THE INGAA FOUNDATION, INC.

Discussion of Effects of Long-term Gas Commodity and Transportation Contracts on the Development of North American Natural Gas Infrastructure

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EXECUTIVE SUMMARY

This paper presents a discussion of contracts for natural gas commodity, transportation and storage services signed by large natural gas consumers and local distribution companies. The issues addressed here can be summarized by a series of questions:

- Has the move away from long-term contracts in the U.S. gas industry increased the risk profile for new pipeline and LNG projects?
- Will the move away from long-term contracts affect the timing and level of new pipeline and LNG investments?
- Is there a public interest to be served by policies that would facilitate an increase in prevalence of long-term contracts as part of diversified contract portfolios?

This paper provides background information on the relevant issues, estimates what is at stake in terms of economic consequences and discusses available policy options, including encouraging more long-term contracts.

The analysis conducted here finds that the move away from long-term contracts has increased the risks of infrastructure investment and that these added risks could indeed influence whether, and when, investments are made. The paper also shows that there are large adverse economic consequences of infrastructure delays in terms of higher natural gas prices and greater price volatility. The direct costs to gas consumers of delays of 12 to 36 months in natural gas infrastructure construction would range from $179 to $653 billion over the next 15 years. There would also be additional costs born by consumers through higher electricity prices and lost jobs as energy-intensive industries adjusted to higher

energy prices. In addition, the volatility of gas and electricity prices would go up if natural gas infrastructure is delayed, causing further economic loss through slower and less efficient investment decisions by energy producers and consumers.

Given these factors, encouraging more long-term contracting by all classes of shippers should be considered as an element in Federal and State policies to ensure adequate investment to maintain current capacity as well as adequate investment to expand natural gas infrastructure to meet market demand. Also, measures to encourage portfolios with long-term contracts should address the regulatory and market risks for cost recovery.

1.1 Historical Perspective

Fundamental changes resulting from regulatory restructuring and market events have changed the historical profile of contracting practices throughout the natural gas industry. LDCs and large end-users have moved away from 20-year contracts for pipeline capacity and commodity toward 5-year or shorter pipeline contracts and a mix of spot and short-term commodity purchases. To some degree, the decline in long-term contracts by LDCs and large end-users coincided with the emergence of large energy marketing companies, who took on the role of intermediaries. The fallout from the Enron collapse, however, reduced the ranks of these intermediaries and led to declines in trading liquidity, market transparency, and the number of willing, creditworthy counterparties for long-term transportation capacity and natural gas commodity purchases.

As important, power generation customers, who represent the most rapidly growing segment of natural gas end-use demand, have not entered into long-term gas supply and transportation contracts in amounts commensurate with their growth in gas use. Rather, these customers have generally relied on short-term gas commodity purchases, interruptible transportation (IT) and capacity release. Power generation customers typically have firm transportation contracts only along laterals and in the most constrained portions of the pipeline network rather than along the entire transportation path.

The North American natural gas industry is now facing a critical period as the industry's ability to meet growing demand over the next 15 years will depend on whether large, expensive gas pipeline and LNG projects are built. Although the ranks of energy marketers have recently been boosted somewhat as large oil and gas producers have increased their gas marketing role and some financial companies have entered the energy trading space, there are real concerns that large-scale natural gas infrastructure projects may be delayed, diverted to other countries or abandoned because they lack assured markets and reduced risks afforded by long-term transportation and commodity purchase contracts.

1.2 Disincentives to Long-term Contracts

The current market and regulatory situation provides disincentives to long-term transportation and commodity contracts for all of the major classes of natural gas customers including power generators, industrials and local gas distribution companies (LDCs). LDCs often have been discouraged from contracting for additional gas transportation capacity or entering into long-term, fixed price supply contracts. Risk management through portfolio diversification and hedging programs is not yet well understood by many regulators. In addition, regulators are often reluctant, or in some instances are unable within existing statutory authority, to "pre-approve" a program.

Independent and utility power generators in many regional power markets have decided that living with the volatility of a short-term gas market makes economic sense given the regulatory and market structure of the electricity industry. Without properly structured capacity payments, a generator assumes cost recovery risk whenever it enters into a long-term contract that creates a financial obligation that is not avoidable when the generator is not being dispatched. Contracts for fixed volumes of gas or pipeline/storage capacity can create such obligations. In contrast, a decision to purchase gas at prevailing market prices – whatever the cost – can present significantly less risk of under-recovery. If gas supplies are not available at all, the power plant can simply shut down.

Industrial customers have always had incentives to minimize their contractual commitments while implementing their gas purchasing risk management strategies. Industrial customers with alternative fuel capability, in particular, are reluctant to enter into long-term contracts. Such contracts can create fixed costs and liabilities on the balance sheet that reduce the optional value created by the dual-fuel capability.

The “free-rider” problem also creates disincentives for all classes of shippers including power generators, industrial and LDCs considering contracts for gas pipeline capacity. The “free-rider” problem refers to the fact that shippers can often use released capacity or IT service to get many of the benefits of increased capacity and reduced transportation costs when new capacity is built. The problem is particularly evident for the construction of new capacity, but also affects the incentive to renew contracts for existing capacity. This free rider problem provides an incentive for shippers to delay as long as possible any contractual commitment to a new project because of uncertainty regarding future prices and the hope that the project will be built without their commitment. This is particularly true for unregulated shippers that do not have a regulated obligation to serve, but also affects the contracting practices of gas distribution companies that must worry about the competitiveness of their system gas supply portfolio compared to unregulated marketers. This fundamental problem in the current regulatory framework has yet to be addressed in any meaningful way.

Unless Federal and State regulators address the fundamental structural and cost recovery issues, all classes of gas customers will continue to have an incentive to minimize the quantity and term of contractual commitments. Without such actions, getting capacity built and in service when it is needed will continue to be a difficult challenge.

1.3 Natural Gas Supply and Demand Balance

From 1998 through 2004, gas consumption as reported by EIA and industry analysts has been relatively flat at 22 to 23 Tcf. Natural gas consumption in the United States for the year 2004 was 22.3 trillion cubic feet.[1] In recent years, natural gas supplies available to the United States have not grown in a manner that would allow for increases in gas consumption. At the same time, the underlying drivers for gas consumption – including a rapidly increasing need for gas-fired electricity generation – remain. Extended periods of high gas prices and increases in price volatility have resulted from the lack of development of new sources of gas supply sufficient to meet the market's desire for more natural gas, and in some cases volatility has been amplified by infrastructure constraints.

The latest EEA Base Case presented in this study anticipates that U.S. natural gas consumption should approach 30 Tcf by the end of the next decade if the supply of gas is developed. But if this growth in consumption is to occur, large amounts of infrastructure including pipeline capacity, storage capacity, and LNG terminal capacity must be built in the United States and Canada and sufficient LNG liquefaction and shipping capacity must be added worldwide.

While gas produced in traditional basins such as the Mid-continent, onshore Louisiana and the shallow waters of the Gulf of Mexico will continue to be important sources of supply, they will not by themselves be sufficient to satisfy growing demand over the next two decades. To meet a growing demand, gas from "frontier regions" also must be developed. These frontier supplies include the deepwater offshore in the Gulf of Mexico, unconventional gas in the U.S. and Canadian Rockies, Arctic gas, and large volumes of LNG. The development of these resources will require large capital commitments and the construction of major infrastructure projects. If, however, government policy and public opposition to the construction of the required infrastructure prevent the facilities from being built, gas supplies will be unable to grow to meet market demand. As a

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[1] EIA Natural Gas Monthly, preliminary estimates

result, there could be tremendous pressure on gas prices that could hinder economic growth and the competitiveness of U.S. industry.

1.4 LNG Infrastructure Requirements

LNG imports must play a key role. U.S. LNG imports for 2002 totaled 229 Bcf. Imports for 2003 doubled the previous year at 507 Bcf and in 2004 were 650 Bcf. By 2020, U.S. LNG imports could be nearly 7 Tcf per year, more than a ten-fold increase from 2004. LNG is competitive with North American production at prices ranging from $3.50 to $4.00 per Mcf depending upon the distance that the LNG travels from the liquefaction plant to the import terminal. Imported LNG, in large part, becomes an economically viable energy supply because of the low cost of developing and producing abundant stranded gas resources located throughout the world. The total investment required to deliver the incremental LNG volumes needed by 2020 exceeds $100 billion (in 2004 dollars) including regasification terminals and ships, plus all liquefaction plant, transportation, processing and production investments in the exporting country.

1.5 Gas Pipeline, Storage and LNG Terminal Infrastructure Requirements

Pipeline investments will be needed to connect new domestic and LNG gas supply sources, to interconnect new customers to the grid and to maintain capacity on traditional pipeline corridors. Nearly $29 billion will be needed for construction of new pipeline to new supply sources and to new customers. Of that, $19 billion will be associated with the Alaskan and MacKenzie Delta projects that will access needed supplies of Arctic gas.

Approximately $16.4 billion of investment will be needed for refurbishing and replacing existing pipeline to maintain current throughput capacities. Recently promulgated pipeline integrity inspection requirements will require additional investment be made in equipment such as pig launchers and catchers on the existing pipeline network. Also, existing pipeline must be upgraded as denser development encroaches on existing pipeline rights of way. For the lower-48, investment to maintain capacity on existing corridors represents 62 percent of all pipeline investment expected for the next 15 years.

In addition to pipeline construction, underground storage projects costing $5.5 billion will be needed. These include both conventional storage to meet growing winter season gas consumption and high-deliverability storage that will be required to serve fluctuating daily and hourly power plant loads. Together with the $9.4 billion for new LNG terminal capacity, total needed natural gas infrastructure investment in the U.S. and Canada will be $60 billion by 2020.

1.6 Natural Gas Price Volatility

Price volatility refers to up and down movement of prices and can be described in terms of standard deviation or other statistical measures. Because of changes in the structure of natural gas markets and the tightening of the supply/demand balance, price volatility has gone up in U.S. and Canadian natural gas markets. Price volatility has contributed to a climate of uncertainty for energy companies and investors and a climate of distrust among consumers, regulators, and legislators. Energy price volatility creates uncertainty and concern in the minds of consumers and producers, who may delay decisions to purchase appliances and equipment or make investments in new supply. Such delay may result in lost market opportunities and inefficient long-run resource allocations. In addition, volatility may create pressures for regulatory intervention that can bias the market and penalize regulated entities and market participants by generating wide and unpredictable revenue swings. Finally, volatility can hurt the image of energy providers with the customers and policymakers and create doubt about the industry’s integrity and competency to reliably provide a vital economic product.

Infrastructure that is supported by longer-term contracts can play a role in reducing the adverse impacts of volatility in gas prices. There are two mechanisms by which this occurs.

First, empirical research has shown that gas price volatility is correlated to the level of prices.[2] Simply stated, the overall tightness in the supply and demand balance that creates the conditions that lead to high prices also increases the impact of small changes in demand that occur as a result of weather or economic activity. Small changes create large price movements. As a result, increases in investment in infrastructure that ease the tightness of supply and demand will also reduce volatility. The reduction in volatility reduces the uncertainty that delays investments, which in turn results in additional supply and increased economic activity. The effect is to reduce further the volatility in the underlying market.

Secondly, longer-term contracts can be used to hedge prices and provide stability to the parties entering into the contract in the face of the remaining volatility. In total, the impact of longer-term contracts can be quite powerful in terms of reducing volatility and its adverse effects. Moreover, because the infrastructure supported by the longer-term contracts can reduce the underlying volatility of the market, the cost of hedging gas prices using financial tools such as options and/or swaps can be reduced.

1.7 Project Financing and Risks: Role of Long-term Contracts

Long-term commodity purchase and transportation contracts reduce risks to developers and lenders of large-scale supply projects, thereby making the projects more likely to be financed and built. Long-term sales and service contracts are important because they increase the assurance that the investment will receive adequate revenue. Long-term contracts can mitigate volume risk by assuring that a minimum amount of sales or throughput occurs. Long-term sales contracts also can mitigate price risk by setting a fixed price or by specifying a pricing formula based on a well understood – and possibly hedgeable – price index.

Lenders and equity holders look at many sources of risk when they evaluate large-scale supply projects. Risks are allocated based on contracts and the absence of contracts

[2] B. Henning, M. Sloan and M. de Leon, "Natural Gas and Energy Price Volatility", Oak Ridge National Laboratories, October 2003

may expose equity holders and lenders to added risks that may increase the cost of capital, delay projects or divert gas supplies to other countries.

Without longer-term contracts for all or substantially all of capacity, pipelines will be seriously challenged when they seek financing for new pipeline construction or capital investment required to maintain existing capacity. Under current rate policy, the regulated returns that pipelines are granted are based upon the assumption of full capacity contracting. These returns are not sufficient to attract capital without the revenue stream assurances that long-term contracts provide.

1.8 Consequences of Delays in Infrastructure Construction

Since 1999, the natural gas market events identified above have created a market environment that has resulted in increased natural gas prices and gas price volatility. The potential magnitude of these effects first became evident in early 2000. In the winter heating seasons of 2000-01 and 2002-03, gas prices “spiked” to levels that had previously seemed unimaginable.[3] The increase in prices and in price volatility occurred because there was no unutilized capacity to deliver additional supplies of gas to the market when weather, economic activity, and increased power generation increased gas demand. The supply/demand imbalances became too large to be moderated by the behavior of customers who could easily respond to changing price conditions. As a result, large and rapid increases in delivered gas prices occurred.

Once production and storage approach their physical deliverability limits, price increases do not result in an immediate increase in the quantity of gas that can be delivered to consumers. New sources of gas, either from North American production or from LNG imports, must be developed along with storage capacity that enables the delivery of gas to match the customer’s load profile. Similarly, as pipeline transmission capacity limits are reached, increases in the market value of pipeline transmission – the basis – will not result in an immediate increase in the amount of gas that can be

[3] The 2001-02 heating season did not experience a natural gas price spike because of unusually warm weather that reduced gas demand for space heating.

delivered. The lead-time associated with new pipeline capacity does not allow for an instantaneous supply response when all of the capacity is being utilized. Once capacity is reached, available supply changes very little, regardless of price.

Natural gas projects (production, LNG, pipeline or storage) inherently involve large capital investments. In addition, large numbers of environmental, land use, and other permits must be obtained before construction can begin. While FERC and other permitting agencies have made commendable efforts to accelerate these processes, these requirements still can result in a considerable period of time between the identification of market need and the commencement of service. For even small projects, the period can be many months, and for large projects, the period can stretch to multiple years.

As a result of these market fundamentals, any additional delays in the construction of natural gas infrastructure caused by the lack of long-term contracts and other obstacles can be costly to natural gas consumers and to the stability of North American energy markets. To examine the consumer cost impacts, we have explored two alternative scenarios to the EEA Base Case, one of which assumes that all pipeline and LNG import terminal projects not already under construction will be delayed by 12 months. The second alternative case assumes a 36-month delay.

Using the Henry Hub price as a measure of the impact on gas prices, a 12-month delay in pipeline and LNG import terminal construction will increase U.S. natural gas prices by an average of $0.80 per MMBtu from 2006 – 2020, $0.67 per MMBtu in constant 2004 dollars (Table 1-1). Price effects will be immediate and lasting throughout the forecast period. A longer, 36-month delay in pipeline and LNG import terminal construction will increase U.S. natural gas prices by an average of $2.89 per MMBtu from 2006 – 2020, $2.35 per MMBtu in constant 2004 dollars.

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Table 1-1
Natural Gas Price Effects of a 12 to 36-month Delay in Pipeline and LNG Terminal Construction

Average Henry Hub Price Nominal $ per MMBtu

Time Period	Base Case	12 Month Infrastructure Delay	Price Increase
2006-2010	$7.66	$8.71	$1.04
2011-2020	$8.05	$8.74	$0.68
2006-2020	$7.92	$8.73	$0.80

Average Henry Hub Price Real 2004$ per MMBtu

Time Period	Base Case	12 Month Infrastructure Delay	Price Increase
2006-2010	$6.94	$7.87	$0.93
2011-2020	$6.04	$6.58	$0.54
2006-2020	$6.34	$7.01	$0.67

Average Henry Hub Price Nominal $ per MMBtu

Time Period	Base Case	36 Month Infrastructure Delay	Price Increase
2006-2010	$7.66	$10.25	$2.58
2011-2020	$8.05	$11.09	$3.04
2006-2020	$7.92	$10.81	$2.89

Average Henry Hub Price Real 2004$ per MMBtu

Time Period	Base Case	36 Month Infrastructure Delay	Price Increase
2006-2010	$6.94	$9.23	$2.29
2011-2020	$6.04	$8.42	$2.38
2006-2020	$6.34	$8.69	$2.35

The price impact in market areas where delay results in pipeline capacity constraints can be even larger. **In total, a 12 to 36 month delay in natural gas infrastructure construction will cost U.S. gas consumers from $179 to $653 billion (in constant 2004 dollars) by 2020**. Higher gas costs will be seen in all parts of the country.

In general, price volatility increased along with price levels in the alternative case with delays in infrastructure construction. For example, for Henry Hub, Chicago and California, the standard deviation of natural gas prices went from $1.15 to $1.24 per MMBtu in the Base Case to $2.02 to $2.08 per MMBtu in the 36-month delay case. More constrained total gas supplies and more severe transportation caused these substantial increases in volatility bottlenecks.[4] The increase in volatility would increase the costs of hedging a gas commodity and transportation portfolio.

1.9 Policy Options

In order to reduce or eliminate the risk that consumers will be saddled with billions of dollars of additional energy costs as a consequence of delays in the development of natural gas infrastructure, five broad areas must be addressed.

General Recommendations

First, regulators at the state and federal level **should consider actions that attract capital to pipeline and storage projects**. In particular, state utility regulators should conduct a comprehensive and consistent review of existing rules and policies, including cost recovery, that discourage state regulated local gas distribution companies and power generation customers from entering into the long-term capacity contracts for transportation and storage that are necessary to underpin new infrastructure projects. Current state regulation often inhibits LDCs from entering into long-term contracts either

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[4] It should be noted that the quantification of the impact of volatility provided in this analysis likely understates the impact of delays in infrastructure on volatility because the alternative case assumes "normal weather" for each month in each year. Variability in weather would result in additional volatility even in years that are "normal" for the year as a whole and the differences between the Base Case and the alternative case would also be larger.

actively – in the name of increasing the competitiveness of third party marketers – or implicitly through the risk of a retroactive prudence review that could disallow gas capacity costs. State regulation should recognize the public benefit of capacity into a market and create a cost recovery mechanism that promotes the construction of sufficient facilities to allow for incremental supplies of gas to be delivered during peak demand periods.

Second, federal and state regulators **should consider electricity resource planning that reflects the reliability benefits of firm pipeline and storage capacity to gas-fired generation**, as well as the reliability benefits of alternative fuel capability. Specifically, regulators should consider policies that differentiate between a gas-fired generator with firm pipeline and storage capacity under contract and those that do not. Regulation should consider recovery mechanisms and market structures that create tangible advantages for generators that hold capacity contracts.

Third, the gas industry should work with state and local officials including state economic development offices to **ensure that all of the societal, employment, and consumer cost benefits of a pipeline, storage, or LNG terminal project are presented** during the process of evaluating a proposed project. As part of this, public education and outreach efforts should include information regarding details of the construction process, the ultimate (post construction) impacts on the environment and safety as well as the ongoing direct and indirect benefits of construction.

Fourth, federal and state regulators should **conduct regional analyses to identify the market needs of multi-state regions**. While FERC currently conducts such reviews, the impact of these analyses could be enhanced by a process that develops additional ownership or buy-in of the conclusions within state and local governments. However, these regional studies should not be used to implement a “centralized planning” approach to facilities selection. Rather, market participants must be allowed to design, propose and competitively market projects in response to the specific needs of the market.

These regional studies can provide two types of benefits. First, the studies can provide all market participants with the best available information. Second, the studies can help regulators evaluate market fundamentals behind contracts entered into by power generators and others. The regional analyses should explicitly consider the impact on consumers and economic development of a decision to prohibit or delay infrastructure development. Further, Federal, State, and local permitting proceedings must evaluate and consider the adverse consequences on the local general population and on citizens in surrounding jurisdictions of inhibiting the construction of infrastructure. They should identify the forecasted need of the different market segments and the holders of firm capacity.

Fifth, homeland security and safety concerns, particularly regarding LNG, must be met with a **balanced and informed evaluation of risk**. There are many elements of modern life that present manageable risk but almost none that can be described as risk-free. All appropriate actions to ensure safety and security should be required. Still, to the extent that any residual risk cannot be eliminated, that risk should be evaluated in terms of the overall cost to citizens and the economic insecurity that would result from a failure to build natural gas infrastructure that is required to meet growing energy demand.

Specific Policy Options and Alternatives

Under the first item, state and federal actions to attract capital, the following areas should be considered as ways of making the contracting and building of needed infrastructure possible and more timely:

1) Through market design and reliability standards, create incentives and cost recovery mechanisms for power generators to enter into long-term gas supply, transportation and storage contracts. Regulators and the electricity industry should consider the following policy options:

- Incorporating firmness of fuel supplies into installed capacity payments as a means of providing power generators cost recovery for firm commodity and transportation contracts. State regulators should consider the positive impact of properly constructed installed capacity payments on a generator's ability to enter into long-term contracts to bring gas into the region.
- Incorporating firmness of fuel supplies into reliability rules to encourage long-term contracting and/or alternative fuel backup capability.
- Allowing ISO/RTOs or states to contract gas pipeline and storage capacity for reliability benefits. The cost of such infrastructure could be spread over all electricity customers through non-bypassable charges.

2) Reduce the "asymmetric risk" faced by LDCs in long-term contracting through regulatory policies. States could pre-approve LDC contracting practices for cost recovery by taking steps including:

- Limiting the risk of disallowance of the costs of contracting and/or hedging activity.
- Determining the applicable accounting methods to be applied, including accounting for financial derivatives.
- Limiting the risk of second guessing by regulators if market prices subsequently are below the locked-in gas price of the hedged portfolio.

States could also review customer choice programs to ensure that they do not unreasonably discourage long-term contracts. Steps could include:

- Increasing the predictability of LDC load by limiting the frequency or level of customer migration.
- Facilitating capacity assignment by the LDC to unregulated suppliers when migration takes place.
- Increasing reliability standards for non-LDC marketers so that they are encouraged to develop balanced long-term supply portfolios.

3) Use pricing policies to make long-term firm pipeline contracts more attractive relative to shorter-term alternatives. FERC and the pipelines could review pipeline rate policies to consider their impact on contract term. Policies that can impact contract term include:

- Consider policies that place upward pressure on prices for short-term transportation service to improve price signals in constrained markets. For example, IT maximum rates could be based upon a load factor that is less than 100 percent thereby increasing the incentive to enter into contracts for firm service. In addition, removing the cap on capacity release could also increase the desirability of firm service contracts from a shipper's perspective.
- Considering rolled-in pricing for capacity expansions to make signing contracts for new capacity more attractive.
- Considering the impact of shortened depreciation periods to reduce the financial risks of new capacity.
- Promoting the use of term-differentiated rates to provide incentive for longer-term lengths.
- Allowing greater flexibility for pipelines to design negotiated rate proposals to meet market needs. This could include index-based rate formulas to allocate risk between pipeline and willing shippers.

