Appendix A

Overview of Pipeline Design and Operational Factors

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The principal requirement of the natural gas transmission system is to be capable of meeting the peak-day demand of its customers 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 reservoirs closer to the market areas to meet surges in demand.

Transmission System Design

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

Underground storage is essential for efficient and reliable interstate natural gas transmission. A pipeline company avoids the need to expand transmission capacity from production areas by contracting for or establishing storage facilities. In market areas where there is a strong seasonal variation to demand, they are used as an alternative supply source, and also for load balancing and to provide other services to customers. During the nonheating season, when customers do not use the full capacity of the trunkline system, natural gas is transported and injected into storage. By the beginning of the heating season (late October to early November), storage 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the portion of natural gas in storage sites ordinarily available for withdrawal and delivery to markets,[89] is then withdrawn during periods of peak demand. Underground storage facilities are also located in production areas. These sites are also used to store gas that may not be economically marketable at the time of production.[90]

The great majority of storage is used in the classic mode of injection in summer and withdrawal in winter. However, new storage sites and an increasing number of older sites are used increasingly for off-season and short-term needs.

The size of the transmission line depends in large part on the availability of storage. Rather than size a line to meet peak-day requirements, the line need only satisfy the difference between peak needs and maximum withdrawal from storage as it enters the market area. In off-peak periods, the line must be able to provide 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.

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.[91] Because of flow dynamics, doubling the diameter of the pipe will increase the 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.

[89]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. Upon development of a storage site, and in order to develop and maintain adequate storage reservoir pressure to meet required deliverability rates for withdrawal operations, additional gas is injected, and combined with the native gas, if any.

[90]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.

[91]Standard design codes require that all pipelines passing through 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.

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.

Customer Requirements

It is ultimately the customer requirements that determine the design capacity of pipeline system facilities. Pipeline companies seek to obtain a mix of customers and contract types in order to maximize system throughput. Firm customer requirements, generally written into long-term transportation agreements, 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. The pipeline company agrees to reserve capacity to provide a customer, such as a local distribution company (LDC), industrial user, or electric utility, with a firm quantity on any given day. Pipeline companies must stand ready to provide up to the contracted-for capacity under firm contracts even though their customers may not actually transport or request transport of that gas.

LDC's are the principal providers of supply to end users. They typically contract with pipeline companies for a variety of services, including transportation, and storage. They contract for firm service to meet the requirements of their high- priority customers and for interruptible service to meet the needs of their lower priority customers.

Some electric utility and industrial customers 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 delivery under firm contracts. Rates for interruptible service are generally less expensive than for firm service. Transportation for interruptible customers is extremely important to the pipeline companies in their efforts to maintain a high pipeline 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 customers 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 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.

Pipeline Utilization

Pipeline companies prefer to operate as close to capacity as possible, thus maximizing revenue; however, the average utilization usually does not reach 100 percent. Average utilization rates below 100 percent may not indicate that any unused capacity is available in practice. A pipeline company with a highly seasonal load 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 and interruptible transportation, it may be unable to provide further interruptible service to comple-ment 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.

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 average utilization levels well below that of the trunklines, although during peak periods, usage levels are generally also at much higher rates. 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 customer (or group of customers) with a very flat load profile, or have a significant interruptible market.

Grid systems usually show a marked variation between high- and low-flow levels, which reflects their seasonal and local market characteristics. In contrast, trunklines show less of a spread between the two as load tends to be fairly constant because of the load management designed into the system.

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 system-wide pipeline flow rates, which highlight variations in monthly system usage relative to an estimated system peak throughput level (see below, "Synopsis of Utilization Measures"). Although useful, peak-day utilization rates are not used in this report because of the limited availability of peak-day consumption data, that is, coincidental and noncoincidental peak-day flows.[92] Furthermore, these data do not necessarily measure the ultimate potential of any pipeline system, because it may be physically possible to increase flow beyond the observed levels. Also, the sum of noncoincidental peak-day flows may be greater than the total actual capacity of the system if peak demand in one location can only be supplied if lesser volumes are being delivered elsewhere. Thus, while important, this report does not address this aspect of system utilization.

Capacity Expansion

Although pipeline systems have some flexibility to handle changes in demand, sometimes system expansion and new pipeline routes are needed. There was substantial interest in expansion of the pipeline system during the late 1980's. One of the largest proposals was the Iroquois project built to bring Canadian natural gas into the Northeast through the new Iroquois pipeline. This new line began service in December 1991. Other new systems 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 west coast.

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.[93] 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) and the risks associated with recovery of those costs are minimized.[94] Other options are also available to pipeline companies for capacity expansion, depending on the size of the projec 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. 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 customers.

- **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 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.

[92]A coincidental peak flow is the flow on the day during a specified period (usually a year) when the entire pipeline system has its maximum throughput. (Thus the day for this measure coincides for all customers.) Noncoincidental peak-day flows are the maximum volumes received by each customer on any day during a specified period. They are called noncoincidental because the days on which customers in a pipeline system experience their peak flow may not coincide.

[93]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.

[94]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.

Synopsis of Utilization Measures

Pipeline Utilization 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. The average-day throughput was computed by dividing annual State-to-State flows in 1990 and 1994 (reported by pipeline companies) by 365 days. Average-day utilization was 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 transportation 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 the average daily utilization approaches 100 percent. (Transportation 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 is close to 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.

System-Wide Utilization

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 1990 and 1994 monthly throughput on the entire pipeline system with the largest throughput (sales, transportation, and intercompany transfers) that occurred in any month over a 16-year period (1979-1994). 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 16-year period was used as the proxy for the system-wide capacity of the pipeline. (Using this baseline ignores changes in ownership of components of the various pipeline systems and construction that may have occurred throughout the period.) For 1990 and 1994, (1) average-month throughput, (2) high-month throughput, and (3) low-month throughput were each divided by the 16-year high-month throughput to derive three flow-rate percentages.

An analysis of the high, low, and average throughput rates provides some understanding of the load variability on a pipeline system during the year. For instance, systems with a high-month rate of 100 percent in 1990 had a record monthly throughput level in 1990. If these same systems also exhibited high average utilization rates at State border crossings, they may be constrained in their abilities to serve additional customers without capacity expansion. In contrast, systems with a relatively low peak-month throughput, but high aver-age utilization levels at specific points along the network, probably experience more localized capacity constraints.

Comparison of the system-wide 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 system-wide 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 system-wide 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.

Appendix B

Regional Profiles: Pipeline Capacity and Service

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Regional Profiles: Pipeline Capacity and Service

The U.S. interstate natural gas pipeline system has grown substantially since World War II, maturing from a dedicated field-to-market structure into a national network. Of the lower 48 States, 27 are totally dependent upon the interstate natural gas transmission network for their natural gas supplies, which must be transported from only 11 States, located primarily in the Southwest and Central regions of the country. The requirement for natural gas pipeline service varies throughout the country. Each region possesses its own natural gas service profile based on factors involving weather, historical access to gas supplies, and population characteristics.

This appendix presents a brief profile of each of the geographic regions used in Chapter 3 of this report. The emphasis is upon the capabilities, that is, the capacity of each, of the interstate natural gas pipelines entering or exiting each region. It also provides some regional highlights concerning the growth in capacity of the interstate pipeline systems into or from each region and also at the level of planned additions to capacity over the next several years. Data on capacity, pipeline flows, pipeline utilization, and production and consumption are for the years 1990 and 1994. Data on proposed additions to capacity cover the period 1995 through 1998.

Producing Regions

Southwest Region

The Southwest Region is unique not only because of its long-held position as the major natural gas producing and consuming region, but also because it supplies the bulk of the gas consumed by all the other regions. It supplies a vast network of pipelines consisting of major interstate trunklines that deliver gas to each of the other regions of the country, smaller interstate lines that primarily serve the regional market, and intrastate pipelines that deliver gas exclusively within the States of the Southwest. More interstate natural gas pipeline companies operate within the Southwest Region than in any other, but it is the primary market for only a few of them.

Twenty of the major interstate pipelines originate in the Southwest (Figure B1). They extend to the Southeast Region through Louisiana and Arkansas, to the Central Region through Oklahoma and Arkansas, and to the Western Region through New Mexico. The Southwest Region currently exports about 60 percent (8.7 trillion cubic feet in 1994) of its production, which is 61 percent of the total natural gas consumed in the entire country.[95] Pipelines exiting the region have the capacity to accommodate as much as 35.7 billion cubic feet per day: 60 percent to the Southeast Region, 24 percent to the Central Region, 15 percent to the Western Region, and the rest to Mexico (Table B1). Much of the pipeline capacity to the Southeast traverses the region, delivering supply to the Midwest and Northeast; to a lesser degree this is also true for the pipeline capacity exiting to the Central Region, much of which is ultimately destined for the Midwest Region.

Between 1990 and 1994, regional export capacity increased by only 8 percent, but in incremental daily flow capacity that came to 2.7 billion cubic feet per day. While capacity additions into the Southeast Region represented only a 5-percent change from 1990, there was a 1.0 billion cubic foot per day increase in volume. While the volumetric increase was not comparable to the increase in capacity from Canada to the Northeast and Western regions, it still represented a substantial increase in capability to supply the Southeast Region. Export capacity to the Central Region showed a decrease during the period, but this was mainly due to a reversal of flows as more supplies began to emerge from the coalbed methane and tight gas fields of southern and central Colorado.

In recent years, partly because of improved recovery techniques and tax credit incentives, substantial development of coalbed methane resources has occurred in northern New Mexico and in the adjacent Central Region in southern Colorado. This has brought on additions to capacity along the interstate pipeline systems serving the San Juan Basin and nearby production areas.

[95] For purposes of this appendix, exports pertain to all volumes leaving a region for another region or country.

Table B1. Interregional Pipeline Capacity, Average Daily Flows, and Usage Rates, 1990 and 1994

Receiving Region	Sending Region	Capacity (MMcf per day)			Average Flow (MMcf per day)			Usage Rate (percent)		
		1994	1990	Percent Change	1994	1990	Percent Change	1994	1990	Change
Canada	Central	66	66	0	9	44	-80	14	67	-53
	Midwest	2,093	1,211	73	1,443	961	50	69	79	-10
Total into Region		2,159	1,277	69	1,452	1,005	44	67	79	-12
Mexico	Southwest	844	354	138	117	38	208	14	11	3
	Western	45	45	0	7	5	40	16	11	5
Total into Region		889	399	123	124	43	188	14	11	3
Central	Canada	1,544	1,254	23	1,469	941	56	95	75	20
	Midwest	2,333	1,765	32	1,489	974	53	[a]90	[a]75	15
	Southwest	8,483	8,716	-3	4,722	4,119	15	56	[a]49	9
	Western	298	250	19	0	196	-100	0	78	NA
Total into Region		12,658	11,985	6	7,680	6,230	23	[a]67	[a]56	11
Midwest	Canada	2,780	2,161	29	2,487	1,733	44	89	[a]84	5
	Central	9,722	8,988	8	6,986	5,684	23	72	63	9
	Northeast	2,037	2,024	1	887	714	24	[a]56	[a]45	11
	Southeast	9,815	9,645	2	6,712	6,134	9	68	64	4
Total into Region		24,354	22,818	7	17,072	14,265	20	[a]71	[a]64	7
Northeast	Canada	2,135	467	357	1,656	309	436	78	66	12
	Midwest	4,803	4,572	5	3,185	3,464	-8	66	76	-10
	Southeast	4,783	4,782	0	3,705	4,086	-9	77	85	-8
Total into Region		11,721	9,821	19	8,546	7,859	9	73	80	-7
Southeast	Northeast	535	113	373	86	69	25	[a]75	[a]69	6
	Southwest	21,051	20,006	5	14,374	14,703	-2	68	73	-5
Total into Region		21,586	20,119	7	14,460	14,772	-2	[a]68	73	-5
Southwest	Central	1,745	1,283	36	1,122	572	96	[a]79	[a]58	21
	Mexico	350	350	0	19	0	NA	5	0	NA
	Southeast	335	335	0	15	15	0	[a]60	[a]60	0
Total into Region		2,430	1,968	23	1,156	587	97	[a]64	[a]69	-5
Western	Canada	3,546	2,406	47	2,866	1,871	53	81	78	3
	Central	1,164	365	219	917	196	368	79	54	25
	Southwest	5,351	4,340	23	3,383	3,910	-13	63	90	-27
Total into Region		10,061	7,111	41	7,166	5,977	20	71	84	-13
Total Lower 48 States		**85,858**	**75,498**	**14**	**57,656**	**50,738**	**14**	**[a]69**	**[a]70**	**-1**

[a]Usage Rate shown may not equal the average daily flows divided by capacity because in some cases no throughput volumes were reported for known border crossings. This capacity was not included in the computation of usage rate.

MMcf = Million cubic feet. NA = Not applicable.

Sources: Energy Information Administration (EIA). **Pipeline Capacity:** EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database as of August 1995. **Average Flow:** "Natural Gas Annual 1994," draft report. **Usage Rate:** Office of Oil and Gas, derived from Pipeline Capacity and Average Flow.

Even though large volumes of natural gas leave the Southwest Region for other regional markets, significant volumes remain in the region to fulfill the high level of industrial demand encouraged over the years by proximity to production. In many respects, the States in the Southwest Region represent complete markets for natural gas, independent of other regions, and much of the movement of gas is completed by means of intrastate rather than interstate pipeline systems. The region has large petrochemical and electric utility industries drawn there by the local availability of substantial natural gas supplies.

In addition, the region has numerous underground storage reservoirs, most of which are used to store excess natural gas production during months of low consumption (Figure B1). Total storage capacity (over 1.6 trillion cubic feet) is the second highest of the regions. The region has temperate winters and long, hot summers. Louisiana and Texas are the second and third warmest States in the lower 48 States, which accounts for large electricity load levels for air-conditioning services.

