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# **The Outlook for U.S. Gas Prices in 2020: Henry hub at \$3 or \$10?**

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## PREFACE

In what now seem like the very far off years of the early 2000s, it was still the case that only North Americans needed to pay ongoing attention to Henry Hub gas prices. Those years are long gone; by 2011 such has become the importance of what was considered to be just a US price reference, that gas executives worldwide are required to follow daily Henry Hub prices to within a few cents. The international relevance of Henry Hub prices was already recognised in early 2007 when Michelle Foss wrote her first paper for us on North American gas prices. That paper, written before the unconventional gas revolution had become conventional wisdom, when Henry Hub prices were well above \$6/MMbtu and had recently been in the \$10-14/MMbtu range, suggested that a reasonable expectation of a price range during the period up to 2015 would be \$3-6/MMbtu. This was greeted with considerable scepticism at a time when large numbers of regasification terminals were under construction in preparation for imports of high priced LNG, but has thus far proved to be absolutely correct. As a result, only a fraction of the LNG destined for those terminals has been delivered.

In 2011, conventional wisdom, as expressed by the US Energy Information Administration, is that Henry Hub prices will stay at around \$4/MMbtu for at least the rest of this decade, and will not rise significantly above \$6/MMbtu until around 2030. Yet how likely is this to be correct? Is it really the case that the costs of shale gas production, and production of associated gas from shale oil, will remain at such low levels for a considerable period of time. And if so, might there be a market response, both in terms of increased domestic demand for a potentially resurgent manufacturing industry and a plethora of proposed US LNG export terminals which would require very substantial increases in production? These are the questions addressed in this paper.

Much research on this subject simply recycles official projections. This has never been Michelle Foss' style and is one of the main reasons why the OIES Gas Programme has forged such a strong link with her Center for Energy Economics at the University of Texas at Austin, over the past decade. The relevance of Henry Hub prices for gas stakeholders worldwide means that the need for research and informed opinion is more important than ever. As readers will find, this is a subject of enormous complexity not suitable for those seeking convenient soundbites, or quick summaries for powerpoint presentations. The phrase from the paper which sticks in the mind is "Black Swans permeate the random walk". Over the past two decades, the North American gas developments have surprised us many times, and are likely to continue to do so in the future. We are enormously grateful to Michelle for this contribution to our work – but also the global debate – on gas pricing which will be the major theme of OIES Gas Programme research during 2012, culminating in a book to which she will also contribute a chapter on North America pricing.

Jonathan Stern

Oxford, December 2011

## **U.S. ACRONYMS**

AIPN - Association of International Petroleum Negotiators

BEG-CEE/UT - Bureau of Economic Geology's Center for Energy Economics, The University of Texas

BOEMRE – Bureau of Ocean Energy Management, Regulation and Enforcement, former Minerals Management Service (U.S. Department of Interior); in October 2011 reorganized into Bureau of Ocean Energy Management and Bureau of Safety and Environmental Enforcement

DOE - U.S. Department of Energy

EDF - Environmental Defense Fund

EIA – U.S. Energy Information Administration

EPA - U.S. Environmental Protection Agency

FERC – U.S. Federal Energy Regulatory Commission

GWPC - Groundwater Protection Council

IAEE – International Association for Energy Economics

IOGCC - Interstate Oil and Gas Commission

NOAA – U.S. National Oceanographic and Atmospheric Administration

NPC - National Petroleum Council

OCS – U.S. Federal Outer Continental Shelf

RRC - Texas Railroad Commission

USAEE - U.S. Association for Energy Economics (affiliate of IAEE)

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Dr. Michot Foss has more than 30 years of experience on U.S. 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 and wellhead price decontrol during the early 1980s to broad research on U.S. natural gas industry restructuring, North American continental natural gas trade, and international natural gas and liquefied natural gas (LNG) developments. In addition to Texas, the U.S., and North America, 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 U.S. Association for Energy Economics for her contribution to the profession and association, was 2003 president of the International Association for Energy Economics and 2001 president of the USAEE. She was selected as one of the Key Women in Energy-Americas (2003) and to the Scientific Council, 50<sup>th</sup> Anniversary of ENI Commemorative Encyclopedia of Hydrocarbons. She is a member of the Council on Foreign Relations; the Association of International Petroleum Negotiators (AIPN), serving on the education advisory board; Society of Petroleum Engineers; and was appointed to the National Research Council's Committee on Earth Resources. She holds degrees from the University of Louisiana-Lafayette, the Colorado School of Mines, and the University of Houston. Prior to her university appointments, she worked in energy investment banking (Simmons & Company International), and energy, environment, and regional economics research and consulting. She is a partner in a Texas-based exploration and production company. For information on CEE-UT, go to:

[www.beg.utexas.edu/energyecon](http://www.beg.utexas.edu/energyecon).



## ABSTRACT AND SUMMARY

This working paper follows a previous OIES paper, NG 18, *United States Natural Gas Prices to 2015* prepared in 2006 and published in 2007. In that paper, and in response to a query from our OIES colleagues, I presented a set of arguments supported by data and analysis that U.S. prices could fall to a lower price deck of \$3-6 per million Btu (MMBtu), rather than remain at a higher price deck. NG 18 represented a contrarian view at the time. One of the factors I identified was potential growth in U.S. domestic production, which at the time was being discounted in lieu of liquefied natural gas (LNG) import strategies. This paper also takes a contrarian view, again spurred by our dialogue with OIES colleagues, but in the opposite direction. In *The Outlook for U.S. Gas Prices to 2020: Henry Hub at \$3 or \$10?*, I survey the forces that could drive prices away from the widely accepted view of a low and stable platform for the foreseeable future.

The U.S. enjoyed a surge of investment in domestic natural gas drilling in response to higher price signals from 2000-2008. Prices began falling as the current supply build became evident. Economic recession has kept demand low, so that price deterioration is expected to continue into 2012. The U.S. has a large hydrocarbon resource base, but one that is not without challenges. Cost structures for U.S. shale basins and producers are lofty; shale plays are complex; environmental management and public acceptance have contributed to regulatory risk and uncertainty. The oil price premium over natural gas has pushed capital expenditures away from gas drilling and toward liquids where returns are more attractive and can better support drilling economics. Indeed, a parallel turnaround in oil production, as well as new opportunities to commercialize natural gas liquids (NGLs) in some shale plays is perhaps even more significant for the U.S. as oil imports are a large component of the U.S. current account deficit. Offsetting success in shale gas production are normal declines in established provinces like the Gulf of Mexico offshore. These declines, coupled with a shifting upstream business model that favors shales (development risk) over conventional plays (exploration risk) will reduce deliverability from conventional reservoirs. Slack economic activity and producing region storage capacity additions contributed to bearish price conditions during 2011 in spite of storage indicators being in bullish territory based on historical averages and relationships. Demand growth is widely seen to be most significant in the electric power sector. Coal plant retirements could pull heavily on natural gas but continued support for renewables could counter natural gas gains. Growth in renewables could also contribute to gas price volatility given the tendency to use gas generators to balance daily swings in electricity demand and to back up and “load follow” intermittent renewables. Industrial use is benefitting from lower natural gas prices and natural gas liquids production. Price spreads between oil, NGLs, and natural gas are fueling interest in downstream petrochemicals and associated midstream investment.

The long history of natural gas supply-demand balances and Henry Hub price cycles is indicative of transitory periods or eras. At times, new tranches of reserves and production in response to appealing price and profit margin signals yield oversupply and price deterioration until demand revives and catches up. Meanwhile, lower prices and typical, late cycle over-leveraging (indebtedness) in the producer segment spur reorganization, mergers, and acquisitions as companies struggle to rationalize exploration and production portfolios. Any combination of factors such as production challenges and associated costs, including costs imposed by more rigorous environmental oversight, economic recovery, and increased “pull” on gas deliveries to displace coal-fired power generation could contribute to upward price pressure. Specific conditions, such as constraints in gas deliverability and midstream bottlenecks in the face of growing demand, could trigger sharp price increases. Countervailing forces within the U.S., as well as mixed global patterns, create attendant risks

and uncertainties for potential LNG exports of domestic production. In all, the past 15 or so years demonstrate the dynamic nature of commodity markets and inherent difficulties in building resilient strategies. For all of these reasons, it is worthwhile to be circumspect about the Henry Hub price trajectory to 2020.

This working paper is the precursor to a chapter in the forthcoming book by OIES, *The Pricing of Internationally Traded Gas*. Given prevailing opinions that Henry Hub prices will be lower rather than higher and that the U.S. is disconnected from global markets, and will remain so, it is important to consider alternative views and scenarios. The summary table at the close of this paper provides grounds for viable scenarios in support of both lower and higher prices for the 2012-2020 time frame.

## 1 Introduction – where things stand in 2011 and key questions

In February 2007, *United States Natural Gas Prices to 2015* was published by the Oxford Institute for Energy Studies (NG 18).<sup>2</sup> That paper was written while U.S. natural gas prices were still rising; a consequence of tight supply-demand fundamentals and influence from oil and other commodities. In NG 18 I took on the research question of whether prices could soften. At the time, this was completely contrary to what other commentators were saying. Specifically, in NG 18 I explored whether an array of dynamics – such as investment in drilling spurred by higher natural gas prices and attractiveness of the large unconventional resource base and other domestic plays along with shifts in demand and other factors – could lead to a lower rather than higher price deck, with \$3 constituting a “floor” and \$6 a cap. A corollary question was whether lower prices might persist for some time. Indeed, after peaking above \$13 per MMBtu<sup>3</sup> by mid-2008, prices began falling sharply as domestic production surged from unconventional shale gas plays and other sources. A bubble did form, exacerbated by U.S. economic conditions. In the time frame between NG 18 and mid-2011, Henry Hub prices tested a bottom below \$3, as I suggested they might, including a daily spot price low of \$1.80 on September 4, 2009. Prices have hovered around \$4 for much of the period since then, firmly in the \$3-\$5 range (my initial price deck for analysis when work on NG 18 was initiated) since early 2010.

Across a wide array of market participants today, the prevailing thinking is that both price levels and price volatility will be moderated over the longer term. This would be a consequence of the “proving up” of large unconventional shale gas plays, including “just in time” shale gas deliverability, as well as peak shaving liquefied natural gas (LNG) receipts. Moreover, the current conventional wisdom on both lower, rather than higher, prices and price volatility going forward largely holds in spite of the slow recovery of drilling in the U.S. Gulf of Mexico (see later sections) or more robust demand. Higher natural gas consumption is already being induced by lower prices and growth in natural gas utilization certainly is being widely encouraged by domestic producers, some utilities, plenty of policy makers and many others; as well as by operators of global LNG supply chains that have significant, and underutilized, receiving capacity in North America.

