STAFF ANALYSIS OF NATURAL GAS CONSUMPTION AND PIPELINE CAPACITY IN NEW ENGLAND AND THE MID-ATLANTIC STATES

December 1999

INTRODUCTION

This study has been prepared by the staff of the Federal Energy Regulatory Commission (Commission) to analyze the need for natural gas capacity in the Northeastern United States. It is undertaken pursuant to language contained in the House Appropriations Committee report accompanying H.R. 2605, Fiscal Year 2000 Energy and Water Development Appropriations Act (Pub. L. 106-60). That language, which states concerns with the "proposed market link expansion project in Northern New Jersey (known as the TRANSCO pipeline)", provides that:

> [T]he Committee is concerned by the Commission's lack of analysis and future plan for capacity needs in this area. Therefore, the Committee directs the Commission to provide an analysis of how much expansion is anticipated for this area. The analysis should provide, but not be limited to, a 20-year outlook of the number of pipelines that will be needed to handle future capacity in this region.

As a staff analysis, this study does not necessarily reflect the view of the Commission.

PURPOSE OF THE STUDY

The purpose of the staff's study is to analyze the potential need for natural gas capacity in the Northeastern United States. This analysis is highly predictive, and hence highly uncertain, because it is based on assumptions pertaining to, among other things, the rate of economic growth in the region in question during the time period of the study, the future price of fuels, electric generation patterns, technological changes, environmental regulations, and other factors.

TIME PERIOD OF STUDY

This staff paper analyzes the period starting with the present time and extending through the year 2020. Of the studies available to staff, only one extended for 20 years, the period suggested by the House Appropriations Committee report. The staff believes that the analysis of need described is subject to so many variables that the specific predictions described in this study may be highly uncertain even within more immediate time-frames.

STUDY AREA

Staff has determined that the appropriate area for this particular study includes the New England states of Maine, New Hampshire, Vermont, Massachusetts, Connecticut, and Rhode Island; and the Mid-Atlantic states of New York, New Jersey, and Pennsylvania. These states were chosen as the study area because there are several pending and proposed pipeline projects to serve this region which have engendered a great deal of discussion as to the issue of need.

Historically, natural gas pipeline capacity into the New England and Mid-Atlantic regions could be separately studied with almost all natural gas flowing north into New England from Texas, Oklahoma, and the Gulf of Mexico through the Mid-Atlantic. With the advent of the new and increased interconnections with Canadian pipelines, however, substantial volumes of natural gas now flow from Canada south and more substantial displacement of volumes into the Mid-Atlantic can be expected to occur in the future. Thus, for purposes of this study, the capacity of the two regions is consolidated into one region. Further, only two of the studies analyzed by staff (EIA and GRI) show consumption separately for the New England and Mid-Atlantic region.[1]

Given the fact that natural gas markets and the interconnected web of pipelines serving those markets do not correspond to political boundaries, it is difficult, if not impossible, to study the issue of future need for natural gas capacity for a specific state or region. One must look at the region as a whole and extrapolate from that the likely needs of areas within that region. Such an exercise is admittedly imprecise given that, depending on many various factors which cannot be evaluated absent specific information about existing conditions, there may be supply dislocations (i.e., either too much or too little supply of natural gas) at a given location or at a given point in time. In addition, every region is part of the nationwide natural gas market and transportation system.

BACKGROUND

Natural gas is a deregulated commodity which is bought and sold freely in the market place. Supplies of natural gas are delivered from the well-head by a highly interconnected web of more than 1,000,000 miles of interstate natural gas pipelines

---

[1] A map showing certificated capacity into this area is set forth in Attachment A.

extending throughout significant portions of the country, including the Northeastern United States.

The organic legislation setting forth the Commission's responsibilities, the Natural Gas Act, declares in section 1(a) "that the business of transporting and selling natural gas for ultimate distribution to the public is affected with a public interest, and that Federal regulation in matters relating to the transportation of natural gas and the sale thereof in interstate and foreign commerce is necessary in the public interest." As set forth in this and other sections of the NGA, the Commission is charged with furthering the public interest in authorizing the construction and operation of interstate natural gas pipelines. This entails consideration of many interests and goals. As Congress, the Commission, and the courts have interpreted it over the decades, this mission includes, among other things, the assurance of adequate supplies of natural gas to consumers, and the assurance of adequate competition among suppliers to cut costs and improve market conditions for the benefit of consumers. It also includes factors as diverse as considerations of clean air and other environmental benefits, and the energy security of the Nation.