4) Continue government programs and incentives designed to reduce risks to LNG, Alaska pipeline and other infrastructure projects. Federal and State governments can consider making project financing easier with policy options including:

- Offering flexible loan guarantees to large, high-risk projects such as the Alaska gas pipeline.
- Offering tax certainty and incentives to project developers.
- Contracting directly for pipeline capacity for state royalty gas or for general reliability benefits.

- Participating as an equity holder or through “port authority” sponsorship.
- Continuing and accelerating loans and loan guarantees for LNG development projects through Export-Import Bank, Overseas Private Investment Corporation, Multilateral Investment Guarantee Agency and similar agencies.

2
INTRODUCTION

In July 2004, the INGAA Foundation published **An Updated Assessment of Pipeline and Storage Infrastructure for the North American Gas Market: Adverse Consequences of Delays in the Construction of Natural Gas Infrastructure.** This was the most recent in a series of studies examining the opportunities and challenges facing the natural gas industry in serving the growing natural gas market. In those studies, Energy and Environmental Analysis, Inc. (EEA) provided updated views of future natural gas infrastructure requirements for the U.S. and Canadian markets. The gas industry used those studies to highlight the importance of new pipeline and storage capacity in achieving the economic and environmental benefits of increased gas consumption. These studies found that serving a growing gas market was economically feasible. The studies also concluded that all segments of the gas industry would face challenges in growing the market. One of those challenges was the need to attract capital to natural gas infrastructure projects. Consequently the 2004 INGAA Foundation study recommended that:

> In particular, state utility regulators [should] conduct a review of existing rules and policies that discourage state regulated local distribution companies from entering into the long-term capacity contracts for transportation and storage that are necessary to underpin new infrastructure projects. Current state regulation often inhibits LDCs from entering into long-term contracts either actively – in the name of increasing the competitiveness of third party marketers – or implicitly through the risk of retroactive prudence review that could disallow gas capacity costs. State regulation should recognize the public benefit of capacity into a market and create a cost recovery mechanism that promotes the construction of sufficient facilities to allow for incremental supplies of gas to be delivered during peak demand periods.
>
> In addition, State PUCs and ISO market structures also inhibit gas powered electric generators from entering into long-term contracts. Federal and state

regulators should consider electricity resource planning that reflects the reliability benefits of firm pipeline and storage capacity to gas-fired generation as well as alternative fuel capability.

Last, the major marketing companies have corporate goals that understandably focus on total maximized returns. Inherently, the most to gain (or lose) for a marketing company is found in a volatile market dominated by short-term contract.[5]

Some of the same themes were found in the conclusions of the 2003 National Petroleum Council (NPC) Natural Gas Study, which contained the following:

Finding #9: Regulatory barriers to long term contracts for transportation and storage impair infrastructure investment. The average transportation contract term on pipelines has shortened. New pipeline and storage infrastructure are generally financially supported by long-term contracts for a period of ten to twenty years. Companies are less willing to invest dollars in new infrastructure if contract duration for existing or new pipeline/storage capacity are shortened by the impact of regulatory policies… A contributing factor in the shortening of pipeline contracts was the restructuring of many LDC businesses in the 1990's. The opening of LDC distribution system capacity to transport by third parties was developed as a means to increase competition and lower prices. By the end of the 1990's restructuring was complete in many states for gas in the industrial and electric generation segments and was underway in the residential/commercial sector. Although retail choice programs are in place in many states, to date the vast majority of residential customers have elected to remain with their original utility. Nevertheless, a directive from some states is that LDCs should not contract for the long term in pipeline, storage, or upstream capacity since their share of the future market was unknown and subject to considerable risk in the face of developing competition. Generally, LDCs are not willing to contract for long-term capacity and take the risk of being second-guessed in future prudence reviews… Similarly, power producers, especially those that provide peaking service, are reluctant to contract for firm pipeline service because charges for firm service cannot be economically justified in power sales. The result is that regulatory barrier may be inhibiting efficient markets and discouraging the financial incentive to develop and maintain pipeline infrastructure.[6]

In May of 2005 Governor Frank Murkowski of Alaska voiced similar concerns to the Interstate Oil and Gas Commission regarding a pipeline to bring gas from his state to

[5] EEA Inc., "An Updated Assessment of Pipeline and Storage Infrastructure for the North American Gas Market: Adverse Consequences of Delays in the Construction of Natural Gas Infrastructure." INGAA Foundation, July 2004, page 11.

the lower 48. He said, "Naturally a project of this magnitude requires a degree of predictability and financial stability not only on issues of throughput, but also long term marketing agreements. To deal with that issue, as chairman of IOGCC I am today joining with the National Association of Regulatory Utility Commissioners and will be appointing a special task force. Its mission will be to study ways to enhance the ability of utility companies to enter long-term gas marketing agreements…"[7]

The resulting NARUC/IOGCC Joint Task Force issued a Notice of Inquiry August 2 that requested comments on the following questions

> (1) What are the State regulatory barriers hindering investment in natural gas and LNG delivery infrastructure?
>
> (2) In what manner may investment in natural gas and LNG delivery infrastructure be encouraged and/or increased by State regulators?
>
> (3) Should long-term natural gas transportation and storage agreements be encouraged as a way to increase in natural gas and LNG delivery infrastructure?
>
> (4) If your answer to question (3) is "yes," in what manner may long-term natural gas transportation and storage agreements be encouraged by State regulators? Also, what is the appropriate length of a long-term natural gas transportation and storage agreement?[8]

This paper discusses how the existence or absence of long-term commodity purchase and transportation contracts signed by large natural gas consumers and local distribution companies could affect whether and when natural gas infrastructure is built. This paper provides background information on the relevant issues raised in the INGAA Foundation and NPC reports and in the NARUC/IOGCC NOI. The paper also estimates what economic consequences are at stake by estimating the consumer impacts of delays in natural gas supply, transportation and storage infrastructure investments. Finally, the paper discusses available policy options to encourage the timely

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[6] National Petroleum Council, "Balancing Natural Gas Policy: Fueling the Demands of a Growing Economy, Volume 1 Summay, 2003, pages 46-47.
[7] Chairman's Address to IOGCC May 16, 2005.

[8] NARUC Press Release August 2, 2005

construction of infrastructure, including the role that could be played by policies encouraging more long-term contracts.

3
HISTORCIAL BACKGROUND

3.1 Historical Natural Gas Market Trends

Long-term contracts for gas commodity and transportation had been the norm throughout most of the history of the U.S. and Canadian gas industry. Natural gas producers in the U.S. sold to interstate and intrastate pipelines under long-term contracts that lasted for the “life of reserves” or a long, fixed period such as 10 or 20 years. Interstate sales were subject to Federal regulation, including controlled wellhead prices that started in 1954 and phased out between 1978 and 1990.

Natural gas pipelines sold to local gas distribution companies a bundled service that included the commodity and transportation. These contracts also were long-term, with typical lengths of 20 years. Interstate pipelines were subject to Federal cost-of-service regulation, so that the entire price (both commodity and transportation components) paid by their LDC customers was under Federal review and control.

The pipelines’ long-term wellhead contracts with producers and long-term service contracts with LDCs were essential to get regulatory approval of and debt financing for interstate natural gas pipeline capacity. In fact, much of the natural gas infrastructure was developed during this period when long-term contracts predominated. The Federal authorities (the Federal Power Commission and then the Federal Energy Regulatory Commission) required both long-term gas-supply contracts and long-term LDC service contracts as a prerequisite for issuing a certificate of public convenience and necessity under Section 7 of the Natural Gas Act. These documents were also important to debt issuers who were concerned with repayment of the notes and bonds used for the debt portion of the pipelines' capital financing.

Throughout much of the 1970s Federal regulation caused shortages of gas in the interstate markets because wellhead prices were kept artificially low. In response, Congress passed the Natural Gas Policy Act of 1978, which raised prices for all gas dedicated to interstate markets and immediately deregulated some categories of new gas. The maximum price of other (non-deregulated) new gas was set according to complex categories that had various initial prices, escalation rates and dates of decontrol. By 1985 most gas dedicated to interstate markets had been deregulated under NGPA, and by 1990 essentially all natural gas was free of price controls due to the Natural Gas Wellhead Decontrol Act of 1989.

Throughout the 1980s FERC policies altered the relationship between interstate pipelines and LDCs. In 1984 FERC issued Order No. 380 that freed LDCs from minimum bill requirements that had obligated the LDC to buy all minimum volumes called for in their service contracts. In 1985 FERC Order No. 436 effectively required interstate pipelines to offer open access transportation service on a non-discriminatory basis, thereby providing LDCs and other large volume gas consumers with an alternative to purchasing bundled pipeline merchant services. Because the interstate pipelines had purchased gas under heavy take-or-pay and high pricing provisions, the subsequent fall-off in gas volumes purchased by LDCs from the interstates combined with falling natural gas prices, left the pipelines with substantial take-or-pay exposure.

During the period of 1930 through 1990, under these regulatory regimes that favored long term contracts, over 88 percent[9] of the present onshore and offshore interstate pipeline infrastructure was built.

In 1992 FERC issued Order No. 636 that mandated the unbundling of merchant and transportation service. By the mid-1990s, the interstate pipelines had ceased to provide

[9] 2004 Transmission Annual Report sorted by interstate pipelines; http://ops.dot.gov/stats/DT98.htm

a merchant function, offering only transportation and storage services. The LDCs now purchased gas from producers and marketers under negotiated price terms. Since these gas prices were no longer FERC-approved and subject to the filed-rate doctrine, this move toward negotiated prices exposed the LDCs to cost-disallowance during prudency reviews.

Just as FERC moved the interstate pipelines to unbundle services, many state public utility commissions restructured state gas markets and LDC services. Traditionally each LDC held an exclusive franchise to serve a geographic area, serving as merchant and distributor. Starting in the 1980s and accelerating in the 1990s, some state public utility commissions made a policy determination that some large industrial and commercial customers or even all customers should be able to purchase gas from suppliers and have the LDC serve only as the distributor. These retail choice programs varied a great deal from state to state in terms of:

- Which customers were eligible,
- How often the election to change suppliers could be made,
- The obligation of the LDC or other party to serve customers as a Supplier or Provider of Last Resort if a new supplier defaulted, and
- The recovery of stranded costs attributed to long-term commodity and/or transportation contracts that the LDCs had entered expecting to continue as an exclusive franchised merchant.

The existence of retail choice programs or the prospect that one could be implemented in the future caused LDCs to take a cautious approach to contracting of commodity and transportation. This factor, combined with disallowance risk for market-based wellhead gas pricing, helped to make short-term gas supply and transportation deals more attractive and common among LDCs. Excess gas supplies and low gas prices created a sense of security that made gas buyers and regulators comfortable with the shift to short-term contracts.

The Federal and State rulemakings that occurred in the 1990s transferred contracting and management responsibility from a few pipelines that had aggregated demand to a large number of individual LDCs and large gas consumers balancing smaller gas volumes. This tended to reduce operating flexibility and remove the cushion that helped provide reliability. More recently, the “gas bubble” has been worked off as the deliverability declined in the traditional gas fields that were connected with available pipeline capacity. Even with significant new supplies coming from Canada and the Rockies, we are now in a situation where the gas system operates nearly year-round with little excess wellhead deliverability. With the resulting high prices and greater volatility, the dependence on short-term contracts now seems questionable to more people.

3.2 Historical Electricity Market Trends

At one time electricity utilities were predominately vertically integrated and regulated by states as exclusive franchisees in a given service territory. Operating under cost of service rates, the electric utilities would make all needed investment and operating decisions for generation, fuel supply, transmission, and distribution assets. This structure began to change with the PURPA legislation of 1978 that required electric utilities to buy power from cogenerators and other qualified generators at avoided costs. Further changes were made by FERC to open up transmission capacity so that non-utility generators could more fully compete.

As with natural gas, the states followed the Federal lead and encouraged competition in the electricity markets through state legislation and public utility commission actions. Now the electric industry has been restructured in some states and ownership for each segment of electricity supply (generation, transmission, distribution, and marketing) has been split among various (often unregulated) parties. Responsibility for retail service still rests mostly with franchised electric distribution companies but customer choice programs exist in several states. Depending on the nature of restructuring in a state, important elements of electricity supply (most often generation) may be owned by unregulated companies or under the control of multi-state Independent System

Operators or Regional Transmission Organizations. Where they exist, ISOs/RTOs have much of the operational control over use of transmission capacity and often generation dispatch. ISOs/RTOs set up and manage the markets and payments for energy, capacity credits, ancillary services (regulation, spinning reserves, etc.) and transmission capacity.

Throughout much of the historical period, gas use for power generation by electric utilities was supplied through contracts with pipelines and (often sister-company) gas LDCs. Outside the Southwest region served by intrastate pipelines, interruptible service was common and utility boilers were typically equipped with residual oil backup, which was regularly used each winter during periods of high natural gas demand from residential and commercial customers. In regions where peaking turbines were needed to meet winter loads, the turbines would typically be fired with distillate oil or be gas-fired with oil backup.

During the period of 1978 to the early 1990s when gas-fired PURPA cogeneration projects were being built, long-term gas commodity and gas pipeline transportation contracts were common for those new units. The cogenerators had long-term electric sales contracts with electric utilities and were willing to sign supply and transportation contracts for gas supply. In fact, creditors wanted to see firm gas supply as a prerequisite for financing.

For the most part, the 200 GW of gas-fired generation capacity added in recent years was built by independent power producers (i.e., non-cogenerating, non-utilities) intending to supply electricity to a competitive market. Few of those new units had long-term electricity sales contracts when they were built. Because they lacked firm electricity sales agreements, these new gas-fired power plants seldom have long-term gas commodity contracts. And, except for the lateral connecting the plant to the nearest pipeline segment, they also typically lacked firm gas pipeline transportation contracts. Also, to ease the environmental approval process and to reduce initial capital costs, these new gas-fired combined-cycle and simple-cycle turbine units seldom have a fuel oil backup capability.

This lack of firm gas supplies or back-up fuel for these new units is a point of concern among electric industry groups and regulators, who are worried that electricity reliability will suffer in periods of high gas demand or gas supply disruptions. These concerns are being influenced by various studies sponsored by the New England ISO, the New York ISO and NYSERDA, PJM, and the Western Governors Association that show an increasing reliance of on natural gas by power generators in the future. In addition to efforts by these groups, NERC has been moving forward through its Regional Coordinating Councils to assess fuel transportation reliability and to devise mitigation measures as one leg of its ongoing general reliability efforts. These fuel-related measures could include encouraging firm fuel supply and transportation contracts, minimum fuel inventories, and alternative fuel backup.

3.3 Recent Natural Gas Market Status

According to the Index of Customers provided by the U.S. Federal Energy Regulatory Commission, over 2,500 different market participants had contracted for interstate natural gas pipeline capacity in 2001 (Table 3-1)[10]. The largest single group of shippers is gas utilities, with almost 1,000 different gas LDCs contracting pipeline capacity in 2001.

A significant number of gas marketers contract for pipeline capacity. Table 3-2 shows interstate contract volumes for the two years 1998 and 2002 and indicates that marketers had the biggest increase in that span. The current volumes held by marketers is probably less because a number of gas marketers have exited the business after 2001. That said, there remain a significant number of large gas marketers currently in business. Table 3-3 lists the top marketers based on the volume of gas marketed during the first quarter of 2001 and where they stand this year. There has been substantial turnover in gas marketing in recent years. Almost half of the companies in Gas Daily's ranking of top North American marketers in 2001 are not in the list for 2005.

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[10] More recent data is not readily available. The total number of market participants and the split among different groups probably has not changed much over the past few years.

Table 3-1
U.S. Index of Customers for Interstate Pipeline Capacity, 2001[11]

Customer Class	Number of Customers	Percent of Customers
Gas Utilities	986	39
Marketers	614	24
Industrial Consumers	500	20
Cogenerators and Independent	72	3
Combined Utilities	70	3
Electric Utilities	46	2
Other Consumers	255	10
Total	2,543	100

Source: U.S. Federal Energy Regulatory Commission

Table 3-2

Firm Transportation Contracts (Billion Cubic Feet per Day)

				Share of Totals	
	2002	**1998**	**Increase/ (Decrease)**	**2002**	**1998**
Power	18	13	5	15%	12%
Marketer	29	14	15	24%	13%
Producer	12	10	2	10%	9%
LDC	50	50	0	42%	46%
Industrial	4	4	0	3%	4%
Pipeline	6	10	(4)	5%	9%
Other	1	8	(7)	1%	7%
Total	**120**	**109**	**11**	**100%**	**100%**

Source: NPC, Balancing Natural Gas Policy, Volume V, page T-15.

[11] We have not reconciled all naming inconsistencies, so there is potential for double counting in the table.

Table 3-3
Top North American Natural Gas Marketers
Source: Compiled from Gas Daily

	Ranking		
	Q1 2001	**Q1 2003**	**Q1 2005**
Enron	1	n.a.	n.a.
El Paso	2	n.a.	22
Duke	3	n.a.	n.a.
Mirant	4	2	n.a.
BP	5	1	1
Sempra	6	4	4
Reliant/ Centerpoint Energy	7	7	21
Aquila	8	13	n.a.
Coral/Shell	9	3	3
Transcanada	10	n.a.	n.a.
Conoco	11	5	2
Koch/Merrill Lynch (2004)	12	11	15
PG&E	13	n.a.	n.a.
Texaco	14	n.a.	n.a.
Williams	15	8	14
Cook Inlet	16	n.a.	n.a.
Dominion	17	n.a.	n.a.
Exxon	18	n.a.	13
Chevron	19	n.a.	7
AEP	20	n.a.	n.a.
CMS	21	n.a.	n.a.
TXU	22	n.a.	n.a.
PanCanadian/EnCana	23	14	11
Tenaska	24	11	8
Cinergy	25	6	5

New Players in 2003 and 2005

	Ranking		
	Q1 2001	**Q1 2003**	**Q1 2005**
Nexen	n.a.	8	6
Oneok	n.a.	8	9
Amerada Hess	n.a.	15	19
Anadarko	n.a.	16	22
Western Gas Resources	n.a.	17	25
Louis Dreyfus	n.a.	n.a.	9
UBS	n.a.	n.a.	12
Devon	n.a.	n.a.	16
Sequent/ AGL Resources	n.a.	n.a.	16
Calpine	n.a.	n.a.	18
Burlington Resources	n.a.	n.a.	20
Enserco (Black Hills)	n.a.	n.a.	24
Marathon	n.a.	n.a.	25

Still, two things are worth noting: First, many of the large marketers still in business are large multinational E&P companies with diversified business models. Second, financial houses are increasingly becoming involved in gas marketing and in 2005 two major financial institutions – UBS and Merrill Lynch – debuted in the rankings.

Industrial consumers were the third largest group of consumers for natural gas pipeline capacity in 2001, with 500 different consumers identified in the Index of Customers database. Of course, this far understates the total number of industrial gas purchasers, since it does not include industrial buyers that purchase gas from utilities or marketers. Typically, only the largest industrial consumers purchase transportation capacity directly from pipelines.

3.3.1 LNG Imports

In 2004 imports of LNG into the U.S. totaled 652 bcf, with 201.9 bcf under long-term contracts. Data from DOE's Office of Natural Gas Regulatory Activities show that 16 different entities sold LNG into the U.S. in 2004. (Table 3-4) On the other hand, just five importers controlled all the capacity at the four terminals in operation in 2004. (Table 3-5) Of these five, only Distrigas is a regulated entity, while the other four (BG, BP, Shell and Statoil) are unregulated gas marketers.

Table 3-4 Sellers of LNG

Sellers of LNG to U.S. 2004
(Bcf)

	Long-Term	Short-Term	Total	Percent of Total
Asean	0.0	20.0	20.0	3%
Atlantic LNG 1	78.1	0.0	78.1	12%
Atlantic LNG 2/3, PFLE	103.7	10.4	114.2	18%
BG	2.6	5.4	8.0	1%
BP	0.0	22.8	22.8	4%
Gas de Euskadi, SA	0.0	0.7	0.7	0%
Gas Natural	0.0	85.4	85.4	13%
Marathon	8.1	0.0	8.1	1%
Med LNG	0.0	27.2	27.2	4%
Mitsubishi	9.4	0.0	9.4	1%
NaturCorp Multiservicios	0.0	8.2	8.2	1%
Nigeria LNG	0.0	8.8	8.8	1%
Repsol	0.0	102.5	102.5	16%
Shell	0.0	17.9	17.9	3%
Sonatrach	0.0	89.4	89.4	14%
Tractebel	0.0	51.3	51.3	8%
	201.9	450.1	652.0	100%

Source: DOE Office of Fossil Energy, Office of Natural Gas Regulatory Activities

Table 3-5 Importers of LNG

Importers of LNG to U.S. 2004
(bcf)

	Long-Term	Short-Term	Total	Percent of Total
BG LNG Services, LLC	117.2	151.8	268.9	41%
BP Energy Company	0.0	80.9	80.9	12%
Distrigas Corporation	84.8	89.0	173.8	27%
Shell NA LNG, LLC	0.0	62.1	62.1	10%
Statoil Natural Gas, LLC	0.0	66.3	66.3	10%
	201.9	450.1	652.0	100%

Source: DOE Office of Fossil Energy, Office of Natural Gas Regulatory Activities

3.3.2 LDC Contracting

The latest data on gas procurement practices by LDCs comes from the American Gas Association's survey on winter 2004-2005 gas supplies. With regard to pipeline capacity, the survey shows an overwhelming reliance of firm transportation capacity, with only two of fifty respondents indicating any peak-month use of interruptible pipeline capacity.[12] The survey results regarding suppliers of gas to LDCs is shown in Table 3-6. The table indicates how many of the LDCs responding to the survey received gas from each type of supplier and what portion of the peak-day gas is attributable to that type of supplier. For example, nine LDCs reported getting from 1 to 25 percent of their peak-day gas directly from gas producers, while 21 reported no gas from that source. The survey shows that how merchant pipelines have ceased being suppliers to LDCs. Roughly speaking, about a quarter of the supplies come from each gas producers, producer marketing affiliates and independent marketers.[13]

Table 3-6 Providers of LDC Gas Supply
PERCENT OF PEAK-DAY BY TYPE OF SUPPLY PROVIDER
(Number of Companies)

Percent of Peak Day Gas Supply	Producer	LDC-Owned Production	Producer Marketing Affiliate	Pipeline	Pipeline Marketing Affiliate	Independent Marketer	Other
1 - 25	9	1	7	0	8	11	7
26 - 50	9	1	8	0	0	17	1
51 - 75	9	0	9	0	1	6	2
76 - 100	4	0	5	0	0	3	6
none	21	50	23	52	43	15	36

SOURCE: 2004-2005 AGA LDC Winter Heating Season Performance Survey

The length or term of the LDC contracts is shown in Table 3-7. The AGA survey indicates that 32 out of 52 respondents had some supply contracts that were 12 months or longer in length. Roughly speaking, these "long-term" contracts made up about 30 percent of peak-day supplies on average. Contracts lasting from 2 to 11 months were

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[12] AGA, "2004-05 LDC Winter Heating Season Performance Survey," July 19, 2005, page 7.
[13] These approximate volume-weighted averages were computed by EEA assuming an equal weight for each LDC respondent. They are not values reported by AGA.

another 42 percent of supply, while monthly contracts made up 13 percent. The remaining 15 percent came from daily purchase contracts.