Eventually, it is hoped, recovery from the deep U.S. recession that officially dates from December 2007 and officially troughed in June 2009<sup>4</sup> will also help to rebalance the market and diminish the current large supply overhang. When that happens, some price firmness would take hold. The timing and speed of adjustment would depend on many factors. Business conditions for non-associated gas producers at present are quite depressed. As emphasized later, shale production economics in the current gas price environment are driven by presence of liquids in leaseholds, (the acreage held by producers). The timing of price

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<sup>2</sup> See NG 18, <http://www.oxfordenergy.org/2007/02/united-states-natural-gas-prices-to-2015/>. Authored by Michelle Michot Foss, Chief Energy Economist, Bureau of Economic Geology-Center for Energy Economics, Jackson School of Geosciences, The University of Texas. NG 18 and this current working paper are part of a collaboration between BEG/CEE-UT and OIES-Natural Gas Programme.

<sup>3</sup> Btu - British thermal units - are , the measure of energy value typically used in the United States. Natural gas prices are also often quoted in terms of U.S. dollars per thousand cubic feet or MCF. These terms are used interchangeably in this document. All prices are with reference to Henry Hub located in Erath (South), Louisiana. Henry Hub is the largest and most liquid pricing point in the world and the basis for the traded natural gas futures contract and other derivatives. See CME Group, <http://www.cmegroup.com/>, for information on the Henry Hub futures contract and natural gas trading activity at the New York Mercantile Exchange (NYMEX).

<sup>4</sup> See National Bureau of Economic Research, <http://www.nber.org/cycles/cyclesmain.html>. This precludes any “double dip” as a consequence of fiscal and monetary policy and other macroeconomic factors in the U.S. At the time of writing, a “double dip” recession seems more likely than not.

adjustments hinges on whether associated gas production can satisfy U.S. demand with eventual economic recovery. If not – a reasonable assumption – then price adjustments could be sharp, fast, and disruptive. At issue, then, is whether the past will be a pattern for the future, with tighter supply-demand balances leading to sharp variations in price, *or* whether shale gas deliverability, LNG peak shaving, underground storage capacity, and myriad other forces will tend to keep prices moderated and stable for the foreseeable future. These are distinctly different views of the future, captured in vigorous discussions and distinctly competing viewpoints and agendas not only in the U.S. but worldwide.

Apart from recession effects, building demand for natural gas beyond traditional applications is not easy. The primary target – power generation – pits natural gas against an array of competing options among which renewable energy technologies have stirred the most ambiguity. Supply side adjustments are likely to be much faster. In truth, few if any domestic producers or their international partners are truly comfortable in the present \$3-5/MMBtu price environment. The lower price deck has also challenged LNG developers and raised serious questions about how best to formulate investment strategies in dynamic commodity markets, including the persistent and strong price discount for natural gas as compared to crude oil and NGLs. Natural gas (specifically dry gas or methane) requires considerable capital investment in infrastructure per unit of energy content. Denser and more fungible liquid fuels and feedstocks can deliver more value on investment. Because of this, liquids can earn a premium, increased so far in this century by more pronounced constraints on oil supply development. These relationships – energy content and price differentials favoring crude oil and natural gas liquids over methane – mean greater attractiveness of liquids for upstream, exploration and production, capital investment. A critical question for short to mid-term outlooks is: how much associated natural gas can be delivered from oil and natural gas liquids rich locations (those that yield propane, butane, ethane, and other attractive, higher value molecules in the natural gas stream)? At some point, a stronger methane price signal, i.e., a stronger Henry Hub price, will be needed to lure and sustain investment in non-associated gas wells and fields in order to sustain even current levels of demand, much less demand growth. Meanwhile, shifts in price signals and production flows are exerting profound effects on infrastructure plans, end user applications, pricing and contracting, business models, policy and regulatory decision making, energy politics, and, underlying all, expectations.

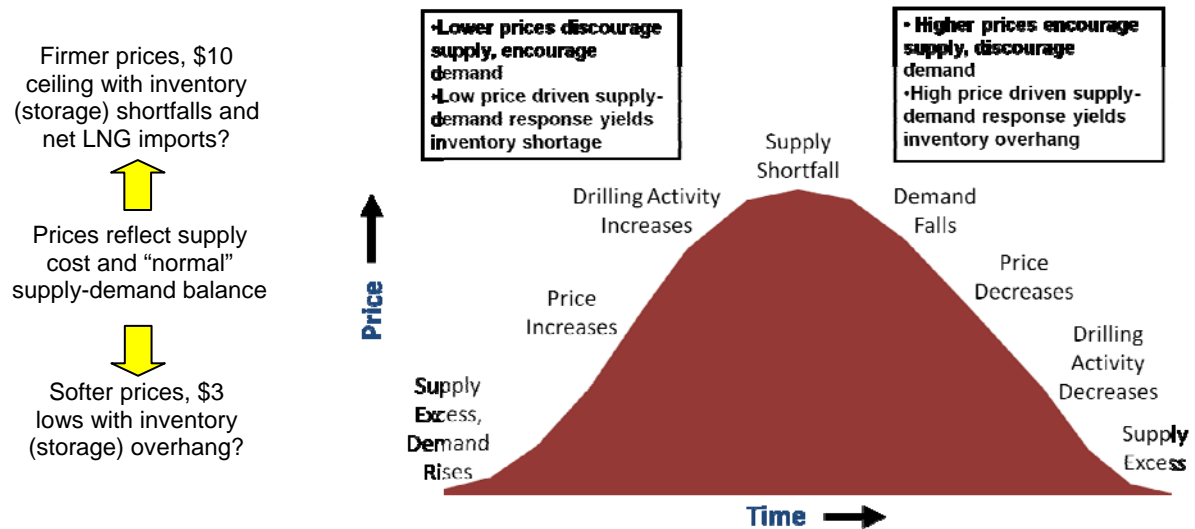
Can the prevailing views on longer term moderate prices and price volatility be proven correct? What factors would drive an alternative viewpoint or scenario? These are the central questions for this working paper. Given the prevalence of error in building price outlooks, it is always useful to explore alternative scenarios to conventional wisdom. The array of factors to be evaluated is as complex as those detailed in NG 18, if not more so, given widespread debates fostered by lower U.S. natural gas prices:

- What is the commerciality of renewable energy systems?
- What are the implications of stubborn crude oil and natural gas price spreads for the tradition of pricing natural gas and LNG supply contracts against oil?
- How might some end users shift decisions on fuels and feedstocks, should natural gas remain cheap against crude oil and oil products?

Using a “forensic” analysis of natural gas markets and business segments, this working paper will explore the potential risk of a wider price range and a return to higher prices and higher price volatility forward to 2020. What factors could drive prices at the main U.S. pricing point, Henry Hub in South Louisiana, to swing between extremes of \$3 and \$10? What supply-demand fundamentals and exogenous variables could create these conditions? What

would be the implications for various market participants? To illustrate and frame these central questions, Figure 1 below provides a conceptual schematic of a typical natural gas price cycle with different stages in supply-demand balances, how these different stages are linked to drilling activity, and resulting implications for supply.

**Figure 1: Typical Natural Gas Price Cycle**



Sources: Author's compilation.

In tackling these points, I explore many considerations underlying natural gas price formation and market structure in the United States. In 2012, the regulatory and industry transition to a more competitive natural gas marketplace in the U.S. will be 20 years old, dating from implementation of the Federal Energy Regulatory Commission's (FERC's) Order 636 (final rule) in April 1992. It is worth reflecting on the past 20 years of effort to restructure the natural gas industry, how this underpins the present, what could change in future, and whether, and how, the U.S. experience might be impacting natural gas industry and market developments worldwide. As such, this working paper is a precursor to a chapter on U.S. natural gas pricing mechanisms and related implications in a forthcoming OIES book, *The Pricing of Internationally Traded Gas*.<sup>5</sup>

By most measures, the U.S. and Canada together are blessed with rich sedimentary basins that have yielded, and will continue to yield, an array of hydrocarbon resources essential for economic growth and development. It is worthwhile for industry, government and other stakeholders to consider how to develop and use these resources in the most optimal ways. As industry progresses ever further along the path of exploiting unconventional resources, from the initial waves of investment in coalbed methane (coal seam gas) and tight gas reservoirs to the shales and beyond, complexities increase. Costs and profit margins are more difficult to contain and sustain. Understanding the scale and scope of the available technically recoverable resource base through traditional resource assessments and reserves estimation is fraught with difficulty. Within professional societies and the industry at large there is broad agreement that resource assessment practices and regulatory criteria for reserves reporting, established over decades of experience with conventional reservoirs, may not be appropriate for unconventional resources. Front end costs associated with unconventional resource plays are large, and as companies progress through phases of

<sup>5</sup> <http://www.oxfordenergy.org/2011/08/the-pricing-of-internationally-traded-gas-ed-jonathan-stern/>

development, capital commitments must continuously be made; as noted later, production decline curves, while variable, tend to be steep. The search is on for technologies that might “flatten” decline curves, reduce drilling intensity, and thus relieve some of the cost pressures. Human resource skills are more demanding, both for technical professionals and to manage the myriad financial, environmental, socioeconomic, and other hurdles. Traditional practices for environment, safety, and other requirements may not be suitable for the particular problems faced in unconventional resource plays. In short, given the technical and financial risks and uncertainties as well as difficulty of prediction these are not easy businesses and should not be portrayed as such. Reasonable views must emerge and coalesce regarding longer term benefits, commitments, and tradeoffs associated with unconventional hydrocarbon resources and their role.

### ***1.1 The big picture in 2007: What was said in NG 18, why it was said, and what actually happened***

My analysis in NG 18 incorporated several key points associated with U.S. natural gas fundamentals. To aid the reader, these are presented in a summary table in Appendix I.

NG 18 was written and published in the wake of the 2003 National Petroleum Council natural gas study.<sup>6</sup> That effort attempted to cast a wide net over both North American resource potential and the possible role of LNG imports. As one observer put it: “The 2003 study...was prescient in a way; lots of resource in a \$3.50 - \$7.50 range; we just didn't know from where back then (all assumed Alaska and LNG).”<sup>7</sup> NG 18 was bracketed by industry assumptions, at the time, of diminishing returns in resource recovery such that the most optimistic case, to 2030, was about 1,400 trillion cubic feet (TCF) of economically recoverable North American resource at a supply cost of \$6/MCF (money of the day, 2002) and about **1,700** TCF at a wellhead cost of \$10. At the time NG 18 was written, this was considered to be ambitious. Many NG 18 peer reviewers questioned the 2003 NPC study supply curves.

The “first wave” of shale gas investment did demonstrate the cost amortization that many felt was needed, i.e., wells were economic and costs could be amortized over the life of production (but with a supporting price). And the burst of new production has affected opinions about whether long-lasting results were achieved. The upshot has been broad revisionist thinking about the prospects for future supply, with even more robust outlooks than in previous studies. A new NPC study, just released,<sup>8</sup> *Prudent Development of North American Natural Gas and Oil Resources* suggests that an optimistic case for recoverable resource at a wellhead cost of \$6/MCF (money of the day, 2007) could be about 2,000 TCF and at \$10/MCF could well exceed 3,000 TCF of ultimate recoverable resource, with the outer years being 2035-2050.<sup>9</sup> A rough comparison is shown in Figure 2 of the 2003 and 2011 NPC study natural gas supply assumptions.

