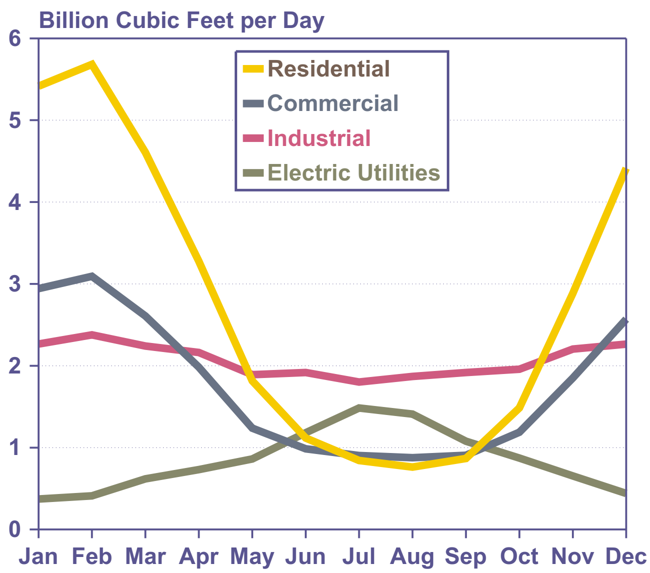
4. Natural Gas Supply, Infrastructure, and Pricing

Introduction

One of the goals of this study is to assess the ability of the natural gas infrastructure in the Northeast to support a shift by large-volume users of distillate fuel oil to natural gas. Demand for natural gas tends to be seasonal, and the infrastructure is designed and operated primarily to meet the need for firm service. The additional demand that would result from a shift of large-volume distillate users to gas would require an increase in gas deliveries to the Northeast.[55] More importantly, the new customers would require firm service throughout peak demand periods, to avoid the risk of adding demand to the oil market when conditions are tight. To provide the additional service, capacity expansions would be needed across the delivery system, with emphasis on ensuring physical deliverability even when demand in the region and the load on the gas infrastructure are at peak levels.

Natural gas consumption requirements in the Northeast are met through the combined operation of the three major components of the gas supply chain: transportation, storage, and distribution. Transportation generally refers to long-distance shipment of natural gas, primarily in interstate commerce. Storage generally refers to three methods of storing gas for later delivery: underground storage of large volumes of natural gas in depleted oil and gas reservoirs, and two “peak shaving” options for storing smaller volumes of liquefied natural gas (LNG)[56] or propane. Distribution refers to operations associated with the local delivery of gas, primarily to end users. Distribution, provided by local distribution companies (LDCs) within the borders of each State to deliver gas to customers at the burnertip, falls under the jurisdiction of State authorities. Transportation falls under Federal jurisdiction when it involves interstate commerce, or under State jurisdiction if the transportation service provider operates wholly within the borders of one State.

Figure 34. Average Monthly Natural Gas Consumption in the Northeast by Sector, 1989-1998



Source: Energy Information Administration (EIA), Oil and Gas Information Retrieval System (OGIRS) (February 2000).

Current Status of the Natural Gas Industry in the Northeast

Consumption

Although natural gas can be stored in the vicinity of major consumption markets, consumption by end users in U.S. markets generally occurs on a “just-in-time” basis, with most customers drawing supplies from the system as needed. With limited capability for on-site storage at customer locations, the system must meet customer requirements under a wide range of operating conditions. In the Northeast, seasonal patterns of gas consumption vary among the end-use sectors (Figure 34). For the residential and commercial sectors, average daily volumes peak in the months of the heating season and fall to yearly lows in the summer months. Average daily demand in the residential sector during February is more than 7 times the average during August. For electric utilities the pattern is reversed, with peak demands during the summer air-conditioning season (when demand for electricity peaks and even the most inefficient turbines are brought into service) and lows during the winter heating season. In the future, as more intermediate and base electric load is served by natural gas, the proportion of winter usage is expected to rise,

[55]In the discussion of natural gas supply, the Northeast consists of the New England Census division (Connecticut, Massachusetts, Maine, New Hampshire, Rhode Island, and Vermont) and the Middle Atlantic Census division (New Jersey, New York, and Pennsylvania).

[56]LNG is natural gas converted to a liquid state by cooling to -260°F (-162°C). The transformation reduces volume by a factor of 600 to 1, which makes it a useful storage option. The ability to regasify LNG rapidly makes it especially suitable as a source of gas supply to satisfy peak demand.

although not as high as in the summer. The seasonal pattern for industrial demand is similar to that for the residential and commercial sectors, but with much smaller shifts between the high and low points.

Supply

Sources of gas in the Northeast are production, imports, pipeline transportation, and storage withdrawals. Production of natural gas in the Northeast is limited to relatively small volumes in States in the Middle Atlantic region, where 1998 production was less than 4 percent of the total volume delivered to end users in the Middle Atlantic and less than 3 percent of the total delivered to end users in the Northeast as a whole.[57] The Northeast received 71 percent of current supply[58] in 1998 from net inflows from other U.S. regions, 24 percent from pipeline imports, and 2 percent from LNG imports. In New England, 89 percent of current supply was obtained from the domestic transportation network.[59] Although LNG is a small part of total regional supply, it is significant in New England. LNG made up 11 percent of New England supplies in 1998, and LNG volumes more than doubled in 1999 (96 billion cubic feet, compared with 43 billion cubic feet in 1998).

The key issue for the natural gas infrastructure is the ability of the supply system to meet gas demand requirements on winter peak days. At times of peak gas demand, system operators rely on various methods to manage demand and obtain suitable supplies. Demand is managed by removing some users from the system, usually under the terms of interruptible service contracts. To ensure delivery to customers who generally pay higher rates for firm service, supplies from the pipeline system may be supplemented with inventories drawn from regional underground storage facilities or with smaller amounts of LNG or propane from storage. As demand rises to peak levels, maintaining gas service to firm customers requires the use of increasingly costly measures, eventually involving LNG and propane storage volumes. On average, net storage withdrawals provide 20 percent or more of total U.S. natural gas consumption during the winter period; however, reliance on storage can be much higher in some peak periods. For example, on a typical winter day, gas from storage meets 60 to 80 percent of Ohio's natural gas requirements.[60]

Transportation

Gas transportation pipelines entering the Northeast, including domestic lines from the Southwest into the Middle Atlantic region and cross-border lines from Canada, have a combined design capacity of 12.52 billion cubic feet per day, or an annual equivalent of 4.57 trillion cubic feet—well in excess of the region's total consumption of 2.9 trillion cubic feet in 1998. Existing pipeline capacity in many parts of the Northeast is adequate to meet current firm-service demand, and some of the area's pipeline systems have unused capacity on an annual basis. In fact, capacity utilization rates along pipeline corridors entering the Middle Atlantic and New England regions averaged 61 to 86 percent during 1998.[61] During peak periods, however, most service providers are heavily, if not fully, utilized.