In reviewing the data on contract length, AGA made the following comments:

> As a general statement, comparing 2004-2005 data to that collected two years ago (2002-2003) winter heating season with 65 companies responding to the survey), daily and monthly contract terms are less prevalent today than two years ago among the survey participants. This may be because recent daily pricing have been high relative to history. It may also be, however, that companies and Public Utility Commissions are becoming more comfortable with longer-term supply agreements as a part of a supply portfolio, remembering that a long-term deal today may be two years not 10 or 15 as in the past.[14]

Table 3-7 Contract Term of LDC Gas Supply Contracts

PERCENT OF PEAK-DAY BY CONTRACT TERM

(Number of Companies)

Percent of Peak Day Gas Supply	12 Months or More	2 to 11 Months	Monthly	Daily
1 - 25	15	10	13	12
26 - 50	7	9	8	9
51 - 75	7	9	2	3
76 - 100	8	13	1	1
none	15	11	28	27

SOURCE: 2004-2005 AGA LDC Winter Heating Season Performance Survey

The type of pricing provisions in recent LDC contracts is shown in Table 3-8 from the AGA survey. As in the other tables from the survey, the numbers shown indicate how many respondent companies report themselves as being in each category. Based on EEA's analysis of these numbers, we conclude that roughly 15 percent of the average volume is priced at fixed or negotiated prices. The remaining volumes are priced based on published index or futures market price formulae. Monthly indices or NYMEX prices are used to price about 63 percent of the surveyed volume while daily indices are used to price about 15 percent of volume. As one would expect, daily indices are most likely to be used for the shortest duration (one month or less) category of contracts.

Table 3-8 Pricing Provisions of LDC Gas Supply Contracts

GAS SUPPLY PRICING MECHANISM

(Number of Companies)

Percent of Peak Day Gas Supply	First-of-Month Index	Weekly Index	Fixed Price	Daily Index	Average Last 3 Days	NYMEX	Other
One Year or Longer Term							
1 - 25	0	0	5	4	2	3	0
26 - 50	3	0	1	4	0	1	3
51 - 75	10	0	4	0	2	2	1
76 - 100	17	0	3	0	0	2	5
none	19	49	36	41	45	41	40
2 to 11 Month Term							
1 - 25	6	0	8	4	0	4	1
26 - 50	9	0	5	5	0	3	1
51 - 75	10	0	3	2	0	2	0
76 - 100	14	0	4	2	0	8	0
none	13	52	32	39	52	35	50
Term of One Month or Less							
1 - 25	8	0	9	11	0	3	2
26 - 50	8	0	5	6	0	3	0
51 - 75	14	0	3	8	1	5	0
76 - 100	10	0	2	10	0	1	2
none	13	53	34	18	52	41	49

SOURCE: 2004-2005 AGA LDC Winter Heating Season Performance Survey

3.3.3 Electric Generator and Industrial Contracting

No comprehensive data exists showing supply contracting practices of electric generators or industrial users.

[14] AGA, "2004-05 LDC Winter Heating Season Performance Survey," July 19, 2005, page 3.

4
CURRENT VIEWS AND PERCEPTIONS

4.1 Introduction

Contracting for gas commodity and pipeline/storage infrastructure capacity involves transactions between parties that are regulated and unregulated. Pipelines, LDCs, and some entities in the electricity industry are subject to "cost-based" economic regulation, prudence review and contracting oversight. Contracts entered by regulated entities are subject to "regulatory risk" beyond the market and credit risks inherent in gas market contracts.

Natural gas industry restructuring was rooted in a philosophy that economic efficiency was the primary objective. As a result, policies promoted the transfer of market price signals to gas producers and purchasers as quickly as possible. Distributors were often discouraged from contracting for additional gas transportation capacity or entering into long-term, fixed price supply contracts. Increased reliance on spot gas purchases ensured that volatility in the commodity market was transferred to consumers.

For regulated entities, such as gas local distribution companies, regulatory approval of contracting practices intended to promote infrastructure development in order to enhance reliability and/or reduce price volatility can be problematic. Risk management through portfolio diversification and financial and physical hedging programs is not yet well understood by many regulators. In addition, regulators are often reluctant or unable within existing statutory authority to "pre-approve" a program. A concerted effort to educate regulators and to engage regulators in discussions regarding contracting, portfolio management and the impact of contracts on price levels and volatility could result in changes to regulatory practices and regulatory risk.

4.2 Local Distribution Company Perspective

One LDC, Enbridge Gas Distribution of Ontario has made the following comment.

> Gone are the days when long-term arrangements were made that helped to underpin the development of new supply and transportation infrastructure. These have been replaced with short-term arrangements that attempt to meet immediate industry needs. This has caused a tightening in the supply/demand balance and price volatility. This in turn has caused “demand destruction” as businesses close and industry moves offshore.
>
> In order to drive investment into new sources of supply, transportation and storage, companies must be willing and able to enter into long-term contracts with suppliers, transporters, and storage providers. Given current experience, the only parties supportive of the types of arrangements appear to be the LDCs. The investment in their distribution systems encourages them to support the long-term viability of the natural gas industry through improved price stability and adequacy of supply for all customers. The support for long-term arrangements is viable only if the utilities continue to manage a portfolio of system customers large enough to substantiate investment in long-term infrastructure.[15]

At the same time, a number of regulatory policies at the state and federal level may lessen the use of longer-term contracts. In a recent article in Public Utility Fortnightly, Dr. Ken Costello identified four areas where market and regulatory distortions lead to a non-optimal mix of contractual relationships.[16] Specifically, identified were:

> (1) regulatory uncertainty at the state level over the prudence of long-term contracts (which local gas utilities fear easily could lead to regulatory opportunism and a potential stranded-cost problem);
>
> (2) the design of some gas choice programs that allow customers to switch suppliers on short notice and consequently make it difficult for a gas utility to contract on a long-term basis for default customers;
>
> (3) the unwillingness of some state commissions to hold retail marketers to the same standard of reliable service as the default gas utility; and,

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[15] Enbridge Gas Distribution Inc., “Discussion Paper: The Utility Role in Gas Supply,” December 18, 2003.

[16] Dr. Ken Costello, “Pipelines: Are Regulators in It for the Long Haul,” Public Utility Fortnightly, July 2005

(4) FERC's pricing policies, which, as some industry observers have argued, may induce excessive demand for short-term transactions (which include interruptible service and capacity release transportation) in relation to longer-term transactions.

Beyond these, increased gas prices and gas price volatility can create a disincentive for longer-term contracting. When gas prices are high, LDCs are under increased public scrutiny. Not surprisingly, the popular press reports more frequently on natural gas when prices are rising significantly – regardless of the cause of the increases – than when prices are stable or falling. As a result, regulators can be subjected to additional pressure to be perceived as taking action that can reduce prices in the short-term. Prudency proceedings offer an opportunity for action that is visible to the public.

Volatile prices also increase the risk that LDC contracting practices will be "out of the money," meaning that the price of the of a purchaser's gas portfolio is above or below market prices as measured by short-term spot transactions. This is true for a regulated or un-regulated party. But for an LDC, there is an additional element. If the LDC portfolio is below the prevailing market, its customers generally capture most or all of the difference. If the LDC portfolio is above the prevailing market, the LDC may face a lengthy, difficult, and expensive proceeding that at best (for the LDC) will allow for the recovery of all the gas costs. At its worst, the proceeding can result in a disallowance that can be quite large in comparison to the net earnings of the LDC.

As a result, there is pressure for an LDC to "shorten up" commodity contract terms in the face of high and volatile prices. The result is that commodity contracts entered into during such periods will tend to be somewhat shorter unless the LDC management and the regulators have settled in advance on appropriate portfolio and hedging practices.

4.2.1 Cost Recovery Mechanisms and Prudence Review

Without an assured cost recovery mechanism, LDCs often see the cost of holding capacity as an unnecessary cost that will be at risk. As a result, they generally oppose these types of requirements. Compounding this problem, a number of LDCs have been directly or indirectly restrained from entering into long-term contracts needed to finance the infrastructure investments that could moderate volatility.

Pre-approval of longer-term contracts along with increased certainty for cost recovery within the context of a diversified portfolio of contracts could remove a significant barrier to the use of such contracts. For many states, such approval would represent a major departure from current practices. Indeed in some instances, a State Commission may need additional statutory authority to grant such approval.

4.2.2 Contract Term and Customer Choice Program Design

In the U.S., more than 30 million of the nation's 60 million households with natural gas service have, or will soon have, a "customer choice" option. To date, about one of every eight households eligible to purchase natural gas from a non-utility supplier has actually made the switch.[17] As a percentage of total U.S. natural gas volumes consumed by households, about eight percent of residential gas was purchased through choice programs.

Over the past decade, a number of states have examined their state customer choice programs in an attempt to foster additional participation. In a number of instances, changes have been proposed to make migration easier for consumers while allowing customers to return to utility service and create a "provider of last resort" to assure service in the event of a default by an unregulated marketer or other market event.

The possibility of migration of a significant portion of their "peak load" customer base attaches risk to holding longer-term commodity and/or capacity contracts for an LDC. In

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[17] U.S. Energy Information Administration "Retail Unbundling – U.S. Summary", www.eia.doe.gov.

particular, regulatory policies designed to assure sufficient pipeline capacity to meet the requirements of all customers regardless of the merchant provider can create additional risks for an LDC.

The lack of predictability concerning future pipeline capacity requirements that results from the design of some customer choice programs adds to the uncertainty inherent in the market and creates an additional incentive for LDCs to “shorten up” the contract portfolio. Without viable cost recovery mechanisms and improved predictability, LDCs in states with customer choice programs will continue to view longer-term contracts as a source of additional risk.

4.2.3 FERC Pricing Policies and Contract Term

Two basic tenets of FERC pricing policy for gas pipeline transportation services are articulated in the Commissions Policy Statement on Rate Design.

> The Commission has stated the objectives of rate design for pipeline services. Section 284.7(c)(1) states "[r]ates for service during peak periods should ration capacity." Section 284.7(c)(2) provides that "[r]ates for firm service during off-peak periods and for interruptible service during all periods should maximize throughput."

While it is hard to argue with these tenets in terms of short-term market efficiency, the regulations and orders implementing these tenets have affected the willingness of shippers to enter longer-term firm contracts for pipeline capacity. The policy has created a large difference between the rates charged for long-term firm transportation contract at maximum rate and the rates charged shorter-term capacity acquired as Interruptible Transportation (IT), discounted shorter-term firm capacity or capacity release.

This difference reduces the desirability of longer-term contracts for all shippers and creates particularly difficult situations for LDCs. LDCs have an obligation to serve peak requirements and, as a result, may not be able to utilize capacity at or near a 100 percent load factor. This point is significant because on a per-unit basis the difference between the long-term firm contract and the short-term market price is even greater if a shipper has less than a 100 percent load factor. Therefore, LDCs recover only a portion of their firm capacity costs when they release pipeline capacity during off-peak periods.

4.3 Power Generator Perspective

As discussed previously, gas-fired generation has accounted for the majority of growth in gas consumption over the past decade. Moreover, virtually all forecasts project that this trend will continue for at least the next decade. In general, gas-based electric generation is considered intermediate or peaking load on the dispatch curve and, therefore, its capacity utilization is less than base load coal or nuclear plants

The needs of gas-fired power generators for transportation capacity and their willingness to enter into long-term capacity contracts have not come into balance. Gas generators, particularly peaking units, are extremely reluctant to enter into firm contracts. This is due to the high per-unit costs that occur when gas transportation contracts are used at a low load factor. It will be imperative to address this mismatch and identify a cost recovery mechanism for these gas shippers if sufficient infrastructure is to be developed.

A considerable effort has been made in a number of forums to facilitate dialog between the gas and electric industry to align business and communications practices more closely. To date, these efforts have not resulted in a fundamental change in gas commodity and pipeline and storage capacity contracting practices for power generation customers.

For generators in many regional power markets, the decision to accept the volatility of short-term gas market makes economic sense given the regulatory and market structure of the electricity industry. Without properly structured capacity payments, a generator assumes cost recovery risk whenever it enters into a contract that creates a financial obligation that is not avoidable when the generator is not being dispatched. Contracts for fixed volumes of gas or pipeline and/or storage capacity can create such obligations. In contrast, a decision to purchase gas at prevailing market prices – whatever the cost – can present significantly less risk of under-recovery.

In much of the country, natural gas-fired generating capacity provides the majority of the marginal power generation capacity, primarily meeting shoulder and peak period loads. In a region with competitive wholesale electricity markets, such as the Pennsylvania-New Jersey-Maryland power pool (PJM), increases in natural gas prices tend to result in increases in wholesale power prices. In a market where the gas-fired generation is needed and there is no additional alternative fuel capability, the electricity price will be high enough to justify paying almost anything for gas supply.

When this happens, power generation demand for gas is almost completely inelastic and power generation load will bid away gas from other uses at almost any price. The generator is contributing to the localized spike in gas prices, but is acting in a rational manner because the revenue from the electricity sales remain aligned with the fuel costs. The result, however, is that all other gas consumers are exposed – to a greater or lesser degree – to the volatility in gas prices and price spikes.[18]

An alternative regulatory structure that provides incentives to support sufficient pipeline capacity and/or dual-fuel generation capacity can create a much different market dynamic. Under those conditions, gas demand for power generation is more elastic, the impact of gas use for power generation is much less dramatic and spread over a much wider geographic area, and gas price spikes can be dampened.

Contracting for pipeline capacity and gas commodity can – and would – impose additional costs that would need to be recovered from electricity consumers. In exchange, spikes in gas prices would not have such a direct and severe effect on marginal electricity prices. In addition, all other gas consumers would also avoid the localized price spike.

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[18] If the other gas consumers have hedged some or all of the price volatility risk can be avoided.

While recent discussions of natural gas market behavior have placed more emphasis on longer-term contracts, public policy and natural gas industry regulation-remains focused on short-run economic efficiency. This emphasis inhibits the use of long-term contracts and the investment in facilities that would provide capacity. While there has been increased discussion regarding the desirability of longer-term contracts and the need for additional infrastructure, there remains no consensus regarding the appropriate mechanism to provide economic incentives for such investment or to allow for the recovery of costs that may be "at risk" in competitive electric power markets as they have been restructured in several regions.

In many instances, consumer advocates and new entrants object to capacity payments that are viewed as favoring incumbent generators. Moreover, such payments rarely – if ever – differentiate in favor of a generator with firm pipeline and storage capacity under contract. Without a cost recovery mechanism or a structure that creates tangible advantages to those generators that hold capacity contracts, generators will continue to keep long-term contractual obligations to a minimum.

4.4 Gas Pipeline Perspective

As now regulated, pipelines are not in a position to construct pipeline expansion projects without contractual commitments from shippers. Regulated rates of return for pipeline capacity are not sufficient to justify "speculative" or "at risk" construction. FERC looks upon the degree to which capacity is contracted as an indicator of market need.

But perhaps as important as the legal and regulatory framework, both regulated and unregulated shippers have become increasingly reluctant to enter into the new long-term contracts that are necessary to support new pipeline and storage construction projects. Existing regulation has failed to overcome a fundamental economic externality[19] in the market for pipeline transportation and storage service – the so-called "free rider" problem.

When new pipeline capacity is constructed, a constraint that existed and resulted in expanded basis between the markets connected by the pipeline is alleviated until demand growth and/or supply deliverability grow to fill the new pipe capacity. Until that occurs, some of the capacity that was built will be available as interruptible service (IT) or as capacity release. Often that capacity sells at a discount from the maximum regulated rate for the pipeline capacity. The result is that the shippers that entered into the pipeline contracts that were necessary to support the construction of the project in the first place operate with an imbedded cost structure that times may be higher than the cost structure for shippers that rely on IT or capacity release.

This "free rider" problem provides an incentive for shippers to delay as long as possible any contractual commitment to a new project, because of uncertainty regarding the future value of the capacity and the hope that it will be built without their commitment. Existing regulation, including the policy favoring incremental pricing of new pipeline construction, compounds the "free rider" problem. The benefits of some level of contracted pipeline capacity to all consumers in the downstream market are not recognized under the current framework and there is no mechanism to recover any of the fixed costs from those parties that are benefiting without entering into contracts.

4.4.1 Existing Pipeline Capacity

Although much of the public concern about long-term contracts is focused on new gas pipeline, storage and supply projects, many of the same financial and regulatory issues are important for existing pipeline and storage capacity as well. A considerable amount of pipeline investment is directed to maintaining existing capacity. It is expected that about 62 percent of non-Arctic gas pipeline investment in the next 15 years will be directed to refurbishing or replacing existing line pipe and compressors to maintain

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[19] In economics, an externality is a cost or benefit of a transaction that accrues to an individual or company that is not a party to the transaction.

current throughput capacities. Recently promulgated pipeline integrity inspection rules will require that additional equipment such as pig launchers and catchers be added to the existing pipeline network. Also, existing pipeline may have to refurbished or replaced as it ages and some pipeline must be upgraded as denser development encroaches on existing pipeline rights of way. Continued investment in existing storage capacity will also be needed to replace worn equipment and to compensate for lost well deliverability that occurs as storage reservoirs deteriorate from repeated injection and withdrawal cycles.

Long-term contracts will be needed to assure pipelines that they will recover the substantial investments that will be required to maintain existing pipeline and storage capacity. Moreover, average contract length is an important element in credit agencies' ratings of pipelines. Longer contracts improve credit ratings and reduce the cost of borrowing for pipeline companies, hence lowering transportation rates to shippers.

5
THE NEED FOR NEW NATURAL GAS INVESTMENTS

5.1 Natural Gas Demand

Natural gas consumption in the United States for the year 2004 was 21.7 trillion cubic feet (Table 5-1). EEA anticipates (forecasting a modest GDP growth) that U.S. natural gas consumption will reach 30 Tcf near the end of the next decade if the industry is allowed to construct the infrastructure needed to supply a growing market. This is an increase of 8.3 Tcf or a growth rate of 2.05 percent per year. All sectors of the economy – residential, commercial, industrial, and power generation – contribute to this growth. The power generation sector contributes well over three-fourths of the total increment, however.

Table 5-1 U.S. Natural Gas Demand
(Bcf per Year)

	2004	2005	2010	2015	2020	2004-2020 Change	Annual % Change
Residential	4,836	4,946	5,236	5,503	5,774	938	1.11%
Commercial	3,051	3,099	3,188	3,374	3,516	465	0.89%
Industrial	7,424	7,309	7,050	7,419	7,633	209	0.17%
Power Generation	4,588	5,056	7,394	10,035	11,035	6,447	5.64%
Other	1,825	1,854	1,947	2,080	2,118	293	0.93%
Total	**21,723**	**22,265**	**24,815**	**28,412**	**30,076**	**8,353**	**2.05%**

There are several drivers behind this view of increasing natural gas demand. The most important among them are:

1) **The pace of economic activity and growth**: EEA has assumed that from 2006-2020, the U.S. economy will grow 2.8 percent per year and while industrial production will grow at 2.3 percent per year. These rates of

economic expansion are consistent with the average rates of growth over the past 30 years rather than with the more rapid expansion of the 1990s.

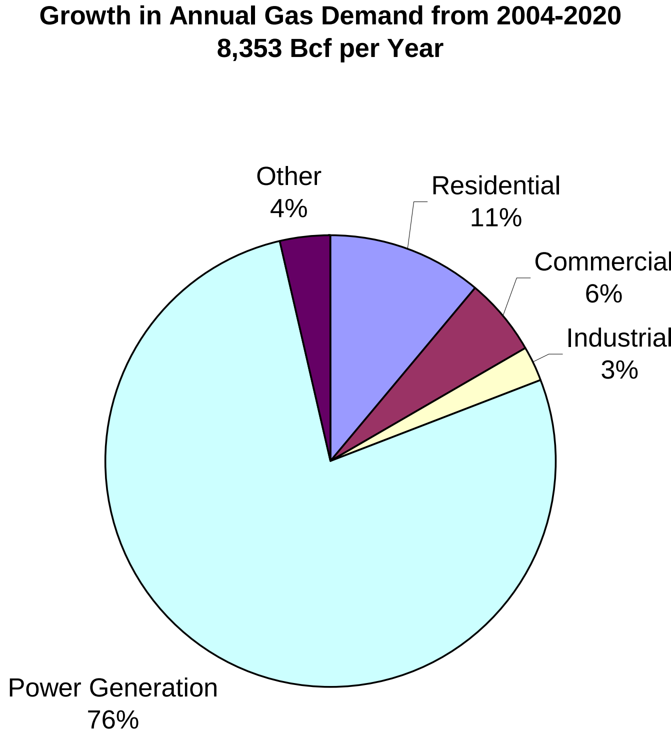
2) **The price and availability of alternative fuels**: Large industrial and power generation customers with dual-fuel capability are approximately 8 to 10 percent of total gas consumption. EEA has assumed that oil prices will return to more historical price levels by the beginning of 2006. Longer-term oil prices are projected to be $41 per barrel in constant $2004. This equates to a real $2004 distillate fuel price of $11.00 per MMBtu and a real residual fuel price of $6.50 per MMBtu. In the industrial sector, fuel switchability in industrial boilers is assumed to stay at current levels of 5 percent of the boiler stock. Fuel switching capacity of the fleet of combined cycle and combustion turbines in the power generation sector increases from 11 percent today to 25 percent by 2020.

3) **Demand for electricity**: In recent years, the income elasticity of electricity demand has been approximately 0.7. For this study, EEA has assumed that the income elasticity declines to 0.65 by 2020. Implicitly, the projection assumes that the economy continues to improve the efficiency of end-use electricity applications while also continuing to expand the number and scope of electric applications.

4) **Environmental regulations**. The EEA Base Case assumes a continuation of existing laws and does not assume mandatory controls on carbon emissions.

Power generation is the fastest growing sector for natural gas consumption in the U.S. In 2004, gas-fired generation consumed 4.6 Tcf. EEA predicts that this consumption will increase at a rate of 5.6 percent per year. Three-fourths of the U.S. incremental gas demand from 2004 to 2020 will come from the power sector (Figure 5-1). Sometime near the middle of the next decade, the power generation sector will surpass the industrial sector as the largest natural gas consuming portion of the economy with natural gas use more than doubling to 11 Tcf in 2020.

