Task Force on

Ensuring Stable Natural Gas Markets

Draft Final Report

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Executive Summary

Natural gas is one of America's most important energy resources. Comparatively clean-burning and less carbon-intensive than oil or coal, it is used as a fuel in a wide variety of applications throughout the economy and as a chemical feedstock in the industrial sector. Until recently, however, U.S. supplies of natural gas were also perceived as relatively limited. This meant that the potential to advance long-term environmental or energy security goals through expanded reliance on domestic natural gas would necessarily be constrained. It also implied that natural gas markets would continue to be susceptible to the sharp price run-ups and extreme volatility that had captured news headlines in the mid-1990s and again in the early- and mid-2000s.

This picture of natural gas as an attractive but limited domestic resource has changed dramatically in just a few short years, along with the assumptions that go with it. Technological advancement in horizontal drilling and hydraulic fracturing has unlocked a tremendous volume of additional gas resources in North American shale gas formations. These developments have altered the supply outlook for natural gas such that identified domestic reserves are now thought to be sufficient—barring environmental or other impediments to tapping these reserves—to support more than 100 years of demand at present levels of consumption.

With these developments in gas supply, the market for natural gas has shifted in a profound way. Expectations for future prices, as shown in Figure 1, have declined dramatically as the full extent of the impact of new technology for identifying and developing natural gas supplies has been recognized.

In combination with recent investments to expand capacity for storing and importing natural gas, the developments in gas supply should allow the U.S. market to respond more smoothly to future demand fluctuations and should substantially alleviate long-standing supply adequacy concerns. Given the availability of highly efficient conversion and end-use technologies for natural gas, this is good news from multiple perspectives—whether the objective is to reduce pollutant emissions, reduce U.S. dependence on imported energy sources, or maintain a competitive industrial base.

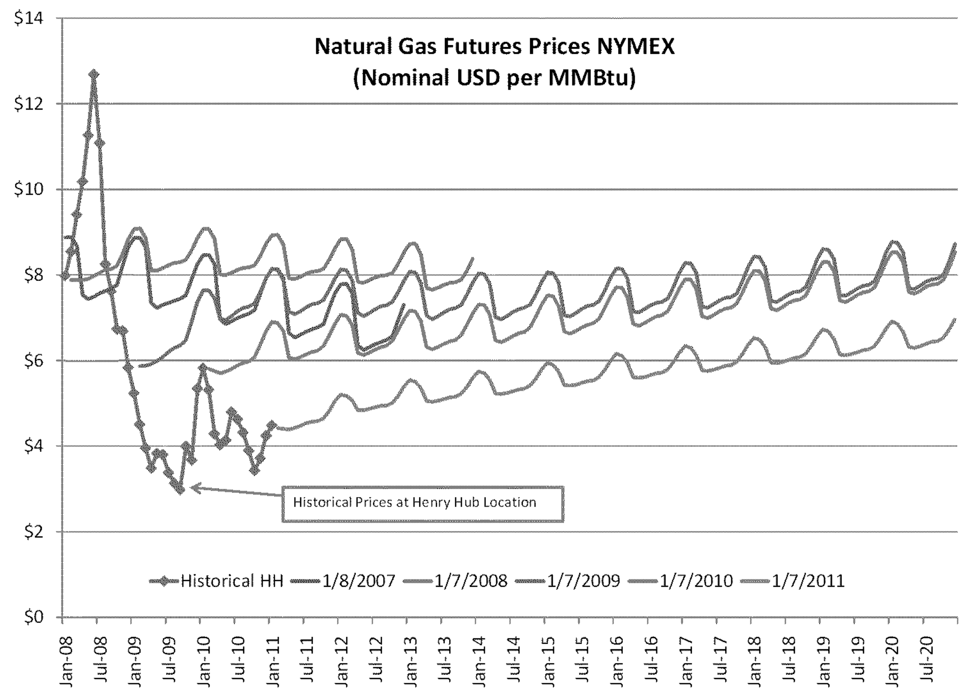

Figure 1 - Natural Gas Futures Prices

Realizing and maximizing these benefits, however, will require that investors have confidence in the mid- to long-term stability of natural gas prices. On the demand side, consumers, electricity generators, and large industrial users will need confidence that gas prices will be sufficiently competitive and stable to make investments in new gas-using technologies cost-effective. On the supply side, the natural gas industry needs confidence that market demand and prices will justify new investments in expanded production capacity. Both sides would benefit from avoiding the price variability that has characterized natural gas markets in the past, when spikes hurt consumers and created difficulties for gas-dependent industries.

The Task Force on Ensuring Stable Natural Gas Markets

The Bipartisan Policy Center's Task Force on Ensuring Stable Natural Gas Markets (hereafter

"Task Force") was convened in May 2010 to examine historic causes of instability in natural gas markets and to explore potential remedies. The membership of the Task Force was unique in its diversity and unique in the sense that it brought together key stakeholders from both sides of the supply–demand equation. Individual Task Force members are listed in Appendix A; they represent natural gas producers and suppliers, consumer groups and large industrial users, as well as independent experts, state regulatory commissions, and environmental groups.

Over the course of three meetings and with the help of original commissioned research on several related topics, the Task Force examined the causes of past variability in natural gas markets and the implications of recent shale gas discoveries and other, infrastructure-related developments in terms of the likelihood that similar price shocks would recur going forward.[1] The Task Force also developed a comprehensive set of recommendations aimed at bolstering investor confidence in the stability of future gas markets and at improving the tools available for effective price risk management. Together with a vastly improved supply outlook, we believe that a small number of practical regulatory and policy measures would go a long way toward providing the confidence needed to support a significant expansion in the deployment of efficient natural gas technologies and toward capturing the economic and environmental benefits such an expansion would provide. As summarized in one of the studies commissioned for the project: "Commitment to long-term use of natural gas is also potentially one of the most effective ways to create hundreds of thousands of sorely needed, skilled and well-paying jobs. This could help to reignite confidence in the U.S. economy – especially because it utilizes a huge new domestic energy resource that has been unlocked by American entrepreneurial drive and intense focus on process innovations (many of which stem from the skilled application of very sophisticated technology)[2]."

Key Task Force Findings and Recommendations

1. Recent developments allowing for the economic extraction of natural gas from shale

[1] For a list of commissioned research papers see Appendix C.
[2] "*New Approaches to Reducing Natural Gas Price Instability*", Andrew Weissman, prepared for the Task Force Ensuring Stable Natural Gas Markets, July 2010.

formations significantly reduce the susceptibility of gas markets to price instability and provide an opportunity to expand the efficient use of natural gas in the United States

2. Government policy at the federal, state and municipal level should encourage and facilitate the development of domestic natural gas resources, subject to appropriate environmental safeguards. Balanced fiscal and regulatory policies will enable an increased supply of natural gas to be brought to market at more stable prices. Conversely, policies that discourage the development of domestic natural gas resources will reduce the supply that can be brought to market, which will have an adverse effect on the stability of natural gas prices.

3. The efficient use of natural gas has the potential to reduce harmful air emissions, improve energy security, and increase operating rates and levels of capital investment in energy-intensive industries.

4. Public and private policy makers should remove barriers to assembling a diverse portfolio of natural gas contracting structures and hedging options. Long-term contracts and hedging programs are valuable tools to manage natural gas price risk. Policies, including tax policy and accounting rules, which unnecessarily restrict the use or raise the costs of these risk management tools, should be avoided.

5. The National Association of Regulatory Utility Commissioners (NARUC) should consider the merits of diversified natural gas portfolios, including hedging and longer-term natural gas contracts, building on its 2005 resolution. Specifically, NARUC should examine:

> a) Whether the current focus on shorter term contracts, first-of-the-month pricing provisions, and spot market prices conflicts with the goal of enhancing price stability for end users,
>
> b) The pros and cons of long-term contracts for regulators, regulated utilities and their customers,
>
> c) The regulatory risk issues associated with long-term contracts and the issues of utility commission pre-approval of long-term contracts and the look-back risk for regulated entities, and
>
> d) State practices that limit or encourage long-term contracting.

6. As the Commodity Futures Trading Commission (CFTC) implements financial reform legislation, and specifically, Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (Pub. L. 111-203), the CFTC should preserve the ability of natural gas end users to cost-effectively utilize the derivatives markets to manage their commercial risk exposure. In addition, the CFTC should consider the potential impact of any new rulemaking on liquidity in the natural gas derivatives market, as reduced liquidity could have an adverse affect on natural gas price stability.

5. Policy makers should recognize the important role of natural gas pipeline and existing import and storage infrastructure in promoting stable gas prices. The policies that have underpinned the development of a robust gas transmission and storage infrastructure including streamlined regulatory approval and options for market based rates for storage in the United States should be continued.

9. Finally, regulators should be mindful of the lead time required for markets and market participants to adjust to new policies.

Background and Context for the Task Force Recommendations

The full Task Force report describes in detail the evolution of the U.S. natural gas market over the last half century and the specific causes behind more recent episodes of price variability in this market. Several points from that discussion are worth highlighting as part of this summary because they provide the context and rationale for Task Force findings and recommendations:

- Natural gas plays a uniquely important role in the U.S. economy, both because it is a major contributor to the nation's overall energy portfolio (second only to petroleum in terms of total primary energy consumption) and because it is used across multiple sectors of the economy and in a wide variety of applications.

- U.S. natural gas markets have only been open and competitive for about 17 years. Starting in the 1950s and until the early 1990s, concerns about domestic supply adequacy and a desire to direct limited gas resources to particular uses led to extensive regulation and government intervention. This approach resulted in mostly stable prices but also led to severe supply shortages and significant market distortions.

- After deregulation in the early 1990s, a combination of declining production capacity and increasing demand led to a tightening supply/demand balance. Prices spiked sharply in 2000 and again in 2005 in the wake of Hurricanes Katrina and Rita. Though prices fell again after both these spikes, they did not return to the levels that had been typical of earlier decades; in fact, prices remained high relative to historic norms until the economic downturn of 2008 and the rapid growth in gas production from shale and other "unconventional" gas resources.

- Large gas-dependent industrial users, especially if they compete with producers from countries with access to low-cost gas, are likely to be especially hard-hit by major price run-ups in the U.S. market. Small users tend to be at least somewhat insulated from wholesale prices because they generally purchase natural gas from regulated distribution companies. In the electric power sector, companies interested in adding or replacing generation capacity must weigh uncertainty about future fuel prices in making technology and resource investments.

- Because U.S. capacity to import natural gas from overseas suppliers has historically been very limited, the market for this commodity is primarily national (rather than global, as in the case of petroleum). This means that prices are tightly coupled to domestic and North American supply and domestic demand. In the early 2000s, an expectation that domestic demand would soon begin to outstrip domestic production capacity led to higher prices and prompted new investments in the physical infrastructure needed to import and store natural gas. As a result, the United States now has more terminals for receiving liquefied natural gas (LNG) shipments and more facilities for storing gas (in depleted reservoirs, aquifers, and salt caverns) than at any time in the past. Together with a robust pipeline network, these changes in import and storage capacity by themselves would have been expected to go some way toward mitigating the market volatility and upward price pressures that emerged in the last decade.

- The years between 2005 and 2010, however, saw an even more dramatic change in the domestic supply picture for natural gas as it became clear that recoverable U.S. reserves of shale gas are far more extensive and broadly distributed than previously thought.

- The technologies used to extract shale gas, including horizontal drilling and sequenced, multi-stage hydraulic fracturing, were pioneered in the late 1980s. Since then the shale gas industry has matured and the technologies involved have become more sophisticated and cost-effective. ICF recently estimated that almost 1,500 trillion cubic feet (Tcf) of shale gas can be produced at prices below $8 per million Btu (MMBtu). By comparison, annual U.S. consumption of natural gas currently totals approximately 22 Tcf.

- Ample domestic supply will likely be the single most important factor in promoting moderate and stable natural gas prices over the next several decades. This result, however, is predicated on the successful management of environmental concerns associated with current methods of shale gas production and on the willingness of local communities to accept this type of development, even in areas with little prior exposure to energy activities.

- The most important environmental issues related to shale gas production include the potential for water contamination; water consumption for fracturing operations, particularly in areas where water resources are already stressed; and general emissions and disruption associated with the use of heavy equipment and related infrastructure (e.g., roads, drill pads, and gathering lines). If environmental and other local impacts are not properly managed and remediated, an increasing number of communities could begin to oppose shale gas production activities. To address these impacts, several states are currently developing regulations for shale gas extraction; in New York, meanwhile, the state assembly voted in August 2010 to impose a moratorium on hydraulic fracturing until state regulatory authorities could conduct a thorough review of associated environmental risks and of the adequacy of current environmental protections and safeguards.

- Contracts and hedging mechanisms are important tools for managing risk in commodities markets, including the natural gas market. In recent years, a number of stakeholders and observers have called for a return to greater reliance on long-term contracts between gas suppliers and purchasers to help address price risks and promote price stability. Such contracts can play a useful role as part of a diversified portfolio, although it is also important to recognize that few long-term contracts (even when such contracts were more common) are or have been truly “fixed price” in the sense that both parties are locked into a single specified price regardless of other market or regulatory developments. In sum, more sophisticated forms of long-term contracts and other options (such as direct acquisition of gas reserves or long-term pre-purchase arrangements) are available that can offer an element of price stability while also minimizing downside risks to the parties involved.

- Hedging, by contrast, is a strategy that is better suited to managing short-term price risks. It is generally implemented through the use of financial instruments known as derivatives. Properly applied, financial derivatives can provide an efficient mechanism for transferring risk, though they can also be used for speculative purposes that generally have the effect of increasing (rather than reducing) price volatility. A concern has been raised that new restrictions on derivatives trading under the recently passed Dodd–Frank financial reform legislation could have the unintended consequence of reducing liquidity in natural gas and other commodities markets, with potentially adverse impacts on price stability in those markets.

Conclusion

Recent assessments of the extent of the North American natural gas resource base suggest that the United States is well positioned to take advantage of natural gas as a low-emitting, domestic fuel that can be used throughout the economy in a variety of efficient and cost-effective applications. Realizing this potential could provide significant economic, environmental, and energy security benefits but requires that investors have confidence in the ability to develop and deploy natural gas resources at moderate and reasonably stable prices. The Task Force believes that a set of relatively modest but well-designed and forward-looking policy interventions could go a long way—in combination with continued efforts to better characterize the domestic gas resource base; address environmental concerns; develop improved extraction technologies; and expand critical pipeline, import, and storage capabilities—to build that confidence. At a time when political and economic conditions have paralyzed much of the national-level energy policy debate, the fact that a group as diverse as the Task Force could reach consensus on these measures would seem to suggest that here is at least one important area where progress is well within reach. Given how much could be at stake in ensuring stable U.S. natural gas markets over the next several decades, the opportunity is one that should not be missed.

I. Introduction

A. Overview

It is now widely recognized that the United States has extraordinarily large reserves of natural gas, which is a comparatively clean burning energy resource that can be efficiently used for heat and power generation in many contexts. Gas is also an important chemical feedstock. Yet, despite these attractive characteristics, until recently gas has been perceived as a limited energy source that cannot meet all of the domestic demands. This has led to policy debates over how and where the "limited" supply is best applied. In addition, occasional periods of high prices, especially over the last ten years, have raised concerns over the economic risk associated with investments and policies based on expanded use of natural gas.

Starting in 2005, however, the demonstration of technology to cost-effectively recover gas from the substantial North American shale gas reserves began to dramatically increase the economically recoverable supply of natural gas. Indeed, current estimates suggest that identified U.S. gas reserves alone could support more than 100 years of demand at present levels of consumption, assuming success in addressing environmental challenges. This is good news from multiple perspectives, since confidence in the long-term adequacy of natural gas supplies could greatly improve prospects for advancing broadly held environmental and economic goals. The efficient use of natural gas can provide a low-carbon, low-cost alternative to other fossil fuels in the electric power and industrial sectors—while also playing a critical role in rebuilding a vigorous, globally competitive manufacturing base here in the United States. Still, as noted earlier, to make the most of this potential it is necessary to address concerns about long-term supply adequacy and price stability that have been an impediment to wider use of gas in the past.

Price stability is particularly important for several sectors that purchase gas, such as for industrial production, as a chemical feedstock, and for electric power production. Frequent, large price spikes can discourage investment in new gas-based infrastructure (new manufacturing or power facilities) and/or cause disruption in gas-reliant industries that have international competitors who are not subject to similar price variability. Local natural gas distribution companies (LDCs) that provide gas to residential, commercial and small industrial gas users are also interested in better ways to provide price stability to their customers.