Transported gas is the major source of new gas supplies in the Northeast, and capacity entering the region grew by 13 percent from 1996 to the end of 1998. Expansion continued in 1999, with the completion of nine projects providing 1,080 million cubic feet per day, or about 0.4 trillion cubic feet per year, of additional capacity (Figure 35). More than half of the new capacity in 1999 (618 million cubic feet per day) was associated with the Maritimes and Northeast Pipeline and Portland Gas Transmission System projects, which will transport Canadian gas to the New England area. Those two projects alone increased overall pipeline capacity into the Northeast region by 5 percent.[62]

There are some problem areas in the Northeast. Pipeline capacity in the New York City area appears inadequate to meet growing market demand, as indicated by recent price spikes in the area due to several constraint points that have developed in recent years. The Leidy area of north central Pennsylvania (a major hub area with numerous interconnections among major interstate natural gas pipelines) is rapidly becoming a potential constraint for pipeline gas flowing to the East Coast, and particularly for northern New Jersey and New York City. Although the current pipeline capacity through the area appears sufficient, growing demand for gas trading and transport capacity probably will require some

57The last year of available EIA natural gas data with regional detail is 1998.

58Current supply is the sum of production, imports, and net inflow from other domestic regions. It excludes storage withdrawals.

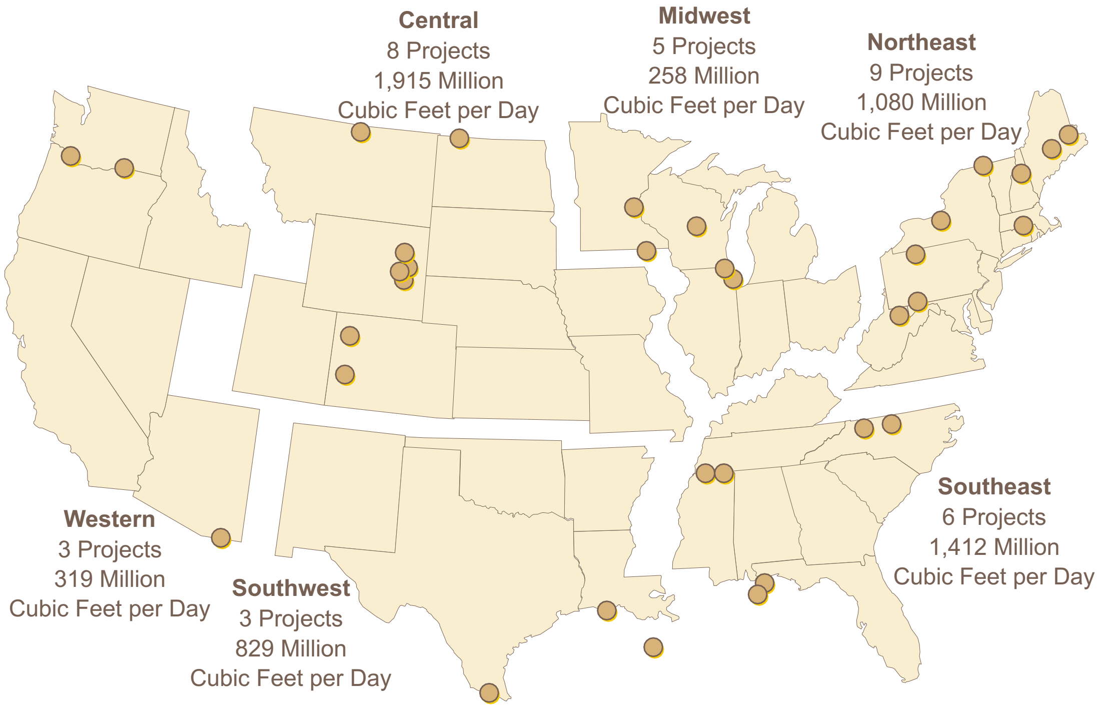
59"Supplies from the domestic transportation network" refers to the infrastructure from which the gas enters the region. The supplies may originate either as domestic production or as foreign production that passes through other U.S. regions.

60Public Utility Commission of Ohio, *Weather Impacts on Gas Cost and Residential Winter Heating Bills, 1996-1997* (January 31, 1997), p. 6.

61Energy Information Administration, EIAGIS-NG (March 2000).

62The completion of the Maritimes & Northeast Pipeline occurred late in the year. It did not initiate flow to U.S. markets until January 4, 2000.

Figure 35. U.S. Pipeline Development Projects Completed in 1999



Note: A dot on the map indicates the location of either a compressor station expansion or the furthest delivery point along a segment of new pipeline capacity.

Source: Energy Information Administration, derived from EIAGIS-NG Geographic Information System, Natural Gas Pipeline Construction Database, as of March 2000.

expansion of existing pipelines.[63] In the Boston metropolitan area, demand from developers of gas-fired power generation plants has been growing and is expected to grow more rapidly over the next decade, creating the potential for capacity shortfalls.

Another 23 interstate pipeline projects have been proposed for the Northeast region in 2000-2002—the largest number for any U.S. region (Figure 36). Several major projects were scheduled for completion by November 1, 2000, but delays in the approval process are expected to push back the startup dates for the Millennium, Independence, and several associated projects representing some 2 billion cubic feet per day of potential additional capacity. Given the competing nature of some proposals and the possibility of other alternatives to meet at least a portion of projected demand, generally not all proposed projects are expected to be built.[64]

The 23 projects proposed for the Northeast over the next several years would add a total of 5.9 billion cubic feet per day to the region's pipeline transportation capacity. The prospects are uncertain, however, for some of the projects.[65] For example, the New York portion of the Millennium pipeline has been delayed due to regulatory concerns about its necessity and safety, and negative public reaction to parts of its proposed route,[66] despite the fact that other sections have been approved by the Federal Energy Regulatory Commission (FERC) and the project is already underway. Some of the proposed projects involve new pipelines from the Midwest to the East Coast that would carry transshipments from

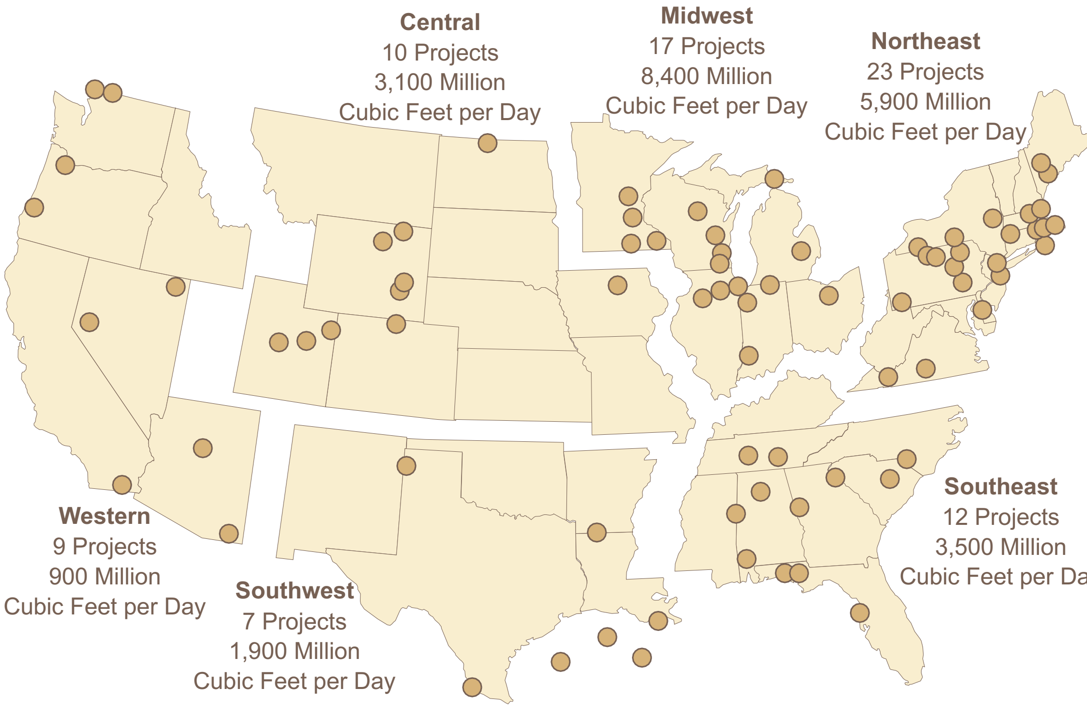
[63]Major pipeline segments operated by the Columbia Gas Transmission Company, CNG Transmission Company, National Fuel Gas Supply Corporation, Tennessee Gas Pipeline Company, Texas Eastern Transmission Company, and Transcontinental Gas Pipeline Company traverse the area around Leidy, Pennsylvania. The new Independence Pipeline and Transco Market-link projects both propose significant development of capacity in the area, and Tennessee Gas Pipeline and National Fuel Gas Supply Companies have also indicated tentative plans to expand segments of their systems in the area.