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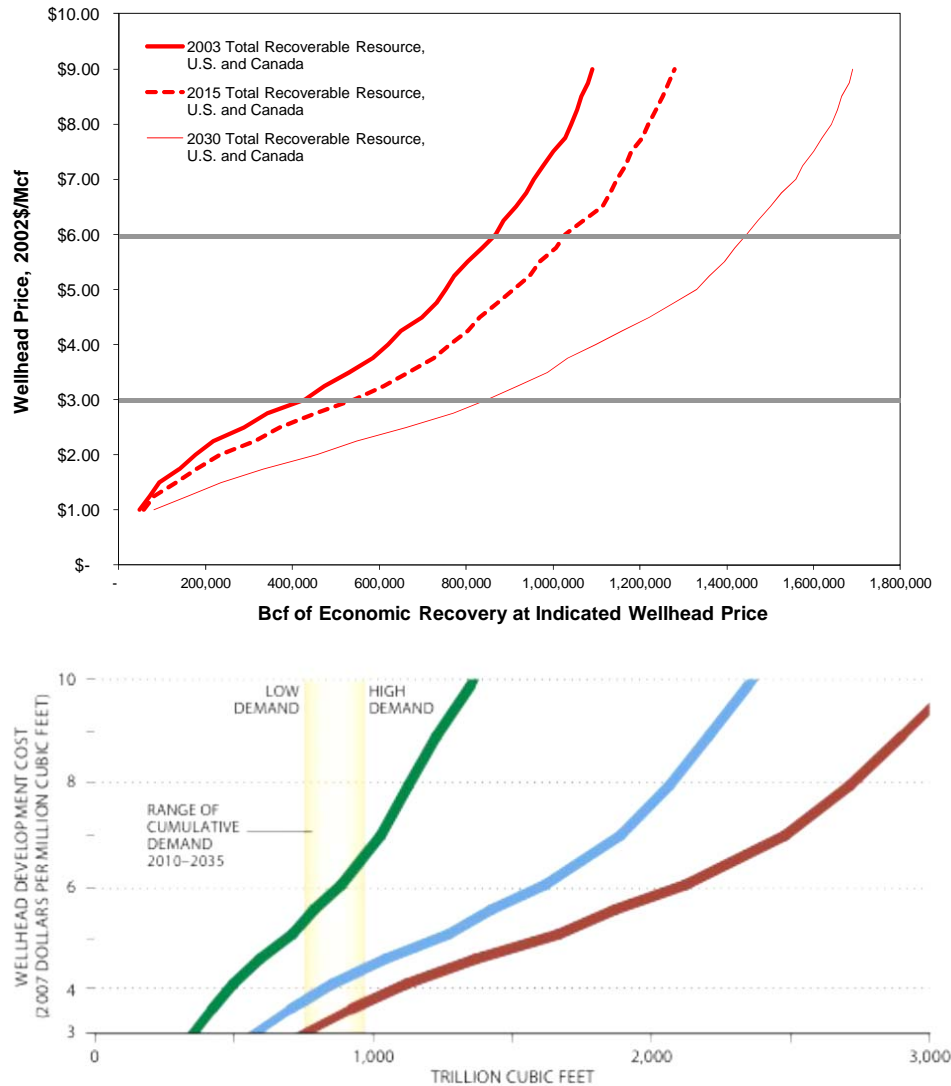
<sup>6</sup> See *Balancing Natural Gas Policy – Fueling Demands of a Growing Economy*, [www.npc.org](http://www.npc.org). The author peer-reviewed sections of the study and hosted a meeting for study chairs and U.S. and Canadian government representatives on findings.

<sup>7</sup> Comment from Edward M. Kelly, Vice President, North American Gas & Power, Wood Mackenzie, following CEE’s December 2010 natural gas forum.

<sup>8</sup> See References and Resources.

<sup>9</sup> The NPC study was released September 15, 2011. See [www.npc.org](http://www.npc.org). The author participated in the industrial demand subgroup. Supply side data for the study was based on a recent MIT study. See *The Future of Natural Gas* at <http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml>.

**Figure 2. NPC 2003 Supply Curves “Then” (top) and NPC 2011 Supply Curves “Now”**



*Note: North American (U.S. and Canada) total supply curves indicate volumes of gas economically recoverable at a specific wellhead cost (price). NPC 2003 data (chart on top) incorporated assumptions about technology advancements to 2030. For NPC 2011 (chart on bottom), green is the mean resource estimate with current technology, blue is the mean resource estimate with advanced technology, red is a high resource estimate with advanced technology and successful environmental impact management. Sources: Top, as reconstructed by Foss, NG 18, 2007; bottom, NPC 2011.<sup>10</sup>*

The main difference between the NPC 2003 and 2011 studies lies in critical assumptions about volumes of natural gas resource that can be delivered with advanced technology given a price signal to support wellhead cost. Notably, the 2011 study compares delivery with demand. In doing so, the price tensions are well framed; the effective conclusion of the 2011 study is that if all pre-conditions are met (including underlying policy, regulatory, technology, work force, capitalization and other factors) the industry can easily meet demand at a lower cost. Should any of these conditions not be met, and if volumes delivered entail higher costs, the supply-demand balance is less well assured. The NPC 2011 supply chapter

<sup>10</sup> See footnote 9.

states: “Because these technologies [represented by the outer, red supply curve in Figure 2] were viewed as advanced when the MIT study was developed but are now considered standard by the industry, they do not take into account future technology improvements.” This critical difference would apply to the NPC 2003 analysis as well. But while many of the advanced technologies are now deployed (popular phrasing is that the “unconventional has become conventional”) great uncertainties revolve around what the industry might need to do going forward to address myriad production and environmental challenges and at what cost. On the demand side, end users would be adversely affected by the upward pressure on prices that higher costs would trigger. The focus of the 2011 study is on mobilization of North American hydrocarbon resources to meet challenges of carbon constraints. If natural gas is the best, or only, practical solution then the ability to deliver large volumes of low cost supply is clearly an advantage. But many competing alternatives to natural gas are pushed actively and vocally. With producers facing an uncertain demand environment, volumes delivered and timing become dictated by market receptiveness (meaning prices and other factors).

When it comes to drilling success, a lively debate is underway regarding reserves bookings and well productivity. A distinct set of opinions has formed since 2005-2006, growing more insistent since 2009, to counter claims of success in the shale gas plays and to question how U.S. producers estimate and report reserves under U.S. Securities and Exchange Commission (SEC) rules. With the sharp drop in gas prices, producer responses have been mixed depending upon locations of their leaseholds. The most notable reaction to low Henry Hub prices has been a shift to drilling for liquids. Fewer rigs are being contracted to drill for natural gas; for the first time in many years, most operational rigs are drilling for oil. This is a logical response to the strong oil and gas price differentials. In fact, the true “game changing” aspects of shale resource play investments may be the turnaround in U.S. oil production - which challenges all preconceived notions about U.S. oil production and frames enticing arguments about what could be done if more territory was made available for drilling - an abundance of NGLs, which has fostered vigorous conversations about recovery in industrial demand as companies position themselves to build new or expand existing petrochemical capacity around NGLs.

The shift in drilling targets from dry (non-associated) gas to locations that are liquids-rich (associated gas) will play out eventually in lower methane production and deliverability; the amount of dry gas supply derived from production in NGLs-rich locations and associated with oil can only be roughly estimated and is highly variable. Other questions for deeper discussion include the style and business model for U.S. exploration. The “death of conventional plays” has been an unintended consequence of the emphasis on shales and “resource plays” in general.<sup>11</sup> No one truly knows what effects might stem from the steep natural declines in fields where conventional reservoirs are produced, including most prominently offshore Gulf of Mexico (GOM), and lack of investment or reinvestment in

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<sup>11</sup> Generally speaking, the working argument is that little geologic risk exists in unconventional (or resource) plays. In these locations, drilling and production target hydrocarbons locked in shale source rocks as opposed to conventional plays in which hydrocarbons have migrated out of shale source rocks and into reservoir rocks and become trapped. To be successful, essential conditions in conventional plays include presence of source rock, migration pathways and sufficient porosity, permeability, trap and seal characteristics for the overlying reservoir to be commercially productive. Coalbed or coal seam methane is also considered an unconventional resource play; methane trapped in buried coals is the target for production. Tight sands are considered “unconventional” by virtue of the absence of “conventional” reservoir porosity and permeability; successful tight sands plays are contingent on presence of source rock but, in some instances, little difference may exist between a tight sands and shale resource play. Finally, as explained later, the assumption of low geologic risk can be misleading. Recovery risk associated with shale oil and gas plays can be considerable.



conventional plays. Prior to the “shale revolution”, long term production declines in established fields and lack of confidence in replacing those reserves with sufficient new domestic supplies, bolstered LNG import strategies. Shale gas production exhibits even steeper declines, requiring regular outlays of capital to create dense drilling patterns, replenish reserves, and stabilize deliverability. The technology envelope is being pushed in ways that can sustain production and minimize the “drilling footprint” but costs have risen steadily. Finally, looming in the background is continued uncertainty about the future for offshore GOM development after the Macondo oil spill on April 20, 2010. That province had been expected to provide as much as a quarter of future U.S. oil-equivalent supply. Moreover, disagreements about how to manage environment and safety protections in the Gulf have trickled into public activism and regulatory oversight for onshore fields. Domestic oil and gas producers face a contentious public and regulatory environment, albeit one that is not without creative solutions.

NG 18 incorporated views on LNG such that, if robust enough, these imports could accelerate deterioration in the supply-demand balance (i.e., would widen the supply-demand gap); moreover, I suggested that even low utilization rates of LNG import terminals could be sufficient to achieve that impact. None of the opinions that I expressed was unique at the time. Also, of course, recession effects were building. Since 2007, LNG imports have been substantially lower, ranging from about one-quarter to just over one-half of the peak values. Import terminal utilizations have been well below 50 percent, my estimate for market softness, running at about 20 percent as capacity continued to come online.

Erosion of natural gas prices occurs largely because new sources of supply seek markets where natural gas is already being utilized. Patterns of demand use in the U.S. are well established. Creating new demand, for instance through natural gas vehicle transportation, is attractive but historically fraught with difficulty. The infrastructure required per unit of energy density is greater for natural gas than for liquid fuels, and infrastructure for retail natural gas vehicle refuelling simply does not exist on a large scale. Extending, expanding, building new infrastructure is expensive and slow, even with the mature, dense U.S. natural gas pipeline and distribution systems, and increasingly burdened by regulatory reviews. In addition, natural gas has lost out to electricity service in the utility segment; new homes and buildings are more often built with electric appliances and furnaces, a consequence of national standards that tend to favour electrification (in spite of efficiency benefits associated with direct use of natural gas).

