UNITED STATES NATURAL GAS PRICES TO 2015

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CONTENTS

FIGURES

FOREWORD

The United States is the world's biggest gas market and second largest gas producer. For these reasons alone, any natural gas research programme would need to have an interest in US market development. But until a few years ago, the interest for those of us living outside North America was somewhat academic. Since 2000, that situation has changed. Today any company which operates in the LNG market, and any country involved in importing or exporting LNG – wherever they are in the world, but particularly in the Atlantic Basin - needs to monitor North American gas prices on a daily basis.

In mid-2005, I asked Dr Michelle Foss if she could recommend somebody to write a paper on US gas prices because their extraordinary rollercoaster ride during the 2000s combined with a frenzy of LNG regasification terminal construction made it seem as if the bulk of European LNG supplies could be sucked across the Atlantic. At that time, NYMEX prices were around $7/mmbtu; European prices were a little lower and Pacific LNG prices a little higher. As I write in early February 2007, NYMEX is at $7.70mmbtu, Continental European prices are a little higher – but UK NBP prices significantly lower – and Pacific LNG prices are up around $10/mmbtu. In the intervening period, spot prices on both sides of the Atlantic have fluctuated wildly – upwards and downwards – while the Pacific has seen spot LNG cargoes sold at prices in excess of $20/mmbtu. While there has been no substantial and sustained movement of LNG cargoes between the three major markets, this period has highlighted the need for all gas market participants to understand the dynamics of US gas supply and demand to a much greater extent than previously, and particularly how prices can move substantially over short periods of time.

I am absolutely delighted that Michelle agreed to write this paper herself. She has a deep knowledge of North American gas and energy markets acquired over a long period of time, and we maintain strong links with the Center for Energy Economics at the University of Texas at Austin as it is possibly the closest North American academic counterpart in natural gas and LNG developments to the interests which we have at the Oxford Institute. My thanks go to Michelle and her colleagues at CEE and we in Oxford look forward to ongoing collaboration reflecting the increasingly close links between natural gas and energy markets which we study. This paper will be followed in the next few months by a companion paper on European gas prices.

Professor Jonathan Stern

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1. ACKNOWLEDGEMENTS AND AUTHOR BIOGRAPHY

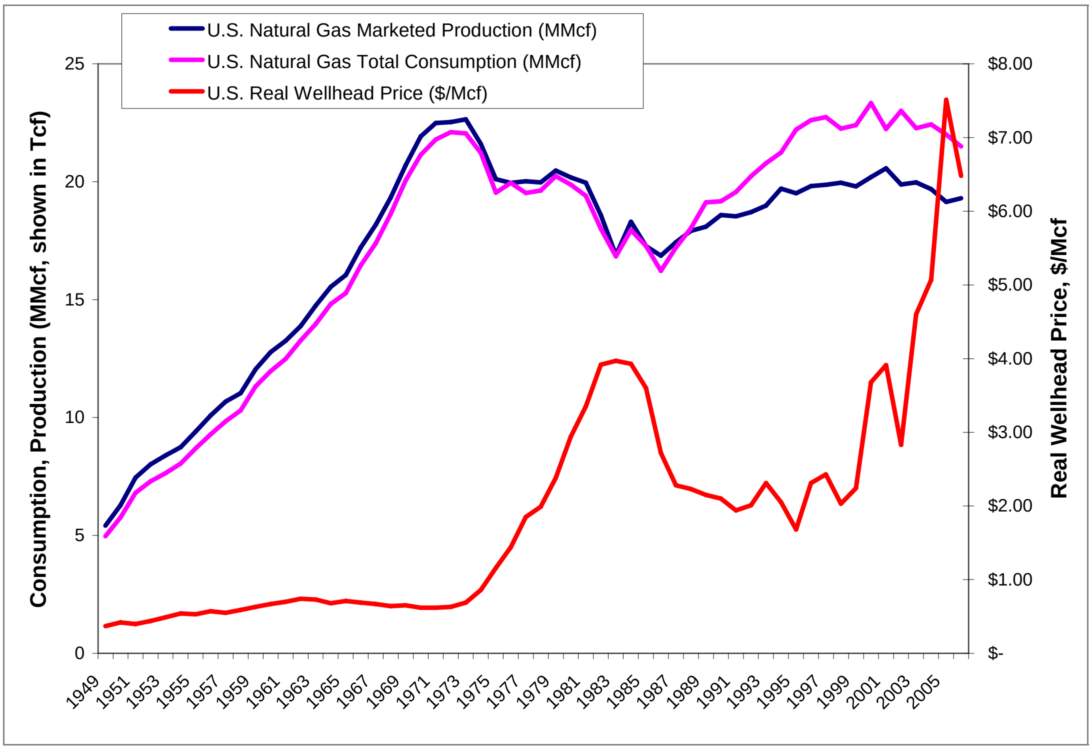
The author acknowledges and thanks the many corporate donors who support energy economics research at CEE-UT, as well as input for this paper provided by peer reviewers and by Professor Jonathan Stern, Director of Gas Research Programme at the Oxford Institute for Energy Studies and member of the CEE-UT's international board of advisors.

Dr. Michot Foss directs and conducts research, specializing in the energy value chains and associated investment frameworks; advises US and international energy companies and governments; publishes and speaks widely on energy issues; and provides public commentary and testimony to governments. She has more than 25 years of experience on US and North American natural gas market, industry, and policy/regulatory issues. This expertise ranges from large-scale natural gas resource and infrastructure developments in the Rocky Mountains during the early 1980s to broad research on US natural gas industry restructuring, North American continental trade, and international natural gas and liquefied natural gas (LNG) developments. Dr. Michot Foss built and leads CEE's LNG research consortium. This encompasses LNG safety and security; the siting of import terminal facilities; economic and community benefits associated with LNG import infrastructure development and operations; US and North American natural gas supply and demand balances and role of LNG; and international LNG supply development and trade, including energy-sector technical assistance activities in producing countries where CEE has presence through its US Agency for International Development cooperative agreement. Dr. Michot Foss also developed and directs *New Era in Oil, Gas & Power Value Creation*, CEE's international capacity building programme. In addition to Texas and the US, Dr. Michot Foss and the CEE team have experience in Canada and Mexico; South America; Russia and the Caspian; Western Europe and Turkey; West Africa; and East Asia. In 2006, Dr. Michot Foss was chosen as a Senior Fellow by the US Association for Energy Economics for her contribution to the profession and association. She was selected as one of the Key Women in Energy-Americas (2003). She was the 2003 president of the International Association for Energy Economics and 2001 president of the USAEE. She is a member of the Council on Foreign Relations; the Association of International Petroleum Negotiators (AIPN); and the Scientific Council, 50th Anniversary of ENI Commemorative Encyclopedia of Hydrocarbons, among others. She serves on the advisory boards of *Energy Magazine* and the Consumer Energy Alliance, and on the editorial board of the *International Journal of Regulation and Governance*. She holds degrees from the University of Louisiana-Lafayette, the Colorado School of Mines, and the University of Houston. Prior to her current appointment, she was research director and assistant research professor at the University of Houston and held consultant positions in energy investment banking and energy, environment, and regional economics research. She is a partner in a Texas-based exploration and production company. For information on CEE-UT, go to www.beg.utexas.edu/energyecon.

2. INTRODUCTION

For 2005, total United States natural gas consumption as reported by the US Energy Information Administration (USEIA)[2] was just below 22 Tcf[3], which was about 1 Tcf less than the historic high of 23 Tcf reached in 2000. At roughly 19 Tcf, the total figure for marketed production reported by USEIA was lower than the recent high of 20.6 Tcf reached in 2001 and substantially below the all-time high of 22.6 Tcf reached in 1973. For 2006, consumption will register slightly lower and production slightly higher, continuing the essentially flat to slightly declining market conditions that have prevailed since the mid-1990s. A perennial "gap" between domestic production and demand became a feature of the US natural gas marketplace in 1988. After jumping a new hurdle of 2.7 Tcf in 1995, the supply-demand gap has generally ranged between 2 and 3.2 Tcf every year since then, except for 2000 when it achieved its widest point, reflecting a tightening of the US natural gas balance that was ultimately expressed in a sharp spike in prices set at Henry Hub in Erath, Louisiana, the main US (and North American) trading point. A narrowing in the supply-demand gap is estimated for 2006, a reflection of softer fundamentals and a precursor to a widely expected correction in prices during 2007.

Figure 1. US Natural Gas Demand and Supply (USEIA)[4]



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[2] All quoted data from USEIA are taken from current data tables at www.eia.doe.gov.

[3] For this paper, measures of US and North American natural gas demand and supply used interchangeably are million cubic feet (MMcf), billion cubic feet (Bcf) and trillion cubic feet (Tcf). Measures of natural gas prices used interchangeably based on rough equivalence are thousand cubic feet (Mcf) and million British thermal units (MMBtu).

[4] 2006 estimates constructed by the author.

Pipeline exports from Canada have long been used to balance the US "Lower 48" market. Maturity in Canada's main producing region, the Western Sedimentary Basin in Alberta, along with growth in natural gas consumption in that country, has led to a flattening of US-bound deliveries since 2002-2003. Coupled with maturity in US fields, mainly for natural gas produced from "conventional" reservoirs,[5] these longer-term trends have triggered questions on a range of issues concerning the extent to which liquefied natural gas (LNG) may be needed to balance the huge US natural gas marketplace; whether breakthroughs can be achieved in US policies regarding access for drilling and exploitation of major new resources (offshore and Alaska); how the structure of demand for natural gas might change; and whether fuel competition will intensify (not only among the hydrocarbons, but also between natural gas, coal, and nuclear for electric power dispatch).

Long-term patterns stand in sharp contrast to shorter-term market conditions. After the previous winter peak in December 2005, US natural gas prices at Henry Hub began a sharp correction that reflected high levels of natural gas in storage relative to demand. The price decrease between December 2005 and January 2006 was roughly one-third. Since January 2006, Henry Hub prices have dropped an additional $3/Mcf, resulting in the overall erosion in prices since year end 2005 of almost 60 per cent. For a period in early autumn 2006, cash prices were below the front month of the New York Mercantile Exchange (NYMEX) futures contract. They have since converged, with cash prices moving toward the higher NYMEX contract price rather than the other way around. Contrary to expectations, cash and futures prices remained firm during December 2006, reflecting the onset of more rigorous winter conditions in some areas of the country. It is possible that weak fundamentals (mainly in the form of mild winter weather indicators) will induce traders to unwind NYMEX speculative positions, with both cash and futures prices dropping to a new equilibrium in 2007, which could easily test a $3-4/Mcf floor. Should crude oil prices erode further,[6] natural gas could drop below the psychological barrier of $3.

This current short-term price pressure stems from storage levels that are at historic highs, due to a combination of factors: recovery from the 2005 hurricane outages in the US Gulf of Mexico, production from new drilling, and powerful demand-side adjustments—the result of several years of high prices and price volatility—have all contributed to the current high storage levels. In addition, the decline in industrial consumption is roughly 2 Tcf since the onset of persistently high and volatile prices in 1999. At least some of that demand loss is considered to be permanent, a result of both shuttered operations and efficiency gains.

The picture ahead is clouded by the interplay of short- and long-term trends and a complex mix of upside and downside factors.

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[5] Conventional reservoirs are those that do not require treatment to stimulate natural gas production. Natural gas production from conventional reservoirs may be in association with crude oil. "Unconventional" reservoirs, by contrast, generally require either fracturing or "fracing"—pressurized injection of fluids to increase permeability for shales, mudstones and tight sands—or, in the case of coalbed methane, de-watering to reduce pressure and encourage desorption of methane-bearing coal seams.

[6] After a roller coaster year, light sweet crude prices ended 2006 roughly where they began, including a 21 per cent or so drop from the August high of $77/bl. Concerns are that the financial liquidity which is largely credited with bolstering oil prices will dissipate as supply-demand fundamentals are reasserted.

In this paper, I review current and prospective driving forces for US natural gas prices. In particular, I address several key questions.

- What is the likelihood that the US will be persistently short on natural gas supplies, resulting in long-term prices remaining high (at least $6/MMBtu)?
- Is it likely that natural gas prices would fall to a range of $3-$3.50/MMBtu for a prolonged period? Or, would any significant retrenchment in prices be short-lived, with prices returning to $6/MMBtu or above?
- How important is imported LNG for US natural gas price scenarios? Could other factors such as permanent shifts in demand and/or better than expected results in North American drilling exert meaningful influence?
- What can be deduced from the recent decoupling of natural gas and oil prices with respect to long-term fuel competition and switching?

To evaluate these questions, I examined and present key attributes of US natural gas demand, supply and price formation, with 2015 as the out year. I reached several conclusions and argue the following.

- Over the longer term, $6/MMBtu represents an effective cap on natural gas prices while $3/MMBtu represents a floor.[7] This "price deck" reflects three compelling realities.
- The first is diminishing returns from US and Canadian exploration and production (E&P) activity associated with prices above $6/MMBtu, a reflection of continuing maturity in the US/Canadian resource base.
- The second constraint is the moderating force on natural gas prices of demand elasticity and demand restructuring, which also limits other options, such as LNG that is not competitive within the $3-6MMBtu price deck.
- The third constraint is structural change in demand, the key issue being which application will set the price of natural gas at the margin. I argue that electric power will be the marginal application; that efficient gas-fired power will dominate the generation capacity mix; and that petroleum liquids switching capacity will at best remain constant, but is more likely to decline as a share of net summer generation capacity. Increased efficiencies overall in the large-volume industrial consuming sector is a permanent feature of the natural gas marketplace.
- My arguments have considerable bearing with regard to the effect natural gas prices will have, in particular on inter-fuel price competition. I suggest that the relationship between petroleum liquids and natural gas prices will be less contingent in the future, due to the dominance of natural gas drilling and production over oil, and as a result of changing patterns of natural gas use. While efficiency gains will sustain some large-volume natural gas users and applications, ultimately these efficiency gains will reduce the volumes of natural gas required, providing support for a lower long-term equilibrium price and lower price deck than might have been experienced otherwise.

[7] My price deck is based on Henry Hub expressed in real terms, with continued low inflation expected to minimize the differences between real and nominal prices.

3. US NATURAL GAS PRICES AND ASSOCIATED DRIVERS

In the short term, and given the current structure of demand and supply sectors, US natural gas prices are mainly a function of weather, storage, prices of competing fuels (principally petroleum distillates), and wellhead deliverability for peak seasonal use. Natural gas in inventory relative to historic norms (usually a five-year range) provides one of the most actively watched short-term indicators for pricing. The front months of the NYMEX futures strip are calculated to a great extent on the basis of the amount of natural gas in storage, or that is injected or withdrawn, along with forecasts and expectations for peak summer cooling and winter heating seasonal needs.

The 2005 hurricane season caused considerable damage to US Gulf of Mexico offshore production and pipeline systems, particularly the latter. The relatively warm winter 2005-2006 and the absence of hurricane-induced production and deliverability outages[8] in 2006 resulted in natural gas inventories being very high by historical standards, not to mention the typical five-year range typically used for market monitoring. Since 1992, the previous historic high for working gas in storage based on weekly data was 3,213 Bcf on November 5, 1998; the corresponding natural gas price at Henry Hub was $2.00/MMBtu. By contrast, the recent high of 3,461 Bcf on October 20, 2006 corresponded to a price of $6.26/MMBtu.