PART I: FUTURE NEED FOR NATURAL GAS

Background

While there are many factors that must be evaluated to determine the need for additional natural gas transportation capacity into any given market, one of the primary requirements is to have an estimate of the future need for natural gas for the area in question. The determination of future need for natural gas in a given region of the country is difficult. It involves identifying and assessing a great many factors such as future economic growth, patterns of electric generation, technological advances, and changes in environmental regulation. For this reason, the issue of need is most appropriately analyzed using complex computer models which take into account these factors, and which are capable of evaluating the impacts of changes in assumptions. As with any model, the results that are predicted reflect the assumptions that are used. For this reason, such models typically use a range of assumptions pertaining to key variables.

From a practical standpoint, we note that estimates of future need for natural gas in the near-term (i.e., the next two to three years), and the capacity required to serve that demand, are essentially moot from a policy and certification point of view. Given the lead times required to plan, market, receive regulatory approvals, and construct pipeline capacity, existing capacity and capacity already under construction, or well along the regulatory path, must be assumed to be adequate to serve this near-term load.

We also note that, from an historical perspective encompassing the past several decades, projections as to future natural gas prices and demand have tended to understate future demand and overstate future price. This pattern is particularly pronounced with respect to longer-term projections.

Studies Utilized

Given the complex econometric models required to conduct viable studies assessing the need for natural gas, the staff typically relies on studies conducted by other entities with expertise in this area. For purposes of this analysis, we have relied on studies conducted by:

The Department of Energy's Energy Information Administration (EIA);

The Gas Research Institute (GRI);

The Interstate Natural Gas Association of America (INGAA);

Primark EFA (formerly Wharton Econometrics); and

Cambridge Energy Research Associates (CERA).

Information pertaining to these studies was presented to staff in the proceedings and conferences described below. The study from DRI presented by Edison Electric Institute was not utilized in Table 1 because its definition of the Northeast region included states outside of the area examined by Staff in this analysis, and those states could not be segregated out.

Although the studies consider many alternative scenarios, none of them address the question of whether any specific project or combination of projects is required, either now or at any point in the future. For example, the aggregate estimates of gas consumption in the studies considered are annual, whereas the need for pipeline capacity is primarily determined by the maximum throughput, which in turn requires estimates of monthly or daily demand. It is not possible to use these studies to determine accurate estimates of monthly or daily demand, which is the critical issue faced in making decisions to authorize the construction of additional projects.

To conduct this analysis, we first examined the available information to determine the projected forecasts of annual natural gas consumption. As noted above, the studies conducted by entities such as EIA and GRI and others typically involve extensive

computer modeling that incorporates a large number of factors such as predictions of economic growth, the price of fuels such as coal, oil and natural gas, and changes in environmental regulation. Because of the difficulty in predicting these factors into the future, the models typically use various scenarios in which, for example, the projected price of fuels are examined within a price range, and within a price range relative to the cost of other fuels, and assumptions are made as to the availability of sources of electricity generation, such as nuclear power plants. Thus, these studies typically produce a range of estimates.

To assess the impact of various scenarios, the studies typically set forth a reference or baseline case against which the scenarios can be compared. For example, a typical reference case might incorporate the current cost of oil, the current cost of electricity, and current economic growth rates, among many other factors, to develop a baseline. Scenarios are then used which alter these variables to determine alternative possibilities that may be expected. Table II lists several of the primary assumptions used by the studies to the extent that they were identified in the public record.

Table 1 of this study compares the various forecasts made by EIA, GRI, INGAA, WEFA, and CERA for the states that comprise what we have described as the Northeastern region for purposes of this study. The information set forth for EIA and GRI are their reference or baseline cases. The numbers in question for the given year reflect the forecast of annual natural gas consumption stated in billions of cubic feet (Bcf). Thus, for the year 2000, EIA estimates annual natural gas consumption in the region as 3,294 Bcf; GRI estimates annual natural gas consumption for the year 2000 as 3,291 Bcf in its 1998 study, and as 3,152 Bcf in its 1999 study.