[64]Three projects that were originally announced for development in 2000 have yet to be filed with the FERC, and another 10 projects currently scheduled for 2000 in their filings have yet to be approved by the FERC.

[65]This simple summation of project capacities is for illustrative purposes. Because some of the projects are complementary and some are competing and might be mutually exclusive, the estimate of 5.9 billion cubic feet per day does not mean that these projects, if built, could satisfy additional market demand of that magnitude.

[66]For example, in January 2000, the New York Public Service Commission, fearing potential disruptions of electric service, asked FERC not to award final environmental clearance to the Millennium pipeline, because they were opposed to the sharing of a transmission right-of-way with Consolidated Edison Co. of New York as an "unacceptable risk." See "NY Pulls in Welcome Mat for the Millennium," *NGI's Daily Gas Price Index* (January 26, 2000).

Figure 36. Proposed U.S. Gas Pipeline Expansions, 2000-2002



Note: A dot on the map indicates the location of either a compressor station expansion or the furthest delivery point along a segment of new pipeline capacity.

Source: Energy Information Administration, derived from EIAGIS-NG Geographic Information System, Natural Gas Pipeline Construction Database, as of March 2000; and Federal Energy Regulatory Commission, Applications for "Certificate of Public Convenience and Necessity."

cross-border pipeline projects bringing gas from Canada to the Midwest region. If one or more of the new domestic pipelines were not built, unused capacity on existing pipelines from the Midwest to the Northeast could pick up a portion of the excess import load; however, this would likely prove inadequate in the long term, and even if the new projects are brought to completion, the existing lines are likely to undergo expansion if Northeast demand continues to grow as expected.

Storage and Local Distribution

Two types of gas storage are currently in use in the Northeast: underground sites—primarily, depleted oil and gas reservoirs[67]— and above-ground LNG facilities. LNG has a higher deliverability (or drawdown rate relative to stock levels) and is available in New England, but it is used only for short durations, generally to satisfy peak demand. Depleted oil and gas reservoirs take 5 months or more to fill and generally can be depleted over a 3-month period. The difference in flow performance for the two types of storage is reflected in their contributions to deliverability and capacity totals. Almost 95 percent of Northeast stock storage capacity in 1998 was attributed to underground facilities in western New York and Pennsylvania, which account for only 70 percent of maximum deliverability (Table 8). This difference affects supply availability: the LNG storage units contain only 8 days of supply when filled, as compared with more than 57 days of supply available on average from the underground units when they are filled.[68]

A simple view of gas storage is that it allows supplies to be acquired during periods of slow demand and delivered to end users during peak demand periods. In practice, however, storage utilization strategies tend to be more complex and interwoven with Public Service Commission requirements to provide reliable service to firm customers. Storage activities are managed to meet a combination of objectives: supplying gas to satisfy peak

[67]Salt cavern sites are becoming common in other regions of the country, but the only one in the Northeast as of December 1998 was the N.Y. State Electric & Gas facility in Seneca county. Maximum deliverability from the site was only 80 million cubic feet per day, and it is included with the data for other underground units. Another potential underground storage option is lined rock cavern (LRC) storage, which is being researched currently. If commercially successful, LRC storage would be suitable for the Northeast. This option was not included in the present analysis.

[68]Days of supply is measured as the ratio of working gas capacity to peak day deliverability. LNG supplies and normal underground storage should not be combined for this calculation. The addition of LNG distorts the calculation because it has a very high deliverability for only short durations. In practice, flows diminish as underground stocks are depleted, and actual drainage of all working gas from depleted reservoirs would require more time.

Table 8. Gas Storage Capacity and Deliverability in the Northeast, 1998

Region and State	Working Gas Capacity (Million Cubic Feet)	Total Capacity (Million Cubic Feet)	Peak Day Deliverability[b] (Million Cubic Feet per Day)	Days of Supply at Full Capacity
Middle Atlantic				
Underground				
New York	84,389	187,924	1,097	76.9
Pennsylvania	384,610	739,492	7,070	54.4
Total	**468,999**	**927,417**	**8,167**	**57.4**
LNG				
New York	3,399	3,399	772	4.4
New Jersey	4,962	4,962	714	6.9
Pennsylvania	4,253	4,253	544	7.8
Total	**12,614**	**12,614**	**2,030**	**6.2**
New England				
LNG				
Connecticut	2,549	2,549	127	20.1
Massachusetts	9,413	9,413	999	9.4
New Hampshire	4	4	5	0.8
Rhode Island	2,469	2,469	257	9.6
Total	**14,435**	**14,435**	**1,388**	**10.4**
Northeast				
Underground	468,999	927,417	8,167	57.4
LNG	27,049	27,049	3,418	7.9
Total	**496,048**	**954,466**	**11,585**	**—[a]**

[a]LNG totals should not be added to underground storage, because LNG is normally used to satisfy peak demand when underground storage is also being used.

[b]Peak day deliverability at 11,585 million cubic feet per day is available only for about 8 days. For the remainder of the winter, without LNG, peak day deliverability is 8,167 million cubic feet per day.

Sources: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Underground Natural Gas Storage Database and LNG Facilities Database, as of March 2000.

demand, balancing pipeline loads, and financial arbitrage. For the LDCs, which generally are responsible as the supplier of last resort, the ability to meet peak demand throughout the entire winter is arguably the predominant consideration, and their withdrawal strategies often reflect their concerns about being able to meet demand surges in the event of a late season cold snap. An unfortunate consequence of such a strategy is that reduced reliance on natural gas from storage restricts gas supplies to lower levels and may lead to higher prices in the short run. This apparently is what happened in the winter of 1996-1997, when gas was kept in storage during an early cold snap. Warm weather followed, and at least some withheld storage volumes were not needed later in the winter.[69]

Ideally, gas storage facilities in the Northeast would be sited close to major markets on the Atlantic coast, in order to minimize the time and expense required to move supplies to consumers and avoid potential transportation bottlenecks when demand surges. Proximity of storage facilities to end users would reduce the need for construction of additional pipeline transportation capacity to meet peak demands, allowing long-distance transportation lines to be designed to accommodate average flows, with some excess for responding to demand surges. Off-peak transportation would be able to move gas for baseload demand, storage replenishment, and incremental service to low-priority customers not supplied during peak periods. Local distribution networks in the Northeast already are designed to meet very high demand surges.[70] For example, the 1999 flow capacity of transportation pipelines into New England is only 2.7 billion cubic feet per day, but local gas utilities managed peak deliveries of 3.4 billion cubic feet on January 17, 2000.[71] The incremental sendout most likely represents a combination of storage gas and LNG imports.