Do current conditions and short-term price movements provide clues to longer-term trends? As natural gas market conditions in the US unfolded over the past six years, a number of changes have become manifest that, when explored in light of demand and supply activity, suggest that there has been a permanent shift in market fundamentals. The following sections highlight market observations and their implications.

3.1 Prices and Inferred Indicators for the Mid- to Long-Term

The value of natural gas vis-à-vis crude oil and oil products is usually demonstrated by comparing Btu-equivalent prices (see Figure 2 below). Typically, a ratio of 5.8 to one is used. Figure 2 also shows the actual ratio between crude oil and natural gas prices to indicate periods when natural gas trades at a discount (above the typical 5.8 conversion factor) or premium (below 5.8). Overall, natural gas prices are generally positively correlated with crude oil (with a factor of about 0.84). After December 2005, crude oil, oil product, and natural gas prices diverged widely. Indeed, excluding the winter 2005-2006 price peak, a pattern of natural gas “decoupling” from oil over the past two years or so reversed the erosion in demand in key natural gas markets. In some US winter heating markets, more favourable natural gas pricing has encouraged residential and commercial heating oil furnaces to be replaced with natural gas equipment. Appliance replacement rebate programmes implemented by natural gas utilities in these locations are creating permanent new natural gas

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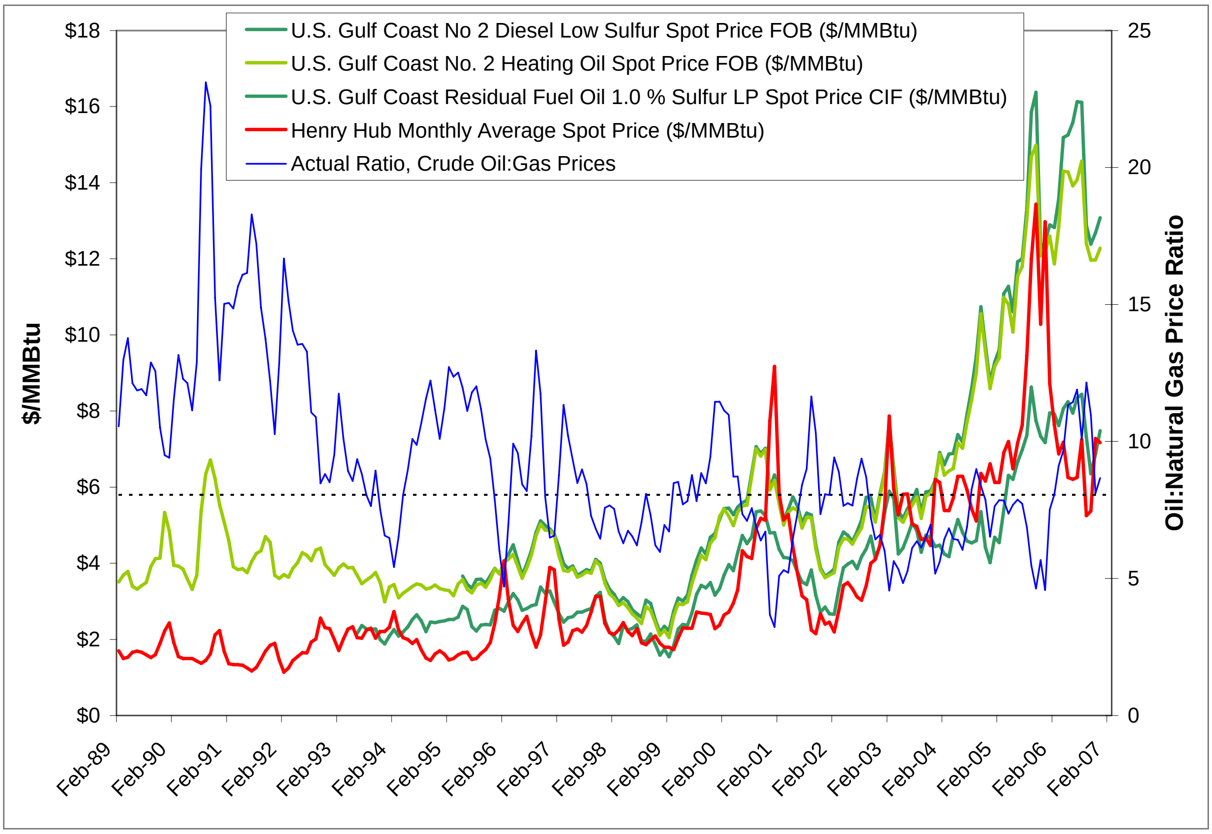
[8] The 2005 hurricane season stimulated considerable debate with regard to potential severity of the 2006 and future storm seasons. Accuracy of data beyond the past 20 years or so of satellite reconnaissance and record keeping should rightly moderate debate about climate change and hurricane activity. In the initial draft of this paper (June 2006), the 2006 season was projected to be less intense. That outlook was based on a cross-section of opinions and experience on variability of hurricane formation and US landfalls from year to year. Warmer waters generally correlate with increased storm activity. As the 2006 storm season progressed, data from the US National Oceanographic and Atmospheric Administration (NOAA) indicated a decline in temperatures in the Atlantic Ocean in the prime tropical storm region extending from West Africa. A less active tropical storm “hatchery” plus a new El Niño event in the Pacific and associated wind shears combined to foster a much different hurricane season than initially embedded in forward prices for natural gas. For more information on hurricane activity and related research, see http://www.nhc.noaa.gov/.

demand nodes that could serve to stabilize consumption, at least for the core residential segment. Furthermore, this load growth is supporting new transportation projects for gas delivery to the Northeast and Midwest US from the Rockies and Texas/Gulf Coast.[9]

While the relationship between crude oil and natural gas is generally valued at roughly six to one, reflecting relative heating values, that relationship is actually rarely in evidence. More often than not—in fact, approximately 92 per cent of the time—natural gas sells at a substantial discount to oil products. From the beginning of 1992, which marked full implementation of the US natural gas wholesale market and competitive access to interstate pipelines, the average oil to natural gas ratio has been more than eight to one. Even during periods when a tighter correlation exists between oil, oil products and natural gas prices (mainly winter peaks), significant price advantages for natural gas can develop, depending upon market fundamentals.

Natural gas is considered to be a highly valued, premium fuel that affords substantial environmental benefits when combusted. And yet, it has tended to trade at a fairly persistent discount with oil products. Past and present pricing of natural gas is a reflection of viewpoints regarding the competitive position of natural gas relative to other commodities.

Figure 2. Natural Gas and Petroleum Product Prices and Long-Run Crude Oil: Natural Gas Price Ratio (USEIA; Natural Gas Week, NGW)



9 Based on research conducted by the Center for Energy Economics and a forthcoming review of northeastern US natural gas markets. The mild winter2006-2007 may delay these projects, but is not expected to alter the underlying demand load over the longer term.

One viewpoint is that when natural gas is priced above No. 2 fuel oil or diesel, switching away from gas is triggered. Under this assumption, the discount for natural gas relative to oil products during the past 24 months or so has made natural gas more attractive to customers able to switch among competing hydrocarbon fuels. But as illustrated in Figure 2, natural gas rarely trades above or even near competing petroleum products. Furthermore, as noted in the discussion on demand below, other factors have greater influence: these include changes in natural gas prices, US economic conditions, business conditions within the large power and industrial demand sectors, environmental constraints mainly in the form of air quality regulations, and, for power, added competition from coal and nuclear generation. Finally, the sharp and prolonged increase in oil and oil product prices, the persistently higher cost of these fuels relative to natural gas, and air quality restrictions would seem to be strong disincentives for the development of new switching capacity or even for existing switching capacity to be used for anything except marginal applications during very short time periods.

A second viewpoint holds that when natural gas is priced below residual fuel oil, gas producers will earn insufficient returns resulting in shuts in wellhead production. As shown later, natural gas production increased fairly consistently from 1989 to 2002, and then fell sharply for a variety of reasons. Production has yet to recover fully, even as drilling climbed well past the previous historic high of 2002. While the inferred relationships between natural gas and resid pricing and natural gas production generally hold true, they are statistically insignificant. In addition, natural gas has sold at a discount to resid for almost two-thirds of the time since 1993. If the price of resid was an important variable, drilling for natural gas would have been suspended long ago, but this has not been the case. Natural gas plays are distinct from oil, and becoming even more so (at least for the broad swathe of Lower 48 and Canadian onshore). Drilling decisions and drilling financing are linked to Henry Hub and to locational basis associated with transportation. Oil and its derivatives are inconsequential to gas-directed drilling.

In sum, the price relationships between natural gas, crude oil and oil products present a mixed bag of indicators. Natural gas can, at times, be influenced by and correlated with oil prices. Natural gas can also decouple from oil and oil products. As discussed in the next section, higher priced natural gas has a large impact on the most sensitive, constrained industries and customers; higher prices negatively affect consumption and, in the worst case, will trigger temporary or permanent shutdowns and lost market share. Customers making decisions between oil products and natural gas for critical needs have been tremendously advantaged of late by more favourably priced natural gas. Persistent questions remain as to the total size of this customer group and their marginal costs for fuel switching. Equally persistent questions rotate around marginal cost of gas production. Conventional viewpoints regarding the influence of natural gas and oil products pricing are subject to debate. This could have profound implications for the structure of natural gas demand and the cost basis of the gas supply industry.

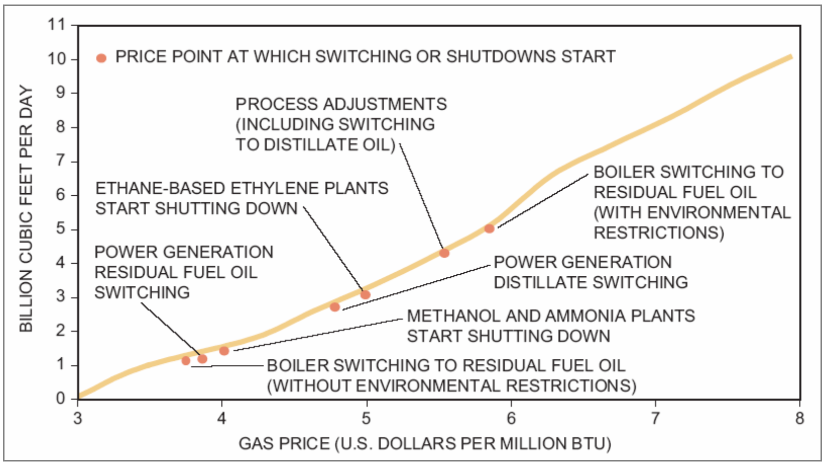
3.2 Demand for Natural Gas

The sensitivity of certain natural gas applications to price was explored in the 2003 National Petroleum Council's (NPC's) periodic update of US and North American natural gas market and policy conditions.[10] The demand-side analysis undertaken for the 2003 update aimed to provide better understanding of fuel competition and trade-offs, and demonstrated the

[10] See www.npc.org for all 2003 report documents.

sensitivity of highly price-elastic customers to systematic increases in natural gas fuel and feedstock costs. In Figure 3 below, customer decision-making, extent of switching capacity and associated marginal costs come into play. For many natural gas users, it is not simply the absolute price of natural gas that induces switching or shutdowns, but the change in price and the price of natural gas relative to the most immediately available substitutes.

Figure 3. Natural Gas Price Impact on Fuel Switching and Shutdowns (NPC 2003)



Total natural gas use for the major sectors is shown in Figure 4 (monthly) and Figure 5 (annual). Beginning in 2000, as real natural gas prices rose to exceed previous historic highs, the impact on demand in the industrial segment was immediate. Since 1999, industrial consumption as a share of total natural gas demand has declined from roughly 45 per cent to just over 30 per cent. After slipping in 2003, natural gas consumption for electric power generation resumed an upward trend. Overall, the residential and commercial components largely reflect inelastic demand in many parts of the US. The recent support for natural gas heating load within the core residential and commercial consumer segments, a function of Btu equivalent pricing as explained above, has helped to offset losses elsewhere.

Figure 4. Monthly Industrial and Electric Power Demand with Natural Gas and No. 2 Fuel Oil Prices (USEIA[1], NGW)

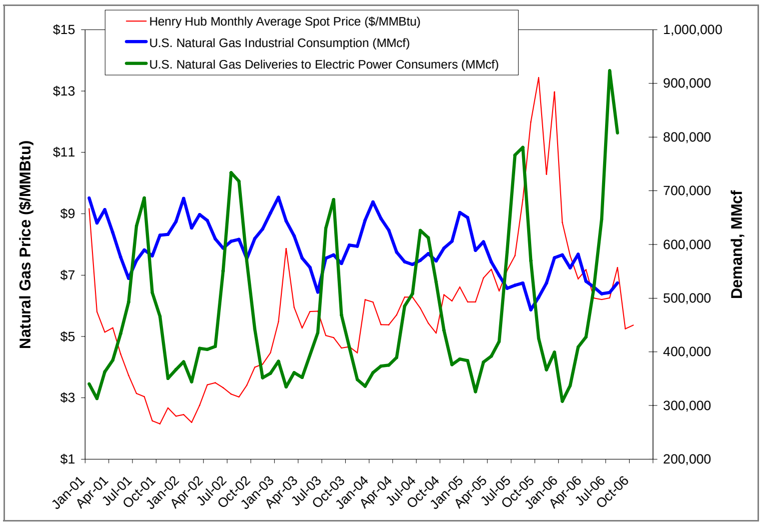
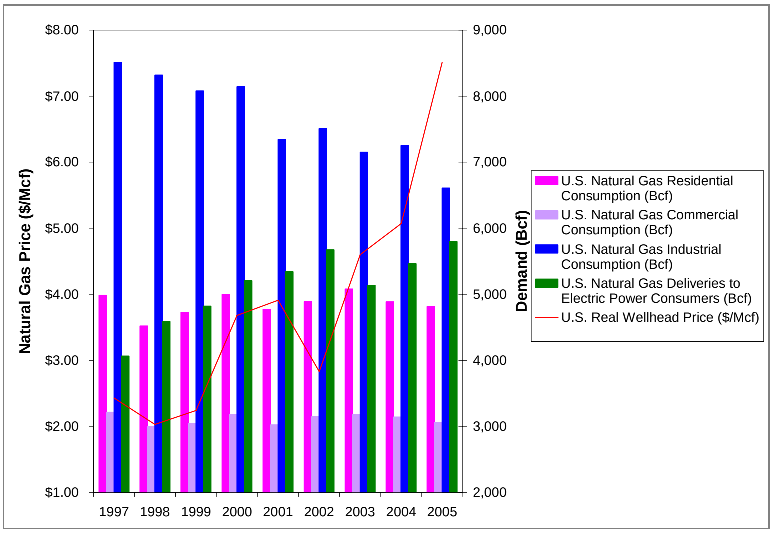


Figure 5. Annual Industrial and Electric Power Demand and Natural Gas Prices (USEIA)



Year-over-year changes in demand for the major segments (power and industrial) are shown below in Figure 6 (based on monthly data) and Figure 7(based on annual data).