In sum, the prospect of a steady increase in domestic natural gas resources (see e.g., Figure 8 below), the possibility of increased gas use is plainly attractive provided historic concerns on price stability can be resolved. Thus, this Task Force was largely focused on understanding past sources of mid- to long-term gas price variability, both to promote a more complete and up-to-date understanding of the history and future outlook for U.S. natural gas markets, and to provide a basis for suggesting policies and measures that would reduce price variability and market instability going forward.

B. Structure of Task Force and Work Plan

The Task Force was jointly convened by the Bipartisan Policy Center[3] and the American Clean Skies Foundation[4] in March 2010. The aim of the Task Force was to examine historic causes of instability in natural gas markets and to explore potential remedies. Its membership—which includes natural gas producers and suppliers as well as gas consumers, independent experts, state regulatory commissions, and environmental interests—was carefully selected to allow for a full airing of the issues from multiple perspectives (See Appendix B for a listing of participants).

During 2010, the Task Force held three day-long workshops to review [ten] commissioned papers and policy briefs. See Appendix C. The Task Force also held five working meetings in 2010 and 2011. As a result of this year-long effort, the Task Force adopted a set of findings and recommendations for better managing price variability in the future. Throughout, the Task Force has focused on practical measures that would promote the mid- to long-term price stability needed to support the requisite capital investments going forward—both in new gas production capacity and in efficient new gas-using infrastructure.

C. Report roadmap

[3] *Flagged* – Add sentence on BPC and role.
[4] *Flagged*—Add sentence on ACSF.

The body of this report is organized as follows: Section II of this report provides background on the role and uses of natural gas in the U.S. economy as a context for the practical and political considerations behind the interest in gas use and pricing. Section III discusses approaches to improving mid to long-term gas price stability. Section IV offers conclusions and recommendations and identifies next steps.

II. Background on Natural Gas Markets, Use and Supply

A. Uses and Markets

To understand the past and future pricing of natural gas, it is important to understand the role of gas in the economy, how it is bought and sold, by whom, and what affects these markets. Figure 1 shows that natural gas is the second largest primary source of energy in the United States, behind petroleum and slightly ahead of coal.

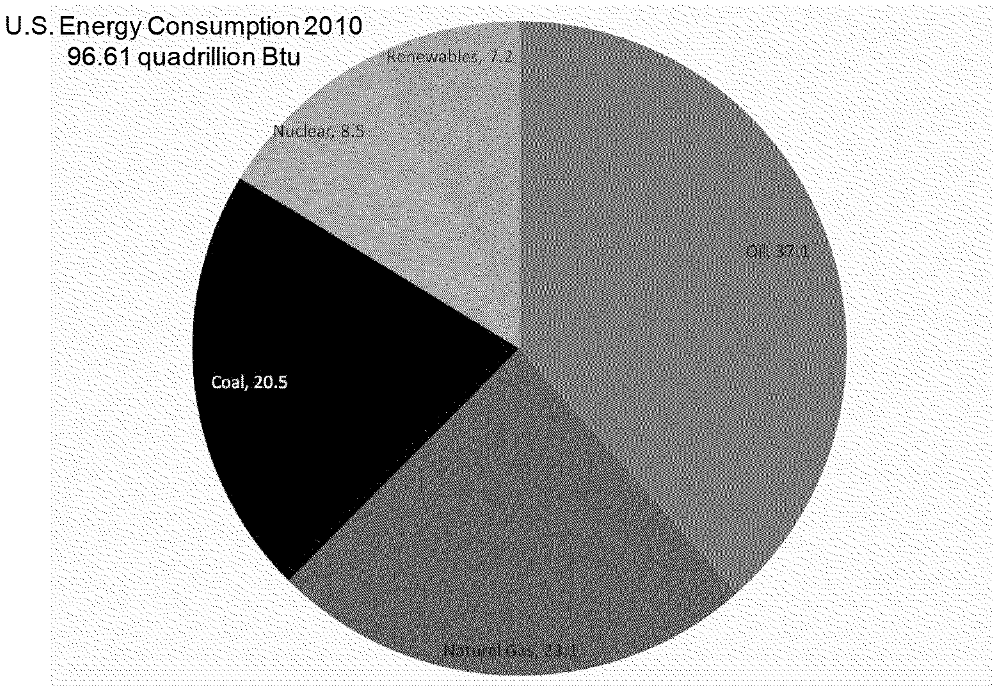

Figure 2 - U.S. Energy Mix - 2010

Moreover, natural gas is unique among the energy sources shown in Figure 1 in that it plays a major role in multiple, diverse sectors of the economy. Figure 2 shows that coal is almost exclusively used in the power sector, petroleum is primarily used for transportation and only secondarily as an energy source and petrochemical feedstock in the industrial sector, and hydro and nuclear power are used solely for electricity generation. Natural gas, by contrast, is used as a fuel in the residential, commercial, power, and industrial sectors, and as a chemical feedstock. This diversity of end uses means that the behavior of natural gas markets has a direct and significant impact on many sectors of the broader economy.

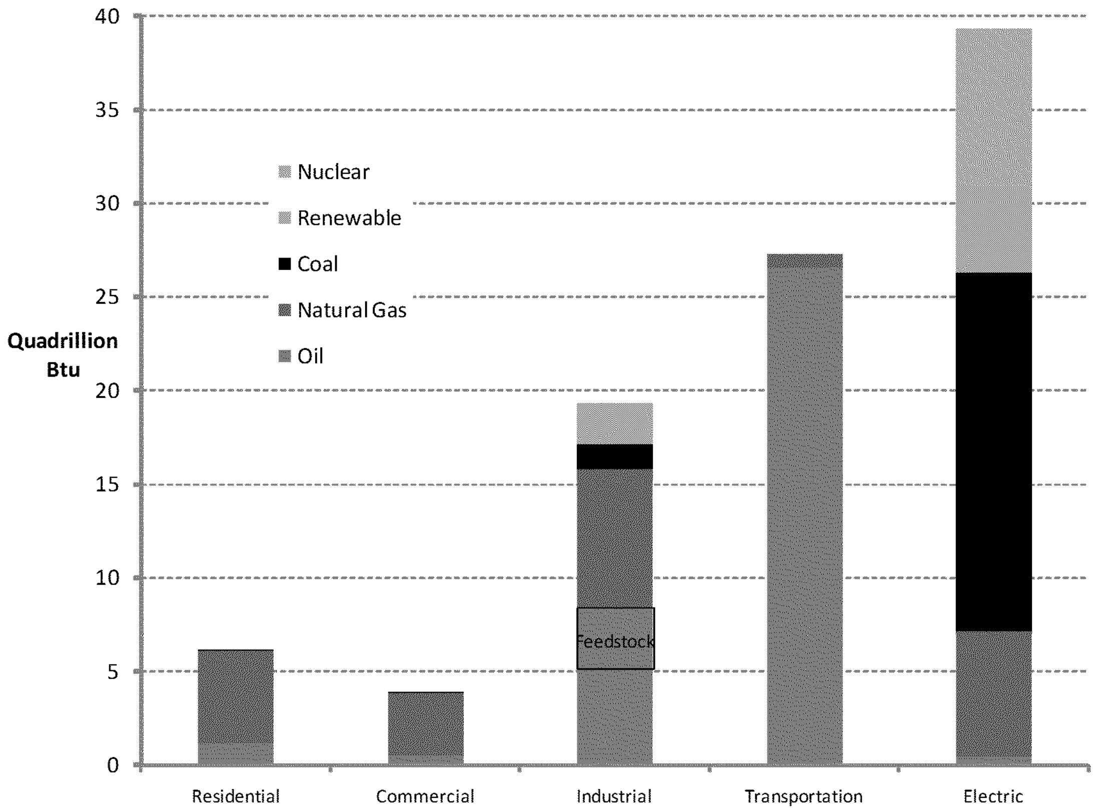

Figure 3 - U.S. Energy Consumption by Sector - 2010

Because natural gas has been supply-constrained at various times over the last few decades, this diversity of end uses has also created real or perceived competition between sectors and/or customer classes for access to gas supplies. Policy-makers have debated what constitutes the "best" use of gas – as a fuel for home heating, a chemical feedstock, a source for power generation, or in industrial applications. At various times, government policies have sought to limit – or prohibit – use of gas by large industrial and power sector users in order to prioritize or allocate gas use to residential or other uses. Perhaps the most extreme example was the 1978 Fuel Use Act[5]. Thus, at times, the priorities for gas use have been subject to direct government regulation in a way that generally has not been applied to other fuels. These efforts failed to recognize that limiting potential markets inevitably had an impact of exploration and production activity.

[5] *Flagged*—Add Fuel Use Act citation

The sources and applications of different fuels also affect their pricing. U.S. demand for natural gas and coal consumption is supplied almost entirely from North American producers. As a result, prices are determined by North American supply and demand. By contrast, 60 percent of U.S. petroleum is imported (including from Canada) and prices are determined by the world petroleum market which the U.S. does not control.

Their different applications also affect the way that different fuels are purchased and priced. Most coal transactions are wholesale transactions between coal producers and large industrial and power sector consumers. In addition, because coal characteristics vary widely from one mine to another it was standard practice for many years for power plants to be designed for a specific type of coal. This means plant operators could purchase coal from only one mine or supplier for the life of the plant. As a result, both suppliers and users benefited from long-term contracts that could ensure, on the one hand, that the plant would have a lifetime supply of the fuel it required, and, on the other hand, that the producer would have a long-term customer to justify the cost of developing that supply. In recent years, some coal-fired power plants have introduced more flexibility in their coal supply options, and as a result this has been reflected in more flexible contracting structures and decreasing reliance on long-term contracts in the coal industry (see discussion in Section III.B).

Natural gas and petroleum products are more standard commodities that have historically traded in more liquid markets where consumers can choose between suppliers based on market conditions and other factors rather than being limited by product characteristics. Changes in the price of crude oil are passed through very directly to all customers; an increase in world oil price is quickly reflected at the gasoline pump. On the other hand, the majority of natural gas customers are small residential, commercial and industrial customers who purchase gas from regulated local distribution companies (LDCs). The LDCs purchase gas from producers and use a variety of physical and financial strategies to manage their costs. The consumer price includes a gas purchase charge as well as a charge to cover the cost of delivering or distributing the gas (i.e., for interstate and local pipeline charges which may amount to half the total retail price). For both of these reasons, the price of natural gas to small consumers is typically much less variable than the underlying wholesale gas price. Large natural gas consumers must manage fuel costs themselves and are more directly exposed to changes in wholesale prices.

Figure 3 shows U.S. natural gas prices from 1976 through the end of 2010[6]. It shows a period of gas prices around $2 per thousand cubic feet (mcf) through about 1996, at which point variability increases. In 2000, prices increased sharply, declining in 2001 but then increasing gradually until another sharp peak in 2005 and another in 2008. Prices have declined sharply since 2008 and remain in the pre-2000 range.

This price trajectory, especially during the last decade, explains recent concern about gas price variability, particularly among large gas consumers. There are two components to this concern. First, the price of natural gas increased dramatically during the last decade. Second, price fluctuations have been pronounced, with prices ranging from less than $4/mcf to over $12/mcf. At the low end of this range, the price of natural gas would be attractive for investment in new gas-based industrial or power facilities. However, such investments are likely to appear too risky if there is a chance that prices may suddenly rise to and remain at the high end of the range. The next section discusses the reasons behind this historic price variability.

[6] Wellhead prices through 1994. Henry Hub prices from 1995 – 2010.

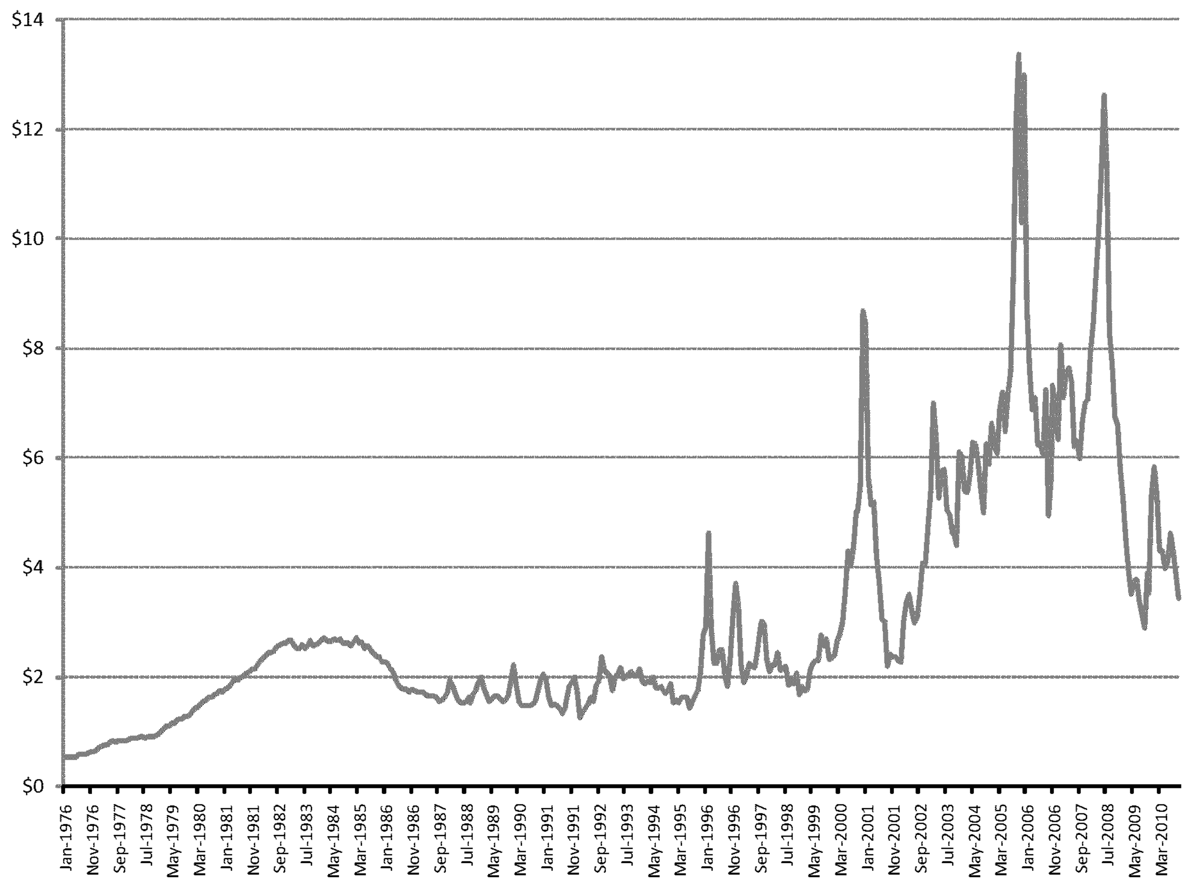

Figure 4 –U.S. Natural Gas Price 1976 to 2010 (Nominal dollars)[7]

B. History and Sources of Price Variability

The U.S. natural gas industry has been in existence at least since the 1920s[8]. However, today's competitive natural gas market is only seventeen years old and the major sources of natural gas have changed as well. Natural gas was originally produced from associated (i.e., collocated) reservoirs as a by-product of oil production. Early in the 20th century it was simply burned off in flares (as it is still in other countries with no gas distribution infrastructure). Eventually the gas was captured for use and with the development of the natural gas pipeline network after World War II, it began to play an important role in the U.S. energy system. Most gas was still "associated" with oil production, though some "non-associated" gas-only wells were developed in conventional geological formations.

[7] *Flagged*--Citation.

[8] Much of this section is based on ***Price Instability in the U.S. Natural Gas Industry Historical Perspective and Overview,*** Navigant Consulting, prepared for the Task Force on Ensuring Stable Natural Gas Markets 2010.

Until the Natural Gas Wellhead Decontrol Act of 1989 (implemented in the 1990-1991 time frame) and Federal Energy Regulatory Commission's (FERC's) Order No. 636 (issued in 1992, with implementation in 1993),[9] natural gas pricing was highly regulated through a system of cost-based wellhead pricing. This pricing system, which was imposed in 1954 as the result of the U.S. Supreme Court's decision in the Phillips case, led first to chronic shortages, then to significant oversupply with radically varying prices. During this period, the national ceiling price for natural gas in interstate markets was set by the Federal Power Commission ("FPC," the predecessor to the FERC) at $0.52/mcf.[10] At the same time, prices in the non-federally regulated intrastate markets of Texas and Louisiana were several times that, approximately $2.50/mcf. Due to the low interstate price, there was a disincentive to produce and sell gas for the interstate market. This led to gas shortages and, required the FPC to spend much of its time in administrative curtailment proceedings to allocate scarce gas supplies among markets. Nevertheless, some areas of the country still experienced crippling shortages—albeit at stable prices.