There are distinct tradeoffs in performance and cost among storage, transportation pipelines, and LDCs. Although there are advantages to storage in managing transportation costs, reliance on storage incurs costs for injection (into an underground reservoir or conversion to LNG for above-ground storage), storage, and

[69]Energy Information Administration, "Natural Gas Residential Pricing Developments During the 1996-97 Winter," *Natural Gas Monthly*, DOE/EIA-0130(97/08) (Washington, DC, August 1997).

[70]In some areas, gas is delivered directly to consumers by interstate pipeline companies, bypassing the LDCs. This practice is not thought to be widespread in the Northeast.

[71]"New England's Natural Gas Industry Reaches New Growth Levels," New England Gas Association Press Release (March 23, 2000), web site biz.yahoo.com/prnews/000323/ne_gas_ass_1.html.

withdrawal (or LNG regasification) that add directly to the unit costs of delivered gas. Further, in responding to the needs of a growing market, the costs of incremental storage expansion are likely to be higher than the average to date. The number of potential future underground storage sites is limited, and siting of new LNG storage tanks tends to be problematic, encountering local resistance that can increase costs even when it is successfully overcome. Generally, the high deliverability and higher costs make LNG storage most suitable as a source of supply in periods of extreme peak demand.

Sales and Service Contracts

Because natural gas demand is seasonal and pipeline systems generally are designed to handle expected loads during periods of peak demand (for example, pipelines typically are operated at as much as 120 percent of design pressures[72] to increase "line pack" during short-term demand peaks), spare capacity usually is available during off-peak periods, even after accounting for gas to replenish storage inventories. The combination of fixed pipeline capacity and variable load has led to the development of interruptible service contracts for some natural gas customers, as opposed to firm service contracts, which guarantee uninterrupted gas supplies throughout the year. Interruptible service contracts with pipeline operators or LDCs vary in terms and conditions but, generally, allow for service interruptions as a result of either temperature threshold triggers or system operating conditions (for example, when line pressure is threatened by high rates of drawdown on the system). In addition, some contracts provide firm service only for a limited duration, such as a month, or on a seasonal basis, with suspensions of service permitted during the winter. Suspension of service is not considered an interruption as long as the terms of the arrangement are fully met. Roughly 10 to 15 percent of all natural gas deliveries to U.S. consumers by interstate pipelines in 1997 were on an interruptible basis, down substantially from roughly half of all deliveries in the late 1980s.[73]

Interruptible gas contracts and firm service on a temporary basis allow pipeline operators to increase utilization of their fixed assets and better manage costs of service on average. Higher utilization overall enhances the economic return on pipeline assets, encourages further investments in the gas delivery system, and provides opportunities for large-volume energy consumers, such as industrial customers and electricity generators, to obtain energy supplies at lower prices. Sales of off-peak interruptible capacity also generate revenues that contribute toward at least a portion of pipeline capital costs, providing benefits to firm service customers as well.

Natural gas service may also be suspended voluntarily by some customers with switchable or dual-fuel capability, even when delivery capacity is available. For example, there are reports that some demand shifted from natural gas to distillate fuel oil during January and February 2000 because of the relative fuel prices, although most information to date on this market behavior is only anecdotal. Understanding this behavior and the motives behind it, based on relative fuel prices, is important.

Preliminary information indicates that there were interruptions of gas service in the Northeast in January 2000 as a result of both temperature and operating conditions.[74] There were no interruptions under firm service contracts, and there were no service interruptions at all in February. During January 2000, operational flow orders (OFOs) were issued by three pipeline companies serving the Northeast, alerting customers that they were expected to manage their gas takes from the system to conform strictly to the terms of their contracts. This was done by the pipelines for purposes of load management, and it does not indicate a reduction in service below capacity levels.

Interstate transporters and LDCs go to great lengths to avoid performance failure under firm service contracts because of the serious implications for their customers and others. (Although quite rare, interruptions may occur under firm service contracts when extreme conditions diminish system capability to the point that deliveries cannot be made to meet all of the supplier's firm contract obligations.) The companies also try to continue service even under interruptible contracts, subject to the availability of capacity during peak periods and the ability to continue service without resort to high-cost measures, such as propane injection, that are not provided for under interruptible service fees. As a result, interruptions are a regular feature of the gas industry. The movement to regulatory reform at the Federal and State levels has not altered the basic role or impact of interruptible gas contracts. The distinguishing characteristic of regulatory reform in the natural gas industry is a separation of commodity sales from other services. The impact of

[72]A pipeline's design capacity is defined as the maximum throughput that can be sustained throughout the year. Actual flow can exceed the design capacity for brief periods.

[73]Interstate Natural Gas Association of America, *Gas Transportation Through 1997*, Report No. 99-01 (April 1999). The stated percentages reflect primary capacity contract arrangements. Through capacity release transactions, at least some of the capacity held by firm contracts is resold on an interruptible basis.

[74]EIA is conducting a data collection effort directed to local distribution companies in an attempt to develop independent, statistically based estimates of gas service interruptions and their impact on distillate fuel oil markets across the Northeast. Results will be provided in a study scheduled for release later in 2000.

and response to a failure to deliver gas are the same whether the contract is for service only or for service and sales of gas to the customer.

Prices

End-use prices for natural gas are determined by the costs of the commodity (fuel) and related supply services (transportation, storage, and local distribution). They also reflect the type of service provided (firm or interruptible). For residential users, gas commodity price is only about 30 percent of the delivered price, and the remainder reflects the cost of services between the wellhead and the burnertip on a firm service basis. Because natural gas commodity prices are a small percentage of the delivered price, fluctuations in the gas commodity price result in much smaller relative changes in the delivered price to small-volume customers.

Small-volume customers, such as residential and some commercial and industrial consumers, generally receive their gas from LDCs, which typically bill their customers monthly. Monthly billing smooths out some of the daily price volatility seen in upstream markets, but it also introduces an information lag. Bills arrive after the billing period during which consumption decisions have been made, and the bill is stated in terms of totals or averages for the period. It is difficult at best for consumers to ascertain their marginal costs for timely decisions within the consumption period. Thus, if upstream supply prices rise rapidly, small-volume customers are not likely to be aware of the change in prevailing prices until after the billing period.

Effective price signals to residential customers also are limited by residential billing procedures, such as levelized billings, that are designed to avoid unexpected large increases in monthly gas expenditures when possible. This objective has resulted in the availability of consumer options such as budget-payment plans, in which the consumer is charged a uniform rate for 11 months, and discrepancies between cumulative payments and costs are addressed in the 12th month.[75] Budget-payment plans obscure not only the marginal cost of additional gas units consumed on any day, but also the average cost for the month or season.[76]

Natural gas billing methodologies can help the consumer by blunting the immediate impact of gas price fluctuations, but they do not provide a means to avoid paying their gas costs. In fact, residential prices and bills can rise dramatically during the heating season. A prime example occurred during the winter of 1996-1997. Nationally, although gas consumption was down 5.7 percent from the prior year, monthly prices were 10 to 20 percent higher, resulting in an expenditure increase by residential customers of 9 percent for the entire heating season.