INGAA forecasts of annual natural gas consumption use several different scenarios. In Cases 1 and 3, INGAA assumes high economic growth with a Gross Domestic Product Deflator (GDP) of 2.8% per year and a Federal Reserve Board Industrial Product Index (FRB) of 3.3% a year. Cases 2 and 4 assume a GDP of 2.5% and a FRB of 3.0% per year. Cases 2 and 4 also assume nuclear electric generating facility retirements of 11.1 gigawatts by 2010 with no impediments to continued operation of existing coal-fired units.

Table 1 contains the results of three WEFA scenarios. In the Stringent Environmental (SE) scenario it is assumed that tight air quality environmental regulations, nuclear shutdowns, and strong regional economic growth create strong natural gas demand and limit the ability of electricity providers to meet peaking-demand through fuel-switching. In the Conventional Wisdom (CW) scenario it is assumed that regional economic growth slows, but gas demand-growth is strong, as some nuclear shut-

down and the construction of merchant plants (i.e., electricity generators) result in strong gas demand-growth for power generation. In the High Technology (HT) scenario it is assumed that a combination of a world-wide recession, strong technology development, improved management of nuclear plants, and slow regional growth results in slow gas demand growth and low delivered prices.

Table 1 also contains the results of three CERA scenarios. The Gas Favored (GF) scenario analyzes demand potential for both gas and power under favorable conditions. As power demand grows and electricity generators turn to the use of natural gas, regional gas demand could nearly double by 2015 if the needed natural gas supply and pipeline infrastructure are developed. The Constrained Growth (CG) scenario reflects the uncertainty regarding the ability of U.S.-based gas supplies to meet the strong demand growth potential for gas in the energy marketplace. The Great Expectations (GE) scenario explores the possibility that an over investment is made in largely gas-based new power generation in the Northeast based on expectations of continuing economic strength and poor nuclear performance.

Forecasts of Annual Natural Gas Consumption

As noted above, staff assumes that short term growth in natural gas demand must be satisfied with existing pipeline capacity, or capacity that is near an in-service date. Given a typical regulatory time frame of two years to approve and construct new pipeline capacity, staff believes the earliest gas supply projections relevant to a forward looking analysis of natural gas pipeline capacity is 2002. Table I shows that total gas demand projections from the available studies for the year 2002 range from a low of 3,297 Bcf to a high of 3,895 Bcf. In looking further to the year 2015, the range of projected demand rises to 4,276 Bcf and 5,435 Bcf.

The studies agree that the Northeast gas market will experience significant growth in demand from current levels under all scenarios tested. The studies also agree that all customer groups will at least maintain current consumption levels, and most agree that all customer groups will grow. In addition, the studies agree that the electric power generation market will constitute the single fastest growing segment of the Northeast gas market.

To the extent other parties in various Commission proceedings have commented on the future demand for natural gas in the Northeast, they have not disputed the similar aspects of the studies' projections identified in Table I. Rather, individual assessments tend to focus on small market areas, and preferences for various assumptions that, while

always resulting in growth in demand, change the rate of growth up or down relative to other assumptions.

PART II: CAPACITY REQUIREMENTS

The gas demand studies, with the exception of EIA's, did not examine in any great detail pipeline capacity serving the Northeast market. Pipeline capacity was apparently assumed to either exist, or that it would be constructed in a timely fashion as not to become a constraint on the market.

EIA estimated that the Northeast has approximately 15.3 Bcf/d in delivery pipeline capacity. EIA's estimate was based on annual throughput figures. Staff converted EIA's figures to daily numbers as shown on Table III, as pipeline capacity is typically described on a daily basis.

Pipeline capacity can be defined many ways. The Commission typically uses several definitions for construction, service, and rate design purposes, including maximum day under maximum optimal conditions, design day, and seasonal design days. As relevant here, for design day purposes, natural gas companies typically design pipeline facilities in order to provide the operational capacity to meet the pipeline's service obligations under a specific set of operating and weather conditions. Typical items considered include contractual obligations, seasonal temperatures, facility limitations, storage deliverability, and customer load profiles. To determine seasonal design days, natural gas companies typically design pipeline facilities in order to provide the operational capacity to meet the pipeline's service obligations under a specific set of expected seasonal operating and weather conditions. For example, a company in the northeast with market area storage may design its pipeline upstream of storage facilities under summer operating conditions in order to maximize injections into storage while designing the system downstream of storage facilities under winter conditions to meet the winter demands of customers.