In 1976, the FPC attempted a limited remedy by significantly raising the cost-based ceiling, from $0.52 to $1.42 per mcf. In 1978, Congress passed and enacted the Natural Gas Policy Act of 1978 ("NGPA"). The NGPA was part of a package of statutes designed to reform energy regulation. Among other things, the NGPA prescribed new, non-cost-based prices for new sources of natural gas, with the aim of focusing economic incentives on the development of new gas resources and particularly "deep gas." Existing regulated sources of gas were essentially frozen at the old, regulated price. As a result, when the NGPA took full effect in 1979, the natural gas industry was subject to 27 different ceiling prices, ranging from

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[9] FERC Order 636, known as the Restructuring Rule, was issued on April 8, 1992, and was designed to allow more efficient use of the interstate natural gas transmission system by fundamentally changing the way pipeline companies conduct business. Whereas previous orders had encouraged pipeline companies to provide transportation service on a nondiscriminatory basis, without favoring their own source of supply, Order 636 required interstate pipeline companies to unbundle, or separate, their sales and transportation services. The purpose of the unbundling provision was to ensure that the gas of other suppliers could receive the same quality of transportation services previously enjoyed by a pipeline company's own gas sales. Unbundling increased competition among gas sellers and diminished the market power of pipeline companies.

[10] Mcf, a standard designation of a volume of natural gas, is 1000 standard cubic feet or approximately 1,031,000 British Thermal Units (Btu) of energy. As a point of reference, on gallon of gasoline contains approximately 132,000 Btus.

approximately 40 cents to approximately $7/mcf (with some categories being altogether deregulated over time). It was thought that offering high prices for new supply would stimulate new drilling, while freezing most "old" gas at its old prices would mitigate consumer impacts.

The Powerplant and Industrial Fuel Use Act (FUA) was also passed in 1978 in response to concerns over national energy security. The FUA restricted the construction of power plants using oil or natural gas as a primary fuel and encouraged the use of coal, nuclear energy and other fuels in the electric power sector. It also restricted the industrial use of oil and natural gas in large boilers.

High prices for new gas were successful in bringing forth substantial new supplies but because consuming markets had been depressed by erratically high pipeline prices and by statutory limitations on the use of natural gas, the industry entered a long period of oversupply and stable low prices. In 1987, the Fuel Use Act was repealed, allowing the construction of new large gas facilities.

As of 1990, a parallel system of open-access pipeline transportation had evolved under FERC Order No. 436. Congress had also passed the Wellhead Decontrol Act, which fully deregulated all wellhead natural gas prices. Accomplishing these changes without major price spikes was possible because the industry had built up a relatively large backlog of excess supply capability. Then in 1992, the FERC issued Order No. 636, essentially completing the transition to an open market. By that order, interstate pipelines were relieved of their marketing role entirely—now consumers would purchase natural gas directly from producers, paying separately for the pipeline transportation and storage services necessary to deliver the gas. By establishing a direct link between ultimate buyers and the original suppliers of gas, the FERC allowed (and still allows) supply and demand to interact directly and quickly.

The regulated period prior to 1990 established a historical context for gas users in which gas markets were characterized by mostly stable prices but limited supply and extensive government intervention. This period concluded with the transition to a much more open market for natural gas, one that still exists today and that set the stage for the price record over the last decade.

For the most part, the 1990 through 2000 period saw continued stable prices and strong supply. Henry Hub prices started somewhat below $2/mcf as decontrol began, settled in at $2/mcf until 1996 when they began to show a seasonal pricing response to high winter heating loads. Prices spiked briefly to $5.50/mcf during an unusually cold winter, then settled back down to levels that hovered around $2/mcf.

Figure 5 shows producing capacity in the lower 48 states, the actual quantity of gas produced, and the price. In the first period, the gap between the productive capacity or "deliverability[11]" and production lines represents the "excess" production capacity of the "gas bubble" and the continued low and relatively stable prices that accompanied it. However, with the end of the preferential pricing for non-conventional gas production, productive capacity had started to decline. At the same time, the repeal of the Fuel Use Act allowed gas use for large industrials and power generation to increase. Natural gas consumption for electric generation rose from 2.6 trillion cubic feet (Tcf) in 1988 to 5.7 Tcf in 2002, an increase of about 119 percent. Natural gas consumption for industrial processing rose from 6.4 Tcf in 1988 to 7.6 Tcf in 2002, an increase of almost 19 percent.

11 Gas deliverability is the maximum production rate that can be delivered to the market.

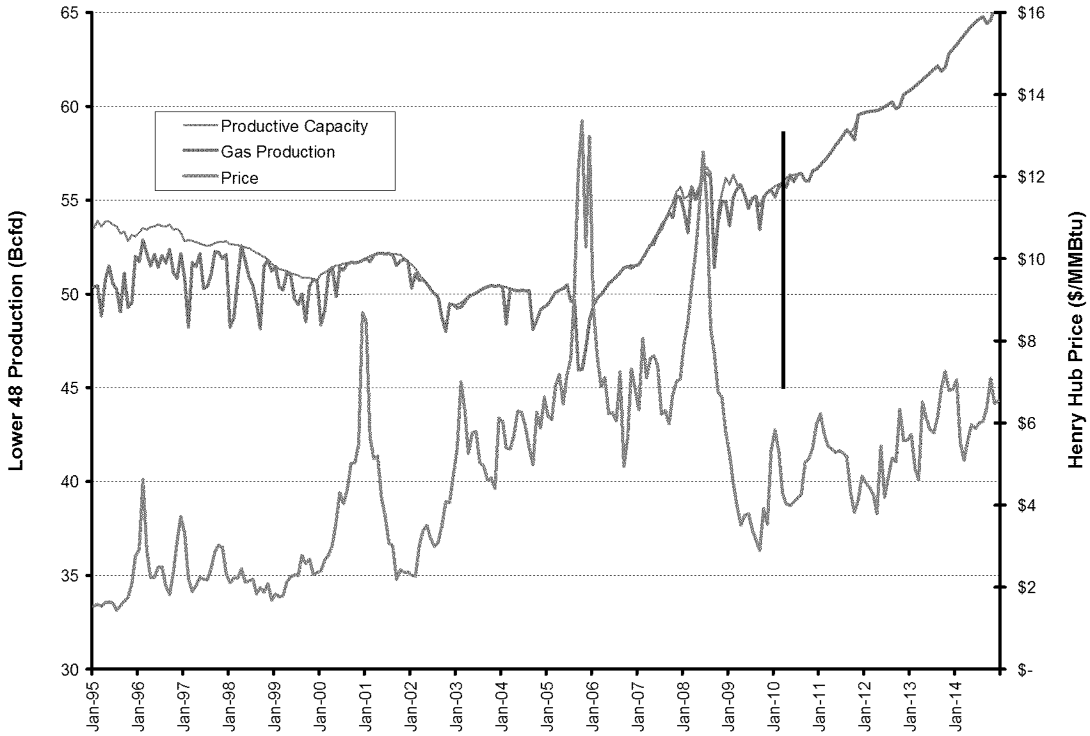

Figure 5 - U.S. Natural Gas Balance and Pricing

The combination of declining productive capacity and increasing demand spelled the end of the gas bubble. By 2000, there was no excess production capacity, all of the available production was being consumed and there was demand for additional supply that was not being met. On a pure supply and demand basis, this resulted in a sharp spike in gas prices in 2000. While prices declined in 2001, largely as the result of an economic downturn that reduced demand, tightening supplies relative to demand produced a gradual return to higher prices in the first half of the decade. In 2005, hurricanes Katrina and Rita shut down production in much of the Gulf of Mexico and even some on-shore production, resulting in another, higher price spike. Finally, in 2008, prices for natural gas, as for other energy commodities, first increased sharply. However, due, in part to large financial inflows to gas and other markets by mid 2008, they began to fall and soon dropped sharply.[12]

Figure 6 shows spot prices for gas, oil and coal since 1995, indexed to 2000 levels. The figure

[12] *Flagged*—Citation to FTC reports.

shows that gas has some notable price spikes that are different from the other fuels, but that overall, the price trends are not that different. The exceptions for gas are the 2000-2001 spike, discussed above, and the spike in 2005 due to hurricane activity. On the other hand, in 2008, all three fuels experienced a price spike that is not well explained except as a response to broader financial and commodity trends.

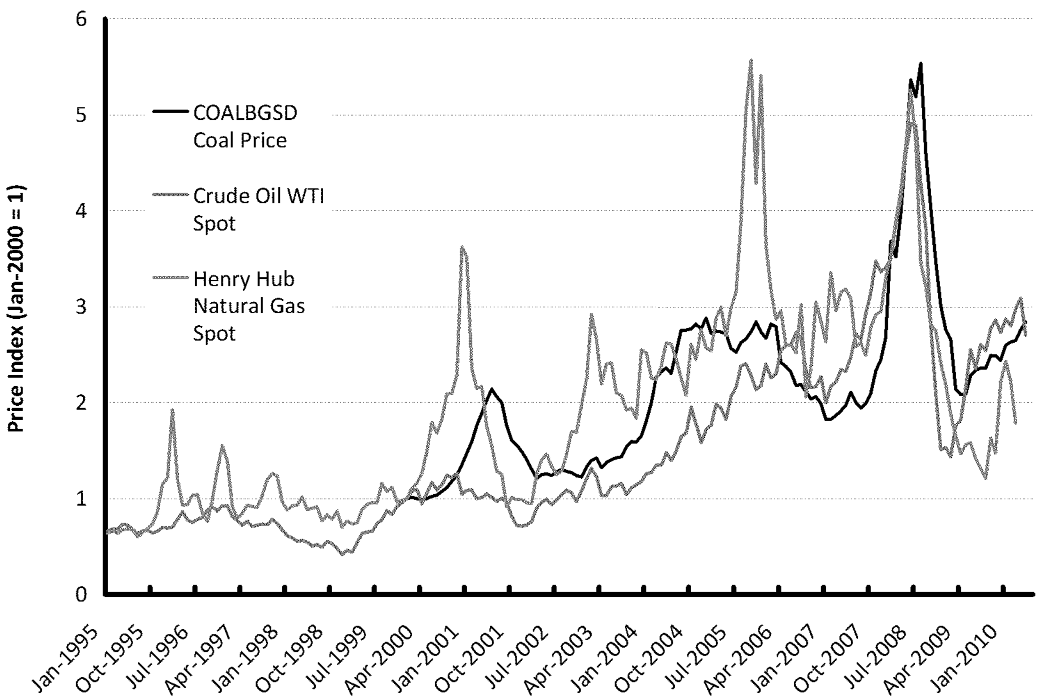

Figure 6 - Indexed Fuel Prices - 1995-2010

As already noted, lower gas prices starting in 2008 were partly the result of reduced demand due to the economic downturn. More importantly for long-term price stability, the period of higher prices in the preceding decade had triggered renewed interest in developing non-conventional gas resources. This resulted in advances in hydraulic fracturing technology that, starting in 2005 (See Figure 4) are reflected in the increasing productive capacity which are forecast to continue (see discussion in Section III.A.i.). These advances in exploration and production technology will affect gas production economics in North America for decades to come.

This review of recent gas market trends suggests several conclusions:

- Natural gas markets have been competitive and open markets for less than 20 years.
- The periods of highest gas prices in the last 10 years have resulted from well-defined circumstances, such as changes in regulatory circumstances, hurricane disruptions and broader trends in energy commodity markets.[13]
- The broader increase in gas prices in the first part of the last decade resulted from increasing demand relative to supply, which increased more modestly.
- Periods of higher gas prices have prompted the development of new gas resources, the application of improved technology, and increased supply.

C. *Impact of Gas Pricing and Variability on the Economy*

It should be clear that price of natural gas has important economic implications for both large and small consumers who rely on it. In addition, two different forms of price movements affect gas market participants in two fundamentally different ways:

1) Investment/planning price variability. Planning price variability refers to long-term uncertainty about energy price levels that influence investment planning. For example, both natural gas producers and large consumers in today's environment are unsure whether prices in the next one to three years will remain at recent levels around $4 mcf to or rise to levels seen in 2007 and 2008. But see prior views in Figure 7 on forward price curve to 2015 – based on futures contracts. This uncertainty can prevent investment by both producers and consumers, making them less likely to take advantage of the North American natural gas resource with a concomitant loss of potential economic growth.

2) Trading price variability. Trading price variability reflects short-term (day-to-day or month-to-month) price fluctuations that influence short-term energy purchasing and hedging strategies.[14]

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[13] *See also* AGA Foundation 2003 report reviewing volatility. The report also pinpointed the importance of having an adequate storage cushion to buffer short term changes in demand in supply constrained markets.

[14] In the deliberations, the Task Force examined publications including ***Natural Gas and Energy Price Volatility***

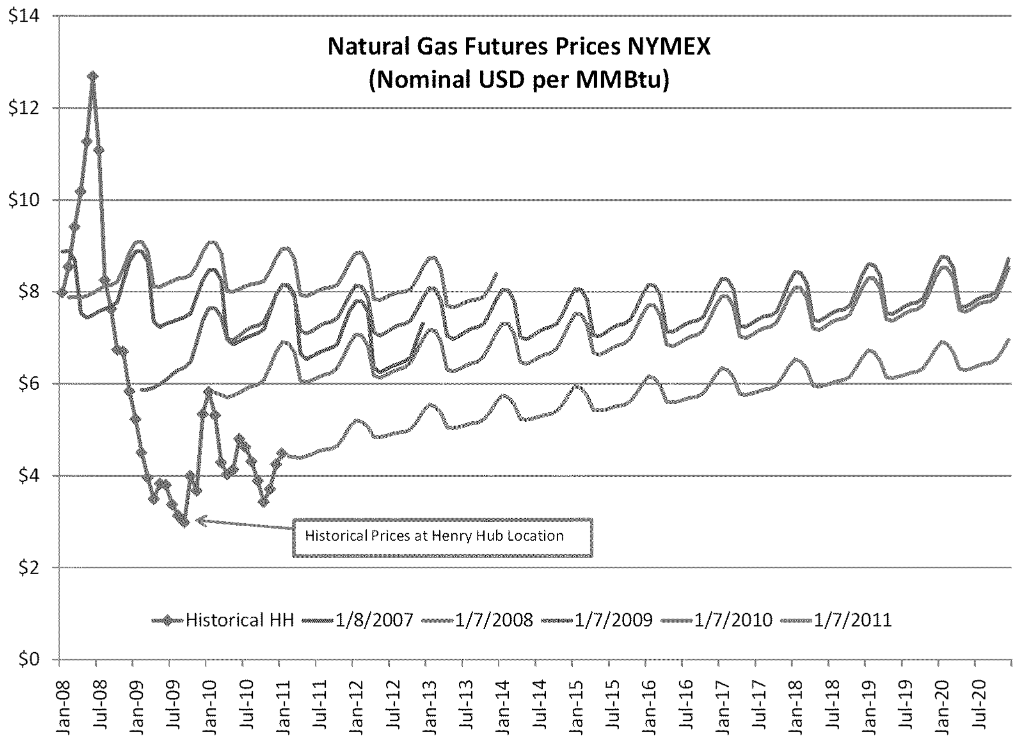


Figure 7 – Natural Gas Futures Prices – 2008 - 2010

The adverse impacts arising from price variability are related principally to the uncertainty and risk that are created by longer-term price fluctuations rather than day-to-day movements.

i. Impact on Small Consumers

Most LDC firm service customers are insulated from day-to-day variability in natural gas prices. Firm service customers, who account for almost all residential deliveries and about 63 percent of total commercial deliveries, purchase natural gas at regulated rates from the LDC. The cost of natural gas to these customers is set through a regulatory approval process, and generally reflects the rolled-in average cost of natural gas over several months (or longer) to the LDC city gate plus the LDC distribution charge.

Small customers typically are not highly sensitive to natural gas prices. They care about natural

(Oak Ridge National Laboratory 2003) as well as various papers commissioned specifically by the Task Force including ***Price Instability in the U.S. Natural Gas Industry Historical Perspective and Overview*** (Navigant 2010).

gas bills. Moreover, many residential consumers only react when there is an unexpectedly high gas bill. In addition, most residential and small commercial customers do not differentiate between a high bill that is due to an increase in the price of gas rather than a consumption increase (e.g., due to colder weather).

Price variability mainly impacts household budgets for residential customers. For commercial customers, the impact may affect profitability. In many cases, the impact of weather on gas consumption and prices can result in fluctuations in gas bills of 50 percent or more from one season to the next, much more than typically variability in actual prices.