Figure 6. Year Over Year Changes in Monthly Industrial and Electric Power Demand with Natural Gas and No. 2 Fuel Oil Prices (USEIA, NGW)

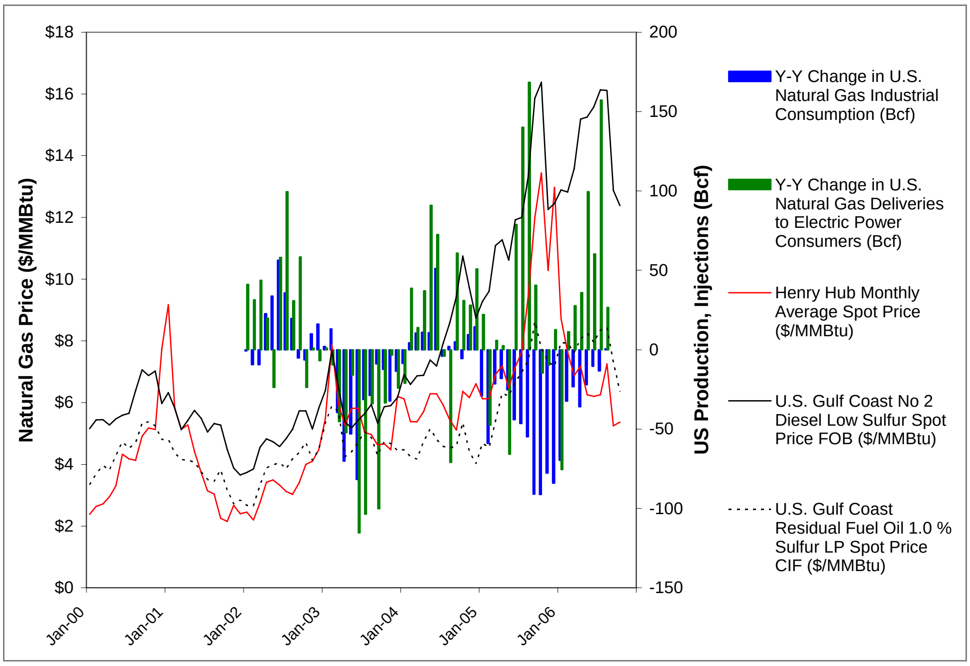
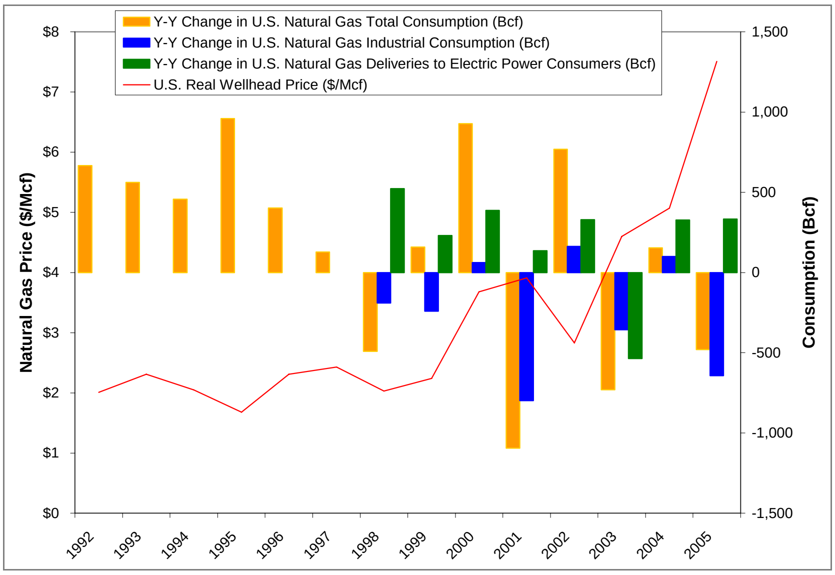


Figure 7. Change in Annual Industrial, Electric Power and Natural Gas Prices (USEIA)



A number of observations can be drawn from the preceding charts. Of note is the upward trend in natural gas demand for power generation even following periods during which natural gas price increases have been at their most pronounced and volatile. Indeed, gas consumption for power generation has returned to, and slightly exceeded, the 2002 high. Overall, from 1994 to 2005, the share of total net generation of electricity attributed to natural gas facilities has increased from 13-14 per cent to almost 19 per cent. This gain has been mainly at the expense of coal and hydroelectric based on USEIA data.

Of late, gas-fired power generators have benefited from cheaper gas (due to increased supply)—mainly in absolute terms and somewhat relative to oil products. The scale of the price-sensitive physical switching between residual fuel oil, which provides a petroleum product floor, and natural gas is about 1.5 Bcfd (billion cubic feet per day) out of a 70 Bcfd liquid market (when Canada is included). An improvement in near-term natural gas supply can push gas prices through the resid floor, as happened in February 2006 (compare Figure 6 and Figure 2).[11] The question of whether this kind of event could happen again, and its relevance, hinges on fuel-switching capability in the US power sector. Power generators with natural gas as the nameplate capacity constitute about 41 per cent of the total US fleet, about 437 Gigawatts (GW). Roughly 383 GW is counted as net summer capacity for peak use, or 88 per cent of all natural gas nameplate capacity. By comparison, petroleum liquids nameplate capacity is only six per cent of the total US fleet, about 90 per cent of which is counted as net summer capacity. Based on USEIA data for 2005, roughly 31 per cent of gas-fired power generators reported net summer switching capacity to petroleum liquids, while about 38 per cent of generators that mainly use petroleum liquids reported net summer switching capability to natural gas. However, just eight per cent of natural gas generation can be switched to petroleum liquids free of air quality regulatory limits, which would seem to reduce or even negate the impact of switching. Also, given the higher cost of petroleum liquids, the outlook for oil supply and prices, and the stringency of air quality regulations (unlikely to change in the foreseeable future) it is unlikely that new petroleum-based power

[11] Comment from industry source.

generation investments will be made. Indeed, less than one per cent of planned nameplate capacity additions through 2010 are targeted to be petroleum-based, according to USEIA data;[12] the proportion of new natural gas nameplate plants that might have fuel switching capability is not known.

A more important factor in the data on gas-fired power has been the reduction of surplus capacity in power generation in many locations as a result of growing demand (and thus shrinking power reserve margins). By 2005, reserve margins across the contiguous US had dropped to about 15 per cent. In large states dominated by gas-fired generation capacity, like Texas and Florida, reserve margins fell to less than 12 per cent and less than nine per cent, respectively. Lower natural gas prices and gas decoupling from oil have facilitated re-entry of "stranded" gas-fired generation facilities built under more expensive commercial terms by merchant energy businesses and at a time when surplus power generation capacity had emerged in many parts of the US. Further capacity additions slated for these and other large states are dominated by natural gas.

Yet clearly, even while natural-gas-fired power generators suffered the consequences of over-development and excess capacity, plant operators continued to use natural gas for peak requirements. Independent power producers will dispatch gas-fired generation so long as variable costs are covered. Wholesale market rules enforced by the US Federal Energy Regulatory Commission (FERC)[13] ensure that price information associated with economic dispatch flows through the bulk power market. Few states have created or experimented with retail markets. The transfer of costs by integrated utilities for more expensive natural gas-fired electricity through core customer prices remains an issue across the state public utility regulatory landscape. Some state public utility commissions have limited cost recovery for both electric power and natural gas utilities associated with fuel costs; the impact of these decisions is well documented in utilities' financial reports. On the other hand, utilities in several states have not reduced retail prices to reflect recent lower natural gas costs, increasing conflict between utilities, regulators, and customer groups.

Coal producers and coal-fired power generators have benefited hugely from higher natural gas prices. Coal producers in particular have earned substantial profits as coal prices have generally risen to follow natural gas price trends. However, the strength in gas consumption by the electric power segment suggests that natural gas also continues to benefit from its environmental advantages relative to coal and oil products (especially for coal facilities subject to sulphur dioxide and nitrous oxides emissions allowances). Over the longer term, some expectations are that coal will enjoy resurgence and compete strongly with natural gas or other fuels and technologies for electric power dispatch. These viewpoints tend to emphasize the very large US coal resource base and discount the significant challenges associated with developing and commercializing low or zero emissions clean coal technologies as well as environmental resistance to new coal mining. There is opposition to most of the new announced pulverized coal steam-power plants on environmental grounds.[14]

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[12] Data are as of October 2006.

[13] The Public Utility Commission of Texas, PUCT, and Electric Reliability Council of Texas Independent System Operator, or ERCOT-ISO, enforce and implement, respectively, wholesale market rules for the separate ERCOT interconnection.

[14] Comments from Kyle Danish, Van Ness Feldman. CEE is conducting a survey of coal-fired capacity additions and related issues.

The substantial uncertainties associated with increased reliance on coal raise questions about long-terms outlooks that dramatically increase coal's share of the US energy portfolio, in spite of the energy security advantages that greater use of domestic coal might offer. Undoubtedly, coal producers and utilities with large coal generation assets will present a compelling case, especially for natural gas imported as LNG. If coal and natural gas do compete as vigorously at the electric power burnertip as they are expected to, downward pressure on natural gas prices would accumulate.

Like coal-fired power plants, nuclear facilities have also benefited from higher natural gas and petroleum product prices. Based on USEIA data, between 1994 and 2005, nuclear power held relatively steady at 19 to 20 per cent of net generation. A number of interesting developments are underway, including upcoming pre-filing reviews that will test public and regulatory support for new nuclear units. At this point, it simply is not possible to predict the ultimate outcome of attempts to license new units.

The competition between natural gas, coal and nuclear in the electric power segment is a long-term issue, a 25- to 30-year forward prospect, or well beyond. It will continue to be true that the cost to install new gas-fired power generation will be much cheaper than either coal or nuclear per unit of nameplate capacity. It will also remain true that more power can be generated from coal (and presumably nuclear) plants because of the cheapness of those fuel sources on a per unit basis. While the USEIA and other sources generally capture electric-power capacity additions only through the next five years or so, the life of installed equipment ensures that there will be a strong natural gas share (so long as the gas supply requirements can be met). With the amount of gas-fired capacity already in place, the roughly 437 GW or 41 per cent of the US fleet previously mentioned, and planned capacity additions through 2010 of 57 GW or 60 per cent of total capacity additions, gas suppliers will enjoy a hefty share of the US electric power capacity. The key question is whether future fuel cost will support greater output.

Finally, if fuel switching would seem to be less of a factor, in particular for future management of power generation fuel supply, and given the large and growing presence of natural-gas-fired power generation as well as the continued improvement in generation efficiency of the US fleet (through both additions and retirements), what are the price sensitivities for generators? Two views are presented below. In Figure 8 I compare natural gas delivered to power generators with Henry Hub price using short term (monthly) data, and in Figure 9 I use net generation by natural gas-fired plants and real wellhead price. Both of these charts show that increases in natural gas consumption and gas-fired generation are longitudinal with time as well as positively correlated with natural gas prices (albeit more weakly in Figure 8). Generators are clearly more comfortable making and expanding natural gas purchases at $6/MMBtu or below. The dispersion of aggregate purchases reflects the highly varied power market and operating cost conditions at the time decisions are made. Figure 8 is also illustrative of efficiency gains and/or dispatch obligations as large volumes of natural gas are purchased at higher prices. Figure 9 makes an even stronger case—thus far—that gas-fired power generation operators are able to accommodate, and pass along, higher fuel costs. Does Figure 8 suggest more tolerance for electricity generated with higher-priced natural gas? The data would seem to suggest that $7/MMBtu could be an upper range. However, there are clear indications that large electric-power customers see more efficient use of electric power as the next horizon in energy cost management. Based on the apparent trend, gas-fired power generation could be expected to increase more readily at lower rather than higher natural gas prices, and the closer to a $6/Mcf (or approximately equivalent MMBtu) upper band the better.

Figure 8. Natural Gas Consumption for Electric Power and Natural Gas Price, Monthly Data, January 2001-August 2006 (USEIA, NGW)

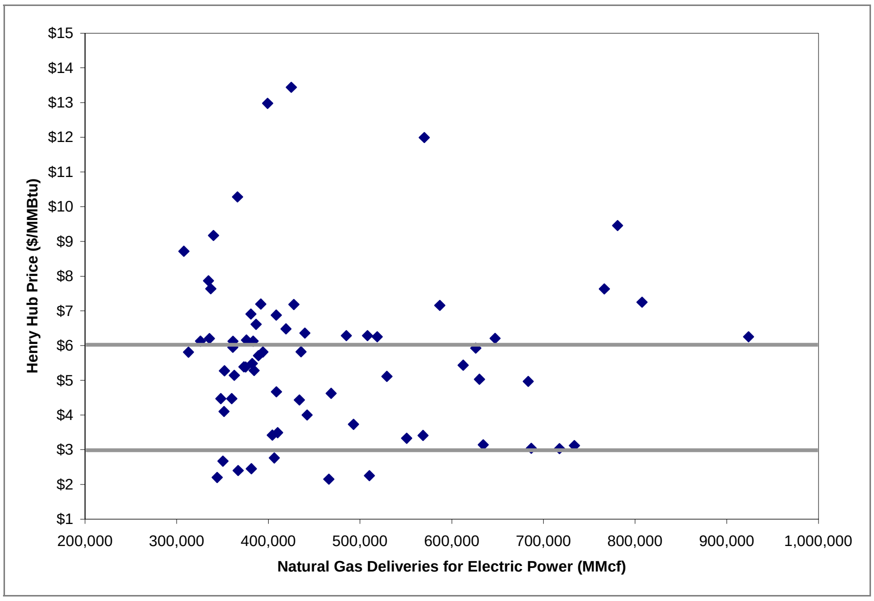


Figure 9. Net Generation of Electricity by Natural Gas Power Plants and Natural Gas Price, Annual Data, 1994-2005 (USEIA)

