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TASK FORCE ON ENSURING STABLE NATURAL GAS MARKETS

Disclaimer

This report is the product of a Task Force with participants of diverse expertise and affiliations, addressing many complex and contentious topics. It is inevitable that arriving at a consensus document in these circumstances entailed compromises. Accordingly, it should not be assumed that every member is entirely satisfied with every formulation in this document, or even that all participants would agree with any given recommendation if it were taken in isolation. Rather, this group reached consensus on these recommendations as a package, which taken as a whole offers a balanced approach to the issue.

It is also important to note that this report is a product solely of participants from the BPC–ACSF convened Task Force on Ensuring Stable Natural Gas Markets. The views expressed here do not necessarily reflect those of the Bipartisan Policy Center or the American Clean Skies Foundation.

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Letter from the Co-Chairs

Over the last year, we have been privileged to co-chair an unusual and highly productive Task Force that was formed to review the conditions for creating a more certain U.S. market for using and producing natural gas.

The Task Force brought together a remarkable group of industry participants and experts, including industrial consumers, electric utilities, independent and integrated gas producers, chemical companies, public utility regulators, environmental experts, financial analysts and consumer advocates. Together, we approached our inquiry from a wide range of perspectives, but with a common interest in working to ensure that market conditions support increased investment in efficient gas production and end-use technologies.

This is an important public-interest challenge with far-reaching consequences. The United States recently became the world's largest natural gas producer. Meanwhile, in a few short years, technology advances combined with new shale gas discoveries have more than tripled estimates of the nation's economically recoverable natural gas resources. In the context of a dramatically improved supply outlook, expanding our use of this comparatively clean–burning, domestic fuel in an efficient manner is a winning proposition for consumers, for America's economy and industrial competitiveness, for the environment, and for our nation's energy security.

Good news, in other words, rather than concern over some pending crisis, provided the inspiration and backdrop for our deliberations. But Task Force members were also aware that the price instability that has come to be associated with natural gas markets in past years still raises investment uncertainty for gas suppliers and users alike. And so long as this is the case, some of the opportunities associated with efficient applications of gas technologies are likely to be realized more slowly than need be.

The findings and recommendations in this report reflect optimism that the robust supply horizon for natural gas presents fresh opportunities—not only to move beyond prior market concerns but to develop new tools for managing price uncertainty. Fundamental changes in the domestic supply and demand balance for natural gas, including an unprecedented level of available storage and import capacity, should allow markets to function more efficiently and fluidly in the future. This should create more favorable investment conditions and significantly dampen the potential for destructive cycles of price volatility and market instability.

At the same time, our work emphasizes the importance of actions by regulators and private market participants to ensure that these positive trends materialize as quickly and fully as possible. In particular, we urge the industry and regulators to re-evaluate the scope for using longer-term gas purchasing arrangements for managing price risk in the context of a diversified supply portfolio. The report also stresses the need for environmental protections so as to secure continued access to, and public support for, the development of shale gas reserves. Finally, though the Task Force did not address issues of aging infrastructure or pipeline integrity, we acknowledge that concerns involving the safe handling and transportation of natural gas must be fully vetted and satisfactorily resolved. Public safety is not an area for compromise.

Our recommendations are pointed at government policymakers, federal regulators, state utility commissions, producers and major consumers. We welcome feedback and look forward to working with all stakeholders to leverage the considerable potential of natural gas in building a clean energy foundation for American prosperity.

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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 price run-ups and 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 advances in horizontal drilling and hydraulic fracturing have 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 resources 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.

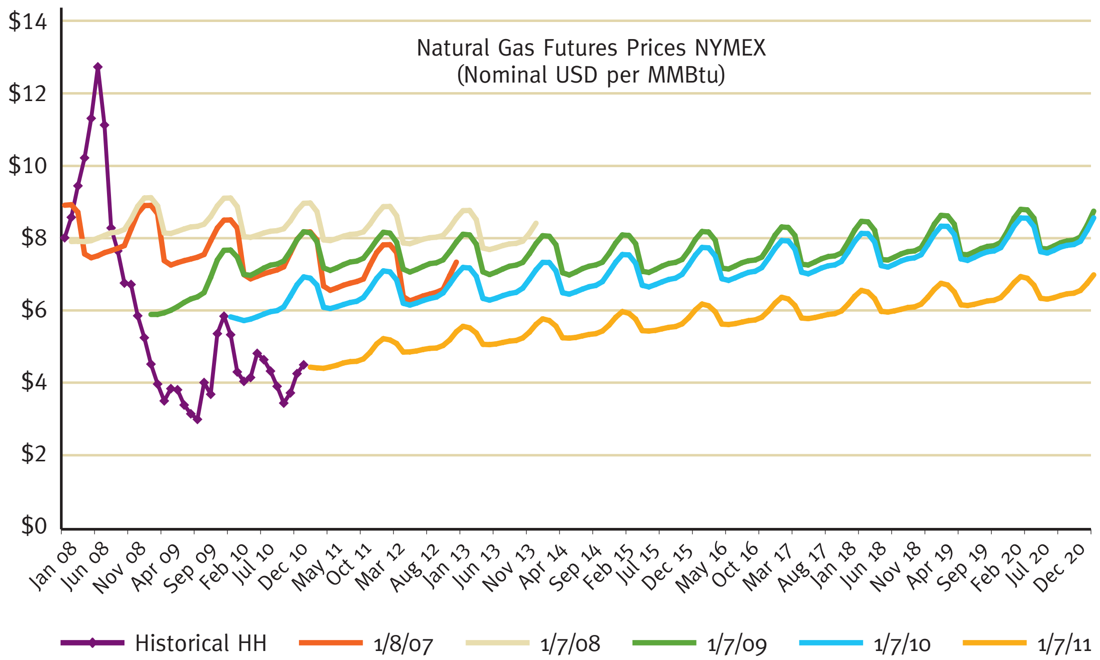
With these developments in gas supply, the market for natural gas has shifted in a profound way. Price expectations, as shown in Figure 1, have declined dramatically as the full impact of new technology for identifying and developing natural gas supplies has been recognized.

In combination with recent investments to expand capacity for storing, transporting and importing natural gas, these supply developments 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.

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, residential and commercial consumers, electricity generators and large industrial users will need confidence that gas prices will be

Technological advances in horizontal drilling and hydraulic fracturing have unlocked a tremendous volume of additional gas resources in North American shale gas formations.

Figure 1. Natural Gas Futures Prices - 2008 to 2010



Note: Henry Hub (HH), Louisiana, is a major production area delivery point in the gas industry. The NYMEX Natural Gas Futures contract uses the Henry Hub price as the reference price.

Source: New York Mercantile Exchange.

Together with a vastly improved supply outlook, the Task Force believes 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.

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 Task Force on Ensuring Stable Natural Gas Markets (hereafter “Task Force”) was jointly convened by the Bipartisan Policy Center and the American Clean Skies Foundation in March 2010 to examine historic causes of instability in natural gas markets and to explore potential remedies. The membership of the Task Force is unique in its diversity and unique in the sense that it brings together key stakeholders from both sides of the supply–demand equation. Individual Task Force members are listed in the Preface; they represent natural gas producers, transporters and distributors, consumer groups and large industrial users, as well as independent experts, consumer advocates, state regulatory commissions and environmental groups.

Over the course of five 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 prices and considered how recent shale gas discoveries and other, infrastructure-related developments affect the likelihood that similar price shocks might recur in the foreseeable future.[1] The Task Force also developed a comprehensive set of recommendations aimed at bolstering consumer, policy maker and investor confidence in the stability of future gas markets and at improving the tools available for effective price risk management.

[1] For a list of commissioned research papers see Appendix B.

Together with a vastly improved supply outlook, the Task Force believes 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.

Key Task Force Findings and Recommendations

1. Recent developments allowing for the economic extraction of natural gas from shale formations 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, that discourage demand, or that drive or mandate inelastic demand will disrupt the supply-demand balance, with adverse effects on the stability of natural gas prices and investment decisions by energy-intensive manufacturers.

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 using 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 measures and accounting rules, that unnecessarily restrict the use or raise the costs of these risk management tools should be avoided.

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.

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.[2] Specifically, NARUC should examine:

a. Whether the current focus on shorter-term contracts, first-of-the-month pricing provisions and spot market prices supports 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, including 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.

7. Policy makers should recognize the important role of natural gas pipeline and storage infrastructure and existing import infrastructure in promoting stable gas prices. Policies to support the development of a fully functional and safe gas transmission and storage infrastructure both now and in the future, including streamlined regulatory approval and options for market-based rates for new storage in the United States, should be continued.

[2] National Association of Regulatory Utility Commissioners. Resolution on Long-Term Contracting. Adopted by the NARUC on November 16, 2005. http://www.naruc.org/Resolutions/GAS-1Long-TermContracting.pdf

8. 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 the deregulation of gas commodity markets 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 Rita and Katrina, which temporarily curtailed gas supplies from the Gulf of Mexico. Though prices fell again after both of these events, 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 natural gas, are likely to be especially hard hit by major price run-ups in the U.S. market. Higher natural gas prices are also passed on to smaller users such as homes and businesses. Regulated gas distribution companies are required to pass on the cost of gas they purchase for consumers at cost (without price markup or markdown). 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 has meant that prices are tightly coupled to 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, U.S. capacity for receiving liquefied natural gas (LNG) shipments (now equivalent to roughly 20 percent of annual demand) and U.S. capacity for storing gas (likewise equivalent to about 20 percent of annual demand) is greater than at any time in the past. Together with a robust pipeline network, these changes in import

Natural gas plays a uniquely important role in the U.S. economy because it is used across multiple sectors of the economy and in a wide variety of applications.

and storage capacity by themselves would have been expected to help mitigate 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. In 2003, the National Petroleum Council estimated recoverable shale gas resources at 35 trillion cubic feet (Tcf). Six years later, in 2009, another widely respected group, the Potential Gas Committee, estimated the resource base at more than 616 Tcf, based on 2008 industrywide data (Table 1).

- The technologies used to extract shale gas, including horizontal drilling and sequenced, multi-stage hydraulic fracturing, were pioneered in the 1980s. Since then, the shale gas industry has matured and the technologies involved have become more sophisticated and cost-effective. ICF International, Inc. recently estimated that almost 1,500 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 be among the most important factors 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 production activities.

In recent years, a number of stakeholders and observers have called for a return to a greater reliance on long-term contracts between gas suppliers and purchasers to help address price risks and to promote price stability.

- The most important environmental issues related to shale gas production include the potential for water contamination if proper procedures aren't followed; water consumption for fracturing operations, particularly in areas where water resources are already stressed; and air 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 revisiting existing 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.

- Contract mechanisms to hedge future price variability 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 a greater reliance on long-term contracts between gas suppliers and purchasers to help address price risks and to promote price stability. Such contracts can play a useful role as part of a diversified portfolio. However, the current fair value accounting treatment for some of these contracts (e.g., quarterly market pricing, also known as "mark-to-market") may discourage some buyers and sellers from using such contracts due to the unknown impact of future quarterly disclosures to investors on corporate balance sheets. Similarly, some public utility commission (PUC) rules (e.g., regarding when gas purchase costs may be recovered from ratepayers) may also discourage regulated gas suppliers from using such contracts to manage the impact of price variability even though they might benefit customers.

- 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. Nevertheless, various forms of long-term contracts and other options (such as direct acquisition of gas reserves or long-term pre-purchase arrangements) are available to provide an element of price stability, while also minimizing downside risks to the parties involved.

- Hedging 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. 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 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 initiatives could go a long way toward building that confidence. These initiatives should be combined with continued efforts to better characterize the domestic gas resource base; address environmental concerns; develop improved extraction technologies; and provide critical pipeline, import and storage capabilities.

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 suggests that here is at least one important area—natural gas markets—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 natural gas resources. Natural gas is a comparatively clean-burning fuel that can be efficiently used for heat and power generation in many contexts. It is also an important chemical feedstock. Yet, despite these attractive characteristics, natural gas has been perceived until recently as a limited energy source that cannot meet all of domestic demand. This has led to policy debates over how and where the nation's "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 substantial North American shale gas resources began to dramatically increase the economically recoverable supply of natural gas. Indeed, current estimates suggest that identified U.S. gas resources 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, security and economic goals.

The efficient use of natural gas can provide a cleaner, low-carbon, low-cost alternative to the use of other fossil fuels in the electric power and industrial sectors. Notably, President Obama, in his 2011 State of the Union address, called for a new federal clean energy standard for generating electricity that could be satisfied, in part, by using natural gas.[3] Gas can also play a critical role in rebuilding a vigorous, globally competitive manufacturing base here in the United States. To make the most of this potential, it will be 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

CURRENT ESTIMATES SUGGEST THAT IDENTIFIED U.S. GAS RESOURCES ALONE COULD SUPPORT MORE THAN 100 YEARS OF DEMAND AT PRESENT LEVELS OF CONSUMPTION.

[3] Obama, B. H. Address before a joint session of the Congress on the State of the Union, January 25, 2011. Retrieved from The Office of the Press Secretary, The White House: http://www.whitehouse.gov/the-press-office/2011/01/25/remarks-president-state-union-address

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.

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.

In sum, with the prospect of a steady increase in domestic natural gas resources (see e.g., Table 1), 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[4] and the American Clean Skies Foundation[5] 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, transporters 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 Preface for a list of members).

During 2010, the Task Force held three daylong workshops to review 11 commissioned papers and policy briefs (see Appendix B). The Task Force also held five working meetings in 2010 and 2011. As a result of this yearlong 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 Structure

The body of this report is organized as follows: Section II 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.