Large-volume customers vary in their approach to gas acquisition, because the scale of their energy use provides opportunities that generally are unavailable to small-volume customers. Large customers tend to purchase gas "off system" directly from a marketer or producer and contract for delivery separately, rather than purchasing from a merchant LDC. The companies seek the best deals for their requirements, and if energy is particularly important to their operations they may even utilize an energy acquisition unit that specializes in sophisticated market trading.

Large-volume customers that cannot switch from natural gas depend on gas-on-gas competition and competition between service providers for advantages in their deals. Those with dual-fuel or switchable capability look for the least expensive fuel, relying on interfuel competition to yield advantageous transactions. The alternate fuel used by consumers who have natural gas as one option generally is distillate or residual fuel oil. The gas commodity itself, excluding the addition of substantial transportation, delivery, and storage charges, typically is much less expensive than petroleum products on a Btu basis. When natural gas delivery can be arranged at discounted rates, the combined costs result in an economic advantage generally favoring gas use; however, discounted service usually is available only under interruptible contracts.

Evaluating the Effects of Changes in Natural Gas Consumption Patterns

The potential for large-volume consumers of distillate to switch to natural gas varies over the short term versus the longer term horizon. The goal under the short-term scenario would be to prevent large-volume dual-fuel customers, including those with interruptible gas service contracts, from entering the distillate market to purchase distillate fuel oil during peak demand periods. In the longer term scenario, an additional goal would be to shift at least some large-volume consumers of distillate fuel oil (not currently able to switch) to year-round

[75] Complete reconciliation may not be achieved in a single month, depending on the amount owed by the consumer. The objective of these plans is to "smooth" the amounts owed by the customer, and in practice, *ad hoc* adjustments are introduced to achieve that goal. For example, payments under a budget-payment plan may be adjusted upward, even when out of cycle, if costs have risen so much that further delays in cost recovery are likely to result in a substantial "shock" if allowed to accumulate until the next reconciliation month. Thus, even customers under a plan for payment smoothing will experience some impact from a sudden, large increase in upstream gas prices.

[76] Alternative payment plans are not particular to natural gas markets. Similar plans are offered to heating oil customers.

use of natural gas.[77] In both cases, demand for natural gas in the Northeast region would be expected to rise above the levels already expected to result from the continuation of current market trends. The focus of this analysis is to estimate the effect of such shifts on natural gas infrastructure requirements.

One measure that provides insight into the potential short-term impact is provided by estimating the incremental load that shifted from natural gas to distillate fuel oil in the Northeast in January 2000. A comprehensive, direct estimate of the energy volumes affected is not available. In Chapter 3 of this report, it is estimated that the maximum switchable dual-fuel capability in the Northeast during a colder-than-normal winter heating season (December-February) is 133,000 barrels per day. That analysis is extended here to estimate the implications of such a switch on the natural gas infrastructure. A separate estimate of incremental demand for distillate fuel oil due to gas service interruptions in the short-term scenario was developed by EIA from in-house data and information provided by State agencies in New York, New Jersey, Connecticut, and Massachusetts—four of the top distillate-consuming States in the Northeast. The increase in distillate consumption from customers shifting out of natural gas is estimated at roughly 97,000 barrels per day.[78] The impact of distillate purchases by such customers, however, remains unclear pending results of an EIA survey of customers whose gas service was interrupted. This volume is equivalent to incremental peak demand of 510 million cubic feet of natural gas per day in the Middle Atlantic region and 40 million cubic feet per day in New England.[79] The long-term impact, through 2005, includes the projected market growth in the Northeast in the reference case of the *Annual Energy Outlook 2000* (*AEO2000*), the short-term impact, and the additional effects of shifting large-volume consumers of distillate fuel oil to natural gas through equipment conversions and retrofits.

A number of uncertainties are involved in estimating natural gas infrastructure requirements. EIA's *AEO2000* forecast, available monthly data, anecdotal evidence, and a number of assumptions were used in developing the estimates presented here. The initial focus of the analysis was to estimate the average daily natural gas and distillate consumption levels for a more extreme peak month.[80] In reality, peak day consumption levels can exceed average peak month levels by consequential amounts. However, for the purposes of this analysis it was assumed that natural gas storage and pipeline infrastructure requirements would increase in proportion to the increase in the estimates for the average daily consumption within the peak month. Estimates of 1999 and 2005 business-as-usual energy requirements for the Northeast were based on annual consumption projections from the *AEO2000* reference case, which shows distillate consumption in 2005 that is 11 percent higher than 1999 consumption in the industrial sector, 10 percent lower in the residential sector, and 39 percent lower in the electricity generation sector.

Peak-month volumes for natural gas in a colder-than-normal winter (Table 9) were estimated on the basis of the peak month to average annual ratios that occurred in 1994, a recent cold winter, and applied to the 1999 and 2005 reference case forecast from *AEO2000*. The methodology used in Chapter 3 (see Table 7) to derive estimates of switchable distillate consumption by large-volume, dual-fired customers in the winter season (December to February) was applied to 1999 base levels. The estimates were then converted to peak-month values by assuming that 40 percent of the winter consumption occurs in the peak month. The resulting values represent an estimate of the amount of distillate consumption in a colder-than-normal peak month that could be switched to natural gas in the short term without conversions or retrofits of existing equipment. These values include natural gas consumption that would have been switched to distillate fuel due to gas service interruptions.

Over the longer term, by 2005, it was assumed that some of the large-volume distillate users not currently dual-fired could convert to natural gas use with equipment conversions or retrofits. For the sake of this analysis, the extreme position was taken that all such users

[77] Present small-volume heating oil customers, such as residential and commercial consumers, can shift to natural gas also, but the present analysis is limited to large-volume customers. In general, small-volume consumers do not have strong economic incentives to switch from distillate.

[78] The EIA estimate is based on confidential data and therefore cannot be described in detail; however it is quite close to the 100,000 barrels per day estimated independently by the Petroleum Industry Research Foundation (cited in Chapter 2).

[79] Although not essential to the present analysis, the market impact of energy consumers shifting from natural gas to distillate depends on market transactions, and not on changes in fuel oil consumption, which are not necessarily equivalent. They can differ due to consumer use of on-site stocks of their alternative fuel, thus resulting in market purchases less than the daily consumption increase. On the other hand, the purchasing practices of switchable customers might increase transactions by more than the increase in consumption: i.e., on the day of purchase, large-volume users may buy fuel oil supplies for a number of days or longer. An analysis of the fuel oil market response also would depend on the duration of the incremental demand, because the cumulative drawdown would affect available inventories. Because the present analysis is concerned with the magnitude of incremental switching volumes to estimate gas capacity requirements at peak, duration is not considered to be relevant.

[80] Although the schedule of distillate purchases can have a significant impact on the distillate market, this analysis estimates distillate consumption, as opposed to purchases, because the focus is to calculate the comparable level of natural gas that would be consumed if natural gas were consumed in place of distillate.