Several of the major pipeline projects planned for development between 1991 and 1994, which were, in large part, to provide greater access to supplies from the Arkoma Basin in Arkansas/Oklahoma to the Northeast and Midwest markets, were not built. Part of the reason may have been planned Canadian import expansions and the already low utilization rates on the existing lines extending to the Midwest Region. In contrast, almost all of the 1991 through 1994 planned expansions into the Western Region were implemented. Capacity from the Southwest to the Western Region increased by 22 percent, to 5.3 billion cubic feet per day, but about 57 percent of the increase represented Central Region supplies traversing the region on their way to the California market.

Expansion projects currently planned for the Southwest Region, totaling 2.2 billion cubic feet per day through 1997 (see Figure 7, Chapter 3), reflect a pattern similar to other regions, that is, an emphasis on localized pipeline improvements and intraregional capabilities. More than 64 percent of the planned capacity additions are within the region. Several, however, do complement the interstate system in that they improve hub and/or underground storage accessibility, or they improve service to interstate pipelines. Only 14 percent of additional capacity is on the interstate system itself. Export expansions to Mexico represent 22 percent of announced expansions.

Central Region

The Central Region is becoming increasingly important as a supply area. It is the only region other than the Southwest to produce more gas than it consumes. Its 1994 natural gas production of about 2.4 trillion cubic feet was about 10 percent of the total gas consumed in the Nation and it provided 3 percent of the natural gas consumed elsewhere in the country. This region had the largest production increase in the Nation between 1990 and 1994—557 billion cubic feet, or 32 percent. Most of the increased production came from newly developed fields in Colorado and Utah, and some expanded development of existing fields in Kansas and Wyoming.

The region's cold winters, combined with the lowest residential prices for natural gas of any region, help make the residential sector the largest consumer of natural gas in this region. The region has the second coldest weather of the six regions (see Table 3, Chapter 3). Plentiful supplies from production and storage sites within the region and adequate capacity on local transmission and distribution lines ensure that peak demands of residential customers are met during the winter.[96]

The region is the largest in area and the least populated. The total volume of gas consumed in the region in 1994, 1.7 billion cubic feet, was also the least of the six regions. Most of this gas is consumed for space heating, as it has the second highest percentage of households using natural gas.

While the Central Region consumes 73 percent of the natural gas it produces, and is the second largest gas producing region, its pipeline export capacity is a substantial 12.7 billion cubic feet per day (Table B1). Export pipeline capacity has increased 18 percent since 1990, primarily because of new pipeline capacity built to deliver the emerging Colorado/Utah supplies, mostly to California. Increased direct service to the Western Region was provided by the completion of the Kern River Pipeline system (700 million cubic feet per day) and indirectly through expansions on the Northwest Pipeline Company, El Paso Natural Gas Company, and Transwestern Gas Pipeline Company lines from the Southwest Region (Figure B2).

[96]Less natural gas is consumed in the Central Region than in any of the other five regions.

The Central Region is also a major transit region for Canadian supplies imported into the United States. The northern section of the region receives large amounts of gas from Canada at Monchy near the Saskatchewan and Montana borders. Monchy is the second largest of the nine entry points for natural gas imports from Canada. There are two main flow patterns for natural gas through the region. One is from Canada across the northern States and into the Midwest. The second is from Oklahoma and Arkansas through the southeast part of the region into Illinois. Intraregional flows are from supply sources in Wyoming and Kansas into Denver, Colorado; from Kansas into Kansas City and St. Louis, Missouri; and from Kansas north through Nebraska to Iowa.

Much of the capacity in the region is designed to traverse the region. The pipeline systems with the largest capacities in the region are Northern Natural Gas Company, Natural Gas Pipeline Company of America, Panhandle Eastern Pipe Line Company, ANR Pipeline Company, and Northern Border Pipeline Company. All of these lines bring gas through the region to either Iowa or Illinois. The flow from the Southwest toward Chicago, Illinois is over the oldest long-distance transmission lines in the Nation. The Natural Gas Pipeline Company of America's line from the Texas Panhandle to Chicago was laid in 1931, traversing Kansas and Iowa, while the Panhandle Eastern Pipe Line Company line from the Texas Panhandle to Illinois, also laid in 1931, traverses Missouri. Most of the major lines in Wyoming, Montana, and Colorado were built before 1932, and the lines that serve Kansas have been in place for 70 years.

The increase in capacity to the Midwest Region that occurred over the past several years came principally from expanded service on the Northern Border Pipeline system. Some minor increases in capacity also occurred on routes serving the Midwest Region out of Kansas. Existing capacity from the latter was capable of handling a 90 percent increase in flows from expanded production in the Hougoton Basin.

Although planned additions to capacity in the region between 1995 and 1997 amount to 3.0 billion cubic feet per day, 97 percent of this is capacity directly or indirectly exiting the region. Principal among the new pipelines planned for the region are the Altamont Pipeline (1996, 719 million cubic feet per day) and the Transcolorado Pipeline (1996, 300 million cubic feet per day). Major expansions include the Kern River Pipeline (452 million cubic feet per day), which is tied into the Altamont project, the Northern Border Pipeline Company (336 million cubic feet per day), Northern Natural Pipeline Company (106 million cubic feet per day) and Natural Gas Pipeline Company of America (900 million cubic feet per day).

Consuming Regions

Western Region

Population in the Western Region has increased rapidly. During the 1980's, Nevada and Arizona were the fastest growing States in the Nation, sustaining population increases of 51 and 35 percent, respectively. These rates are considerably higher than for other States, with only Florida growing faster. In addition, California, already heavily populated, grew by 26 percent during the same period.

Because the Western Region has limited indigenous natural gas reserves, its gas customers rely on the interstate pipeline network to bring supplies relatively long distances from major domestic and Canadian producing regions. Yet, geographic features and environmental regulations limit access to gas supplies. Environmentally sensitive terrain limits the pipeline corridors providing access to supplies in the East. Offshore leasing moratoria impede further development of resources in the Pacific.

About two-thirds of the capacity into the region is on pipeline systems that carry gas from the Rocky Mountains area and the Permian and San Juan Basins. These systems enter the region at the New Mexico-Arizona and Nevada-Utah State lines. The rest arrive on pipeline systems that access Canadian supplies at the British Columbia-Idaho and Washington State border crossings.

Only five interstate pipeline companies provided service into the region in 1994, the fewest serving any region (Figure B3). Capacity entering the region was also the lowest of all gas-importing regions, approximately 10 billion cubic feet per day (Table B1). A fifth interstate system, the Mojave Pipeline, is mainly a provider of transportation services (400 million cubic feet per day) from Arizona into California. It eventually merges with the Kern River Pipeline to serve customers in southern parts of the State.

The electric utility industry is a major user of natural gas. In three of the six Western Region States (Arizona, Nevada, and California), the electric utility industry accounts for 24 percent or more of total natural gas deliveries to consumers. Coincidently, Federal and State environmental regulations are encouraging more natural gas use, particularly in applications where petroleum products and coal dominate the market. In some parts of the region, regulations to limit atmospheric emissions may make natural gas the only fossil fuel that can be used for electric power and steam generation. The region is also the leader in demonstration projects for compressed natural gas vehicles.

During the 1980's combined pipeline and storage capacity was not adequate to meet peak-period demand. In California, capacity-induced curtailments to interruptible customers during peak periods became a regular element of the natural gas market. These curtailments and the significant potential for further market expansion within the region resulted in intense competition for existing pipeline and storage capacity. In response to the situation, and with expectations of greater market growth, several new pipeline systems were built and several existing ones were expanded.

Capacity into the Western Region increased overall by more than 41 percent, or 2.9 billion cubic feet per day between 1991 and 1994. The majority of this increase occurred on routes transporting gas from Canada, where 47 percent more capacity was implemented. Pacific Gas Transmission Company and Northwest Pipeline Company accounted for all of these capacity additions. In spite of a general economic downturn in the region during the period, particularly in California, average capacity usage rates declined only slightly, by 2 percentage points, from 1990.

On a percentage basis, however, the largest growth in capacity, 219 percent, was on routes bringing supplies from States in the Central Region—Wyoming, Utah and Colorado. With the completion of the Kern River Pipeline Company line into California, capacity from the Central Region reached 3.5 billion cubic feet per day. Average usage rates on lines from the Central Region climbed from 54 percent in 1990 to 79 percent in 1994, principally from the almost full utilization of the Kern River Pipeline.

Added capacity from the Southwest Region, which also carries supplies from Colorado's coal-bed methane fields, amounted to over 1.0 billion cubic feet per day. Transwestern Pipeline Company and El Paso Natural Gas Company added the bulk of this new capacity. It, however, faced a soft market. Capacity serving California from the Southwest Region displayed the largest drop in usage within the interregional network. While the enhanced oil recovery (EOR) market supported and maintained high average utilization rates (79 percent) on the pipelines originating in Central Region, capacity utilization from the Southwest Region fell by 27 percent.

The level of pending capacity additions into the Western Region currently stands at only 0.5 billion cubic feet per day (through 1997) compared with 2.9 billion cubic feet per day completed between 1991 and 1994 (Table B1). One project accounts for a large portion of this proposed capacity expansion. The Kern River Pipeline increment based upon the Altamont pipeline project is scheduled to bring in Canadian supplies sometime in 1996. However, the Altamont itself has been postponed several times because of market conditions and delays in getting approval from the FERC.

Within the region itself, additional pipeline capacity is being developed to serve new markets. The Mojave Pipeline extension proposes to provide an additional 0.5 billion cubic feet per day to the north and north central area of the State, bringing supplies up from the south. The Tuscorora Pipeline would bring 0.1 billion cubic feet per day from Oregon (Canadian Gas) to the northeast part of the State in the Lake Tahoe area. And, although current usage rates are down, El Paso Natural Gas has planned several projects that will improve its local deliverability and increase efficiency by improving or altering some current flow patterns.

Northeast Region

The Northeast consumes more energy than any other region, although only 18 percent is in the form of natural gas. It is the most heavily and densely populated of the six regions. Because regional production is quite limited, natural gas customers in the Northeast Region must rely on an extended interstate pipeline system to bring supplies from producing areas outside the region.[97] At one time, the Northeast was a major source of natural gas; in fact, manufactured and natural gas first became commercially available there over 175 years ago. A complex distribution network of pipelines has long been available. Similarly, the region has considerable access to underground storage since gas storage fields were first created and used in the area.

When local supplies were being depleted in the 1920's and 1930's, trunk pipelines were built to bring gas supplies from the Southwest Region to replace gas manufactured for residential use. However, the Northeast was the last region to be linked to the interstate pipeline network, with some areas only getting service as recently as 1966. Today the interstate pipeline companies serving the region have access to supplies from all major domestic gas-producing areas and Canada (Figure B4). In addition, liquefied natural gas is imported into Massachusetts from Algeria.

Transportation capacity into the northeastern market increased by more than 19 percent, or 1.9 billion cubic feet per day between 1990 and 1994 (Table B1). This made it the second most active regional natural gas market during the period. The vast majority of this new capacity provided greater access to Canadian supplies. Principal projects completed between 1991 and 1994 included the intrastate Empire Pipeline (affiliated with ANR Pipeline Company—0.5 billion cubic feet per day), the Iroquois Pipeline (0.6 billion cubic feet per

[97]Regional production of natural gas, the equivalent of 14 percent of area consumption in 1990, fell to 10 percent in 1994.

day), and Tennessee Gas Pipeline Company's expansion of its Niagara import facilities (by 0.4 billion cubic feet per day). Utilization of this new capacity in 1994 was above 95 percent except for the Empire line, which primarily serves the upper New York intrastate market.

The two main flows of gas into the region are from the Southeast into Virginia and West Virginia, and from the Midwest into West Virginia and Pennsylvania. Gas then moves within the region toward New York City and Boston. In 1994, the interstate pipeline system serving the region had the capacity to move 4.8 billion cubic feet per day from the Southeast and Midwest regions.

The region has large swings in gas demand because of weather. Overall, it is the third coldest of the regions, with some of the coldest States in the Nation at its northern limits. Withdrawals from storage are necessary to meet peak demand, as total capacity entering the region plus regional gas production are only about two-thirds of the region's peak demand. Gas demand is driven by the growing, highly populated urban corridor that stretches from Boston, Massachusetts to Richmond, Virginia.

Capacity expansions of 2.8 billion cubic feet per day, 15 percent above current levels, have been proposed by regional suppliers. This represents 32 percent of total proposed expansions nationwide. Of that, 0.4 billion cubic feet per day is additional capacity into the region. Long dependent on fuel oil, the Northeast has seen a steady increase in the availability of, and demand for, natural gas in recent years. The expected growth markets for the planned expansions will be the co-generation facilities and industrial customers.

Southeast Region

The Southeast Region is the least developed market for natural gas in terms of per-capita consumption. In fact, natural gas accounts for only a small percentage of the total energy consumed in the region. Nevertheless, because of its location, numerous interstate natural gas pipeline companies operate through the region (Figure B5), carrying significant supplies through the region to the Northeast and the Midwest. During peak periods, the interstate pipeline system has the capacity to move up to 21.6 billion cubic feet into the region, principally from the Southwest Region (Table B1). This is the second-largest capacity level for any region. The region has an exit capacity level to the Northeast and Midwest of 14.8 billion cubic feet per day.

The region has temperate weather conditions and has historically had low winter demand for heating. Overall, the region has the mildest weather of any region, with Florida being one of the warmest States in the Nation.

The region has some of the fastest growing States. While it is still only the third most populous region, with 46 million people, population increased substantially during the 1980's. The population of Florida has increased by more than 33 percent since 1980; it is now the fourth most populous State. Georgia was the eighth fastest growing State during the 1980's.

Essentially all of the interstate natural gas pipeline capacity entering the region comes from the Southwest Region. More than 70 percent of this capacity is directed out of the region, with 9.8 billion cubic feet per day into the Midwest and 4.9 billion per day into the Northeast Region. The region is a net consumer of gas, with only Mississippi, Alabama, and Kentucky producing significant quantities of gas.