[4] The Bipartisan Policy Center (BPC) is a non-profit organization that was established in 2007 by former Senate Majority Leaders Howard Baker, Tom Daschle, Bob Dole and George Mitchell to develop and promote solutions that can attract public support and political momentum in order to achieve real progress. The BPC acts as an incubator for policy efforts that engage top political figures, advocates, academics and business leaders in the art of principled compromise.

[5] The American Clean Skies Foundation is a Washington, D.C. non-profit organization, created in 2007 to advance energy independence and a cleaner, low-carbon environment through expanded use of natural gas, renewable energy and efficiency.

II. BACKGROUND ON NATURAL GAS MARKETS, USE AND SUPPLY

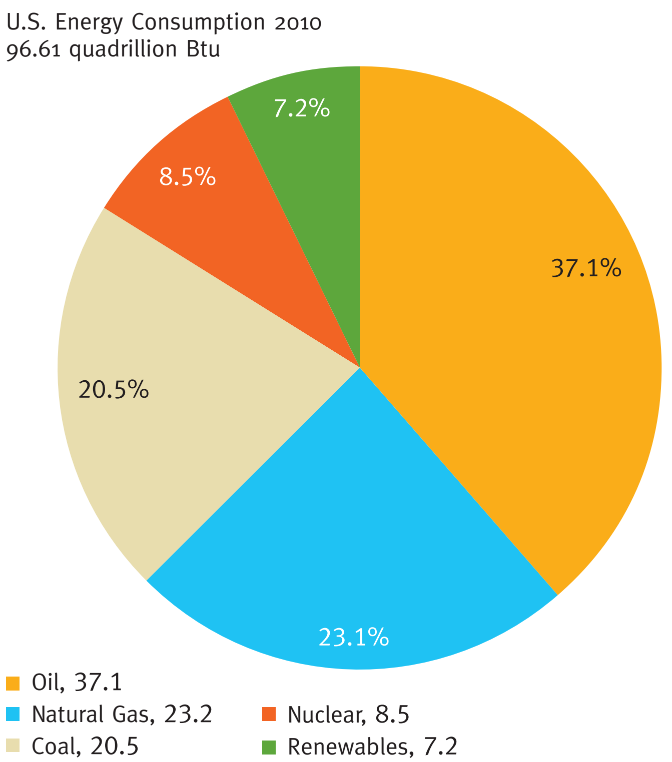
A. Uses and Markets

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 2 shows that natural gas is the second largest primary source of energy in the United States, behind petroleum and slightly ahead of coal.

Moreover, natural gas is unique among the energy sources shown in Figure 2 in that it plays a major role in multiple, diverse sectors of the economy. Figure 3 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.

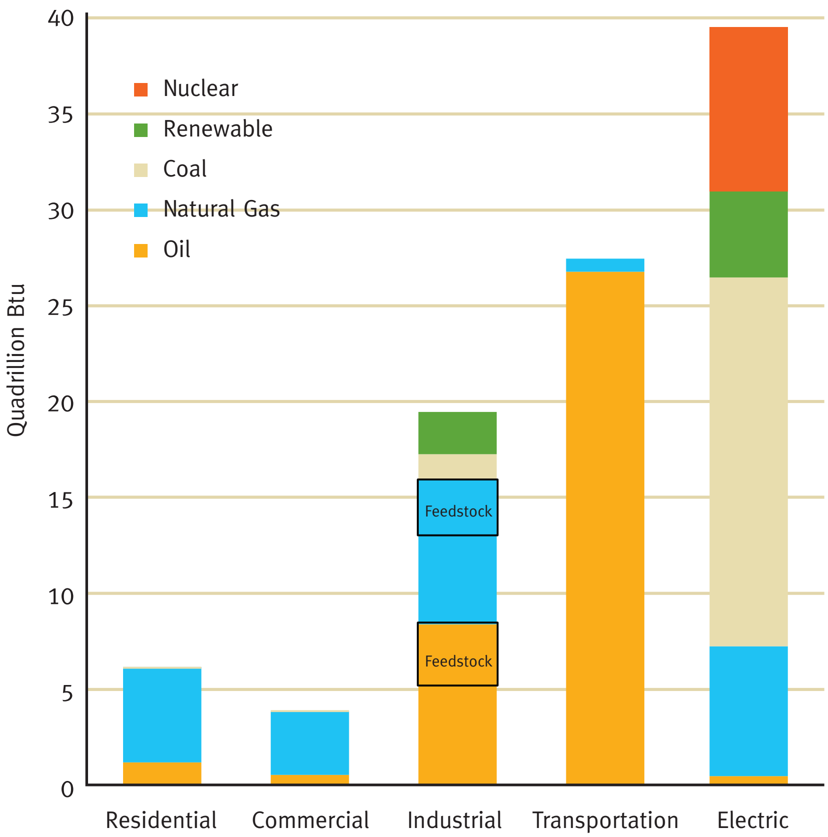
Because natural gas has been supply-constrained at various times over the last few decades, this diversity of end uses has also created real or perceived competition between sectors and/or customer classes for access to gas supplies. Policymakers have debated

Figure 2. U.S. Energy Mix - 2010



Source: U.S. Energy Information Administration. Annual Energy Outlook 2010.

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



Source: U.S. Energy Information Administration. Annual Energy Outlook 2010.

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 Power Plant and Industrial Fuel Use Act.[6] Thus, uses of natural gas have at times been subject to direct government regulation in a way that generally has not been applied to other fuels. These interventions failed to recognize that limiting potential markets inevitably had an impact of exploration and production activity.

The sources and applications of different fuels also affect their pricing. U.S. demand for natural gas 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 United States 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 meant plant operators could purchase coal from a limited number of mines or suppliers. 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. This has resulted in more flexible contracting structures and reduced 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

[6] 42 U.S.C. 8301 et seq. This Act 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.

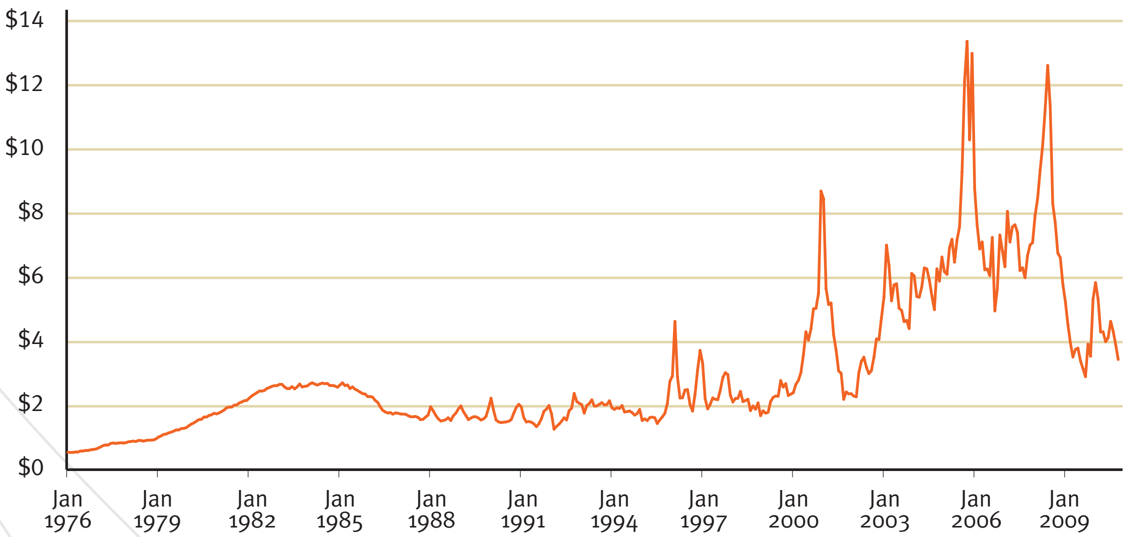
in the price of crude oil are passed through very directly to all customers; an increase in the world oil price is quickly reflected at the gasoline pump.

The majority of natural gas customers are small residential, commercial and industrial customers who purchase gas from regulated local distribution companies (LDCs).[7] The LDCs purchase gas from producers and are required by law to sell the gas to their customers at the price they paid for it. This means LDC customers will generally see any natural gas price increases or decreases. However, LDCs use a variety of physical and financial strategies to manage their costs, and this often helps buffer the immediate impact of short-term price movements. In addition, the consumer gas bill is made up of two parts: the cost of delivering or distributing the gas, and the cost of the gas itself. The LDC delivery charge is regulated by PUCs or municipalities and tends to be relatively stable, generally increasing at approximately the rate of inflation over time. For these reasons, the price of natural gas service to small consumers is typically 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 4 shows U.S. natural gas prices from 1976 through the end of 2010.[8] It shows a period from the early 1980s to mid-1990s when gas prices stayed roughly stable at around $2 per thousand cubic feet (mcf). Starting in 1996, variability increases. In 2000, prices increased sharply but then declined again in 2001. Price spikes reappeared in 2005 and 2008, but prices have since declined sharply and now 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

Figure 4. U.S. Natural Gas Price 1976 to 2010 (Nominal dollars)[9]



Source: U.S. Energy Information Administration.

[7] Note that power generation users are also exposed to gas price variability, and that the owners of power generation are typically not LDC's.

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

[9] Energy Information Administration, U.S. Department of Energy, http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm

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 more than $12/mcf. At or below the middle end of this range, the price of natural gas may 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.

TODAY'S COMPETITIVE NATURAL GAS MARKET IS ONLY 17 YEARS OLD AND THE MAJOR SOURCES OF NATURAL GAS HAVE CHANGED.

B. History and Sources of Price Variability

The U.S. natural gas industry has been in existence at least since the 1920s.[10] However, today's competitive natural gas market is only 17 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 (this is still common practice in 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.

Until the Natural Gas Wellhead Decontrol Act of 1989 (implemented in the 1990–1991 time frame) and the Federal Energy Regulatory Commission's (FERC's) Order No. 636 (issued in 1992, with implementation in 1993),[11] 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,[12] 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 (the FPC was the predecessor to the FERC) at $0.52/mcf.[13] At the same time, prices in the nonfederally 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.

[10] Much of this section is based on *Price Instability in the U.S. Natural Gas Industry Historical Perspective and Overview*, Navigant Consulting. See Appendix B.

[11] 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.

[12] That case, Phillips Petroleum v. State of Wisconsin, 347 U.S. 672 (1954), held that under the Natural Gas Act, the federal government has the authority to regulate prices charged by natural gas producers at the wellhead.

[13] 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, one gallon of gasoline contains approximately 132,000 Btus. Thus, 1 Mcf of natural gas is approximately equivalent in energy content to 8 gallons of gasoline.

In 1976, the FPC attempted a limited remedy by significantly raising the costbased ceiling, from $0.52 to $1.42 per mcf. In 1978, Congress passed 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, noncostbased 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."[14] 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 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 Power Plant 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 large new 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, FERC issued Order No. 636, essentially completing the transition to an open market. Under Order 636, 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, 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.

THE POWER PLANT AND INDUSTRIAL FUEL USE ACT 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.

[14] In the Natural Gas Policy Act of 1978, 15 U.S.C.A. Sec. 3301, Section 107, deep gas is defined as natural gas that is produced from sources greater than 15,000 feet below the surface.

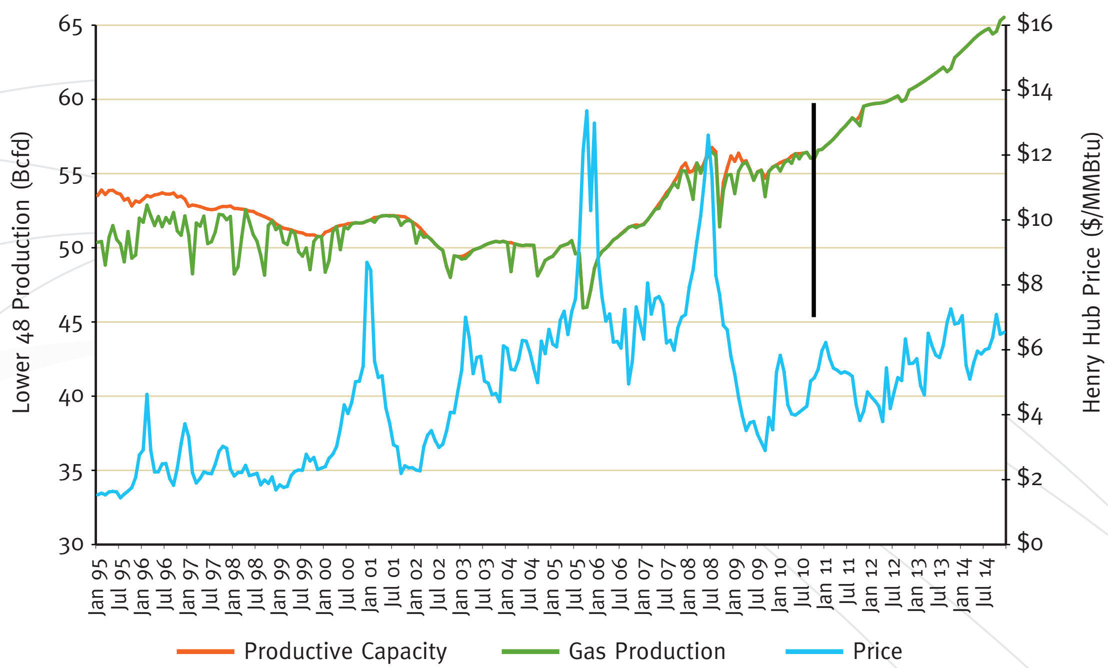
For the most part, the 1990 through 2000 period saw continued stable prices and strong supply. Prices at the nation's largest pipeline junction (known as the Henry Hub[15] and located in Louisiana) started somewhat below $2/mcf as decontrol began and settled in at approximately $2/mcf until 1996 when the market 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 wellhead price. In the first period, the gap between productive capacity or "deliverability[16]" and actual production represents the "excess" production capacity of the "gas bubble" period and the continued low and relatively stable prices that accompanied it. However, with the end of preferential pricing for nonconventional gas production, productive capacity began 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 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.