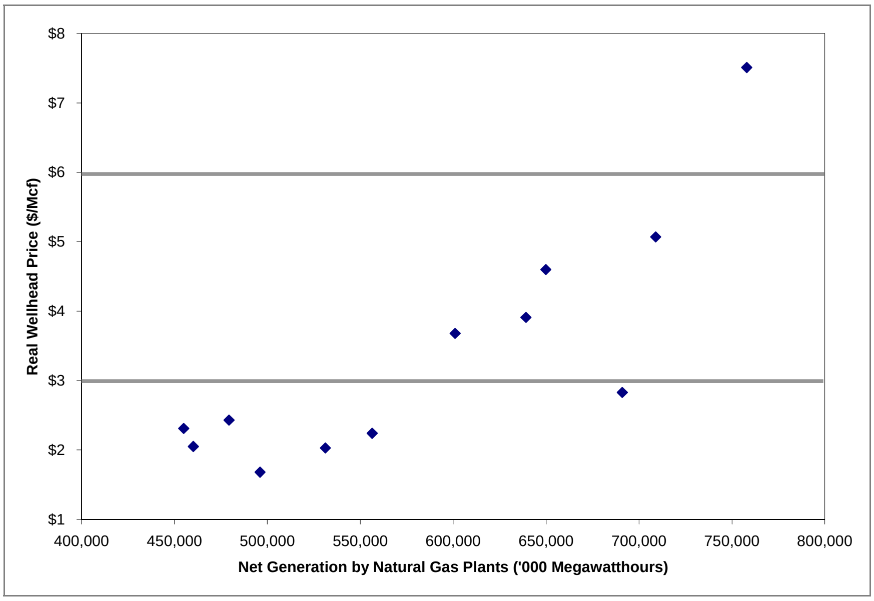
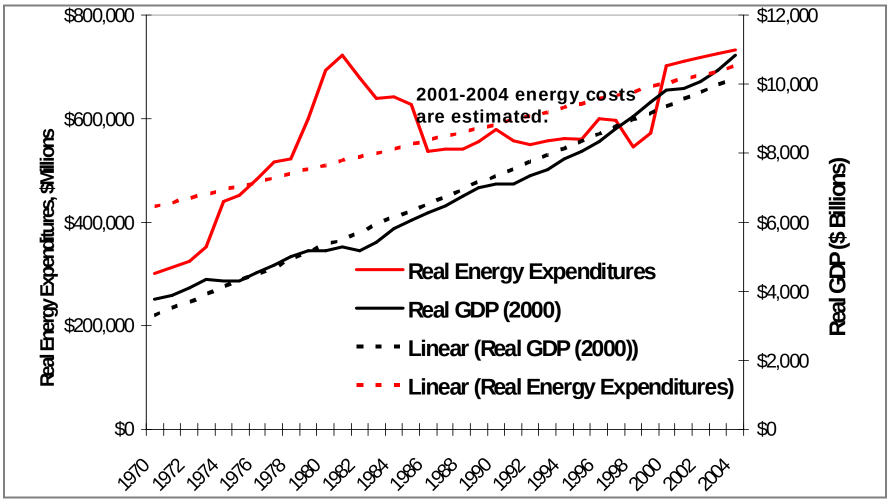


Figure 4 through Figure 7 above illustrate the strong contrasts between the situation for gas-fired electric power and the much more sensitive industrial demand segment. Two factors account for these differences—the sharp consequences of higher natural gas prices for industries that use natural gas as a basic material feedstock, and the prevalence of combined cycle gas turbine (CCGT) capacity on the power generation landscape, especially in industrial combined heat and power (CHP) facilities.[15] In the case of the former, apart from shut down, few alternatives exist for high marginal cost industries (ammonia fertilizer and methanol in particular). With respect to CCGT, improved efficiency means less natural gas required for power production. All together, the near-parity for electric power and industrial consumption represents the most fundamental shift in the natural gas marketplace. The prevalence of CCGT equipment, the efficiency gains associated with new higher heat rate turbines, and the distinct possibility that natural gas consumption for power generation may overtake natural gas for industrial use all indicate that natural gas pricing at the margin will be driven much more by gas-fired power.

The experience with higher natural gas prices in the US has instigated a vigorous debate on how natural gas should be used. Initially, industrial customers—in particular natural gas feedstock customers—argued that natural gas was too important to be burned for electric power. Creation of the bulk wholesale markets for natural gas and electric power, frameworks that supported independent gas-fired power generation as a way of capitalizing on much lower natural gas prices in the early to mid-1990s, was roundly criticized as questionable public policy. These criticisms eased as large industrial customers were better able to recover their costs for higher priced natural gas purchases and as gas-fired power continued to perform. Should the debate be turned around? As new materials and processes are introduced, providing innovative substitutes for the array of goods we consume in daily life, reliance on hydrocarbons should alter and continue to decline. In contrast, natural gas provides a relatively clean and flexible power-generation fuel that is difficult to replace within existing cost constraints, unless significant progress can be made to introduce renewable technologies. Consequently, it seems that not only is there is a strong argument in favour of established public policy, but also that the policy envelope with regard to wholesale and retail electric power markets and market sensitive pricing should be pushed further.

Over the longer term, the US displays an impressive ability to absorb both higher energy costs and greater energy price volatility (Figure 10).

Figure 10. US Real GDP and Real Energy Costs (USEIA)



[15] Based on the USEIA net summer generation capacity inventory, CHP constitutes about 45 GW or 12 per cent of the total US fleet. CHP for industrial applications is about 32 per cent of the 45 GW; the balance is designated as "electric power sector" (utility or independent power producer, IPP) operated. Fuel switching capability for any of the CHP generation capacity is negligible.

There are a number of reasons for this resilience, including competitiveness and innovation in the energy industries; phasing out of older, less efficient equipment to attain improved energy consumption efficiencies in the large energy-intensive demand sectors; and monetary factors for the current high price cycle (a soft dollar and low inflation and interest rates). Overall, energy is a minor portion of disposable income for most American households. Energy prices tend to be regressive; the customers who are hardest hit are lower-income and fixed-income households. However, these customer groups are often constrained in their ability to contribute to GDP.

There is, however, a potentially significant downside to energy cost resilience in the US, which has only just become part of the debate. The argument in favour of market-based solutions, i.e., relying on the transfer of price signals for demand-side adjustments to be made, has been frustrated by the current commodity cycle. The generally higher costs of energy and other basic materials have been absorbed, with effects offset by the relatively low inflation and interest-rate environment.

Impacts of higher gas prices are most evident in the energy-intensive industrial sectors. Current estimates are that approximately 100,000 jobs have been lost as industrial customers responded to higher natural gas prices.[16] The impact is analogous to oil-based smokestack industry retrenchment in the US heartland during the 1970s crude oil price shocks. To the extent that efficiency gains mean stronger, more competitive basic industries in the long run, the US economy benefits. Staff at the Office of Energy Efficiency and Renewable Energy at the US Department of Energy (USDOE-EERE) estimate that, based on approximately 200 energy assessments conducted for a range of industrial users with thermal systems, about seven per cent savings in energy consumption has been achieved overall, with 11-12 per cent savings for natural gas alone.[17] About 20 per cent of industrial CHP capacity is shut down.[18] Some industrial feedstock uses of natural gas have been, or are being phased out.[19] New relationships and feedbacks are in evidence as process managers turn to alternative feedstock providers only to encounter supply and/or price disruptions there as well.[20] And it is questionable whether investment in major new natural gas feedstock industrial capacity will be made in the US, at least in traditional process applications. Large chemical and materials companies that use natural gas (and petroleum products) in process applications are searching for feedstock substitutes, often by investing in new locations.[21] More importantly, as the types

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[16] For a typical view on natural gas price impacts and industry adjustments, see http://www.nam.org/s%5Fnam/doc1.asp?CID=202493&DID=235622.

[17] Based on discussions with USDOE-EERE staff in December 2006. Interestingly, in formal presentations, EERE compares natural gas reductions to "LNG cargoes saved". EERE is planning a more comprehensive analysis of its industrial data. CEE plans a more formal survey of industrial segment natural gas consumption.

[18] Based on input from industrial facility managers with CHP operations obtained during August-December 2006.

[19] In keeping with the NPC 2003 assessment, first to drop out of the industrial market were US Gulf Coast ammonia and methanol producers. A number of commentators point to issues in fertilizer availability as a result of ammonia shut downs, and LNG has been targeted as a solution, although the energy and materials balance in this case would seem to be questionable.

[20] Based on comments by Lee Rosen, Praxair, in December 2006. His comments pertained especially to industrial oxygen as an alternative process using sludge as the feedstock.

[21] According to a recent presentation by John Chen, president, American Institute of Chemical Engineers, global petrochemical facility investment between 1995-2005 was directed as follows: Middle East, 149 per cent; Asia-Pacific, 71 per cent; US, 23 per cent; Latin America, -8 per cent; Europe, -14 per cent; Canada, -18 per cent.
Footnote continued on next page.

of materials they produce change, and as technologies for both materials production and end-use applications continue to advance, both new feedstock sources and different ways of using traditional hydrocarbons feedstock will evolve. For significant new investment to be made in the basic process industries that have been the hallmark of the US petrochemical complex, there would need to be much higher confidence that lower natural-gas prices and price volatility could be achieved, or the risk managed. In addition, as noted later, natural gas producing and exporting countries are looking to retain value added for their domestic economies from natural gas and natural gas liquids, and some are succeeding in attracting new basic industries that are even further advantaged by lower-wage work forces.[22]

In spite of the economic dislocations triggered by higher natural gas prices, and in spite of vigorous political positioning, and many veiled threats, the US Congress has not attempted (or at least not succeeded) in undermining any of the significant restructuring rules that made the natural gas industry more competitive and market sensitive.

3.4 Supply and Deliverability of Natural Gas

3.4.1 Production

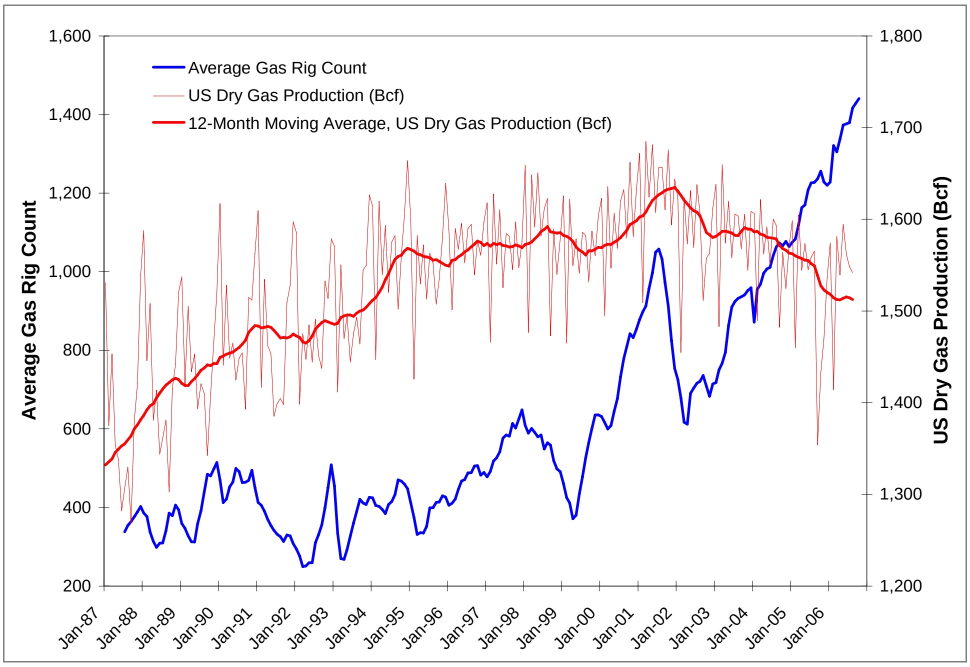
Field maturity and declining natural gas production in the US and Canada are now the focus of considerable attention. Of note has been a decline in total production for the US even while drilling reached an all-time high (Figure 11). With a maturing resource base and unconventional plays increasingly the target of drilling, the production of new wells does not match historical results, nor is it expected to. The decline in production was also a consequence of demand response to higher prices in 2000 and the drop-off in US economic activity in late 2001. Hurricane activity during the 2004 and 2006 seasons was another major contributor. Indeed, 2006 storm activity and related outages masked production gains associated with new plays that were just beginning to show up in data.

I already mentioned the relationship between natural gas and resid prices and natural gas production in conjunction with Figure 2. By the mid-1990s, drilling in the US became dominated by natural gas plays and thus more sensitive to natural gas price. Figure 12 and Figure 13 show changes in natural gas production and injections to storage with corresponding natural gas and resid prices. The reduction in demand during higher price periods triggers production turnbacks and thus higher injections. Lower prices mean drops in production and injections. In my earlier discussion on Figure 2, I stated that the price of oil does not drive decisions to drill for gas.

Middle East investment is feedstock driven; in other locations investment is a combination of feedstock cost and market demand.

[22] Based on information collected from natural gas and petrochemical industry sources. For a typical view on natural gas price impacts and industry adjustments, see http://www.nam.org/s%5Fnam/doc1.asp?CID=202493&DID=235622.

Figure 11. "Just in Time" Natural Gas Development and Delivery (Baker Hughes, USEIA)



Nor does resid pricing appear to have any influence on natural gas; production growth was still achieved in periods when Henry Hub price fell below that of resid in Btu equivalent terms. Oil and natural gas price trade-offs would mainly apply where natural gas is produced in association with crude oil. In those cases, pricing decisions that impact crude oil would then affect wellhead deliveries of natural gas. However, such instances are increasingly rare and will become even less frequent in the years ahead. Fundamental shifts are occurring not only with respect to demand, but also with respect to supply. One might consider these to be "seismic" shifts, given their consequences for the future of US natural gas supply.

Figure 12. Year Over Year Changes in Monthly Injections, Production, and Natural Gas and Resid Prices (USEIA, NGW)

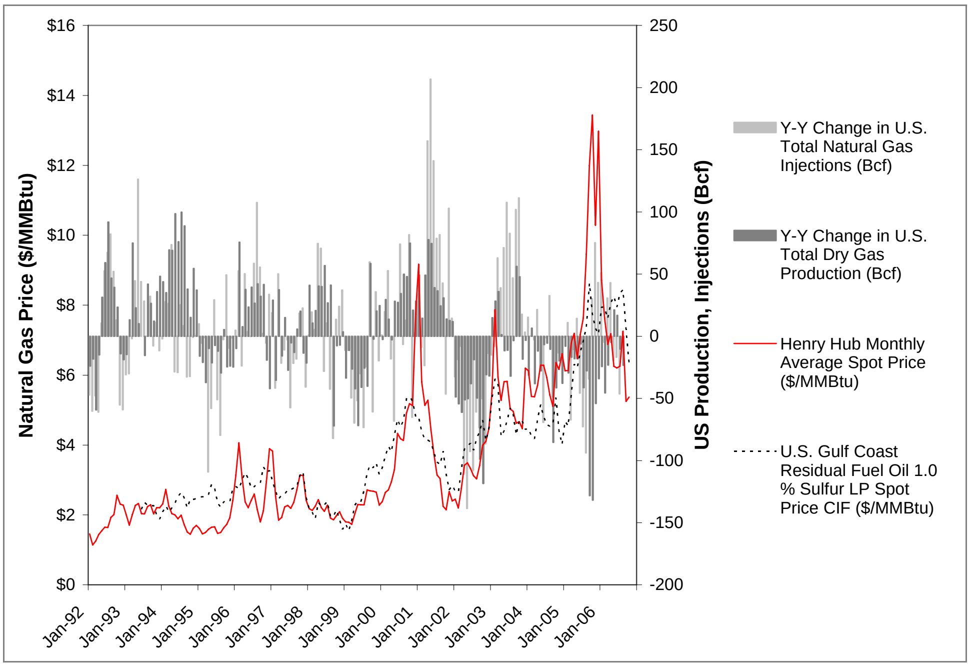
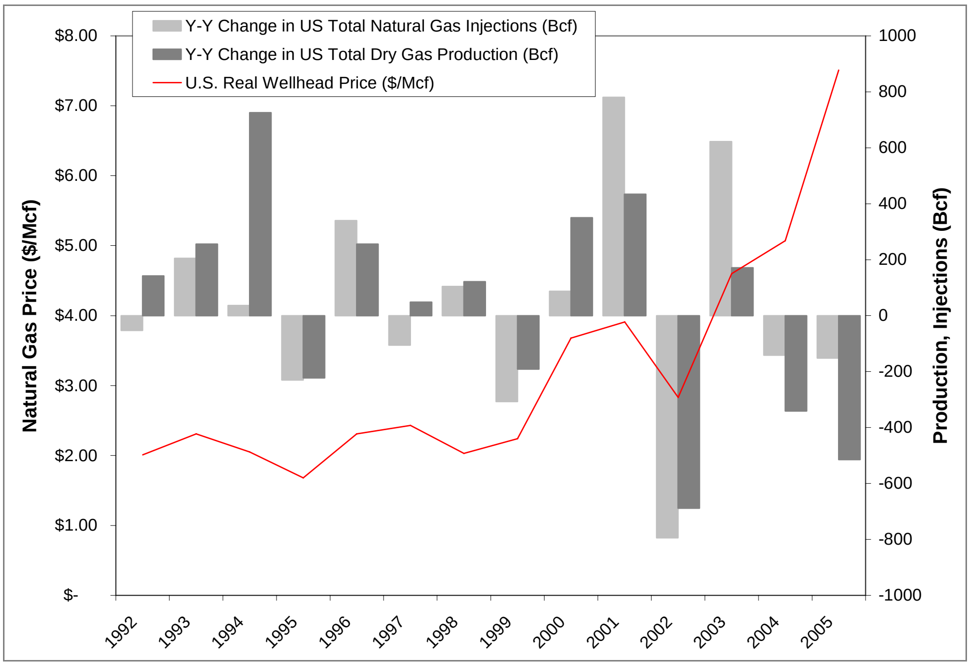