Capacity into the Southeast Region grew by about 7 percent between 1990 and 1994. Most capacity additions occurred within the region. The major projects completed were the Florida Gas Transmission expansion, the Mobile Bay Pipeline, and the Transcontinental Gas Pipeline southern expansion. Noteworthy were the additional pipeline expansions serving the northern North Carolina market. Several pipelines from the Northeast Region (Columbia Gas Transmission and Transcontinental Gas Pipeline Company) extended their systems into the Southeast Region market in 1993. On the other hand, several major projects announced in 1990 were subsequently withdrawn, postponed, or canceled outright. Among these were the Cornerstone Pipeline (0.6 billion cubic feet per day), the Tennessee Gas Pipeline West-to-East crossover (0.5 billion cubic feet per day), and the Texas Eastern Pipeline OK-AR pipeline (0.5 billion cubic feet per day).

Expected and actual growth in demand for natural gas as an electric utility plant fuel (and its use as other than a space heating fuel) has spurred new construction in the region. A prime example is in the State of Florida. Installed capacity on the Florida Gas Transmission (FGT) system, which supplies almost all the natural gas to the eastern and southern parts of State, increased by 15 percent, from 820 in 1990 to 943 million cubic feet per day at the end of 1994. Another 532 million cubic feet per day became operational in March 1995, yielding an 80-percent increase since 1990. The electric utility industry accounts for over 50 percent of total natural gas consumption in the State. Indeed, citing expected future growth in this sector, FGT has proposed to FERC to expand its service capability even further. Proposed additions to capacity into the region over the next several years amount to a substantial 915 million cubic feet per day, up 4 percent from 1994 levels, but below what has been added since 1990.

Midwest Region

An intricate, long-distance natural gas transmission network has evolved over the past 70 years to serve the Midwestern market (Figure B6). Today 15 interstate pipeline companies have the capacity to move 24.3 billion cubic feet of gas into the region per day (Table B1). The total capacity of the interstate pipelines entering the region is larger than for any other region.

The current level of pipeline capacity into and within the Midwest was essentially reached in the late 1970's. Except for the completion of the Northern Border Pipeline (the eastern leg of the Alaska prebuilt system), which provided increased availability of gas supplies from Canadian sources by way of the Central Region, construction and system expansion during the past decade was minimal. However, pending and potential capacity expansion projects provide some indication that growth in natural gas consumption is expected over the next several years. Capacity additions into the Midwest Region between 1991 and 1994 were 1.5 billion cubic feet per day, an increase of 7 percent over 1990 levels. No new major pipelines were constructed in the region although a number of expansion projects were completed. Primary among these were additions to the Great Lakes Transmission System (a 41 percent increase in capacity), the Northern Border Pipeline (36 percent) and ANR Pipeline Company (18 percent in Michigan and Indiana).

The interstate pipeline system extending into the Midwest Region taps the major gas-producing areas of East Texas, Louisiana, and offshore Gulf of Mexico for about one-half of its supplies, and to southwest Kansas, Oklahoma, and north Texas for an additional one-third. Regional production, principally from Ohio and Michigan, provides a little more than 6 percent of gas consumption in the region. The remaining supply comes from Canada.

Several characteristics of the Midwestern market underlie its status as the Nation's second largest market for natural gas and help explain its extensive pipeline network. The region is weather-sensitive, with cold winters and moderate summers. Minnesota and Wisconsin are among the coldest States in the Nation, and the other four States in the region are colder than the national average. It also has a number of major population centers and is the second largest of the six regions in population. The large number of residential space-heating customers, combined with the cold winters, result in large residential requirements for natural gas. The geographic position between the Central and Northeastern United States has resulted in a significant portion of the region's pipeline system capabilities being reserved for deliveries beyond its borders. Eight major pipeline systems serving the region also serve customers in the Northeast Region or in eastern Canada. Customers in eastern Canada receive Canadian gas that was transported through the Midwest Region for delivery into Ontario.

The interstate pipeline systems operating in the area are primarily trunk pipeline operations, transporting large volumes of gas from distant supply sources to local distributors. They differ greatly in size, type of service market, and the importance of the Midwest market to their overall operations. While the two most northern States, Wisconsin and Minnesota, as well as portions of Michigan, are serviced by pipelines importing Canadian supplies, the southern portion of the region is serviced primarily by the major trunklines coming from the Southwest.

Appendix C

Data Sources

Appendix C

Data Sources

The data presented in the body of the report came from many sources and often required some adjustment to provide information on a comparable basis for use in the analysis. This appendix provides detailed information on the methodology and source material used to develop the estimates of 1990 interstate pipeline capacity at State borders and the changes in energy usage patterns from 1980 through 1989.

The following is a list of the data sources discussed in this appendix.

- Annual pipeline company reports filed with the Federal Energy Regulatory Commission (FERC) under 18 CFR 260.8, Format 567, "System Flow Diagrams"
- FERC Form 11, "Natural Gas Pipeline Monthly Statement"
- Energy Information Administration, Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition"
- *Natural Gas Annual*, DOE/EIA-0130, various issues.

Pipeline Capacity

The measure of pipeline capacity that was estimated and addressed in this report is the daily capacity of the interstate natural gas pipeline network at regional and State boundaries. Specifically it is an estimate of the maximum volume of gas that can be transported under normal operating conditions for a sustained period of time. While the pipeline systems have considerable operational flexibility to increase deliveries of natural gas to certain areas above design capacity for short periods of time, this often means either reduced deliveries elsewhere or the use of line packing. Neither measure is likely to be sustainable for more than a short period of time.

Information on capacity levels for the interstate pipeline systems is generally available from filings at the Federal Energy Regulatory Commission (FERC). However, this information is typically associated with compressor stations and not State border capacity. Thus, an approach was required to estimate the State-to-State capacities on the pipelines. Further, while there is a regulatory requirement for the submission of design information, the terminology provided in the submissions sometimes is unclear as to whether the data provided by a company are in fact the information requested.

The original compilation of pipeline capacity estimates was done by the Energy Information Administration during 1991 and 1992, using 1990 as the base year. The initial approach taken to derive the State-to-State capacity information was the following:

- Develop initial capacity estimates using the compressor station data from FERC Format 567, "System Flow Diagrams."
- Adjust initial estimates using delivery requirements of customers located between the State line and the station and for any contracted receipts from other pipelines.
- When compressor station data were unavailable on Format 567, derive a statistical estimate using a regression equation based upon the diameter(s) of the pipeline segment in question.
- Impute remaining missing values using proxies for capacity. Data used for this purpose included the contract demand data (CD) that were available for the years 1988 and 1989 for pipeline sales customers.
- Cross check the State border capacities for reasonableness, using contract demand levels (if not used as a proxy for capacity), flow data from Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition," and consultations with FERC staff and company officials.

Capacity estimates for 1994 were developed using the 1990 estimates as a starting point. Next, the 1994 and 1990 FERC Format 567 "System Flow Diagram" were compared to determine to what extent the throughput capabilities of the pipeline compressor stations had changed. In addition, comparisons of receipt and delivery point volumes were also performed to determine changes in peak-day deliverabilities and as a replacement for contract demand data that were no longer current. Available data on pipeline construction projects proposed to be built between 1991 and 1994 and their current status were also factored into the estimates. These comparisons were done, to the extent possible, through comparative analyses of updated databases. Initial estimates of revised capacity levels were produced and displayed on annotated pipeline maps.

These initial estimates were then forwarded to willing pipeline company staff for their review and evaluation. If company input was not available, the estimates were given to FERC staff for an evaluation. These input were used to settle upon a final estimate.

The initial (1990) estimates of capacity on a pipeline segment at a State border were based on reported compressor station throughput, the daily output of whichever compressor station appeared to be closest to the State border. The working assumption was that throughput capability, even if only an estimated flow under current operating conditions, of any compressor station is a reasonably good estimate of peak-period throughput at that point on the line. (Compressor station output may be a "constraint" on throughput when downstream pipeline diameter, and other characteristics of the segment, may allow the physical pipeline to handle greater loads than required under current customer peak-day commitments. Conversely, the designed compressor output may be greater than can be sent through existing pipeline configurations.)

When no delivery or receipt points were between the selected compressor station and the State line, the capacity at the State border was assumed to equal the station capability, even though some friction losses would occur because of the distance between the line and compressor. When data were available for both receipts and contract demand deliveries between the compressor station and the State line, then the initial capacity estimates were adjusted to account for these volumes.

In some cases, peak-day information rather than design capacity was reported on FERC Format 567. These estimates were considered a reasonable proxy for capacity.

Under certain conditions, contract demand (CD) data were used to estimate capacity levels at a State border. CD data were assumed to be a reasonable reflection of current peak-day demands on the pipeline system and therefore a close approximation of the capability or capacity of the pipeline to supply those customers. A pipeline company's CD commitment levels within a State were used as a surrogate for a measure of that pipeline's capacity into the State when the pipeline system, or a branch, terminated in the State. Even in this instance, however, the pipeline company could meet a portion of its commitments from sources within the State borders.

In some cases, compressor station data and contract demand data were inadequate to develop an initial capacity estimate, and other methods were pursued to make the initial capacity estimate. For instance, regression equations to estimate capacity were developed using a universe of 814 compressor stations with known pipeline diameters, capacity, and pressure, extracted from the Format 567 filings. The results indicated that diameter alone was a good predictor of capacity in these equations.

Average Daily Pipeline Flow

The data source for actual average daily pipeline volume flows across State borders was Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition." In addition, these data are the basis for supply, consumption, and transportation volumes presented on each State in this report.

The respondent universe of the Form EIA-176 includes interstate and intrastate pipeline companies; investor and municipally owned natural gas distributors; underground natural gas storage operators; synthetic natural gas plant operators; and field, well, or processing plant operators that deliver natural gas directly to consumers and/or transport gas to, across, or from a State border through field or gathering lines.

The average daily flow volumes presented in the "Interregional Capacity" tables in Chapter 3 are based upon preliminary 1994 data extracted from Form EIA-176. They are the sum of data that can be identified as volumes brought across a border: onsystem purchases received at a State border, plus transportation and/or exchange receipts received at a State line, plus transported into the report State. The data on Form EIA-176 are annual; average daily levels were computed on a 365-day basis.

Greater detail concerning Form EIA-176, its background and EIA processing methodology, may be found in the appendices of the EIA publication, *Natural Gas Annual 1990* (DOE/EIA-0131).

System Flow Rate Data

The pipeline system-wide flow rate data discussed in Chapter 3 and used for utilization analysis are based on monthly throughput volume data reported on FERC Form 11, "Natural Gas Pipeline Monthly Statement." These data for the period January 1979 through December 1994 are maintained and available on computer tape.

Transportation, sales, and intercompany transfer throughput volumes are reported, but for the total pipeline system only. As a result, these data cannot be used to compute regional or State-level utilization levels. However, the historical data were used to identify and quantify the largest monthly throughput level occurring on individual pipeline systems over 16 years, 1979 through 1994. Average monthly throughput rates for 1989 and 1994 were then divided by the largest monthly throughput (which was used as an approximation of a 100-percent load factor or a surrogate measure for full capacity utilization) to estimate the overall relative flow rate (throughput) on the various pipeline systems in 1994.

Maps and Mapped Data

The geographic displays in the main body of this report were produced, in whole or in part, using the EIAGIS-NG Geographic Information System. The system consists of a series of site-specific databases and digitized pipeline maps residing in a PC (personal computer) environment. The pipeline map files were developed from publicly available sources, although in some cases, more detailed maps were provided by the individual pipeline companies. Currently, the EIAGIS-NG contains map data for 60 interstate and 55 intrastate pipeline companies.

Each interstate pipeline map file also contains profile (attribute) data, such as pipe diameter, maximum allowable pressure, looping, etc., for each pipeline segment. These data were compiled from the pipeline system schematic contained in the FERC Format 576 "System Flow Diagram." The individual databases supporting the system include such pipeline related data as:

- Compressor stations
- Delivery points
- Receipt points
- Major interconnections
- State border crossings and capacity levels.

Nonpipeline-related databases include:

- Underground storage sites
- Planned underground storage projects
- Proposed construction projects
- Local distribution company service areas
- Exports and imports
- Market hubs
- Electric power plants, etc.

The principal geographic data used in this report to compile capacity estimates were the pipeline maps and their receipt, delivery, interconnection, and compression station points. Planned and existing underground storage site data were used to develop estimates of supplemental peak day deliverability to the pipeline network.

U.S. Regional Definitions

The six regions used in this report were based in whole or in part upon the 10 Federal regions originally defined by the Bureau of Labor Statistics. The groupings are as follows:

Northeast Region—*Federal Region 1*: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. *Federal Region 2:* New Jersey, and New York. *Federal Region 3:* Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, and West Virginia.

Southeast Region—*Federal Region 4:* Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee.

Midwest Region—*Federal Region 5:* Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin.

Southwest Region—*Federal Region 6*: Arkansas, Louisiana, New Mexico, Oklahoma, and Texas.

Central Region—*Federal Region 7:* Iowa, Kansas, Missouri and Nebraska. *Federal Region 8:* Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming.

Western Region—*Federal Region 9:* Arizona, California, and Nevada. *Federal Region 10*: Idaho, Oregon, and Washington.

Appendix D

FERC Ratemaking Process

Appendix D

FERC Ratemaking Process

The Natural Gas Act of 1938 (NGA) gave the Federal Energy Regulatory Commission (FERC) broad authority to regulate the interstate sales and transportation of natural gas. FERC ensures that rates are reasonable and nondiscriminatory by presiding over rate hearings. During a rate hearing, the pipeline company is required to justify its proposed rates by providing detailed information on its costs and proposed service levels (volume and demand requirements). Before deciding on the appropriate cost and service levels that will be used in determining pipeline company rates, the regulatory process provides all concerned parties the opportunity to present testimony to FERC.

The ratemaking process can be separated into five distinct steps:

- **Determine the overall costs that should be recovered in the rates.** FERC generally uses a historical cost approach to ratemaking in which actual costs for a recent 12-month period (base period) are adjusted for known and measurable changes expected to occur within nine months of the end of the base period. FERC sets up a "test period cost of service" that includes all pipeline company costs of providing service, including a fair return on investment. The individual components of the cost of service are discussed in greater detail below.