Figure 5-1 Growth In Annual Gas Demand



Between 1998 and 2004, over 200 Gigawatts (GW) of new capacity was built in the U.S. (Table 5-2). Of the new plants, about 10 percent have the capability to switch to oil for a limited number of hours per year, but most operate exclusively on natural gas. This expansion phase has recently slowed down and will continue at a lower rate, since existing capacity can meet most incremental electricity load growth in the next decade.

Table 5-2 Lower-48 Generating Capacity

	2004	2005	2010	2015	2020	2004-2025 Change	Annual % Change
Pre 1997 Oil/Gas Capacity	196	190	178	163	147	-49	-25%
Post 1997 CT/CC Additions	214	233	276	308	343	129	60%
Total Oil/Gas Capacity	411	423	454	471	490	80	19%
Coal	314	317	329	329	362	48	15%
Nuclear	97	97	98	99	101	4	5%
Hydro	99	99	99	99	99	0	0%
Renewables and Others	13	13	18	25	39	26	207%
Total Capacity	**933**	**948**	**997**	**1023**	**1091**	**159**	**17%**

Power plant developers have chosen to build gas-fired plants for a variety of reasons. The initial capital cost for construction is lower for gas-fired plants than other types. The construction time is shorter and the plants are easier to permit than most other types of plants, hence, they can be built more quickly. Sulfur dioxide and particulate emissions are far lower for gas-fired plants than for coal or oil plants. And, at least until the late 1990s, natural gas appeared to be an abundant and inexpensive fuel.

The pace of construction will be slowed by the recent and anticipated increases in natural gas prices. Still, due to their advantages over other types of plants, it is generally agreed that gas-fired plants will continue to provide an increasing share of the nation's needs for electricity. We see an additional 129 GWs of gas-fired generation being built by 2020. The lead-time required to build a significant amount of new coal-fired capacity or any nuclear capacity effectively removes these options from the marketplace during the next several years. In the near term, coal generation is expected to increase but not as quickly as the increase in electricity demand. Increases at existing coal plants are limited by current environmental regulations and future regulations on mercury and carbon emissions could further limit coal generation. We predict that approximately 48 GWs of new coal capacity will be built in the U.S. by 2020.

Electricity sales are anticipated to grow from 3.6 trillion kWhs in 2004 to 4.9 trillion kWhs in 2020. Increases in gas-fired generation are anticipated to account for more than half of the increase. Gas-fired generation as a percent of total generation grows from 14 percent in 2004 to 26 percent in 2020.

5.2 Natural Gas Supplies

Natural gas supply from multiple sources must grow to meet the projected 30 Tcf U.S. market by 2020. Most industry analysts, including EEA, believe that U.S. and Canadian natural gas production from traditional basins is in decline (Figure 5-2). Production from traditional supply basins such as Western Canada, West Texas and Oklahoma, the Onshore Gulf of Mexico, the Gulf of Mexico Shelf, and the San Juan Basin is approximately 20.8 Tcf per year and currently accounts for just over 80 percent of the production in North America (Figure 5-3). While production from these regions will still be an important part of the supply portfolio through the next decade, production is forecasted to decline in both absolute terms and market share, although there are some small regional gas production plays (North Texas for instance) that have experienced some recent troth. However, in aggregate, by 2020, volumes from traditional basins are anticipated to decline by 2.4 Tcf per year to 18.4 Tcf, which will only be 68 percent of North American production (Figure 5-4).

The declines in production from traditional supply sources are mainly due to the lack of quality drilling prospects in the areas. Already, the North American gas market is experiencing declines in some basins. Gas producers have had to work harder to develop additional deliverability. Producers are working harder in mature areas, but are developing less productive gas resources. Whether it is due to increased decline rates, lower reserves, or a higher percentage of non-conventional wells (tight sands, coal bed methane, or shale), it appears that more wells are needed just to maintain the current rate of production.

In order for production to be maintained as fields naturally deplete, more expensive formations must be completed. The wells may be in deeper formations that have higher temperatures and pressures or the gas may be sour (containing sulfur) and more corrosive, requiring additional processing. Less permeable formations may be drilled. Such wells need to be fractured down hole[20] in order to be produced economically. In general, most of the large natural gas reservoirs have been found. Future fields will be smaller and need to be more numerous to maintain the same amount of production.

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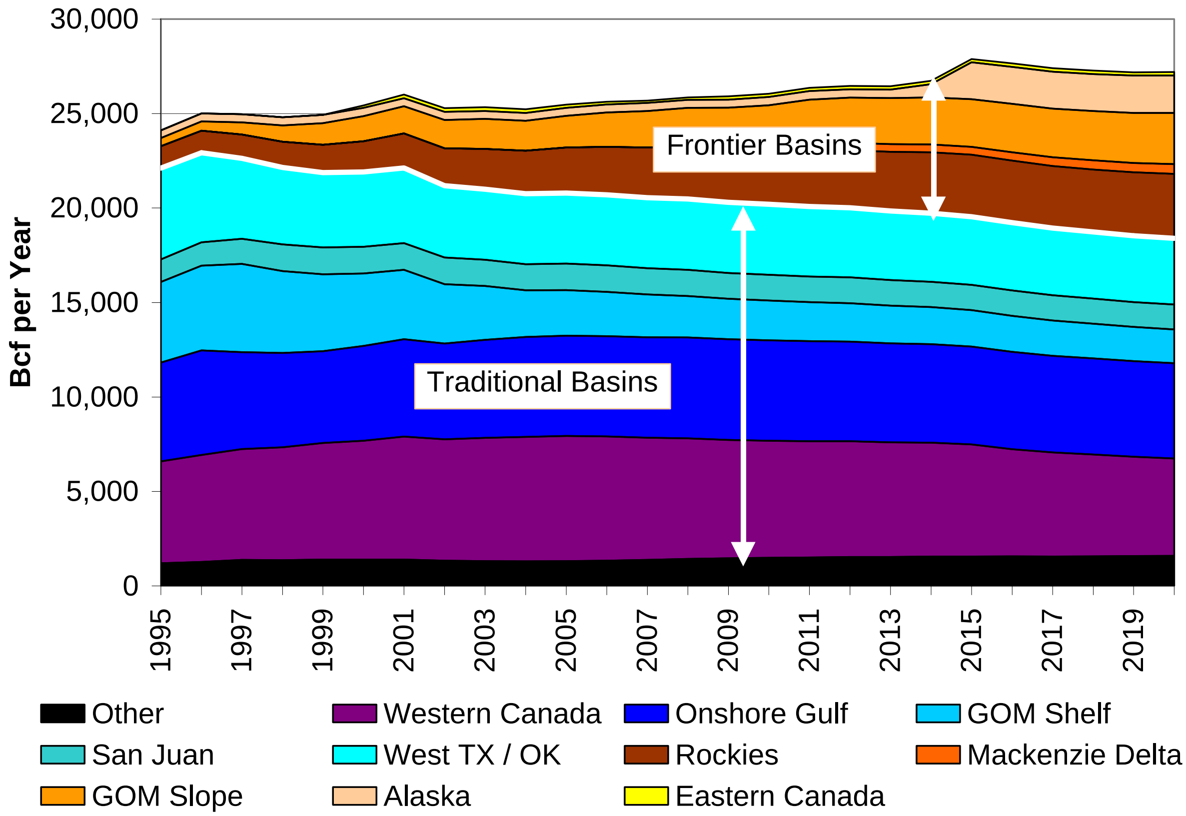
[20] "Fracturing down hole" is the process of breaking the rock in the producing region of the well in order to increase the rate of production.

Figure 5-2
North American Natural Gas Production by Region



North American production including gas produced and consumed in Canada but excludes Mexico

Hence, much of the growth of the gas market over the next 20 years must be sustained by developing currently untapped supplies from areas that are generally more remote from the consuming markets in North America. LNG imports must also play a key role (see next section). Frontier basins in the Arctic, such as Alaska and the Mackenzie Delta, new offshore regions, such as the Gulf of Mexico Deepwater and Offshore Eastern Canada, and underdeveloped domestic areas such as the Northern Rockies all will be needed to serve U.S. demand by 2020. Of course, to bring gas from the new supply regions, pipeline infrastructure must be built.

Current supplies from "frontier" basins are 4.4 Tcf per year and account for 18 percent of North American natural gas production. By 2020 the volumes could more than double to 8.8 Tcf per year and account for nearly 32 percent of North American production. Although actual amounts and timing of production from frontier basins may vary from the EEA Base Case, supplies from such regions will be significant by the end of the next decade.

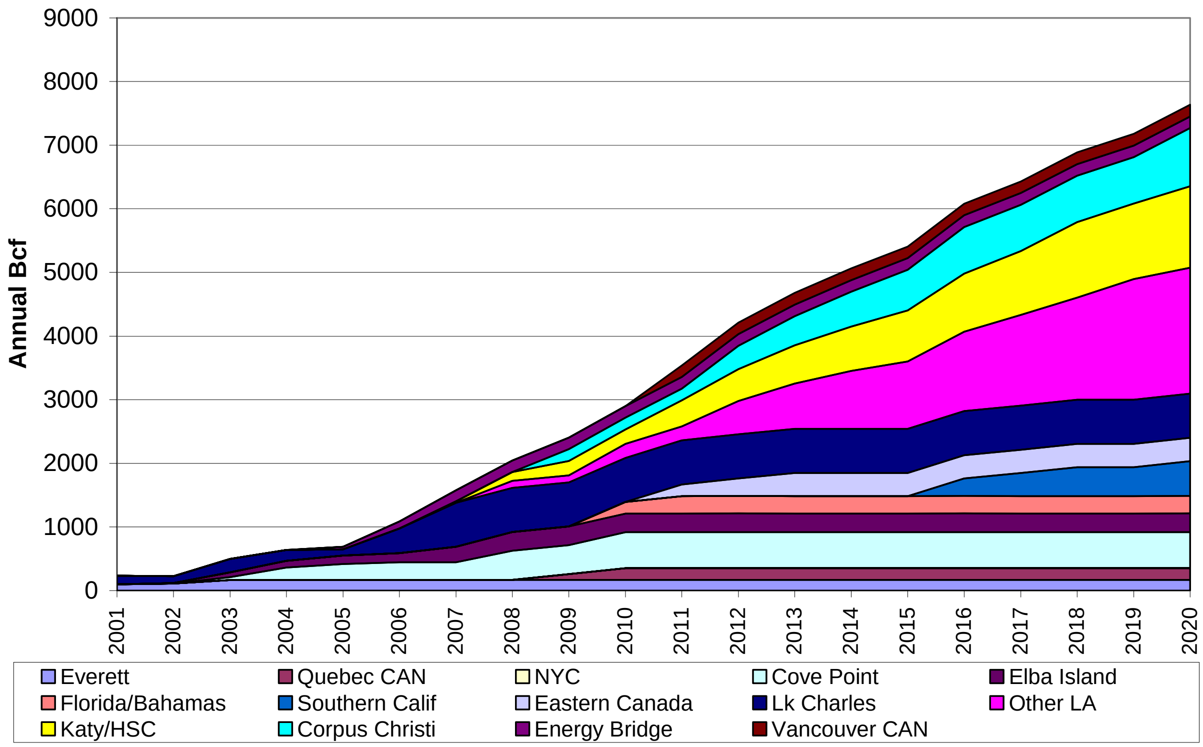
5.2.1 LNG Imports

In addition to the need for gas production from more remote locations, the base projection relies on an order-of-magnitude increase in LNG imports to meet the requirements of the U.S. market. U.S. LNG imports for 2002 totaled 229 Bcf. Imports for 2003 doubled the previous year at 507 Bcf while 2004 LNG imports increased to over 650 Bcf. By 2020, U.S. LNG imports could be nearly 7 Tcf per year, over a thirty-fold increase from 2002. The EEA Base Case projects that by 2020, Canada will also import LNG at a rate of over 700 Bcf per year. Figure 5-3 presents the forecast of the amount and location of imports and exports of LNG assumed in the study. Currently, there are four operating land-based LNG import terminals and one offshore terminal in North America.[21] In order to attain the level of LNG imports assumed in the EEA Base Case, approximately 14 additional terminals will need to be constructed.

[21] In addition to the five import terminals, there are more than 100 LNG peak shaving facilities that are used principally by local distribution companies to meet peak day demand.

Figure 5-3

U.S. LNG Imports (BCF/Year)



LNG deliveries compete with wellhead production. LNG is competitive with North American production at prices ranging from $3.50 to $4.00 per Mcf depending upon the distance that the LNG travels from the liquefaction plant to the import terminal. Imported LNG, in large part, becomes an economically viable energy supply because of the low cost of developing and producing abundant stranded gas resource located throughout the world. Most of the gas may be developed and produced at costs under $1 per MMBtu at the wellhead, but the additional costs of liquefaction, tankering, and regasification are significant. Hence, the delivered cost of LNG imports are high, making LNG one of the most expensive sources of new supply on a unit basis. Unlike domestic or Canadian supplies, the U.S. must compete with the rest of the world for LNG. World market conditions influence LNG prices.

In addition to expansion plans at the existing four import terminals, there are nearly 50 new LNG terminals proposed for North America. Obviously not all of them will be built. Actual locations for new terminals will not only be based on economic factors, such as proximity to consuming markets, but also political factors of permitting and siting. There is significant value in siting LNG terminal facilities in "market area" locations that are downstream of pipeline constraints such as the Northeast U.S. Such locations, however, may have limited pipeline access or face additional hurdles in permitting. Terminals along the Gulf of Mexico will have access to a more extensive pipeline network but may receive a lower price for their natural gas supplies. In the end, a mix of supply area and market area terminals will most likely be built. Of the four existing land-based terminals, three are on the East Coast, Everett, Cove Point, and Elba Island; while Lake Charles is located along the Gulf of Mexico. Gulf Gateway Energy Bridge, the single U.S. offshore terminal, is located 116 miles south of Louisiana in the Gulf of Mexico. The EEA Base case assumes one additional East Coast terminal, nine Gulf Coast terminals, one terminal on the West Coast and three Canadian terminals.

5.3 Required Infrastructure

With few exceptions[22], the EEA Base Case is constructed assuming that pipeline and storage infrastructure that is economically justified is built within a year or so of when the basis differentials justify the construction. The basis differential is a measure of the difference in the price of natural gas between two geographic locations. A basis differential that is greater than the pipeline transportation rate between the two locations indicates that the transportation capacity is highly utilized and the path is becoming constrained. If the basis differential is high enough and occurs over a long enough period, it provides justification for the shipper to purchase additional pipeline capacity. The following presents a discussion of transmission and storage infrastructure that is expected to be economically justified and needed to deliver natural gas into consuming markets.

[22] In some markets, such as New York City, additional pipeline capacity is already economically justified by the "economic" criteria. Indeed there are already several projects that have been proposed to relieve the constraint. However, none of these projects appears likely to be in service before 2006.

Pipeline investments will be needed to connect new North American and imported LNG gas supply sources, to interconnect new customers to the grid and to maintain capacity on traditional pipeline corridors (Figure 5-4). Nearly $29 billion will be needed for construction of new pipeline to new supply sources and to new customers. Of that, $19 billion will be associated with the Alaskan and MacKenzie Delta projects that will access needed supplies of Arctic gas.

Approximately $16.4 billion of investment will be needed for refurbishing or replacing existing line pipe and compressors to maintain current throughput capacities. Recently promulgated pipeline integrity inspection rules will require that additional equipment such as pig launchers and catchers[23] be added to the existing pipeline network. Existing pipeline may have to be refurbished or replaced as it ages. In addition, some pipeline must be upgraded as denser development encroaches on existing pipeline rights of way.

In addition to pipeline construction, underground storage projects costing $5.5 billion will be needed. These include both conventional storage to meet growing winter season gas consumption and high-deliverability storage that will be required to service fluctuating daily and hourly power plant loads. Together with the $9.4 billion for new LNG terminal capacity, total needed natural gas infrastructure investment in the U.S. and Canada will be $60 billion by 2020.

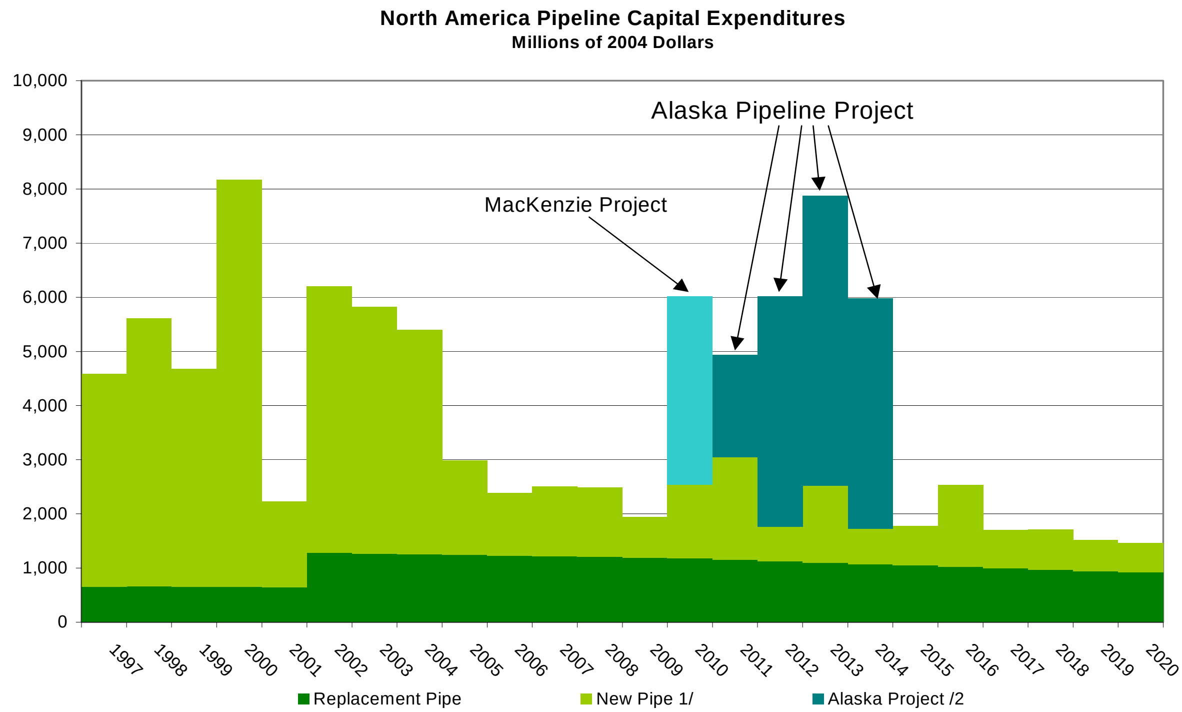
There is considerable uncertainty regarding the precise timing of the Arctic projects. To the extent that completion of an Alaskan Gas project is delayed beyond 2013, the timing of the facilities and investment results presented here would be affected. However, the magnitude of the average annual infrastructure requirements would be relatively unchanged as long as he project is completed before 2020.

The need for interregional pipeline capacity must be analyzed from the perspective of current interregional capacities and flows and how they might change in the future.

[23] Pig launchers and catchers are equipment used to insert and recover “smart pigs” that are used to inspect the interior of a natural gas pipeline.

Most natural gas is consumed in a region different from where it is produced and must be transported over significant distances to the consuming market. The largest supply regions for the United States are the Gulf Coast, both on and offshore, and Western Canada. Other smaller, but important supply areas include the San Juan Basin in New Mexico and Colorado, the Powder River Basin in Eastern Wyoming, the Permian Basin in Western Texas and Eastern New Mexico, and the Mid-continent producing area in Northwest Texas, Oklahoma, and Kansas. LNG imports currently play a small but growing role.

Figure 5-4

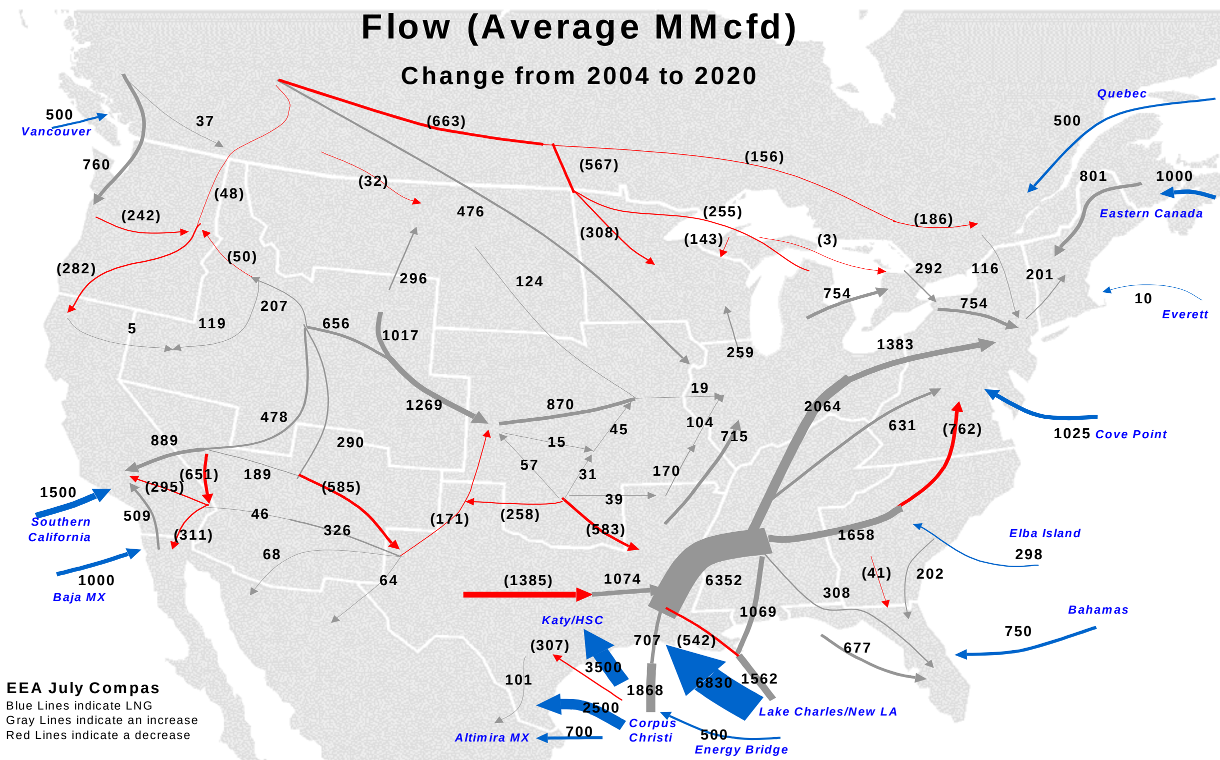


/1 Includes estimates for new transmission pipe, production plant hookup, cost for new underground storage, and power plant connection costs.

/2 Includes cost of new pipe built to Chicago in conjuction with Alaska Pipeline Project and pipe to connect production plants to the pipeline, but excludes cost of gas processing plants in Alaska and natural gas liquids extraction plants in western Canada.