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

By 2000, all of the available production was being consumed and there was demand for additional supply that was not being met.

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

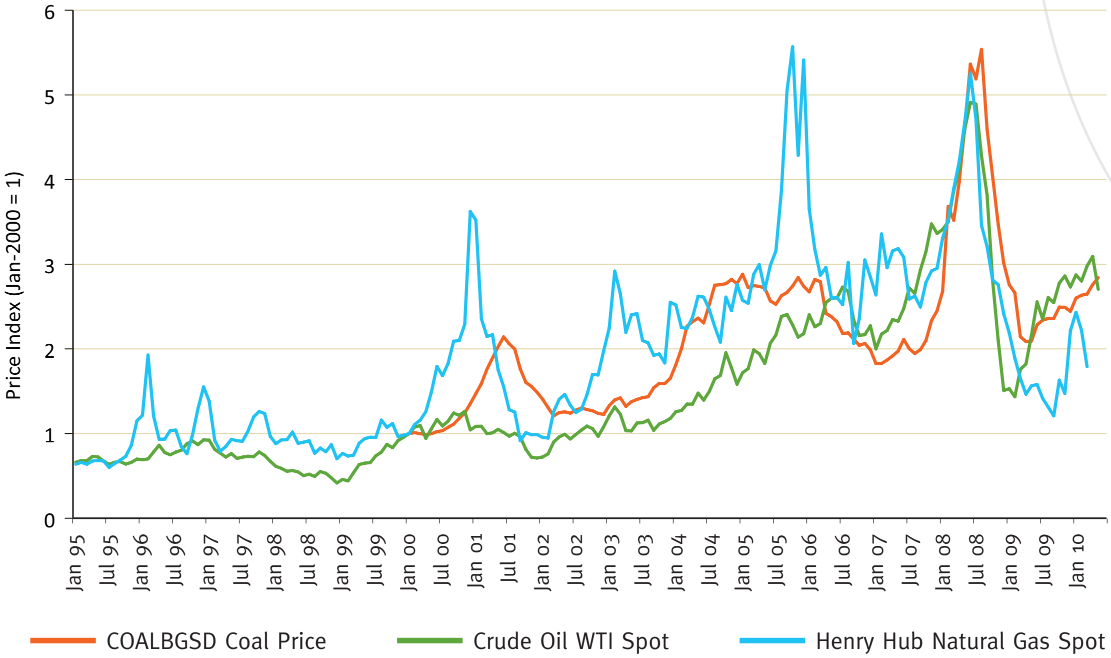


Source: ICF International.

[15] Henry Hub, Louisiana, is a major production area delivery point in the gas industry. The NYMEX Natural Gas Futures contract uses the Henry Hub price as the reference price.

[16] Gas deliverability is the maximum production rate that can be delivered to the market.

Figure 6. Indexed Fuel Prices - 1995 to 2010



Source: ICF International analysis of U.S. Energy Information Administration data.

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 onshore production, resulting in another, higher price spike. In early 2008, prices for natural gas, as for other energy commodities, increased sharply due, in part, to large financial inflows to gas and other commodity and derivative markets. By mid-2008, however, prices had begun to fall and soon dropped sharply.[17]

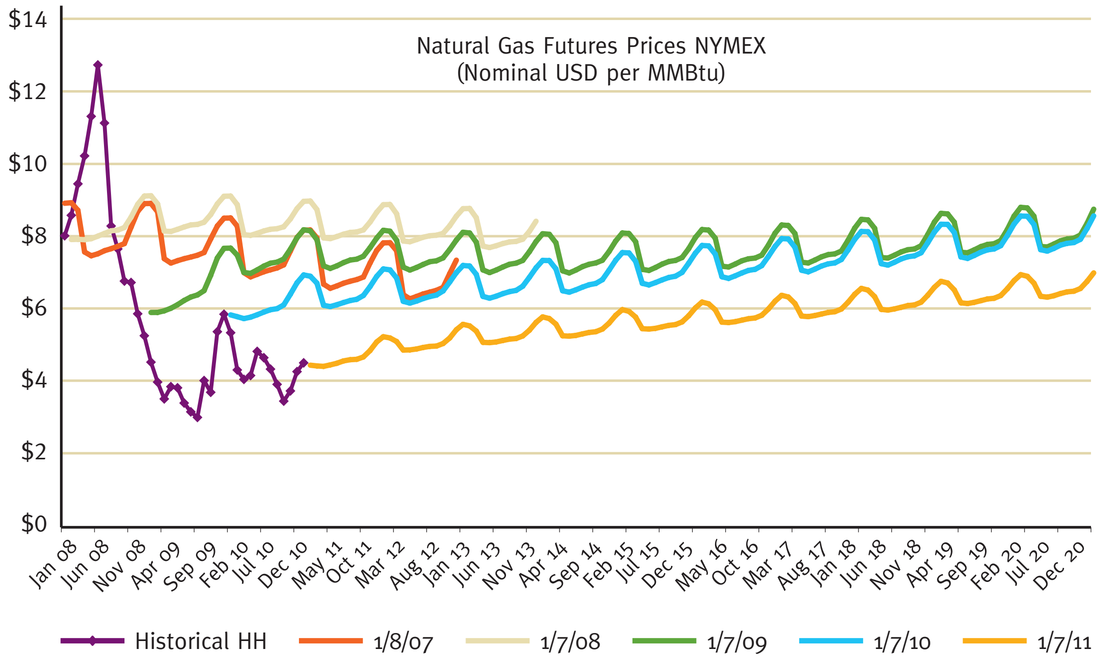
Figure 6 shows spot prices for gas, oil and coal since 1995, indexed to 2000 levels. The figure shows that gas markets have experienced some notable price spikes that are different from the other fuels, but that overall, the price trends are not that different. The exceptions for gas are the 2000-2001 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.

As already noted, lower gas prices starting in 2008 were partly the result of reduced demand due to the economic downturn. More important 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, began to be reflected in increasing productive capacity (see Figure 5). These trends are forecast to continue (see discussion in Section III.A.i.). Clearly, advances in exploration and production technology will affect gas production economics in North America for decades to come.

Gas markets have experienced some notable price spikes that are different from the other fuels, but overall, the price trends are not that different.

[17] U.S. Department of Energy, Energy Information Administration, "U.S. Natural Gas Wellhead Price," EIA Data Navigator. Accessed 2/14/2011. http://tonto.eia.gov/dnav/ng/hist/n9190us3m.htm.

Figure 7. Natural Gas Futures Prices - 2008 to 2010



Source: New York Mercantile Exchange.

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.

This review of recent gas market trends suggests several conclusions:

- Natural gas markets have been competitive and open for less than 20 years.
- The periods of highest gas prices in the last 10 years have resulted from identifiable circumstances, such as changes in regulation, hurricane disruptions, market momentum and broader trends in energy commodity markets.[18]
- The broader increase in gas prices in the first part of the last decade resulted from increasing demand relative to supply, at a time when supply was effectively flat. This price increase also reflected a return to unregulated market pricing.
- 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 the price of natural gas has important economic implications for both large and small consumers. 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 five to seven years will remain at recent levels—that is, around $4 mcf—or rise to levels

[18] 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.

seen in 2007 and 2008. Currently, this seems unlikely, based on the forward price curve to 2015, which reflects gas futures contracts (Figure 7). This uncertainty can discourage investment by both producers and consumers.

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.[19]

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.[20]

i. Impact on Small Consumers

Gas bills for small customers are driven by three factors: the cost of natural gas, the amount of natural gas used each month and the cost of getting the gas from the producer to the customer. Firm service customers, who account for almost all residential deliveries and about 63 percent of total commercial deliveries, purchase natural gas at regulated distribution rates from LDCs. These distribution rates cover the cost of safely getting the gas from the producer to the customer. The firm customer is also charged for the cost of gas purchased by the LDC for the customer. The LDC is not allowed to mark up the price of gas. The customer pays what the LDC pays—no more and no less. The cost of gas delivered to the city gate, which includes transportation and storage, is usually the largest part of the customer's bill. This means that a firm service customer will usually have a very predictable regulated distribution charge but far less predictable charges for the gas itself. Of course the other big factor in the customer's bill is the amount of gas used. Colder weather means higher bills. Many residential consumers react only when they receive 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 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 typical variability in actual prices.

[19] In its deliberations, the Task Force examined available reports, including *Natural Gas and Energy Price Volatility* (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).

[20] That said, the ability of industrial customers to recover fluctuations in day-to-day gas prices can be limited by competition and the structure of their own industries.

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. For some companies, the natural gas feedstock can constitute more than 70 percent of the cost of production. Moreover, with global markets for many – if not most – of these products, gas price movements in North America that do not correlate with gas prices in other countries can be extremely disruptive. On the other hand, in some countries, these products are produced from petroleum feedstocks, which can be higher in price.

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 a net exporter of NGLs and propane and will likely remain so until or unless additional domestic capacity to use the products is built.

Competition with imports is a significant risk for domestic manufacturers with a strong dependence on local energy resources.

That said, a long-term increase in price will affect consumers and may lead to a response from utility regulators. Some LDCs have developed programs to help insulate their customers 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 and feedstock 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 have, and have

had, an enormous impact on the competitiveness and viability of the U.S. industry. The production of chemicals such as ethylene from natural gas liquids is a related industry that is also sensitive to natural gas availability and pricing. Gas price variability has a huge effect on the viability of these industries and the workers and consumers that depend on them.[21]

Fuel and feedstock prices 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 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 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 any 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 (such as environmental attributes) may also come into play. Gas-based generators compete with coal, nuclear and renewable generators for a share of the baseload electricity market. At low gas prices, gas is competitive against all of these alternatives, but higher prices may put gas out of the baseload market. Meanwhile, uncertainty

[21] Frank, C. Graves and Steven H. Levine, The Brattle Group, *Managing Natural Gas Price Volatility: Principles and Practices Across the Industry*. See Appendix B.

about future prices prevents utilities and developers from investing in new gas-fired capacity even though it can be among the most efficient and least polluting 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 as the backup 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 gas delivery and generating capacity that is used only intermittently be paid for and by whom if there are no baseload 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 baseload gas generation with renewable production.

When prices are high, power sector 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 North American gas resources, both to provide stable pricing to consumers and to provide a stable demand outlook for producers. As the industry has gained experience in producing unconventional gas, production cost curves have shifted downward. Recent experience with shale gas production provides considerable evidence of this trend, given the steady growth of the estimated recoverable resource base at $6/Mcf or less.[22] Despite recent positive supply developments, 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 future demand for their product and about the potential for 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 DG infrastructure 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 patterns, 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 uncertainty about future prices.

Despite recent positive supply developments, many large consumers remain cautious about investing in new gas-consuming facilities due to uncertainty over mid- to long-term gas prices.

[22] See e.g., MIT Energy Initiative, the Future of Natural Gas, an Interdisciplinary MIT Study, Interim Report, Executive Summary, June 2010, p. XXI; ICF International Compass Publication, Summer, 2010, 2010 Natural Gas Market Review, prepared by ICF International for the Ontario Energy Board, August 20, 2010

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 both supply and demand trends have a direct impact on gas pricing. The foregoing strongly suggests that one approach to moderating natural gas prices over the mid- to long-term would be to promote expanded capacity for producing and delivering natural gas.

The lack of significant excess domestic production capacity in the last decade made gas commodity prices sensitive to short-term changes in supply and demand, and in the short run, to the availability of gas storage.[23] As one would expect in any commodity market, prices have responded 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 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.