- **Separate the "test period cost of service" into pipeline functions such as gathering, transmission, and storage.**

- **Classify "functionalized" costs into demand and commodity components.** Variable costs, costs that vary with the volume of gas flowing through the pipeline, are classified as the commodity component. Depending on FERC's ratemaking goals, fixed, or nonvariable, costs are allocated to the demand and/or commodity component. Because the natural gas pipeline industry is very capital intensive, the majority of pipeline company costs are fixed.

- **Allocate demand and commodity components among pipeline company services.** Demand costs are traditionally allocated among services based on customer capacity requirements, while commodity costs are allocated on a volumetric basis. Part of the allocation process may also incorporate the distance gas travels to the customer.

- **Design unit rates.** Unit rates are developed by dividing the allocated demand and commodity costs by billing units for the respective services. Rates can be designed to incorporate a one-, two-, or three-part rate structure of billing. A one-part rate is designed to recover demand and commodity costs in a single volumetric charge—the customer is billed based on the number of gas units it consumes or transports. In a two- or three-part rate structure, reservation rates are designed to recover demand costs while volumetric rates recover commodity costs.

Rates are also designed to reflect the pipeline company's quality of service. For example, firm service rates recover more of the pipeline company demand costs than interruptible service rates. Firm customers have first call on capacity contracted for, while in cases of a shortage, interruptible customers may be bumped from the system. Hence, interruptible rates are usually one-part rates that are generally lower and include only a small portion of the demand cost.

While this description of the ratemaking process appears fairly straight forward, FERC can influence the ratemaking process to achieve policy goals that are pertinent to prevailing market conditions.[98] To achieve policy goals, FERC uses the cost classification aspect of the ratemaking process to classify fixed costs as either demand or commodity or some mixture of the two.

During the early 1980's FERC adopted the modified fixed-variable (MFV) method of cost classification. MFV classified all fixed costs as demand costs except for the return on equity and related income taxes (and sometimes fixed production and gathering costs) which were classified as commodity costs. This had the effect of lowering overall transportation rates. FERC adopted the MFV method to promote two goals: first, to reduce underutilization of the national natural gas pipeline system and second, to make natural gas more competitive with alternate fuels.

In addition to the MFV classification, FERC proposed to split demand costs between two demand components: the (D-1) component recovered demand costs through a peak-day charge, and the (D-2) component recovered demand costs through an annual demand charge. FERC proposed this change in rate

[98] FERC Docket Nos. RM91-11-000 and RM87-34-065, Order No. 636, p. 120.

design to mitigate the cost-shift impact on low-load-factor customers of the move to MFV rates.

In 1989 FERC once again reviewed its ratemaking policies in light of institutional changes that were affecting the pipeline industry, such as open-access transportation and the decontrol of natural gas wellhead prices. As part of this review, FERC released its *Policy Statement Providing Guidance with Respect to the Designing of Rates*, which evaluated the effectiveness of different aspects of ratemaking in meeting the goals of rationing transportation capacity and maximizing throughput. Specifically, FERC discussed seasonal rates, capacity adjustments, discounted transportation, maximum interruptible rates, and the classification of fixed and variable costs to demand and commodity charges. In its Policy Statement, FERC suggested that to meet the goals of rationing capacity in peak periods and maximizing throughput, the annual demand component associated with the MFV rate design should be eliminated and costs formerly recovered under the D-2 component be moved to the D-1 component. This essentially was a transition to the present practice of using straight fixed-variable (SFV) rate design prompted by Order 636.

While the changes in cost allocation and rate design initiated by FERC do not affect the total costs collected by the pipeline company, they do affect the overall unit cost of service charged to the customer. For example, the SFV rate design collects a larger share of fixed costs via the capacity reservation charges than does the MFV design. As discussed in the corridor rate study, the shift of costs to reservation charges increases the average unit cost of service to customers whose peak requirements are larger than their average annual requirements. Therefore, excluding any other changes in costs and services, the switch from MFV to SFV would increase the average unit cost of service to low-load-factor customers.

Components of the Pipeline's Cost of Service

The starting point for designing rates is to determine the total cost of service necessary for the pipeline company to provide service to its customers. The cost of service contains five base components.

- **Return on Rate Base.** The return is calculated by multiplying the allowed rate of return by the company's rate base. The rate base is generally calculated as net plant (gross gas plant in service plus construction work in progress less the accumulated depreciation, depletion and amortization) plus prepayments and inventory items (gas stored underground, materials and supplies, etc.) less accumulated deferred income taxes. The rate base is the foundation on which the natural gas pipeline company earns its profit (return on equity) and its financing costs (return on debt).

- **Operation and Maintenance (O&M) Expenses.** O&M expenses include the labor and materials expenses required for the pipeline company to perform its day-to-day service. These expenses are related to the production, distribution, transmission, and storage functions of the pipeline company and include the costs for customer services and administrative and general support.

- **Depreciation, Depletion and Amortization (DD&A) Expenses.** This represents a charge or credit to income taken against the decrease in value of an asset over a period of time. Some of the factors considered in determining DD&A are wear and tear, obsolescence, and salvage value.

- **Income Tax Allowance.** Income tax allowance provides the pipeline company a method to recover the booked cost of Federal and state income tax expenses from its rate payer. The income tax allowance is computed by multiplying the return on equity, as adjusted for tax purposes, by an income tax factor. The income tax factor is generally computed by dividing the tax rate by one minus the tax rate.

- **Other Operating Expenses.** These expense items include taxes other than income taxes, revenue credits, deferred income taxes, and other such miscellaneous expenses.

A number of factors have a natural tendency to influence rates over time. For example, depreciation of the natural gas plant facilities will tend to reduce rates over time. Depreciation reduces the return component of rates by reducing the rate base on which return is computed. If pipeline companies did not restore depreciated plants or invest in new plant facilities, rates would decline over time.

Increases in any one of the cost items identified above will place upward pressure on average unit rates, while decreases will tend to lower rates. However, the ability of a component to affect rates significantly is related to its share of the total cost of service. A large decrease in a component does not automatically lead to a large decrease in average unit rates. For example, between 1988 and 1994, other expenses almost doubled, however, they represent only a small portion of the total cost of service, and the increases did not dramatically increase average unit rates (Table D1). In fact, the rate base has increased by about $6 billion since 1988.

Unlike individual rate components, relative changes in deliveries to customers can and do have significant and inverse effects on average unit rates. For example, the 1994 sample average unit rate is $0.59 per thousand cubic feet. The unit rate calculated using 1988 volumes is $0.68 per thousand cubic feet. This indicates that the 16-percent increase in volumes from 1988 to 1994 results in a 12-percent decrease in average unit rates.

Table D1. Aggregate Cost of Service and Rate Components for Major Interstate Pipeline Companies, 1988-1994

	1988	1989	1990	1991	1992	1993	1994
Aggregate Cost of Service (nominal dollars, thousands)							
Return on Rate Base							
Total Rate Base	$20,219,700	$18,943,698	$23,177,756	$25,711,373	$26,307,394	$26,136,744	$25,617,891
Percent Return on Equity	6.43	6.39	6.64	6.62	6.37	6.63	5.74
Percent Return on Debt	5.05	5.30	4.79	4.77	4.27	4.84	4.42
Equity portion of Return	1,300,127	1,210,502	1,539,003	1,702,093	1,675,781	1,732,866	1,470,467
Debt portion of Return	1,021,095	1,004,016	1,110,215	1,226,432	1,123,326	1,265,018	1,132,311
O&M Expenses (excluding cost of gas)	6,965,146	8,035,884	5,514,858	8,411,606	7,162,898	6,794,636	5,419,034
Other Expenses							
Depreciation, Depletion, Amortization	1,550,952	1,343,755	1,348,979	1,301,518	1,118,227	1,528,583	1,307,123
Income Taxes	724,834	681,867	866,395	989,253	1,020,474	1,012,925	847,512
Other Expenses	508,255	733,191	677,666	15,130	739,712	721,141	916,759
Total Aggregate Cost of Service	$12,070,409	$13,009,215	$11,057,116	$13,646,032	$12,840,418	$13,055,171	$11,093,205
Natural Gas Delivered to Consumers (billion cubic feet)	16,320	17,102	16,820	17,305	17,786	18,488	18,851
Unit Rate Components (1994 dollars per thousand cubic feet)							
Total Return on Rate Base	$0.17	$0.15	$0.18	$0.18	$0.16	$0.17	$0.14
O&M Expenses (excluding cost of gas)	0.52	0.55	0.36	0.52	0.42	0.38	0.29
Other Expenses							
Depreciation, Depletion, Amortization	0.12	0.09	0.09	0.08	0.07	0.08	0.07
Income Taxes	0.05	0.05	0.06	0.06	0.06	0.06	0.04
Other Expenses	0.04	0.05	0.04	0.00	0.04	0.04	0.05
Total Unit Cost of Service	$0.90	$0.88	$0.73	$0.85	$0.75	$0.72	$0.59

O&M = Operating and maintenance expenses.

Sources: 1988-1989: Energy Information Administration, Statistics of Interstate Natural Gas Pipeline Companies 1991 (December 1992).
1990-1994: Federal Energy Regulatory Commission (FERC) Form 2, "Annual Report of Major Natural Gas Companies", Balance Sheet, O&M Expenses and Statement of Income files from FERC Gas Pipeline Data Bulletin Board System.
The Federal portion of the income tax expense is calculated by multiplying the equity portion of return by the Federal tax factor.

Appendix E

Corridor Rate Analysis Results

Appendix E

Corridor Rate Analysis Results

To compare the transportation rates for delivering gas from various supply areas to selected market areas, over time, the maximum firm transportation reservation and usage rates (including surcharges) were converted to one-part usage rate equivalents. These one-part rates represent the total per unit cost of transporting gas from supply to market for two customer load profile types (100-percent load factor and 40-percent load factor). The results of the study present the trends in these transportation rates and provide some insight into the change in the cost of moving gas.

Source of Rate Component Data

Most of the rate component data for 1991 and 1994 were taken from the Foster Associates, Inc., *Competitive Profile of U.S. Interstate Pipeline Companies* (October 1991) and *Competitive Profile of Natural Gas Services* (December 1994), respectively. The 1994 data from Foster Associates' report were compared with the pipeline company tariff rates obtained using the Federal Energy Regulatory Commission Automated System for Tariff Retrieval (FASTR). FASTR was also used to obtain Kern River Gas Transmission Company's 1994 base transportation rates that were used in the study. The 1991 rate components for Florida Gas Transmission Company are from H. Zinder & Associates, *Summary of Rate Schedules of Natural Gas Pipeline Companies*, March 1991. The components used to compute unit rates include the reservation charge, the usage charge, the cost of fuel retained by the pipeline company, and all applicable surcharges. Surcharges are included in the reservation as well as usage portions of the rate components. The specific surcharges included in the rate components vary among the pipeline companies. However, all pipeline companies include Gas Research Institute (GRI) funding and Annual Charge Adjustment (ACA) surcharges. Additional surcharges may include Gas Supply Realignment (GSR), Stranded Costs, and Purchased Gas Adjustment (PGA) surcharges. The cost of fuel retained by the pipeline company is calculated by multiplying the retention rate by the unit cost of gas. Therefore, the unit cost of fuel retained by the pipeline company will vary depending on the supply source of the gas.

In at least one instance, seasonal rates were filed by a pipeline company included in the corridor rate study. Noram Gas Transmission Company (Noram) has separate 1994 rates applicable for service during the winter (November through March) and summer (April through October) seasons. The seasonal rates were converted to a levelized rate by weighting the respective rate by the number of months in the season and dividing the sum of the two weighted amounts by 12. For example, the Noram winter reservation charge is $9.39 per million Btu (MMBtu) and its summer reservation charge is $3.79 per MMBtu (excluding surcharges). Therefore, the levelized rate is the sum of the products $9.39 times 5 and $3.79 times 7 divided by 12 or $6.12 per MMBtu. The surcharge is added to the levelized rate to arrive at the reservation charge component used in the corridor rate study.

A pipeline company will sometimes offer firm transportation rates under various rate schedules which accommodate differences in its customers' characteristics. For example, Algonquin Gas Transmission Company (Algonquin) offers lower transportation rates to customers whose total maximum daily requirements do not exceed 10,000 MMBtu per day. Algonquin also offers different transportation service rates to customers depending on the rate schedule under which the customer was formerly served (e.g., prior to Order 636). A customer's former rate schedule varied depending on the type of service (sales for resale, transportation, etc.), the type of customer (local distribution company), and the pipeline company that delivered the gas to Algonquin. Algonquin's firm transportation reservation charges for these customers range from $7.18 per MMBtu to $16.46 per MMBtu. However, the corridor rate study compares general service rates for 1991 and 1994 to avoid tracking changes in rate schedules that are based on special circumstances.

Surcharges, which are included in the corridor rates, may also vary depending on customer characteristics. One notable example is the Gas Research Institute (GRI) demand surcharge. All monthly reservation rates in the corridor rate study include a $0.2180 per MMBtu GRI surcharge for customers with load factors over 50 percent and a $0.1340 per MMBtu GRI surcharge for customers with load factors of 50 percent or less. The difference in the GRI demand surcharge causes the reservation charge for 40-percent load factor rates to be slightly lower than that for the 100-percent load factor rates.

Development of One-Part Rates

The one-part rates are developed by summing the demand component converted to a unit basis, the usage rate, and the unit cost of fuel retained by the pipeline company. To convert to a unit basis, the reservation charge is divided by the product of the average number of days in a month times the load factor. In this way the one-part rate demonstrates the actual maximum unit cost of transporting gas on the selected pipelines for the customer load profile (Table E1).

Customer Load Profiles

The corridor rate study compares 1991 and 1994 rates for two customer load profiles. High-load-factor customers who tend to transport gas at a constant level throughout the year and low-load-factor customers who do not take gas at a constant rate throughout the year. The high-load-factor customers impose a daily demand on the system that is about equal to the average of their annual volume transported. For example, a customer who transports 365 MMBtu of gas per year will tend to transport about 1 MMBtu of gas per day. The industrial and electric utility sectors tend to be high-load-factor customers because their gas requirements are related to manufacturing needs as opposed to the demand for space heating.