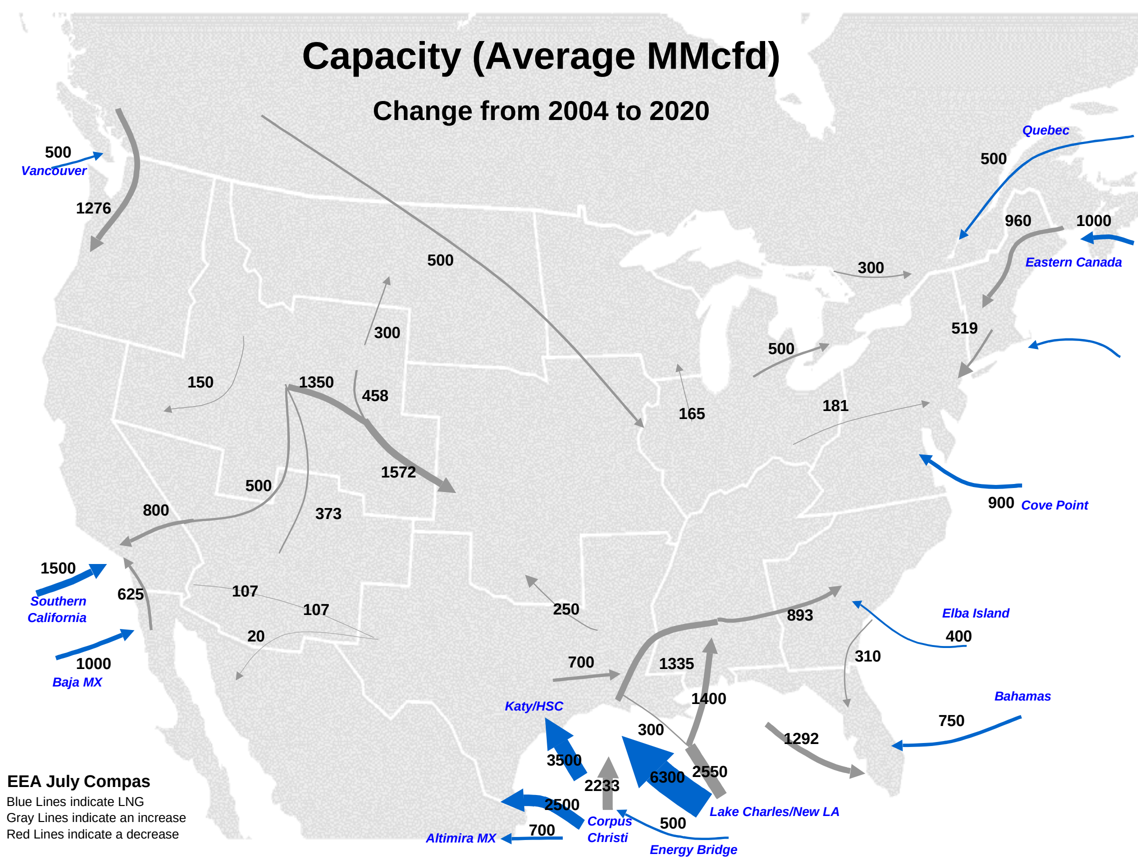
By the end of the next decade, flow patterns of natural gas supply to natural gas markets will be about the same as they were in 2004. The most important supply areas will still be the Gulf of Mexico and Western Canada. New supply sources such as the new LNG import terminals will emerge, however. Other sources will increase in volume, mostly the new frontier supplies, and flows from some of the mature producing areas will decline by 2020. Incremental flows will determine where new interregional pipeline capacity will be needed (Figure 5-5).

Figure 5-5
EEA Base Case – Incremental Flow 2004 –2020



The amount of additional interregional pipeline capacity built by 2020 in EEA's Base Case is substantial. Beyond the next few years, it is difficult to identify specific pipeline projects, but general predictions for new capacity can be made. Most of the capacity will be used to access new supply areas and the expansions correspond with the increased flows identified in Figure 5-5. In addition to accessing frontier basins, pipeline infrastructure will be needed to accommodate increased LNG imports and reinforce market areas that are experiencing high electric generation growth (Figure 5-6).

Figure 5-6
EEA Base Case – New Pipeline Long Haul Capacity Requirements



From 2004 to 2020, approximately 1.8 Bcfd of additional pipeline capacity will be needed from of Western Canada. The new capacity volumes are less than the forecasted 5.0 Bcfd of additional Arctic and LNG supplies entering Alberta and British Columbia. This difference is attributable to current spare pipeline capacity, declining Western Canadian Sedimentary Basin production, and increased demand in Western Canada, most notably oil sands development.

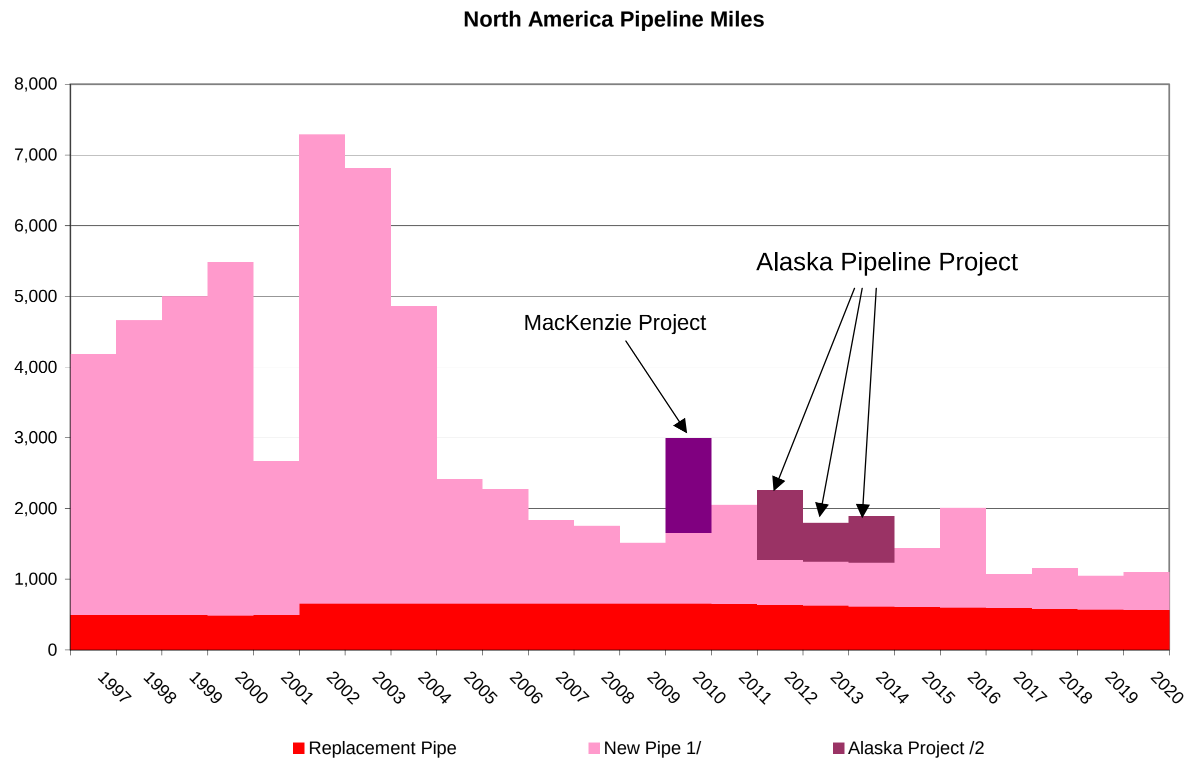
Other notable areas where interregional capacity will be needed include: 0.7 Bcfd from Central and West Texas to Louisiana: 1.0 Bcfd from Eastern Canada: 2.7 Bcfd out of the Rockies: and 4.8 Bcfd out of the deeper waters of the Gulf of Mexico. In addition to projects connecting new supply basins, there will be numerous pipeline projects that relieve local bottlenecks in market areas. For example, 1.6 Bcfd of additional pipeline capacity is projected to be needed into Florida. Also, 20 Bcfd of additional LNG terminal receipt capacity and the associated pipeline infrastructure to bring it to market will be needed.

Many major supply corridors that exist today will not need expansion. For example, no increases are anticipated out of the Mid-continent even with 1.3 Bcfd of additional Rockies supplies that are forecasted to enter from the Northwest. Nor are expansions anticipated in the Midwest or along the eastern corridor. However, these corridors will require continued investment for integrity measures and to maintain existing throughput capacity.

It is important to recognize that the estimates of the amount of new pipeline capacity presented here may understate the requirements depending upon the location of new LNG terminals. Recently, a number of proposed LNG projects along the East Coast have faced stiff local opposition. Projects along the Gulf Coast may find greater acceptance because of their local populations' experience with other heavy industries including chemicals and refining. Additional pipeline capacity from the Gulf to Eastern markets that is not reflected in the EEA Base Case may be necessary if LNG import terminals cannot be sited along the East Coast.

Including both regional and interregional pipelines, the natural gas industry will need to install more than 26,000 miles of pipe to meet market demands for natural gas in North America. Approximately 17,000 miles will be new pipe while 10,000 miles will be needed to replace existing pipe. Of the 35,000 miles of new pipe, approximately 3,400 miles will be associated with bringing Alaskan and MacKenzie Delta gas to the lower-48. Figure 5-7 presents the estimated number of miles required by year.

Figure 5-7
EEA Base Case – Miles of Pipeline Additions in North America



[/1] Includes estimates for new transmission pipe, production plant hookup, pipe for new underground storage, and power plant connection laterals.
[/2] Includes new pipe built to Chicago in conjuction with Alaska Pipeline Project and pipe to connect production plants to the pipeline.

Although long distance large diameter pipes will be needed to access frontier basins, most of the pipeline built in the coming decades will be for regional needs.

Approximately two-thirds of anticipated pipeline capacity built will be less than 24 inches in diameter. Such pipe will most likely be used to relieve local bottlenecks, connect new industrial customers, connect new power plants, or access new supply within a basin.

Along with the expected 26,000 miles of pipeline, 5.2 million horsepower of compression will be required. Approximately three-quarters of total compression additions will be associated with new pipeline projects, over 50 percent with the Alaskan and MacKenzie Delta projects. Replacement of existing compressors accounts for a fifth of the total. The remaining 5 percent of compression will be needed in new storage projects.

6
PROJECT FINACING AND RISKS: THE ROLE OF LONG-TERM CONTRACTS

6.1 Contracts Allocate Obligations and Risks

Contracts are the means by which parties associated with an investment (equity holders, debt holders, insurers, suppliers, buyers, etc.) can assign rights and obligations and allocate risks. Equity holders and lenders will evaluate each source of risk and methods of mitigating those risks before committing money. Any source of added risks to a project that is not mitigated may reduce credit ratings of the project or its equity holders, increase costs of borrowing, delay the project or lead to its abandonment.

Long-term sales contracts are one way of reducing risks to developers and lenders for large-scale, energy-supply projects. Long-term sales contracts are important because they increase the assurance that the investment will receive revenue. The long-term sales contract can mitigate “volume risk” by assuring that a minimum amount of sales or throughput occurs. The long-term sales contract also can mitigate “price risk” by setting a fixed price or by specifying a pricing formula based on a well understood – and possibly hedgeable – price index.

Long-term sales contracts can reduce volume and price risks for nearly any type of investment. Generally speaking, however, long-term sales contracts tend to be most important and most common in financing industries and projects for which the market is limited by geography or by the specialized nature of the product and where capital costs are a large part of total production costs. Wise investors will not put themselves in the position of negotiating sales having already sunk large capital costs in a market with limited buyers. Long-term sales contracts may also be common in situations where an unusual degree of coordination is needed between the provider and the buyer or where transaction costs from frequent short-term contracting is high. On the other hand, long-term sales are relatively less important when an investment has relatively low capital costs and produces a product or service that has a broad, liquid market with easy price discovery and low transaction costs.

The contracts that are the focus of this paper are long-term commodity purchase and transportation contracts signed by large natural gas consumers and local gas distribution companies related to LNG projects and gas pipeline projects. The next section discusses contracting and financing of gas pipeline projects and is followed by a section related specifically to Alaska gas pipeline projects. The section after that discusses contracting and financing of LNG projects.

6.2 Gas Pipeline Contracts and Financing

Gas pipelines are good examples of investments that normally require long-term service contracts before developers and lenders are willing to risk money. Gas pipeline service has only a very limited geographic market (moving gas between point A to point B) and a high capital cost component. U.S. gas pipelines also must adhere to a government mandated open access policy that prohibits withholding unused capacity from of the market and a rate design policy with minimum commodity rates that cover only variable costs. A gas pipeline that was built speculatively could face enormous pressures to discount rates as it tried to sign up would-be FT service shippers, who would have access rights to the pipeline in any case through short-term interruptible service. Since the rate paid for interruptible service in the U.S. could never exceed FT rates no matter what the market conditions, the pipeline could only break even under favorable market conditions and lose money the rest of the time. The builder of a speculative pipeline would do well only if the demand for transportation far exceeded its capacity and it could either negotiate FT contracts after the project was built or could somehow command high interruptible rates nearly all the time. Even if the pipeline were willing to take the risk of speculative build, it would be difficult to get lenders to go along, since the expected pipeline revenue would be so uncertain.[24]

An example of recent contracting and financing a new pipeline is Cheyenne Plains, which can be described as a “supply driven” project needed to move growing gas production out of the Rockies. The El Paso Corporation's Cheyenne Plains pipeline is a 36-inch natural gas pipeline that runs 380 miles from the Cheyenne Hub near Cheyenne, Wyoming to Greensburg, Kansas. Phase I of the pipeline project began full service in January 2005 with a design capacity of 560 MDth/day. The cost of pipeline and related facilities is approximately $425 million (Phases I & II). A Phase II 170 MDth/day expansion is projected to be in-service by early 2006. The project was underwritten with long-term firm transportation contracts for the full capacity of the pipeline (Table 6-1). Customers are mostly gas producers and marketers with one gas LDC (Kansas Gas Services) holding 13 percent of capacity. The contract lengths are mostly 10 years with one 13-year and one 15-year contract.

FERC approved Cheyenne Plains rates based on its parent company’s capital structure at 69 percent debt and 31 percent equity, a 14 percent return on equity (ROE), and the actual debt cost. In May 2005, Cheyenne Plains entered into a non-recourse senior secured financing agreement for $266.0 million with a group of banks led by WestLB. The 10-year term loan, which matures on March 15, 2015, has a fifteen-year amortization with the remaining balance due at maturity. Interest for the loan is based on a London Interbank Offered Rate (LIBOR) plus an applicable Eurodollar margin of 1.375 percent to 1.625 percent. The term loan is collateralized by the pipeline’s physical assets and contract proceeds. The term loan requires a debt service reserve amount equal to six months’ interest and principal payments and is currently funded through a $12.0 million letter of credit with WestLB.

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[24] The only example of a new gas pipeline built without long-term firm contracts for most of its capacity is Gulfstream, which began operations in 2002 between Mobile Bay and Florida with only 28 percent of its capacity signed up. The project was built with the expectation that capacity would be filled in the future by rising power generation gas use in Florida. In fact, the recent extension of the line in 2005 to more customers has brought firm contracts up to 70 percent of capacity.

Table 6-1

Index of Customers for Cheyenne Plains

Customer	Start Date	End Date	MDQ
ANADARKO ENERGY SERVICES COMPANY	12/1/2004	1/31/2015	100,000
BP ENERGY COMPANY	12/1/2004	1/31/2015	40,000
ANADARKO ENERGY SERVICES COMPANY	6/1/2005	1/31/2016	11,500
YATES PETROLEUM CORPORATION	6/1/2005	1/31/2016	18,500
OGE ENERGY RESOURCES INC	12/1/2004	3/31/2015	60,000
KANSAS GAS SERV A DIV OF ONEOK INC	12/1/2004	1/31/2015	75,000
KENNEDY OIL	12/1/2004	1/31/2015	15,000
KERR MCGEE ENERGY SERVICES CORP	12/1/2004	1/31/2015	40,000
NATIONAL FUEL MARKETING COMPANY LLC	12/1/2004	1/31/2015	10,000
NOBLE ENERGY INC	12/1/2004	1/31/2015	4,560
ONEOK ENERGY SERVICES COMPANY LP	12/1/2004	1/31/2015	120,000
PALO PETROLEUM INC	12/1/2004	1/31/2015	2,000
KERR MCGEE (NEVADA) LLC	12/1/2004	1/31/2015	43,440
ATMOS ENERGY CORPORATION	12/1/2004	1/31/2020	11,000
BILL BARRETT CORPORATION	12/1/2004	4/30/2018	9,000
			560,000

The bank loan was only for 10 years because that was the maximum length of the service contracts. El Paso must refinance the pipeline with another loan after the initial loan runs out and the balloon payment comes due. After the bank loan was made, El Paso entered interest rate swap agreements to lock in interest payments at 4.56 percent plus a margin on 40 percent of the term loan amount. The effective interest rate on the debt, therefore, is over 8 percent.

An example of a recent “demand driven” pipeline is North Baja Pipeline, the 80-mile United States leg of a 220-mile gas pipeline system that crosses Baja Mexico and Southwest California. The North Baja pipeline runs from the Mexican border west of Yuma, Arizona to connect to the El Paso system at Ehrenberg, Arizona. The Baja Mexico leg, Baja Norte Pipeline, runs 140 miles from south of Tijuana to the U.S. border. The pipeline system was originally developed by PG&E National Energy Group

(U.S. segment) and Sempra Energy International and Mexican investors. Service began in September 2002. TransCanada acquired North Baja in 2004 as part of a large buyout of the PG&E interstate gas transmission affiliate. The pipeline has a capacity of 500 MMcfd and has plans in place to transport LNG imports from the Costa Azul regasification terminal. The pipeline was near fully subscribed by Mexican shippers before it was built. Service contracts are for various lengths up to 25 years. (Table 6-2).

Table 6-2

Index of Customers North Baja Pipeline (in U.S.)

Customer	Start Date	End Date	MDQ
Energia Azteca X S. de R.L. de C.V.	9/1/2002	3/31/2028	119,955
Energia de Baja California	9/1/2002	3/31/2028	37,000
MGI Supply Ltd.	9/1/2002	8/31/2022	96,000
Termoelectrica de Mexicali	1/1/2003	12/31/2022	105,000
Gasoducto Rosarito S. de R.L. de C.V.	7/1/2002	12/31/2009	74,000
Energia de Baja California	1/1/2005	12/31/2005	15,045
			447,000

North Baja's capital structure, as reported in their May 2005 FERC filing, is 70 percent long-term debt and 30 percent equity. The allowed ROE is 14 percent and the cost of debt, based on NBP's average, is 7.21 percent. The resulting weighted-average capital cost is 9.25 percent.

These two examples illustrate how long-term contracts are needed for pipeline projects to go forward. With Cheyenne Plains, shippers were mostly producers seeking an outlet for their gas while North Baja Pipeline was primarily contracted by end-users. In the case of Cheyenne Plains, where the firm transportation contracts mostly had 10-year terms, the long-term project financing loans only cover that same 10 years. This underscores the point that lenders will not lend money to pipelines in the absence of contracts. Because of competitive pressures from rival proposed pipelines, El Paso proceeded with the project and took the risk that contracts will be successfully renewed or replaced and that refinancing will be possible in ten years. Therefore, the contracts brought the risks to the pipeline developer down to an acceptable range, but did not completely eliminate them.

One other factor that is complicating pipeline investments is the required time from inception to completion of a project. Various factors from “Not In My Back Yard” syndrome to broadened environmental concerns have extended the period to plan, design and construct a pipeline. Several high profile pipeline projects in areas of constrained pipeline capacity have had and continue to have significant delays. These delays extend the volatile and high pricing caused by insufficient pipeline capacity. This raises the concern that the present market signals for shippers, regulators, and pipelines to expand capacity may not anticipate needs as far in advance as necessary to prevent market disruption. It is important to note that all three of the participants (shippers, regulators and pipelines) must be committed for a pipeline project to move forward. Unfortunately, the time between market recognition (basis differential criteria reached) and pipeline in-service date has been increasing for many pipeline projects, making it more critical that long-term shippers commit as quickly as possible to minimize the consumer impact from high and volatile prices.

6.3 Alaska Gas Pipeline Projects

A key project forecasted to moderate delivered gas prices to consumers is the Alaskan Gas Pipeline. The state of Alaska has received five applications for gas pipeline projects under the state’s Stranded Gas Development Act. This law requires that the applicants provide evidence that their application is a Qualified Project and that the applicants are a Qualified Sponsor or Sponsor Group. In order to meet the requirements of a Qualified Project, the application must demonstrate that the project will transport Alaska gas by pipeline to potential markets in North America, that it will transport at least 500 Bcf, and that it is capable of making gas available within Alaska. The sponsor groups of the original five proposals were:

(1) TransCanada
(2) Mid-American Energy Holdings
(3) Enbridge
(4) BP/ConocoPhillips/ExxonMobil
(5) Alaska Gasline Port Authority

Although the first four proposals varied somewhat in design and scope, they were all based on the movement of gas from the Alaska North Slope through the Yukon to Alberta and on to Lower 48 markets. The cost to build the Alaska to Alberta portion of the pipeline is anticipated to be approximately $12 billion. A new “greenfield” line from Alberta to Chicago could cost another $5 billion, but it is unclear at this time how much additional capacity out from Alberta will be required, as some existing capacity and cheaper expansion is expected to be available as a consequence of production plateauing in the Western Canadian Sedimentary Basin. North Slope gas conditioning and NGL extraction plants could add another $3 billion to the project costs.

The proposal from the Alaska Gasline Port Authority (a municipal port authority formed by the municipalities of the North Slope Borough, Fairbanks North Star Borough, and the city of Valdez) combines gas pipeline transportation to the Canadian border and transportation to Valdez for LNG export. A total of 1,075 miles of pipeline is included. Throughput capacity from the North Slope is 6.0 Bcfd. The system branches at Delta Junction, with a 2.6 Bcfd pipeline to Valdez for LNG, and a 3.1 Bcfd pipeline to the Canadian border for export. The total estimated cost is $18.4 billion including a North Slope gas conditioning plant, the pipeline segments, an LNG plant, and a LPG extraction facility.

6.3.1 Federal Loan Guarantee for Alaska Pipeline

The Alaska Natural Gas Pipeline Act authorizes the Department of Energy to issue loan guarantees for up to 80 percent of capital costs subject to a ceiling of $18 billion dollars as adjusted for inflation. Guarantees can be issued for both the U.S. and Canadian portions of the project. These guarantees will require loan guarantee agreements. DOE has issued a NOI to request comments on various issues to be resolved including:

- Special terms and conditions, if any
- Whether there will be a loan guarantee fee imposed on lender
- Minimum amount of equity to be asked from pipeline owners (minimum 20 percent per law) and form of guarantee to fully fund project and any cost overruns.
- Term on guarantee (maximum 30 years per law) and whether to count construction period against term.
- Loan collateral, recourse in case of default
- Whether cost overruns can be funded by guaranteed loans
- Project reporting and monitoring requirements

The Federal loan guarantee was designed to help improve the commercial viability of the Alaska project. Congress thought the benefits of the project would be great enough and shared broadly enough to warrant the Federal government guarantee. Even with the loan guarantee, lenders and equity participants will require longer-term capacity commitments to support investment in this massive project. The contracts will also help to support Congress' decision to provide the guarantees. Also, any additional pipeline capacity needed to move the gas out of Alberta to the U.S. markets will require long-term firm contracts.