Table 9. Average Daily Consumption of Natural Gas in the Peak Month Before and After Switching from Distillate to Natural Gas in the Northeast

Region	Short Term		Longer Term (2005)	
	Million Cubic Feet	Million Barrels[a]	Million Cubic Feet	Million Barrels[a]
New England				
Base Natural Gas Consumption (Not Switchable)	2,405[b]	425	2,582	456
Distillate Switchable/Convertible[c]	298	53	566	100
Total Consumption After Switching	2,703	477	3,148	556
Percentage Increase From Short-Term Base Consumption (2,405 Million Cubic Feet per Day[b])	12.4%	12.4%	30.9%	30.9%
Middle Atlantic				
Base Natural Gas Consumption (Not Switchable)	10,572[b]	1,868	11,182	1,975
Distillate Switchable/Convertible[c]	566	100	976	172
Total Consumption After Switching	11,138	1,968	12,158	2,148
Percentage Increase From Short-Term Base Consumption (10,572 Million Cubic Feet per Day[b])	5.4%	5.4%	15.0%	15.0%
Northeast				
Base Natural Gas Consumption (Not Switchable)	12,977[b]	2,292	13,764	2,431
Distillate Switchable/Convertible[c]	864	153	1,542	272
Total Consumption After Switching	13,841	2,445	15,306	2,704
Percentage Increase From Short-Term Base Consumption (12,977 Million Cubic Feet per Day[b])	6.7%	6.7%	17.9%	17.9%

[a]Distillate equivalent of natural gas consumption shown in the preceding column.

[b]1999 base consumption, used to calculate percentage increases after switching for both the short term and longer term.

[c]In the short term, this includes only customers with dual-fuel capability switchable from distillate to natural gas, using existing equipment. Also included is natural gas consumption that would have been switched to distillate due to gas service interruptions. In the longer term, it also includes customers choosing to convert to natural gas by retrofitting existing equipment or purchasing new equipment to burn natural gas.

Sources: Energy Information Administration, derived from *Annual Energy Outlook 2000*; and EIAGIS-NG Geographic Information System, Natural Gas Pipeline Database, as of March 2000.

would convert to natural gas by 2005. As in Chapter 3, the customers in this category, in combination with the dual-fired customers, were assumed to include all the distillate consumption in the electricity generation sector, the space heating portion of the commercial sector (52 percent), and the manufacturing segment of the industrial sector (48 percent). These factors were applied to the 2005 distillate consumption levels from the *AEO2000* reference case. The reference case shows the following increases in natural gas consumption in the Northeast from 1999 to 2005 by sector: residential, 2.9 percent; commercial, 3.5 percent; industrial, 10.6 percent; and electricity generation, 152 percent. For the commercial and electricity generation sectors, the process used to convert annual estimates of switchable distillate consumption to a peak month was the same as used for the short-term analysis. For the industrial sector, it was assumed that 20 percent of the switchable distillate consumption in a year would occur in the peak month.

Using the ratio of estimated peak-day consumption to average day consumption, peak day natural gas requirements in the Northeast in the near term could increase by 864 million cubic feet per day over the 1999 estimated peak consumption levels (Table 9). In the longer term, a scenario in which all large-volume distillate consumers in the Northeast shifted to natural gas would increase peak-month consumption of natural gas by up to 2,329 million cubic feet per day from the 1999 base by 2005. This scenario could raise peak-month natural gas consumption by 15 percent in the Middle Atlantic region and by 31 percent in New England by 2005 above the short-term base. The associated capacity expansion requirements could be substantial.

Pipeline Capacity Requirements

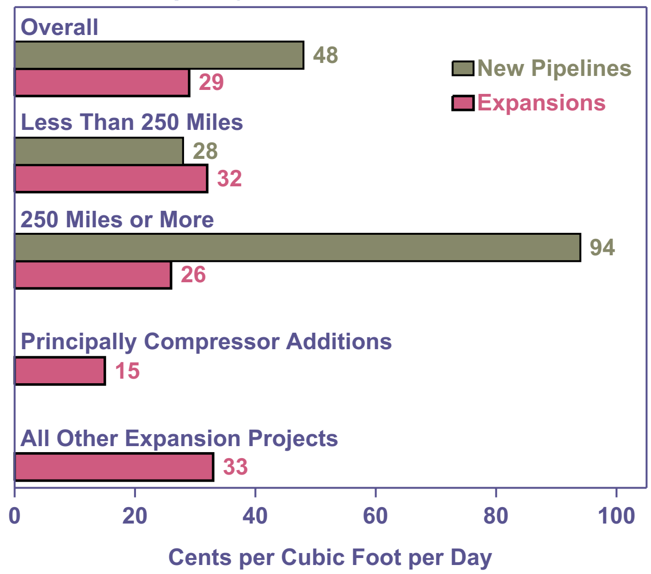
Because the Northeast relies heavily on natural gas supplies from outside the region, the interstate transportation system is a key element in satisfying demand increases. Given the general lack of interruptible service on the system during late January 2000, additional loads at peak times would require expanded capacity. Estimated new pipeline capacity entering a region must reflect the needed increase to accommodate the load that otherwise would have shifted to or remained with distillate fuel oil, and to handle the increase in the peak day volumes resulting from the shift to gas.

Estimated natural gas pipeline capacity entering New England at the beginning of 1999 was 2,739 million cubic feet per day. It is estimated that an additional 340 million cubic feet per day of capacity into New England would be required to support the short-term shift to gas. By 2005, the initial 1999 capacity would need to be increased by 846 million cubic feet per day. The recently built Maritimes and Portland pipelines (618 million cubic feet per day) should be sufficient for the indicated requirements in the short term, and they probably can meet a portion of the additional longer term requirements.[81] Pipeline capacity entering the entire Northeast region was 12,519 million cubic feet per day at the beginning of 1999. The shift from distillate to gas could require additional pipeline capacity of 839 million cubic feet per day in the short term and 2,241 million cubic feet per day by 2005 (Table 10).[82] The higher estimates represent a more successful conversion scenario, and the lower estimates reflect a more conservative assumption about the willingness and ability of large-volume consumers to shift from distillate fuel oil.

The arrival of gas into the Middle Atlantic and New England regions is the first stage of the supply process. Subsequent delivery of the gas to consumers would require the intraregional infrastructure to handle local distribution and management of system loads to meet the new peak load requirements. The introduction of the estimated new firm demand would require either new construction or the identification of uncommitted local capacity and assignment of that capacity to the new customers. The likelihood of identifying spare capacity that is properly positioned to serve the entire incremental load is low.

The need for new or additional pipeline capacity to meet the growing demand for natural gas in the Northeast can be handled in several ways, each with particular physical and/or financial advantages and disadvantages. The least expensive option, often the quickest and easiest, and usually the one with the lowest environmental impact is to upgrade facilities on existing routes. Typically, new pipelines, for which right-of-way land must be purchased, new pipeline laid, and operating facilities installed, would cost much more than expansion of existing routes. For instance, a new pipeline, such as the proposed long-distance Alliance Pipeline system, is expected to cost as much as $1.81 per added cubic foot of daily capacity. In contrast, the relatively short-distance Texas Eastern Lebanon expansion project is expected to cost about $0.25 per added cubic foot of daily capacity. When recently completed and proposed projects are categorized by project type, new pipeline projects average about $0.48 per added cubic foot, major expansions about $0.33 per cubic foot, and small (compression-only) expansions about $0.15 per cubic foot of capacity (Figure 37).[83]

Figure 37. Average Costs for New Pipeline Capacity in the Northeast, 1996-2000



Note: Data for each category were not available on all projects. For example, estimated or actual project costs or miles of pipeline were not announced or not available until filed with the Federal Energy Regulatory Commission. In some cases, where profiles of projects were similar but for which one cost was unavailable, an estimated cost was derived and assigned to the project based on known data.

Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Natural Gas Pipeline Construction Database, as of August 1998.

Table 10. Projected Pipeline Capacity Requirements Entering the Northeast Region If Large-Volume Distillate Consumers Switch to Natural Gas
(Million Cubic Feet per Day)

Region	1999 Base Level	Short Term	Longer Term
New England	2,739	3,079	3,585
Middle Atlantic	11,889	12,531	13,672
Northeast	12,519	13,358	14,760

Source: Energy Information Administration, EIA GIS-NG Geographic Information System, Natural Gas Pipeline Database, as of March 2000..

[81] Although new pipeline generally is built to service an expanding market, it can also serve to relieve low pressure areas on the existing system and to offer competitively priced gas from an alternative source to an area already served, thus displacing existing capacity. Furthermore, pipelines are built to target specific customers in a region. The resulting pipeline may not be suitably located to serve an unanticipated emerging market, such as consumers wishing to switch from distillate to natural gas use.

[82] Peak day consumption is met also by storage withdrawals, and so flow capacity into the region increases by less than the rise in peak day consumption.

[83] Pipeline construction cost estimates are from Energy Information Administration, *Natural Gas 1998: Issues and Trends*, DOE/EIA-0560(98) (Washington, DC, June 1999).

The cost of a project also varies according to location. Projects that must go through major population areas, as in the Northeast region, on average cost more than those developed in more sparsely populated areas. Although many of the projects completed in the Northeast in recent years have been expansions of existing systems, which are less expensive overall, future development in the region will include large new and expansion projects that are, on average, more expensive. For instance, 13 projects were completed in the Northeast Region during 1996 and 1997 at an average cost of about $0.22 per cubic foot of added daily capacity,[84] but projects over the next 3 years are expected to average about $0.37 per cubic foot. Based on the rough averages of $0.37 per cubic foot of expansions and new construction in the Northeast and $0.48 for new pipelines nationwide, the estimated capital costs for incremental interregional capacity would range between $829 and $1,076 million for the full impact of policies that eliminate switching from and promote conversion to natural gas. These estimates are for pipelines from the border through the Northeast region. They do not include additional capacity that might be required to transport gas to the Northeast border.

On average, construction and expansion projects completed in 1996 or 1997 took about 3 years from the time they were first announced until they were placed in service. Construction itself typically was completed within 18 months following FERC approval, sometimes in as little as 6 months. The remainder of the period was consumed with the initial open season (2 months), plan development prior to filing (3 months), and FERC review and reaction to FERC revisions, if any. Generally, FERC review takes from 5 to 18 months, averaging about 15 months.[85] When approval is delayed, however, the schedule can be extended considerably. For example, two of the four major pipeline proposals for capacity expansion into the Northeast, the Independence and Millennium projects, have been seeking FERC approval for more than a year, and their possible in-service dates now appear to be no earlier than 2001 (Table 11). The combined cost of the two projects and associated projects exceeds $1 billion. These two projects would provide a combined 1,700 million cubic feet per day of new pipeline capacity, which would appear sufficient to serve most of the projected incremental demand.[86]

Natural Gas Storage Requirements

The short-term shift to retain all gas consumers on the system year-round would heighten the peak day gas demand. Severe “needle peaks” would require timely supply responses, likely depending on volumes from storage. Although deliverability from storage, including LNG, is 10,197 million cubic feet per day in the Middle Atlantic, and 1,388 million cubic feet per day in New England, use of this gas as a frequent source of supply during peak periods would also depend on the aggregate storage capacity. Storage in underground sites contains less than 2 months of supply at maximum working gas capacity. Storage drawdowns from LNG facilities at close to maximum rates would exhaust LNG supplies in less than a week in the Middle Atlantic region and in 10 days in New England (Figure 38).

Given the more severe peaks in demand for natural gas that can be anticipated with an aggressive shift to natural gas, storage capacity and deliverability likely would have to be increased by more than the proportionate rise in regional demand. However, using the demand increase as a conservative guideline for the needed regional storage capacity and deliverability, they would need to be expanded by up to 15 percent in the Middle Atlantic region and 31 percent in New England, requiring an increase of 70 billion cubic feet in underground

Table 11. Proposed Pipeline and Capacity Expansion Projects into the Middle Atlantic Region

Name	From Region	States Involved	Possible First Year of Service	Status	Incremental Capacity (Million Cubic Feet per Day)
Independence Pipeline	Midwest	IL, IN, OH, PA, NY	2001	Pending FERC Approval	1,000
Millennium Pipeline Project	Canada	IL, MI, OH, NY	2001	Pending FERC Approval	714
Iroquois Gas Pipeline Eastchester Expansion	Canada	NY	2002	Not yet filed	220

Note: No firm proposals to expand pipeline capacity into the New England region have been announced or filed with the FERC during the past year. The Portland Natural Gas Transmission Company held an open season for possible expansion of its recently (1998) completed 178 million cubic feet per day import system but has yet to announce the results of the market test. The Maritimes and Northeast Pipeline (400 million cubic feet per day), completed in late 1999, can be expected to expand as Sable Island (Canada offshore) gas production continues to be expanded, but no plans to do so have been officially announced.

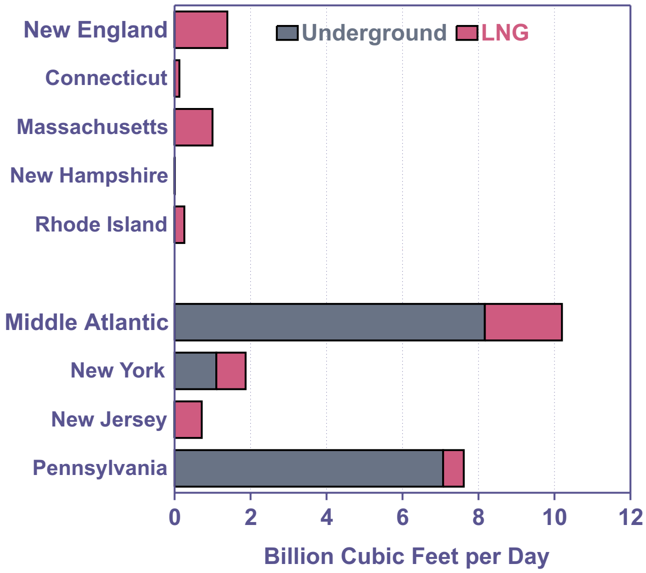
Source: Energy Information Administration, derived from EIAGIS-NG Geographic Information System, Natural Gas Proposed Pipeline Construction Database, as of March 2000; and Federal Energy Regulatory Commission, Applications for Certificate of Public Convenience and Necessity.

[84] One of the reasons for this was that almost all of the projects were low-mileage or compression additions rather than long-haul new pipelines.

[85] Federal Energy Regulatory Commission, Office of Pipeline Regulation, Case Tracking System.

[86] A complete determination of the ability of these specific projects to satisfy the projected demand would require a detailed analysis that is beyond the scope of the present effort.