The low-load-factor customers have a peak daily usage that far exceeds the average of their annual use. Residential and commercial sectors are generally low-load-factor customers because they depend on natural gas as a space-heating fuel. Their demand tends to fluctuate with weather temperature. Hence, the pipeline company must be prepared to meet these sectors' highest load requirement even though the maximum load may only occur a few times a year.

For this analysis a 100-percent load factor was used to represent the high-load-factor customers and a 40-percent load factor was used for low-load-factor customers. The 40-percent load factor assumes that the variable-use customers will impose a peak-day load on the system that is 2.5 times the customers' average daily requirements.

Transportation Routes and Pipeline Companies

Unit rates were developed for 21 transportation flow paths or routes. Each route represents the path gas must take on one or more pipelines to travel from the supply area to the point of use or market. A shipper may be able to choose between two or more routes to transport gas along any regional corridor. For example, a shipper wishing to transport gas on the Gulf Coast to Boston corridor may route his gas through Texas Eastern and Algonquin or route his gas through Tennessee Gas Pipeline Company.

The pipeline companies whose rate components are used to develop the corridor rates are:

Algonquin Gas Transmission Company
Altamont Gas Transmission (proposed)
ANR Pipeline Company
Colorado Interstate Gas Company
El Paso Natural Gas Company
Florida Gas Transmission Company
Iroquois Gas Transmission System, L.P.
Kern River Gas Transmission Company
Mojave Pipeline Company
NorAm Gas Transmission Company
Panhandle Eastern Pipe Line Company
Tennessee Gas Pipeline Company
Texas Eastern Transmission Corporation
Texas Gas Transmission Corporation
Transcontinental Gas Pipe Line Corporation
Trunkline Gas Company.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994

Northeast Region: Gulf Coast to Boston Transportation Corridor (1994 dollars per million Btu)

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
Route A						
TEXAS EASTERN (WLA-M3)						
Gas Costs	$1.82	$1.90	4.3	$1.82	$1.90	4.3
Reservation Charge (1994 $/MMBtu-Mo.)	13.11	15.24	16.2	13.11	15.16	15.6
Usage Charge	0.43	0.15	-65.0	0.43	0.15	-65.0
Fuel Retention	4.0%	5.2%		4.0%	5.2%	
Total - Transportation Cost	0.93	0.75	-19.4	1.58	1.49	-5.7
Total - Delivered Cost of Gas	2.75	2.65	-3.7	3.40	3.39	-0.4
ALGONQUIN						
Gas Costs	2.75	2.65	-3.7	3.40	3.39	-0.4
Reservation Charge (1994 $/MMBtu-Mo.)	5.05	5.91	17.1	5.05	5.91	17.1
Usage Charge	0.17	0.02	-88.3	0.17	0.02	-88.3
Fuel Retention	0.6%	0.5%		0.6%	0.5%	
Total - Transportation Cost	$1.28	$0.98	-23.4	$2.19	$2.01	-8.2
Route B						
TENNESSEE (Z1-Z6)						
Gas Costs	$1.82	$1.90	4.3	$1.82	$1.90	4.3
Reservation Charge (1994 $/MMBtu-Mo.)	7.76	26.77	244.9	7.76	26.69	243.8
Usage Charge	0.17	0.08	-53.4	0.17	0.08	-53.4
Fuel Retention	6.7%	7.8%		6.7%	7.8%	
Total - Transportation Cost	$0.55	$1.11	101.8	$0.93	$2.42	160.2

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994

Northeast Region: Appalachia to Boston Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
Route A						
TEXAS EASTERN (M2-M3)						
Gas Costs	$2.18	$2.16	-0.7	$2.18	$2.16	-0.7
Reservation Charge (1994 $/MMBtu-Mo.)	8.25	10.35	25.4	8.25	10.27	24.4
Usage Charge	0.21	0.11	-48.7	0.21	0.11	-48.7
Fuel Retention	2.0%	2.9%		2.0%	2.9%	
Total - Transportation Cost	0.53	0.51	-3.8	0.94	1.02	8.5
Total - Delivered Cost of Gas	2.71	2.67	-1.3	3.12	3.18	2.0
ALGONQUIN						
Gas Costs	2.71	2.67	-1.3	3.12	3.18	2.0
Reservation Charge (1994 $/MMBtu-Mo.)	5.05	5.91	17.1	5.05	5.91	17.1
Usage Charge	0.17	0.02	-88.3	0.17	0.02	-88.3
Fuel Retention	0.6%	0.5%		0.6%	0.5%	
Total - Transportation Cost	$0.88	$0.74	-15.9	$1.55	$1.54	-0.6
Route B						
TENNESSEE (Z4 - Z6)						
Gas Costs	$2.18	$2.16	-0.7	$2.18	$2.16	-0.7
Reservation Charge (1994 $/MMBtu-Mo.)	5.83	12.74	118.5	5.83	12.66	117.0
Usage Charge	0.14	0.05	-64.1	0.14	0.05	-64.1
Fuel Retention	4.9%	2.2%		4.9%	2.2%	
Total - Transportation Cost	$0.44	$0.52	18.2	$0.73	$1.14	56.2

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994
Northeast Region: Canada to Boston Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	% Change
Route A						
IROQUIS (Zone 1)						
Gas Costs	$2.47	$2.20	-10.9	$2.47	$2.20	-10.93%
Reservation Charge (1994 $/MMBtu-Mo.)	10.01	13.57	35.5	10.01	13.49	34.69%
Usage Charge	0.14	0.01	-92.8	0.14	0.01	-92.82%
Fuel Retention		1.0%			1.0%	
Total - Transportation Cost	0.47	0.48	2.1	0.96	1.14	18.75%
Total - Delivered Cost of Gas	2.94	2.68	-8.8	3.43	3.34	-2.62%
TENNESSEE (Zone 5 - Zone 6)						
Gas Costs	2.94	2.68	-8.8	3.43	3.34	-2.62%
Reservation Charge (1994 $/MMBtu-Mo.)	6.82	12.34	80.9	6.82	12.34	80.94%
Usage Charge	0.09	0.04	-55.6	0.09	0.04	-55.56%
Fuel Retention	2.4%	2.1%		2.4%	2.1%	
Total - Transportation Cost	$0.85	$0.98	15.3	$1.69	$2.26	33.73%
Route B						
TENNESSEE (Niagra)						
Gas Costs	$2.47			$2.47		
Reservation Charge (1994 $/MMBtu-Mo.)	2.42			2.42		
Usage Charge	0.04			0.04		
Fuel Retention	1.2%			1.2%		
Total - Transportation Cost	0.15			0.27		
Total - Delivered Cost of Gas	2.62			2.74		
TENNESSEE (Niagra - Zone 6)						
Gas Costs	$2.62	$2.20	-15.9	$2.74	$2.20	-19.58%
Reservation Charge (1994 $/MMBtu-Mo.)	6.82	16.20	137.6	6.82	16.12	136.38%
Usage Charge	0.09	0.06	-30.0	0.09	0.06	-30.04%
Fuel Retention	2.4%	2.1%		2.4%	2.1%	
Total - Transportation Cost	$0.52	$0.64	23.1	$0.71	$1.43	101.41%

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994
Northeast Region: Gulf Coast to New York Transportation Corridor
(1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
Route A						
TENNESSEE						
Gas Costs	$1.82	$1.90	4.3	$1.82	$1.90	4.3
Reservation Charge (1994 $/MMBtu-Mo.)	7.76	22.89	194.9	7.76	22.81	193.8
Usage Charge	0.17	0.08	-53.4	0.17	0.08	-53.4
Fuel Retention	6.7%	7.0%		6.7%	7.0%	
Total - Transportation Cost	$0.55	$0.97	76.4	$0.93	$2.09	124.7
Route B						
TEXAS EASTERN						
Gas Costs	$1.82	$1.90	4.3	$1.82	$1.90	4.3
Reservation Charge (1994 $/MMBtu-Mo.)	13.11	15.24	16.2	13.11	15.16	15.6
Usage Charge	0.43	0.15	-65.0	0.43	0.15	-65.0
Fuel Retention	4.0%	5.2%		4.0%	5.2%	
Total - Transportation Cost	$0.93	$0.75	-19.4	$1.58	$1.49	-5.7
Route C						
TRANSCO (Zone 3-Zone 6)						
Gas Costs	$1.82	$1.90	4.3	$1.82	$1.90	4.3
Reservation Charge (1994 $/MMBtu-Mo.)	12.71	9.78	-23.1	12.71	9.70	-23.7
Usage Charge	0.30	0.16	-46.7	0.30	0.16	-46.7
Fuel Retention	7.4%	3.9%		7.4%	3.9%	
Total - Transportation Cost	$0.85	$0.56	-34.1	$1.48	$1.03	-30.4

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994

Northeast Region: Canada to New York Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
IROQUIS						
Gas Costs	$2.47	$2.20	-10.8	$2.47	$2.20	-10.8
Reservation Charge (1994 $/MMBtu-Mo.)	17.91	24.08	34.4	17.91	24.00	34.0
Usage Charge	0.21	0.02	-90.7	0.21	0.02	-90.7
Fuel Retention		1.0%			1.0%	
Total - Transportation Cost	$0.80	$0.83	3.7	$1.69	$2.01	18.9

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994
Southeast Region: Gulf Coast to Louisville Transportation Corridor
(1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
TEXAS GAS						
Gas Costs	$1.82	$1.90	4.3	$1.82	$1.90	4.3
Reservation Charge (1994 $/MMBtu-Mo.)	8.49	13.14	54.8	8.49	13.06	53.8
Usage Charge	0.31	0.06	-80.7	0.31	0.06	-80.7
Fuel Retention	3.7%	2.3%		3.7%	2.3%	
Total - Transportation Cost	$0.66	$0.54	-18.2	$1.08	$1.18	9.3

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994

Southeast Region: Gulf Coast to Miami Transportation Corridor
(1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
Florida Gas Transmission						
Gas Costs	$2.04	$1.90	-6.7	$2.04	$1.90	-6.7
Reservation Charge (1994 $/MMBtu-Mo.)	6.99	13.17	88.3	6.99	13.09	87.1
Usage Charge	0.11	0.07	-34.8	0.11	0.07	-34.8
Fuel Retention	2.3%	2.3%		2.3%	2.3%	
Total - Transportation Cost	$0.38	$0.55	44.7	$0.73	$1.19	63.0

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994
Southeast Region: Arkoma Basin to Louisville Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
Noram (Arkla in 1991)						
Gas Costs	$1.67	$1.73	3.4	$1.67	$1.73	3.4
Reservation Charge (1994 $/MMBtu-Mo.)		6.32	N/A		6.24	N/A
Usage Charge	0.14	0.05	-64.1	0.14	0.05	-64.1
Fuel Retention	1.0%	1.7%		1.0%	1.7%	
Total - Transportation Cost	0.16	0.29	81.3	0.16	0.59	268.8
Total - Delivered Cost of Gas	1.83	2.02	10.2	1.83	2.32	26.6
Texas Gas (Z1 - Z4)						
Gas Costs	1.83	2.02	10.2	1.83	2.32	26.6
Reservation Charge (1994 $/MMBtu-Mo.)	8.04	12.09	50.4	8.04	12.09	50.4
Usage Charge	0.28	0.04	-85.6	0.28	0.04	-85.6
Fuel Retention	2.5%	2.3%		2.5%	2.3%	
Total - Transportation Cost	$0.75	$0.77	2.7	$1.15	$1.68	46.1

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994

Midwest Region: Gulf Coast to Detroit Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
Route A						
TRUNKLINE						
Gas Costs	$1.82	$1.90	4.3	$1.82	$1.90	4.3
Reservation Charge (1994 $/MMBtu-Mo.)	6.24	12.82	105.5	6.24	12.74	104.1
Usage Charge	0.16	0.05	-68.9	0.16	0.05	-68.9
Fuel Retention	1.5%	2.0%		1.5%	2.0%	
Total - Transportation Cost	0.39	0.51	30.8	0.70	1.13	61.4
Total - Delivered Cost of Gas	2.21	2.41	8.9	2.52	3.03	20.1
PANHANDLE EASTERN						
Gas Costs	2.21	2.41	8.9	2.52	3.03	20.1
Reservation Charge (1994 $/MMBtu-Mo.)	9.33	6.95	-25.5	9.33	6.95	-25.5
Usage Charge	0.23	0.03	-86.7	0.23	0.03	-86.7
Fuel Retention	5.1%	2.2%		5.1%	2.2%	
Total - Transportation Cost	$1.03	$0.82	-20.4	$1.82	$1.80	-1.1
Route B						
ANR						
Gas Costs	$1.82	$1.90	4.3	$1.82	$1.90	4.3
Reservation Charge (1994 $/MMBtu-Mo.)	8.62	12.33	43.1	8.62	12.25	42.1
Usage Charge	0.39	0.05	-87.0	0.39	0.05	-87.0
Fuel Retention	2.0%	4.4%		2.0%	4.4%	
Total - Transportation Cost	$0.71	$0.54	-23.9	$1.13	$1.14	0.9
Route C						
TRUNKLINE (Field - Z2)						
Gas Costs	$1.82	$1.90	4.3	$1.82	$1.90	4.3
Reservation Charge (1994 $/MMBtu-Mo.)	6.97	14.05	101.6	6.97	13.97	100.4
Usage Charge	0.17	0.05	-70.8	0.17	0.05	-70.8
Fuel Retention	1.8%	2.2%		1.8%	2.2%	
Total - Transportation Cost	$0.43	$0.55	27.9	$0.78	$1.24	59.0