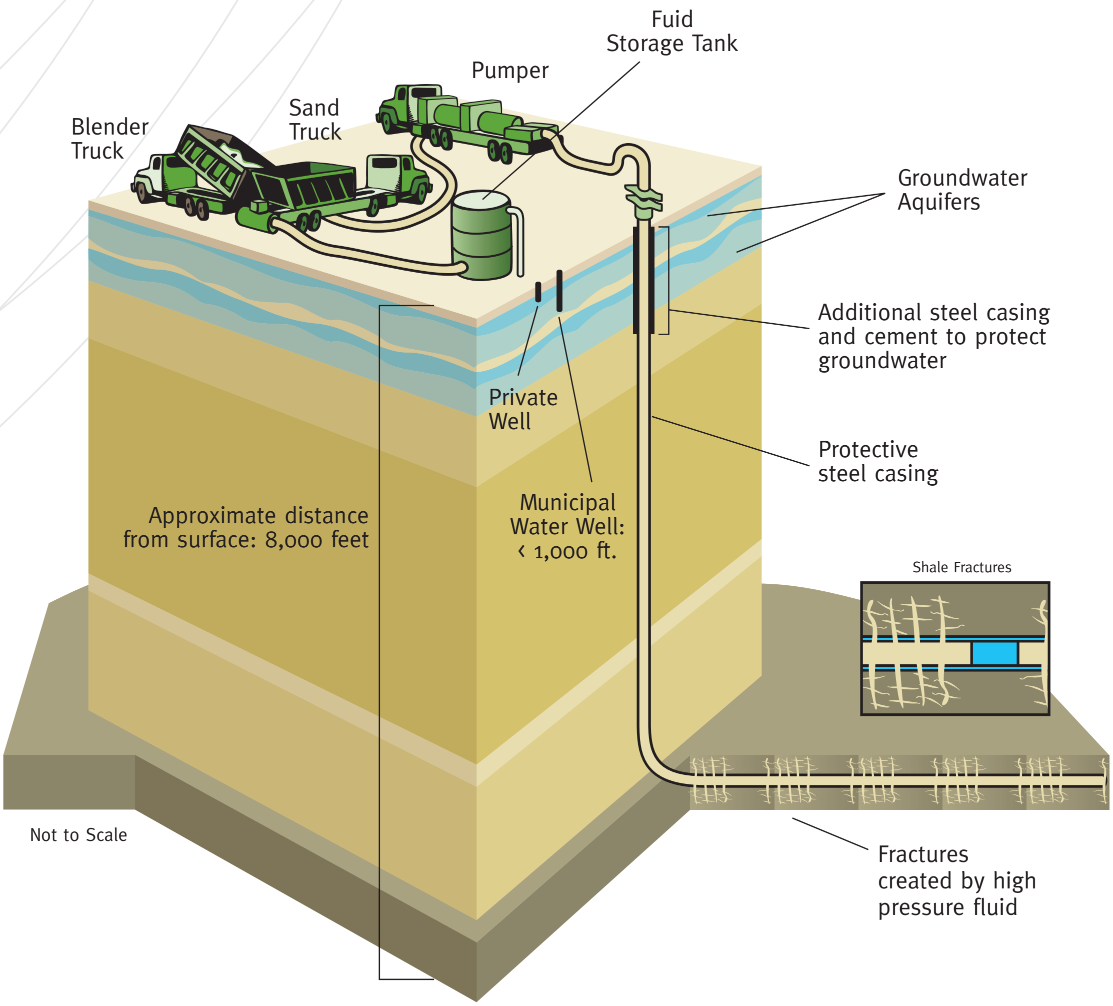
i. Shale and the New Gas Supply Paradigm

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

The expansion of gas shale production already appears to be having a dampening effect on price variability.

[23] American Gas Foundation. *Natural Gas and Energy Price Volatility*. Chapter 3: Outlook for Future Natural Gas Price Volatility. Page 3-13.

Figure 8. Diagram of Hydraulic Fracturing Process



THE SCIENCE OF SHALE GAS EXTRACTION HAS MATURED INTO A SOPHISTICATED PROCESS INVOLVING HORIZONTAL DRILLING AND SEQUENCED, MULTI-STAGE HYDRAULIC FRACTURING TECHNOLOGIES.

be understood. Clearly, a significant increase in available U.S. natural gas resources, assuming it leads to rising production, will have a moderating effect on gas prices and variability.

While shale formations were long known to contain substantial quantities of 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 dramatically increase the amount of gas that can be recovered.

In the 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 in 1986; 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 accelerated and 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.[24]

[24] 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.

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

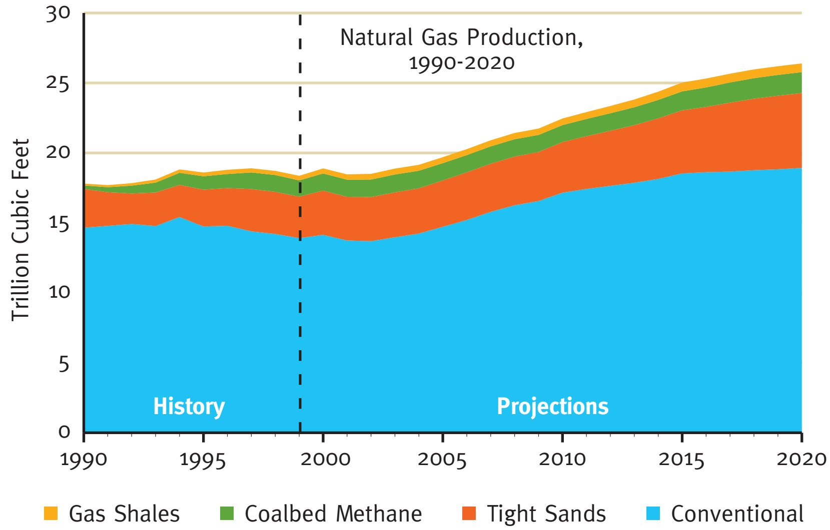
Even as late as the 2005 Annual Energy Outlook, the full scope of the shale revolution had not yet been recognized. By then, conventional resources were seen as declining and LNG imports were expected to be the next large incremental source of natural gas supply to meet growing demand (Figure 10).

Between 2005 and 2010, shale gas 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).

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

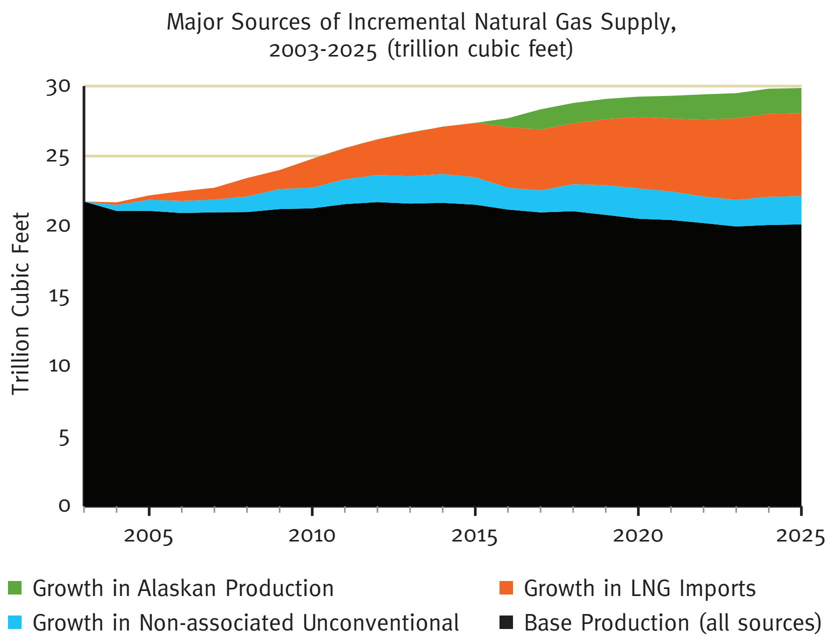
The size of the U.S. shale resource base is only one aspect of its new-found importance to the domestic supply outlook for natural gas. Another is the widely distributed nature of that resource base. Table 1 shows that

Figure 9. Natural Gas Production, 1998 to 2020



Sources: **History:** Advanced Resources International, Inc. (ARI).
Projections: U.S. Energy Information Administration. Annual Energy Outlook 2000.

Figure 10. U.S. Energy Information Administration Supply Forecast - 2005



Source: U.S. Energy Information Administration. Staff's Forecast of Natural Gas Prices. Annual Energy Outlook 2005.

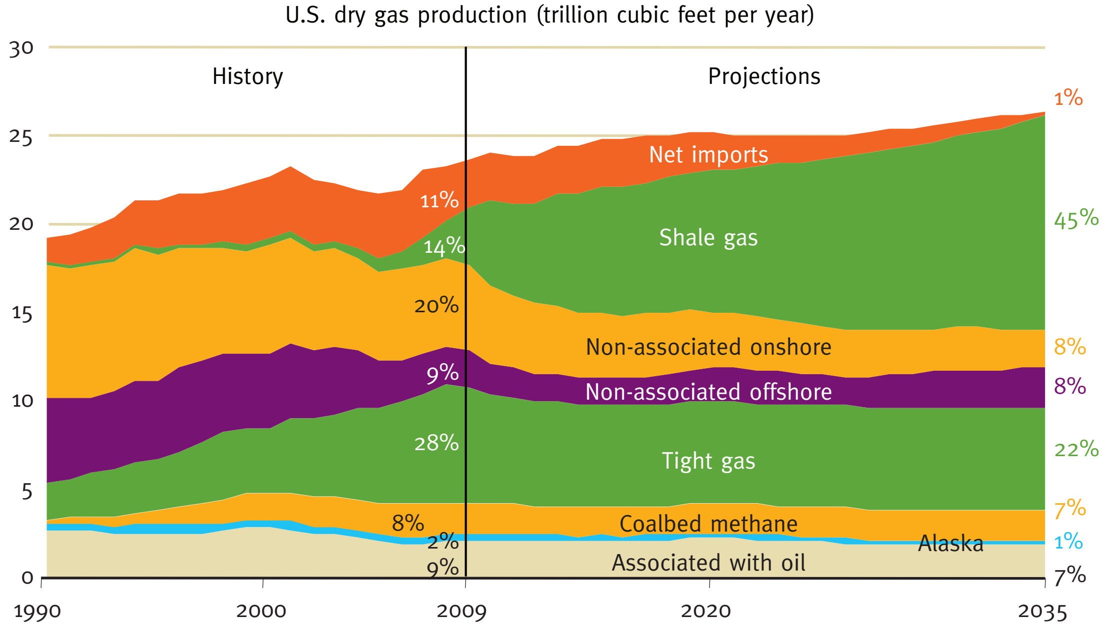
Table 1. Published Estimates of U.S. Lower 48 Recoverable Shale Gas (Tcf)

USGS (Various years)	EIA 2000	NPC 2003	EIA 2007	ICF 2008	PGC 2009	ICF 2010[25]
85	3.7	35	125	385	616	1,395

Source: ICF International. 2010 Natural Gas Market Review. Prepared for the Ontario Energy Board. August 2010. Page 48.

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

Figure 11. U.S. Energy Information Administration U.S. Dry Gas Production Forecast - 2011



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

shale is ubiquitous, with major production opportunities located in Texas (Barnett and Woodford), Arkansas (Fayetteville), Louisiana (Haynesville), and 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 to the north, is the largest shale resource, conservatively estimated to be approximately 700 Tcf.[26]

In late 2010, the MIT Energy Initiative published its Interim Report, *The Future of Natural Gas,* re-examining the supply outlook.[27] 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.

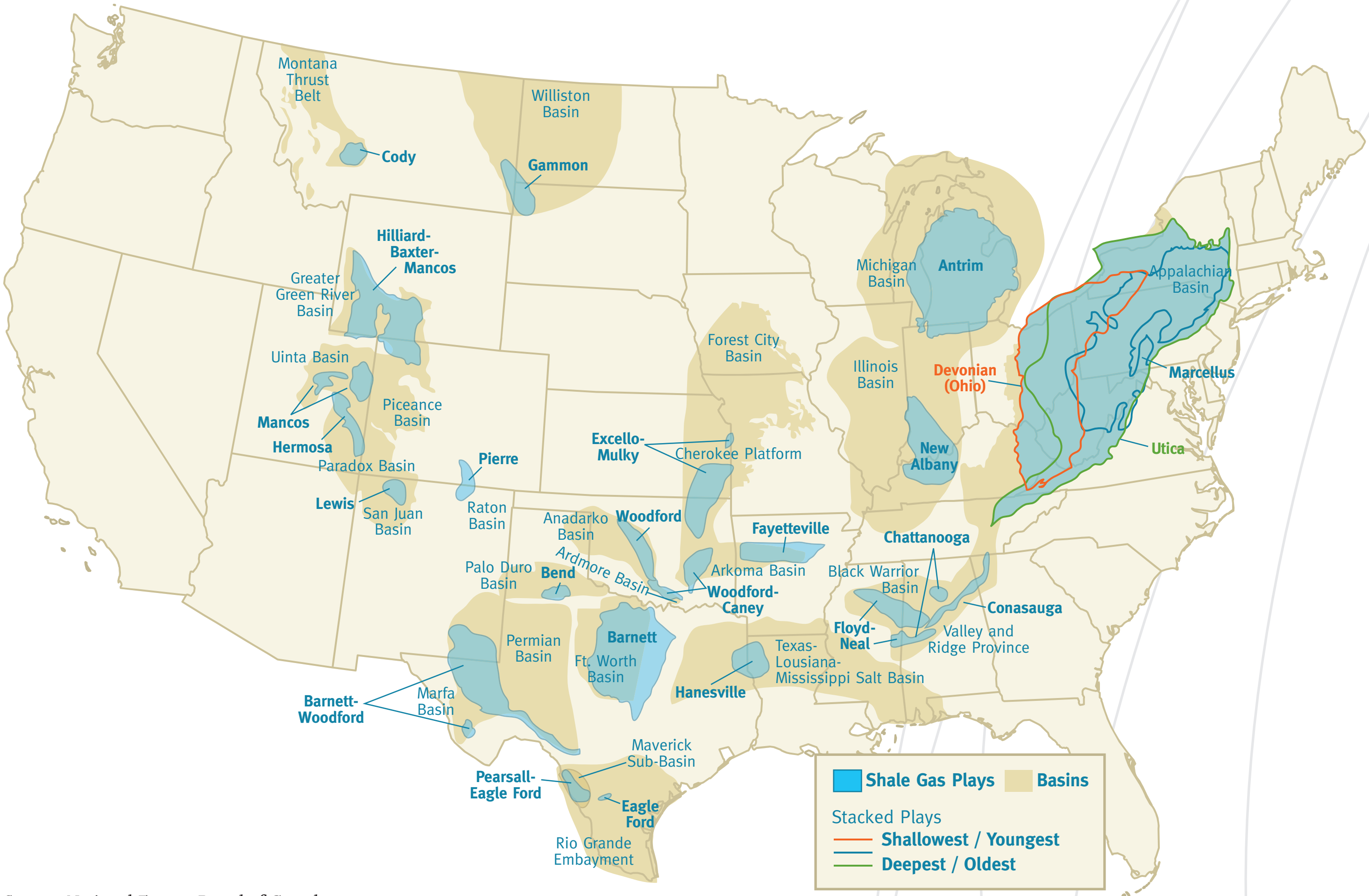
While estimates of supply have increased, the cost of producing shale gas has declined as more wells have been drilled and as new techniques have been developed and field tested. The MIT study estimated that between 250 and 300 Tcf of shale gas can be produced at prices below $8/MMBtu (in 2007 dollars).[28] More recently, ICF International estimated that almost 1,500 Tcf are available at $8/MMBtu, while 500 Tcf are available at $4/MMBtu (Figure 13). In either case, the opportunity for substantially expanded domestic gas production is large. The MIT report summarized the situation as follows:

[26] ICF International, p. 48.