Figure 38. Regional Daily Deliverability from Underground and Liquefied Natural Gas Storage in the Northeast, 1998



Source: Energy Information Administration, EIAGIS-NG Geographic Information System, Underground Natural Gas Storage Database and LNG Facilities Database, as of March 2000.

working gas capacity and 1,225 million cubic feet per day in deliverability in the Middle Atlantic region and an increase of 6.4 billion cubic feet in LNG working gas capacity and 733 million cubic feet per day in deliverability in the Northeast. The siting of new storage units could present a formidable challenge in light of previous experience. For example, 12 underground storage projects were proposed in New York and Pennsylvania for the 4-year period 1995-1998, with an associated working gas capacity of 40.2 billion cubic feet. The projects included 8 salt dome or salt bed projects with 14 billion cubic feet of working capacity.[87] By the end of 1998, only the smallest of the salt projects had been built. Based on the estimated average cost of $8.7 million per billion cubic feet for the 12 projects, achieving 70 billion cubic feet of additional underground capacity alone would require an estimated $609 million.

A final option relies on propane supplies as a source of peak shaving supplies. Propane can be stored on site and then used to meet peak load requirements, but in practice its use is limited for several reasons. First, storage facilities for petroleum products are not well received in many locations for environmental reasons. Second, propane is an expensive source of supply. Third, increased reliance on propane, even if economically viable, would not disentangle the natural gas and petroleum fuels markets. Its regular use in supplementing gas supplies would require operators to purchase propane supplies to replenish depleted stocks. Given that average propane sales for any month in the New England and Central Atlantic regions[88] only occasionally exceed 100,000 barrels per day, the redirection of just a fraction of switchable energy demand to propane probably would overwhelm the regional propane market, potentially causing severe price spikes.

Economic and Institutional Obstacles to Gas Conversion

Although the natural gas industry in the Northeast probably could accommodate the infrastructure requirements of a shift from distillate to gas by large-volume consumers, economic and institutional obstacles may be more problematic. The economics indicate that the shift would be likely to involve about $1.5 billion in capital costs for pipeline capacity into the region, additional storage facilities, and additional investment in local distribution capacity. In addition, regulatory, environmental, and public perception issues would have to be addressed (see box on page 49). Local resistance to projects can be fierce, despite the vested interest of communities in increased access to gas supplies. This is especially problematic in terms of moving gas into and through States to provide benefits on a regional basis. For example, Transco has proposed an expansion project that will traverse New Jersey.

The conflicting goals of cost recovery and attracting new customers through low service charges present an especially difficult problem that will affect pricing strategies. Capital expansion and the associated expenditures needed to retain large-volume customers that otherwise would be subject to interruption of gas service are unlikely to enhance service to other firm service customers. The direct association between the incremental investment and costs with an identifiable group of customers is likely to discourage acceptance of rolled-in (average) pricing by State Utility Commissions, and the likelihood for success of incremental pricing is unclear. Current large-volume customers were enticed to gas by offers of heavily discounted rates. Higher prices may not discourage gas use if the discounted rates were due to gas-on-gas rather than interfuel competition, but the nature of the competition cannot be determined beforehand. If delivered prices under the proposed policies are higher than the delivered prices with interruptible service under the current system, the additional costs may actually discourage gas use. Unless the conversion to

[87]Energy Information Administration, *The Value of Underground Storage in Today's Natural Gas Industry*, DOE/EIA-0591 (Washington, DC, March 1995).

[88]The Central Atlantic region includes Delaware, District of Columbia, Maryland, plus the Mid-Atlantic Census Division, which is composed of New Jersey, New York, and Pennsylvania.

Environmental Considerations for Natural Gas Pipeline Expansion Projects

The environmental impacts of natural gas pipeline construction for interstate transportation or local distribution projects depend on project size, length, and design. A large greenfield pipeline route, built from scratch, necessitates a good deal of environmentally sensitive action compared with a project that only involves the upgrading of existing facilities to expand capacity. For instance, planning of a new route must include an evaluation of its need to cross wetlands, wildlife-sensitive areas, and potential archaeological sites. Alternative routes must also be available in the event that regulatory authorities withhold approval. Other impacts that must be evaluated include the effects of clearing construction routes and building access roads, the temporary or permanent redirection of waterways, possible discharges of oil-residues (when converting an oil line), and discharges of hydrostatic test water when leaks are detected.

The potential environmental impacts of completed projects must also be considered, such as emissions and noise from compressor station operations. When natural gas is used to fuel a compressor station, the unit will emit approximately 50 tons of nitrogen oxide, 75 tons of carbon monoxide, and 50 tons of volatile organic compounds per year (based on continuous year-round operation of a unit with a 3,300 horsepower rating). Some compressor stations use electricity rather than natural gas for fuel; their on-site direct emission levels are zero, although off-site emissions result from electricity generation.

The National Environmental Policy Act of 1969 (NEPA) requires that anyone proposing to undertake a major interstate-related project, such as construction of a pipeline, LNG import terminal, gas storage field, or other major project that may have a significant impact on the environment first produce an environmental impact study (EIS). The EIS must examine the environmentally sensitive features of the project and describe the actions that are to be taken to mitigate potential damage. The FERC must evaluate and approve any EIS associated with a pipeline construction project within its jurisdiction.

Depending on the project profile and its proposed route, the preparation of the EIS itself can be a major undertaking, the approval process lengthy, and the cost of implementing remedial actions significant. Regulators often ask for additional data, and delays often arise before environmental approval is granted. In some instances, when only conditional environmental approval is granted, the project's economic viability may be affected by unanticipated costs and schedule delays. Although most proposed pipeline projects encounter little or no delay as a result of environmental review, the review can become quite lengthy when approval has been delayed.

gas is required, gas consumers will respond to the economics of the choice.

Another possibility is that the retention of gas customers on the system on a year-round basis could alter pricing in a fundamental way. The retention of large-volume customers on the system even during peak periods could effectively eliminate "off-peak service" and the revenues associated with interruptible service contracts. The economics of investments in incremental capacity could also be affected adversely unless the pipeline system can capture a customer base without any significant degree of demand seasonality. The lost opportunity for revenue generation during off-peak periods probably would diminish the value of infrastructure assets, affecting the returns to owners of existing infrastructure and reducing the incentive to invest in the needed capacity. This would not eliminate all capacity development, but it would tend to discourage investment in marginal projects or ones with significant seasonal load variation, which would make implementing the maximum gas conversion scenario more difficult.

Investment in equipment is another significant challenge that might discourage conversions to natural gas. Conversion from distillate-only equipment to natural gas requires either modifying the consumption equipment to burn natural gas or replacing the equipment entirely. The cost of modification or replacement of the equipment could, by itself, make the conversion economically unattractive.

Finally, although the elimination of incremental demand for distillate fuel oil from customers switching from natural gas during peak demand periods could mitigate the potential for distillate price spikes in the short term, it cannot eliminate their possibility. For example, the bulk of the demand surge in Northeast distillate markets in January 2000 seems to have been a weather-induced increase involving the regular customer base, and it is likely that prices would have risen sharply even without the additional demand as other customers switched from natural gas. Indeed, the successful achievement of the maximum switching of large-volume customers from heating oil to natural gas could actually exacerbate the potential for price spikes in the longer term by reducing the stable base of heating oil consumption. The remaining heating oil market would be smaller, consisting of the portion of current customers with a more seasonal pattern of use, and the remaining portion of the distillate market would consolidate to match the new demand. Operators would be inclined to reduce inventories given the smaller market, the relative swing between seasons would be larger, and inventory management would be more uncertain. As the stock cushion diminished, the market could become less prepared for sudden increases in demand or decreases in supply.