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994
Central Region: Rocky Mountain to Denver Transportation Corridor
(1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
Colorado Interstate Gas						
Gas Costs	$2.14	$1.62	-24.4	$2.14	$1.62	-24.4
Reservation Charge (1994 $/MMBtu-Mo.)	5.80	9.13	57.4	5.80	9.05	56.0
Usage Charge	0.13	0.04	-68.9	0.13	0.04	-68.9
Fuel Retention	3.0%	2.8%		3.0%	2.8%	
Total - Transportation Cost	$0.38	$0.39	2.6	$0.67	$0.83	23.9

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994

Central Region: Mid-Continent to Kansas City Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
PANHANDLE EASTERN						
Gas Costs	$1.67	$1.73	3.4	$1.67	$1.73	3.4
Reservation Charge (1994 $/MMBtu-Mo.)	5.13	11.34	120.8	5.13	11.26	119.2
Usage Charge	0.21	0.05	-76.7	0.21	0.05	-76.7
Fuel Retention	3.6%	3.0%		3.6%	3.0%	
Total - Transportation Cost	$0.44	$0.47	6.8	$0.70	$1.03	47.1

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994
West Region: San Juan to Southern California Transportation Corridor
(1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
EL PASO NATURAL GAS						
Gas Costs	$1.65	$1.62	-1.9	$1.65	$1.62	-1.9
Reservation Charge (1994 $/MMBtu-Mo.)	6.30	9.39	49.0	6.30	9.31	47.6
Usage Charge	0.43	0.07	-83.7	0.43	0.07	-83.7
Fuel Retention	5.0%	5.0%		5.0%	5.0%	
Total - Transportation Cost	0.72	0.46	-36.1	1.03	0.92	-10.7
Total - Delivered Cost of Gas	2.37	2.08	-12.3	2.68	2.54	-5.3
MOJAVE						
Gas Costs	2.37	2.08	-12.3	2.68	2.54	-5.3
Reservation Charge (1994 $/MMBtu-Mo.)			N/A			N/A
Usage Charge	0.31	0.33	6.2	0.31	0.33	6.2
Fuel Retention	0.5%	0.5%		0.5%	0.5%	
Total - Transportation Cost	$1.04	$0.80	-23.1	$1.35	$1.26	-6.7

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994

West Region: Canada to Southern California Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
ALTAMONT						
Gas Costs	$2.14	$1.75	-18.4	$2.14	$1.75	-18.4
Reservation Charge (1994 $/MMBtu-Mo.)			N/A			N/A
Usage Charge	0.55	0.51	-6.7	0.55	0.51	-6.7
Fuel Retention	1.4%	1.5%		1.4%	1.5%	
Total - Transportation Cost	0.58	0.54	-6.9	0.58	0.54	-6.9
Total - Delivered Cost of Gas	2.72	2.29	-15.9	2.72	2.29	-15.9
KERN RIVER						
Gas Costs	2.72	2.29	-15.9	2.72	2.29	-15.9
Reservation Charge (1994 $/MMBtu-Mo.)		23.77	N/A		23.68	N/A
Usage Charge	0.91	0.01	-98.4	0.91	0.01	-98.4
Fuel Retention	1.5%	1.0%		1.5%	1.0%	
Total - Transportation Cost	$1.53	$1.36	-11.1	$1.53	$2.52	64.7

See footnotes at end of table.

Table E1. Corridor Maximum Unit Transportation Rates 1991, 1994

Southwest Region: Arkoma Basin to Little Rock Transportation Corridor (1994 dollars per million Btu) - Continued

	100% Load Factor Rate			40% Load Factor Rate		
	1991	1994	Change (percent)	1991	1994	Change (percent)
NORAM (formerly Arkla)						
Gas Costs	$1.67	$1.73	3.4	$1.67	$1.73	3.4
Reservation Charge (1994 $/MMBtu-Mo.)	4.75	6.32	33.1	4.75	6.24	31.3
Usage Charge	0.27	0.05	-81.3	0.27	0.05	-81.3
Fuel Retention	2.3%	1.7%		2.3%	1.7%	
Total - Transportation Cost	$0.46	$0.29	-37.0	$0.70	$0.59	-15.7

MMBtu = Million Btu. Mo. = Month.

Note: For 1994 rates, first reservation charge in each route includes a Gas Research Institute (GRI) surcharge of $0.2180 per MMBtu for 100 percent load factor rates and a $0.1340 per MMBtu GRI surcharge for 40 percent load factor rates.

Sources: Energy Information Administration, Office of Oil and Gas, derived from: **1991:** Florida Gas Transmission Company base rates—H. Zinder & Associates, *Summary of Rate Schedules of Natural Gas Pipeline Companies* (March 1991); Other rates—Foster Associates, *Competitive Profile of U.S. Interstate Pipeline Companies* (October 1991); **1994:** Kern River Gas Transmission Company base rates—Federal Energy Regulatory Commission Automated System for Tariff Retrieval (FASTR); Other rates—Foster Associates, *Competitive Profile of Natural Gas Services* (December 1994).

Appendix F

Companies with Electronic Tariffs on File at FERC

Appendix F

Companies with Electronic Tariffs on File at FERC

Respondents to FERC Form 2—Annual Report for Major Natural Gas Companies

1. Algonquin Gas Transmission Company
2. ANR Pipeline Company
3. Arkla Energy Resources Company
4. CNG Transmission Corporation
5. Colorado Interstate Gas Company
6. Columbia Gas Transmission Corporation
7. Columbia Gulf Transmission Company
8. East Tennessee Natural Gas Company
9. El Paso Natural Gas Company
10. Equitrans, Inc.
11. Florida Gas Transmission Company
12. Great Lakes Gas Transmission Limited Partnership
13. High Island Offshore System*
14. Iroquois Gas Transmission System, l. P.
15. Kern River Gas Transmission
16. KN Energy Inc.*
17. KN Interstate Gas Transmission
18. KN Wattenberg Transmission Ltd. Liability Co.*
19. Koch Gateway Pipeline Company
20. Michigan Gas Storage Company*
21. Midwestern Gas Transmission Co.
22. Mississippi River Transmission Corporation
23. Mojave Pipeline Company
24. National Fuel Gas Supply Corporation
25. Natural Gas Pipeline Company of America
26. Northern Border Pipeline Company
27. Northern Natural Gas Company
28. Northwest Alaskan Pipeline Company*
29. Northwest Pipeline corporation
30. Overthrust Pipeline Company*
31. Pacific Gas Transmission Company
32. Panhandle Eastern Pipe Line Company
33. Questar Pipeline Company
34. Sea Robin Pipeline Company*
35. Southern Natural Gas Company
36. Stingray Pipeline Company*
37. Tennessee Gas Pipeline Company
38. Texas Eastern Transmission Corporation
39. Texas Gas Transmission Corporation
40. Trailblazer Pipeline Company
41. Transcontinental Gas Pipe Line Corp.
42. Transwestern Pipeline Company
43. Trunkline Gas Company
44. U-T Offshore System*
45. Viking Gas Transmission Company
46. Williams Natural Gas Company
47. Williston Basin Interstate Pipeline Company
48. Wyoming Interstate Company Ltd.*

*These companies are not considered as major interstate pipelines. They file with the Federal Energy Regulatory Commission because they operate in offshore Louisiana/Texas Federal waters or they otherwise tie into or support other major interstate pipeline companies or services.

Respondents to FERC Form 2-A—Annual Report for Nonmajor Natural Gas Companies

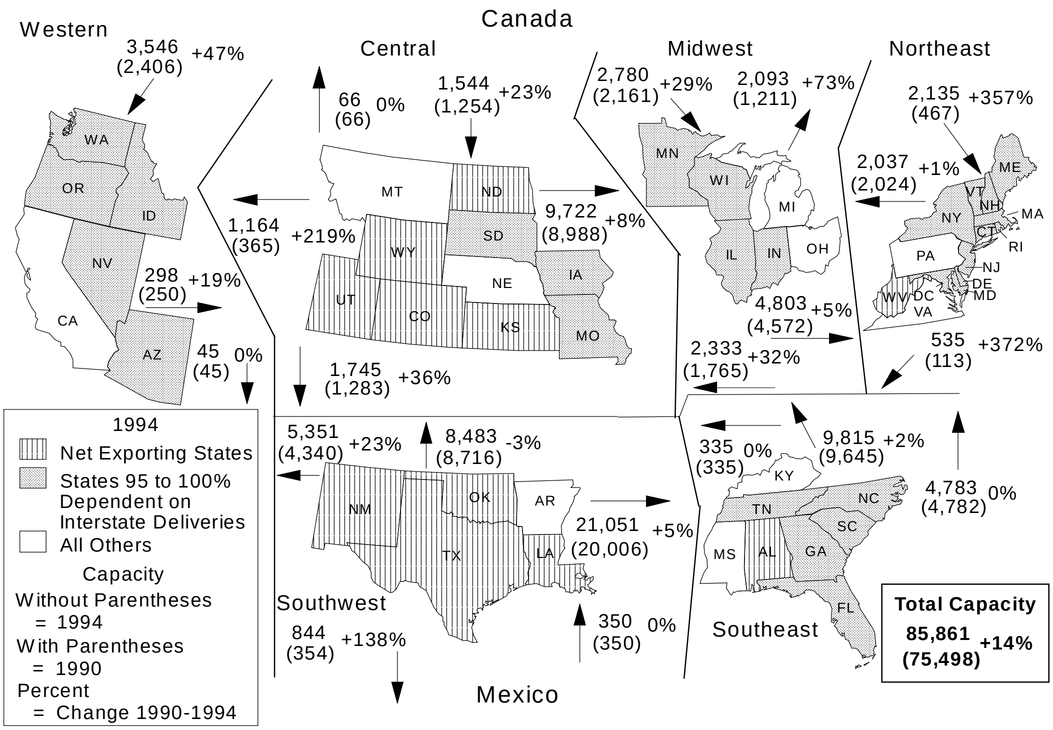
1. Alabama-Tennessee Natural Gas Company
2. Algonquin LNG Inc. *
3. ANR Storage Company
4. Arkansas Oklahoma Gas Corporation
5. Arkansas Western Pipeline Company
6. Arkansas Western Gas Company *
7. Bear Creek Storage Company *
8. Black Marlin Pipeline Company *
9. Blue Lake Gas Storage Company
10. Bluefield Gas Company
11. Boundary Gas Company
12. Canyon Creek Compression Company
13. Caprock Pipeline Company
14. Carnegie Natural Gas Company
15. Centra Pipeline Minn. Inc.
16. Chandeleur Pipe Line Company
17. Columbia LNG Corporation *
18. DistriGas of Massachusetts Corporation
19. Eastern Shore Natural Gas Company
20. Freeport Interstate Pipeline Company
21. Gasdel Pipeline System Inc.
22. Gas Transport Inc.
23. Glacier Gas Company
24. Granite State Gas Transmission
25. Greely Gas Company *
26. Gulf States Transmission Company
27. Hampshire Gas Company
28. Honeoye Storage Corporation
29. Iowa-Illinois Gas & Electric *
30. Jackson Prairie Underground Storage Project
31. Jupiter Energy Corporation
32. KB Pipeline Company *
33. Kentucky-West Virginia Gas Company
34. Louisiana-Nevada Transit Company
35. Mid-Louisiana Gas Company
36. MIGC, Inc.
37. Mobile Bay Pipeline Company
38. Moraine Pipeline Company
39. National Pipeline Company
40. Nora Transmission Company
41. Oktex Pipeline Company
42. Orange & Rockland Utilities
43. Ozark Gas Transmission System
44. Pacific Interstate Offshore Inc.
45. Pacific Interstate Transmission Company *
46. Paiute Pipeline Company
47. Penn-Jersey Pipe Line Company
48. Penn-York Energy Corporation *
49. Pennsylvania & Southern Gas Company
50. Phillips Gas Pipeline Company
51. Point Arguello Natural Gas Line
52. Raton Gas Transmission Company
53. Richfield Gas Storage System
54. Riverside Pipeline Company, L. P.
55. Sabine Pipe Line Company *
56. South Georgia Natural Gas Company
57. Southern Energy Company (LNG) *
58. Southwest Gas Storage Company
59. Southwest Gas Transmission Company
60. Steuben Gas Storage Company
61. Sumas International Pipeline Inc.
62. Superior offshore Pipeline Company
63. TCP Gathering Company
64. Tarpon Transmission Company
65. Texas-0hio Pipeline, Inc.
66. Trunkline LNG Company *
67. Union Light, Heat & Power Company *
68. Valero Interstate Transmission Company *
69. West Texas Gas Inc.
70. Western Gas Interstate Company
71. Western Transmission Corporation
72. WestGas Interstate, Inc.

* Denotes nonmajor natural gas companies filing in Form No. 2 format.