[27] MIT Energy Initiative, the Future of Natural Gas, an Interdisciplinary MIT Study, Interim Report. Cambridge, Massachusetts: Massachusetts Institute of Technology, 2010.

[28] MIT Energy Initiative, p. 11.

Figure 12. Shale Gas Basins in North America



Source: National Energy Board of Canada.

"The large inventory of undrilled shale acreage, together with the relatively high initial productivity of many shale wells, allows 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."[29]

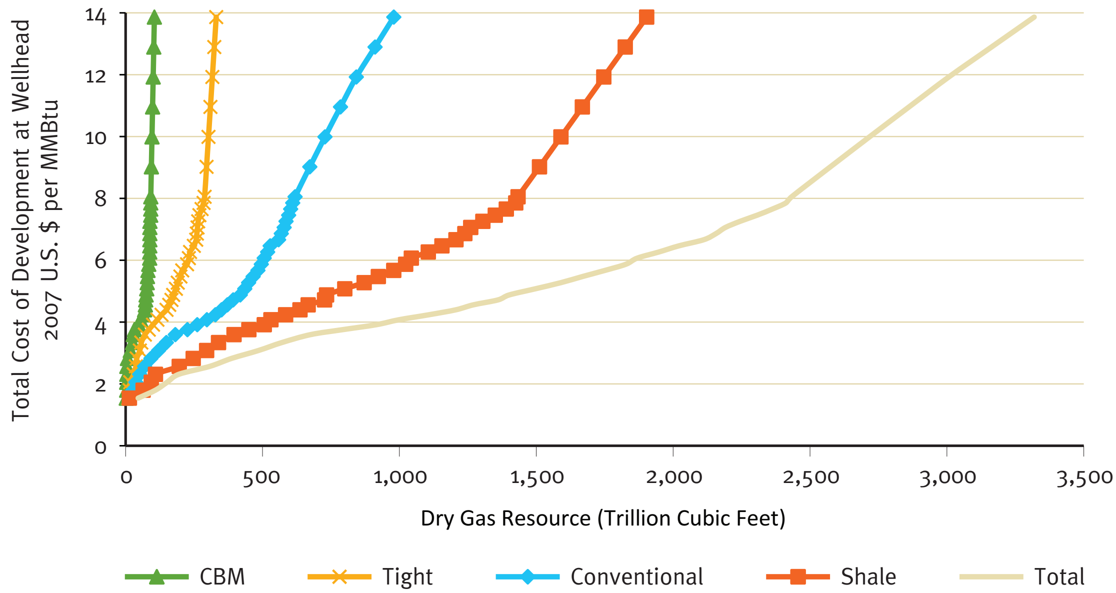
While the development of shale gas offers the potential to make significant new supplies of natural gas available at moderate prices, large uncertainties remain regarding the future development of these resources.

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 base is still evolving and questions remain in a number of areas: whether productive areas are representative of an entire play; whether and to what extent "sweet spots" may be skewing resource assessments; uncertainty about the trajectory of well production decline; and the effect of 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

[29] MIT Energy Initiative, p. 13.

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



Source: ICF International.

A TYPICAL FRACTURING OPERATION CONSUMES 2 TO 4 MILLION GALLONS OF WATER. THERE IS CONCERN ABOUT THE POTENTIAL FOR AN EXCESSIVE DRAIN ON WATER RESOURCES IN AREAS WHERE LARGE NUMBERS OF WELLS ARE BEING DRILLED.

base; and well drilling costs, which are a large technological and cost component in the development of shale gas resources.

ii. Environmental Impacts Associated with Shale Gas

A third and last (but by no means least important) source of uncertainty 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.[30] (See Text Box)

At the same time, the industry and its regulators must continue to devote attention to the environmental issues associated with hydraulic fracturing and water use, and take the steps necessary to avoid problems that could undermine public confidence in the industry's ability to access this resource base in an environmentally safe and a prudent manner.

[30] MIT Energy Initiative, p. 15.

Environmental Impacts of Shale Gas Production

With the growth of shale gas production, and particularly the move to produce in areas outside of the traditional gas-producing areas, such as in the Marcellus shale, there has been an increasing focus on the environmental impacts of shale gas production. While the debate is often centered on shale gas production in general and the hydraulic fracturing process in particular, many of the issues are not specific to either and must be addressed for any type of natural gas production. Nevertheless, the rapid growth of shale gas production and its high visibility require that these issues be addressed and resolved. State and federal regulators have already begun new initiatives to review and update their evaluations of these issues.

Hydraulic fracturing: There are concerns that the hydraulic fracturing process itself could allow either fracturing fluids or gas to migrate into drinking water resources. Fracturing typically takes place at a depth of 6,000 to 10,000 feet, while drinking water tables are typically less than 1,000 feet deep; thus the fracturing process per se is unlikely to impact fresh water aquifers. There are concerns however, over other facets of shale gas production (e.g., faulty well casings), which may have affected drinking water. In 2011, the U.S. Environmental Protection Agency (EPA) will begin a two-year study to review the extent to which hydraulic fracturing poses a threat to safe drinking water supplies.[31]

Well casing and maintenance: While there is little evidence that leaks from hydraulic fracturing have affected ground water, there have been documented incidents where fracturing fluids or methane have impacted surface and well water supplies due to improper well casing. While this risk is not unique to shale gas production, the migration of shale gas production into new areas is generating more interest in this issue.

Water consumption for fracturing: A typical fracturing operation consumes 2 to 4 million gallons of water. While this is less than many industrial processes, less than typical consumption to water a golf course, and much less than the water consumed by a power plant, there is concern about the potential for an excessive drain on water resources in areas where large numbers of wells are being drilled. Among other approaches, producers are investigating the use of water recycling to reduce consumption.

Management and disposal of fracturing fluids and produced water: The fracturing fluid is mostly water but does contain some chemicals. After the fracturing job, most of the water is discharged from the well, possibly along with water from the producing formation. In addition to the chemicals in the fracturing fluid, the produced water may include other organic and inorganic contaminants as well as naturally occurring radioactive material. These millions of gallons of gallons of water must be properly managed and disposed of. Some water treatment facilities may not be capable of treating this volume or type of discharge. In addition, fracturing contractors have heretofore refused to disclose the exact composition of some fracturing fluids, creating additional concerns. Several industry organizations have recently agreed to voluntarily disclose the content of fracking fluids through an online database.[32]

General emissions and disruption: Natural gas production involves the operation of trucks and other heavy equipment as well as the possible construction of new roads, gathering lines and drill pads in remote areas. This produces a range of potential impacts, including air pollution, noise, risk of spills, changes in land use, potential disruption of wildlife and general disruption of the area around the production area.

Methane leakage: Natural gas or methane is itself a potent greenhouse gas. Thus an important aspect of the natural gas industry's environmental performance involves efforts to reduce and minimize methane leakage in all phases of extraction, transportation, storage and delivery.

EPA analysis of the available data demonstrates that switching from another fossil fuel to natural gas reduces emissions of carbon dioxide and of air pollutants that are associated with direct adverse public health impacts, such as particulate matter. Ongoing efforts by industry, working in conjunction with EPA, to implement best practices to reduce all forms of harmful emissions and to update estimated emission factors for transmission and distribution facilities are needed, as are improved data concerning emissions from production facilities. Importantly, confidence in these efforts must be maintained or the benefits of natural gas usage could be called into question.

[31] United States Environmental Protection Agency, Office of Research and Development, "Draft Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources," EPA/600/D-11/001/February 2011/www.epa.gov/research. Accessed February 8th, 2011. http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/upload/HFStudyPlanDraft_SAB_020711.pdf.

[32] American Petroluem Institute Press Release. December 14, 2010. http://api-ec.api.org/Newsroom/chemical-disclosure.cfm.

Industry and government will need to work together to proactively address environmental and public safety concerns.

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 the broader use of gas in efficient applications for power and transportation. At the same time, more abundant supply has the potential to moderate future fluctuations in gas prices. However, to assure access to this resource base, industry and government will need to work together to proactively address environmental and public safety concerns, including public safety concerns that are unrelated to hydraulic fracturing per se. In particular, the Task Force is mindful that recent, well-publicized pipeline accidents have drawn attention to integrity of the existing natural gas transportation and distribution infrastructure. While outside the scope of issues considered by the Task Force, attention to public safety obviously needs to remain a paramount concern for the industry and its regulators going forward.

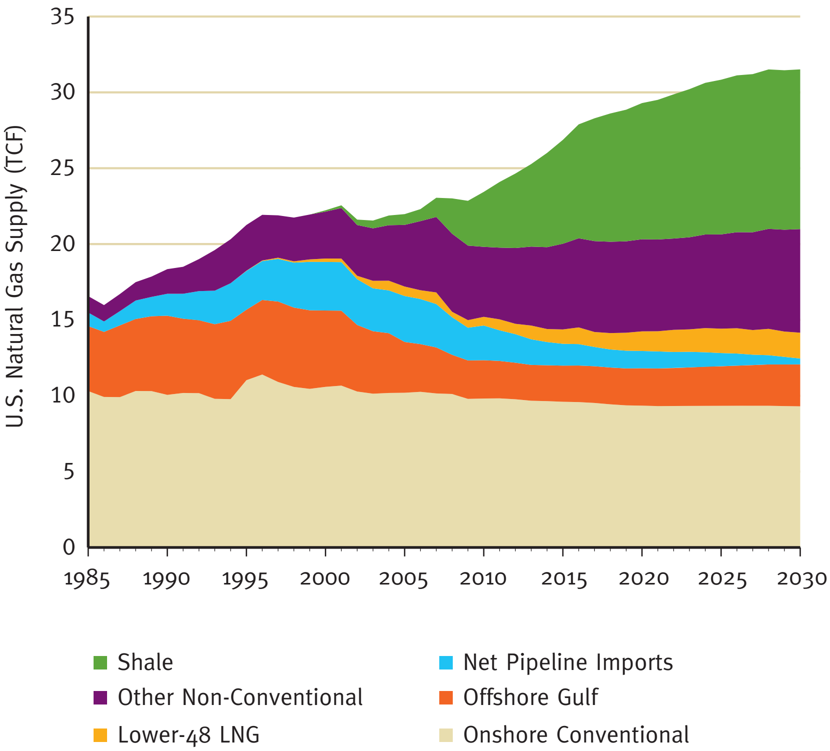
Figure 14 shows sources of U.S. natural gas supply since 1985 and projected through 2030. U.S. gas consumption has totaled about 20–23 Tcf per year since the 1990s. The figure also shows changes in gas production over time. Onshore conventional production has supplied less than half of consumption since 1990 and is flat or declining. Offshore production in the Gulf of Mexico was the next largest source to come into the mix, 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 low-price U.S. shale gas depresses demand for Canadian gas.[33] Finally, non-

[33] In recent years, gas production from conventional wells in the Western Canadian Sedimentary Basis (WCSB) has declined. The WCSB is the primary source of gas production in Canada for domestic consumption and export to the United States. While the development of unconventional gas including shale gas in British Columbia may offset further declines, increases in Canadian consumption for domestic use (e.g. power generation and the development of oil production from oil sand projects) are likely to result in less gas being available for net export from Canada to the United States. See ICF International, Inc. "2010 Natural Gas Market Overview," August 20, 2010, p. 8.

conventional production of tight gas and coal-bed methane has been the last piece added to the supply to boost total U.S. annual production up to approximately 23 Tcf in recent years.

With offshore and Canadian production declining and prices rising, there has been more financial support for nonconventional production and more interest in LNG imports. High prices also supported the development of shale gas production techniques over the last decade. The currently understood and projected shale gas resource has allowed the United States to project a significant increase in economically recoverable gas resources for the first time in the last 15 years. And for the first time since the 1990s, it now appears that deliverability (i.e. available production) could be adequate to meet increasing gas demand, meaning that the United States will no longer be in the tight supply/demand regime that has historically made natural gas markets vulnerable to price instability.

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



Source: U.S. Energy Information Administration, Annual Energy Outlook 2011, Reference Case, Preliminary Release, December 16, 2011.

iii. Imports: Liquefied Natural Gas[34]

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 ones).[35] Today there are seven operating LNG import terminals in the 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.

[34] Includes information from *"LNG, Globalization, and Price Volatility,"* Kenneth B Medlock III. See Appendix B.

[35] 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."

Access to Resources

Natural gas resources exist in almost every part of the United States and in coastal areas. Efforts to develop these resources, as with other natural resources, are subject to tensions between development and preservation of the natural environment. While gas development is under way in many parts of the United States, 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 it should be developed in light of environmental or other land-use concerns. The venue for resolving the question depends on the specific location and jurisdiction in question and there are often overlapping authorities involved. The public policy and regulatory processes should carefully weigh the value of gas production against protection of the environment and public health to ensure that a proper balance is struck.

Thus, based on existing import capacity, LNG could theoretically meet 20 percent 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 terminals have been proposed on the West Coast, virtually all of the new terminals that have actually been constructed are located 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. Gulf Coast communities have been far less hostile to these facilities, largely, it is believed, because the region is already accustomed to extensive petrochemical development.