Projecting Capacity Requirements

The data in the record indicate two different methods of projecting capacity. First, projections can be based on regional demand and capacity utilization, such as those shown on Table I and the EIA capacity study. This method can be characterized as a "macro" approach. The second method utilized by many parties in the record is a project-by-project analysis, which is similar to that used by staff. This approach

evaluates individual projects with limited coverage, and can be characterized as a "micro" approach.

EIA's basic approach of using pipeline capacity utilization can be used to project future pipeline capacity requirements, assuming no other changes in the underlying assumptions. The key conversion factor is the capacity utilization. The utilization factor should be acceptable in achieving several objectives, including limited capacity constraints at peak periods for most customer classes, limited constraints for suppliers and end users to meet, and limited opportunity for pipelines to exercise market power.

Staff expects long-line natural gas transmission systems extending from production regions (e.g., the southwestern United States or Canada) to market regions (e.g., New York City) to operate at an annual capacity utilization of 90% to 95%. This is because long-line pipelines, which have the ability to convey a given, steady-state volume (subject to limited variables such as line pack and temperature), transport natural gas directly from the producing regions to the market region and should, therefore, operate at a high, relatively constant annual capacity utilization. Put differently, long-line natural gas transmission systems are essentially designed to transport natural gas in relatively constant amounts from production regions to regions where the natural gas is ultimately consumed by the end-user or put into storage facilities (e.g., depleted natural gas fields) for later withdrawals and consumption during periods of increased need.

Other natural gas transmission systems may serve a somewhat different function and require a different annual average capacity utilization factor. For example, it is more typical in a market region, such as the Northeastern United States, with large amounts of natural gas storage capacity available, to expect natural gas pipelines in that market region to have an annual average capacity utilization of 75% to 78% in order that peak day design loads may be served at a capacity utilization of 100%. Ultimately, the lower annual average capacity utilization factor for these natural gas transmission systems, as compared to long-line natural gas transmission systems, reflects their different function and the fact that the former must be designed to take into account peak needs. Load management tools, such as the availability of natural gas from storage facilities, are used to meet the difference in capacity utilization expectations. The average underground storage withdrawal capacity in the Northeastern United States is approximately 3.3 Bcf/d, which is equal to 21.6% of the identified pipeline capacity of 15.3 Bcf/d. In a regional analysis, such as this study, load factors greater than 78% on an average annual basis for these types of natural gas pipelines indicate a capacity constraint.

Several parties, however, have argued that up to an 85% pipeline capacity utilization is achievable. Based the range of 75% to 85%, Table II indicates that

additional capacity may be required as early as the 2003 to 2005 time frame. This inference is based on the maximum growth scenario. Staff believes consideration of reliability, changing customer demand profiles, a more dynamic and liquid natural gas market, and the long lead times and high capital costs associated with pipeline construction require the use of the peak growth scenario. The costs to consumers and society associated with a lack of capacity to meet demand cannot be rectified in a short period of time due to the long lead times associated with pipeline construction.

Both the EIA data and the total Northeast natural gas demand projections are based on annual figures. As discussed below, staff believes that there are serious limitations in using such data and projections in evaluating the need for new incremental pipeline capacity into any market.

Limitations on the Use of Annual Demand Figures

Most forecasts of natural gas consumption only project the annual demand for gas. However, annual throughput into any given market area only provides a rough estimate of the actual pipeline capacity necessary to deliver that volume. Most pipelines are not designed on the basis of annual demand because annual demand gives little indication of the actual seasonal, monthly, daily and hourly demand profile of customers, either as a total or individually. The Commission's regulations require an applicant to submit flow diagrams showing the daily design capacity of their facilities, and reflecting operation of the facilities with and without the proposed facilities. As noted previously, when speaking of a pipeline's flowing capacity, the terms "peak" and "design day" are usually interchangeable. The maximum design of a pipeline refers to the largest volume of natural gas a transmission system can deliver under continuous steady-state conditions. Pipelines are designed to establish a delivery capacity, which, in turn, reflects the demand profiles of the intended customers. For example, residential and small business demand profiles in the Northeast are typically seasonally high in the winter season with daytime peaks and morning and evening needle peaks that vary by business or non-business day. Firm industrial load typically runs year-round at a high load factor. Thus, the capacity of a pipeline designed to serve exclusively a residential and small business load would be considerably different from one designed to serve an industrial load.