The analysis in NG 18 demonstrated the very tough realities for industrial users and, commensurately, the role of manufacturing in the U.S. economy. High natural gas prices during 2000-2006 had significantly eroded industrial demand with some permanent loss of capacity. The 2003 NPC study included attempts to quantify the loss of industrial demand for both feedstock and fuel applications with higher natural gas prices. Given the overall context of long term U.S. manufacturing decline, market rebalancing based on a recovery in industrial demand is a difficult proposition. However, industrial customers that face higher relative prices for alternative petroleum feedstocks or fuels have begun to take advantage of more abundant natural gas supplies and more favourable pricing. A nascent recovery in manufacturing which, by all appearances, has benefitted from, or even been driven by, lower natural gas costs has been one of the brighter spots on the U.S. macroeconomic front. This includes the potential renaissance in petrochemicals mentioned above. (As discussed later, it also adds tension to the debate about whether to approve LNG exports of domestic production and about the environmental impacts of drilling.)

In NG 18, I pointed to conflicting arguments between industrial and electric power uses, noting the strong views within industry clusters regarding the value of natural gas for materials, but also the compelling arguments for natural gas as a relatively clean-burning electric power generation fuel. These competing viewpoints have since played out in legislative battles around climate policy and within the framework of the current 2011 NPC *Prudent Development* study. Growth in industrial consumption is contingent on a host of factors ranging from U.S. competitiveness and labor laws and regulations to currency values and trade pacts. It is clear that in certain industry subsectors, cheaper and more abundant natural gas and liquids can make a huge difference. Whether and how growth in *total* industrial natural gas demand could happen remains fuzzy.

All of the above means that, to all intents and purposes, electric power generation use will continue to dominate the scene. Significant new twists and complications have emerged that will be dealt with in more detail below (see Section 4). New factors include the push to accelerate renewables capacity along with implications for electric power grid management and market balances. The Texas experience (discussion in Section 4 below) affords a most interesting illustration of hotly debated dynamics, and raises distinct questions about sources of volatility for both natural gas and electric power prices as the share of renewables grows and gas generation is used for load following and to balance renewables. Competition between natural gas and coal for electric power has intensified, although forces against coal use are growing. Environmental pressure has centered on developing “clean” coal applications, primarily through carbon capture and storage (CCS) for greenhouse gas, (GHG), mitigation. However, in NG 18 I noted other sources of opposition, for instance to coal mining and from traditional health and safety concerns regarding emissions, that could disrupt reliance on coal as a hedge against natural gas price volatility or for energy security assurance. Opposition to mining (and global carbon emissions) is also impacting desires of U.S. coal producers to replace shrinking domestic demand with exports.<sup>12</sup>

In fact, since NG 18 was published, opposition to all facets of coal development and use along with lower natural gas prices, the very high cost of clean coal projects, and lack of climate policy has resulted in cancellations or postponements of a large number of new coal-fired power generation projects and expansions. In NG 18 I briefly raised the prospects for nuclear energy expansion. At the time, considerable discussion was underway regarding prospects for a “nuclear renaissance” in the U.S. and worldwide. Nuclear energy benefitted from the high and volatile natural gas price signal prior to 2008. A signature event –the Japan earthquake and tsunami and residual damage to the Fukushima nuclear power complex – has however altered completely expectations about the role nuclear energy might play in satisfying electric power demand in the U.S. and other countries. Yet, even before Fukushima, rapid escalation of costs for prospective nuclear energy projects was impacting on the likely progress of new plants.

With respect to drilling access and environmental restrictions, concerns about drilling intensity and associated impacts have surfaced strongly, even influencing energy politics in other countries. Along with lower prices, environmental opposition and looming regulatory actions have created considerable uncertainty about the pace, timing and cost of shale gas drilling and production activity. In the Appendix I table I mention the “*Gasland* effect”: organized agitation against drilling and, especially, hydraulic fracturing. “Fracking” is commonly deployed to complete wells in low porosity and permeability settings. In

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<sup>12</sup> Recent comments from utilities and coal producers suggest that their outlooks for continued coal use for electric power generation in the U.S. are even grimmer than captured in NG 18. However, environmental opposition to expansion of West Coast export capacity is complicating the effort to build overseas markets.

unconventional plays, it is essential. Successful shale gas (and oil) wells cannot be completed without fracking. Fracking is not the only source of public concern and environmental opposition. Local air emissions from drilling and production operations, including fugitive GHG (exacerbated by the broader debate regarding GHG and climate, and associated regulatory actions), water use and handling, local truck traffic and related issues (even the approach of using multiple completions per drill pad to minimize “footprint” still means intense activity), and local property values. Any and all of these issues can affect public perceptions and acceptance.

On the climate front, political positioning was extreme. The natural gas industry was among various interest groups disappointed in the outcome, the U.S. House of Representatives-approved, massive American Clean Energy and Security Act of 2009 (ACESA), otherwise known as “Waxman-Markey” for its key sponsors, Californian Henry Waxman and Ed Markey of Massachusetts.<sup>13</sup> Action in the U.S. Congress on climate fell into disarray following:

- Democratic loss of control of the U.S. House of Representatives,
- narrower voting margins and a high degree of uncertainty on climate policy in the U.S. Senate,
- problems in the U.S. economy and the global economy
- apparent loss of momentum on a comprehensive climate treaty at the Copenhagen and Cancun climate conventions and lackluster results at the November 2011 Durban meeting.

Short of action in the U.S. courts, the U.S. Environmental Protection Agency (EPA) seems to be the default body for resolving whether and how GHG mitigation will happen in the U.S., much to the consternation of: those who would prefer a Congressional solution; all critics of the EPA; industry and many large customers, utilities, and a slew of other stakeholders.

The experience with climate policy in the years since NG 18 was released has been one of the more revealing “schisms” in U.S. energy politics, as well for energy politics in many other countries and regions. Several things have become apparent.

- **First**, the natural gas industry does not necessarily need “climate” to win out over competing fuels.

In spite of the vigorous (stronger language could be used) antipathy between natural gas and coal proponents, opposition toward coal utilization remains more organized, focused and less amorphous than opposition against natural gas drilling (at least thus far). The biggest constraints to natural gas use remain fixed in the cost (and reliability) of supply and, thus price and price volatility. How well natural gas stacks up against the best coal options and lower (up to now) supply cost of coal is a source of continued friction.

- But, **second**, by opening the Pandora’s Box on climate all manner of demons in the form of unintended consequences have popped out to plague not only the natural gas industry but other energy industry segments and businesses, customers, stakeholders, political actors and so on.

Attendant, climate-related issues such as fugitive methane from natural gas production and infrastructure – a worse pollutant in the view of those strongly concerned about GHG – have

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<sup>13</sup> BEG/CEE-UT provided a review of Waxman-Markey in collaboration with staff at the Texas Comptroller of Public Accounts. See <http://www.window.state.tx.us/finances/captrade/> and [http://www.window.state.tx.us/finances/captrade/txpolicies\\_programs/tx\\_studies\\_reports.html](http://www.window.state.tx.us/finances/captrade/txpolicies_programs/tx_studies_reports.html) for the report link.

grown in importance, with EPA evaluating actions. The EPA's total portfolio of air and water standards could have large scale effects on energy suppliers and customers across the energy value chains including, contrary to expectations, natural gas. Many states are positioning around these concerns. State initiatives that might provide creative solutions for local disturbances associated with drilling and fears about hydraulic fracturing could preclude or supplant EPA actions. The issue cycle for climate and environment has evolved rapidly and not necessarily in beneficial ways for natural gas, burdening an already fragmented industry that historically has had great difficulty in building a consistent and common message. Last but not least, the gamut of environmental issues and energy policies has been hugely impacted by lower natural gas prices. Cheaper gas makes renewables less viable, hampers "clean coal" cost recovery, and creates myriad other irritations for proponents of those solutions. These play out in politics by fomenting opposition to natural gas development and utilization among those who do not perceive abundant natural gas supplies to be a blessing.

## ***1.2 Going forward – lessons learned and how to think about the major themes***

When NG 18 was written, natural gas prices had been propelled upwards by a dearth of investment in drilling during the long period of low prices in the 1990s and subsequent surge in demand as the new century opened. In 2006, the U.S. natural gas industry was still in recovery mode after the collapse of Enron and the energy merchant businesses, which had spun out of the regulated gas pipelines and gas and electric utilities in response to more competitive open access, lighter handed regulation and natural gas derivatives trading that came with FERC's Order 636 (see forthcoming OIES book, *The Pricing of Internationally Traded Gas*). There was also a conviction that FERC would restructure the massive electric power industry through some form of unbundled "wires" access. In 1995 the Energy Policy Act had formalized recommendations from industry and the U.S. Department of Energy (DOE) creating a competitive wholesale or bulk power market at the national level. The FERC appeared ready to foster competition at the regional level and FERC, DOE and the state public utility commissions (which supervise electric power and natural gas grids and markets within state boundaries) were actively engaged in the effort. "Energy merchants", unregulated entities carved mainly out of regulated businesses, were considered harbingers of innovation in an otherwise staid industry, the energy sector equivalent of "dot-coms". These merchants combine "midstream" gas businesses like pipelines, storage, processing and LNG receiving and imports, with independent power production; trading and hedging using both futures and spot or cash markets; and packaging financial and physical products into service contracts to provide supply and price risk management as well as market-driven efficiency strategies for customers.

The high-profile failure in 2000 of California's electric power market design, manipulation of prices in some of the nascent markets and widespread over-leveraging (merchant companies had taken advantage of the same cheap credit that fueled mortgage and other property markets) created an unsustainable situation. The collapse of the energy merchants, as well as California's electric power restructuring regime, and the prominent price spike at Henry Hub in early 2001 all drew heavy scrutiny from federal and state regulators and elected officials, large consumers, utilities, consumer advocates, and news media. Most states and the FERC reigned in experiments to instill competition in electric power markets. All of these disruptions played out in natural gas price shocks that deeply impacted both large and small end users. Meanwhile, oil prices began an almost relentless march toward their 2008 peak.

In a fashion similar to the rise of the energy merchants, the domestic oil and gas E&P (exploration and production) industry entered a period of rapid change and transition. By

2000, higher commodity prices and new drilling drew attention to the E&P segment. New money and players flooded in; by the 2008 peak, both the money and the players reflected typical late stage commodity cycle cost structures – more expensive with ever-increasing expectations about returns. With these new entrants, induced by higher prices and strong margins associated with the first wave of shale plays, leasing for drilling skyrocketed and bonuses and royalties surged. The unconventional resource plays attracted technology and fostered new upstream business models and new business entities.