6.4 LNG Contracts and Financing of Projects

LNG projects are very capital intensive. Examples of capital costs for a 1 Bcfd project are shown in Table 6-3 and range from $3.45 to $7.8 billion. Approximately 73 percent of the investment is located in the country of origin for upstream and midstream facilities (gas field development, gas processing plant, gas pipeline) and for the liquefaction plant. Approximately 20 percent of the costs are for shipping. The cost of receipt terminal and storage, located in the country consuming the LNG, is about 7 percent of total investment.

Equity ownership patterns in LNG projects are varied. Many of projects under development today are joint ventures that include integrated international petroleum companies, state-owned national petroleum companies and international energy trading companies, who may own all segments of the LNG value chain. Sometimes consuming companies (e.g. Japanese electric utilities) or equipment suppliers also have equity interest in the liquefaction facilities or ships. Because of the specialized knowledge required, LNG tankers in many cases are owned by shipping companies who operate and lease the tankers to the LNG seller or buyer.

Table 6-3

Example Capital Costs for a 1 Bcfd LNG Project

	Million Dollars			
	Lower End		Upper End	Approx. Percent
Upstream	**1,400**	**-**	**2,900**	**38%**
Liquefaction Plant	**1,400**	**-**	**2,500**	**35%**
Ships	**500**	**-**	**1,800**	**20%**
Receipt Terminal & Storage	**150**	**-**	**600**	**7%**
Total	**3,450**		**7,800**	**100%**

When ownership is split by value chain segment, the varied relationships are controlled by long-term contracts among the key entities. The allocation of risks and rewards among the parties depends on how ownership is split up and how each party is getting paid, including what sort of take-or-pay or revenue guarantees each receives:

> **Gas producers** may be obligated to provide given quantities of gas to the liquefaction plant. They may receive compensation for the gas according to a fixed price or, more likely, a formula based either on an oil price index or a gas price index in the market country. The value of natural gas liquids (ethane, propane, butane and pentanes plus removed before the LNG is made) typically all goes to the gas producer if the gas is processed before entering the LNG liquefaction plant. In other circumstances if the LNG plant is a "tolling" operation, the gas producers keep the LNG and pay the liquefaction plant a fee.

The **liquefaction plant** may be obligated to process and liquefy certain quantities of gas to a certain quality specification. Under tolling arrangements compensation is in the form of a percent of the gas used as fuel plus a fixed amount per unit of LNG and/or a fixed amount per period of time. If the plant is buying the gas from the producer, the plant will pay the producer based on a fixed price or formula.

Shipping companies are obligated to dedicate a certain fleet of ships and provide a certain level of service between the liquefaction plant and receiving terminals. Compensation for long-term contracts is usually time-based, but other arrangements based on number and distance of trips are also possible. In some cases, LNG is purchased at the liquefaction plant by the buyer and shipped via tankers owned or controlled by the buyers.

Receiving terminal may charge for each element of service such as dock time, offloading, storage and regasification. The current capacity at the four existing U.S. terminals is subject to FERC jurisdiction and FERC-approved rates. Because of FERC's Hackberry Decision, future terminals in the U.S. may charge market-based rates and are not subject to open access requirements.

The compensation received by the **country of origin** in terms of royalties, taxes and fees is another important element in the value calculation. These are usually set out in concession terms for the gas producer's lease and other agreements made with the government related to gas pipelines, liquefaction plants and port facilities needed for the project. If state-owned companies have equity in the project, then the terms of their participation is also part of the government's benefit.

One important question in evaluating project economics is the stage at which ownership of the gas is transferred and the price terms for each transfer. The most common pattern for the LNG projects currently under development is for the gas producers (private international petroleum companies and state-owned national petroleum companies) to keep ownership of the gas through the liquefaction process (through tolling agreements with or by ownership of the liquefaction plants). The "off-take" or sale of the LNG will take place at the liquefaction plant (FOB sale) or at the receipt terminal (ex ship sale). The off-taker can be a third party consumer or marketer (not related to owners of gas production or liquefaction facilities), or as is often the case for projects under development, a marketing affiliate of one or more of the gas producers.

The price paid by the off-taker is usually in concept the "market value" of the gas where it is sold, less the marketing costs, re-gassification costs and whatever are the applicable shipping costs. LNG sold in Asia and in Europe was historically and still is mainly tied to a basket of oil prices against with the LNG is considered to compete. In the U.S. most LNG prices are currently tied to Henry Hub or other indices. A U.S. consumer or LDC may buy LNG directly from the off-taker or from an intermediary to which the LNG was sold. The buyer will usually pay whatever the going price for gas is – not the "cost" of the LNG to the off-taker or final marketer.

Even when a large private petroleum company has equity in and operates all parts of the LNG value chain, the value of the gas at various stages may still be important because the partnership shares and revenue allocation at each stages might differ. Also, the royalties and taxes owed the country of origin will depend on the prices in that country – not the final sales price.

6.5 Long-term Contracts and Infrastructure Development

There is no simple relationship between the existence and nature of sales contracts and the financial viability of a project. Equity holders and lenders, of course, would prefer to see contracts with creditworthy buyers for all of a project's capacity at an adequate price for the entire cost-recovery period of the project. Projects, however, can proceed without being fully subscribed for the long-term. The degree of financial risk is usually measured by services that assign credit ratings. If the investment is being project financed, the rating is assigned specifically for the project. If general corporate or sovereign credit is being used, the relevant rating is for the company, country or state. Figure 6-1 shows the credit grades used by four credit services. The top four ratings are considered "investment grade" and typically would apply to newly issued debt. The six "non-investment grades" usually refer to old debt that has been downgraded due to adverse economic trends.

The historical yields of long-term corporate bonds for the four Moody's investment grades are shown in Figure 6-2. There has been a general downward trend in rates over the last 25 years caused by declines in inflation. There has also been a worldwide surplus of savings in the last several years that has allowed American companies and governments to borrow from overseas at moderate rates. The difference in borrowing costs have been roughly about 0.30 to 0.50 of a percentage point between each grade or a total or 1.10 percentage points between the highest (Aaa) and lowest (Baa) investment grades.

Figure 6-1

CREDIT RATINGS

Credit Risk	Moody's	Standard & Poor's	Fitch IBCA	Duff & Phelps
INVESTMENT GRADE				
Highest quality	Aaa	AAA	AAA	AAA
High quality (very strong)	Aa	AA	AA	AA
Upper medium grade (strong)	A	A	A	A
Medium grade	Baa	BBB	BBB	BBB
NOT INVESTMENT GRADE				
Lower medium grade (somewhat speculative)	Ba	BB	BB	BB
Low grade (speculative)	B	B	B	B
Poor quality (may default)	Caa	CCC	CCC	CCC
Most speculative	Ca	CC	CC	CC
No interest being paid or bankruptcy petition filed	C	C	C	C
In default	C	D	D	D

Examples of how investment ratings might affect project economics are shown in Table 6-4 for three hypothetical LNG projects. Assuming that equity will make up 40 of capitalization in all cases and that it will require an 18 percent annual return, the delivered LNG price needed for the projects, goes up about 1 percent for each grade drop in credit rating from the interest rate effect alone. Lower credit ratings can have even greater impacts on project economics because they may require a larger percent equity participation, greater insurance coverage and more stringent cash reserves and cash management provisions.

Figure 6-2

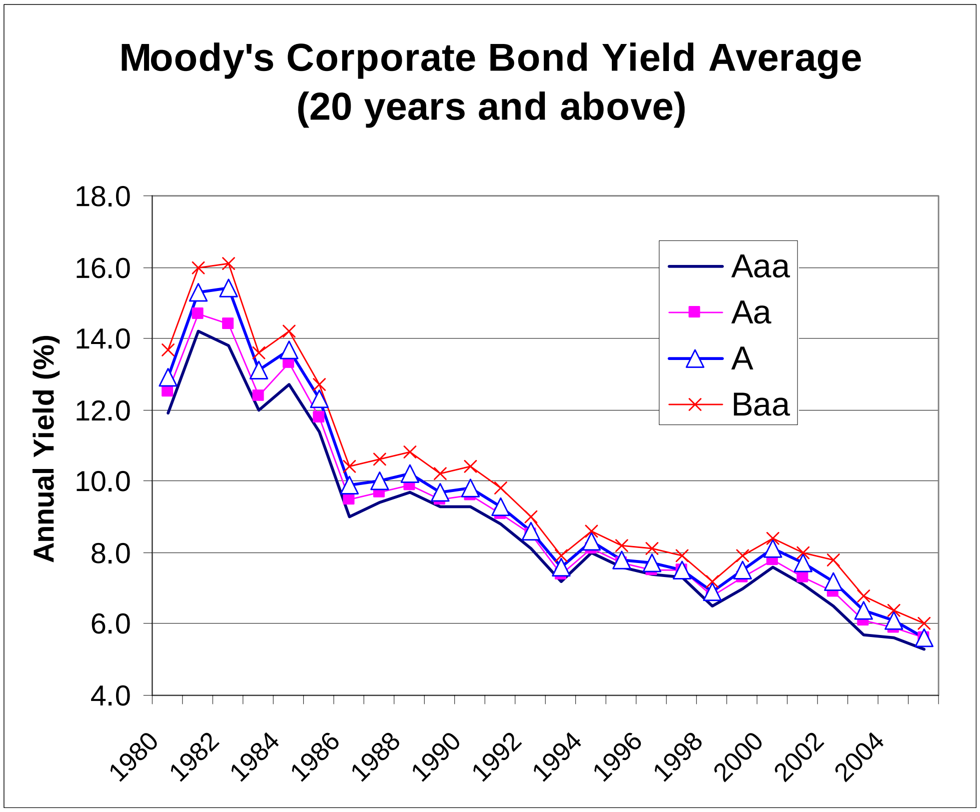


Table 6-4

Examples of Impact of Debt Rating on Required Price for LNG Projects

Rating	Cost of Debt	Required Price ($/MMBtu, Ex Ship) Example 1	Example 2	Example 3
Aaa	7.00%	$ 4.00	$ 4.50	$ 5.00
Aa	7.32%	$ 4.04	$ 4.55	$ 5.05
A	7.62%	$ 4.08	$ 4.59	$ 5.10
Baa	8.09%	$ 4.12	$ 4.64	$ 5.15

Assumes 60% debt, and 40% equity at 18% ROE. Annual operating costs are 5 percent of capital costs. Project life is 20 years.
Interest rate differences between ratings are averages for last 25 years.

Credit agencies, lenders and equity holders will look at several sources of risk and what the project has done to mitigate those risks. Sources of risk may include:

1) Construction Risks: Problems can arise during construction phase that delay project and cash inflows. Mitigation can be provided by penalty provisions in Engineering, Procurement and Construction (EPC) contracts and through insurance.

2) Technical Risks: Technologies used in the project may not perform as expected. Mitigation is available through performance guarantees by equipment and technology suppliers and by insurance.

3) Operational Risk: Includes items such as equipment failure, supply disruptions, Acts of God, etc. Mitigation is available through performance guarantees by suppliers and insurance

4) Price Risk: Mitigation may be available through pricing provision in sales contracts, selling into multiple markets, and hedging.

5) Demand Volume Risk: Volume of sales may not be as high as expected. The best mitigation is must-take provisions in sales agreements and being able to sell into multiple markets.

6) Payment Risk: Buyer may not be able to pay. Mitigation includes signing only creditworthy buyers, bonding provision triggered by changes in buyer's credit rating and insurance.

7) Regulatory Risk: If successful investment depends on regulatory provisions, changes can effect prices and volumes that are sold or cost-recovery mechanisms.

8) Political Risk: Includes changes to government, expropriation, war, civil disobedience, etc. Mitigation possible through insurance from Overseas Private Investment Corporation (OPIC), Multilateral Investment Guarantee Agency (MIGA, up to $200 million per project) and other such agencies.

9) Exchange Rate Risk: If project is in a different country from the market, payments may have to be converted. Mitigation options includes converting debt to the currency of commodity/service payments or currency swaps.

10) Geologic Risks: If project relies on gas reserves, there is chance the proven reserve estimates are overstated or that new discoveries expected in later years do not materialize. Best mitigation option is to have alternative gas supply options or penalty provisions for gas suppliers.

Export Credit Agencies (ECA's), such as the U.S.'s Export-Import Bank, promote their home country exports especially to developing countries. ECA's can provide loans and loan guarantees for up to 85 percent of the value of equipment and engineering services for overseas gas field development, gas pipelines and liquefaction plants. Thus, ECA's can mitigate many of the sources of risks for LNG projects for a substantial portion of the total investment.

Obviously, long term supply contacts provide robust physical hedging for these complex projects,that maintain low delivered gas prices only if the value chain (production, processing liquefaction, shipping and regasification) are operated on a continuous basis.

6.6 Conclusions Regarding Long-term Contracts

Because of the regulatory environment for natural gas pipeline, the capital intensity of the business and the dedication of each asset to a limited geographic market, it cannot be expected that new gas pipeline capacity will be built unless substantially all of the capacity is contracted for a long term. The customary contract period is 20 years, but shorter periods of 10 years are possible, especially when competitive conditions exist among pipeline projects. Debt financing of gas pipeline projects can come from the long-term corporate debt of a financially healthy parent. Otherwise, when project financed, the loan term cannot be expected to exceed the contract terms.

Unfortunately, the time between market recognition (basis differential criteria reached) and a pipeline in service date has been increasing for many pipeline projects, making it more critical that long-term shippers commit as quickly as possible to minimize consumer impact from high and volatile prices.

The long-term contracting of existing pipeline capacity is also important. Long-term contracts help to assure pipelines that they will recover the substantial investments that will be required to maintain existing pipeline and storage capacity. Also, average length of the contract portfolio is an important element in credit agency ratings of a pipeline. Longer contracts improve credit ratings and reduce the cost of borrowing for pipeline companies, thus making it more likely they will invest in existing or expanded capacity.

Even when debt on a new gas pipeline project is guaranteed by the government, as with the Alaska gas pipeline, there still exists considerable risk for equity holders. Therefore, long-term contracts will affect project viability for the Alaska gas pipeline and for any pipelines needed to move the Alaskan gas from Alberta to the U.S.

LNG projects can have a number of different configurations with various contractual relationships. All projects, however, will have a long-term off-take agreement with a gas marketer, distribution company or consumer. An important issue for future LNG projects serving the U.S. and Canada will be whether, on the one hand, LDCs and large gas consumers sign long-term contracts (either directly with the project developer or with the off-taker/marketer) or, on the other hand, the off-taker/marketer bears all the risks of being able to sell the gas at acceptable prices. Having long-term contracts with U.S. gas consumers and LDCs (directly or indirectly) will reduce the risk profile for the LNG development project making it more likely that the project will be built. The long-term purchase contracts with U.S. consumers and LDCs will also help guarantee that the LNG does not get bid away from the U.S. in periods of high foreign natural gas prices.

7
COSTS TO CONSUMERS OF INFRASTRUCTURE DELAYS

7.1 Definition of Scenarios

Delays in pipeline infrastructure construction create significant impacts for consumers. Delayed pipeline and LNG terminal construction will reduce the available supply of natural gas to the market. Delivered natural gas prices will be relatively higher to all consumer groups. Electricity prices will rise as natural gas, an increasing source of clean fuel for electric generators, is utilized more. U.S. industrial competitiveness in world markets will suffer due to increased costs, causing job losses and encouraging importation of products. Federal and state revenues will be affected as the economy tries to adjust to higher natural gas prices. With a relatively higher gas price, more coal will be dispatched to meet electric generation needs. This will affect the quantity of air emissions.

EEA utilizes a long-term economic projection model that has been the basis of strategic thinking for many segments of the industry and the government. Being a long-term economic model, it predicts future impacts in a “smoothed” fashion and, therefore, does not predict short-term economic aberrations that frequently occur.

Two Alternative Scenarios to the EEA Base Case were constructed in an attempt to quantify the costs associated with pipeline and LNG import infrastructure delay. The Alternative Scenarios assume that all pipeline and LNG import terminal projects not already under construction, assumed to be those projects post 2007, will be delayed from 12 or 36 months. While there may be other reasons why these projects may be delayed, commitment by shippers and their regulators are key components to assure that these projects move forward. Major frontier projects and the associated natural gas production such as the Alaskan Gas Pipeline and the MacKenzie Delta Pipeline are also delayed 12 or 36 from the EEA Base Case. All other assumptions in the EEA Base Case (economic, price of alternative fuels, weather, generating capacity, etc.) were kept constant.

7.2 Impact of Infrastructure Delays on Prices

Using the Henry Hub price as a measure of price impacts, a 12-month delay in pipeline and LNG import terminal construction will increase U.S. natural gas prices by an average of $0.80 per MMBtu from 2006 – 2020, $0.67 per MMBtu in constant 2004 dollars (Table 7-1). Price effects will be immediate and lasting throughout the forecast period (Figure 7-1).

Table 7-1
Natural Gas Price Effects of a 12-month Delay in Pipeline and LNG Terminal Construction

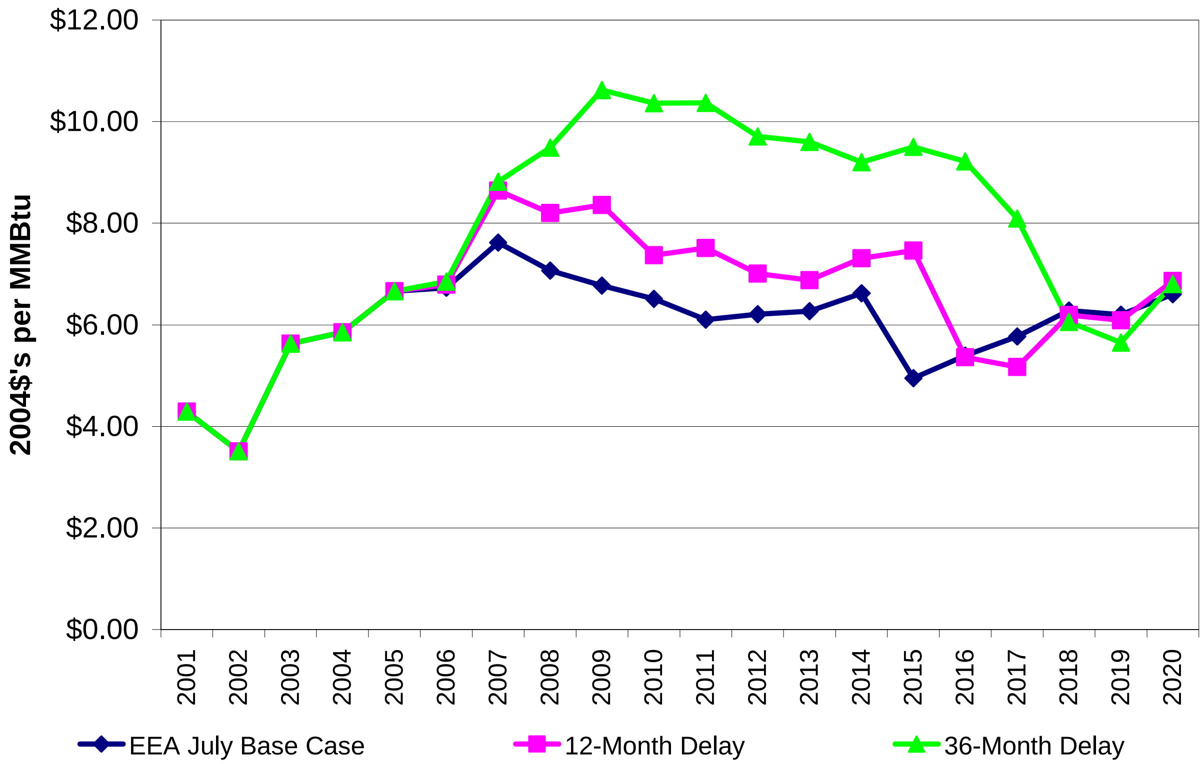
Average Henry Hub Price Nominal $ per MMBtu

Time Period	Base Case	12 Month Infrastructure Delay	Price Increase
2006-2010	$7.66	$8.71	$1.04
2011-2020	$8.05	$8.74	$0.68
2006-2020	$7.92	$8.73	$0.80

Average Henry Hub Price Real 2004$ per MMBtu

Time Period	Base Case	12 Month Infrastructure Delay	Price Increase
2006-2010	$6.94	$7.87	$0.93
2011-2020	$6.04	$6.58	$0.54
2006-2020	$6.34	$7.01	$0.67

Figure 7-1
Real Henry Hub Average Annual Natural Gas Price



In total, a 12-month delay in natural gas infrastructure construction will cost U.S. gas consumers in excess of $179 billion (in constant $2004) by 2020 (Table 7-2). Higher gas costs will be seen in all parts of the country, and even greater impacts will be seen in certain market areas because of local constraints.

The second Alternative Scenario was a 36-month delay, which was ramped in over three years. Projects built in the Base Case in of 2007 were delayed 12 months. 2008 projects were held back for 24 months and projects for 2009 and later were delayed the full 36 months. Prices for that case are shown in Table 7-2.

Table 7-2
Natural Gas Price Effects of a 36-month Delay in Pipeline and LNG Terminal Construction

Average Henry Hub Price Nominal $ per MMBtu

Time Period	Base Case	36 Month Infrastructure Delay	Price Increase
2006-2010	$7.66	$10.25	$2.58
2011-2020	$8.05	$11.09	$3.04
2006-2020	$7.92	$10.81	$2.89

Average Henry Hub Price Real 2004$ per MMBtu

Time Period	Base Case	36 Month Infrastructure Delay	Price Increase
2006-2010	$6.94	$9.23	$2.29
2011-2020	$6.04	$8.42	$2.38
2006-2020	$6.34	$8.69	$2.35

The consumer costs go up by 179 billion dollars with a 12-month delay in gas infrastructure. Table 7-3 shows the added consumer costs of natural gas by State by period for the 12-month delay case. Table 7-4 shows impacts by consumer sector for the entire 2006 to 2020 period.

The consumer costs go up by 653 billion dollars with a 36-month delay in gas infrastructure. Tables 7-5 and 7-6, respectively, show these data for the 36-month delay case by period and by sector.