The market which all of the gas studies underlying this analysis agree represent the greatest potential for gas growth is electric generation. Electric base load generation can be expected to maintain high load factors. However, the gas market studies assume a significant amount of the new electric generation load will be to supply a peaking electric market. This customer class will present a high peaking gas demand profile. We expect that pipelines serving electric load will design their facilities to meet their customer

demand profiles. There are many potential ways that these peak demand profiles could be met, including new pipeline capacity, new peaking capacity, and demand side alternatives. In a region as diverse as the Northeastern United States, these factors introduce an especially high degree of uncertainty. Predictions of the need for new pipeline capacity using the model-based studies, therefore, are limited in their ability to isolate any single factor of pipeline capacity as compared to other possible factors.

Limitations on the Use of Annual Utilization Rates of Pipeline Capacity

Also, the use of annual utilization rates of pipeline capacity for large regional market areas have similar limitations in determining incremental pipeline capacity requirements for a given market. For example, if the new customer demand profiles are different than those currently served, pipeline utilization factors can also be expected to be different. Gas surveys agree that new gas demand profiles will not be uniform. The studies project that electric power generation is expected to be the primary area of gas growth. Neither the pipeline industry nor the Commission staff expects the electric generation market to have the same load profile as residential, small business, and industrial customers. Therefore, historical capacity utilization factors may not be appropriate to determine future capacity requirements.

Furthermore, pipelines may be already constrained in rendering current services. As such, the concept of available capacity from existing pipelines to service new natural gas demand may not exist because existing pipeline operations require utilization of certain facilities that, in effect, isolate available capacity from servicing any market. Examples include systems designed to utilize excess summer capacity to deliver gas to storage to provide winter peak load services.

Average utilization factors mask the extremes in individual pipeline load factors. If a new market for natural gas develops in one geographic area with little existing pipeline capacity, the availability of excess capacity in the broader geographic area provides no contribution to solving a capacity shortfall to serve customers. This is because pipelines cannot be moved from one market to another.

Finally, the fact that pipeline capacity is available to a market is not the same as satisfying the market's demand for pipeline capacity. For example, pipeline capacity that originates from a supply area that is overpriced or depleted is not truly "available" capacity, as it is not a realistic alternative. Yet this capacity will likely be counted in survey of existing capacity.

PART III: PUBLIC COMMENTS

At a public conference held on June 7, 1999 (Docket No. PL99-2-000), the Commission conducted an inquiry into anticipated natural gas demand in the Northeastern United States over the next 10 to 20 years.[2] The Commission also provided an opportunity to file written comments after the conference. As the following summary shows, a broad range of views and opinions were presented on several topics.

Growth Projections and Existing Pipeline Capacity

Texas Eastern Transmission Company and Algonquin Gas Transmission Company (Texas Eastern/Algonquin) stated that aggregate demand for natural gas will increase in the Northeastern United States over the next decade at a rate of approximately 2.9% per year. Iroquois Gas Transmission System, L.P. (Iroquois) projected that, between 1997 and 2006, annual growth in firm load in the New England area and in the New York market will average 1.9% and 1.6% (or approximately 7 Bcf/year and 12 Bcf/year, respectively).

Many entities stressed that in determining the need for pipeline capacity, the Commission must consider reliability, point-specific changes in demand, alternative supply sources, and competitive sources of transportation rather than simply looking at regional growth. Thus, entities such as the Public Service Commission of New York (PSCNY), the Edison Electric Institute (EEI), and the Conservation Law Foundation predicted a need for additional pipeline capacity within the next several years. Similarly, Energy Markets and Policy Analysis, Inc. asserted that there is no way to predict precisely the amount of pipeline capacity that the region will need in the future; consequently, it urges the Commission to assure that fully adequate capacity is certificated, even if that means erring on the high side of perceived requirements.