Were strategists and decision makers unable to pick up crucial signposts that would ordinarily trigger questions about whether market conditions were fully understood? *Convictions that U.S. natural gas production could not, and would not, recover were widespread.* Surrounded by the detritus of the merchant failures, the rush to build LNG import facilities, the erosion of natural gas demand first from higher prices and then later from economic recession, indications of an eventual burst of new domestic production definitely was missed. Not least among factors was the absence of major companies from the domestic, onshore U.S. E&P business. They were the primary investors in LNG import surge capacity, part of global value chain strategies. Almost certainly, the lack of attention to domestic activity indicators and lack of awareness about how rapidly changes were occurring contributed to many being caught flat-footed as the shale plays accelerated.

- Thus, a **first lesson learned** from the past 20 years is the extent to which deep industry reorganizations and restructurings along with attendant market disruptions and shocks can cloud information and analysis.

A more in-depth analysis of corporate strategies is beyond the scope of this working paper. A fair question to ask, however, is whether we are witnessing a similar set of circumstances in late 2011? *Is it reasonable for the pendulum to swing so strongly toward perceptions of supply surplus and attendant lower natural gas prices and volatility? Are we still missing crucial signposts?* Inevitably, these kinds of questions point to larger perplexing uncertainties in how companies and their managers, as well as government bodies, collect, distill, process, analyze, and act upon intelligence in complex and dynamic markets. Behavioral tendencies, increasingly an important focus for the economics profession, overwhelm our assumptions of rational decision making. Consequently, it seems useful to challenge current conventional wisdom on supply deliverability, prices, and price volatility and explore whether alternative outcomes are possible.

- A **second lesson**, crucial to the stage at which the natural gas industry currently finds itself, is how best to build sustainable demand.

“Price sensitive” demand is important for moderating commodity cycles. Price sensitivity can also mean permanent loss of customers – witness the strong negative reaction among industrial users when U.S. natural gas prices reached the first shock level of \$4/MMBtu in 2000. A compelling argument now is that lower natural gas prices, both for the foreseeable future and relative to oil products, could reinvigorate manufacturing activity in the U.S. Multiple benefits could be created ranging from new business activity and job growth to improved competitiveness and more robust and stable natural gas sales (industrial customers being more consistent off takers day-to-day and season-to season). As mentioned previously, signs of interest are already evident. A sustained industrial recovery would entail a suite of factors well beyond energy costs, which constitute a relatively small part of manufacturing costs. Not least are all of the components of U.S. fiscal, monetary, international trade, labor, and health policy that define the current political battleground.

As a consequence, the majority viewpoint is that electric power affords the best strategy for natural gas “monetization”, with the greatest potential for growth. For all the efforts and good justifications to do so, combining the natural gas and electric power “value chains” is difficult. Integration of these value chains is complex: the path from field to market for natural gas impacts the pricing of natural gas for electric power generation, demand for gas at the electric power burnertip impacts the value of natural gas wellhead production. Both value chains are heavily influenced by seasonal effects and, especially for electric power, fluctuations in daily use (in the residential segment). Early thinking that electric power could be restructured along the lines of the gas industry missed key constraints ranging from technical difficulties in unbundling power grids, to basic and pervasive political differences across state and federal jurisdictions (the “all [utility] politics is local” syndrome). In addition, electric power fuels and generation technologies are intensely competitive, in both industry and, importantly, political perception terms. The inability to instill a more open, flexible marketplace for electric power works against natural gas in many respects. This happens most obviously by enabling policy and regulatory promotion of generation technologies, namely renewables but also other adventures such as “clean coal”, which are heavily dependent upon subsidies and regulated cost of service regimes. Last, as alluded to above, the post-Fukushima world has only made things more complicated. The “call” on gas to replace any nuclear retirements and/or planned additions could push demand side factors hard. Any supply-side constraints could be felt in sharper, more volatile pricing. Nor will the pressure to expand renewables ease. Post-Fukushima, and for those for whom GHG mitigation is paramount, renewables are the win-win strategy while gas simply is “no regrets”.

- These last points raise the **third lesson** – the shifting nature of energy politics in the U.S. and worldwide and the impact of evolving issue cycles.

Viewpoints on natural gas resource development and gas utilization vary widely across the political spectrum. Viewpoints shift as priorities change on the political agenda. News cycles can be as sharp and volatile as commodity cycles (no surprise there given some degree of interaction). “Above ground” risk and uncertainty (meaning political, policy, regulatory, and market as opposed to “below ground” geological risk and uncertainty) in the oil and gas businesses is always considerable.

- A **final lesson** is the danger of treating “Henry Hub” at any one time as an isolated price signal rather than part of an emerging and ever-expanding global energy “bazaar” marked by expanding international trade and transfer of price signals.

It is popular to view the U.S. now as “detached” from other global locations, largely self-supplied, perhaps even a net exporter, with a prevailing soft Henry Hub price as evidence. Just as higher Henry Hub prices drove expectations of rapid growth in U.S. demand for LNG, impacting strategies in ways that had ramifications in many different locations, lower Henry Hub prices could have hastened reactions and unexpected outcomes. The question is not so much whether Henry Hub becomes “a”, or even “the”, dominant gas price index for transactions (i.e., a “globalized” Henry Hub) but how prices across different locations around the globe interact, how basis differentials (spreads) form and mutate, how market participants perceive these differentials and react, and over what response times, and what new equilibriums might mean. *For that matter, what is the future of Henry Hub in the U.S.?* Is it likely to remain the dominant and most liquid price point? Should some of the more forceful projections of natural gas production from the Marcellus and other shale basins in the northeastern U.S. come to pass, why not a bifurcated northeast-Gulf Coast natural gas market or some other split that could provide producers and customers with better price signals and

risk management opportunities? All possibilities can be on the table. Having reached the NG 18 lower price deck, now what?

## 2 Henry Hub 2007-2011, historical context

The context for Henry Hub price signals going forward is richly informed by the backdrop of U.S. natural gas restructuring, a true “grand bargain”.<sup>14</sup> In sum, the general idea underlying U.S. restructuring, devised through long interactions between industry, government, and outside experts and implemented by FERC, was to foster competition and obtain more competitive commodity businesses. Greater access to transportation capacity, more freedom to engage in transactions by more and more diverse market participants, would increase market responsiveness, reveal bottlenecks, provide more options to both suppliers and customers – in short, create a more efficient (and larger) natural gas marketplace. Liberalized commodity industries and markets are also more cyclic, and so market designs tend to incorporate the notion that risk-loving entrepreneurs will rise to the occasion and act in ways that mitigate volatility. Questions that emerged in the late 1990s and early 2000s focused on whether these risk-loving entities were so motivated by returns from volatility that they would act in ways that could undermine market integrity (through round-trip trading and other market manipulations). But a fair question also, and one rarely explored if at all, is this: *what might happen during those times when the system is “stable” and thus not lucrative enough for the risk-loving businesses that have been created or that will be needed in the future?* The role of risk loving entities and risk mitigation in competitive, cyclic commodity markets has not been well thought out for unintended consequences during periods of low volatility. Market participants, from midstream merchants to bankers and traders, which emerged to monetize risk and that thrive on volatility have been undermined by the dissipation of volatility with lower prices and the prevailing deliverability surplus. That may seem a *quid pro quo* from the point of view of those participants that are most volatility sensitive, but diminished capacity to respond to higher volatility may have implications later. More is said on price volatility and storage in later sections. This question is worthy of further research and analysis, particularly when it comes to similar “grand bargains” for market restructurings in other industries or other public policy needs.<sup>15</sup>

In a nutshell, market structures that facilitate the transfer of price risk, and thus foster growth in risk-loving businesses, may therefore also need a resumption of volatility to sustain the intended market design. Many of the “volatility-loving” components of the gas system that were unleashed with Order 636 restructuring in 1992 are challenged in the current, lower volatility environment. Gas storage developers and operators are a prime example (gas storage is dealt with in more detail later). Volatility also makes natural gas derivatives more attractive to investors seeking commodity risk for portfolio diversification. These realities are a far cry from previous years when surging prices and volatility led many to wonder

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<sup>14</sup> For a history and key natural gas restructuring actions in North America see CEE, *North American Energy Integration*, <http://www.beg.utexas.edu/energyecon/documents/naep.pdf> as well as a summary of *Natural Gas and Electric Power Monetization in North America*, [http://www.beg.utexas.edu/energyecon/new-era/case\\_studies/Natural\\_Gas\\_Marketization\\_in\\_North\\_America.pdf](http://www.beg.utexas.edu/energyecon/new-era/case_studies/Natural_Gas_Marketization_in_North_America.pdf). U.S. and North American natural gas restructuring will be addressed in the forthcoming OIES book, *The Pricing of Internationally Traded Natural Gas*.

<sup>15</sup> During the heated debate on the Waxman-Markey climate proposal, significant opposition coalesced around commodity market dynamics and the degree to which the proposed cap and trade scheme for GHG might ignore experience from other physical and financial markets. Potential volatility in traded carbon, use of derivatives, and roles of expected market participants (swaps dealers and so on) fuelled controversies related to commodities trading oversight into the climate conflict. Dodd-Frank financial reform legislation exacerbated that can of worms.

whether bilateral, long term contracting, similar to pre-open access era, might return. Yet long term, bilateral contracts remain an option and continue to be discussed as a means of providing some surety to producers that they have markets for their production.

Prevailing views on supply and demand conditions can be distilled into two major thematic views on natural gas as shown in Table 1. These competing viewpoints have changed little over the years, although the population of stakeholders shifts and morphs as underlying market signals and business conditions alter.

**Table 1: Competing Viewpoints on Natural Gas and Implications**

<b>“Gas Short”</b>	<b>“Gas Long”</b>
❖ Prevailing political sentiment (state regulators, customers, consumers and their utilities)	❖ Prevailing natural gas industry sentiment
❖ Unconventional plays are unsustainable	❖ Unconventional plays are sustainable
❖ Global competition for LNG disadvantages U.S.	❖ LNG will swing to U.S. for storage, peak shaving
❖ Persistently high and “volatile” prices	❖ Generally lower, less volatile price deck
<i>Implications</i>	<i>Implications</i>
❖ Undermines critical assumption that gas will be available for balancing energy systems ➤ Especially sensitive for renewables dispatch	❖ Gas can expand beyond “bridge fuel” aspirations ❖ Search for non-weather sensitive base load ➤ Price sensitive load preferred by large customers
❖ Limits gas to incremental use	❖ Builds customer expectations regarding deliverability, pricing and price risks
❖ Discourages continued progress on key upstream and midstream initiatives ➤ OCS and other moratoria/restrictions ➤ ROW for midstream	❖ Adds pressure on producers for value creation
❖ Discourages domestic LNG exports	❖ Discourages incremental LNG import development near load centers

The “gas short” camp mainly consists of reliability sensitive actors with varying degrees of skepticism regarding the robustness of the U.S. resource endowment and deliverability. Included in this camp are those that feel electric power grid-based renewables are affected by volatility in natural gas pricing (as opposed to arguments presented later that renewables may underlie natural gas price variability because natural gas generation tends to be load following). Yet it is clear that expanding renewables on electric power grids is much more easily done with gas-fired generation, creating a perpetual love-hate dichotomy. While a “gas short” scenario implies higher gas prices and thus a need for greater investment in drilling, views typically are more complex. For many of these stakeholders, it makes no sense to broaden natural gas utilization; any additional increments of demand will simply worsen price volatility when inevitable shortages resume. Thus, contrary to expectations, many “gas short” stakeholders oppose developments such as expanding federal Outer Continental Shelf access (OCS, the federal offshore domain), or expanding rights of way for transportation, believing that investment should be directed toward natural gas alternatives. (“Peak gas” adherents tend to populate the “gas short” side of Table 1.) For many of this persuasion, the idea that domestic production could be exported via LNG is anathema.