That said, long-term increase in price trends affect consumers and may lead to a response from utility regulators. Some, LDCs have developed programs to ensure that their customers can be insulated as much as possible from short term price changes in wholesale markets. However, while LDCs have a variety of physical and financial options to do this, they are also limited by their regulators and may be subject to retroactive review of their actions. This issue is discussed further in Section III.C.ii.

ii. Impact on Large Consumers

Industrial customers (including power generators) can be much less insulated from changes in energy prices than either residential or commercial customers. LDC sales account for only a small percentage of the natural gas supplied to industry (about 17 percent in 2001). The remainder is delivered by the LDC via gas transportation services or directly from pipelines. Industrial customers purchase the natural gas commodity either at market prices, or hedged through a natural gas marketer. In both cases, industrial customers are directly exposed to market prices. If the customer does not have any hedged supply, the customer will be purchasing at market prices. Even if gas supplies are hedged, the industrial customer typically will value the natural gas at the opportunity cost reflected by the market price.

For these customers, changes in gas prices can put severe pressure on profit margins and the competitiveness of their products. Some manufacturers can pass higher costs on to their customers while manufacturers in other markets may have less ability to do so. The situation for many domestic producers has become more detrimental with the globalization of many markets, leading them to compete with foreign producers who may not be subject to the same fuel price pressures.

Competition with imports is a significant risk for domestic manufacturers with a strong dependence on local energy resources. Although energy costs make up a relatively small share of production costs in many industries, some industries are particularly energy-intensive. These include many of the basic commodity industries such as iron and steel; stone, clay and glass; and the basic chemical industries. The cost of natural gas is particularly important for industries that use gas for feedstock as well as fuel. For example, ammonia producers use natural gas as a feedstock and a fuel. Since ammonia is a globally traded commodity, increases in U.S. gas prices can, and have had, an enormous impact on the competitiveness and viability of the U.S. industry. The production of chemicals such as ethylene

> Natural gas price movements are particularly important to the petrochemical industry where natural gas is used as a feedstock to produce diverse products including fertilizer, plastics, and other products. In some instances, the natural gas feedstock can constitute more than 70 percent of the cost of production of the product. Moreover, with global markets for many – if not most – of these produces, gas price movement in North America that do not correlate with gas prices in other countries can be extremely disruptive.
>
> At the same time, recent developments in the production of shale gas can have positive impacts on feedstock uses as well as fuel uses. The production of natural gas liquids (NGLs) in the United States has increased significantly in conjunction with unconventional gas production growth. Book reserves of NGLs have grown even faster to the point where the United States has become an exporter of NGLs and propane and will likely remain so until or unless additional domestic capacity to use the products is built.

from natural gas liquids is a related issue that is also linked to natural gas availability and pricing. Gas price variability has a huge effect on the viability of these industries and the industries and consumers that depend on them[15].

These factors also affect siting decisions as manufacturers consider where to invest in new facilities. There is increasing pressure to locate new facilities in areas or countries with low and stable energy prices, although other considerations, such as labor, infrastructure, and transportation costs, obviously also remain important factors. In the case of natural gas, there are countries with ample, underutilized natural gas resources where gas prices are much lower than in the United States. In some countries, the gas resource is owned and managed by the government, which is in a position to establish long-term pricing arrangements. Although this mitigates the price risk in one way, it creates susceptibility to political risk in the event of a change in policy or regime. Nevertheless, a recent surge in the development of chemical and manufacturing capacity in foreign countries with large, low-priced gas resources illustrates the potential impact and risk to the U.S. economy.

In the power sector, there is by comparison, limited risk of competitive imports from outside of the United States. Nevertheless, there is competition between generators that rely on gas and those powered by other fuels. Since the electricity product is itself a uniform commodity (a kilowatt-hour is indistinguishable from another kilowatt-hour, regardless of how it was generated), competition between different fuel sources in this sector is largely-based on price, although other factors (environmental attributes of a fuel) may also come into play. Gas-based generators compete with coal, nuclear and renewable generators for a share of the base-load electricity market. At low gas prices, gas is competitive against all of these alternatives, but higher prices may put gas out of the base-load market. Meanwhile, uncertainty about future prices prevents utilities and developers from investing in new gas-fired capacity even though it can be among the most efficient and lowest emitting options.

Expectations about future gas prices can also have important implications for the competitiveness of renewable energy resources because natural gas capacity is often looked to

[15] Flagged—Cite to Brattle Paper.

as the back-up source to provide firm capacity for intermittent resources like wind and solar. However, there are questions related to the financing of the gas resource and delivery capacity, just as there are on the electric side. That is, how will the gas delivery and generating capacity that is used only intermittently be paid for and by whom if there are no base load customers. From the standpoint of gas producers, there is also concern that the increased demand for gas-fired "balancing" service as a result of expanded renewable capacity will be less than the demand lost as a result of replacing of base load gas generation with renewable production.

When prices are high, power and industrial users of gas may lose market share, resulting in reduced gas consumption. This response is useful to maintain the balance of supply and demand but may entail lost output and jobs in the affected sectors. The balancing of demand with supply is critical to increased use of the North American gas resources both to provide stable pricing to consumers and to provide a stable demand outlook for producers. Steady and growing demand allows producers to move down the production cost curve and supply more gas, often at reduced prices. Recent experience with shale gas production provides considerable evidence of this trend, given the steady growth of the estimated recoverable resources at $5/mcf or less.

There is a potential for a win-win result but, today, many large consumers remain cautious about investing in new gas-consuming facilities due to uncertainty over mid to long-term gas prices. At the same time, many gas producers are cautious about continued investment in production due to uncertainty about the future demand for their product and thus a sustained low gas price environment.

iii. Impact on Energy Production and Delivery Companies

Sharp and unpredicted or misunderstood movements in gas prices – up or down – create additional uncertainty in the planning process for producers as well as consumers, making the capital budgeting process more difficult. The economics of a decision to expand investment in infrastructure, or to spend resources in an attempt to develop a new market area such as distributed generation (DG), gas cooling, or natural gas vehicles, are made much more uncertain. Planning for the development of a distributed generation (DG) market becomes even more complex because of volatility in electricity prices.

The primary risk to producers is the longer-term cycling of gas prices that is generated by "boom-bust" investment cycles, variations in economic activity, and pipeline capacity constraints that can limit the ability to move gas out of a production region. For gas producers, variability and price uncertainty raise the hurdle rates needed to justify a drilling program. As a result, the long-term expected price of gas is increased because of the "risk premium" arising from the uncertainty in future prices.

III. Approaches to Improving Mid- to Long-Term Price Stability

Based on the historical context and market trends identified in Section II, this section discusses policies and other changes related to natural gas markets that could improve mid-to long-term price stability.

A. Supply and Infrastructure

The preceding historical discussion noted that natural gas prices are primarily determined by the North American market and that the balance between supply and demand does have a direct impact on gas pricing. The foregoing strongly suggests that the most effective approach to moderating natural gas prices over the mid- to long-term would be to promote expansion of capacity for producing and delivering natural gas

The lack of significant excess domestic production capacity in the last decade has made gas commodity prices sensitive to short-term changes in supply and demand, and in the short run, to the availability of gas storage. The importance of the supply and demand relationship has been especially apparent in the North American natural gas market.[16] Historically, prices have responded dramatically when supply is tight and demand is strong. A further factor influencing the short-term volatility of gas prices is the availability of sufficient pipeline capacity from production areas, transport hubs and storage facilities.

The expansion of gas shale production already appears to be having a dampening effect on price variability. Again, see Figure 5 and Figure 7 on forward curves to 2015. These developments and other trends in infrastructure investment that may contribute to less variable gas prices over the mid- to long term are discussed below.

i. Shale and the New Gas Supply Paradigm

Section II discussed the dramatic change in supply forecasts that resulted from new shale gas production technology starting in the middle of the last decade. Although there has been much discussion of the implications of shale gas, it may be that the full impacts have yet to be

[16] *See* AGA Foundation study.

understood. Clearly, a significant increase in U.S. natural gas resources will have a moderating effect on gas prices and variability.

While shale formations were long known to contain substantial gas, the formations are not porous like conventional oil and gas formations, so that when drilled, the gas cannot flow freely to the well. Rather, drilling must be coupled with hydraulic fracturing, -- a process of using high pressure liquids to create cracks in the shale to allow the gas to flow. This technology, shown in Figure 8, has recently been combined with the practice of horizontal drilling to allow enormous increases in the amount of gas that can be recovered.

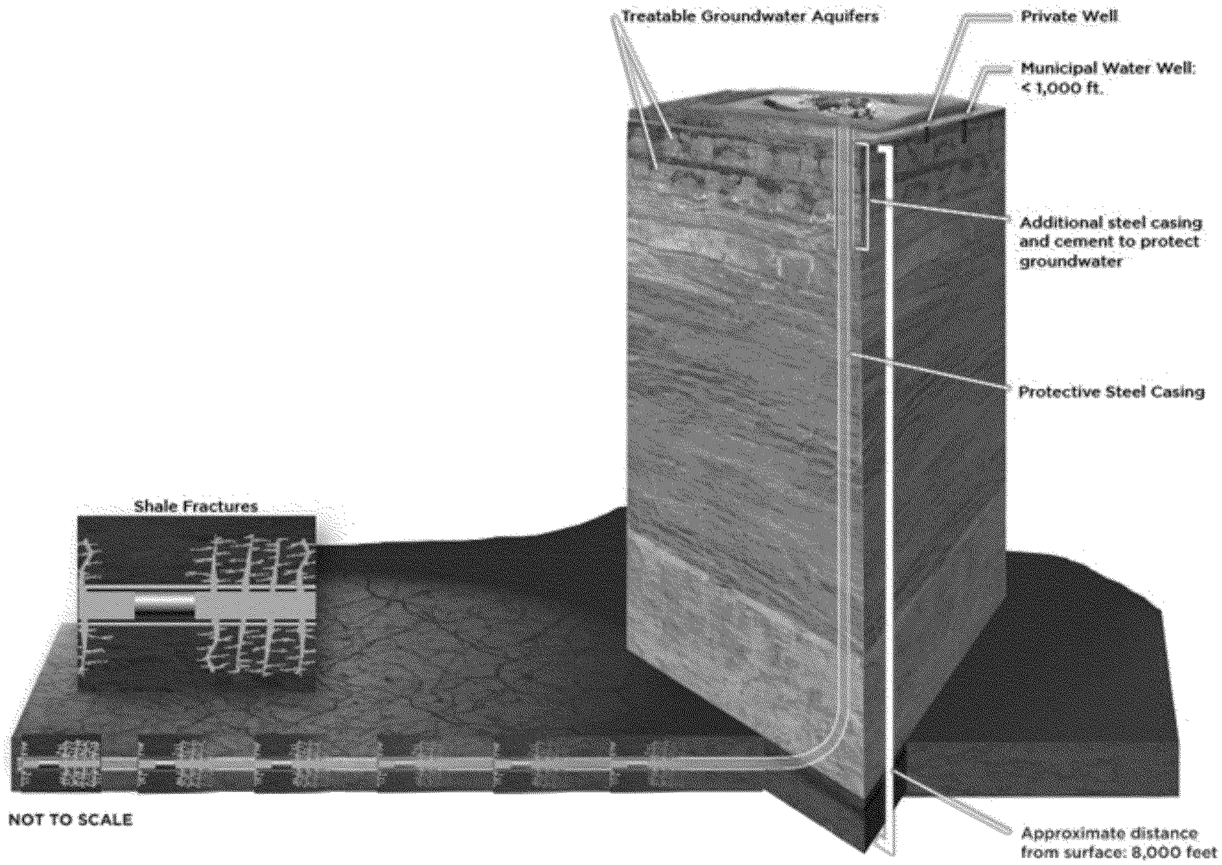
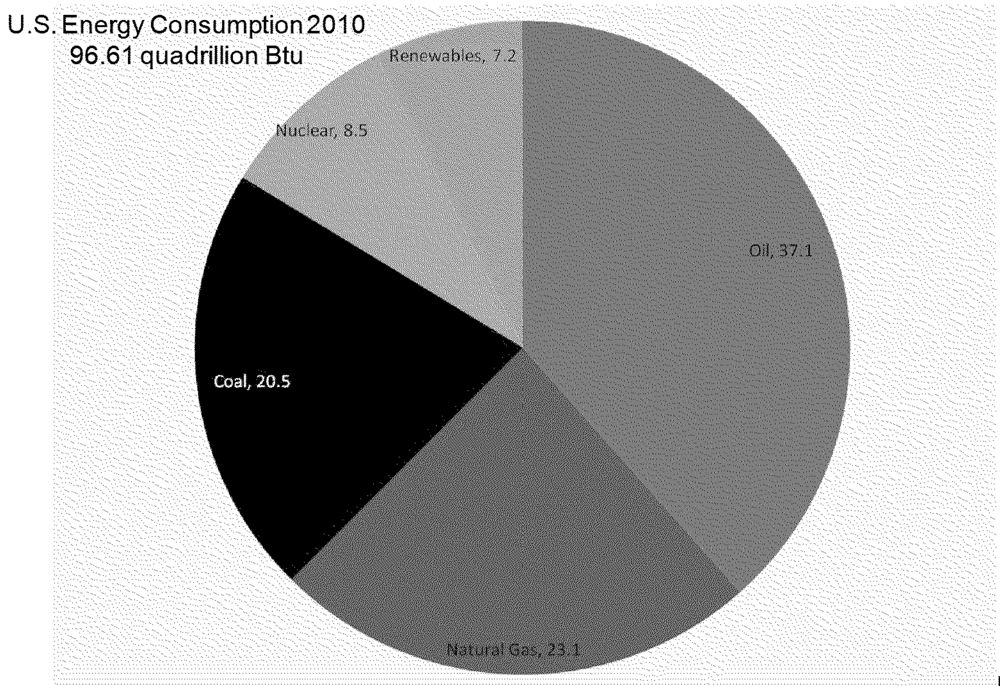


Figure 8 - Diagram of Hydraulic Fracturing Process

In the late 1980s, producers began experimenting with large scale hydraulic fracturing in the area around Fort Worth, Texas, in the geological play known as the Barnett Shale. Fracturing was first used in the Barnett in1986; the first Barnett horizontal well was drilled in 1992.

Through continued improvements in the techniques and technology of hydraulic fracturing, development of the Barnett Shale has accelerated and production caught the attention of the industry. Since then, the science of shale gas extraction has matured into a sophisticated



process involving horizontal drilling and sequenced, multi-stage hydraulic fracturing technologies. The techniques pioneered in the Barnett have spread rapidly to shales in other areas.[17]

Despite these advances, the U.S. EIA's Annual Energy Outlook 2000 estimated shale resources at only 3.7 Tcf and the future contribution of shale to domestic supply was modest (Figure 9).

Figure 9 - Natural Gas Production, 1998-2020

Even as late as the 2005 Annual Energy Outlook, the full scope of the shale revolution was not appreciated. By then, conventional resources were seen as declining, and a major driver of natural gas prices, contributing to the tightness of the gas market, and the resulting price volatility. LNG imports were expected to be the next large incremental source of natural gas supply to meet growing demand (Figure 10).

[17] U.S. DOE, Office of Fossil Fuels and National Energy Technology Laboratory, Modern Shale Gas Development in the United States, a Primer. Prepared by Groundwater Protection Council (Oklahoma) and ALL Consulting. Washington, DC, 2009.

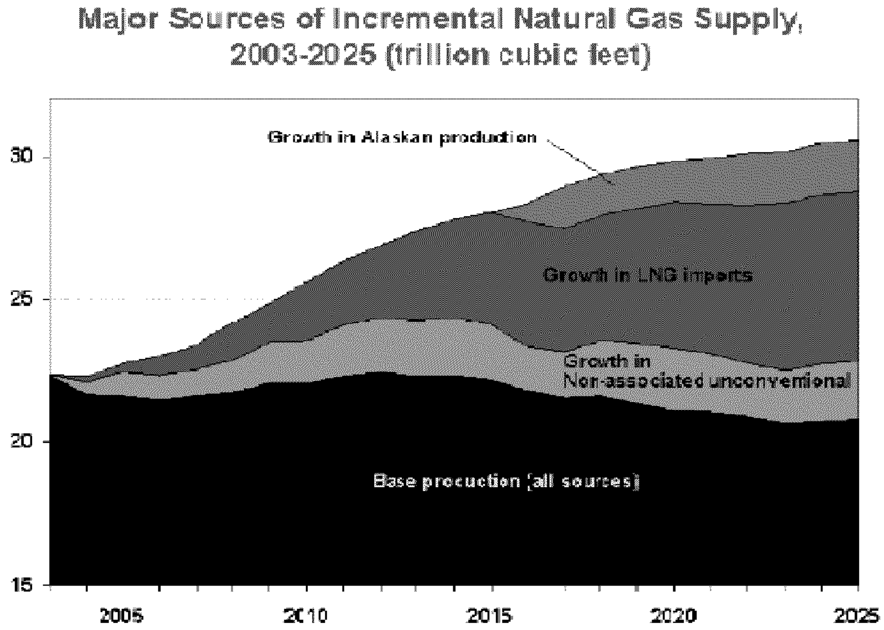


Figure 10 - EIA Supply Forecast - 2005

Source: EIA, Staff's Forecast of Natural Gas Prices. (from Annual Energy Outlook 2005) Presentation, Washington, DC.