Company Data Available Through the FERC FASTR System

1. Alabama-Tennessee Natural Gas Company
2. Algonquin Gas Transmission Company
3. Algonquin LNG, Inc.
4. ANR Pipeline Company
5. ANR Storage Company
6. Arkansas Western Pipeline Co.
7. Black Marlin Pipeline Company
8. Blue Dolphin Pipe Line Company
9. Blue Lake Gas Storage Company
10. Boundary Gas, Inc.
11. Canyon Creek Compression Company
12. Caprock Pipeline Company
13. Carnegie Natural Gas Company
14. Centra Pipelines Minnesota Inc.
15. Chandeleur Pipe Line Company
16. CNG Transmission Corporation
17. Colorado Interstate Gas Company
18. Columbia Gas Transmission Corporation
19. Columbia Gulf Transmission Company
20. Consolidated System LNG Company
21. Cove Point LNG Limited Partnership
22. Crossroads Pipeline Company
23. DistriGas Corporation
24. DistriGas Of Massachusetts Corporation
25. East Tennessee Natural Gas Company
26. Eastern Shore Natural Gas Company
27. El Paso Natural Gas Company
28. Equitrans, Inc.
29. Florida Gas Transmission Company
30. Gas Gathering Corporation
31. Gasdel Pipeline System, Inc.
32. Granite State Gas Transmission, Inc.
33. Great Lakes Gas Transmission Limited Partner
34. Gulf States Transmission Corporation
35. High Island Offshore System
36. Iroquois Gas Transmission System, L.P.
37. Jupiter Energy Corporation
38. K N Interstate Gas Transmission Co.
39. K N Wattenberg Transmission Limited Liability
40. Kentucky West Virginia Gas Company
41. Kern River Gas Transmission Company
42. Koch Gateway Pipeline Company
43. Michigan Consolidated Gas Company
44. Michigan Gas Storage Company
45. Mid Louisiana Gas Company
46. Midwest Gas Storage, Inc.
47. Midwestern Gas Transmission
48. MIGC, Inc.
49. Mississippi River Transmission Corporation
50. Mobile Bay Pipeline Company
51. Mojave Pipeline Company
52. Moraine Pipeline Company
53. National Fuel Gas Supply Corporation
54. Natural Gas Pipeline Company Of America
55. Nora Transmission Company
56. Noram Gas Transmission Company
57. North Penn Gas Company
58. Northern Border Pipeline Company
59. Northern Natural Gas Company
60. Northwest Pipeline Corporation
61. Oktex Pipeline Company
62. Overthrust Pipeline Company
63. Ozark Gas Transmission System
64. Pacific Gas Transmission Company
65. Pacific Interstate Offshore Company
66. Pacific Interstate Transmission Company
67. Pacific Offshore Pipeline Company
68. Paiute Pipeline Company
69. Panhandle Eastern Pipe Line Company
70. Penn-Jersey Pipe Line Co.
71. Penn-York Energy Corporation
72. Petal Gas Storage Company
73. Phillips Gas Pipeline Company
74. Questar Pipeline Company
75. Raton Gas Transmission Company
76. Richfield Gas Storage System
77. Riverside Pipeline Company, L. P.
78. Sabine Pipe Line Company
79. Sea Robin Pipeline Company
80. South Georgia Natural Gas Company
81. Southern Natural Gas Company
82. Southwest Gas Storage Company
83. Stingray Pipeline Company
84. Superior Offshore Pipeline Company
85. Tarpon Transmission Company
86. Tennessee Gas Pipeline Company
87. Texas Eastern Transmission Corporation
88. Texas Gas Pipe Line Corporation
89. Texas Gas Transmission Corporation
90. Texas-Ohio Pipeline, Inc.
91. The Inland Gas Company
92. Trailblazer Pipeline Company
93. Transcontinental Gas Pipe Line Corporation
94. Transwestern Pipeline Company
95. Trunkline Gas Company
96. Trunkline LNG Company
97. U-T Offshore System
98. Valero Interstate Transmission Company
99. Viking Gas Transmission Company
100. Washington Natural Gas Company
101. West Texas Gas, Inc.
102. Western Gas Interstate Company
103. Western Transmission Corporation
104. WestGas Interstate, Inc.
105. Williams Natural Gas Company
106. Williston Basin Interstate Pipeline Co.
107. Wyoming Interstate Company, Ltd.
108. Young Gas Storage Company, Ltd.

Figure 1. Interregional Natural Gas Pipeline Capacity, 1990 and 1994
(Million Cubic Feet per Day)



Sources: **State Export Status:** Energy Information Administration (EIA), Office of Oil and Gas, derived from: Production and Consumption, *Natural Gas Monthly* (April 1995). **Pipeline Capacity:** EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database, as of August 1995.

operational efficiencies resulting from the regulatory restructuring of the interstate pipeline system during this period. These changes to operations have greatly increased the flexibility and accessibility of the system. In addition, lower natural gas prices have increased demand for natural gas.

The principal flow patterns of natural gas from supply areas to markets in the lower 48 States have not changed significantly since 1988. However, several new routes and major increases on several existing routes developed during the period (Figure 3). These changes reflect the effort to meet regional market demands with (often distant) available supplies.[35] The major distribution patterns for natural gas remain those from the Southwest Region to markets located in the Midwest and Northeast Regions. This gas originates primarily in Texas and Louisiana and flows through the Southeast and Central Regions to those markets. Significant gas supplies also flow from the Southwest to markets in the Western Region (primarily California). Although several major pipelines were completed in the 1970's and 1980's to import more Canadian gas to the United States, flows from Canada accounted for only 7 percent of total national consumption in 1988.

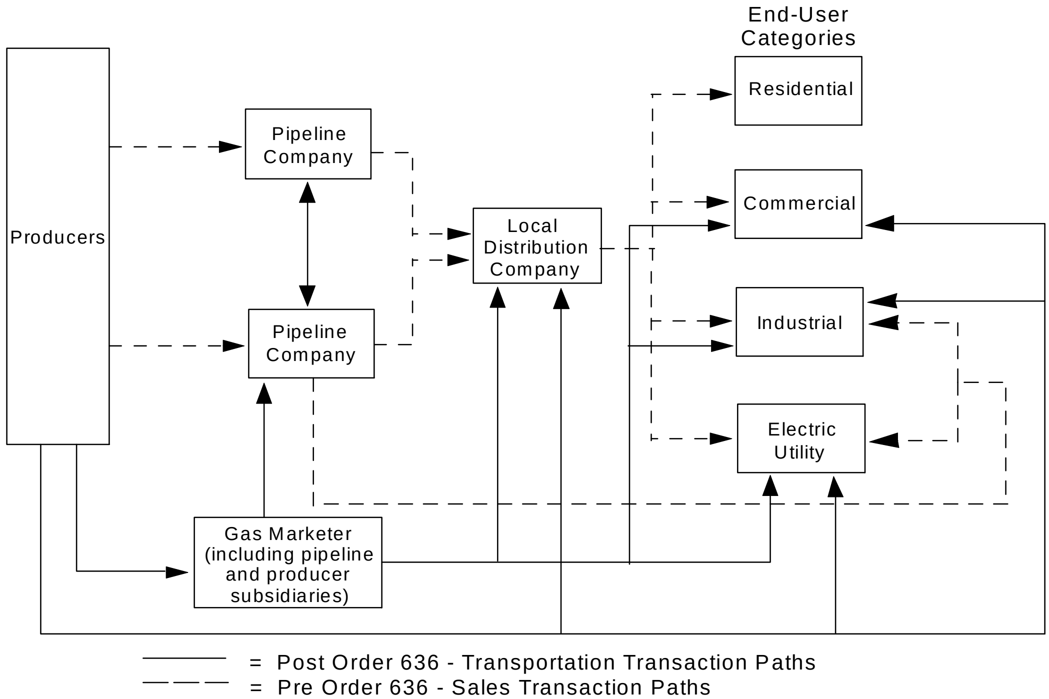
The major change in natural gas flow patterns since 1988 relates to the rapid rise in U.S. imports of Canadian natural gas (Figure 3). For instance, from 1988 through 1994:

- Imports of Canadian gas into the Western Region increased by 51 percent (Figure 4) as more supplies became available from western Canada. Lower prices for Canadian natural gas supplies, the growing demand for gas in the Western Region, and passage of stricter environmental restrictions helped spur this growth.

- Imports of Canadian gas into the U.S. Northeast rose from only 79 billion cubic feet in 1988 to 555 billion cubic feet in 1994. Growth in industrial demand, including electricity generation from both utility and nonutility generators, and in residential demand brought on this change.

[35] For instance, one of the earliest regions producing natural gas for market was the Northeast Region. As some of its fields in Appalachia became depleted in the 1940's, long-haul transmission lines began to be installed to tap into distant developing supply areas.

Figure 2. Principal Buyer/Seller Transaction Paths for Natural Gas Marketing



Note: Post Order 636, local distribution companies still provide sales service to residential and most commercial gas consumers.
Source: Energy Information Administration, Office of Oil and Gas.

- Canadian gas also became more important in the Midwest Region; imports increased by 57 percent, but natural gas consumption in the region increased by only 8 percent during the period.

Another major change in natural gas flow patterns has been the increase in flows from the Southwest and Central Regions to the Western Region. These changes occurred as new supplies were developed in the Rocky Mountain area of Colorado/Wyoming and the coalbed methane fields of southern Colorado and northern New Mexico. Much of this production development occurred in tight gas formations and coalbeds. Production from these sources was stimulated by the Section 29 production tax credits. Volumes destined for the Western Region from the Central Region increased by 915 percent, from 33 billion cubic feet in 1988 to 335 billion cubic feet in 1994. About half of these supplies flowed to the enhanced oil recovery markets in California.

Additional variability in flow patterns has originated in natural gas trade with Mexico. Exports of U.S. natural gas to Mexico grew rapidly between 1988 and 1992, increasing from 2 billion cubic feet in 1988 to 96 billion cubic feet in 1992. But since 1992, the level of exports has fallen by half. During the early 1990's, Mexico was viewed as a large potential market for some of the additional natural gas supplies developing in the Southwest Region. Several additional export terminals were opened in 1991; these more than doubled existing crossborder capacity. Crossborder capacity will expand further with the completion of current projects designed to move gas to Mexican consumers. While several border points with Mexico provide reverse flow capability, imports of Mexican gas to the United States remain negligible.

Changes in Consumption Patterns

Changes in the demand for natural gas are the basic forces that motivate decisions in the production, import, transportation, and distribution of natural gas. Consumers of natural gas respond both to economic signals, such as increased economic activity and relative prices, and to other external influences when they make energy choices. Federal legislation and policies affect the economic environment and other external factors that influence the trends and patterns in consumer energy choices. However, consumers' current decisions about energy are seldom totally independent of their earlier decisions. Because most energy choices are conditioned on matching fuel to available energy-

Figure 3. Flow Patterns on the Interstate Pipeline Network, 1994

Source: Energy Information Administration, Office of Oil and Gas.

using equipment, changes in consumption patterns take place gradually as consumers purchase new equipment to expand or replace existing energy-using facilities. Thus, trends in natural gas consumption generally reflect legislative and policy initiatives over the longer term.

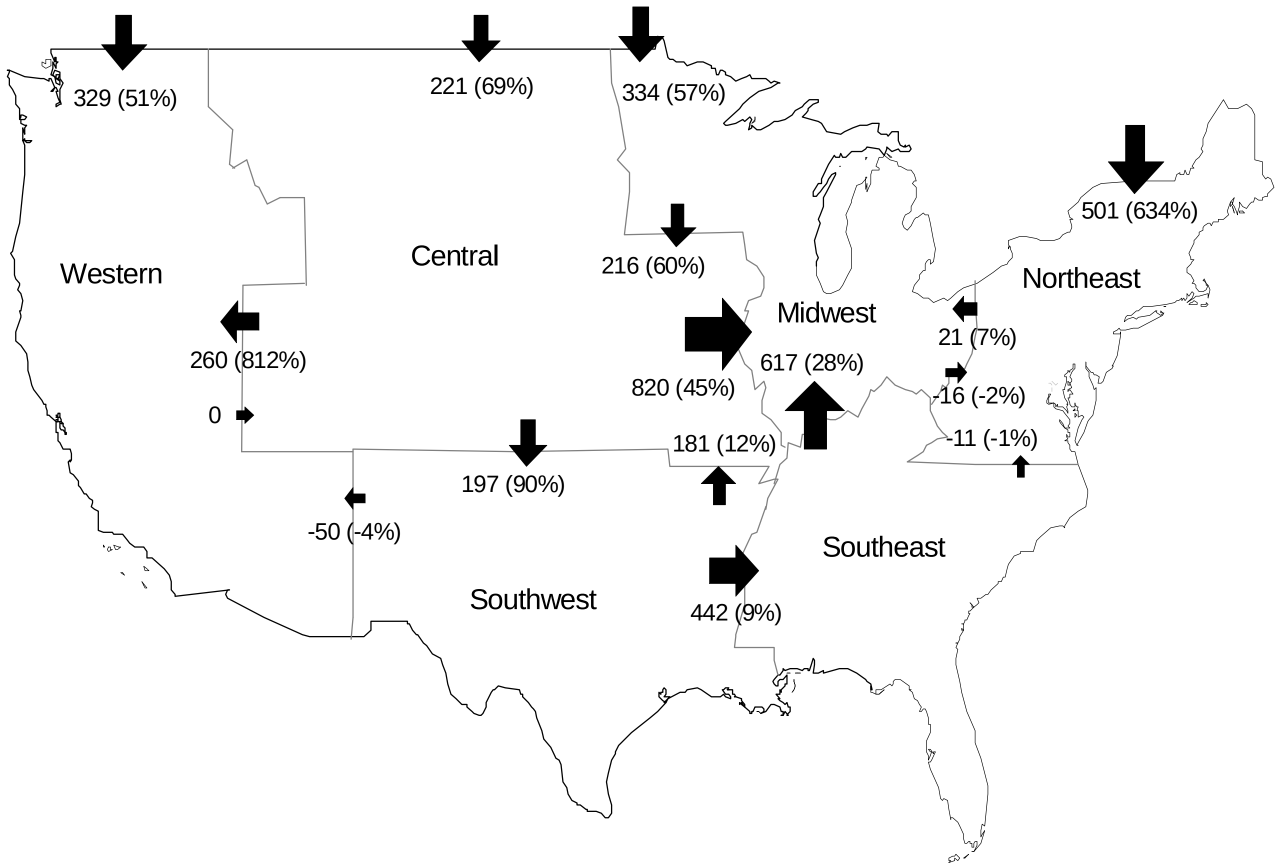
Total national natural gas consumption increased at an annual rate of 2.4 percent to the level of 20.3 trillion cubic feet between 1988 and 1993.[36] Gas consumption as a share of total domestic energy consumption rose correspondingly from 23.1 percent to 24.8 percent. During this same period, deliveries to end-use customers grew at an annual rate of 2.5 percent (Table 3).[37]

Natural gas consumption trends vary by sector and region. The use of natural gas for heating and its resulting seasonal pattern continues to dominate residential and commercial applications. Gas use in the industrial and electric utility sectors is increasingly related because the gas consumed by nonutility generators for the production of electricity is treated as part of industrial consumption. This section discusses trends in national and regional gas consumption. The discussion of sectoral consumption at a national level identifies differences in the

[36]Currently, final consumption data on both a regional and sectoral basis are available only through 1993, although consumption data by customer sector are available for 1994.