The “gas long” scenario captures current industry sentiment and confidence in domestic production gains and is influencing large users and some elected officials. The prospect of



lower and less volatile prices boosts comfort levels with the concept of gas as a “bridge” fuel (“to what” is not generally well-defined or agreed upon). It also encourages more aggressive arguments that natural gas could supplant other energy fuels and technologies and provide long term energy security benefits. Here, tensions rise around positions of large customers that desire more price-sensitive users in the marketplace to ensure a moderating effect should supply-demand balances tighten. Producers would rather promote non-weather sensitive base load – transportation being a favorite option. Apart from the debate regarding LNG exports, the more salient effect of the “gas long” perspective is to discourage development of additional LNG import receiving capacity near critical load centers. As a result, LNG receiving capacity additions have come to a screeching halt in the face of low utilization of installed capacity and perceptions about domestic production.<sup>16</sup>

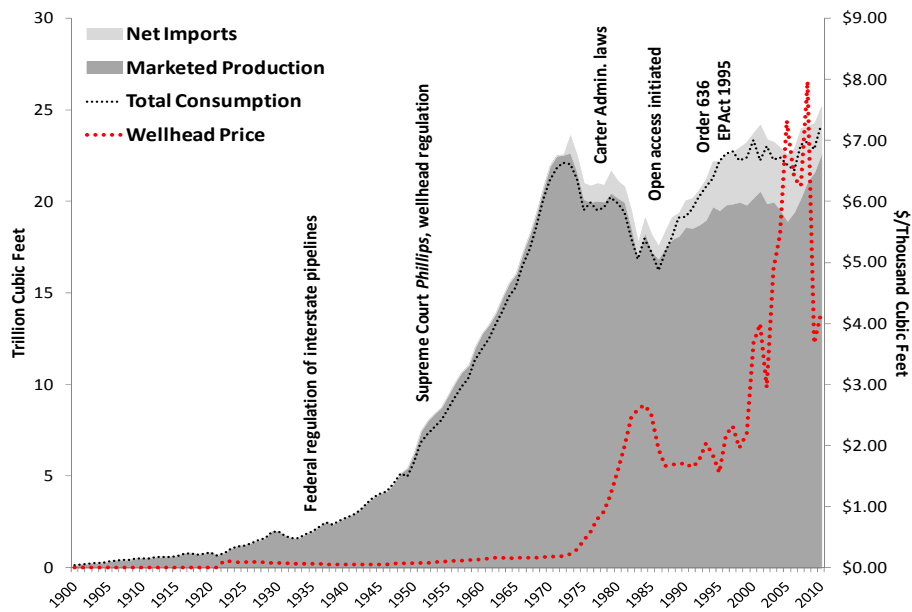
It is fairly well understood that increased gas utilization is needed to propel and sustain supply development. The thinking goes that without substantial new demand to soak up the current and prospective future supply surpluses, it will be hard to sustain responsive domestic production. This belief is particularly prominent within the industry and among keen industry watchers. But persistent fears on the demand side that new commitments will place too large a “call” on highly variable supply sources, creates inertia in the system. As a result, both themes persist, yin and yang, fading or coming closer into view depending upon market conditions.

The competing viewpoints stem, of course, from long history and experience. Figure 3 below provides a long term perspective on the U.S. natural gas marketplace. Natural gas policy and regulation in the U.S. has been a long and winding journey. A crucial Supreme Court decision (“*Phillips*”) in the 1950s led to federal government regulation over the price of natural gas in interstate (cross state) markets, while in intrastate (within state) markets natural gas prices reflected supply-demand conditions. The latter were much more appealing for producer sales. From the early 1970s to mid 1980s, natural gas use, supply, and price reflected the progression of policy and regulatory actions to address imbalances created by the interstate-intrastate split as well as the international oil market and other energy events that defined the times. Supply interruptions during cold winters, in actual fact a consequence of gas being held out of interstate transactions, hastened action on some of the most ill-advised legislation taken in the U.S. energy sector. Carter Administration era laws were rooted in fears that natural gas supplies were chronically short, that the U.S. was contending with a true resource scarcity. The Carter energy policies both initiated more market responsive pricing for natural gas while also imposing barriers to natural gas use. Allowing prices to rise to reflect demand and stimulate supply growth, while also prohibiting boiler use, resulted in loss of baseload consumption mainly among industrial users who were already impacted by high oil prices. Later, the supply response fostered by rising prices was accelerated by Reagan and Clinton drilling incentives.

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<sup>16</sup> In a sign of the times, Hess finally pulled the plug on Weavers Cove near Fall River, Massachusetts, one of the more controversial LNG import projects. See, for instance, “Hess scraps plan for LNG terminal in Mass,” *Bloomberg Businessweek*/Associated Press, June 13, 2011. <http://www.businessweek.com/ap/financialnews/D9NR9OHG1.htm>

**Figure 3: Historical Annual Production, Consumption, Imports, Nominal Price**

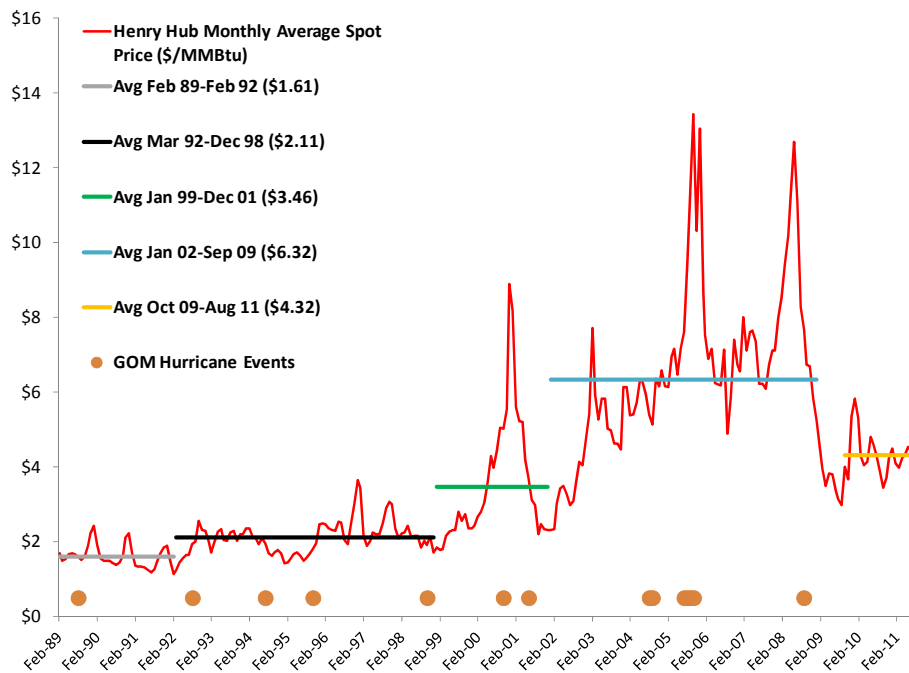


Sources: estimated and compiled by author using U.S. EIA data. The difference between total consumption and marketed production plus net imports is effective working gas in storage and balancing.

Figure 3 thus represents a range of price events. The long period of lower prices, lasting until the late 1990s, encouraged rapid growth in consumption and underscored the 1995 Energy Policy Act and bulk market rule for electric power (Section 1.2). By 2000, “gas long” convictions ended abruptly. Although production had grown since the early 1980s, rapid natural declines in seminal fields collided with surging demand as independent power generators responded to the bulk power rule. A “market call” was placed on imports but also, significantly, on new exploration and drilling. It is of great significance that by 2010 U.S. marketed production had returned to 1971-73 highs. By 2006, few believed that natural gas prices would ever fall below \$8, never mind close to or even below \$3. In 2011, as noted in the opening sections, few believe that sharp price spikes are feasible. Moreover, given the bad public relations associated with price spikes, the industry is working overtime to demonstrate that future disruptions are unlikely or, if they do happen, could be quickly mitigated through the market mechanisms mentioned earlier (storage, LNG responsiveness, or “just in time” shale gas production).

The distribution of price events since 1989, the start of U.S. government monthly data, can be illustrated as distinct “mean reversion” eras, shown below. Comparing Figure 3 and Figure 4 illuminates more recent history and demonstrates the coincidence between rising price decks and new tranches of production (beginning with the earliest forays into unconventional plays in the 1990s and progressing to the shale plays in the 2000s), as well as the downside adjustment as these new tranches filter into the marketplace. Gulf of Mexico hurricanes also are indicated. Trading around GOM storms is always active but GOM hurricanes are not explanatory variables for prices except in narrow trading bands; an exception was the extensive damage incurred from Ivan in 2004 which took substantial offshore pipeline capacity offline for a prolonged period.

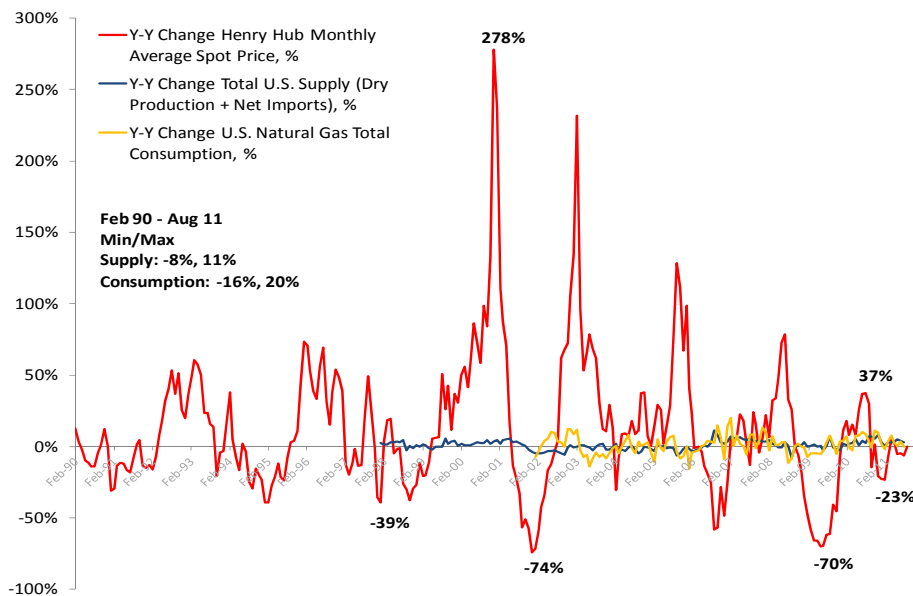
**Figure 4: Henry Hub Price “Eras”**



Sources: Compiled by author using spot price data as reported by U.S. EIA; hurricane event data from National Oceanographic and Atmospheric Administration (NOAA).