Between 2005 and 2010, shale development expanded rapidly. In addition to the Barnett, producers began intensively developing plays in the Woodford, north of the Barnett in Texas and Oklahoma; the Fayetteville in Arkansas; and the Haynesville in Louisiana/East Texas. During this time development also began in the Marcellus Shale of the eastern United States. In the 2011 Annual Energy Outlook, the domestic supply picture has changed dramatically (Figure 11).

The changes in the forecasts of future unconventional and shale production are also matched by the revisions in the estimates of recoverable shale reserves. Table 1 shows the rapid increase in these estimates over the last ten years.

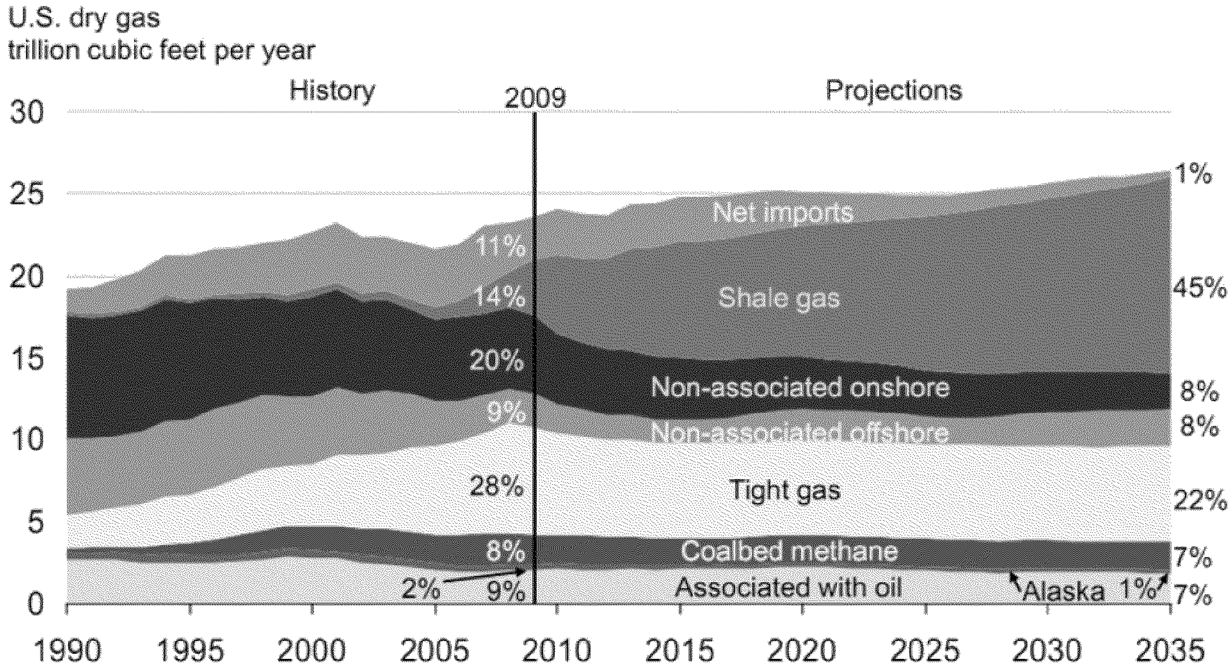


Figure 11 - EIA U.S. Dry Gas Production Forecast - 2011

Source: Richard Newell, Administrator EIA, Energy Outlook 2011. Presentation, Washington, DC: Dec. 16, 2010.

Table 1 - Published Estimates of U.S. Lower 48 Recoverable Shale Gas (Tcf)

USGS (Various years)	EIA 2000	NPC 2003	EIA 2007	ICF 2008	PGC 2009	ICF 2010[18]
85	3.7	35	125	385	616	1,395

The size of the U.S. shale resource base is only one aspect of its new-found importance to the domestic supply outlook for natural gas. Another is the widely distributed nature of that resource base. Figure 12 shows that shale is ubiquitous, with major production opportunities located in Texas (Barnett and Woodford), Arkansas (Fayetteville), Louisiana (Haynesville), the Appalachians, (Marcellus). Shale is also found in Illinois, Michigan and other areas farther west and north. In short, the distribution of shale resources is close to the major eastern U.S. consuming markets and to the pipeline systems serving those markets. The Marcellus shale, extending from Virginia in the south to New York, is the largest shale resource, conservatively

[18] ICF International, 2010 Natural Gas Market Review, prepared for the Ontario Energy Board, August 2010, p. 48.

estimated at approximately 700 Tcf.[19]

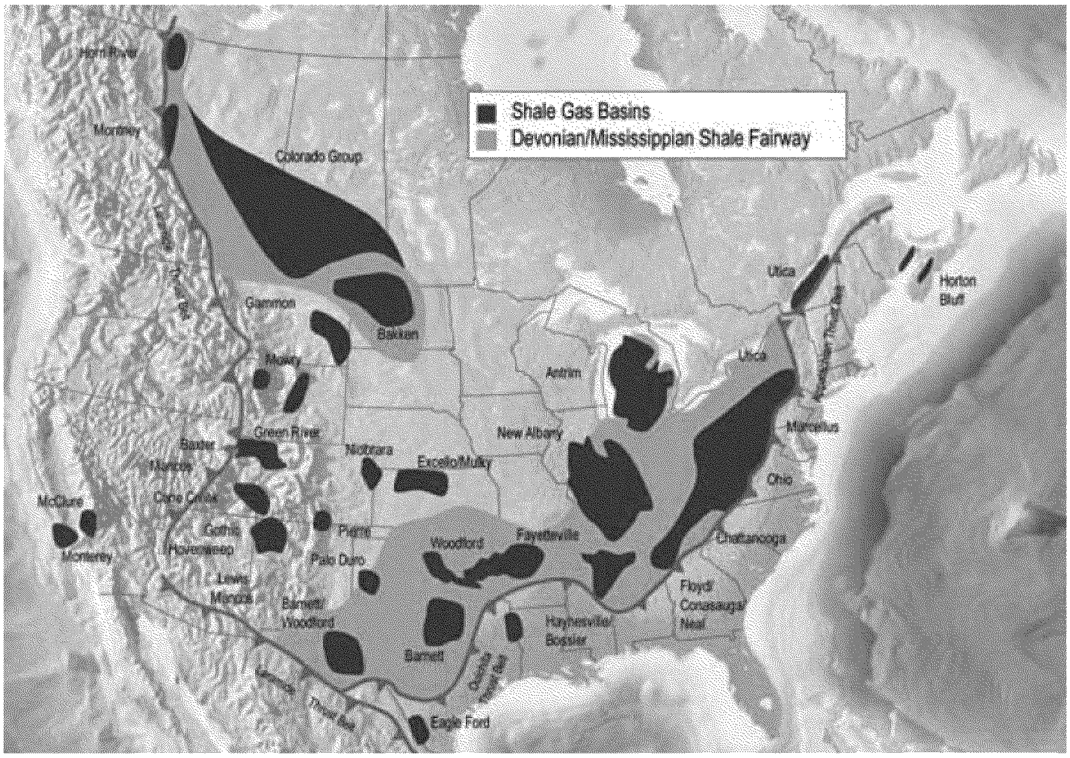


Figure 12 - Shale Gas Basins in North America

Source: National Energy Board of Canada

In late 2010, the MIT Energy Initiative published its Interim Report, *The Future of Natural Gas*, re-examining the supply outlook.[20] One of the major findings of the study was that consensus estimates of the size of the total U.S. resource base (including Alaska) had increased to about 2,100 Tcf, with much of the increase coming from the addition of over 600 Tcf of shale gas in the lower 48 states.

While estimates of supply have increased, the cost of producing shale gas has declined as more wells have been drilled and as new techniques have been developed and field tested. The MIT study estimated that between 250 and 300 Tcf of shale gas can be produced at prices below $8/MMBtu (in 2007 dollars).[21] More recently, ICF International estimated that almost 1,500 Tcf are available at $8/MMBtu, and 500 Tcf at $4/MMBtu (Figure 13). In either case, the

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[19] ICF International, p. 48.
[20] MIT Energy Initiative, the Future of Natural Gas, an Interdisciplinary MIT Study, Interim Report. Cambridge, Massachusetts: Massachusetts Institute of Technology, 2010.
[21] MIT Energy Initiative, p. 11.

opportunity for substantially expanded domestic gas production is large. The MIT summarized the situation as follows:

> "The large inventory of undrilled shale acreage, together with the relatively high initial productivity of many shale wells, allow a rapid production response to any particular drilling effort. However, this responsiveness will change over time as the plays mature, and significant drilling effort is required just to maintain stable production against relatively high inherent production decline rates."[22]

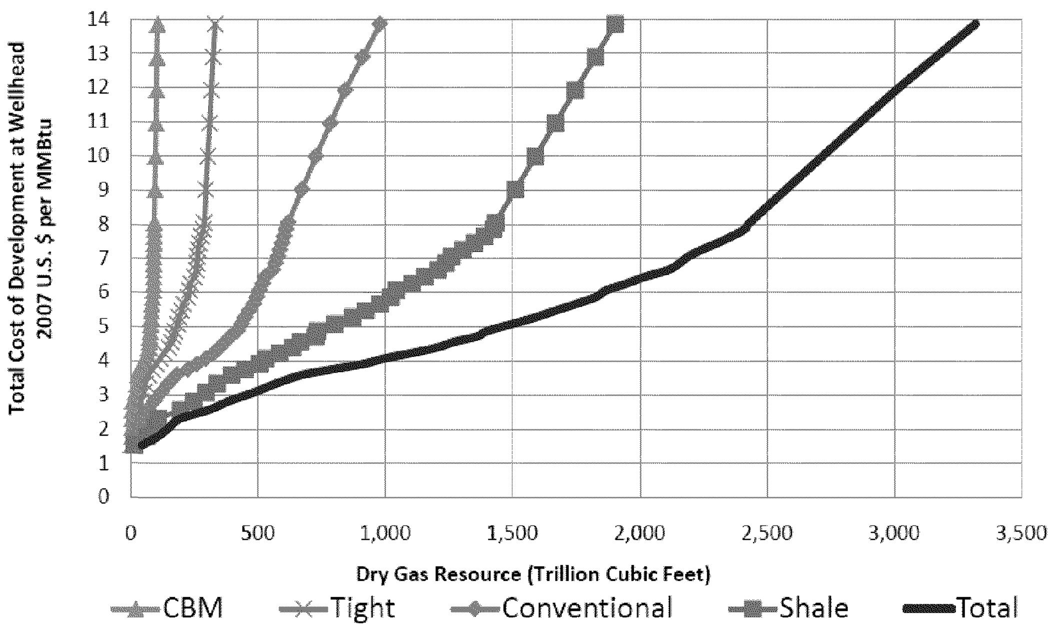

Figure 13 – U.S. Natural Gas Resource Cost Curves by Type

Source ICF International

While the development of shale gas offers the potential to make large new supplies of natural gas available at moderate prices, there are three large categories of uncertainty around the future development of the shale gas resource:

A first question is to what extent current resource assessments accurately capture the actual economically recoverable resource base. Our understanding of key technical aspects of this resource is still evolving and questions remain in a number of areas: whether productive areas are representative of an entire play; the role of "sweet spots" in potentially skewing resource assessments; uncertainty about the trajectory of well production decline; and the effect of

[22] MIT Energy Initiative, p. 13.

technology and technological innovation.

A second category of uncertainty concerns the cost of producing and delivering shale gas; the availability of pipeline and processing infrastructure in proximity to the resource base; and well drilling costs, which are a large technological and cost component in the development of shale gas resources.

A third and last (but by no means least) source of uncertainty

documented incidents of fracturing fluids or methane impacting surface and well water supplies due to improper well casing. While this issue is not specific to shale gas production, the migration of shale gas production into new areas is putting more focus on it.

- Water consumption for fracturing – A typical fracturing operation centers on the environmental risks associated with shale gas development and their implications for public acceptance of increased shale gas production in different areas of the country. The MIT report summarizes the environmental concerns, which include: the risk of shallow freshwater aquifer contamination from fracture fluids; the risk of surface water contamination from inadequate care in the disposal of drilling fluids and produced water; the effects of fracturing water requirements on local water supplies; and the impact of intensive drilling on communities, especially as more drilling occurs in densely settled areas of the eastern United States. While more than 20,000 shale wells have been drilled in the past 10 years with little adverse environmental impact, environmental risks and concerns are likely to become increasingly important if and when production activities expand substantially beyond current levels. These risks and concerns will have to be carefully monitored and managed to avoid adverse impacts and to ensure that communities remain willing to accept shale gas development based on confidence that appropriate safeguards for the protection of the environment and the public are in place.[23] (See Text Box)

In summary, the consensus is that North American natural gas resources are much larger than previously understood and can supply an expanded gas market. Moreover, with current technology, the cost of producing the gas will be lower than previously thought. This will allow gas use in broader applications for power and transportation. At the same time, it has the potential for moderating the fluctuations in gas prices.

Figure 14 shows the sources of U.S. natural gas supply since 1985 and projected through 2030. Gas consumption has been about 20 to 23 Tcf per year since the 1990s. The Figure shows the changes in gas supply that occurred over that time in order to meet the continuing demand. Onshore conventional production has supplied less than half of consumption since 1990 and is flat or declining. Offshore production in the Gulf of Mexico was the next largest source to come into the mix to provide additional supply, but has also been declining and may be even less available going forward due to limits on offshore production. Canadian pipeline imports have been an important supply component since the 1990s, but are projected to decline as more of

[23] MIT Energy Initiative, p. 15.

the gas is expected to be used in Canada for oil sands production. Finally, non-conventional production of tight gas and coal-bed methane has been the last piece of the supply pie to get the U.S. up to 23 Tcf in recent years. With offshore and Canadian production declining and prices rising, there has been more financial support for non-conventional production and interest in LNG imports. These high prices also supported the development of shale gas production techniques over the last decade. The currently understood and projected shale gas resource has for the first time in the last 15 years allowed the U.S. to project a significant increase in available gas resources that can be produced economically. Thus, for the first time since the 1990s, deliverability could be adequate to meet increasing gas demand and the U.S. could be out of the very tight supply/demand regime that has made it vulnerable to price instability.

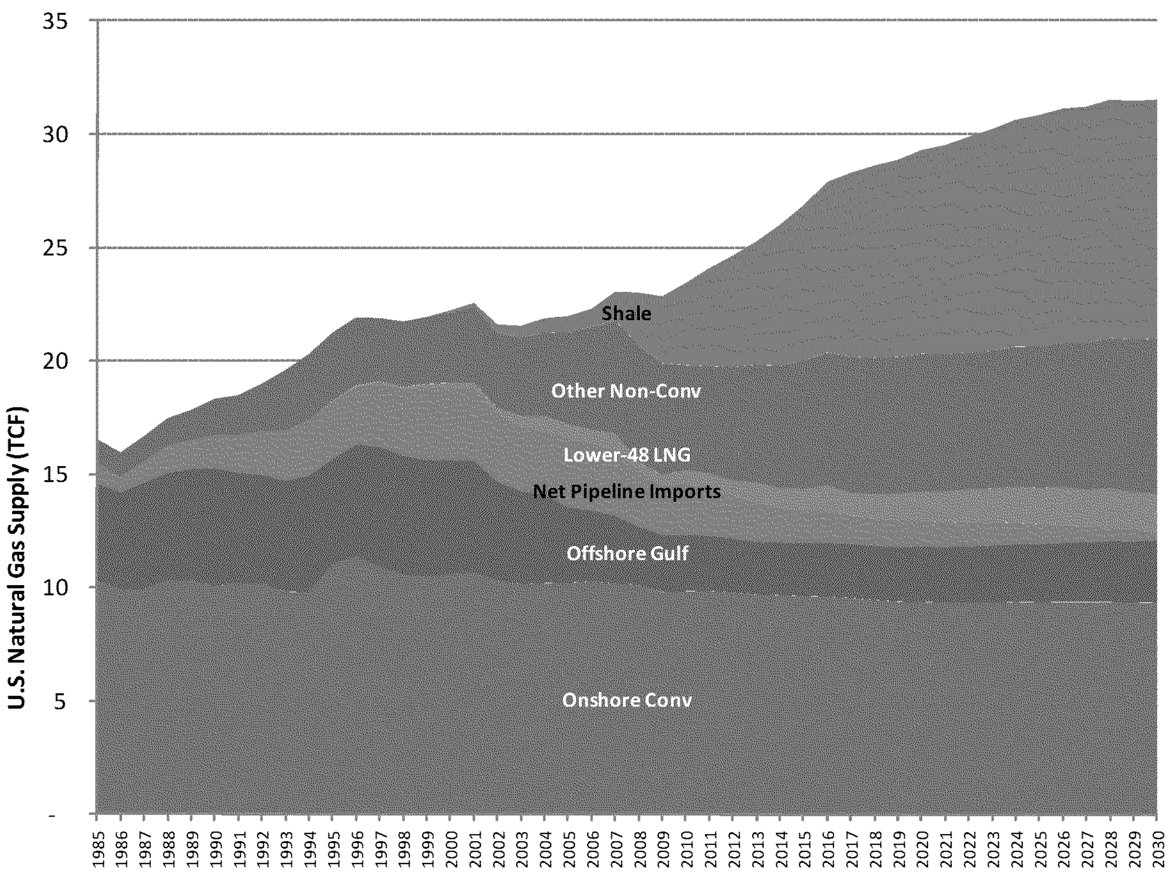

Figure 14 – Evolution of U.S. Natural Gas Supply

ii. Imports: Liquefied Natural Gas[24]

While the natural gas market is primarily a North American market, the potential to import significant amounts of gas from other countries and continents has been available for many years and, in recent years, has grown significantly. This is especially true since the price of gas in some exporting countries (i.e., Qatar) is extremely low due to low production costs and limited domestic demand.