Figure 13. Year-Over-Year Changes in Annual Injections, Production, and Natural Gas and Resid Prices (USEIA)



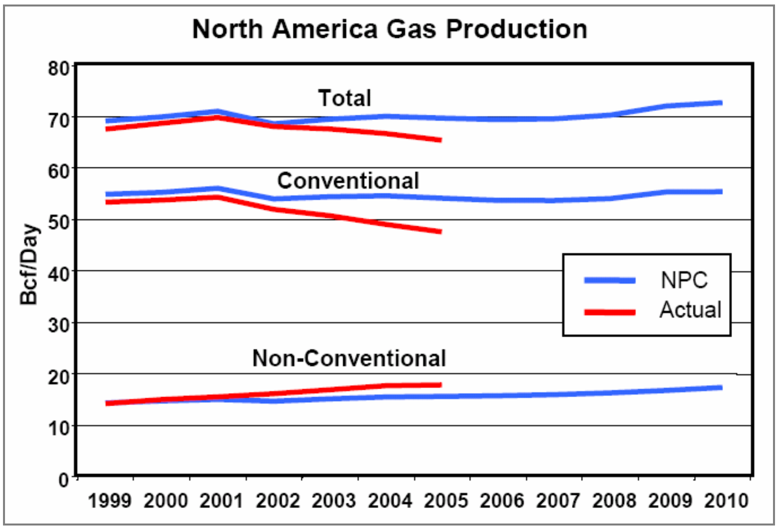
Contrary to many opinions, the US natural gas resource base is large, diverse, and resilient, although certainly not without challenges. North America, overall, remains one of the richest natural gas provinces in the world. It is therefore highly unlikely that the trends in drilling and production will not eventually yield gains in production. How significant these gains are likely to be will hinge on the ability of operators to test new play concepts while commodity prices work to their advantage. The US and Canadian oil and natural gas industry is extremely efficient. Much of the current upstream efficiency came at the expense of painful adjustments following excesses during the late 1970s-early 1980s drilling boom. Periods of high commodity prices have always afforded the industry opportunities to test new technologies and play concepts, amortize associated costs, and reach new plateaus in development. Experience from the early US Gulf of Mexico deep water blocks demonstrated the speed with which E&P operators can test, deploy, commercialize, and reduce costs with technology, sustaining finding and development economics in the US. Furthermore, overall drilling results in recent years have yielded broad improvements with regard to success rates—more than 25 per cent for gas wells with fairly steady improvement since the late 1990s as unconventional play concepts have proceeded. These success rates have worked to largely sustain the critical US domestic onshore and offshore supply base (which delivers 60 to 70 per cent of consumed natural gas and must continue to do so well into the future).[23]

The US natural gas E&P segment faces two specific challenges emanating from the current commodity price cycle. One is to sustain gains in drilling success and achieve cost reductions during a time of intense upward pressure on business expenses due to tight conditions in labour, materials, and field services. The second major challenge is to accomplish these aims while developing and testing the "next big thing" in the US and North American upstream—

[23] Based on US Department of Energy natural gas update of NPC 2003, December 2005.

unconventional and ultra-deep-water play concepts. While natural gas production from conventional reservoirs (normally pressured, with good porosity and permeability) has declined, pulling down total natural gas production, gains have been made to "prove up" new unconventional resources. These resources consist mainly of dense, tight reservoirs (such as "black shales" and tight sands) that must be treated or "fraced" for the natural gas to be produced, or coalbed methane extraction that requires extensive water production in order to sufficiently reduce reservoir pressure so that the coals will de-gas. Unconventional play concepts pose a number of technological and management hurdles. These range from fine tuning seismic modelling and interpretation in order to better define opportunities, improving reservoir characterization and reservoir treatment for drilling and production success, and even fundamental materials and other advances for drilling and completion in extremely low permeability media and fissile coals. Figure 14 serves to reinforce the general trends with respect to the growing preference for unconventional resource plays (which tend to provide larger, long-term deliverability).

Figure 14. North America Gas Production by Type (NPC Section 1818 Update)



Canadian producers are active participants in developing unconventional plays in that country. Canadian drilling was much more sensitive to decreases in natural gas prices during 2006, a consequence of the superheated cost structure (and that a consequence of accelerated investment in Alberta oil sands projects).[24] Many of the new unconventional natural gas plays are in the Rocky Mountain region and East Texas, where the pace of drilling has not shown signs of wear. This regional emphasis is expected to continue. In addition to upstream technologies, infrastructure for delivery of unconventional gas production also poses barriers. Extending or developing new major pipeline systems into areas that are not fully tested or where production is mainly from low-volume, widely dispersed locations are representative of the kinds of commercial tests the industry faces. In the case of widely dispersed, low-volume production, which constitutes a large portion of the US resource base (including low-pressure "stranded" gas that remains in existing fields), there may be a need for entirely new delivery strategies and technologies, such as small-scale LNG or gas-to-liquids conversion. Drilling in deeper waters (Outer Continental Shelf or OCS) and deeper drilling in shallower waters of the US Gulf of Mexico continue to test the Lower 48 resource base. For deep water

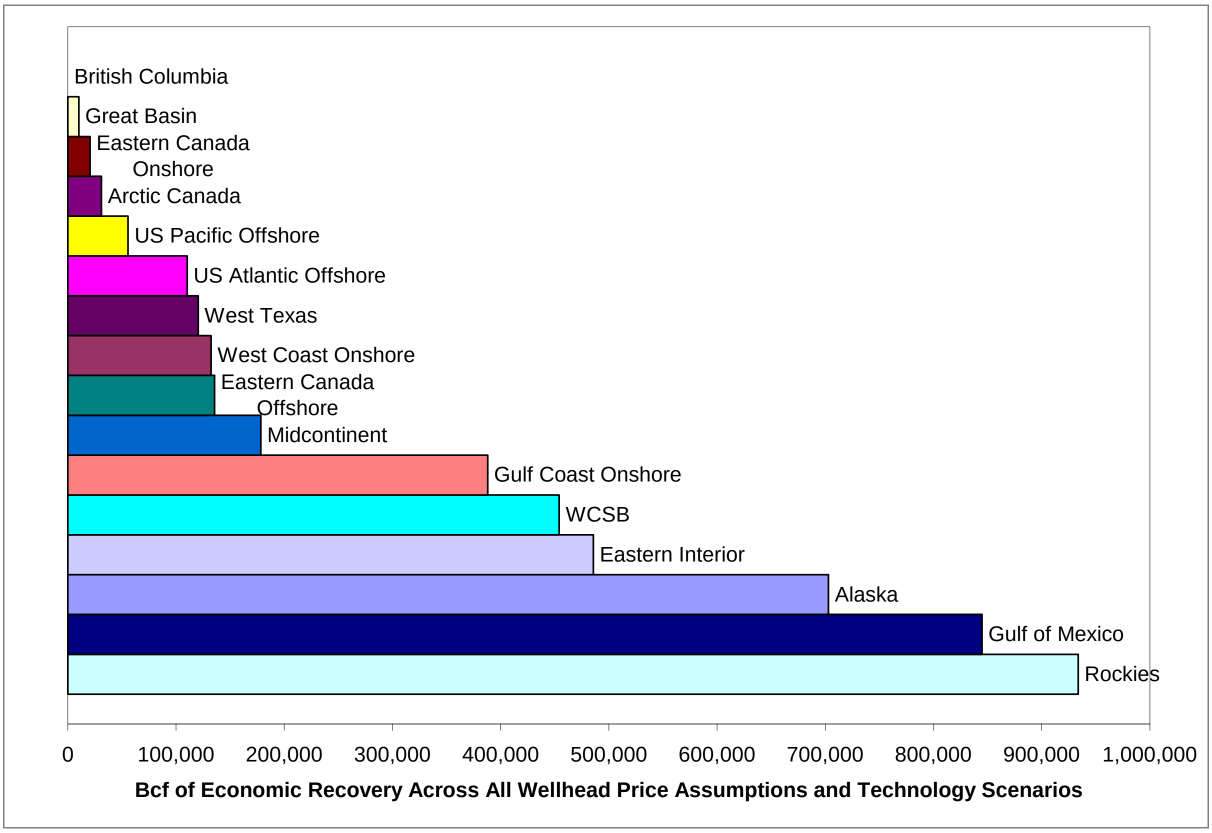
[24] Based on comments from Canadian E&P operators taken in November 2006.

plays, advances in pipeline infrastructure have been achieved in order to deliver these resources to critical Gulf of Mexico downstream industries. Here, new approaches may also be needed to aggregate, store and deliver production from remote deep water blocks. Challenges to future natural gas supply include "hardening" Gulf of Mexico facilities against hurricane activity and damage, and building political support for access to resources for both offshore and onshore development. Large swathes of the OCS are off limits through moratoria, and large sections of the onshore domain are restricted through a variety of laws and regulations affecting public lands (in terms of direct access to surface and subsurface rights access and by imposing environmental constraints).[25]

The combination of higher commodity prices, more successful drilling, better use of technology, and emerging new long-distance pipeline projects has triggered a return of interest in the US and, to some extent, Canadian onshore by major companies. These operators had largely exited the domestic E&P businesses, save for the offshore Gulf of Mexico and Alaska (large E&P organisations also remained active in Canada's frontier basins and offshore Atlantic).

As the time-horizon of interest stretches to 2015, many trends in natural gas resource development will already be well in place. Figure 15 illustrates the previous discussion and indicates the major basins that are expected to yield most of the natural gas supply gains through 2015 (and beyond).

Figure 15. Regional Gains in Supply, 2003-2015, Bcf (NPC 2003)



[25] Near the close of the 109th Congress 2006, the House and Senate succeeded in passing legislation that would open a small portion, roughly eight per cent, of the OCS in the Eastern Gulf of Mexico to offshore oil and gas exploration and development.

While unconventional natural gas resources have been recognized and exploited for some time, price signals simply have not supported the larger-scale exploitation push that is currently underway. Generally speaking, all "unconventional" resources require better technology and commodity prices for commercialization. The main categories targeted in the US, Canada and elsewhere—tight gas sands, gas shales and coalbed methane—have already benefited from research and developmet (R&D) and deployment, as well as associated policy levers to encourage resource exploitation. For these resources to be converted to proven reserves and thus made available for delivery (including sufficient confidence in the reserve conversion process to facilitate midstream investment for transportation and other "field-to-market" options) a number of requirements have been identified. These include the following.[26]

1. Exploration technology for establishing the higher permeability, naturally fractured areas of a tight gas basin or play.

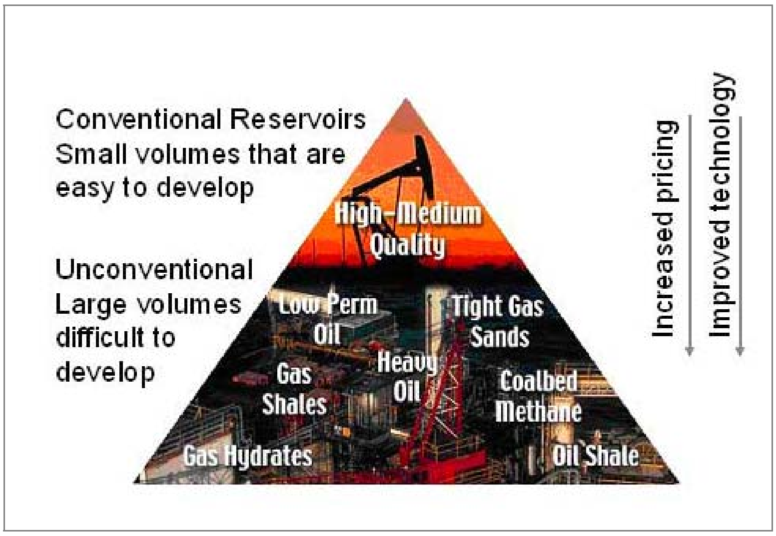
2. Basin and regional studies to understand and avoid high water saturation areas.

3. Reservoir characterization to establish the total productive pay intersected by a wellbore.

4. Emphasis on steadily driving down well drilling and completion costs.

5. Applying intensive resource development.

Figure 16. Resource Triangle[27]



A critical question becomes the marginal cost of exploiting unconventional resources and what should or could be expected as the prime natural gas price indicator, Henry Hub,

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[26] From Kuuskraa and Bank, 2003. Many others have catalogued the technical issues associated with unconventional gas resources and technology, and market requirements for development. See Shanley, et al., 2004. Also see Naik, 2005, Association of Petroleum Geologists of India, http://www.apgindia.org/tight_gas.pdf.