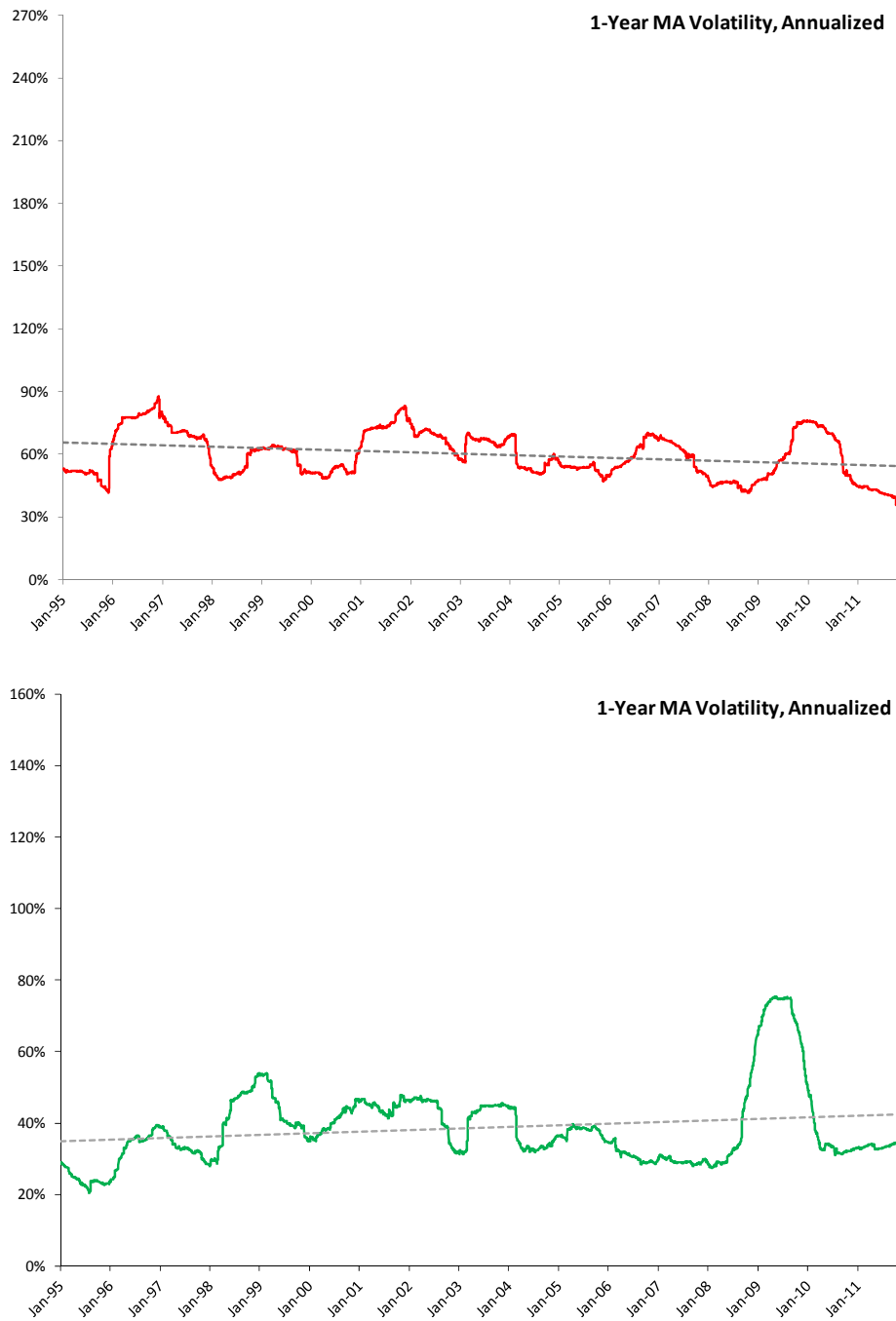
The following Figure 5 and Figure 6 disaggregate the Henry Hub price trend into raw year-to-year changes and a progression of smoothed volatility measures. Also in Figure 6, natural gas price volatility measures are compared with crude oil (West Texas Intermediate).

**Figure 5: Raw Natural Gas Price Changes**



Sources: Compiled by author using spot price data as reported by U.S. EIA.

**Figure 6: Natural Gas(top, red) and Crude Oil (bottom, green) Price Volatilities**



Sources: Compiled by author based on work by Foss and Gülen using spot price data as reported by U.S. EIA (Foss, et.al., 2011). Volatility measures are compiled using the standard deviation of the natural logarithm of  $(P_t/P_{t-1})$  based on daily prices; annualized by dividing with the square root of (1/252). We assume 252 trading days per year. This is a standard definition used in literature and industry.

Key features from the trends in volatility measures are summarized in Table 2, which also compares different moving average time slices.

**Table 2: Price Volatility Metrics, Jan 16, 1995 – Nov 1, 2011**

	<i>Natural Gas</i>			<i>Oil</i>		
	<b>10-day MA</b>	<b>1-month MA</b>	<b>1-year MA</b>	<b>10-day MA</b>	<b>1-month MA</b>	<b>1-year MA</b>
<b>Min</b>	254%	197%	88%	148%	122%	75%
<b>Max</b>	12%	15%	36%	7%	10%	21%
<b>Std Dev</b>	28%	25%	11%	18%	16%	11%
<b>Avg</b>	54%	55%	60%	36%	37%	39%

A number of important observations can be drawn from the preceding charts and accompanying table.

- Raw, year to year price changes attract attention. Yet, smoothed one year moving average volatilities, calculated using “trader” parlance, show that the exceptional natural gas price changes in the early 2000s represented less volatility than was experienced in 1996.
- Higher volatilities during the 1996-1998 time frame were coincident with a shift in price deck – a significant movement from one mean reversion era to the next as demonstrated in Figure 4, and as the first tranches of unconventional and deeper water natural gas production entered the market.
- That said, overall, natural gas has been a more volatile commodity than crude oil, or many other commodities.
- A gentle downward trend in volatility for natural gas is apparent, shown in the one-year moving average used in Figure 6. This compares with a gentle upward trend in volatility for oil.
- Volatilities are highest when supply-demand conditions are tightest.

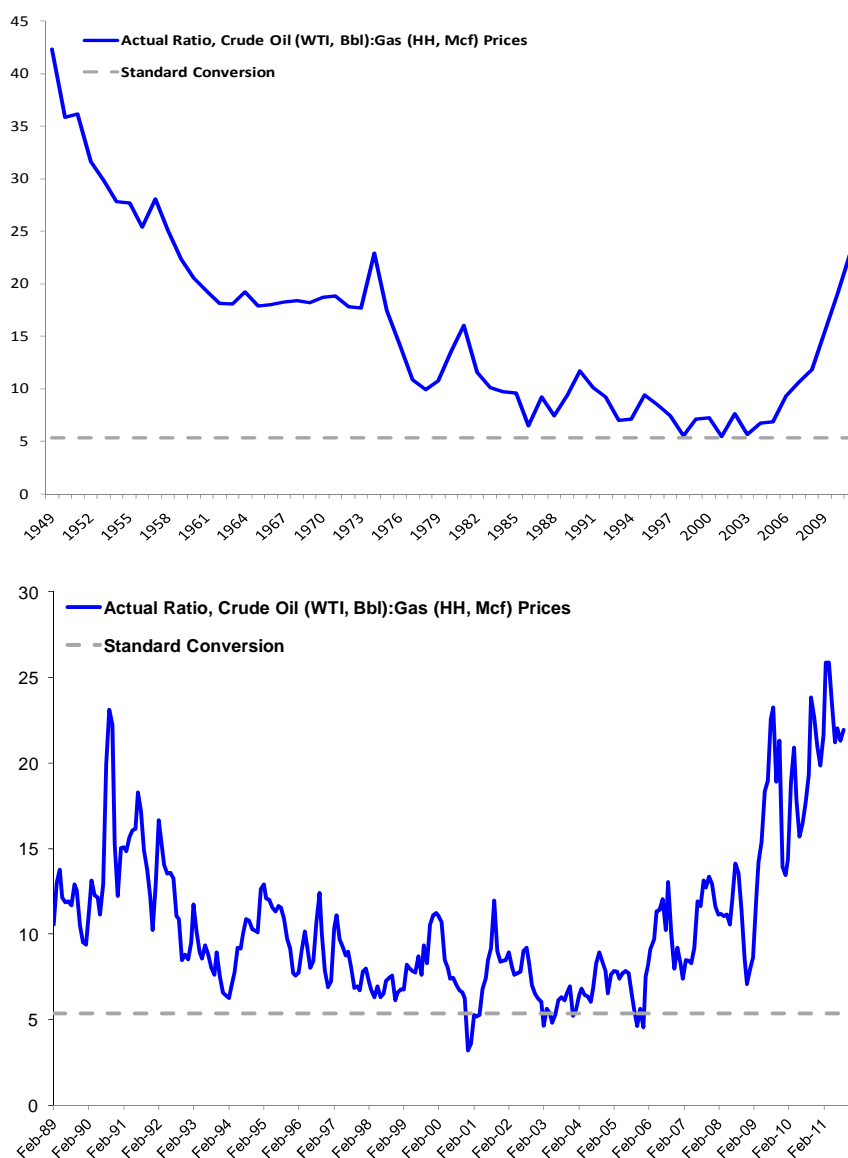
Underlying the grand bargain for U.S. natural gas restructuring was another hope – to finally obtain a natural gas price that revealed the true value of the resource. Historically, natural gas had been treated as a byproduct, and there was a lot of it. If dry, non-associated natural gas was discovered in drilling, wells typically were abandoned. Eventually, large discoveries of natural gas in Texas, Oklahoma and Louisiana spurred re-thinking and development of the first long distance, high volume interstate pipelines. As demand for natural gas grew, first as a replacement for town gas derived from coal in Northeast and Midwest heating markets and then quickly as an important fuel and feedstock for industry, its value also grew, in particular relative to oil. (Figure 7 illustrates the long term decline in the oil:gas ratio and commensurate increase in value of natural gas).

By the mid-1980s, when interest in restructuring the natural gas industry was growing, the idea that natural gas was “not just a byproduct anymore” had firmly taken hold. Key players were starting to build natural gas focused, integrated businesses to link upstream resource development with midstream (processing, pipelines, storage) and trading, marketing and risk management. The value for natural gas relative to oil also is a function of resource scarcity as compared to demand for the respective commodities. As oil prices were falling in the mid

1980s, undermined by collapsed demand and OPEC market share battles, natural gas prices were peaking with partial decontrol achieved through the Natural Gas Policy Act.<sup>17</sup>

In recent years higher oil prices and natural gas supply build with attendant downward pressure on prices ended the brief flirtation with “price parity” (reflecting commonly used conversions of roughly five or six to one for energy content in Btu terms). Natural gas once again is deeply discounted. The historical correlation between crude oil and natural gas prices has dropped to roughly 70 percent from the 84 percent I reported in NG 18, reflecting the widening discount since late 2006. The average oil:gas price ratio since February 1989 stands at roughly 10.5. As I noted in NG 18, natural gas has rarely been valued on par with oil. Yet Btu parity is a common assumption for project development and for pricing natural gas in much of the world.