The first modern liquefied natural gas (LNG) receiving terminal in the United States entered service in Boston in 1971. In response to the supply shortages of the 1970s, three more terminals were constructed by 1982, all on the Gulf and East Coasts. For the next 20 years however, LNG imports were minimal. Largely because of prevailing low gas prices, two of the terminals were mothballed for a long period. After 2000, greater variability in U.S. gas prices brought a renewed interest in importing LNG. By 2005, FERC had received applications for 55 new LNG import terminals (or expansions at existing

Access to Resources

Natural gas resources exist in almost every part of the U.S. and in coastal areas. Development of these resources, like other natural resources, is subject to a tension between development, preservation of the natural environment, and use for habitation and recreation. While there is gas development in many parts of the U.S., there are also large areas in which development is limited or prohibited including parks, other national lands, the Atlantic and Pacific coastlines and parts of the Gulf of Mexico. The identification of a new resource often triggers a struggle over whether or not it should be developed due to environmental or other land use concerns. The venue for resolving the question depends on the specific location and jurisdiction and there are often overlapping authorities. The public policy and regulatory process should carefully weigh the value of gas production against protection of the environment and public health to ensure that a proper balance is struck.

[24] Includes information from "*LNG, Globalization, and Price Volatility,*" Kenneth B Medlock III, prepared for the Task Force on Ensuring Stable Natural Gas, May 2010.

ones).[25] Today there are seven operating LNG import terminals in eastern United States, plus two additional terminals that serve U.S. markets from Baja Mexico and Maritimes Canada. Total LNG import capacity is about 15 Bcf per day within a market that is approximately 65 Bcf per day. Thus LNG could theoretically meet 20% of current market requirements.

LNG terminals are necessarily limited to coastal sites. While many terminals have been proposed for locations along the east coast and a few on the west coast, virtually all of the new terminals have been on the Gulf coast. There are two primary reasons for this. Proposed east and west coast projects have met with intense public opposition. Opponents have been successful in blocking these terminals from getting approvals at the state level, even where FERC has approved the applications. The Coastal Zone Management Act affords state government effective veto power over LNG terminal siting. The Gulf Coast has seen a far less hostile response, largely, it is believed, because the region is already accustomed to large petrochemical development.

Another reason for more LNG terminals being located on the Gulf coast is that the pipeline take-away capacity is much more robust in this region. From the Gulf, importers can reach virtually the entire eastern half of the United States. In addition, the gas market along the Gulf is large and liquid, and price discovery is relatively straight-forward with Henry Hub being nearby. The attraction of east coast sites, especially north of the Carolinas, is the higher gas prices that prevail there than in the Gulf. At the same time, pipeline take away capacity is more limited and these markets are comparatively less liquid, and susceptible to LNG deliveries influencing local prices. Nevertheless, the large price differentials between Henry Hub and the northeast have historically made LNG a more attractive investment in the northeast United States.

At today's prevailing lower prices, however, and with the current outlook for gas supply and prices, it is not likely that new import terminals will be added to the current U.S. fleet with the possible exception of lower volume offshore terminals. In fact, in the face of growing U.S. gas

[25] NARUC, Liquefied Natural Gas: An Overview of Issues for State Public Utility Commissions. Washington, D.C.; National Association of Regulatory Utility Commissioners, 2005. In testimony before the Senate Energy and Resources Committee on July 10, 2003 Alan Greenspan urged expansion of LNG import capability: "Without the flexibility such facilities will impart, imbalances in supply and demand must inevitably engender price volatility."

supplies, some owners of LNG impact terminals have applied for export authorization and intend to install liquefaction facilities. In the next decade, however, even if new export terminals are built, the extent of exports may be modest (less than 5% of the market) and appear unlikely to apply significant upward pressure on U.S. gas markets.[26]

In principle, LNG imports can help to moderate gas price volatility and undoubtedly have done so on some occurrences. However, ongoing LNG sales to the U.S. have been modest in recent years given the historic spread between U.S. prices and gas prices elsewhere in the world. Europe, Japan, Korea, China, and India – the major markets for LNG – pay oil linked prices for LNG. U.S. prices are set by gas-on-gas competition and are consistently below world LNG prices. The American market is only likely to attract global LNG supplies when prices are high (winter), and to high value locations (the Northeast). In general, current policies and the efficient regulation of LNG facility siting by the FERC have allowed LNG capacity to evolve with market needs.

iii. Storage[27]

Gas storage facilities allow gas produced in one time period to be used at later date. Gas wells operate optimally when they produce at steady rates. Gas demand, on the other hand, is highly seasonal due to winter heating load and summer electric generating demand. On top of the seasonal cycle, there are weekly and daily use patterns that do not match well with production and pipeline deliveries. Storage capability is expressed in two ways: the amount of gas that can be stored (capacity of the reservoir in MMBtu) and the deliverability capacity of the storage facility (MMBtu per day). Thus, early in the development of the gas pipeline system, gas storage was designed to manage swings in demand by storing gas in the ground when demand was light and releasing it when demand increased. Following the deregulation of wholesale gas prices, storage has also become a physical way of hedging future price risks for utilities and producers; likewise, it is also provides a financial tool for price arbitrage by marketers and suppliers. Both the physical and financial aspects of storage have can be used as tools to

[26] Needs documentation from Chemiere DOE docket.
[27] Includes information from "*Natural Gas Storage: A Discussion of the Value of Storage Gas, Recent Developments, and Implications for Public Policy*", ICF International, prepared for the Task Force on Ensuring Stable Natural Gas, July 2010.

promote price stability.

There are three types of underground storage: depleted reservoir, aquifer, and salt cavern storage. About 85 percent of the working gas storage capacity and 70 percent of the deliverability – the rate at which storage gas can be withdrawn and delivered to the market – in the U.S. are in depleted natural gas or oil fields, because of their widespread availability. Conversion of a field from production to storage takes advantage of existing wells, gathering systems, and pipeline connections. Most of this storage is cycled once a year to meet seasonal demand: injecting gas in summer and withdrawing in winter.

Salt caverns work on a shorter cycle, providing very high withdrawal and injection rates for their working gas capacity through 2 or more cycles per year. Salt cavern storage accounts for about 5 percent of the working gas capacity but 17 percent of the deliverability. The large majority of salt cavern storage facilities are along the Gulf coast, where there are large bedded salt deposits.

Figure 15 shows the location of U.S. gas storage facilities. Some regions of the country do not have suitable underground storage sites including the east coast, New England, and the southeastern states.

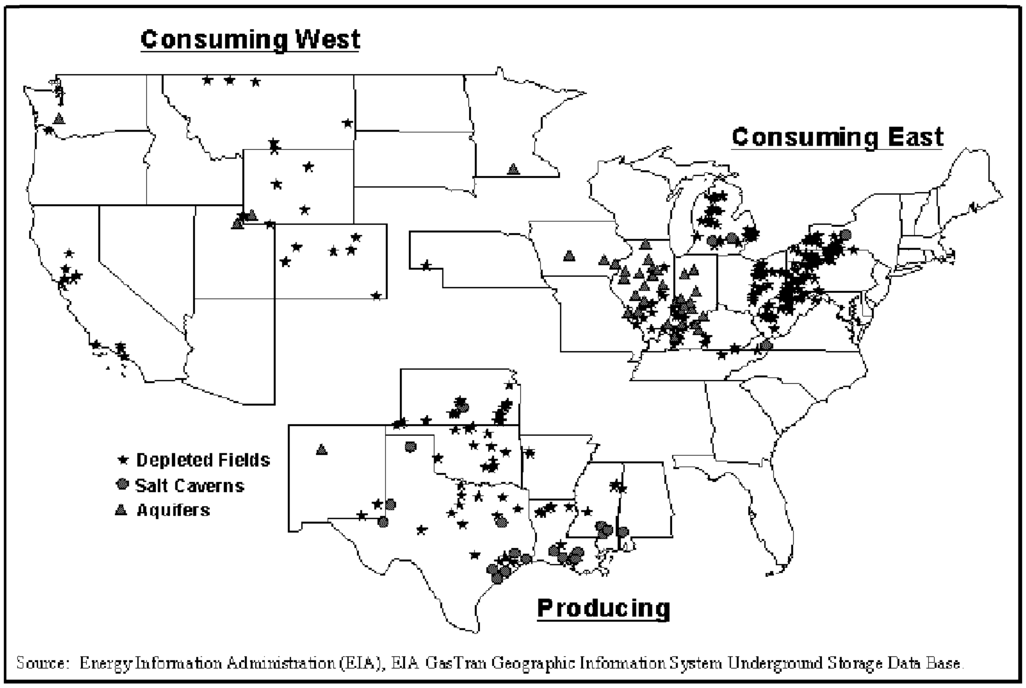

Figure 15 - U.S. Underground Storage Locations

Between 2000 and 2006, new storage capacity increased on average by 46 Bcf per year reaching 8.4 Tcf of total capacity. Since then capacity additions have averaged 109 BCF per year. Between 2000 and 2010, approximately 700 Bcf of new working gas capacity has been constructed. In 2009, U.S. had 8.7 Tcf of total capacity and 4.3 Tcf of working gas storage capacity [28] or nearly 20% of the annual market.[29]

Investment in additional storage is expected to continue. Several factors have contributed to this growth in storage capacity:

- Regulatory changes have encouraged more development at market based rates, thus increasing the potential return to storage developers.
- The growth in natural gas power generation increased the need for high deliverability storage to meet swings in gas load.
- Actual and anticipated growth in LNG imports has led to demand for storage to manage LNG delivery patterns.

[28] U.S. Department of Energy, Energy Information Administration
[29] EIA, Underground Natural Gas Storage Capacity. http://www.eia.gov/dnav/ng/ng_stor_cap_dcu_nus_a.htm

- Historic price variability through 2008 increased the value of storage to a broader array of market participants: utilities needing to manage seasonal and daily price risk; marketers and financial traders wanting to benefit from price variability through physical arbitrage; suppliers interested in maximizing opportunities created by price swings.
- The consequential increase in liquidity and deliverability at gas market hubs has reduced reliance on long-haul pipeline capacity to meet winter load, and further increased the need for market area storage as supplements to gas supply.

The role of storage is likely to become more prominent as overall gas consumption expands. The growth in gas fired power generation increases the need for storage to manage seasonal and weather related swings in fuel requirements. Similarly, as renewable generation grows to increase the reliance on gas units for firming power, gas storage will also be necessary.

Storage has a prominent role in gas system operating reliability and increasingly in gas pricing. Utilities' use of storage to meet swings in demand also allows them to buy gas at lower off-peak prices and deliver it to customers at those prices during winter peak season. Storage has become a major tool in gas market operations for hedging risk and arbitrage. As growth in storage capacity continues to increase, storage operations will tend to moderate gas price.

Storage also plays a critical role in managing and mitigating gas price movements that result from increases in consumption or tightness in gas supply availability. The growth in the amount of storage available to the market is an important contributor to the current outlook for more stable and competitive gas prices.

iv. Pipelines

The North American natural gas market is integrated through an extensive interstate pipeline network that connects gas supply markets with gas consuming markets. Price signals flow across this network and markets adjust based on the availability pipeline capacity and prices.

In principle, gas prices between two markets reflect the cost of transportation between the two markets. The difference, referred to as the "basis," also reflects local market supply and demand balances. Therefore, on the margin, the basis can fluctuate to reflect the relative value of gas in the markets at any point in time. It also fluctuates as a function of pipeline capacity when for instance, demand for gas is strong in a downstream market and there is inadequate capacity to supply all the gas demanded. Basis "blowouts", where the price skyrockets, have been seen in markets where there are severe capacity limitations due to sharp short term increases in demand (e.g., due to an unforeseen cold snap)– New York and New England are prominent examples.

Basis blowouts can also happen in supply markets, but in the opposite direction. If there is inadequate pipeline capacity from a producing region relative to production, sellers will compete for space by cutting prices and wellhead prices collapse. Recurring or persistent basis blowouts signal the need for new pipeline capacity.

Most of the gas pipelines developed in recent years have been driven by supply growth. With the expansion of shale production and increasing production from the Rocky Mountains, the U.S. has seen major new pipeline expansions in recent years to bring this gas to market. Since 2006, major new pipelines include the following:

- Centerpoint, Carthage to Perryville (Texas/Louisiana), 1.2 Bcf/d
- Rockies Express (Wyoming to Ohio), 1.8 Bcf/d
- Gulf South (Louisiana, Mississippi, Alabama), 560 MMcf/d
- Fayetteville Expansion (approved by FERC, 2009, Arkansas/Mississippi), 2.0 Bcf/d
- Ruby Pipeline (approved by FERC, 2010, Wyoming/California), 1.5 Bcf/d

While the Marcellus shale production is nominally in an area of abundant gas pipeline capacity, significant new pipe is necessary to connect and flow the gas into the system. Table 2 lists the announced pipeline projects in the northeast, mostly to serve Marcellus shale production.

FERC has been active in reviewing pipeline proposals and approving new pipelines and pipeline expansions. Over the last 5 years, FERC has approved approximately 68 Bcf per day of new pipeline capacity and 9,000 miles of new pipeline construction.[30] Not all of the pipes have been constructed. Nevertheless, pipeline owners and the FERC have been responsive to the need for additional pipeline capacity to bring new gas to market.

