amount of risk the company is willing to assume. These options include:

- **Blanket Certificate.** Blanket certification can be used for relatively small projects. A blanket certificate approves a series of similar actions in one authorization. For instance, construction of small additions to a pipeline may be authorized by a blanket certificate, provided the total cost does not exceed some threshold level and other eligibility criteria are met. Similarly, pipeline companies may be allowed to transport gas on a self-implementing basis (without prior FERC approval) for many different shippers on the approval of a single blanket certificate. In recent years, FERC has been using blanket certification more frequently to authorize and facilitate both construction projects and transportation programs.

- **Optional Certificate** (formerly known as Optional Expedited Certificate). In 1985, under Order 436, FERC introduced optional certificates whereby construction could be approved without assessment of its market need or competitive proposals. In return, the pipeline company agrees to bear the majority of the risk of the project. Furthermore, the pipeline company may not decrease the projected volume of services used to design rates nor shift costs to pre-existing shippers. Because of the "at risk" factor, some optional certificate projects tend to be more adversely affected by procedural delays since changes in market conditions that occur in the meantime may necessitate a re-evaluation of the project's feasibility and its potential success.

- **NGPA Section 311.** Section 311 of the Natural Gas Policy Act (NGPA) of 1978 allows an interstate pipeline company to sell or transport gas "on behalf of" any

[11]These laws include: the National Environmental Policy Act, National Historical Preservation Act, Endangered Species Act, Toxic Substances Control Act, Clean Air Act, Clean Water Act, Coastal Zone Management Act, Wild and Scenic Rivers Act, Wilderness Act, and National Parks and Recreation Act.

[12]In some instances, FERC may also issue a Section 7(c) certificate subject to "at risk" conditions. In such cases, the pipeline companies are not guaranteed authority to include costs in the rate base, and risks borne by the companies are not reduced. Under an "at risk" certificate, a pipeline company's risk is minimized only where it has fully contracted the capacity of a new line.

Pipeline Utilization Measures

At State Borders

The State-to-State measure of pipeline utilization used in this analysis is based on estimates of average-day pipeline throughput relative to estimates of system capacity at State boundaries. Average-day throughputs were computed by dividing annual State-to-State flows in 1990 (reported by pipeline companies) by 365 days and those in 1996 by 366 days. Average-day utilization for the 2 years were then derived by dividing the average-day flow by the estimated capacity level. This measure provided the basis for the analysis pertaining to usage of specific portions of a pipeline system and additionally some insight into the type of service provided in the area.

But, because it uses averaged annual throughput volumes, the measure implies nothing about the availability of capacity during peak periods, except to the extent that the average daily utilization approaches, or exceeds, 100 percent. (Service levels on a pipeline system often vary from month to month, day to day, and even hourly.) As the computed utilization rate approaches 100 percent, it indicates only that the volume of gas moving through a specific geographic area on an average day during the year approximated estimated capacity. When this does occur, however, it is likely that the specific system location experiences some constraints during peak periods. A system that fully utilizes available capacity for short periods and not on a sustained basis throughout the year will show a lower utilization rate based on a daily averaging of annual throughput.

Systemwide

In order to evaluate operational and utilization levels of the various pipeline systems during the year, several flow-rate derivations were computed. These rates are based on a comparison of 1995 monthly throughput (the latest available monthly data) on the entire pipeline system with the largest throughput (sales, transportation, and intercompany transfers) that occurred in any month over a 15-year period (1980-1995). They were developed to show the degree of difference that occurs on different types of systems over the year as seasons and demand change. In these computations, the highest monthly throughput during the 15-year period is used as the proxy for the systemwide capacity of the pipeline. (This method has its limitations, including the fact that accounting of throughput can vary by pipeline company, leading to the reporting of excess throughput levels.) For 1995, (1) average-month throughput, (2) high-month throughput, and (3) low-month throughput were each divided by the 15-year high-month throughput to derive three flow-rate percentages. In addition, a summer (nonheating season) usage level, using the sum of volumes delivered during the nonshoulder months of May through September divided by 153 days, was also computed. (April and October are considered to be months that “shoulder” the heating season of November through March.)

Another systemwide usage rate was also computed based upon an annual system (deliverability) capacity level reported to the Federal Energy Regulatory Commission (FERC) by the major pipeline companies and the system’s yearly peak 1-day volume. This figure provided a snapshot of the system’s maximum use level containing a minimum skew caused by downtime and other factors.

An analysis of the peak-day, high month, low month, average monthly, and average summer (off-peak) throughput rates provides some understanding of the load variability on a pipeline system throughout the year. For instance, systems with a high-month rate of 100 percent in 1995 had a record monthly throughput level in 1995. If these same systems also exhibited high average utilization rates at State border crossings, they may be constrained in their abilities to serve additional shippers without capacity expansion. In contrast, systems having a relatively low peak-month throughput but high average utilization levels at specific points along the network probably are experiencing more localized capacity constraints.

Comparison of the systemwide average-month flow rates with utilization rates at State border crossings can provide insight into how representative the individual utilization rates are of the whole system. For example, if utilization rates are very high at State border crossings but the systemwide average-month rate is significantly lower, then there are likely to be elements of the system, probably wholly contained within a region or State, where utilization is low. Conversely, if utilization rates at State borders are very low but the systemwide average-month rate is significantly higher, then there are likely to be elements of the system where utilization is quite high. These areas are likely to be near supply regions where interstate pipelines interconnect and transfer large volumes of gas from one system to another.

intrastate pipeline or local distribution company. FERC has exempted the construction of facilities used solely for Section 311 transportation from certificate requirements. Construction is subject to environmental conditions and a 30-day notice to FERC, which requires only information on the delivery point of gas from the interstate pipeline, the total and daily volumes expected to be delivered, and the rate to be charged for transportation or sale.

Planned expansions of the current pipeline system are proposed under each of these options and are detailed in Appendix B. The traditional Section 7(c) application is still the most widely used.

As of March 1998, the Energy Information Administration was tracking more than 100 proposed pipeline expansions and new pipeline projects at various stages of development in the United States, Canada, and Mexico. If all U.S. projects were completed, the amount of new capacity would add more than 29 billion cubic feet of daily deliverability on the national network. The most extensive development is focused on expanding the deliverability of Canadian gas to the U.S. Midwest and Northeast and to Canadian markets. The second-largest focus is on improving access to the increasing deep-water production in the Gulf of Mexico. Next are those projects whose objective it is to increase the flow of lower-cost supplies located in the Central United States to markets located primarily in the Midwest. Currently, the capability to do so is limited. The latter series of expansions will be competing, to some degree, with the projects slated to increase flows of Western Canadian gas to the Midwest marketplace. The potential impact of proposed capacity expansions is discussed in subsequent chapters.