Table 7-3

Consequences of 12-Month Infrastructure Delays
Increase in Consumer (Burner Tip) Costs

Millions2004 dollars

Millions of 2004$	2006 To 2010	2011 To 2020	2006 To 2020
Alabama	1,681	2,006	3,687
Alaska	(34)	28	(7)
Arizona	1,777	2,392	4,170
Arkansas	818	810	1,629
California	9,027	10,804	19,830
Colorado	1,065	288	1,353
Connecticut	666	794	1,460
Delaware	239	289	528
DC	135	123	259
Florida	3,716	5,825	9,541
Georgia	2,082	3,394	5,476
Hawaii	-	-	-
Idaho	210	397	607
Illinois	3,995	5,219	9,215
Indiana	988	970	1,958
Iowa	761	989	1,750
Kansas	742	761	1,503
Kentucky	1,052	1,537	2,589
Louisiana	3,768	3,665	7,434
Maine	423	574	997
Maryland	810	902	1,711
Massachusetts	1,952	2,387	4,340
Michigan	3,125	4,267	7,391
Minnesota	1,345	1,886	3,230
Mississippi	836	685	1,521
Missouri	998	1,323	2,322
Montana	239	333	573
Nebraska	371	439	810
Nevada	884	1,636	2,520
New Hampshire	266	329	595
New Jersey	2,392	2,348	4,739
New Mexico	438	485	923
New York	4,162	4,645	8,808
North Carolina	986	1,284	2,270
North Dakota	121	120	241
Ohio	2,956	2,953	5,909
Oklahoma	1,594	1,692	3,286
Oregon	975	1,852	2,827
Pennsylvania	2,637	2,606	5,243
Rhode Island	316	400	716
South Carolina	724	987	1,711
South Dakota	141	197	338
Tennessee	1,159	1,572	2,730
Texas	14,249	17,082	31,331
Utah	236	55	291
Vermont	33	36	70
Virginia	1,092	1,290	2,382
Washington	989	1,656	2,645
West Virginia	337	346	682
Wisconsin	1,344	1,752	3,096
Wyoming	139	(11)	128
United States	**80,958**	**98,399**	**179,357**

Table 7-4
Consequences of 12-Month Infrastructure Delays
Increase in Consumer (Burner Tip) Costs By Sector
Millions 2004 dollars

Millions of 2004$	Residential	Commercial	Industrial	Power Generation	Total
Alabama	442	163	1,092	1,990	3,687
Alaska	6	5	(14)	(4)	(7)
Arizona	344	268	16	3,542	4,170
Arkansas	362	239	560	467	1,629
California	4,588	1,993	2,019	11,230	19,830
Colorado	394	186	240	532	1,353
Connecticut	402	312	134	613	1,460
Delaware	89	66	67	305	528
DC	128	130	-	-	259
Florida	128	449	282	8,682	9,541
Georgia	1,135	354	831	3,156	5,476
Hawaii	-	-	-	-	-
Idaho	158	94	113	242	607
Illinois	5,159	1,879	2,032	145	9,215
Indiana	812	462	541	143	1,958
Iowa	690	368	540	152	1,750
Kansas	556	226	632	89	1,503
Kentucky	596	287	776	930	2,589
Louisiana	460	166	4,799	2,009	7,434
Maine	10	41	24	921	997
Maryland	791	617	(10)	313	1,711
Massachusetts	1,039	518	497	2,286	4,340
Michigan	3,918	1,634	848	992	7,391
Minnesota	1,423	917	591	298	3,230
Mississippi	229	185	631	476	1,521
Missouri	918	460	265	678	2,322
Montana	186	100	152	135	573
Nebraska	327	165	208	110	810
Nevada	314	212	(30)	2,024	2,520
New Hampshire	64	82	61	388	595
New Jersey	2,203	1,229	(200)	1,507	4,739
New Mexico	289	171	(64)	527	923
New York	3,650	2,526	(431)	3,062	8,808
North Carolina	623	339	388	920	2,270
North Dakota	111	90	40	1	241
Ohio	3,080	1,427	1,433	(31)	5,909
Oklahoma	540	245	807	1,694	3,286
Oregon	497	262	588	1,481	2,827
Pennsylvania	2,151	1,077	648	1,367	5,243
Rhode Island	164	82	(49)	519	716
South Carolina	273	174	393	871	1,711
South Dakota	123	81	88	46	338
Tennessee	697	444	778	811	2,730
Texas	2,015	1,590	10,776	16,950	31,331
Utah	179	107	(43)	48	291
Vermont	26	23	20	1	70
Virginia	688	527	407	761	2,382
Washington	910	507	534	694	2,645
West Virginia	278	170	244	(10)	682
Wisconsin	1,493	799	640	164	3,096
Wyoming	27	20	67	14	128
United States	**45,688**	**24,464**	**34,961**	**74,243**	**179,357**

Table 7-5
Consequences of 36-Month Infrastructure Delays
Increase in Consumer (Burner Tip) Costs
Millions 2004 dollars

Millions of 2004$	2006 To 2010	2011 To 2020	2006 To 2020
Alabama	4,109	10,408	14,517
Alaska	(71)	93	22
Arizona	4,391	10,630	15,021
Arkansas	2,095	4,237	6,332
California	19,308	52,116	71,424
Colorado	681	7,937	8,618
Connecticut	1,667	3,596	5,264
Delaware	591	1,413	2,004
DC	324	583	907
Florida	9,090	25,132	34,222
Georgia	5,243	15,579	20,823
Hawaii	-	-	-
Idaho	283	2,112	2,395
Illinois	8,466	23,884	32,351
Indiana	2,180	4,874	7,054
Iowa	1,554	4,733	6,287
Kansas	1,600	3,871	5,470
Kentucky	2,615	7,094	9,709
Louisiana	9,097	17,788	26,885
Maine	1,071	2,526	3,596
Maryland	1,920	4,134	6,054
Massachusetts	4,928	10,870	15,798
Michigan	6,949	18,910	25,860
Minnesota	2,954	8,530	11,484
Mississippi	2,381	4,641	7,022
Missouri	2,166	6,643	8,809
Montana	547	1,667	2,215
Nebraska	673	2,296	2,969
Nevada	1,475	8,192	9,667
New Hampshire	669	1,461	2,130
New Jersey	5,813	11,536	17,349
New Mexico	1,005	2,255	3,260
New York	10,209	21,588	31,798
North Carolina	2,302	5,776	8,077
North Dakota	268	592	860
Ohio	6,614	13,924	20,538
Oklahoma	3,783	8,336	12,119
Oregon	2,369	8,683	11,052
Pennsylvania	6,415	12,873	19,288
Rhode Island	810	1,859	2,669
South Carolina	1,684	4,332	6,016
South Dakota	302	930	1,233
Tennessee	2,841	7,249	10,090
Texas	34,376	75,585	109,961
Utah	(34)	1,881	1,847
Vermont	83	164	246
Virginia	2,593	5,807	8,400
Washington	2,365	7,337	9,702
West Virginia	813	1,643	2,456
Wisconsin	2,893	7,453	10,346
Wyoming	34	811	845
United States	**186,495**	**466,566**	**653,061**

Table 7-6
Consequences of 36-Month Infrastructure Delays
Increase in Consumer (Burner Tip) Costs By Sector
Millions 2004 dollars

Millions of 2004$	Residential	Commercial	Industrial	Power Generation	Total
Alabama	1,552	555	3,641	8,768	**14,517**
Alaska	29	21	(27)	(1)	**22**
Arizona	1,220	930	10	12,861	**15,021**
Arkansas	1,269	818	1,908	2,338	**6,332**
California	16,171	7,047	6,982	41,224	**71,424**
Colorado	2,624	1,207	1,687	3,099	**8,618**
Connecticut	1,407	1,088	547	2,222	**5,264**
Delaware	316	232	245	1,211	**2,004**
DC	449	458	-	-	**907**
Florida	433	1,526	803	31,461	**34,222**
Georgia	3,963	1,206	2,657	12,996	**20,823**
Hawaii	-	-	-	-	**-**
Idaho	588	350	418	1,039	**2,395**
Illinois	18,590	6,621	6,377	762	**32,351**
Indiana	2,864	1,610	1,657	924	**7,054**
Iowa	2,508	1,305	1,825	649	**6,287**
Kansas	2,105	810	2,140	415	**5,470**
Kentucky	2,108	990	2,649	3,962	**9,709**
Louisiana	1,632	553	16,329	8,370	**26,885**
Maine	37	144	92	3,324	**3,596**
Maryland	2,760	2,147	(75)	1,222	**6,054**
Massachusetts	3,641	1,825	2,023	8,308	**15,798**
Michigan	13,882	5,680	2,246	4,051	**25,860**
Minnesota	5,032	3,205	1,975	1,272	**11,484**
Mississippi	798	635	2,113	3,475	**7,022**
Missouri	3,326	1,644	886	2,954	**8,809**
Montana	692	360	555	608	**2,215**
Nebraska	1,245	598	685	442	**2,969**
Nevada	1,152	773	(92)	7,834	**9,667**
New Hampshire	223	288	228	1,390	**2,130**
New Jersey	7,917	4,379	(560)	5,614	**17,349**
New Mexico	1,038	594	(266)	1,895	**3,260**
New York	12,910	8,813	(1,366)	11,441	**31,798**
North Carolina	2,204	1,175	1,193	3,505	**8,077**
North Dakota	404	318	135	3	**860**
Ohio	10,764	4,952	4,460	362	**20,538**
Oklahoma	1,954	850	2,780	6,535	**12,119**
Oregon	1,777	912	2,074	6,289	**11,052**
Pennsylvania	7,612	3,779	2,541	5,355	**19,288**
Rhode Island	573	290	(87)	1,893	**2,669**
South Carolina	961	601	1,226	3,228	**6,016**
South Dakota	448	287	303	195	**1,233**
Tennessee	2,461	1,537	2,628	3,464	**10,090**
Texas	7,099	5,448	36,395	61,018	**109,961**
Utah	922	586	14	325	**1,847**
Vermont	92	79	71	3	**246**
Virginia	2,403	1,838	1,296	2,863	**8,400**
Washington	3,254	1,774	1,877	2,796	**9,702**
West Virginia	982	573	811	90	**2,456**
Wisconsin	5,109	2,689	1,946	602	**10,346**
Wyoming	174	154	435	81	**845**
US	**163,671**	**86,257**	**118,394**	**284,738**	**653,061**

As significant as these impacts are, the prices produced in the alternative scenarios were not high enough to eliminate growth in gas demand. While delayed, the scenarios assume that the projects are eventually constructed. In the alternative case that assumes 12-month delay, U.S. natural gas annual consumption is reduced by an average of approximately 0.5 Tcf per year; and in the 36-month case average annual consumption declines by 1.4 Tcf.

It is important to note that natural gas provides over 25 percent of the energy consumed in the United States and is an important component in the price of many consumer products from bread to electricity and, therefore, these effects will compound as the additional energy costs ripple through the economy.

If, however, government policies and public opposition to the construction of the required infrastructure prevents the facilities from even being built, gas supplies will be unable to grow to meet market needs even at the reduced level of gas demand. In such a case, there could be tremendous pressure on gas prices, well above those quantified in the delay scenario or today's levels. The price levels would have to be so great that customers who want gas conclude that they simply cannot afford to purchase gas. Given the integral nature of natural gas in homes, businesses, and industry, prices at those levels could hinder economic growth and the competitiveness of U.S. manufacturing.

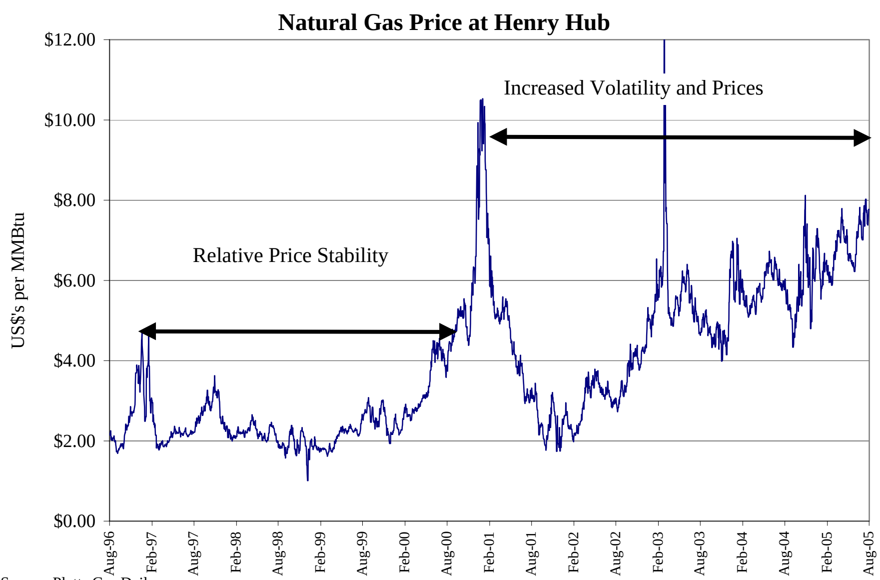
7.3 Impact of Infrastructure Delays on Volatility

7.3.1 Sources of Price Volatility

Over the last five years, energy price volatility has become a significant issue facing the natural gas industry and energy companies. Natural gas, electricity, crude oil and oil product markets have all exhibited high price volatility for some portion of the period. Figure 7-2 illustrates the increased volatility in natural gas prices at Henry Hub.

Commodity markets including natural gas exhibit increased volatility when there is little or no spare supply capability to meet natural fluctuations in demand. In order to remain competitive and profitable, or to comply with regulatory requirements, companies have an incentive to increase efficiency and reduce the amount of unutilized capacity. The large capital requirements and significant lead times associated with gas production and delivery make gas markets particularly susceptible to the imbalances that result in price volatility. In addition, natural gas markets are unusually subject to volatility because fluctuations in weather can change gas demand significantly, and the same increase or decrease in demand affects all competing commodities, such as fuel oil and propane, in the same way.

Figure 7-2
Monthly Henry Hub Natural Gas Prices



Source: Platts Gas Daily

The large increase in gas-fired power generation capacity, which is characterized by rapid and less predictable swings in gas requirements, has increased – and will continue to increase – fluctuations in natural gas demand. The majority of the new natural gas power generating stations will not be operated as a baseload source of power. As a result, they will cycle on and off as the marginal sources of electricity supply, leading to large day-to-day swings in natural gas demand. In addition, the limited amount of dual-fuel capacity being installed in new power plants compounds how these plants effect gas market volatility.

In an efficient market, prices adjust to correct imbalances of supply and demand. The magnitude of the change in prices is determined by the size of the imbalance and the willingness and ability of producers and consumers to respond to relieve the imbalance. This is true for both the short-term and the long-term.

- In the short-term, the demand for natural gas and electricity is affected to a large degree by weather. Because weather conditions can change rapidly and unexpectedly, large and sudden shifts in service demand can occur, which create significant imbalances.
- In the longer-term, prices signal the need to develop new resources and provide the incentive required to stimulate free market investment in new resources. The long-term demand response to higher prices is investment in more efficient equipment, fuel switching and energy substitutes.

7.3.2 Adverse Impacts of Price Volatility

Gas price volatility has a wide range of impacts on market participants. Impacts include increases in budgetary and planning uncertainty experienced by energy consumers; delays or changes in energy providers' capital investment patterns; and potentially fatal liquidity crises for energy marketers and merchant power providers.

Importantly, gas price volatility has contributed to a climate of uncertainty for energy companies and investors and a climate of distrust among consumers, regulators, and legislators. Gas price volatility creates uncertainty and concern in the minds of consumers and producers, who may delay decisions to purchase appliances and equipment or make investments in new supply, because they are uncertain whether prices at levels sufficient to justify such investment will be sustained. Such delay may result in lost market opportunities and inefficient long-run resource allocations. In addition, volatility may create pressures for regulatory intervention that can bias the market and penalize regulated entities and market participants by generating wide and unpredictable revenue swings. Finally, volatility can hurt the image of energy providers with the customers and policymakers and create doubt about the industry's integrity and competency to reliably provide a vital economic product.

7.3.3 Measuring Price Volatility

There are a variety of ways of measuring price volatility, depending on what elements of volatility are considered most critical. For instance, there are two different, points of reference when measuring volatility. The first point of view focuses on **absolute levels** of energy prices. A highly volatile market is a market in which average prices are changing rapidly in unanticipated ways, and in which next month's prices, or next year's prices, are likely to be substantially different from current prices. One typically uses absolute-level volatility when evaluating energy price volatility over an investment planning horizon.

The second perspective measures volatility in terms of "return", or change in price relative to the initial price. "Returns" measure volatility as a **percentage change** in prices, rather than in absolute prices, and can be viewed as a measure of expected return on investment, e.g., a 10 percent increase in price represents a 10 percent return on the value of the underlying asset, regardless of whether the 10 percent return represents a $0.20 increase from $2.00 per MMBtu, or a $1.00 increase from $10.00 per MMBtu. This perspective is most often associated with financial markets, and is the normal frame of reference for traders and risk managers who are concerned with short-term changes in returns. A highly volatile market is a market in which day-to-day changes in prices are very large relative to the base price.

7.3.4 Volatility Management Strategies

There are strategies, policies, and approaches that can be used to manage price volatility. These techniques are designed to reduce the negative impacts in a volatile energy price environment. In general, these can be adopted by an individual market participant.

Statistical Approaches for Measuring Volatility

1) **Standard Deviation:** The standard deviation in average prices represents an absolute measure of the actual price movement over a specific period. The standard deviation represents the expected deviation from the average market price during a given period. A higher standard deviation represents greater price movement, and when looked at in absolute terms, a higher standard deviation represents greater price volatility.
2) **Coefficient of Variation**: The Coefficient of Variation is a relative measure of price movement, and is calculated as the standard deviation divided by the mean value. The coefficient is a useful comparative measure of price volatility for different commodities when prices are measured in different units, and with different baseline prices (e.g., electricity price volatility vs. natural gas price volatility).
3) **Returns**: Traders and risk managers often measure volatility as a percentage change in prices, rather than in absolute prices. Measurements of volatility based on percentage changes in prices are often referred to as "returns" and reflect the expected "return" on investment in a commodity. Return(a) = $Price_a/Price_{a-1}$ Returns are calculated on a log-normal basis using the form: Return(a) = $\ln(Price_a/Price_{a-1})$ The log-normal form is used in order to create a more normal data distribution. Since prices are bounded by zero on the downside, and do not have a limit on the upside, the distribution of price data is often skewed unless evaluated using a logarithmic form.
4) **Annualized Returns**: Returns are usually annualized in order to compare volatility of price series with different time periods (e.g., daily spot price volatility vs. monthly bidweek price volatility). For daily prices, the annualization period is the number of trading days in a year.

Strategies designed to manage price volatility usually involve allocating price risk among the market participants. To the extent that the price risk for one participant is reduced, the price risk for another participant is increased. In considering these strategies, a market participant should carefully assess the nature of the risk and quantify the magnitude of any risk that is assumed.

Three basic elements– long-term contracts, asset acquisition, and financial derivatives – form the core tools for a commodity price hedging strategy. Hedging can be simply defined as establishing a price today for some good or service that will be bought or sold at some time in the future. By “fixing” the price for some future transaction, the value of the transaction to the market participant will not change with price movements in the market.

Hedging may be accomplished using both **physical** means, such as longer-term natural gas supply contracts and natural gas storage, as well as **financial** hedging strategies including gas price options and collars. However, hedging is not a cost-free activity. Hedging is essentially paying someone else to take the risks inherent in price volatility. . Therefore, any increase in volatility also increases the costs of hedging. In addition, while hedging can result in lower gas prices if the market prices are higher than expected, it can also result in costs higher than the market, if the market falls due to factors such as a warmer than normal winter.

An increase in energy price volatility raises the importance of natural gas price hedging for many of the participants in the market. Increased volatility also enhances the opportunity for price arbitrage. As a result, companies that can provide hedging services can benefit from the increase in volatility. The largest of the financial arbitrage markets is the NYMEX Henry Hub futures contract. As price volatility has increased, so has the volume of Henry Hub transactions

Price volatility also has a significant impact on the value of physical arbitrage, primarily natural gas storage. Traditionally, natural gas storage has been used for seasonal supply reliability and for seasonal price arbitrage. However, recent trends in natural gas markets have also increased the value of short-term physical arbitrage opportunities. As natural gas price volatility increases, so does the value of arbitrage using physical storage.

7.3.5 Price Volatility Impact of a 12- to 36-Month Delay Cases

The following tables compare the price and volatility impacts of a 12 to 36-month delay in pipeline and LNG terminal construction. Volatility was measured for four locations - Henry Hub, Chicago, California and New York.

In general, price volatility increased correspondingly with a greater delay in infrastructure construction. For Henry Hub, Chicago and California, the coefficient of variation in prices goes from 14 to 15 percent in the Base Case to 19 percent in the 36-month delay case. The one exception is New York where prices for the 36-month delay case show slightly lower levels of volatility (measured by coefficient of variation or annualized returns) than the 12-month delay case or the Base Case. New York prices behave differently because the market has constrained pipeline capacity, which in the delayed cases became extremely constrained, and price remains continuously at very high levels.

Table 7-7

Average Nominal Price and Volatility Measures for the Period 2006-2020

Time Period: 2006-2020

Average Price

	Henry Hub	Chicago	California	New York
Base Case	7.92	8.17	7.95	9.61
12 Month Delay	8.73	8.95	8.76	10.40
36 Month Delay	10.78	10.99	10.86	12.42

Standard Deviation

	Henry Hub	Chicago	California	New York
Base Case	1.15	1.24	1.15	2.25
12 Month Delay	1.31	1.36	1.36	2.18
36 Month Delay	2.02	2.06	2.08	2.46

Coefficient of Variation

	Henry Hub	Chicago	California	New York
Base Case	14%	15%	14%	23%
12 Month Delay	15%	15%	16%	21%
36 Month Delay	19%	19%	19%	20%

Annualized Return

	Henry Hub	Chicago	California	New York
Base Case	1.98	1.97	2.00	2.78
12 Month Delay	2.03	2.02	2.05	2.77
36 Month Delay	2.10	2.08	2.17	2.53

These model results predict that there will be increased level of volatility aggravating the present climate of uncertainty for energy companies and investors and distrust among consumers, regulators, and legislators. Hedging tools used to control volatility will cost more and, in some cases, be less effective.

Besides reducing overall price levels, long-term contracts supporting new and existing infrastructure can also play a role in reducing adverse impacts of volatility in gas prices. There are two mechanisms by which this occurs.

First, research has shown empirically that gas price volatility is correlated to the level of prices.[25] Simply stated, the overall tightness in the supply and demand balance that creates the conditions that lead to high prices also increases the impact of changes that occur as a result of weather, supply disruptions or economic activity. Small changes in supply or demand create large price movements. This finding is generally confirmed by the modeling results shown in Table 7-7, which are based on normal weather patterns. If the cases had been run with more extreme weather patterns (or any other perturbations in supply or demand), the increases in volatility caused by delayed infrastructure would have been even more dramatic. EEA is now performing work for the Department of Energy to investigate the impacts of the short-term loss of regional pipeline capacity. These results depict clearly the short-term economic dislocations and human needs impacts that can occur in peak conditions in areas of “tight” pipeline capacity.