Table 2- Gas Pipeline Expansions in the Northeast

Pipeline - Expansion Name	Area	Capacity (MMcfd)	Planned In Service
Dominion Transmission - Dominion Hub II	Leidy PA to Albany NY	20	Nov-10
Dominion Transmission - Dominion Hub III	Clarington OH Reciepts	224	Nov-10
Dominion Transmission - Rural ValleyLine 19/20	NW PA to Oakford PA	57	Apr-10
Dominion Transmission - Appalachia Gateway	West Virginia to Oakford PA	550	Sep-12
Dominion Transmission - Marcellus 404 Project	West Virginia	300	Jan-00
Texas Eastern - TIME III	Oakford PA to Transco	60	Nov-11
Texas Eastern - TEMAX	Clarington to Transco	395	Nov-10
Texas Eastern - TEAM 2012	Interconnects OH, WV, PA	300	Nov-12
Texas Eastern - TEAM 2013	Interconnects OH, WV, PA	500	Nov-13
Spectra -TETCO - Algonquin - NJ-NY Expansion	Linden NJ to Staten Island NY	800	Nov-13
Spectra -TETCO - Algonquin - NJ-NY Expansion	Reverse flow of Algonquin	1150	Nov-13
National Fuel - West to East Phase 1	Overbeck PA to Leidy	200	Nov-11
National Fuel - West to East Phase 2	Overbeck PA to Leidy	300	Nov-12
National Fuel - Lamont Compression	Lamont PA	40	May-10
National Fuel/Empire - Tioga County Extension	Tioga PA to Corning NY	200	Sep-11
National Fuel - Line N Expansion	Alnong Western PA border	150	Sep-11
National Fuel - Appalachian Latteral	Clarington OH to Overbeck PA	625	Nov-11
Tennessee Gas Pipeline - Line 300 Line Upgrade	Line 300 across northern PA	350	Nov-11
Tennessee Gas Pipeline - Northeast Supply Diversification	New copression station near Niagara NY	50	Nov-12
Tennessee Gas Pipeline - MLN Project (Marcellus-Leidy-Niagara)	New copression station near Niagara NY	118	Nov-12
Tennessee Gas Pipeline - Northeast Upgrade Project	Line 300 to Interconnects with NJ Pipelines	636	Nov-13
Columbia Gas Transmission - Line 1570/Marcellus Shale	Northwest Pennsylvania	150	Jun-10
Columbia Gas Transmission - Line 1570/Line K Replacment	Northwest Pennsylvania	TBD	2011?
Columbia Gas Transmission - Columbia Penn Corridor Phase 1	Waynesburg PA to Delmont PA	101	Mar-10
Columbia Gas Transmission - Columbia Penn Corridor Phase 2	Leidy PA to Corning NY	500	Jun-12
Williams Transcontinetal - Northeast Supply Project	St195 SE PA to Rockway Deliv Lateral - National Grid NYC	625	Nov-13
Williams/Domminon - Keystone Connector	REX Clarington OH to Transco St195 SE PA	1000	Nov-13
Iroquois Gas Transmission - Metro Express	Waddington or Brookfield to Market areas	300	Nov-12
Iroquois Gas Transmission - NYMarc	Sussex NJ to Pleasant Valley NY	1000	Nov-14
Inergy Midstream - Marc I Hub Line	Bedford PA (Tenn) to Columbia Co PA (Transco)	550	Oct-11
Inergy Midstream - North-South Project	Tioga NY (Millenium) to Bradford PA (Tenn/Transco)	325	Nov-11
Laser Marcellus Midstream - Marcellus Gathering	Susquehanna PA to Millenium (NY)	60	2011
Williams Partners - Susquehanna Gathering(Cabot Oil)	Susquehanna PA to Luzerne PA (Transco)	250	Jun-11
EQT Midstream - EQT Gathering Expansion	WV and West PA	300-900	2013
EQT Midstream - Marcellus Eastern Access Hub	Braxton WV and Upshur WV	TBD	TBD
Dominion Transmission - Marcellus Gathering Enhancement	with Appalachia Gateway	50	Sep-12
PVR Midstream - AMI Gathering	Lycoming PA, Tioga PA, and Bradford PA	700	Nov-10

Source: ICF, compiled from various sources

B. New Approaches to Contracting

In addition to expanding natural gas supplies and the infrastructure necessary for timely delivery, a more stable horizon for gas prices may be facilitated by new contracting arrangements. For example, contracts that fix the terms for delivery of gas over several years, even with agreed price adjustments, may give producers and consumers, greater certainty in

[30] ICF calculations from Approved Pipeline Projects, FERC website, http://www.ferc.gov/industries/gas/indus-act/pipelines/approved-projects.asp

planning their businesses. In turn, the adoption of similar arrangements by other large producers and consumers could, over time, lead to greater overall price stability.

Other, commercial arrangements – including a greater use of physical and financial hedging (See Section C) may also moderate potential price variability for both producers and consumers.

The structure of gas purchase contracts has changed over the years, along with the regulation and structure of the market. The search for future contracting alternatives should be informed by this experience as well as a clear understanding of what can be achieved through the contracting process.

i. Common Contract Terms

Contracts for natural gas (and other energy commodities) are entered into by buyers and sellers to define the parameters of the energy transaction. Major terms typically will include:

- Term – length of the contract
- Volume – how much gas can or must be purchased, which may include a "base" volume and optional or "swing" amount or both. This can affect price stability to a degree, but the degree may be dependent upon the pricing terms of the base and swing. Base volumes combined with pricing terms provide a level of revenue certainty to the seller and a level of fixed obligations to the buyer.
- Price – can be fixed but is often based on a formula such as indexing a standard gas or other energy price
- Delivery Location --Title transfer point(s)
- Re-openers – what provisions will allow the contract to be renegotiated. This can also affect stability to a degree.
- Others – default, Force Majeure, arbitration, etc.

While there is no inherent limitation on the terms that can be negotiated between parties, there is a tendency for parties to gravitate towards contract structures that are common within the industry. This is not surprising since contracts that deviate significantly from industry norms can present risks that the parties may generally regard as excessive.

Pricing terms and contract length are arguably the most important elements of any commodity purchase contract, at least from an economic perspective. It is sometimes asserted that price stability can be achieved by requiring producers to offer a long-term, fixed price, variable volume contract – that is a contract that would allow the buyer to purchase as much or as little gas as desired at an absolute fixed price for a long period of time. However, such contracts have never been common in the gas industry, or in most commodity markets, because they represent an unbearable risk for producers because that would place the pricing and market risks wholly upon producers. Accordingly, in order to share the risks inherent in purchasing this commodity over an extended period, long term purchase contracts typically index[31] prices to market indicators or other commodities. As discussed elsewhere, the Task Force believes that greater availability and use of such contracts, even though allowing for price variability, will tend to provide greater market stability if only because the parameters of future price swings are bracketed by the contract and thus can be better factored into planning by both parties (e.g., through separate hedging arrangements).

ii. History of Long-term Gas Contracts

Prior to the restructuring of the natural gas industry, there was little scope for direct producer-consumer contracting in the natural gas market. Pipelines purchased gas from producers and resold the gas to LDCs or end use customers on a bundled basis. Moreover, in order to issue a Certificate of Public Convenience and Necessity for an interstate pipeline (as required by the Natural Gas Act of 1938), FERC required that the pipeline operator demonstrate sufficient gas supply to justify its construction. To meet this requirement, pipelines operators (not end users) generally entered into long term contracts to purchase gas, which they then used to meet FERC's certificate requirement.

These contracts contained a variety of pricing provisions based on delivery locations, customer

[31] The one exception may be historical coal prices, as discussed below.

classes and other terms. These pricing provisions, however, did not exist in a vacuum. In 1954, the U.S. Supreme Court decided the landmark case of Phillips Petroleum vs. State of Wisconsin, which held that, under the Natural Gas Act, the federal government might regulate the prices charged by natural gas producers when selling gas at the wellhead. From that point until adoption of the Natural Gas Wellhead Decontrol Act of 1989, the price paid under gas purchase contracts was almost exclusively determined by regulation.

Few if any of the long-term contracts of the period were “fixed price” contracts. As noted above, the pricing provision in the contract referenced the regulatory structure of the time and it also contained provisions, such as “favored nations” clauses, that assured a producer that the price received would be commensurate with the price received by other producers in the area. In other instances, the price might be indexed to distillate oil prices.

In addition to pricing terms, most of these contracts also contained “take or pay” provisions that assured a minimum revenue stream to the seller of the gas. As discussed later, these “take or pay provisions” created significant liabilities for gas purchases when the underlying gas market changed in the wake of restructuring.

In addition, other customers, most notably independent merchant power producers, developed contract practices that generally incorporated long-term contracts. Financial backers of new electric power plants often required developers to demonstrate that the project had obtained a reliable source of gas supply and the preferred method for making this demonstration was to enter into a long-term supply contract. These contracts often contained pricing mechanisms indexed to an alternative fuel, such as fuel oil, which influenced the competitiveness of the electricity generated at the facility. The contracts often also included “take or pay terms” similar to the pipeline gas supply contracts. Just as in the case of the pipeline gas supply contracts, the rigidity of the contracts created some liability issues as gas market supply and demand conditions and the structure of regulation changed.

In sum, while these contracts extended over (relatively) long periods of time, they were not fixed price and included a variety of other provisions that created liabilities for purchasers. For example, if oil prices increased, the indexed gas price would rise above the otherwise prevailing price but the buyer would be committed to continue purchasing a fixed amount of gas at the indexed price for the remaining life of the contract. Because of these liabilities and as restructuring created a more liquid gas commodity market that allowed participants to enter and exit commodity positions easily and at relatively low cost, industry practice shifted towards shorter contracts.

iii. Renewed Interest in Long-term Gas Contracts

In recent years, gas market participants, regulators, and other stakeholders have once again given attention to the appropriate role of long-term contracts in gas markets. At least some of the attention has related to the opportunity for long-term contracts to affect price stability for natural gas.

The Task Force believes that this renewed attention is a positive development. Long-term contracts that provide a degree of price stability, either through the use of fixed prices or pricing formulas that allocate or share the impact of unexpected changes in price levels, can be a useful tool in a diversified portfolio. With a portion of the overall portfolio stabilized, buyers and sellers have a greater ability to make investment decisions and invest capital in long-lived facilities. However, one must be aware, that “long-term” typically does not mean “fixed price” and probably implies a variety of other contractual obligations. Some of the parameters of such contracts are discussed below.

Long-term Contracts are a Tool in a Dynamic Portfolio

Long-term contracts are a tool, and not a panacea for promoting greater price stability in natural gas markets. Indeed, history has shown that over-reliance on fixed-price long-term contracts that do not reflect changing market dynamics can create a separate source of market instability and impose unwanted liabilities on market participants. During the 1985-1995 restructuring of the gas market, large “take or pay” liabilities developed, which created major commercial issues and had to be resolved in order to establish a more open market and trading environment.

Similarly, a number of independent power producers and developers of cogeneration projects that were designated as Qualified Facilities (QFs) under the Public Utility Regulatory Reform Act (PURPA), entered into long-term gas supply agreements where the pricing terms for a plant's entire portfolio did not reflect changes in gas market conditions. These contracts often resulted in extensive litigation and, in a number of instances, abrogation.[32]

Relational Contacts

As a component of a diverse and structured portfolio, long-term contracts that offer an element of price stability can be a useful tool in managing/sharing price risk. In addition, long-term bilateral contracts offer an opportunity to develop useful relationships between buyer and seller.

The economic literature and various articles in contract law discuss a class of contracts called "relational contracts." As stated by Schwartz and confirmed by Hviid , "[T]wo features define what lawyers mean by a relational contract: incompleteness and longevity." "Incompleteness refers to the fact that relational contracts do not provide all of the aspects to provide a deterministic outcome to the transactions in terms of the transfer of economic goods, services, or payment. In other words, the contract does not contain a complete specification necessary to determine the financial or product obligations of the buyer and seller. Rather, the contract determines the process and procedures that will govern the legal relationship between the parties.

Relational contracts often contain provisions that allow for mutual or unilateral renegotiation of contract terms including pricing and contract volumes. Other terms, including "market out" or "regulatory out" provisions can also play a role in relational contracts. The degree of "incompleteness" of relational contracts generally extends far beyond traditional "force majeure" provisions.

Relational contracts have flourished in other industries, such as the airline, automotive,

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[32] Examples include Devon Petroleum v. Pittsfield Cogeneration and Calpine v. California Department of Water Resources.

pharmaceuticals, biomedical and chemical development industries. Strategic alliances and joint ventures are often structured as relational contracts because of the need to address uncertainty and risk. Indeed some have lasted for decades. In these and other examples, relationships seek to generate synergies without vertical integration through a merger which, of course, is unlikely between most major gas producers and consumers

In terms of gas markets, where parties find it mutually advantageous related contracts as well as, joint ventures and partnerships, may offer new opportunities for parties to allocate gas price risk. A gas user can develop an effective hedge against gas price movements in the market by creating an implicit "long" position in gas production by participating and having an interest in production. But as is the case in any "hedging" strategy, the user would be forgoing some potential to benefit from an unexpected decline in gas prices. Likewise, relationship-specific contracts (or investments) may also create "switching costs" for a buyer who switches from one supplier to another.

Relationship-Specific Investment

Switching costs can be very large in a non-homogeneous product market. In energy, the market for coal is often cited as an example. A coal-fired power plant is "tuned" for specific attributes of the coal it is burning. Water content, sulfur content, ash content, Btu content and other physical attributes of the coal will all affect the operation of the power plant to greater or lesser degrees.

Switching costs can also exist in homogeneous product markets. These costs can arise from the "learning process" that occurs between parties for procedures and communications. In some markets, it can also arise when small "brand" differentiations exist. In some of the economic literature, costs associated with the identification of alternative supplies are also included as switching costs. In a sense, switching costs can be considered a subset of transaction costs.

It is in the context of switching costs that much of the discussion between produces/marketers of gas and industrial and power plant facility owners that are potential consumers has occurred. In both cases, there are significant costs that become sunk when a decision is made to invest and construct a gas-fired facility. As such, industrial and power generation customers have expressed concerns that the lack of any assurance that natural gas prices in the United States will remain stable and competitive with other options (e.g., other energy sources in the United States or locating facilities overseas) inhibits the construction of gas-fired facilities. In the discussion, the potential buyers have considered long-term contracts with a mechanism to provide price stability as a potential solution.

But this discussion involves two distinctly different concepts of "switching costs." In one case, the switching costs relate to a broad context for considering the market, the choice of energy type and geographic location for investment. In this sense, the switching costs are quite significant. In the second case, the switching costs are associated with the movement from one gas supplier to another gas supplier who is able to supply gas to a specific geographic location where a facility is located. In this sense, the switching costs are much smaller and potentially negligible. Increased market liquidity and increased homogeneity in gas quality specifications can significantly reduce the costs of switching from one supplier to another.

In a sense, the desire to enter into a potential long-term contract with a gas seller might be considered a "proxy" for a warrantee from the gas industry in total that gas will remain competitive. However, a long-term contract might not accomplish its economic goals in an effective manner and could have unintended consequences.

Once a contract is entered into with an individual supplier of natural gas, the buyer becomes subject to some level of credit and default risk associated with the individual supplier. The contract does not – and cannot – operate as a warrantee from the broader gas industry. To receive a level certainty, a buyer would need to evaluate the ability of a supplier to fulfill the terms of the contract. Only the largest suppliers would be very likely to meet such a test.

Acquisition of Gas Reserves by Gas Consumers

An additional alternative that has been used by some large gas consumers is to acquire their own physical reserves. Consumers, including Calpine, have utilized this strategy to hedge gas price risk associated with gas-fired power plants.[33]

Some firms that have regulated gas distribution company subsidiaries have also developed interests in the development of gas reserves. Examples include Energen and Questar. In these instances, this interest operates as a corporate hedge, with separate accounting for purposes of gas cost recovery. In general, the performance risk for gas production and prudence risk are kept completely separate.

Long-term Pre-purchase of Gas Supply

A number of municipally owned gas distribution companies, authorities, or divisions of government have taken a different approach to price stability. Some, albeit a small minority, have entered into pre-purchase agreements for multiple years of gas supply.[34] This can be particularly advantageous to municipal residents since the purchase can be financed with bonds that receive a measurable tax advantage and that benefit may further reduce the retail price ultimately paid by the LDC's customers.

Long-term Contracts for Regulated Entities

As was noted earlier, power plant construction decisions to build gas-fired units subject the project to certain risks from increases in the market prices of gas. One option is for the regulated electric utility to enter into a long-term contract that provides for more stable pricing.

As a regulated entity, however, the electric utility can be subject to the risk from a "prudence" review of the gas acquisition. One option to address this risk is to seek the pre-approval or a finding of prudence at the time that the long-term contract is executed. In some states, state regulators have the legal authority to grant pre-approval. In other states they do not and legislation would be needed to grant this authority.

[33] "Calpine Corporation to Acquire Sheridan Energy, Inc.; Calpine to Add 148 bcf of Proven Gas Reserves", Business Wire, August 25, 1999.

[34] "Municipalities Turn Again to Prepaid Gas Contracts", David Schumacher, Chadbourne & Parke LLP, March 14, 2007. Examples include: Tennessee Energy Acquisition Corporation (TEAC), Municipal Gas Authority of Georgia.

Likewise, regulated investor owned gas distribution companies face a similar regulatory risk. For an investor owned gas LDC, entering into a long-term is an asymmetric risk proposition unless pre-approval is granted. Gas LDCs do not earn their regulated return on the gas itself. A gas LDC's earnings are associated with the services provided to customers associated with installing the pipes, managing the operation and delivering reliable gas service to consumers consistent with the tariff and the obligation to serve.

If the gas LDC is found to be prudent in the gas acquisition function, there is little or no return associated with that performance. If the regulator finds that the utility was imprudent, then the disallowance comes directly out of the earnings of the utility.

When the prudence review occurs long after a contract is executed, there is a tendency to view the gas purchase in the light of market prices, which could not be known at the time a long-term contract was entered into. As a result, regulated gas utilities have an incentive to "match the market" in terms of prices so as to limit the regulatory risk of disallowance. Without some opportunity for pre-approval, there is an inherent tendency and incentive for regulated LDCs to forgo a portfolio that includes long-term contracts that provide some element of price stability.