Another reason for locating LNG terminals on the Gulf Coast is that pipeline takeaway 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 straightforward with Henry Hub being nearby. The attraction of East Coast sites, especially north of the Carolinas, has been that gas prices have historically been higher there than in the Gulf. At the same time, pipeline takeaway capacity is more limited on the East Coast; in addition these markets are comparatively less liquid and local prices are more susceptible to the influence of LNG deliveries. Nevertheless, large price differentials relative to the Henry Hub have historically made LNG a more attractive investment in the northeastern United States.[36]

At today's prevailing lower prices, however, and with the current outlook for gas supply and prices, it is not likely that new LNG 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 supplies, some owners of LNG impact terminals have applied for export authorization and intend to install liquefaction facilities. Even if new export terminals are built, however, the extent of exports is likely to be modest for at least the next decade (i.e., less than 5 percent of the market).[37]

[36] The growth in shale gas production in various geographic locations has changed historical relationships between regional gas prices. In particular, Marcellus gas production in Pennsylvania and West Virginia has compressed price differentials between the Gulf Coast and eastern United States.

[37] See Cheniere Marketing, LLC application, pursuant to DOE Delegation Order No. 00-002.00I (Nov. 10, 2009). Also, Freeport LNG filed an LNG export application with the U.S. Department of Energy on December 17, 2010. The application, available under FE Docket No. 10-160-LNG, contemplates the export of 225 million metric tons of LNG over a 25-year period to countries with which the United States currently has entered into free trade agreements or may enter free trade agreements in the future.

In principle, LNG imports can help moderate gas price volatility and undoubtedly they have had this effect in some instances. However, ongoing LNG sales to the United States have been modest in recent years given the historic spread between U.S. prices and gas prices elsewhere in the world. Europe, Japan, South 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 (i.e., in winter) and in high value locations (the Northeast). In general, current policies and FERC's efficient regulation of LNG facility siting have allowed LNG capacity to evolve with market needs.

iv. Storage[38]

Gas storage facilities allow gas produced in one time period to be used at a 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 (reservoir capacity is typically measured in million British Thermal Units (MMBtu)) and the capacity to deliver a given quantity of gas to the market in a given timeframe, otherwise known as "deliverability" and typically measured in 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.

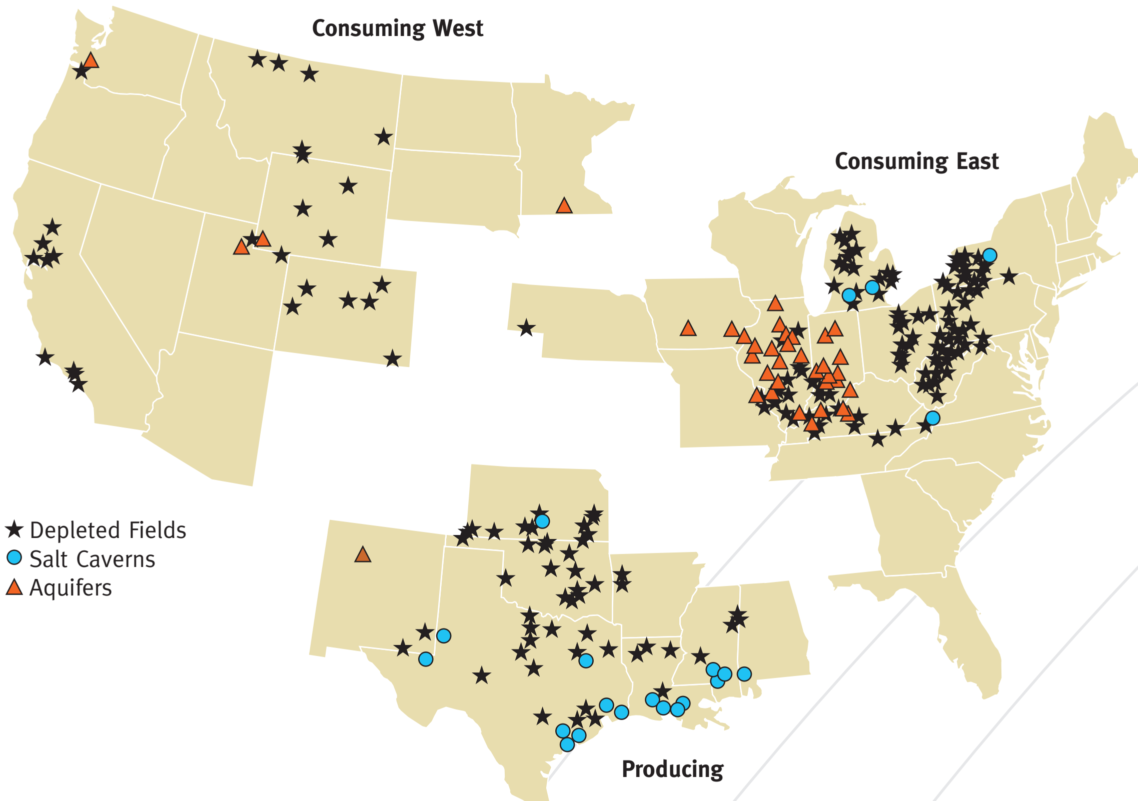
Following the deregulation of wholesale gas prices, storage has also become a physical way of hedging future price risks for utilities and producers; likewise, it is also provides a financial tool for price arbitrage by marketers and suppliers as seasonal demand varies. Both the physical and financial aspects of storage have can be used as tools to promote price stability.

There are three types of underground storage: depleted reservoir, aquifer and salt cavern storage. In the United States, depleted natural gas or oil fields provide about 85 percent of working gas storage capacity and 70 percent of deliverability because of their widespread availability. Converting 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.

In the face of growing U.S. gas supplies, some owners of LNG impact terminals have applied for export authorization and intend to install liquefaction facilities.

[38] 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. See Appendix B.

Figure 15. U.S. Underground Storage Locations



Source: U.S. Energy Information Administration. GasTran Geographic Information System Underground Storage Database.

Growth in the amount of storage available to the market is an important contributor to more stable and competitive gas prices.

Salt caverns work on a shorter cycle, providing very high withdrawal and injection rates for their working gas capacity through two or more cycles per year. Salt cavern storage accounts for about 5 percent of working gas storage capacity but 17 percent of deliverability. The large majority of salt cavern storage facilities are located 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 Southeast.

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 storage capacity has been constructed. In 2009, total U.S. storage capacity reached 8.7 Tcf and working gas storage capacity reached 4.3 Tcf[39] or nearly 20 percent of the annual market.[40] Thus, by 2009, levels of storage capacity had reached a new high, both in absolute and percentage terms.

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,

[39] U.S. Department of Energy, Energy Information Administration.

[40] EIA, Underground Natural Gas Storage Capacity. http://www.eia.gov/dnav/ng/ng_stor_cap_dcu_nus_a.htm.

thus increasing the potential return to storage developers.[41]

- Growth in natural gas power generation has 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.

- Historic price variability through 2008 increased the value of storage to a broader array of market participants, including utilities that need to manage seasonal and daily price risk; marketers and financial traders who want to benefit from price variability through physical arbitrage; and suppliers that are interested in maximizing opportunities created by price swings.

- An 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 more renewable generation capacity is installed, reliance on gas units for firming power is likely to increase demand for gas storage capacity.

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

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. Thus, growth in the amount of storage available to the market—now at a historic high and still growing—is an important contributor to more stable and competitive gas prices.

[41] Pursuant to the implementation of Section 312 of the Energy Policy Act of 2005, FERC issued Order 678. Under this order, guidance was issued as to how FERC will evaluate applications to charge market-based rates when storage providers do not demonstrate that they lack market power. FERC adopted this rule to reduce natural gas price volatility and encourage the development of natural gas storage capacity in the United States.

v. Pipelines

Pipeline owners and the FERC have been responsive to the need for additional pipeline capacity to bring new gas to market.

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 of pipeline capacity and prices.

In principle, gas prices between two markets reflect the cost of transportation between the two markets. The difference—called 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)–prominent examples of this phenomenon have occurred in New York and New England.

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 can collapse. Recurring or persistent basis blowouts signal the need for new pipeline capacity.

Most investment in gas pipeline capacity in recent years has been driven by supply growth. With increased production from shale and in from the Rocky Mountain region, the United States has seen major new pipeline expansions in recent years to bring this gas to market. Several major pipeline segments have been added since 2006:

- 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 gas pipeline capacity is nominally abundant in the Marcellus shale production region, significant new capacity is needed to connect and flow the gas into the system. Table 2 lists 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 five years, FERC has approved approximately 68 Bcf per day of new pipeline capacity and 9,000 miles

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	Nov-10
Dominion Transmission - Appalachia Gateway	West Virginia to Oakford PA	484	Sep-12
Dominion Transmission - Marcellus 404 Project	West Virginia	300	Nov-12
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"	190	Nov-12
Spectra -TETCO - Algonquin - NJ-NY Expansion	Linden NJ to Staten Island NY	800	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 International compilation of public sources.

of new pipeline construction.[42] Not all of this capacity has been constructed. Nevertheless, pipeline owners and the FERC have been responsive to the need for additional pipeline capacity to bring new gas to market.

The Task Force believes that greater availability and use of long-term contracts will tend to provide greater market stability.

B. New Approaches to Contracting

In addition to expanding natural gas production capacity and the infrastructure necessary for timely delivery, new contract arrangements can facilitate a more stable horizon for gas prices. 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 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 greater use of physical and financial hedging (see Section C), may also moderate the potential for 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 by a clear understanding of what can be achieved through the contracting process.

i. Common Contract Terms

Buyers and sellers of natural gas (and other energy commodities) often enter into contracts to define the parameters of the transaction. Major terms typically include:

- Term – the length of the contract.
- Volume – how much gas can or must be purchased. This may include a "base" volume and optional or "swing" amount or both. It 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 to a standard gas or other energy price.
- Delivery Location – the point(s) at which title to the gas transfers from seller to buyer.
- Re-openers – provisions that allow the contract to be renegotiated if certain conditions are met. This can also affect price stability to a degree.
- Others – contract terms that deal with credit, 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 toward 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.

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

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 (effectively granting the buyer a no-cost option to purchase gas). However, such contracts have never been common in the gas industry, or for that matter in most commodity markets, because they represent an unbearable risk for producers (in effect, they place the entire burden of pricing and market risk on the producer). Instead, so as to share the risks inherent in purchasing this commodity over an extended period, long-term purchase contracts are more likely to index prices to market indicators.[43] As discussed elsewhere, the Task Force believes that greater availability and use of such contracts, whether indexed or not, will tend to provide greater market stability. This is 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. Pipeline operators 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 construction. To meet this requirement, pipeline 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 classes and other terms. These provisions, however, did not exist in a vacuum. In 1954, the U.S. Supreme Court decided a landmark case involving Phillips Petroleum. As noted above, the Court ruled that under the Natural Gas Act, the federal government could regulate the prices charged by natural gas producers when selling gas at the wellhead. From that point until passage of the Natural Gas Wellhead Decontrol Act of 1989, the price paid under gas purchase contracts was almost exclusively determined by regulation.

[43] The one exception may be historical coal prices. However, tying the price of natural gas inputs to another index may reduce the correlation of input and output price returns for a company, thereby increasing net income volatility. And the diversification of volatility could mean that idiosyncratic factors in other markets can affect the price paid for natural gas.

Few if any of the long-term contracts of this period were "fixed price" contracts. Pricing provisions referenced the regulatory structure of the time and 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.

While natural gas contracts have often extended over (relatively) long periods of time, they have generally not featured fixed prices and have included a variety of other provisions that created liabilities for purchasers.

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 purchasers 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 horizons. 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 pipeline gas supply contracts. Just as with pipeline gas supply contracts, the rigidity of these contracts created some liability issues as changes occurred in market supply and demand conditions and in the regulatory structure.

In sum, while natural gas contracts have often extended over (relatively) long periods of time, they have generally not featured fixed prices and have included a variety of other provisions that created liabilities for purchasers. For example, if oil prices increased, the indexed gas price might 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 toward 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 this attention has been prompted by the opportunity for consumers to change their risk profiles by adding long-term contracts for natural gas to their gas requisition portfolio.[44]

The Task Force believes that this renewed interest in longer-term contracts is a positive development. Such contracts can 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

[44] See e.g. National Association of Regulatory Utility Commissioners. Resolution on Long-Term Contracting. Adopted by the NARUC on November 16, 2005. http://www.naruc.org/Resolutions/GAS-1Long-TermContracting.pdf. In its resolution, the National Association of Regulatory Utility Commissioners (NARUC), urges state regulators to: "Recognize the need for additional gas infrastructure to accommodate future gas demand, and moderate the volatility of natural gas prices; Consider long term contracting as a potentially appropriate ingredient in a gas utility's portfolio strategy; Encourage gas utilities to develop long-term strategies for capacity and supply contracts to access new and expanded natural gas and LNG supply sources; Not discourage long-term transportation and storage contracts when a specific record merits encouragement; and Consider pre-approval of long-term contracts."

in price levels and 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, it is important to recognize 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 as a Tool in a Dynamic Portfolio

The Task Force views long-term contracts as a tool, and not a panacea for promoting greater price stability in natural gas markets. Indeed, history has shown that overreliance 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 restructuring of the gas market that occurred between 1985 and 1995, large "take or pay" liabilities developed. These 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 Policies 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.[45]

Relational Contacts

Long-term bilateral contracts also 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,[46] "[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 completely specify the financial

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.

[45] Examples include Devon Petroleum v. Pittsfield Cogeneration Action No. 040 1 – 10854, IN THE COURT OF QUEEN'S BENCH OF ALBERTA JUDICIAL DISTRICT OF CALGARY.