[27] From Holditch, 2005, "Statistical Correlations in Tight Gas Sands", American Association of Petroleum Geologists (AAPG) Hedberg Conference Proceedings. http://www.searchanddiscovery.net/documents/abstracts/2005hedberg_vail/abstracts/extended/holditch01/holditch01.htm.

fluctuates. Figure 17 shows marginal cost curves for natural gas supply by type (growth in existing fields and basins, new fields, and unconventional) for the US Lower 48. Figure 18 shows marginal cost curves for total natural gas supply in the US and Canada. Finally, Figure 19 illustrates gains in natural gas supply between 2003-2015 and 2015-2030 associated with discreet natural gas price assumptions. All of these charts are based on data inputs used for the 2003 NPC natural gas supply study. In the NPC study, impact of technology encompasses the three main time periods used in the study: 2003 (current), 2015 and 2030 (deployment of progressively more advanced technologies). The price band of $3/MMBtu and $6/MMBtu is used, based on my previous analysis of demand. Although the last major study by the NPC dates back four years or so (meaning that underlying supply and cost information is a bit more dated), it remains a comprehensive data source by basin. Given that the NPC data is older (2002 base) cost escalation could be used to adjust the curves upward. In doing so, the user needs to bear in mind the impact on demand response. In the current environment, demand will continue to be squeezed if wellhead price must remain in the upper portion of the price band. Favourable monetary conditions (inflation and interest rates) may not persist, making it more difficult to absorb higher costs for gas resource recovery. Users also need to consider that as time progresses and new resource plays are tested, wellhead costs will decline. Tranches of supply that can only come into the market for, say, $4-4.50/MMBtu today will flow at a lower cost in the future, assuming that producers are successful in scaling up operations and managing overhead costs, both of which incorporate the assumptions of technology deployment and commercialization noted earlier. The old adage that "the market will only be as large as can be supplied at a given price" will remain true.

Figure 17. Marginal Cost Curves, Lower 48 Supply, 2003, 2015, 2030 (NPC 2003)

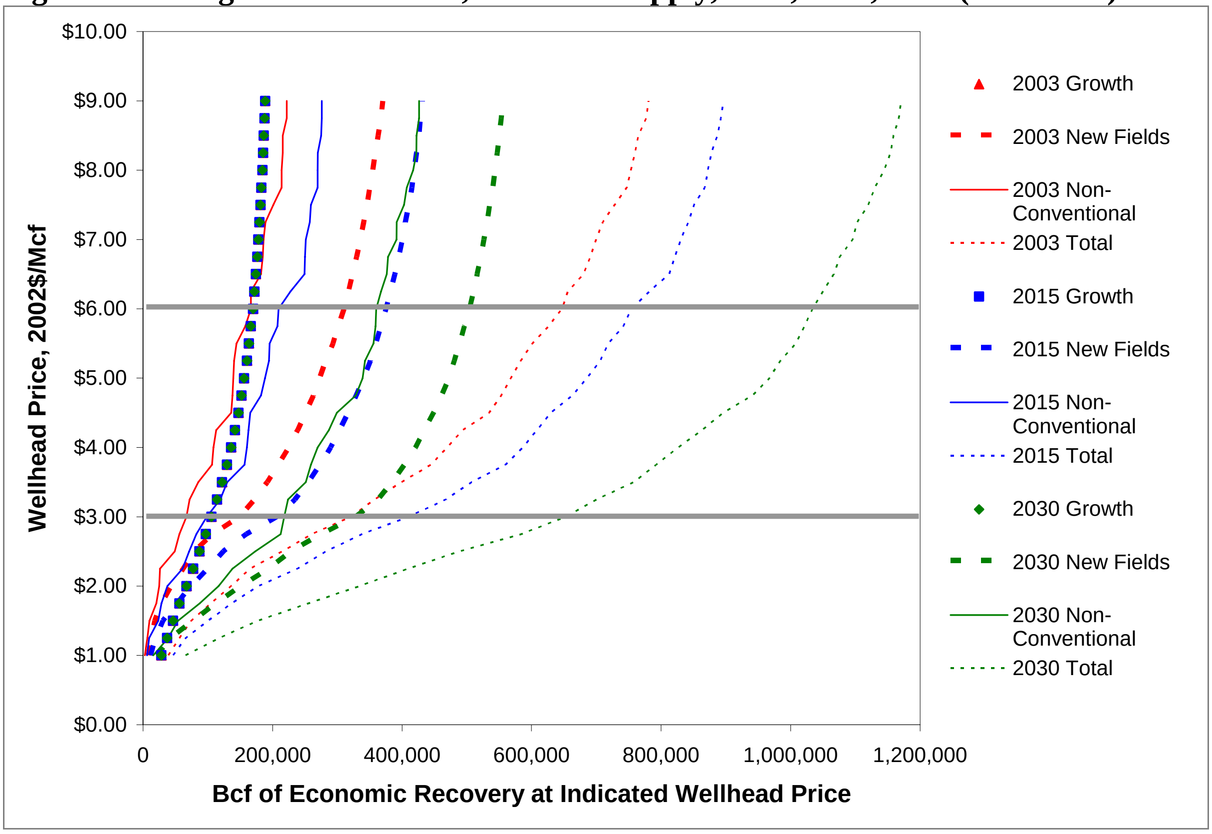


Figure 18. Marginal Cost Curves, Total US and Canada Supply, 2003, 2015, 2030 (NPC 2003)

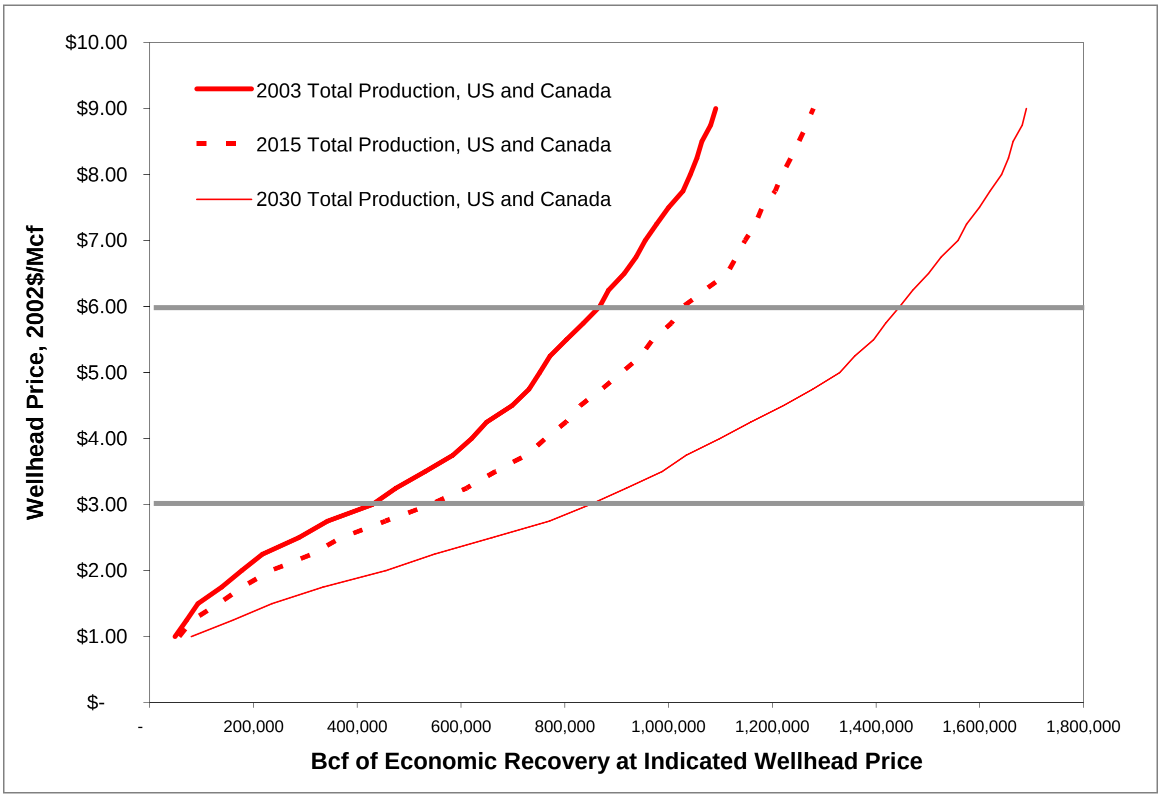
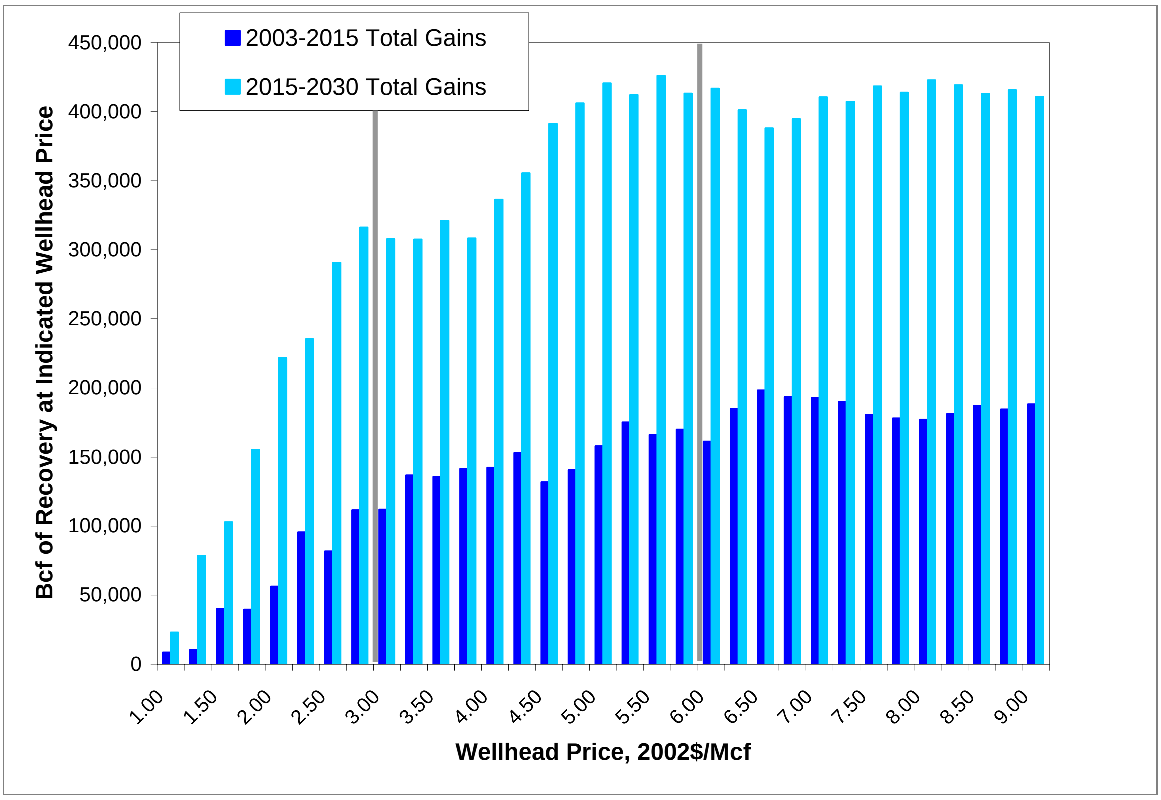


Figure 19. Differences in Natural Gas Production Volumes with Technology and Price Assumptions, US and Canada (NPC 2003)



As these figures show, across a range of finding and development cost assumptions, strong gains can potentially be made to add significant new reserves from the North American resource base, but a number of caveats exist. First, and perhaps most controversial for this particular NPC study, are the diminishing returns associated with higher wellhead prices.[28] This occurs for all types of supply and across all regions. For Lower 48 supply growth from existing fields (reserve appreciation), the same amount of supply growth was assumed for each time period, in spite of technology advances embedded in future time periods. A similar approach was used for Alaska and Canadian production. Both appear to reflect conservative viewpoints on the ability to "harvest" incremental resources from established fields. A second observation flows from the first—greater impact is achieved from new field discoveries than can be obtained from reserve appreciation. Third, gains from unconventional resources become more significant with time and with advances in technology. Again, the supply profiles represent a very conservative stance with respect to supply achievement relative to wellhead cost, reflecting the assortment of known and unknown risks and uncertainties surrounding the conversion of unconventional resources to reserves on a large scale.

A fourth observation is the change in supply elasticity relative to my natural gas price band of $3/Mcf to $6/Mcf across all marginal cost profiles. Within the US and Canadian E&P segments, there is a belief that significant new supply and production, in particular from unconventional plays, needs "$6 gas". Value chain transportation pricing from wellhead to electric power or industrial customers as inferred from USEIA data and reported by industry trade publications is generally $0.50/MMBtu to $1.00/MMBtu, a decline of roughly half when compared to pre-open access, interstate pipeline merchant sales prior to 1992. As reported in the industry trade news, basis differentials are more dynamic during peak seasons and periods of overall tight supply-demand fundamentals. Consequently, as wellhead costs approach $3/Mcf this means sales prices of $3.50/MMBtu-$4.00/MMBtu or $6.50/MMBtu-$7.00/MMBtu to these customer groups ($/Mcf is roughly the same in $/MMBtu terms) when transportation cost ranges are included. The constraints between demand-side and supply-side economics are strongly evident when the charts above and associated wellhead price considerations are compared to those in the previous section on demand. The pressure to effectively "prove up" new technologies and supply, and to reduce costs on a unit basis of production is huge.

The addition of Alaska and Canada to the marginal cost curve analysis changes results somewhat. For example, at the $3/Mcf cost level, Alaska supply adds 33 Tcf to the Lower 48 total of 321 Tcf, while the addition of Canada adds a further 74 Tcf. Greater yields are achieved in outer years. Large but expensive frontier sources exist and have been under discussion for years—delivery of existing and new supplies from the Alaska North Slope and from MacKenzie Delta and other Arctic gas plays in Canada. How best to accomplish the field-to-market commercialization for these resources is an ongoing debate, in view of the high cost associated with transportation infrastructure. A review of pipeline construction costs and mega projects suggests that a most probable cost estimate for an Alaska gas

[28] The 2003 NPC study effort was critiqued on a number of fronts, including too little price elasticity for demand in outer years in particular as a consequence of fuel switching (yielding an overstatement of benefits from recommended policy approaches), understatement in natural gas supply with higher prices, and understatement of imported LNG volumes with higher prices. See Costello, et al., 2005. In many respects, my effort in this paper counters these criticisms and raises other questions and key points. CEE-UT researchers peer reviewed sections of the 2003 NPC report related to LNG supply and hosted a briefing for members of the trilateral government North American Energy Working Group as the final report was released.

pipeline connecting through the province of Alberta to the Chicago city gate is $20.3 billion, and that the high potential for cost overruns through Alberta could push the cost of that portion up significantly.[29]

Clearly, as stated earlier, higher commodity prices now provide the impetus for drilling and technology deployment. The key consideration is whether costs can be amortized and unit cost reductions achieved sufficiently quickly through production economies of scale, in such a way that the current commodity price environment leaves long-lasting results with regard to future supply. Among the obstacles to attaining new domestic natural gas supplies in the future are: limitations on access for drilling and environmental restrictions that could constrain and delay resource development; a lower rate of success rates for drilling in the future than is in evidence now; and, a sharp drop in commodity prices that could cause producers to put critical new projects on hold. In an optimistic scenario, a reasonable amount of success for the given resource base could result in significant new deliverability by 2015 and especially by 2030. Based on a wellhead cost target of $3/Mcf, it is estimated that technically recoverable resources by 2015 would be 112 Tcf and 420 Tcf by 2030); at the $6/Mcf cost these would be 161 Tcf and 578 Tcf by 2030. The effects of current drilling activity that could be manifested over the mid- to long-term horizons suggest that interesting dynamics with regard to natural gas prices are yet to come. Given the high rate of drilling in North America, the potential for "slugs" of new domestic production to enter the market as the 2015 time frame approaches is quite high. If the current high rates of drilling persist and if success is achieved, a "Section 29"[30] type of effect could occur. In this scenario, rapid deployment of E&P financial capital and technology, along with strong supply and production response to higher commodity prices, would mimic the expansion of coalbed methane drilling and production under favourable tax policy treatment during the late 1980s-early 1990s. If demand were to remain moderate, as a consequence of higher prices and efficiency gains, the formation of a new gas supply "bubble" is a conceivable outcome.