[37]Nationally, deliveries to end-use consumers grew slightly faster than total consumption because natural gas consumed in production and delivery of gas (lease and plant fuel and pipeline use) grew at an annual rate of only 1.1 percent.

Figure 4. Interregional Changes in Flow Levels on the Interstate Pipeline Network Between 1988 and 1994
(Volumes in Billion Cubic Feet)



Source: Energy Information Administration, *Natural Gas Annual 1988* (October 1989) and "Natural Gas Annual 1994," draft report.

relevant demand influences, while the description of regional consumption reflects the differences in regional components and the amount of demand by sector.

End-Use Consumption

From 1988 through 1993, total end-use consumption in the lower 48 States grew from 16.2 to 18.4 trillion cubic feet (Table 4), an average annual rate of 2.5 percent. The residential and commercial sectors had growth rates of only 1.4 and 1.8 percent, respectively (Table 3). Slow growth in natural gas consumption in the residential and commercial sectors reflects, at least in part, price changes of energy sources and advances in energy conservation, especially improvements that reduce the amount of energy used to heat a given amount of building space. Despite substantial increases in gas heating applications during the 1988 to 1993 period, the growth in residential and commercial sector gas consumption barely exceeded the overall increase in the population. Growing gas use for space and water heating has been partially offset by improved insulation and new gas heating technologies. A number of new Federal and State laws and policies, including programs to aid low-income home owners retrofit energy conservation measures, have encouraged end-use conservation. These initiatives, including the Energy Policy Act as discussed in Chapter 2, have been quite successful in improved energy end-use efficiency, thus slowing the increase in the growth of demand for gas, especially in the residential and commercial sectors.

Industrial consumption, which represented about 40 percent of all end-use gas consumption in 1993, rose at an annual rate of 4.5 percent. Natural gas consumed by nonutility generators (NUG's) is included in industrial sector gas consumption, so some of the increased consumption can be attributed to the development of nonutility generators of electricity. Much of the

Table 3. Growth in Natural Gas Consumption and Related Factors by Region Between 1988 and 1993

Region	Percent Population Growth	Population Weighted Average Heating Degree Days[1]	Annual Percent Growth of Gas Consumption				
			Residential	Commercial	Industrial	Electric Utility	Total
Northeast	2.4	4,484	1.1	3.6	9.0	4.0	4.0
Southeast	7.5	2,099	2.0	1.3	4.1	3.1	3.0
Midwest	3.3	5,162	1.1	0.7	4.1	8.7	2.1
Central	4.2	4,959	2.2	0.9	5.9	3.5	3.1
Southwest	5.9	2,055	1.5	2.4	2.7	0.1	1.8
Western	10.8	2,425	1.3	1.0	7.3	-2.2	2.3
Total Lower 48 States	5.5	--	1.4	1.8	4.5	0.4	2.5

[1]Degree-days are relative measures of outdoor air temperature used as an index for heating requirements. Heating degree-days are the number of degrees per day that the daily average temperature is below 65 degrees Fahrenheit. The daily average temperature is the mean of the maximum and minimum temperatures in a 24-hour period. The values shown are calculated by weighting State values for heating seasons 1988-89 through 1993-94 by population and averaging the values over the period. A heating season is from November of one year through March of the next year.

Sources: **Population:** U.S. Department of Commerce, Bureau of Census, *Statistical Abstract of the United States, 1994* (September 1994). **Heating Degree Days:** U.S. Department of Commerce, National Oceanic and Atmospheric Administration, *State, Regional, and National Monthly and Seasonal Heating Degree Days* (July 1993) and subsequent monthly updates. **Population Weighted Average Heating Degree Days:** Energy Information Administration, Office of Oil and Gas, derived from: Population and Heating Degree Days. **Gas Consumption:** 1988—Energy Information Administration, *Natural Gas Annual 1992*, Vol. 1 (November 1993); 1993—Energy Information Administration, *Natural Gas Annual 1993* (October 1994).

Table 4. Natural Gas Deliveries to End-Use Consumers by Region and Sector, 1988 and 1993
(Billion Cubic Feet)

Region	Residential		Commercial		Industrial		Electric Utility		Total	
	1988	1993	1988	1993	1988	1993	1988	1993	1988	1993
Northeast	1,177.2	1,244.4	619.1	740.6	629.8	968.5	232.9	283.1	2,659.3	3,236.9
Southeast	369.7	407.4	269.0	286.9	766.9	938.2	196.1	228.5	1,601.6	1,860.8
Midwest	1,546.1	1,636.7	760.6	789.2	1,158.7	1,413.5	33.1	50.3	3,498.5	3,889.8
Central	507.9	564.9	334.6	350.5	397.7	530.5	37.5	44.5	1,277.6	1,490.2
Southwest	412.3	444.1	309.2	348.3	2,737.1	3,127.6	1,514.6	1,519.0	4,973.3	5,439.4
Western	604.1	645.5	355.0	373.8	625.3	887.6	590.7	528.9	2,174.9	2,436.2
Total Lower 48 States	4,617.3	4,943.0	2,647.5	2,889.3	6,315.5	7,866.9	2,604.9	2,654.3	16,185.2	18,353.5

Sources: Energy Information Administration. **1988:** *Natural Gas Annual 1992*, Vol. 1 (November 1993). **1993:** *Natural Gas Annual 1993* (October 1994).

expansion in NUG's can be attributed to the success of Title 2 of the Public Utility Regulatory Policies Act of 1978, which established a program to encourage cogeneration and renewable resource electricity generation. The electricity producers who responded to this 1978 initiative form the backbone of the new nonutility power industry. Many of the NUG's are part of industrial plants that use cogeneration to produce both electricity and useful thermal energy. Therefore, gas consumption in industrial facilities that include NUG's cannot be separated between electricity and other industrial uses. Industrial establishments with NUG facilities are estimated to account for more than 20 percent of all industrial gas deliveries in 1993.[38]

Natural gas consumption in the electric utility sector was nearly stagnant, growing at an annual rate of only 0.4 percent. The low growth in electric utility consumption reflects the marginal role of utility gas-fired generation. Many utilities use gas as a swing fuel to fill in for shortfalls of nuclear generation or hydroelectric resources. Thus, gas consumption by these utilities varies according to the availability of generation from these lower variable cost resources. For example, gas consumption by electric utilities increased by more than 11 percent (about 300 billion cubic feet) between 1993 and 1994, partly because a drought reduced hydroelectric generation.

The use of natural gas for vehicle fuel comprises a large potential market, but it is still in its infancy. Legislative initiatives, including provisions in the Energy Policy Act and the Clean Air Act Amendments, to encourage alternatives to gasoline-powered vehicles have induced significant research and development of natural gas-powered vehicles.[39] But their total impact on natural gas consumption is barely measurable on a national scale. Natural gas used as a vehicle fuel represents a very small fraction of total consumption. The amount of natural gas delivered for use as vehicle fuel in 1993 was only 1 billion cubic feet, compared with U.S. deliveries of 18.5 trillion cubic feet to all consuming sectors. However, the rapid growth of vehicle-fuel gas consumption indicates the potential for natural gas in this developing market.

Regional End-Use Consumption

There are striking differences in gas consumption among geographic regions. Patterns of gas consumption vary in response to regional differences in gas penetration rates and to changes in the level of economic activity, as well as other, more transitory effects. Significant quantities of natural gas are used for space heating in the winter and electric generation in the summer in some regions. This temperature-sensitive gas consumption can drive fluctuations in regional consumption from year to year if there are major variations in weather patterns.

Three of the six regions—the Southwest, the Midwest and the Northeast—account for nearly 70 percent of all gas consumption. The Southwest alone consumes nearly 30 percent of all gas used in the lower 48 States. In the Southwest, gas consumption is concentrated in the industrial and electric utility sectors (85 percent of the total) (Figure 5). In this region, a significantly smaller share of gas use (less than 15 percent) is devoted to residential and commercial customers than is the case elsewhere. In the other two major gas-using regions, the Midwest and the Northeast, a much larger share of gas consumption (60 percent or more) is in the residential and commercial sectors.

Industrial gas consumption in the Southwest continues to represent the largest single regional use of gas, even though the region's share of industrial consumption fell from 43 percent in 1988 to 40 percent in 1993. The Southwest continues to attract industries, such as chemical manufacturing, that use large quantities of gas. In addition, the Southwest has been the leading region in NUG development; by 1993 the Southwest had about 32 percent of the national NUG generating capacity. Industrial consumption in other regions, noticeably the Western, Northeast, and, although from a small base, the Central Region, has shown significant growth. NUG development has contributed to this growth in industrial consumption in both the Western and Northeast Regions.

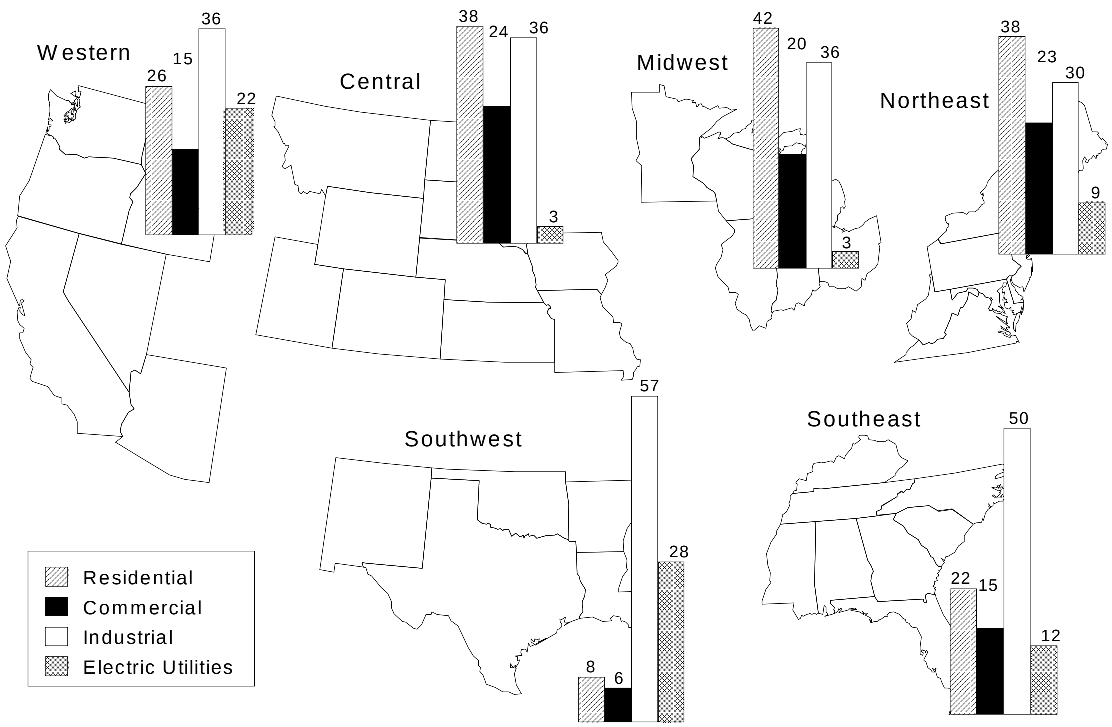
Electric utilities consume the least amount of natural gas of the end-use sectors in each region except the Southwest and Western. In 1993, utilities in the Southwest used 57 percent of all the gas supplied to electric utilities; another 20 percent was used by electric utilities in the Western Region. Although a few utilities in Florida, New York, and other States outside of these two regions also use gas regularly, their effect on gas consumption is relatively small.

As discussed in Chapter 2, patterns of increased gas consumption in large industrial and utility boilers were disrupted by the Power Plant and Industrial Fuels Use Act of 1978 (FUA).

[38]The proportion of industrial gas deliveries going to establishments with nonutility generation facilities is based on data from Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

[39]In order to promote the availability of vehicular natural gas (VNG), the Federal Energy Regulatory Commission issued Order 543 on July 16, 1992, simplifying the certification process for VNG retail sales and minimizing the reporting requirements of VNG wholesalers.

Figure 5. Percent of End-Use Natural Gas Consumption by Sector Within Regions, 1993



Note: Totals may not equal 100 because of independent rounding.
Source: Energy Information Administration, *Natural Gas Annual 1993*.

FUA discouraged both utility and industrial gas-using capacity expansion. However, FUA probably helped start the surge in nonutility generation because it permitted exemptions from FUA for industrial cogenerators. On the other hand, electric utilities started to build new coal-fired and nuclear power plants during the period of FUA restrictions because they were not allowed to rely on additional gas resources. By the time FUA was modified in 1987, most utility expansion needs could be filled by these new plants and by capacity that had been built by NUG's. Therefore, electric utility consumption of gas did not grow compared to the historically high levels of consumption in earlier periods. Nor does it appear that the pollution abatement requirements of the Clean Air Act Amendments have encouraged utilities to substitute significant amounts of gas for other fuels thus far.

Moreover, the expansion of NUG's in the industrial sector makes it difficult to separate growth in industrial applications of natural gas from growth in industrial site generation. Industrial gas consumption, cushioned by NUG development and encouraged by attractive gas prices and new access to pipeline transportation, has nearly returned to levels achieved in the early 1970's. The growth of industrial gas consumption is especially impressive in regions such as the Northeast where pipeline expansions and Canadian import availability have produced annual consumption growth rates as high as 9.0 percent between 1988 and 1993 (Table 3).

Despite the electric utilities' small share in gas consumption, much interest has been focused on gas used for electricity production for two reasons. First, although utility gas consumption has been growing, it still has not returned to its historical peak levels before FUA in the early 1970's. In 1993, electricutility gas deliveries were 33 percent below the 1972 peak.

Second, rapid expansion of nonutility, gas-fired generation led many forecasters to predict that NUG demand for gas would grow substantially during the remainder of the century and would compensate for the slow recovery of utility gas consumption. However, a restructuring of the electric industry has begun in response to provisions of the Energy Policy Act of 1992. Because the restructuring process is still in an early phase, there is a great deal of uncertainty about the need for additional electric generation in a restructured industry. This uncertainty may postpone additions to gas-fired generating capacity by both electric utilities and NUG's.