Some entities, such as CNG and El Paso/Tennessee, maintained that the existing infrastructure, with minor modifications, can meet the increased demand in the near term (i.e. 2004 or 2005). On the other hand, EEI concluded that the adequacy of natural gas pipeline capacity is difficult to gauge because of the substantial swings in utilization over

---

2 For purposes of the conference, this included those states lying east of the Mississippi River and north of Tennessee and North Carolina. The Northeastern United States represents the single largest natural gas market in North America; RDI estimates that approximately 37% of total gas consumption in the United States occurs within this region.

a period of a year. EEI asserted that in the New England sub-region, where natural gas fuels a significant portion of baseload electric generation, seasonal heating demand and electric generation needs will coincide, thereby stressing the available regional pipeline capacity. RDI predicted that without additional deliverability, capacity shortages in the New England sub-region could occur as early as 2002. Based on its modeling of regional power system dispatch economics, the Conservation Law Foundation saw a fairly immediate need (within four years) for PNGTS and Maritimes to be expanded, and for significant (480,000 to 800,000 Mcf/day) new natural gas pipeline capacity. Process Gas Consumers Group asserted that since the interstate natural gas pipeline system into the Northeastern United States has "firmed up," there is less slack to meet growing demands. In the same vein, EEI's "Natural Gas Market Analysis" reflects that the growth in gas-fired generation in the New England sub-region in the next few years may leave the region susceptible to natural gas pipeline capacity shortages as natural gas generation, assuming a baseload role, increases peak month pipeline utilization.

Markets Where Growth Will Occur

Iroquois stated that between 1997 and 2006 annual growth in the New England area associated with new gas-fired electric generation will average 5.7%, or 15 Bcf/year, while annual growth in New York associated with new gas-fired electric generation will average 4.8%, or 11 Bcf/year. PSCNY noted that the 1998 Energy Plan of the New York State Planning Board estimates that the demand for natural gas for electric generation purposes will grow between 0.7% to 4.5% per year from 1998 through 2028. The American Gas Association believes that, on a national basis, natural gas consumption from the electric generating market will double by 2010 from its current level (to 20-25 percent of total natural gas consumption). The "Natural Gas Market Analysis" which RDI performed for EEI forecasts that electricity demand in the Northeastern United States will increase nearly 1.1% a year from current levels. EEI 's analysis also estimates that gas demand by the electric generation sector will increase by 11 percent per year in the Northeastern United States through 2010 due to, among other things, nuclear retirements and environmental restrictions on oil and coal generation. Texas Eastern/Algonquin believe that roughly 80% of the increased demand is associated exclusively with new gas-fired independent electric power projects that will primarily use natural gas during off-peak periods, and will not increase the need for additional peak natural gas pipeline capacity in an amount equal to the increases in aggregate annual demand.

Process Gas Consumers Group noted that a recent INGAA study analyzed various studies of projected future demand for natural gas between 1997 and 2010-2015 and, in every case except a low growth economy case, projected increased industrial demand for

natural gas (from an annual level of about 8.8 Tcf in 1997 to between 9.5 Tcf to 10.6 Tcf).

Available Capacity Due to Turnbacks

CNG Transmission Corporation stated that EIA data demonstrate that the utilization rate of existing pipelines in 1997 was approximately 70%, and that an 80% utilization rate of existing and currently certificated pipelines would satisfy even the most optimistic of EIA's demand projections until 2005. El Paso/Tennessee believe that existing and inexpensive expansions of existing natural gas pipeline systems can satisfy projected market growth for at least the next five years and probably longer. Iroquois believes the Commission should consider the expansion of existing pipeline systems -- in a period of extensive capacity turnback potential -- to fuel this growth in the near term until the extent, timing, location and characteristics of this market can be more fully ascertained. [3]

Independence stated that there is no evidence to show where or when turnback of capacity will occur, and how this turnback would satisfy predictions of growing demand in the Northeastern United States, as well as existing market demand. Independence also maintained that even if there is turnback capacity, the markets that have been served by this capacity will not disappear and these loads will continue to be served even though the capacity may be held by a different market participant. Process Gas Consumers Group maintained that projections of increased demand in the Northeastern United States will exceed the occasional turnback of capacity which will occur as pipelines' historic customers (local distribution companies) reshape their load. PGC stated it is dangerous for the Commission to rely exclusively on turnback capacity to meet the rapidly growing increases in demand for natural gas in the Northeastern United States over the next 10 to 20 years. Public Service Electric and Gas Company asserted that using existing capacity more efficiently through turnbacks on Texas Eastern and CNG can help meet new gas demand; and that some additional capacity likely will be needed if any reasonable portion of the projected electric power demand growth in the Northeastern United States materializes.