3.4.2 LNG Entry and Expansion

The effects of the expansion of existing LNG import receiving capacity and the entry of new greenfield projects in the US and North American natural gas market are also being closely followed. Figure 20 attests to the intense competition underway for positioning in the "first wave" of new development. Most of the new terminal capacity slated for operation by 2010 is located on the US Gulf of Mexico. For many, this raises an additional spectre of insecurity given hurricane activity in the region. LNG ships will usually not enter the Gulf during storms (although the new Excelerate Energy Bridge vessel remained safely in the Gulf during Hurricane Rita without suffering any damage). Thus, the most likely consequence of storm interruptions would be delays in cargo receipts and outages related to other consequences, such as regional electric power disruptions. The preponderance of LNG import terminal activity in the Gulf is a testament to the difficulty of developing new projects on the East and West coasts. Three projects—one under construction in New Brunswick province, Atlantic Canada, one in Baja Norte, Mexico and the new Altamira facility now in operation on

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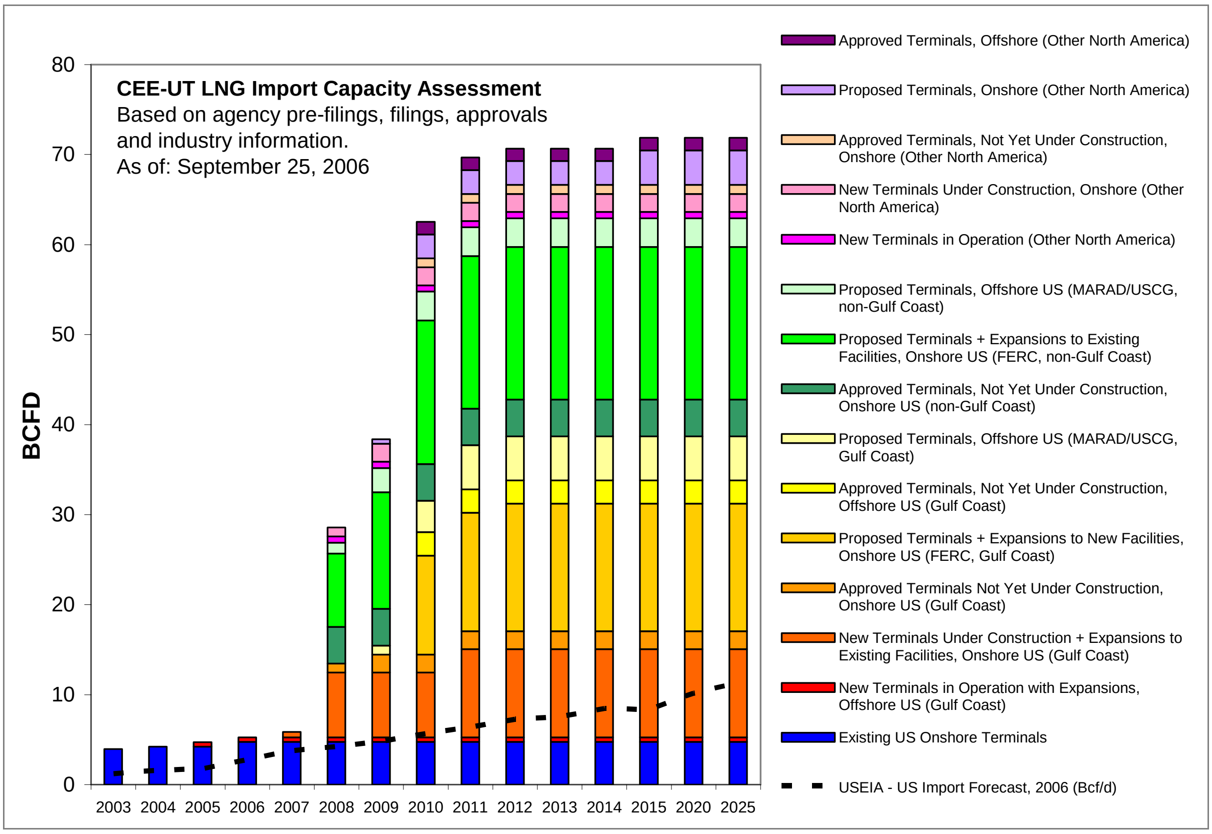
[29] See Gurfinkel, et al., 2006. The size and scope of the large natural gas transportation projects under consideration for Alaska and Arctic Canada resources invite discussion on both new policy and regulatory regimes, with arguments that these should be "extra-market", and speculation on whether other opportunities for commercializing these resources might be feasible, such as LNG from Alaska's North Slope.

[30] Section 29 of the US Tax Code, instituted in 1980, provided credits for drilling and production from new coalbed methane plays to encourage investment.

Mexico's upper Gulf Coast—have the capability of exporting natural gas to the Lower 48, mitigating somewhat public resistance to the siting of facilities in the connecting US regions and states.

Figure 20. North American LNG Import Terminal Developments[31]



The ultimate price impact of expanded LNG imports in the US natural gas supply mix will depend upon the availability of cargoes. The full value, or supply, chain cost for LNG is estimated to range from $2/MMBtu to $3.70/MMBtu.[32] A 30 per cent cost escalation can be added to allow for tight conditions on large-scale energy infrastructure projects worldwide. While capacity that is under construction or due to be constructed will easily meet and probably exceed requirements, not all of that capacity will be utilised and some of it may include LNG that is expensive relative to Henry Hub. At least two distinct possibilities exist with respect to LNG. First, Atlantic Basin competition for cargoes could bid up prices with the result that the downward impact of LNG on Henry Hub is insignificant and incremental. Alternatively, the amount of new receiving capacity available, combined with competition within the US to utilise capacity under development, may result in substantial downward pressure on Henry Hub. A basis decline at Henry Hub would be transferred across the Lower 48; in all likelihood, a strong basis differential would quickly lure investment for additional

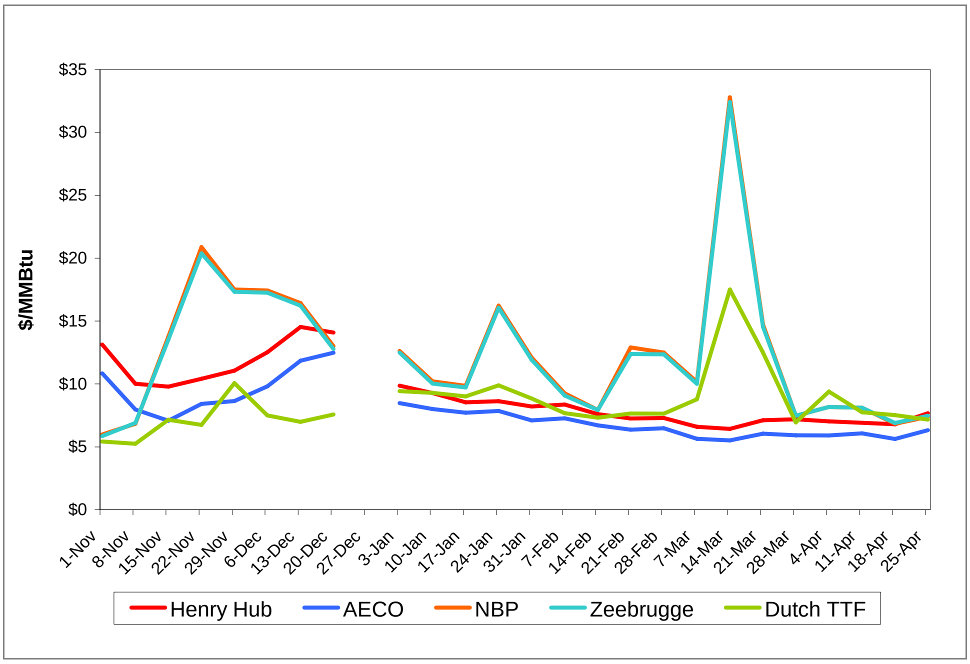
[31] Based on CEE research and analysis for its LNG consortium. See also Foss, 2006 for further treatment on US LNG developments.

[32] CEE estimate. See www.beg.utexas.edu/energyecon/lng. The original CEE estimate is lower than many cost projections for LNG. As natural gas prices were firming during 1999, the number of cargoes diverted to Lake Charles increased. Our cost estimate does not include such items as certain taxes or indirect project charges. Full-cycle LNG value chain costs are most sensitive to upstream, exploration and production fiscal terms and shipping distances.

pipeline takeaway capacity and probably be relatively short-lived. If cargoes are cheaper to contract than many surmise, this would increase the probability of a lower price scenario. Likewise, Henry Hub indexing for LNG is occurring, but oil indexing remains, and indexing to other pricing points, such as in Europe, could also come to the fore. For the most part, Henry Hub and oil-indexed LNG have been converging for a number of years,[33] although according to many observers convergence is toward Henry Hub (mainly for US gas market liquidity) rather than natural gas toward oil. But a number of issues have arisen to complicate long-term LNG arrangements. These include host-country "premiums" for development access, resulting in more stringent fiscal terms, including equity participation across the LNG value chain; another issue is the desire among host countries to use natural gas for domestic economic development and to seek participation in these projects through their natural gas contracts and agreements.[34]

Finally, intra-basin competition will be a factor as international trade in LNG expands. As shown in Figure 21 and Figure 22, winter 2005-2006 provided a lesson in cargo diversions as LNG suppliers sought to maximize returns across US and European pricing points. LNG cargo receipts and trade activity since then, including regular reports of LNG cargo diversions as companies and exporting governments seek the optimal pricing points, serve to confirm the extent to which arbitrage and commercial strategies will drive LNG transactions in the future.

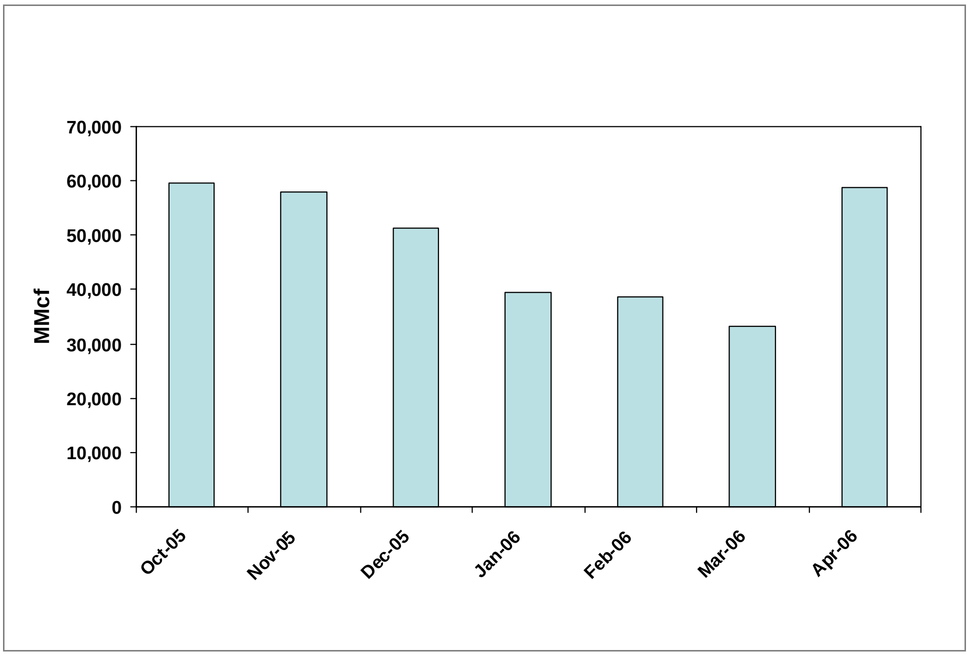
Figure 21. US and European Comparative Natural Gas Prices, Winter 2005-2006 (World Gas Intelligence, WGI)



[33] Based on information from BP Annual Statistical Review of Energy, www.bp.com, GasMatters, and other trade publications.

[34] See Foss, 2005 and Juckett and Foss, 2005 for reviews of critical issues impacting international natural gas and LNG developments.

Figure 22. US LNG Cargo Receipts, Winter 2005-2006 (USEIA)



Stiffer terms set by host producing and exporting countries and tighter competition for natural gas price-indexed LNG cargoes are affecting plans for new import receiving and regasification capacity in the US and North America. Many projects that are not already linked to potential supply sources are unlikely to remain in development, especially the more speculative proposals. Suppliers must be able to meet their customer commitments, dampening the effect of cargo diversions and intra-basin price competition. If supply alternatives do not exist or can be obtained only at a higher cost, this will boost both natural gas prices and the attractiveness of US markets for LNG. When LNG does enter the US supply picture, gas-on-gas competition is the prevailing outcome. In sum, the US with its large, competitive natural gas marketplace and deep liquidity at Henry Hub is expected to be a swing participant in LNG trade.

4. OTHER MAJOR ISSUES

In addition to the factors driving natural gas prices that have already been discussed, other issues deserve mention—prospects for crude oil prices, Mexico's natural gas balance, climate change policy initiatives and US state utility regulatory approaches.

4.1 Longer-Term Crude Oil Prices

Several linkages to crude oil and petroleum product prices have been mentioned. While natural gas appears to be inexorably moving toward independence from crude as a basis for pricing, the potential to switch between natural gas and petroleum fuels will remain present at the margin, at least to some extent. Moreover, as shown earlier, even though natural gas is decoupling from oil with respect to pricing, it is precisely the Btu-equivalent disparity that is having an impact on some demand segments. Thus, the outlook for crude oil is of relevance at least for a period of time, and a number of considerations need to be taken into account.

First, in economic terms, the cost of finding and lifting remains the key variable for oil prices. The marginal producer has long been most influential in setting the upper limit (production declines that force marginal suppliers out of the marketplace merely set the stage for the next high price event). When possible, swing producers act on market signals to spur adjustment.

Key questions pertain to current and prospective oil market organisation with respect to countries holding these positions and their stances toward oil pricing. A target range of $36/bl to $60/bl can be calculated on the basis of average finding costs of $12/bl to $15/bl and profit multipliers of three to four times costs.[35]

Second, a long-standing debate is whether host governments of oil producing and exporting countries charge a "political premium" against barrels produced and sold. Given what is generally known about finding and lifting costs in various locations, it is likely that not only are premiums charged, but that they are substantial. Certainly, a higher price environment makes it that much easier for host governments to realise these rents.