[46] Schwartz, Alan (1992a), "Legal Contract Theory and Incomplete Information," in Werin, Lars and Wijkander, Hans (eds), *Contract Economics*, Oxford, Blackwell, and Schwartz, Alan (1992b), 'Relational Contracts in the Courts: An Analysis of Incomplete Agreements and Judicial Strategies', **21** *Journal of Legal Studies*, 271-318.

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 gas producers or marketers and large potential consumers, including industrial and power plant facility owners, has occurred. In both cases, there are significant costs that become sunk when a decision is made to invest in 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., with other energy sources in the United States or with gas supplies that could be accessed by locating facilities overseas) inhibits the construction of gas-fired facilities. In the discussion, 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, switching costs relate to broad market considerations such as the choice of energy type and geographic location for investment. In this context, switching costs can be quite significant. In the second case, switching costs may be associated with moving from one gas supplier to another. In this case, switching costs are likely to be 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, buyers interested in entering into a long-term contract for gas supplies are seeking a guarantee or warranty from the gas industry as a whole that gas prices 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 buyer contracts with a supplier, the buyer becomes subject to some level of credit and default risk on the part of the supplier. The contract does not—and cannot—operate as a warranty from the broader gas industry. To achieve a level of certainty, a buyer would need to evaluate the ability of the supplier to fulfill the terms of the contract. Only the largest suppliers would be very likely to meet such a test.

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 re-negotiation 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, 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 contracts of this type have lasted for decades. In these and other examples, parties to a relationship seek to generate synergies without vertically integrating through a merger—an option that is, of course, unlikely to exist for most major gas producers and consumers.

Gas markets in which parties may find it mutually advantageous to enter into relational contracts as well as to participate in 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 and create 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.

Acquisition of Gas Reserves by Gas Consumers

Some large gas consumers have sought to manage price risk by acquiring their own physical reserves. Calpine, for example, has utilized this strategy to hedge gas price risks associated with its gas-fired power plants.[47]

Some firms that have regulated gas distribution company subsidiaries have also developed interests in the development of gas reserves. Generally, gas distribution companies and gas production companies are operated separately, with separate accounting for purposes of gas cost recovery. In at least one case, however, the distribution company owns regulated reserves and buys the gas on a cost of service basis. In general, however, 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.[48] This can be particularly advantageous to municipal residents since the purchase can be financed with bonds that receive a measurable tax advantage. This tax advantage can further reduce the retail price ultimately paid by the municipal LDC's customers.

Long-Term Contracts for Regulated Entities

As noted previously, the decision to invest in new gas-fired electric generation capacity subjects power plant owners 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.

Gas markets in which parties may find it mutually advantageous to enter into relational contracts as well as to participate in joint ventures and partnerships may offer new opportunities for parties to allocate gas price risk.

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

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

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

THE TASK FORCE RECOMMENDS THAT STATE REGULATORS REVISIT THE FRAMEWORK FOR REGULATED ENTITIES TO ENTER INTO LONG-TERM GAS CONTRACTS TO ENSURE THAT OPPORTUNITIES TO CAPTURE THE POTENTIAL PUBLIC BENEFITS ASSOCIATED WITH MORE DIVERSE LDC GAS PORTFOLIOS ARE NOT BEING UNREASONABLY FORECLOSED.

Regulated investor-owned gas distribution companies face a similar regulatory risk. For an investor-owned gas LDC, entering into a long-term contract 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 LDC's gas acquisition strategy is found to be prudent, there is little or no upside return associated with that performance. If, on the other hand, the regulator finds that the utility was imprudent, then the disallowance comes directly out of the utility's earnings. An 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."[49]

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 even if they provide some element of price stability. Pre-approval creates risks for regulators (and the customers they represent) because they are in the position of approving management decisions without having access to all the information available to the LDCs. In view of the foregoing, and as detailed below (see section IV), the Task Force recommends that state regulators revisit the framework for regulated entities to enter into long-term gas contracts to ensure that opportunities to capture the potential public benefits associated with more diverse LDC gas portfolios are not being unreasonably foreclosed.[50,51]

iv. Contract Accounting Practices

In recent years, a number of stakeholders and observers has called for greater reliance on longer term contracts between gas suppliers and purchasers as a means of dampening price volatility and promoting greater market stability.

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

[50] For example, the Colorado PUC recently approved a 10-year natural gas supply contract between Xcel Energy and Anadarko. The contract is part of a new resource plan, prompted by state legislation (HB-10-1365), that enables Xcel Energy to close four coal-fired units in the Denver region, switch one unit to natural gas and build a new gas-fired combined cycle plant with substantially lower air pollutant emissions. The Colorado PUC's approval provides for cost recovery of payments under the contract with Anadarko, which contains a fixed price with an annual escalation adjustment, regardless of the future gas price trajectory. (See e.g., The Denver Post, Colorado PUC Adopts Plan to Switch Denver-area Power Plants to Natural Gas, 10 December 2010.)

[51] In states with vertically integrated electric industries where the utility is required to make least-cost decisions about whether to build its own plant or buy from 3rd parties in competitive markets, and where state regulators want to support long-term gas contracting, regulators should take care to adopt long-term gas-contracting policies that do not introduce a bias toward the utility build option. This could happen where regulators allowed a utility to enter into long-term contracts, but not allow comparable protection for the third party competitors. Given the relatively high portion of total electric supply costs that could reside in fuel costs (versus capital recovery and operations/maintenance costs), such a regulatory policy could distort the playing field among the utility and its competitors. See Tierney, S. F. and Schatzki, T. "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," NARUC White Paper, July 2008. http://www.naruc.org/Publications/NARUC%20Competitive%20Procurement%20Final.pdf.

In the United States, these contracts constitute a corporate asset that must be included in company financial statements. To meet this requirement, companies must follow generally accepted accounting rules based on standards established by the Financial Accounting Standards Board (FASB), which operates under the authority of the Securities and Exchange Commission (SEC).

From an accounting standpoint, natural gas contracts are usually handled in one of two ways:[52]

- Fair value accounting, where the market value of the gas contracts and associated obligations are estimated each quarter. Under "mark- to-market" accounting, which is the approach generally used in periodic evaluations of fair value, price fluctuations can cause frequent changes in the balance sheet of a company that enters into long-term contracts.

- The "normal purchases and sales exception" in which costs are expensed as incurred and remain fixed at those levels. As discussed below, there are restrictions as to when and how contracts can be eligible for this exemption and when a company can choose to use the exemption.

It is clear that fair market accounting makes the balance sheet more volatile even when an entity enters into long-term contracts for natural gas. The accounting rules may therefore inadvertently push companies away from long-term contracts to the extent that management wishes to avoid investor concerns arising from volatility in the balance sheet.

It is difficult, however, to determine the degree to which considerations related to balance sheet volatility influence the decision to enter

into different types contracts in practice. For regulated entities such as LDCs and electric utilities, other factors, most notably the ability to recover costs in regulated rates, appear to be more influential. For non-regulated entities, little information is available for assessing whether concerns about disclosing balance sheet fluctuations as a result of different accounting treatments have a significant impact on contracting decisions. The two options and their implications are discussed below.

Fair Value Accounting

The FASB's Accounting Standards Codification (ASC 815), *Derivatives and Hedging*, generally requires all entities to recognize derivative instruments as assets or liabilities in their financial statements and measure them at fair value.[53] Issued as an interim step in FASB's broader initiative to measure all financial instruments at fair value, the guidance in ACS 815 is designed to address immediate problems

[52] The Brattle Group, FASB Accounting Rules and Implications for Natural Gas Purchase Agreements, February 7, 2011. See Appendix B.

[53] Price Waterhouse Coopers, Guide to Accounting for Derivative Instruments and Hedging Activities, 2009-10

with the treatment of steadily more sophisticated derivative instruments. As a result, any gas purchase portfolio that utilizes futures, options, swaps or other derivative products will require fair market (e.g., mark-to-market) accounting for consistent treatment.[54] Many observers believe that FASB's goal is to achieve a full conversion to fair value accounting by 2015.

THE PERIODIC PROCESS OF MEASURING ASSETS AND LIABILITIES IS REFERRED TO AS "MARK-TO-MARKET" SINCE THE FAIR VALUE OF AN ASSET OR LIABILITY IS BASED ON ITS MARKET PRICE.

Fair value accounting provides investors with quarterly information about the fair value of contracts and also provides significant risk disclosure. Under fair value accounting, the fair value of contracts is estimated each quarter. This requires substantial documentation. In addition, those who prepare financial statements are required to identify the purpose and risks of the derivative transactions.

The periodic process of measuring assets and liabilities is referred to as "mark-to-market" since the fair value of an asset or liability is based on its market price. If no market exists for the relevant asset or liability, similar assets or liabilities or possibly an estimate of fair value are used instead. Contracts must be valued based on an index or with reference to an underlying asset that is clearly and closely related to the asset that is being purchased or sold.

The Normal Purchases and Sales Exception

ASC provides for an important exception to the fair market accounting requirement called "normal purchases and normal sales." The exception is available for contracts involving the purchase or sale of something other than a financial or derivative instrument. The transaction must pertain to goods that are expected to be used or sold by the reporting company in the normal course of business. Their costs are therefore expensed as incurred.

Under the normal purchases and sales exception, fluctuations in natural gas prices do not affect the buyer's and/or the seller's financial statements.

Among the advantages of applying this exception over fair value accounting is that the requirement for quarterly contract valuation is avoided. As such, accounting for the contract becomes simpler and less costly. Further, under the normal purchases and sales exception, natural gas price fluctuations do not lead to fluctuations in the reporting entity's income statement or balance sheet. Of course, judgment is required to determine whether the exception is applicable in particular cases.

To be eligible for the exception, the transacted good must be delivered in quantities that (1) are expected to be used or sold by the reporting entity and (2) are reasonable in relation to the reporting entity's normal course of business. Therefore, natural gas contracts that involve an option to change contracted volumes and that are not expected to net settle[55] without complete delivery (i.e., be offset against another contract) typically do not qualify for the exception.

[54] This was the reason given by New Jersey Resources (the corporate parent of a LDC) when the SEC asked it to explain why it had switched from the normal purchases and sales exception to derivative accounting for all its contracts. See The Brattle Group, FASB Accounting Rules and Implications for Natural Gas Purchase Agreements, February 7, 2011, p.14. See Appendix B.

[55] The Brattle Group report, in the Glossary, defines "net settlement" as "A contract with settlement provisions meeting one of the following criteria:
- Neither party is required to deliver an asset that is associated with the underlying and that has a principal amount, stated amount, face value, number of shares, or other denomination that is equal to the notional amount (or the notional amount plus a premium or minus a discount).
- One of the parties is required to deliver an asset of the type described in the first bullet above, but the contract specifies a market mechanism that facilitates net settlement.
- One of the parties is required to deliver an asset of the type described in the first bullet above, but that asset is readily convertible to cash or is itself a derivative instrument."

A more complete discussion of these issues is provided in the Brattle Group report, which also includes several examples of how different accounting treatments would affect balance sheets under various scenarios.[56]

C. Financial and Physical Hedging[57]

Hedging provides 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 engage in hedging activity to manage the price volatility risk. Simply put, hedging can reduce price uncertainty.

i. Objectives, Costs and Limitations of Hedging

In its simplest form, hedging is a mechanism that 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 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 its risk management objectives. A number of financial instruments, generally called financial derivatives, are available to business entities for this purpose. While the specific structure of these financial instruments can be quite complicated and can differ widely, the design and function of hedging instruments are generally relatively straightforward: 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.

Financial derivatives have pluses and minuses. When properly applied, they provide risk management at a manageable cost together with an efficient method for transferring risk. The use of derivatives allows for varying degrees of risk mitigation ranging: Companies can eliminate the vast majority of all risk from market volatility or eliminate just the risk associated with the most extreme price movements.

Like other forms of risk management and insurance that are designed to address the potential for price 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 minimizing

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.

Hedging provides a third major tool for enhancing price stability for both buyers and sellers of natural gas and can reduce price uncertainty.

[56] Ibid.

[57] Includes information from The Brattle Group, FASB Accounting Rules and Implications for Natural Gas Purchase Agreements, February 7, 2011. See Appendix B.

As hedging practices evolved, state Public Utility Commissions were faced with establishing the process by which hedging programs would be reviewed.* The National Regulatory Research Institute (NRRI) describes the challenges 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.

* Kenneth W. Costello and John Cita, Use of Hedging by Local Gas Distribution Companies: Basic Considerations and Regulatory Issues, NRRI 01-08 (May 2001)

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 involves constantly monitoring the risk-reward levels of all the strategies in place for this purpose.

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 derivatives 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 significant limitations. Relatively liquid markets for natural gas derivatives 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 would thus be suitable for managing price risk associated with investments in long-lived facilities such as power plants, refineries, or large industrial facilities. Thus, while hedging is extremely important for managing risks associated with short-term price movements, it does not provide a complete solution to the problem of price uncertainty in the intermediate- and long-term.

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

Gas price movements and market instability more generally present a number of significant challenges to regulated entities such as electric utilities and LDCs and their customers. For customers, volatile gas prices complicate household and small business budgets. Rising gas prices also put pressure on the ability of low-income customers to pay their utility bills. For utilities, the potential for significant shifts in gas prices from one heating season or year to the next creates financial performance risks. When gas prices rise significantly compared to the previous year, the regulated entity faces additional risk in three distinct areas:

1. Financial risk related to decreased throughput,
2. Risk created by an increase in uncollectable accounts receivable (e.g., bad debt), and
3. Increases in operating costs associated with increased shut-off and reconnect activity.