The analysis of hedging developed for the Task Force found that "While electric and gas utilities are making far greater use of hedging tools relative to the 1990s, the hedging programs implemented by many of them could almost certainly benefit from some enhancements.[35]"

In view of the foregoing, and as detailed below (see section IV) the Task Force believes that state regulators should revisit the framework for regulated entities to enter into long term gas contracts to ensure that the potential public benefit arising from more diverse gas portfolios by LDCs are not unreasonably foreclosed.

iv. Effect of Accounting Policies on Long Term Contracts

1. A summary of the current accounting treatment for spot, 1 year, 3-5 year, and 5-10 year gas procurement agreements by large natural gas consumers that are subject to SEC disclosure requirements. Specifically address the following:

[35] *"Managing Gas Price Volatility"*, The Brattle Group, prepared for the Task Force on Ensuring Stable Natural Gas Markets, July 2010

a) How do current FASB rules require a company to report contractual purchase obligations for natural gas on the company's balance sheet? How do FASB rules require companies to report natural gas purchases from the spot market?
b) Do FASB rules provide a disincentive for companies to enter into contracts for natural gas purchases? Do FASB rules incentivize spot market purchases?
c) Provide two real world examples using a natural gas fired power generator and a chemical manufacturer as models.

2. The scope for obtaining waivers from, or the reform of the quarterly mark to market requirements for intermediate-to-long term natural gas purchase agreements.
3. A summary of the arguments both for and against allowing non-mark to market treatment or classification of purchase arrangements (i.e., why an alternative valuation approach could reflect fair value and serve as an adequate disclosure to stock holders; why not?).

Based on the above, this Task Force has recommended that the CFTC and other federal regulators exercise caution in adopting measures that would limit the scope of bona fide hedging opportunities in the natural gas market. Given the potential benefits associated with the domestic production increase described above, it is important that producers (and consumers) have an adequate range of affordable commercial hedging opportunities to bring this supply to the market at reasonable prices. Regulations that unreasonably limit such arrangements would be counter-productive and could lead to more not less price stability.

C. Financial and Physical Hedging[36]

Hedging promotes a third major tool for enhancing price stability for both buyers and sellers of natural gas. Hedging enables market participants to manage exposure to commodity price volatility risk. Many firms and business entities that require large volumes of one or more commodities in the production of their products or services engage in hedging activity to manage the price volatility risk. Simply put, hedging reduces price uncertainty.

i. Objectives, Costs, and Limitations of Hedging

In its simplest form, hedging is a process which allows the buyer (or seller) to set the price of a commodity at the time the hedge is created for some or all of a commodity that will be

[36] Includes information from "*Managing Gas Price Volatility*", The Brattle Group, prepared for the Task Force on Ensuring Stable Natural Gas Markets, July 2010.

available at some time in the future. Hedging can be accomplished with forward contracts for physical delivery of the commodity or through the use of financial derivatives.

There are a number of elements of a hedging program that can be employed by any entity to achieve hedging objectives. A number of financial instruments, generally called financial derivatives, are available to business entities to facilitate risk management objectives. While the specific structure of these financial instruments can be quite complicated and differ widely in its elements, the design and function of the instruments in a hedging program is relatively straight forward. A firm enters into a contractual obligation that involves payment or receipt of an agreed sum to offset the price risk associated with selling or buying the physical commodity in the future.

> **Hedging Example:**
> **Use of a NYMEX Futures Contract**
>
> Futures contracts allow buyers and sellers to achieve price certainty. For example, a buyer of a futures contact might purchase a January 2012 NYMEX futures contract today for $6.00/MMBtu, which provides the right and obligation to purchase gas at that price at that time. If Henry Hub spot prices in January 2012 turn out to be $8.00/MMBtu, the buyer will experience a $2.00/MMBtu gain on the futures contract, thereby achieving an effective gas price in January 2012 of $6.00/MMbtu (assuming the buyer purchases spot gas for $8.00/MMBtu at that time). Likewise, if Henry Hub prices are $4.00/MMBtu in January 2012, the buyer will experience a $2.00/MMBtu loss on the futures contract, again achieving an effective gas price of $6.00/MMBtu.

Financial derivatives have pluses and minuses. When properly applied, financial derivatives provide a manageable cost for risk mitigation and an efficient method for transferring risk. The use of financial derivatives allows for varying degrees of risk mitigation ranging from elimination of the vast majority of market volatility for the coming year to elimination of only the risk associated with the most extreme price movements.

Like other forms of risk management and insurance designed to address volatility, the level of uncertainty that is mitigated using derivatives is commensurate with the cost of the protection. Some risk management strategies can be quite costly, requiring an upfront payment that is analogous to a significant insurance premium. Other strategies may require the surrender of financial gains in exchange for minimization of financial losses. In its pure form, hedging does not provide a means to reduce the expected fuel cost of an electric utility, but rather a method to mitigate the impact of price volatility. Fundamentally, sound risk management constantly monitors the risk-reward levels of all strategies in place.

Nevertheless, strategies that utilize financial derivatives generally have significant advantages over strategies that rely exclusively on physical forward contracts. They are generally more liquid, meaning that the positions can be entered into and exited more easily. Importantly, derivatives will also often have lower transaction costs.

In the context of intermediate and long-term gas price stability, hedging has a significant limitation. Relatively liquid markets for natural gas derivative markets exist for a year or two in the future. However, there is no liquid market for derivative products that extend for a period of 5 to 10 years and are suitable for managing price risk associated with investment in long-lived facilities such as power plants, refineries, or large industrial facilities. As such, while extremely important in the management of price movements, hedging does not provide a complete solution to the changes of gas price stability in the intermediate and long-term.

ii. State Regulatory Treatment of Electric and Gas Utility Hedging Programs

Gas price movements and instability present a number of significant challenges to regulated entities such as electric utilities and local gas distribution companies (LDCs). Chief among these is the risk to the financial performance created by the potential for significant shifts in gas price levels from one heating season or year to the next. When gas prices rise significantly compared to the previous year, the regulated entity faces additional risk in four distinct areas:

1) Financial risk related to decreased throughput,

2) Risk created by an increase in uncollectable accounts receivable (e.g., bad debt),

3) Increases in operating costs associated with increased shut-off and reconnect activity, and,

4) Regulatory risk of disallowance of costs.

As hedging practices evolved, state Public Utility Commissions were faced with establishing the process by which hedging programs would be reviewed. Costello and Cita[36] describe the process and issues facing regulators in the following manner:

1) How hedging fits in with the utility's more traditional gas-management strategy, which involves the purchase of both physical gas and storage, with the latter functioning as a risk management tool affecting both price and operating risk;

2) Establishing the prudent fixed budget for risk management programs;

3) Identifying, among the infinite number of alternatives, a specific risk management strategy or set of strategies that is reasonable for a particular LDC;

4) Establishing regulatory incentives for utility hedging and recovery provisions pertaining to hedging program costs;

5) Specifying the operating features of a hedging program, which can include specific safeguards or limits and reporting requirements;

6) Evaluating the effectiveness of different hedging tools, and;

7) Developing "prudence" standards by which to evaluate a utility's hedging practices.]

States have developed different approaches to the review of LDC hedging activity. The diversity and lack of uniformity makes it difficult to generalize but certain observations regarding programs and program review are possible. First, there is no "inherently correct" level of hedging. Hedging programs can provide various degrees of price protection. There is, however, “no free lunch.” Greater amounts of price protection can only be achieved with a commensurate increase in the tradeoff of forgone potential for gas price reductions or increase in “upfront” costs analogous to insurance premiums.

Second, the appropriate level of price protection desired from hedging should reflect the views of the regulators and the utility operating as a proxy for customer preference. These may include rate spikes by paying an “upfront” cost that is similar to an insurance premium for protection against unanticipated cost increases. In the best case, regulators and the utility create a process to discuss, ex-ante, the objectives and the degree of price protection desired. This type of process, however, does not exist in all jurisdictions.

The lack of guidance that exists in many jurisdictions creates regulatory risk for the utility that ultimately may be reflected in the utility’s cost of capital and/or other elements of utility costs. In many jurisdictions, there is only limited guidance provided by the regulators as to the level of hedging that the regulators consider appropriate. This relative lack of *ex-ante* guidance can be an impediment to the development of program that provides the greatest degree of price protection a minimum costs.

D. Potential Impact of Financial Reform on Hedging Options

The Dodd–Frank Wall Street Reform and Consumer Protection Act (Pub.L. 111-203, H.R. 4173) was signed into law by President Barack Obama on July 21, 2010. The legislation, which was intended as a response to the factors that led to the financial crisis of 2009, is broad and far-reaching in its scope. Title VII of the legislation, which addresses the oversight and regulation of financial derivatives (swaps) including natural gas and other energy products, has the potential to significantly alter the nature of – and cost of – price risk mitigation for gas buyers and sellers alike.

Many of the details of the regulation have yet to be promulgated by the Commodity Futures Trading Commission (CFTC) and other agencies with jurisdiction in the physical and financial markets. These include the establishment of important exceptions for end-users, *bona fide* hedges, and establishing “*de minimis*” participants.

Although there is an expectation that the "end user" exemption will apply to a large number of risk management transactions that use derivatives for hedging purposes, parties will need to verify that individual transactions meet the eligibility criteria for the "end user" exemption. In addition, standardized futures contracts in energy may become subject to many additional regulatory requirements from which they are currently exempt.

Under Title VII, the CFTC can require that any swap , including natural gas and other energy products, be cleared by a centralized clearing house for any over the counter product, i.e., not transacted through a regulated exchange. In addition, the legislation and pre-proposals for regulation, among other things contemplate the imposition of additional; 1) Marginal and collateral requirements; 2) Capital requirements; 3) Segregation of funds, and 4) Regulation of exchanges and swap execution facilities (SEFs).

In addition, many participants in the markets will be subject to new business conduct standard and reporting requirements that are yet to be adopted by regulators. These standards are likely to create costs associated with compliance and record keeping as well as liabilities for the actions of individuals within the organizations.

Economists who have examined the legislation and proposals for regulation have expressed concerns regarding the impact on:

- The administrative and economic costs of hedging;
- The number and type of derivative contracts that will be transacted in the markets;
- The liquidity of contacts that are available and the costs associated with transaction as manifested by larger bid-ask spreads;
- Potential for increased "unhedged" basis risk;
- Increases in balance sheet risk for participating entities;
- Increase in risk for market users and their customers.

In addition, the legislation significantly complicates the regulatory landscape, creating the potential for overlapping jurisdiction and regulation for natural gas and energy market participants. For example, transactions that involve basis risk and physical gas could be subjected to regulation by CFTC, FERC or both, with different timelines for recordkeeping and reporting. In short, while the new regulations are still unclear, they risk limiting the ability of gas market participants to limit price risk through financial methods.

In general, once promulgated, we expect that the regulations will limit the availability and increase the cost of tools that are used by market participants to manage price risk and achieve greater price stability. The increase in cost is likely to affect even those transactions that are exempt from the new regulations. Exempt transactions are likely to be subject to increased costs and reduced availability and liquidity due to the capital that will be reserved and the margin that will have to be posted by financial institutions, swap dealers, and major swap participants that may be counterparties.

IV. Conclusions, Recommendations and Next Steps

Current understanding of the extent of the North American natural gas resource base suggests that the United States is well-positioned to take advantage of natural gas as a low-emitting, domestic, fuel that can be used across the economy in diverse, efficient applications. The investment required to produce and make use of this resource requires confidence that the resource can be developed at moderate and stable prices. While the available information suggests that the underlying resource itself will go a long way towards ensuring this outcome, the Task Force offers the following recommendations.

1. Recent developments allowing for the economic extraction of natural gas from shale formations significantly reduce the susceptibility of gas markets to price instability and provide an opportunity to expand the efficient use of natural gas in the United States

2. Government policy at the federal, state and municipal level should encourage and facilitate the development of domestic natural gas resources, subject to appropriate environmental safeguards. Balanced fiscal and regulatory policies will enable an increased supply of natural gas

to be brought to market at more stable prices. Conversely, policies that discourage the development of domestic natural gas resources will reduce the supply that can be brought to market, which will have an adverse effect on the stability of natural gas prices.

3. The efficient use of natural gas has the potential to reduce harmful air emissions, improve energy security, and increase operating rates and levels of capital investment in energy-intensive industries.

4. Public and private policy makers should remove barriers to assembling a diverse portfolio of natural gas contracting structures and hedging options. Long-term contracts and hedging programs are valuable tools to manage natural gas price risk. Policies, including tax policy and accounting rules, which unnecessarily restrict the use or raise the costs of these risk management tools, should be avoided.

5. The National Association of Regulatory Utility Commissioners (NARUC) should consider the merits of diversified natural gas portfolios, including hedging and longer-term natural gas contracts, building on its 2005 resolution. Specifically, NARUC should examine:

> a) Whether the current focus on shorter term contracts, first-of-the-month pricing provisions, and spot market prices conflicts with the goal of enhancing price stability for end users,
>
> b) The pros and cons of long-term contracts for regulators, regulated utilities and their customers,
>
> c) The regulatory risk issues associated with long-term contracts and the issues of utility commission pre-approval of long-term contracts and the look-back risk for regulated entities, and
>
> d) State practices that limit or encourage long-term contracting.

6. As the Commodity Futures Trading Commission (CFTC) implements financial reform legislation, and specifically, Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (Pub. L. 111-203), the CFTC should preserve the ability of natural gas end users to cost-effectively utilize the derivatives markets to manage their commercial risk exposure. In addition, the CFTC should consider the potential impact of any new rulemaking on

liquidity in the natural gas derivatives market, as reduced liquidity could have an adverse affect on natural gas price stability.

5. Policy makers should recognize the important role of natural gas pipeline and existing import and storage infrastructure in promoting stable gas prices. The policies that have underpinned the development of a robust gas transmission and storage infrastructure including streamlined regulatory approval and options for market based rates for storage in the United States should be continued.

9. Finally, regulators should be mindful of the lead time required for markets and market participants to adjust to new policies.

V. Appendices (*All to be Added*)

A. Glossary

B. Task Force Members

C. List of Workshops and Papers

D. [Selected State PUC Regulations on Gas/Electricity LDC Hedging]

E. [Summary of Relevant FERC Rules and Dockets]

C. Task Force on Ensuring Stable Natural Gas Markets – List of Commissioned Papers

Title	Author	Affiliation	Summary
Natural Gas Price Volatility: Lessons from Other Markets	Austin Whitman	M.J. Bradley & Associates, LLC	The report draws lessons from markets in the U.S., Europe, and Asia to determine (1) how natural gas markets are structured in the largest consuming regions of the world, (2) the effect that exposure to natural gas prices has had on corporate performance, and (3) how natural gas price movements relate to those of other commodities.
Long-term Contracting for Natural Gas	Bruce Henning	ICF Consulting	This paper defines the objectives and elements of long-term contracts; traces the evolution of natural gas contracts; assesses the economic value of long-term contracts; analyzes the relationship between long-term contracts and natural gas price stability; and examines natural gas contracts for regulated entities.
Managing Natural Gas Price Volatility	Steve Levine	The Brattle Group	This paper describes gas market risk characteristics; identifies risk management principles and tools for managing price volatility; describes risk management processes and controls, and analyzes limitations in managing

			price volatility; and compares industry hedging practices.
New Approaches to Reducing Natural Gas Price Instability: Implementing Legal, Regulatory and Financial Options	Andrew Weissman	Carter, Ledyard and Milburn	The author identifies obstacles to reducing price instability and opportunities to address long-term price uncertainty and price spike risk through legal, regulatory, and financial mechanisms.
Staff Memo assessing the extent to which water challenges, particularly water availability, may affect shale gas production	Lourdes Long	BPC Staff	How might water availability challenges constrain efforts to expand shale gas production? This memo summarizes the main water impacts associated with shale gas development in order to address this central question.
Introduction to North American Natural Gas Markets Supply and Demand Side Drivers of Volatility Since the 1980s	Rick Smead	Navigant Consulting, Inc.	This paper examines the history of chronic natural gas price instability across three periods from 1976-2010, and identifies fundamental changes in supply and demand that could influence natural gas markets going forward.

Impact of LNG and Market Globalization	Ken Medlock	Rice University's James Baker Institute for Public Policy	This paper seeks to answer central questions about LNG and market globalization: What are the potential impacts of North American LNG imports and exports on natural gas price volatility? Given the relative abundance of shale gas in North America, is there any reason to believe that LNG imports will rise in the coming years? In the US, how do LNG, the domestic shale gas resource, and domestic storage interact? If there are any potential adverse impacts of globalized gas trade and increased LNG imports, are there policy options available to mitigate the adverse impacts?
Abundant Shale Gas Resources, Short-Term Volatility, and Long-Term Stability of Natural Gas Prices	Stephen Brown and Alan Krupnick	Resources for the Future	This paper examines the extent to which natural gas prices are likely to remain attractive to consumers. The authors examine how the apparent abundance of natural gas and projected growth of its use might affect natural gas prices, production and consumption, using NEMS-RFF to model a number of scenarios through

			2030.