Adequate investment in infrastructure that is supported by longer-term contracts will ease the tightness of supply and demand and will also reduce volatility. The reduction in volatility reduces the uncertainty that delays investments and, in turn, results in additional supply and increased economic activity. The effect is to reduce further the volatility in the underlying market. Secondly, the longer-term contracts themselves can be used to hedge prices and provide stability in the face of the remaining volatility for the parties entering into the contract. A “physical hedge” would occur if the contract price were fixed or if it varied based on a formula that responded slowly to changes in market prices.

Hedging is not a risk-free activity. While hedging can result in lower gas prices if the market prices are higher than contracted prices, it can also result in costs higher than the market if, for example, the market falls due to factors such as a warmer than normal winter. In any given period, there should expected to be a roughly equal chance that the cost of a hedged gas portfolio will be above the market price as there is that the cost of the hedged portfolio will be below the market price.

A "fully hedged" gas supply portfolio does not guarantee that the gas is acquired at the lowest possible price. In fact, because of the transaction and administrative costs associated with hedging, over the long-term the expected cost of a hedged gas supply portfolio will be slightly above average of the market price for gas over the same period. Nevertheless, hedging, like insurance, can be quite valuable to market participants. A portfolio that includes longer-term contracts can provide an increased degree of price stability and mitigate some of the adverse consequences of price volatility.

In total, longer-term contracts can be quite powerful in terms of reducing volatility and its adverse effects. Moreover, because the infrastructure supported by the longer-term contracts may bring on more supply and can actually reduce the underlying volatility of the market, the cost of hedging gas prices using financial tools such as options and/or swaps can be reduced. With lower volatility, the cost of financial hedges will decline.

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[25] B. Henning, M. Sloan and M. de Leon, Natural Gas and Energy Price Volatility, Oak Ridge National Laboratories, October 2003

8

POLICY OPTIONS FOR ENCOURAGING TIMELY NEW INVESTMENTS

8.1 Overview

Concerns about natural gas infrastructure have existed for some time now and several issues have been addressed in the Energy Policy Act of 2005. The positive steps taken in the Act include:

- Confirming FERC's primary role in LNG terminal siting
- Strengthening "Hackberry Doctrine" for LNG terminals
- Encouraging FERC to authorize market-based rates for new gas storage capacity
- Designating FERC as lead agency for NEPA and the Federal Courts as the venue for NEPA reviews
- Requiring faster CZMA reviews by Department of Commerce
- Providing better access and lower prices for public rights-of-way for gas and electric facilities

In order to reduce further or eliminate the risk that there will be delays in the development of natural gas infrastructure costing consumers billions, five broad areas should be addressed.

First, regulators at the state and federal level **should consider actions that attract capital to pipeline and storage projects**. In particular, Federal and State utility regulators should conduct a review of existing rules and policies that discourage all classes of customers, including power generators, industrials and state regulated local distribution companies, from entering into the long-term capacity contracts for transportation and storage that are necessary to underpin new infrastructure projects. For example, current state regulation often inhibits LDCs from entering into long-term contracts either actively – in the name of increasing the competitiveness of third party marketers – or implicitly through the risk of retroactive prudence review that could disallow gas capacity costs. State regulation should recognize the public benefit of capacity into a market and create a cost recovery mechanism that promotes the construction of sufficient infrastructure to allow for incremental supplies of gas to be delivered during peak demand periods.

Second, federal and state regulators should **consider electricity resource planning that reflects the reliability benefits of firm pipeline and storage capacity to gas-fired generation** as well as the reliability benefits of alternative fuel capability. Specifically, regulators should consider policies that differentiate between a gas-fired generator with firm pipeline and storage capacity under contract and those that do not. Regulation should consider recovery mechanisms and market structures that create tangible advantages for generators that hold capacity contracts.

Third, the gas industry should work with state and local officials including state economic development offices to ensure that all of the societal, employment, and **consumer cost benefits** of a pipeline, storage, or LNG terminal project are presented during the process of evaluating a proposed project. As part of this, public education and outreach efforts should include information regarding details of the construction process, the ultimate (post construction) impacts on the environment and safety as well as the ongoing direct and indirect benefits of construction.

Fourth, federal and state regulators should **conduct regional analyses to identify the market needs of multi-state regions**. While FERC currently conducts such reviews, the impact of these analyses could be enhanced by a process that develops additional ownership or buy-in of the conclusions within state and local governments. However, these regional studies should not be used to implement a "centralized planning" approach to facilities selection. Rather, market participants must be allowed to design, propose and competitively market projects in response to the specific needs of the market.

These regional studies can provide two types of benefits. First, the studies can provide all market participants with the best available information. Second, the studies can help regulators evaluate market fundamentals behind contracts entered into by power generators and others. The regional analyses should explicitly evaluate and consider the impact on consumers and economic development of a decision to prohibit or delay infrastructure development. Further, Federal, State, and local permitting proceedings must reflect the consequences of a refusal to allow construction on the local general population and on citizens in surrounding jurisdictions. They should identify the forecasted need of the different market segments and the holders of firm capacity.

Fifth, homeland security and safety concerns, particularly regarding LNG, must be met with a **balanced and informed evaluation of risk**. There are many elements of modern life that present manageable risk but almost none that can be described as risk-free. All appropriate actions to ensure safety and security should be required. Still, to the extent that any residual risk cannot be eliminated, that risk should be evaluated in terms of the overall cost to citizens and economic insecurity that would result from a failure to build natural gas infrastructure that is required to meet growing energy demand.

8.2 Policy Options for Consideration Related to Contract Term

The following presents a broad range of policy options that should be examined if it is determined that current contracting practices are inhibiting the development of natural gas supplies and delivery infrastructure. The discussion is designed to foster a discussion of a wide range of policies that could impact the average term of gas commodity contracts and/or contracts for gas infrastructure including pipeline and storage capacity. Inclusion of a policy option does not imply an endorsement by EEA, the INGAA Foundation, or any members of the INGAA Foundation. Rather, it is intended to initiate a dialog amongst all stakeholders in the consideration of appropriate policies.

The policy options are divided into three areas based upon the subject area and implementing authority or authorities. To be effective and so as to minimize adverse unintended consequences, the options should be evaluated in terms of all relevant costs and benefits.

8.2.1 Regulation of Power Generation Markets

As discussed previously, increasing natural gas use for power generation has increased – and will continue to increase – the need for natural gas supplies and natural gas pipeline and storage infrastructure. Still, long-term contracts for the commodity and for pipeline and storage capacity entered by the power generation sector have yet to match the increase in gas consumption by that sector. For example, as shown in the Table 8-1, the percent of interstate pipeline capacity held by power generators (including short-haul pipeline to the power plants) has recently been about 15 percent, while power use of gas is about 25 percent of the market and is expected to grow to nearly 40 percent.

The electricity industry places great emphasis on reliability. Moreover, the recently signed 2005 U.S. Energy Policy Act will give new tools to the industry with regard to reliability standards and regional coordination. As part of this emphasis, the impact of fuel acquisition and gas capacity and commodity contracting practices should also be considered.

Currently, there has been the lack of any significant impetus for generators to “firm up” gas supply and infrastructure contracts from the regulated structure of the electricity markets themselves. While elements of these issues have been discussed in a few states such as California, other regions have yet to address these issues in a meaningful fashion.

In many markets, for example, installed capacity payments[26] made to power generators do not differentiate between a generator with firm pipeline capacity and gas under

[26] Examples of payments for installed capacity include the New York ISO’s Installed Capacity Market (ICAP) and PJM’s Capacity Credit Market.

contract from a generator that relies in whole or in part upon IT, capacity release, and spot market gas purchases.

Figure 8-1
Pipeline Capacity Held *versus* Gas Consumption

	Percent of Pipeline Capacity Held		Approx. Share of Enduse Consumption	
	1998	**2002**	**2005**	**2020**
LDC	46%	42%	39%	33%
Power	12%	15%	25%	39%
Industrial	4%	3%	36%	27%
Marketer	13%	24%		
Producer	9%	10%		
Pipeline	9%	5%		
Other	7%	1%		
Total	**100%**	**100%**	**100%**	**100%**

Sources: NPC, Balancing Natural Gas Policy, Volume V, page T-15
EEA July Base Case

As discussed previously, a rational generator may well conclude that during periods of peak electricity demand, the marginal generation cost will be high enough to recover their gas cost at any price. While this is true in most instances, an inadvertent result is to increase the volatility and instability in regional gas markets.

Perhaps even more important, the relative absence of the participation of the power generators in the longer-term contracts for infrastructure and gas supply has the effect of reducing the total deliverability of gas available and increasing the cost of gas as well as the cost of electricity generated with gas.

As a result, policy makers, regulators and all stakeholders should discuss the implications of the structure of power generation markets and reliability regulations. RTOs, ISOs, and individual state regulators should consider the impact of existing electricity market regulation on the fuel acquisition contracting practices of generators.

8.2.2 Federal and State Regulatory Policy for Utilities, Pipelines, and Power Markets

The framework for the regulation of gas utilities, gas pipelines and power markets as implemented by FERC and state approached public utility commissions has a strong influence on the term of industry contracts. This influence arises from both the broad regulatory structure and specific elements of rate regulation.

8.2.2.1 Market Structure and Regulatory Approach

Pre-approval of LDC Contracting Practices for Cost Recovery

Over the past few years, a number of gas LDCs have approached public utility commissions requesting that the commissions approve certain parameters of their contracting practices with a particular focus on hedging activities. The utilities have sought approval with the following objectives:

- To limit the risk of disallowance of the costs of the contracting and/or hedging activity;
- To determine the applicable accounting methods to be applied including accounting for financial derivatives, and;
- To limit the risk of "second guessing" by regulators if market prices turn out to be below the "locked-in" gas price of the hedged portfolio.

Intervening parties argued that a commission should not pre-approve any plan unless and until it can be demonstrated that the program provides consumer benefits.[27] In

[27] For example, earlier this year in Maine a Hearing Examiner rejected a hedging plan proposal by Northern Utilities. The proposal called for the approval of a hedging plan that would include futures contracts as a means of reducing the volatility of the price of natural gas. The proposal also requested that any transaction costs incurred in the purchase of futures contracts, as well as any cost of administering the program, be fully passed on to the utility's customers. In her report, the Hearing Examiner argued that the proposal "amounts to pre-approval of the added costs of a hedging plan that may not provide any benefits for ratepayers and does not contain performance incentives for the utility." The state's public advocate argued that weak incentives would result in the utility passively managing the hedging program, contending that "[c]ontinuous oversight and management of a

addition, parties have argued that a utility hedging program would reduce the ability of unregulated marketers to compete with the utility.[28]

Throughout their history, state commissions have been reluctant to restrict themselves or future commissions from taking actions that may be deemed appropriate in the future. Intervenors argue it is inappropriate for a commission to commit itself fully up-front to a utility's actions given that market conditions may evolve in a manner rendering the pre-approved plan imprudent.[29]

To the extent that longer-term contracts create an increased likelihood that the performance of a portfolio will diverge from short-term market conditions, the lack of certainty creates an incentive for LDCs to "shorten up" the portfolio of contracts. Pre-approval of the contract portfolio could directly address this uncertainty.

An alternative, although likely less powerful stimulant to longer-term contracts, would involve establishing clear guidelines that would reduce uncertainty for a gas utility. Guidelines that convey a strong presumption for cost recovery so long as the implementation of the guidelines is performed in a prudent manner can reduce the risk of longer-term contracts. However, the influence of guidelines on contract term would be minimal unless the commission clearly articulates the general position on long-term contracting. Moreover, the guidelines should explicitly address the issue of cost-recovery criteria articulating what constitutes reasonable actions by a gas utility, and the scope of a hindsight review. Finally, in evaluating a gas procurement/supply strategy

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hedging plan is necessary and will be fostered only when the Company shares in both the costs and benefits." The public advocate also argued that the program does not require pre-approval from the Commission, and that consumers may not be willing to pay the cost that would be required of them for having price stability

28 In a Massachusetts proceeding, marketers and the state's Attorney General criticized Bay State Gas' proposed hedging plan. They argued that the proposal would weaken competition and has the potential to harm customers as well by raising gas costs. The Attorney General asserted that the Commission should allow the competitive market to provide gas sales services with capped prices or any other pricing variations, created with or without hedging.

29 In a separate Commission investigation in Massachusetts, the Attorney General strongly recommended against allowing LDCs to hedge with financial derivatives. Among other things, the Attorney General argued that hedging with financial derivatives has not been shown to provide net benefits to consumers and that hedging can produce "huge" losses.

that contains long-term contracting, a commission should consider the risk on a utility and its bundled-sales-service customers.

In a related area, a commission and its LDCs could re-examine regulations that establish capacity contracting for design day and contingency events. To the extent that a commission determines that it is in the public interest to create additional capacity, the LDC would look to enter into additional contracts. However, contracting for additional capacity may result in contracting for capacity that goes unneeded for years until load growth or a contingency event occurs. Not only does this add directly to the costs of an LDC, but it also reduces the market value of the entire portfolio of transportation and storage assets held but the LDC.[30]

8.2.2.2 Customer Choice Programs

Over the past decade, a number of states have examined their state customer choice programs in an attempt to foster additional participation. In a number of instances, changes have been proposed to make migration easier for consumers while allowing customers to return to utility service and create a "provider of last resort" to assure service in the event of a default by an unregulated marketer or other market event.

The possibility of migration of a significant portion of their peak load customer base attaches risk to holding longer-term commodity and/or capacity contracts for an LDC. In particular, regulatory policies designed to assure sufficient pipeline capacity to meet the requirements of all customers regardless of the merchant provider can create additional risks for an LDC.

The lack of predictability of future pipeline capacity requirements – beyond that inherent in the market – creates an additional incentive to "shorten up" the contract portfolio. Without viable cost recovery mechanisms and improved predictability, LDCs in states with customer choice programs will continue to view longer-term contracts as a source of additional risk.

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[30] If the capacity relieves pressure on "bottlenecks" and constraints, the value of the service in short-term market is reduced.

Re-examining policies regarding the rules for customer migration to an unregulated supplier, as well as rules about when a customer may return to the utility, is one opportunity to increase the desirability of long-term contracts for an LDC. Increasing the predictability of LDC load by examining customer migration policies, and possibly increasing the "rigidity" of customer choice programs, would decrease the risk of long-term contracts the LDC. More restrictive opportunities for migration could also be viewed as a barrier to competition, however.

Similarly, re-examining regulations regarding capacity assignment by the LDC to unregulated suppliers might be helpful in reducing risks to LDC, holding long-term contracts.

8.2.3 Regulated Rates

Policy Options That Could Reduce the Differentials between Rates Charged for Short Term and Longer-term Capacity Contracts

As discussed previously, current FERC rate design policy is based upon the tenets described in the Rate Design Policy Statement that: "[r]ates for service during peak periods should ration capacity and that [r]ates for firm service during off-peak periods and for interruptible service during all periods should maximize throughput." Much of the focus in implementing these tenets has been on increasing the utilization of the pipeline during the "off-peak" period within the annual cycle of high winter demand and lower summer requirements.

One of the results of the implementation of these tenets is that the difference between the rates charged for un-discounted firm transportation contracts and discounted interruptible transportation or capacity release can become quite large, especially when load factors on the pipeline are less than 100 percent. At times of less than 100 percent load factors, the cost of IT and capacity release can often approach the variable commodity cost of transportation plus fuel. At such times, there is a strong incentive for a shipper to acquire capacity as IT, capacity release, or short-term FT in order to capture the discount that is commanded by the market at that time.

In these instances, the pipeline is looking to future load growth to improve load factors and reduce the size of the discount needed to sell the capacity. As a result, the pipeline will only accept a longer-term contract that is above the current market value of the capacity.

Conversely, in instances where market constraints increase the value of transportation capacity, existing policies constrain the maximum price of unbundled transportation service, e.g., IT service and capacity release are capped at the 100 percent load factor equivalent of the FT rate. Even though shippers may be limited in their ability to capture the increased value through bundled sales[31] transaction, the price signals are lost in the direct market for unbundled transportation.

Maximum Allowable Rates for IT and Capacity Release

FERC, State regulators and other stakeholders should consider supporting policy changes that increase the maximum allowable rate for IT and capacity release. Such changes could increase the relative desirability of longer-term firm contracts vis-a-vi these short-term services. For example, maximum IT rates could be based upon a load factor that is less than 100 percent. The use of an 80 percent load factor, for example, would increase the maximum by 25 percent making a decision to enter into firm service contracts more desirable.

Similarly, FERC, State Regulators and other stakeholders should consider supporting the removal of the price cap on capacity release in order to increase the value of firm contracts to shippers. Maximizing the value of a firm contract to regulated and unregulated shippers would support the demand for firm service and increase the level of firm contracting using market forces rather than direct regulatory mandates.

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[31] Even here, the application of affiliate codes of conduct can dissuade some LDCs from participating in off-system sales.

Term Differentiated Rates

Another policy that has been discussed focuses on the economic tenets, not within the annual cycle, but over periods of several years. Term differentiated rates that reduce the costs of longer-term contracts over contracts of a few years are permitted under existing FERC policy. However, risks and volatility in short-term markets have apparently overwhelmed the potential for such rates to increase the attractiveness of longer-term contracts the risks and volatility in short-term markets. As a result, the opportunity for term differentiated rates has not generated significant transactions under current market conditions.

Expanded Use of Rolled-In Rates for Expansions

Finally, the existing policy that establishes a presumption for incremental pricing for capacity expansions that would increase the rates to existing customers by more than five percent affects the term of contracts and the attractiveness of new pipeline construction. As it has been implemented, the policy has created an imbedded cost disadvantage for shippers that contract for new and expanded capacity compared to shippers that have held capacity for many years. While the shippers contracting for the capacity initially on the expansion of new pipeline may have to contract for ten years or more to get the pipeline built, at the first opportunity to renegotiate or renew the capacity, there is a strong incentive to re-contract for as short a period as possible.

8.2.4 Direct Government Participation

Loan Guarantees

The Federal Government will offer a loan guarantee of up to $18 billion for an Alaskan gas pipeline and the DOE is now in the process of drawing up provisions for loan guarantee agreements. This process should proceed in a way that provides some latitude for project design and guarantee amount because the full scope of the needed infrastructure from Alberta to U.S. markets may not be known for some time due to the uncertainty regarding future levels of WCSB production.

Tax Treatment

Sometime governments can help spur infrastructure by providing tax certainty or by offering incentives. Certainty can be important for royalties on state lands and *ad valorum* taxes related to large gas supply projects. Incentives for new infrastructure can be in form of low fixed rates or a guarantee of maximum future rates for property taxes.

Holding Capacity

Governments may be able to accelerate infrastructure by contracting for capacity. This could include capacity for marketing of State-owned royalty gas or for “public benefit capacity” that can provide spare capacity for unusual circumstances.

Government Asset Ownership

In some instances it may make sense to consider government equity ownership in gas infrastructure. This is the idea behind the Alaska Gasline Port Authority and proposals by the state of Wyoming to finance gas pipelines from that State. Also, the State of Alaska is considering taking an equity position in a privately-owned pipeline project. Equity ownership seems most appropriate when there is substantial economic benefits from a project (construction jobs, operating jobs, production royalties, improved natural gas service) and the project would otherwise not be built or would be substantially delayed.

8.2.5 Private/Institutional Finance

U.S. government (Export-Import Bank, OPIC) and multinational agencies (MIGA) should continue to support LNG projects through loans and load guarantees and should review their processes to insure that projects proceed as quickly as possible.

9
CONCLUSIONS

The primary conclusions of this paper can be summarized with the following eight points.

1) The reduced roles of long-term commodity purchase and transportation contracts signed by large natural gas consumers and local distribution companies were the result of both a changing market environment and policies. Power producers' and LDCs' **current aversion to long-term contracts reflect rational reactions** to existing polices and will require changes to those policies if the aversion is to be overcome.

2) U.S. and Canadian markets will need a large amount of new infrastructure investment to meet future natural gas demands. Over the next 15 years, **gas pipeline, storage field and LNG terminal investments should reach almost $60 billion** (2004 dollars). Approximately $16.4 billion of investment will be needed for replacement of current pipe simply to maintain existing pipeline capacity. Nearly $29 billion will be needed for new pipeline, $19 billion of which will be associated with the Alaskan and MacKenzie Delta projects to access need supplies of Arctic gas. Storage projects will cost $5.5 billion and new and expanded LNG receipt terminals capacity in the U.S. and Canada will cost $9.4 billion.

3) By 2020, U.S. and Canadian **LNG imports could be over 7,000 Bcf per year**, more than a ten-fold increase from 2004. The investment cost of the incremental LNG volumes needed by 2020 are more than $100 billion (2004 dollars) including regasification terminals and ships plus all liquefaction plant, transportation, processing and production investments in the exporting country

4) **Long-term contracts are an important way of managing risks to all participants in new and existing gas supply, transportation and storage facilities**. Long-term contracts can help reduce project risks and make infrastructure easier to finance and build. The effect depends on the circumstances of the individual project and the overall state of energy and capital markets.

5) Adequate infrastructure facilitated by long-term contacts can have three types of benefits to gas consumers:

- lower average market **price levels** brought on by higher gas supply volume and more assured supplies,
- reduced overall market **price volatility** caused by additional supply volumes and diversity, and
- more **stable prices for the contracted volumes** through pricing mechanisms providing "physical hedges".

6) Delays in needed natural gas infrastructure projects would cost U.S. consumers billions of dollars each year. Using the Henry Hub price as a measure of the impact on gas prices, a 12-month delay in pipeline and LNG import terminal construction will increase U.S. natural gas prices by an average of $0.67 per MMBtu in constant 2004 dollars from 2006 – 2020. A longer, 36-month delay in pipeline and LNG import terminal construction will increase U.S. natural gas prices by an average of $2.35 per MMBtu in constant 2004 dollars from 2006 – 2020. **In total, a 12 to 36 month delay in natural gas infrastructure construction will cost U.S. gas consumers from $179 to $653 billion (in constant 2004 dollars) by 2020.** Higher gas costs will be seen in all parts of the country.

7) In general, **price volatility increased along with price levels in the alternative scenarios with a delay in infrastructure construction**. For example, for Henry Hub, Chicago and California, the standard deviation in prices went from $1.15 to $1.24 in the Base Case to $2.02 to $2.08 in the 36-month delay scenario .

8) **Policy makers should be aware of the importance of current regulatory policies on the desirability of long-term contracts** and fostering timely project

development. Policy should facilitate contracts when appropriate and as a result increase the development of infrastructure The policy areas to consider include:

- Through market design and reliability standards, creating incentives and cost recovery mechanisms for power generators to enter into long-term gas supply, transportation and storage contracts.
- Reducing the "asymmetric risk" faced by LDC's in long-term contracting through regulatory policies.
- Using pricing policies to make long-term firm pipeline contracts more attractive relative to shorter-term alternatives.
- Continuing government programs and incentives designed to reduce risks to LNG and other infrastructure projects.