---

3 Turnback capacity results from the expiration of a firm transportation contract at the end of its term when the firm shipper elects not to exercise the right of first refusal under the Commission's regulations and thereby turns the capacity back to the pipeline.

- Notwithstanding claims of turnback capacity on Texas Eastern's system, neither Texas Eastern, the studies referenced above, or any other party claim that this capacity represents a reduction in demand for natural gas in the Northeastern United States. This turnback capacity may represent shippers shifting their transportation preferences among pipeline suppliers of transportation capacity, as opposed to a real reduction in demand.

Reliance on Markets

The PSCNY urged the Commission to rely on the market to decide whether the additional capacity should be built in the form of incremental expansions to existing pipeline or "greenfield" (i.e., pipelines not constructed in existing pipeline corridors) pipelines. It, and others, contended that investors in new pipeline capacity are more likely to evaluate changes in natural gas demand, and to make better and faster decisions than regulators in forecasting demand and deciding how much capacity should be built. El Paso/Tennessee, on the other hand, urged that while allowing the market to decide is generally appropriate, this approach should not be used in the Northeastern United States in light of existing capacity and potential turnbacks in the region.

Several Congressmen also commented on the issue of anticipated natural gas demand in the Northeastern United States. Representative Frelinghuysen (New Jersey), who authored the directive that resulted in the instant analysis, noted the need for study of this issue. Senator Lieberman (Connecticut) and Representatives Moakley (Massachusetts) and Fattah (Pennsylvania) noted the need for additional electric generation in their areas, and requested that the Commission ensure there is sufficient pipeline capacity to meet the demand. Representatives Blagojevich and Evans (Illinois) noted that the North American Electric Reliability Council projects an electric generation capacity shortfall for the Northeast region, and requested that the Commission consider the environmental and economic advantages of natural gas in satisfying this demand.

CONCLUSION

This study analyzes forecasts of natural gas consumption in the Northeastern United States and compares those forecasts to existing capacity in that region. Given the difficulty of examining this issue on less than a regional basis, the study does not attempt to break out issues of consumption of natural gas and pipeline capacity for particular states or portions of states.

- All projections indicate increasing demand for natural gas in the Northeastern United States over time, and the need for increased capacity to meet that demand. This leads staff to conclude that additional pipeline construction is likely to be required in the near future to meet that demand.

Table 1
Forecast Comparisons
Annual Natural Gas Consumption (Bcf)

Year	Hist	EIA	GRI		INGAA		WEFA			CERA			SUMMARY		
1990	2,301	BPF	1998	1999	1&3	2&4	SB	HT	CW	GF	CG	GE	Max	Midpoint	Min
1991	2,363														
1992	2,646														
1993	2,662														
1994	2,801			2,946											
1995	2,994			3,142			3,075	3,075	3,075	2,994	2,994	2,994			
1996		3,147	3,056	3,139			3,083	3,083	3,083	3,002	3,002	3,002			
1997		3,205	3,081	3,148	3,115	3,115	3,204	3,204	3,204	3,071	3,071	3,071			
1998		2,997	3,129				3,277	3,241	3,238	3,079	3,030	3,038			
1999		3,228	3,180				3,294	3,215	3,198	3,346	3,172	3,252	3,346	3,259	3,172
2000															
2001		3,440	3,385				3,682	3,446	3,447	3,624	3,242	3,623	3,640	3,443	3,242
2002		3,568	3,388				3,895	3,513	3,484	3,756	3,297	3,791	3,895	3,596	3,297
2003		3,691	3,462				4,134	3,535	3,583	3,914	3,358	3,821	4,134	3,746	3,358
2004		3,869	3,590				4,244	3,598	3,607	4,031	3,455	3,942	4,244	3,858	3,455
2005															
2006		4,192	3,811				4,421	3,612	3,763	4,186	3,898	4,169	4,421	3,966	3,498
2007		4,337	3,850				4,536	3,668	3,918	4,301	3,555	4,220	4,536	4,045	3,555
2008		4,412	3,899				4,771	3,721	4,124	4,482	3,628	4,256	4,771	4,199	3,628
2009		4,460	3,922				4,930	3,894	4,341	4,617	3,705	4,216	4,930	4,318	3,705
2010															
2011		4,637	4,118							4,888	3,877	4,433	4,888	4,383	3,877
2012		4,751	4,237							5,049	3,949	4,575	5,049	4,509	3,949
2013		4,816	4,308							4,147	4,058	4,630	4,816	4,437	4,058
2014		4,942	4,547							5,329	4,183	4,754	5,329	4,756	4,183
2015															
2016		5,095													
2017		5,179													
2018		5,210													
2019		5,239													
2020															