State regulators have developed different approaches for reviewing the hedging activities of LDCs under their purview. The resulting diversity and lack of uniformity in state approaches 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 also, however, "no free lunch." Greater amounts of price protection can only be achieved with a commensurate increase in forgone potential to benefit from gas price reductions or with an increase in the "upfront" costs incurred (analogous to insurance premiums).

Second, the level of price protection being sought through hedging should reflect the risk tolerance of the regulators and the utility operating as a proxy for customer preference. Customers may have to pay higher rates to offset the "upfront" cost— 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.

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 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. Though largely animated by the desire to prevent future abuses of non-commodity related derivatives, Title VII of the legislation addresses the oversight and regulation of financial derivatives (swaps) that

THE CHALLENGE FOR THE CFTC WILL BE TO CRAFT RULES THAT PROTECT THE AMERICAN PUBLIC AND THE U.S. ECONOMY FROM DESTRUCTIVE FINANCIAL PRACTICES AND TECHNIQUES WITHOUT UNDULY RESTRICTING THE USE OF BONA FIDE HEDGING TOOLS IN NATURAL GAS AND OTHER ENERGY COMMODITY MARKETS.

include natural gas and other energy products. As such, it 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. Some of these details involve important exceptions for end-users and bona fide hedges, and the criteria used to establish *"de minimis"* participants. The challenge for the CFTC will be to craft rules that, on the one hand, protect the American public and the U.S. economy from destructive financial practices and techniques without, on the other hand, unduly restricting the use of bona fide hedging tools in natural gas and other energy commodity markets in ways that, by hindering the efficient management of risk, would cause producers and consumers to forego large potential savings and discourage gas-related investments going forward.

For example, although there is an expectation that the "end user" exemption will apply to a large number of risk management transactions that rely on derivatives for hedging purposes, parties will need to verify that individual transactions meet the eligibility criteria for this 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., a product that is not transacted through a regulated exchange). The legislation and some pre-proposals for regulation also contemplate, among other things, imposing 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 market participants will be subject to new standards of business conduct and reporting requirements that have yet to be promulgated by regulators. These requirements are likely to create costs associated with compliance and record keeping as well as liabilities for the actions of individuals within organization.

Economists who have examined the legislation and related regulatory proposals have expressed concerns regarding the unintended impact of the new rules 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;
- The potential for increased “unhedged” basis risk;
- Increases in balance sheet risk for participating entities;
- Increased risk for market users and their customers.

In addition, the legislation brings a new complexity to 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”[58] 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 manage price risk through financial methods.

In general, our concern is that new regulations could limit the availability and increase the cost of tools that are used by market participants to manage price risk and achieve greater price stability. Higher costs are likely to affect even those transactions that are exempt from the new regulations. Exempt transactions are also 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 who may be counterparties.

Based on these concerns, the Task Force recommends 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 greater price stability, 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.

[58] Here “basis risk” is defined as the risk associated with imperfect hedging using futures. Such risk could arise because of the difference between the asset whose price is to be hedged and the asset underlying the derivative, or because of a mismatch between the expiration date of the futures and the actual selling date of the asset. Under these conditions, the spot price of the asset and the futures price do not converge on the expiration date of the future. The amount by which the two quantities differ measures the value of the basis risk. In other words, the basis equals the spot price of the hedged asset minus the futures price of the contract.

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-polluting, 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 supply of the underlying resource itself will go a long way toward ensuring this outcome, the Task Force offers the following findings and recommendations.

1. Recent developments allowing for the economic extraction of natural gas from shale formations 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 levels 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, that discourage demand, or that drive or mandate inelastic demand will disrupt the supply-demand balance with adverse effects on the stability of natural gas prices and investment decisions by energy-intensive manufacturers.

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 decision makers should seek to remove barriers to the use of 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, that unnecessarily restrict the use or raise the costs of these risk management tools should be avoided.

5. Building on its 2005 resolution, the National Association of Regulatory Utility

Balanced fiscal and regulatory policies will enable an increased supply of natural gas to be brought to market at more stable prices.

Policy makers should recognize the important role of natural gas pipeline and existing import and storage infrastructure in promoting stable gas prices.

Commissioners (NARUC) should consider the merits of diversified natural gas portfolios, including portfolios that provide for hedging and longer-term natural gas contracts.[59] Specifically, NARUC should examine:

a. Whether the current focus on shorter-term contracts, first-of-the-month pricing provisions, and spot market prices supports 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 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.

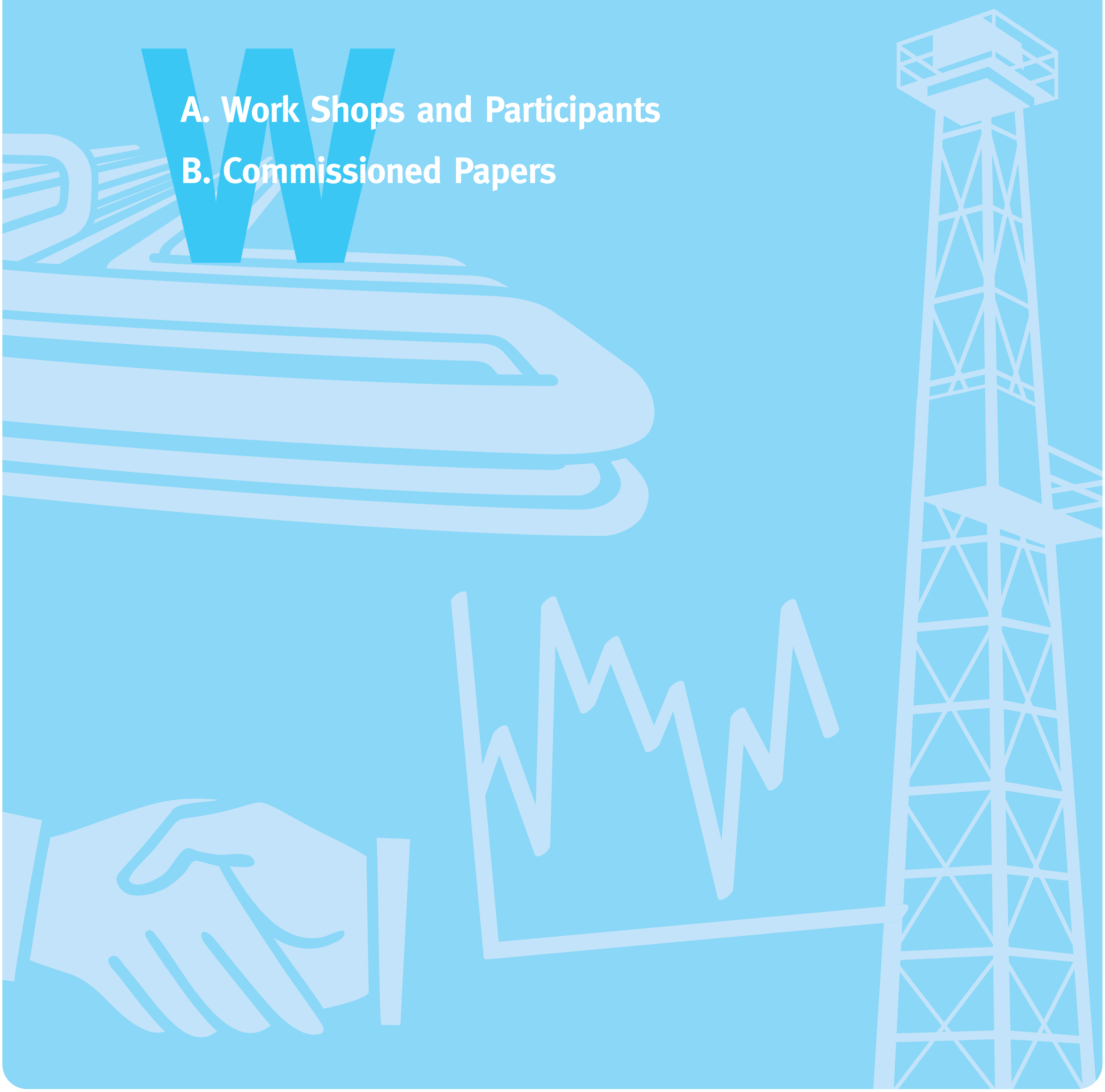
7. Policy makers should recognize the important role of natural gas pipeline and existing import and storage infrastructure in promoting stable gas prices. Policies to support the development of a fully functional and safe gas transmission and storage infrastructure now and in the future, including streamlined regulatory approval and options for market-based rates for new storage in the United States, should be continued.

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

[59] National Association of Regulatory Utility Commissioners. Resolution on Long-Term Contracting. Adopted by the NARUC on November 16, 2005. http://www.naruc.org/Resolutions/GAS-1Long-TermContracting.pdf.

V.

APPENDICES



A. Work Shops and Participants

B. Commissioned Papers

A. List of Work Shops and Participants

Work Shop List

Workshop #1 – The Economic and Legal Background (May 20, 2010)

- An economic background of the history of natural gas price volatility from 1975 to present;
- The major supply and demand drivers of natural gas price volatility
- The potential impact of North American LNG imports and market globalization on natural gas price volatility;
- The supply and production outlook for shale gas; and
- The potential for shale gas to change the paradigm for natural gas economics.

Workshop #2 - Private Sector Options for Managing Price Stability (July 28, 2010)

- An overview of existing commercial options for producers and industrial users to manage price volatility;
- Discussion of regulatory and commercial barriers to more widespread use of these options;
- An empirical review of the impact of gas purchase terms and hedging practices by major categories of industrial users; and
- Case studies of major industrial consumers.

Workshop #3 – Public Policy Options for Managing Price Stability (December 1, 2010)

- Lessons from other U.S. commodities markets (e.g. cotton, copper, fuel oils);
- Lessons from other countries' experience with natural gas price volatility;
- An overview of regulatory and legislative financial reforms and their potential impact on current producer and consumer hedging practices for natural gas; and
- Recommend policy options for managing price stability and identify key insights from commissioned research.

Work Shop Participants

Joel Bluestein, ICF International, Inc.; Kevin Book, ClearView Energy Partners; Geoff Bromaghim, American Clean Skies Foundation; Ken Bromfield, The Dow Chemical Company; Stephen Brown, Resources for the Future; John Bryson, Edison International (Ret.); Carlton Buford, The Williams Companies; Roni Cappadonna, Spectra Energy; Ralph Cavanagh, National Resources Defense Council; Paul Cicio, Industrial Energy Consumers of America; Dave Conover, Bipartisan Policy Center; Roger Cooper, Cleveland Park Policy Consulting, LLC; Peggy Duxbury, The William and Flora Hewlett Foundation; Jim Ford, ConocoPhillips; Russ Ford, Shell Oil Company; Paula Gant, American Gas Association; Sara Glenn, Shell Oil Company; Frank Graves, The Brattle Group, Inc.; Jason Grumet, Bipartisan Policy Center; Carl Haga, Southern Company; Byron Harris, Public Service Commission of West Virginia; Bruce Henning, ICF International; Nate Hill, American Public Gas Association; Jerry Hinkle, American Clean Skies Foundation; Rich Hoffman, Interstate Natural Gas Association of America; Colette Honorable, Arkansas Public Service Commission; Paul Hughes, Southern Company; Sini Jacob, Pacific Gas & Electric; Marianne Kah, ConocoPhillips; Bert Kalisch, American Public Gas Association; Alan Krupnick, Resources for the Future; Steve Levine, The Brattle Group, Inc.; Lourdes Long, Bipartisan Policy Center; Chris McGill, American Gas Association; Ken Medlock, Rice University; Peter Molinaro, The Dow Chemical Company; Sharon Nelson, Consumers Union (Ret.); Frank O'Sullivan, Massachusetts Institute of Technology; John Pemberton, Southern Company; David Rosner, Bipartisan Policy Center; Donald Santa, Interstate Natural Gas Association of America; Dave Schryver, American Public Gas Association; Peter Sheffield, Spectra Energy; Rick Smead, Navigant Consulting Inc.; Gregory C. Staple, American Clean Skies Foundation; Todd Strauss, Pacific Gas & Electric; Norm Sydlowski, Bipartisan Policy Center; Tracy Terry, Bipartisan Policy Center; Sue Tierney, Analysis Group, Inc.; Jeff Wallace, Southern Company; Emily White, Bipartisan Policy Center; Austin Whitman, MJ Bradley & Associates, Inc.; Andrew Weissman, Carter, Ledyard and Milburn; Bill Wince, Chesapeake Energy Marketing, Inc.; and Marty Zimmerman, University of Michigan.

B. Commissioned Papers

Full versions of the commissioned papers listed in the table on the following page can be accessed online at the following locations:

www.bipartisanpolicy.org/naturalgas **www.cleanskies.org/PriceStabilityTaskForce**

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.

Title	Author	Affiliation	Summary
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 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.
Policy Options that Could Impact Natural Gas Supply and Demand	Kevin Book	ClearView Energy Partners LLC	Scenario analysis of policies that could significantly impact U.S. natural gas supply and/or demand; and to quantitatively estimate the potential supply and/or demand impacts of these policies.
FASB Accounting Rules and Implications for Natural Gas Purchase Agreements	Bente Villadsen and Fiona Wang	The Brattle Group	An overview of FASB accounting rules and their implications for natural gas contracts; normal purchases and sales exemption and fair value accounting treatment of natural gas contracts.
The Impact of EPA Utility MACT Rule on Natural Gas Demand	Jennifer Macedonia and Lourdes Long	BPC Staff	A background on the MACT Standards and the results of BPC modeling to analyze the impacts of the MACT rule on electric utility generation and natural gas demand.

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