Third, in many parts of the world, notably in Asia, growth in demand is very real. But much of that demand is artificially induced through subsidies. A large number of governments act to protect their most important customers (national champion industries, for instance) or to shelter low-income customers (while actually benefiting higher income and higher energy using groups). Government subsidies place additional pressure on global petro markets. Price subsidies and other forms of mitigation discourage resource and/or refining investment at home, triggering front-end buying with commensurate reactions by suppliers to raise price. In addition, many parts of the world plagued by corruption at the downstream end are also locations where black market interests work against policies to expand the domestic supply of petroleum and, in particular, of petroleum products. It could be argued, in fact, that refining is the true location of the "oil curse".[36] Data on subsidized demand is understandably difficult to assemble; based on both anecdotal and published reports it could constitute as much as 20 per cent of the global price per barrel.

Finally, given that inventories of crude and products are healthy in many locations and that the very real risk of supply disruptions has so far been avoided, the remaining factor left to balance the price per barrel is speculation. The role of speculation in oil markets has been widely debated but could add upwards of $20 to the price per barrel.

4.2 Mexico's Natural Gas Balance

Pipeline exports of natural gas from the US to Mexico reached nearly 400 Bcf for 2004. This compares to 105 Bcf in 2000 and a low of less than 2 Bcf in 1982. Given its presumably rich resource base, Mexico should be able not only to meet its own needs but also to earn export revenues through sales to the US. Instead, for the past few years, southbound flows of natural gas to Mexico have been roughly equivalent to LNG volumes received by the US.

All indications are that Mexico will proceed apace with several LNG receiving/regas projects beyond the newly opened facility in Altamira, assuming supplies can be procured. These facilities must be more than 50 per cent utilised for their full effect to be felt in both countries, either in the reduction of Mexico's imports from the US or in northward flows for export. Prevailing opinions in Mexico are that natural gas exports to the US—a position Mexico once held and that many believe is its natural comparative advantage—could resume as a consequence of both LNG development and better results from Mexico's own domestic E&P activities. These possibilities depend to a great extent on growth in Mexico's economy and

[35] In this analysis, I follow a similar approach to that taken by Adam Siemenski of Deutsche Bank Commodities Research Group.

[36] Based on CEE comparative country analysis of downstream performance, including financial models. CEE and is engaging in a public study to investigate these issues.

the commensurate energy demand, as well as on resolving the array of social and political issues that encumber Mexico's energy sector.[37]

4.3 US Climate Change Policy

Coal is considered to constitute a floor of sorts for natural gas prices. Substantial political tension surrounds the use of coal in relation to competing fuels such as natural gas. Given its environmental benefits and expectations that greenhouse gas (GHG) targets cannot be met without increasing the natural gas share of total energy use, the natural gas industry could and probably would be included in any comprehensive national policy approach to achieve GHG reductions. Decisions on which industries are targeted, to what extent and with what impacts are entirely a matter of political positioning.

The messy process of negotiating some sort of policy mechanism to address anthropogenic GHG emissions was in full evidence on the publication of a white paper produced by the Senate Energy and Resources Committee and the related hearing on April 4, 2006.[38] National election results on November 7 raised the stakes. How these motions might play out is highly uncertain. US companies, as well as foreign companies operating in the US, have become more actively involved in the process. Companies with footholds in Europe are, in some cases, promoting policy schemes (mandatory caps and emissions credit trading) that could link to their European businesses. Indications are that the costs of any policy mechanism could be considerably higher than expected, a function of the large, diverse, and geographically disparate emissions sources as well as the costs associated with alternatives and mitigation. The climate change issue would seem to benefit natural gas and bolster the position for gas suppliers in electric power burnertip competition. Large coal and nuclear interests will seek favourable treatment through any emissions credit scheme. For many of these operations, GHG cap and trade is appealing as a potential solution for the high cost of new coal and nuclear facilities.

4.4 US State Regulatory Actions

Many of the points made in this paper hinge on regulatory actions at the state level. Beyond federal policy and regulatory actions that affect resource access, access for infrastructure fairways, environmental quality and market oversight, actions taken by states to implement federal rules and deal with their own political and economic dictates can create new issues or exacerbate existing ones. State cost of service regulation for large new energy facilities developed by utilities can affect the competitiveness of natural gas in the electric power segment. While the wisdom of costly and time-consuming prudence reviews and ratemaking hearings is often called into question, the prevailing opinion is that it is unlikely that low or zero-emission coal facilities and almost certain that no new nuclear facilities will be

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[37] See report by Dr. Ernesto Marcos, CEE seminar on Mexican energy, October 6, 2006. http://www.beg.utexas.edu/energyecon/documents/emarcos_mexicoenergy_r.pdf for provocative treatment of current conditions, issues and trends. Extensive research on Mexico has been performed by Dr. Michot Foss, CEE researchers and other collaborators. See www.beg.utexas.edu/energyecon for background info and publications.

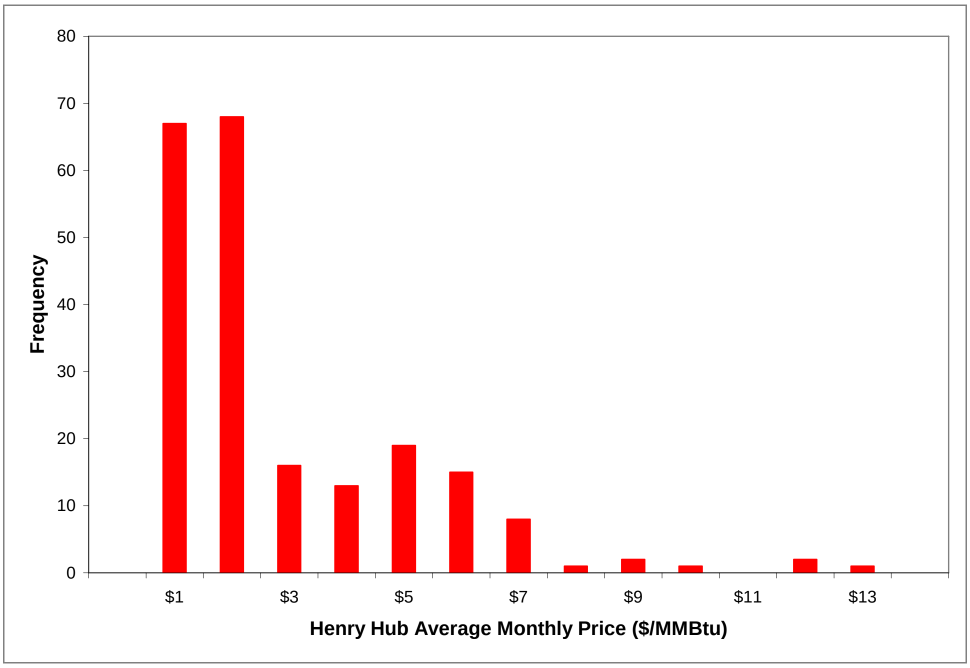
[38] See the US Senate Energy web site, http://energy.senate.gov/public/index.cfm?FuseAction=Conferences.Detail&Event_id=4&Month=4&Year=2006.

undertaken outside of cost of service ratebase determinations.[39] State regulators have largely balked at allowing long-term supply contracts for natural gas. As gas utilities increasingly serve only core residential and commercial customers, many state regulators and consumer advocates may become even more sceptical of natural gas pricing and utility purchase arrangements. New LNG import facilities in some locations may not be developed without long-term anchor contracts, although, as noted above, commercial conventions are that supply contract commitments be honoured regardless of how natural gas supply commitments are sourced.

5. KEY CONCLUSIONS

When a frequency distribution is applied to modern (post-open access and traded) US natural gas prices, the dilemmas underlying the current commodity price cycle are crystallized. Little experience has been gained to date with natural gas prices substantially higher than $3/MMBtu (Figure 23). Demand and supply adjustments are evolving, and the eventual implications of fundamental shifts and restructuring will not be known for some time to come. The lure of "affordable" natural gas to sustain a market share in the US energy portfolio surely remains. Given the complexity and the many caveats identified in this paper, the redefinition of affordability is the salient point.

Figure 23. Frequency Distribution of US Natural Gas Prices, 1992-2006



The analyses conducted throughout this paper can be used to provide responses to the four critical questions posed at the outset.

1. What is the likelihood that the US will be persistently short on natural gas supplies, resulting in long-term prices remaining high (at least $6/MMBtu)?

[39] Historical public utility regulation in the US centered on valuation of regulated utilities' capital assets, the "ratebase". A return would then be applied to the ratebase sufficient to cover utilities' cost of replacement and operation and provide some profit (in effect, long-run utility returns averaged 12 per cent; while often taken as a "guarantee", regulated returns could be revoked or diminished by regulators). The regulated return would then be allocated to customers as cost of service and, for the utilities, as cash flow from tariffs.

Given the richness of the US and North American natural gas resource base, and the mobilization of investment and technology that is currently underway, it is highly likely that significant new supplies will be discovered and delivered to the marketplace. The Lower 48 remains one of the richest supply provinces in the world, if challenging in its maturity and in the commercialization of new supply sources. The main barriers are rapid declines in price and constraints to access for drilling and infrastructure, two hurdles that most influence timing of deliveries. Along with LNG development, a compelling case could be made that the US is entering, albeit in a bumpy way, a new period of natural gas surplus.

2. Do reasonable scenarios exist that would allow natural gas prices to fall to a range of $3-$3.50/MMBtu for a prolonged period? Or, would any significant retrenchment in prices be short-lived, with prices returning to $6/MMBtu or above?

I have built a case that a longer-term US price deck for natural gas will range from $3/MMBtu to $6/MMBtu. Given the forces that have been unleashed by the current price regime—reduced demand through elimination of uses and increased efficiencies, and E&P industry investment response—the most reasonable scenarios are those that couple shorter-term disruptions with a longer-term push to develop new domestic and continental production, with LNG as a natural hedge. During the coming months, a bottom for Henry Hub could be tested by market participants. However, as Figure 2 indicates, the US has experienced several distinct "bottoms" as Henry Hub prices coursed generally upward. Using historical storage and price relationships, a bottom situated at or below $3/MMBtu could easily be attained. Implicit elasticities are such that demand response would quickly soak up cheaper stocks, providing price firmness at $3/MMBtu until results of the longer-term supply development are manifest. Likewise, the ability of the E&P industry to "prove up" new supplies below $3/Mcf real wellhead cost, and the fall off in incremental new supplies above $6/Mcf, provide support to the $6/MMBtu longer-term upper bound.

3. How important is imported LNG for US natural gas price scenarios? Could other factors, such as permanent shifts in demand and/or better-than-expected results in North American drilling, exert meaningful influence?

With new receiving terminals under construction and expansions underway at existing facilities, potential daily send-out capacities have already exceeded most forecasts of LNG development activity through 2015. The impact of LNG will hinge on US market conditions, intra-basin competition for cargoes, and the commercial strategies of LNG operators. LNG will be a price taker in the US; LNG cargoes will contribute to gas-on-gas competition.

4. What can be deduced from the recent decoupling of natural gas and oil prices with respect to long-term fuel competition and switching?

Recent natural gas and oil price relationships reflect the fundamental shifts in demand and supply for gas, with reduced tightness in the US balance (ample storage and new production along with demand adjustments) resulting in natural gas priced at a discount to oil. I find little support for extensive switching from natural gas to oil products. I argue that this decoupling is a hint of new dynamics, with natural gas prices more likely to reflect demand driven by efficient electric-power use than influences from other demand segments (specifically industrial use). It is also a reflection of long-term inter-fuel competition and resource exploitation driven by the price of natural gas.

Table 1 provides a summary of the major themes and considerations drawn from the data and evidence assembled in this paper.

Table 1. Summary of Factors Supporting a US Natural Gas Longer-Term Price Band of \$3/MMBtu-\$6/MMBtu

Pressures Toward \$3/MMBtu	**Pressures Toward \$6/MMBtu**
Before 2015	
Mild weather, no major hurricane disruptions	Adverse conditions (Henry Hub range during winter 2005-2006 was approx. \$6-15) and climatic events increase
Persistent inventory overhang	Persistent inventory uncertainty
Decline in petroleum prices due to demand response	Oil prices remain high, inflationary pressure builds
Success in tight gas plays	Moderate/low supply development
Rockies deliveries	Moderate/low supply development
Surplus LNG cargoes available at Henry Hub prices as new regas opens up	LNG market remains tight/new regas terminals delayed
Demand erosion in key industrial applications does not reverse	Business as usual demand increases
No/little success in climate change initiatives	Climate initiatives begin to bite
Sustained decline in oil prices	Extreme volatility continues to be possible with no critical resource or infrastructure improvements
After 2015	
Permanent loss in critical demand sectors (industrial) and flat demand in core segments (residential, commercial)	Demand increases (despite high prices) due to climate measures and other factors
Entry of new, major infrastructure projects, especially Alaskan pipeline	Alaska (and Canadian Arctic) delays continue
Mexico exports to US, result of LNG imports and excess capacity	Mexican demand surges, no surplus for US
Henry Hub basis detaches with expanding LNG shipments	European and Pacific LNG prices prevent US buyers from obtaining supplies/ substantial new regas capacity remains idle
Coal takes vast majority of new power demand (due to fears of gas price spikes)	State and Federal climate measures become serious; coal suffers, gas benefits.

Overall, the forces underlying US natural gas prices appear to be such that pricing much below \$3/MMBtu would trigger sufficient increases in demand and drops in production to correct the downside. Pricing much above \$6/MMBtu would force moderation in some demand segments and encourage penetration of alternatives, as well as support new gas production and supply “prove ups”. Electric power will set the price of natural gas at the margin. LNG must be price competitive within this band, in particular if electricity demand is the prevailing use for natural gas; otherwise, insufficient market support will undermine LNG import projects. Pressure to invest in coal (as a hedge against gas price volatility or as an energy security rationale) is widely evident. Of note for the longer term is that climate change initiatives may exert considerable impact on major new investments in coal. Traditional environmental and health and safety concerns will also weigh heavily. Reduced effects from switching to competing petroleum products (for electric power or industrial use) do not necessarily imply stronger natural gas prices, since switching seems to be less important than prevailing opinions would indicate. If gas-on-gas competition remains vigorous, through enhanced domestic and Canadian supply and production or when LNG cargoes are attracted to the US market, price discipline will remain healthy. Indeed, a hallmark of the US natural gas marketplace is the extent to which gas is most competitive with itself.

Within the context of my paper, there is plenty of room for new spikes in Henry Hub price. But what about the possibility of a Henry Hub basis collapse? This could come about in two ways. One is the formation of a new gas bubble if new domestic supplies are more rapidly proved up than demand warrants. A second possibility exists with LNG. Given the very significant amount of new LNG receiving terminal capacity under development along the US Gulf Coast, only a 50 per cent utilisation rate may be necessary to balance the Lower 48 marketplace. If LNG cargoes arrive in abundance because of favourable Henry Hub pricing relative to other Atlantic Basin markets, a hefty downward push could occur. US gas market fundamentals would have to support such a scenario (i.e., abundant gas inventories in storage, stronger domestic production, and so on). Erosion of Henry Hub pricing would offer a compelling case for both higher utilisation of existing pipeline transportation and new pipeline infrastructure (new builds plus improvements), soaking up the lower basis.

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