NOTE: Includes ME, NH, VT, MA, CN, RI, NY, PA, NJ

Table II
Summary of Major Assumptions Underlying Studies Identified on Table I

Assumptions	EIA	GRI	INGAA		WETA	CERA
			Cases 1 & 3	Cases 2 & 4		
Annual Economic Growth Rates	2.1 %	2.3 %	GDP - 2.8 % FRB/PI - 3.3%	GDP - 2.5% FRB/PI - 3.0%	N/A	N/A
Prices						
Oil	$22.73 per bbl in 2020	1998 - 2015 $38.92 - $30.28 per bbl	$16.40 per bbl (1998 dollars)		N/A	N/A
Gas	N/A		N/A			
residential		$5.46 per MMBtu by 2015			N/A	N/A
commercial		$4.60 per MMBtu by 2015				
Electricity	N/A		N/A			
residential		6.9 cents per KWH by 2015			N/A	N/A
commercial		6.0 cents per KWh by 2015				
Annual Fuel Demand						
Electricity	1.4 %	N/A	N/A		N/A	N/A
Oil	N/A	N/A	N/A		N/A	N/A
Nuclear	N/A				N/A	N/A
refirements			11.1 gw by 2010			
nuclear demand		64 gw by 2015				
Coal	N/A	27.0 quads by 2015				
Primary Energy Consumption	N/A	1996 - 2015 (quads)	N/A		N/A	N/A
gas		22.5 - 32.1				
oil		36.0 - 43.7				
hydro		3.4 - 3.2				
nuclear		7.2 - 4.8				
coal		20.8 - 27.0				
Efficiency	Yes	Yes	Yes		N/A	N/A

Table III

Conversion of Annual Demand Numbers to Daily Utilization

	Annual Data from Table I Actual and Projected Demand (B			Annual Converted to Daily Maximum		Minimum	
Year	Historical and EIA (Annual)	Maximu (Annual)	Minimum (Annual)	Average Day a/	Utilization Factor b/	Average Day a/	Utilization Factor b/
a	b	c	d	e	f	g	h
1990	2,301						
1991	2,363						
1992	2,646						
1993	2,662						
1994	2,801						
1995	2,994						
1996	3,147						
1997	3,205						
1998	2,997			15.3	c. Peak Day	15.3	c. Peak Day
1999		3,346	3,172	9.17	59.92	8.69	56.80
2000		3,504	3,144	9.57	62.57	8.59	56.14
2001		3,640	3,242	9.97	65.18	8.88	58.05
2002		3,895	3,297	10.67	69.75	9.03	59.04
2003		4,134	3,358	11.33	74.03	9.20	60.13
2004		4,244	3,485	11.60	75.79	9.44	61.70
2005		4,337	3,458	11.88	77.66	9.47	61.92
2006		4,421	3,498	12.11	79.17	9.58	62.64
2007		4,536	3,555	12.43	81.22	9.74	63.68
2008		4,771	3,628	13.04	85.20	9.91	64.79
2009		4,930	3,706	13.51	88.28	10.15	66.34
2010		5,033	3,805	13.79	90.12	10.42	68.14
2011		4,888	3,877	13.39	87.53	10.62	69.42
2012		5,049	3,969	13.80	90.16	10.84	70.88
2013		4,816	4,058	13.19	86.24	11.12	72.67
2014		5,329	4,183	14.60	95.42	11.46	74.90
2015		5,435	4,276	14.89	97.32	11.72	76.57

a/ (column c or d)/(days in year)
b/ (column e or g)/(peak day)