**Figure 7: Oil (\$/barrel) and Natural Gas (\$/Mcf) Price Ratio**



Sources: Compiled by Foss using spot price data as reported by U.S. EIA.

<sup>17</sup> See footnote 14.

Changing views on the U.S. supply mix once again have spurred debate about how best to utilize (now abundant) domestic natural gas resources. Cheap natural gas relative to oil products is altering customer strategies and opening large questions about international pricing. Vehicle transportation and even possible exports of Lower 48 production via LNG are actively contemplated. Neither of these are new ideas. Many of the same threads have been present during other crucial periods of U.S. natural gas history, most notably the last time the U.S. enjoyed an “excess” of natural gas supply in the mid-1990s.<sup>18</sup> Many of the same arguments to bolster natural gas utilization are being recycled, along with business strategies. But, as stipulated in Table 1, the “gas long” perception places particular pressure on natural gas producers to create value; they must sustain or find new sources of profitability if the lower commodity price does not support profit margins. For most producers, this search for value has meant diverting attention to oil.

In the end, what goes around comes around. As Paul Frankel famously noted, the challenge in the petroleum industry is not shortage, but rather surplus.<sup>19</sup>

### **3 Natural gas detectives: supply side drivers**

Our forensic tour to dissect the forces that could drive views and scenarios to 2020 begins with the supply side. Most notable is the resilience of the U.S. domestic industry and its ability to weather cycles (albeit with restructuring and attendant “creative destruction”). Periodically, in time frames that generally match the pace of commercialized technology, E&P players bring new tranches of production into the market when price and technology combine to yield attractive profit margins. Over the years, a steady progression of studies on the U.S. resource base has demonstrated its richness, if increasing complexity. The question is not the robustness of the U.S. resource base, but deliverability of production when demand and price signals warrant.

During the mean reversion era that was in effect from about January 2002 until September 2009 (Figure 4), the Henry Hub price topped out at more than \$15 per MMBtu on a daily basis. That created a powerful pull into Lower 48 and Canadian drilling and, with it, the beginning of a deep shift in upstream business dynamics. LNG import terminal developers had couched their projects in terms of the widespread and widely understood natural declines in long-established conventional natural gas reservoirs. Some of these fields had been in production for 40 or more years. Notable production losses were in the U.S. midcontinent – the same producing locations that had triggered development of interstate pipelines in the 1930s and 1940s. Another focus of attention was the shallow waters of the Gulf of Mexico. The broad swath of natural gas producing fields that had been the mainstay of the GOM industry was becoming exhausted. Investment in the initial wave of unconventional resource opportunities – coalbed methane (CBM) and tight sands – were helping to stave off what many believed to be a collapse in domestic deliverability, but only just.

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<sup>18</sup> With respect to exporting U.S. gas as LNG, the first LNG tanker, Methane Pioneer, carried a cargo from Lake Charles to the United Kingdom in 1959. At that time, natural gas was a surplus byproduct in the U.S. See CEE’s *Introduction to LNG*, and expectations were for exports to continue.

[http://www.beg.utexas.edu/energyecon/lng/documents/CEE\\_INTRODUCTION\\_TO\\_LNG\\_FINAL.pdf](http://www.beg.utexas.edu/energyecon/lng/documents/CEE_INTRODUCTION_TO_LNG_FINAL.pdf). In the battles over Alaska gas pipeline transportation routes, many prominent voices in the state preferred an LNG export option. The gas pipeline, which reached \$35 billion in estimated costs, has been suspended. See <http://www.denalipipeline.com/>, May 27, 2011. Some estimated that costs could exceed \$40 billion. “Latest Risk to Alaska Gas Pipeline: More Gas,” by Ben Casselman, *Wall Street Journal*, January 30, 2010.

<sup>19</sup> Frankel, 1969.

Popular accounts of shale gas development history credit George Mitchell and Mitchell Energy for commercializing the huge Barnett shale basin. Production declines in established fields had pushed Mitchell Energy to seek other possible plays that could support the company's substantial investments in midstream gas gathering and processing. Mitchell had drilled and produced in the Barnett since 1981. A well drilled by Chevron in 1997 (unsuccessfully) with a new approach to measuring initial gas in place (IGIP; measured by Chevron using on-site canister desorption) created a distinct challenge for Mitchell: the Chevron IGIP measures indicated much higher natural gas content than was previously believed to exist. Mitchell Energy had been reporting attractive recovery factors of 30 percent for their Barnett wells, reasonable given the tight formation. New IGIP calculations that were roughly triple previous estimates caused Mitchell's recovery factors to collapse and, along with them, well and field economics. Nothing sows invention like adversity, and so the Mother of advanced hydraulic fracturing methods and, eventually, the combination of hydraulic fracturing and horizontal drilling technologies were brought to bear on the problem. Finally, by the early 2000s, Mitchell's important contribution in revealing the full extent of Barnett shale gas (and oil) potential launched the shale gas epoch.<sup>20</sup> Much improved results with better technology and improved understanding of Barnett resources attracted interest and soon the population of shale players swelled, initially with small and large independents.<sup>21</sup>

During the 1990s, Chevron and other major companies had exited not only the Barnett, but onshore U.S. oil and gas in general. Capital was flowing overseas, where international opportunities seemed more promising (and certainly cheaper on a barrel of oil equivalent basis) or to offshore GOM deepwater plays. In 2011, major companies re-entered the U.S. domestic onshore oil and gas scene, lured by promising developments in shale basins and with few opportunities worldwide that can provide material results to their large balance sheets. For many smaller independents, the arrival of cash flows and technology from the largest companies is not a bad thing. The scale and scope associated with shale basin plays, the large up front capital expense, and myriad environmental and social acceptance challenges are thought by many observers to be more easily tackled by cash-rich larger companies. The connection between "rocks" and "policy" lies in assumptions that larger companies can better manage, or at least absorb, policy and regulatory risk inherent in the U.S. oil and gas sector in general, and with unconventional resource plays in particular. The return of major companies also raises numerous questions about the future of the U.S. upstream business model.

Publicly traded oil and gas companies, especially large ones, have long struggled to satisfy Wall Street's predilection for reduced drilling risk. Dry holes – unsuccessful, noncommercial wells – are a drag on profit margins.<sup>22</sup> In the broadest sense, conventional reservoirs are characterized by dry hole risk, whereas unconventional resource plays are not. At first blush, then, shale plays would appear to offer "nirvana" – a mainly engineering, technical

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<sup>20</sup> David Wethe, March 12, 2009, Barnett Shale Pioneer Mitchell Bets on Pennsylvania Gas Boom, Bloomberg, <http://www.bloomberg.com/apps/news?pid=newsarchive&sid=aTylLUsh7Pwo>. Also see Bowker, 2003 and 2007 and Steward, 2007. Comments provided by former managers of Chevron's Nonconventional Gas Business Unit created by then Chevron U.S.A. president Ray Galvin.

<sup>21</sup> An "independent" in the U.S. oil and gas industry is a nonintegrated, upstream exploration and production company. Some independents "drill and flip" leaving production to others. Use of the term "independent" originally described companies that were not part of John D. Rockefeller's Standard Oil Trust.

<sup>22</sup> Keith Rattie, chairman of Questar Corporation (retired president and CEO) once declared while at Chevron Corporation that there should be no more dry holes. Sir John Brown, then CEO of BP, made a highly publicized tour of Wall Street in the late 1990s to try to build recognition for the E&P industry's risk/reward profile. At the time, worldwide, drilling had fallen precipitously and realization was growing that the industry needed to sink new wells in order to replenish production.



economies of scale problem stemming from drilling and completing multiple well bores to extract a resource that is largely understood to be “in place”. Questions about the presence of hydrocarbons are few; the puzzle is how best to optimize production. Dry hole risk essentially disappears from the equation. However, noncommercial wells drilled in search of “sweet spots” in shale basins, those prime locations that are best in both hydrocarbons in place and recovery, are a drag on margins. As discussed later, quality across the shale basins is uneven. “Below ground” geological uncertainty coupled with substantial “above ground” risk makes the business model for commercializing unconventional resource plays difficult.

How exploration is funded is also a consideration for emerging North American upstream business models. “Rank” exploration, or “wildcatting”, is commonly funded by equity (often referred to as “friends and family” in the U.S.) and cash flow. Traditional risk/reward tradeoffs associated with oil and gas discovery are well understood by experienced equity providers. As natural gas prices soared and new players entered the U.S. and Canadian clusters most capitalization was derived from ever more expensive equity sources as the cycle progressed. A number of companies capitalized their drilling programs through initial public offerings (microcaps). Again, publicly traded entities have a much easier time defending large capital expense associated with development of production and so unconventional plays served to boost the IPO approach. The vigorous price cycle and shale results also enabled companies to utilize debt. The low cost of debt finance facilitated “leveraging up” among many of the independents that had expanded and become specialized shale players.

Another aspect of major company presence is how oil field services are priced. With service industry consolidation over the past 30 years, the majority of offerings are priced for major companies that execute large master contracts for worldwide operations. This means that the “scrappy independent” has to pay major company costs.<sup>23</sup> Expansion of domestic onshore activity along with major company pricing has kept service costs high as well as contributed to escalation in land leasing and other expenses. Inputs like steel followed commodity price trends and pre-recession global economic performance and have remained high with sustained higher oil prices and drilling activity. Major companies also tend to have higher overheads (“general and administrative” costs as well as “G&G” – geological and geophysical – and engineering payrolls). Fierce competition to recruit and retain specialized exploration and development staffs lifted industry labor costs. In sum, the entire cost structure for the domestic industry has inflated (see Section 4.2).

Lastly, major companies re-entering U.S. onshore exploration have brought with them expensive global LNG value chains. How U.S. shale plays fit into that picture is yet to be seen, although most conjecture centers on deployment of both domestic supply and LNG for market share and balancing. This begs the question of price level to sustain shale plays and volatility in view of both domestic and international cost structures, lumpiness of large scale oil and gas investments, and the incessant search for sustainable profit margins.

### **3.1 “Glubbausage”!**

U.S. shale gas production and the commodity price effects spawned by that largesse has variously been called a “revolution” and a “gale”. In a throwback to the 1990s, other words that could be used include “bubble”, the initial descriptor for the excess gas deliverability of that age. It was common to refer to the 1990s gas bubble as having grown into a “sausage” with no end to the surplus in site. Less diplomatic, given political realities, but more to the

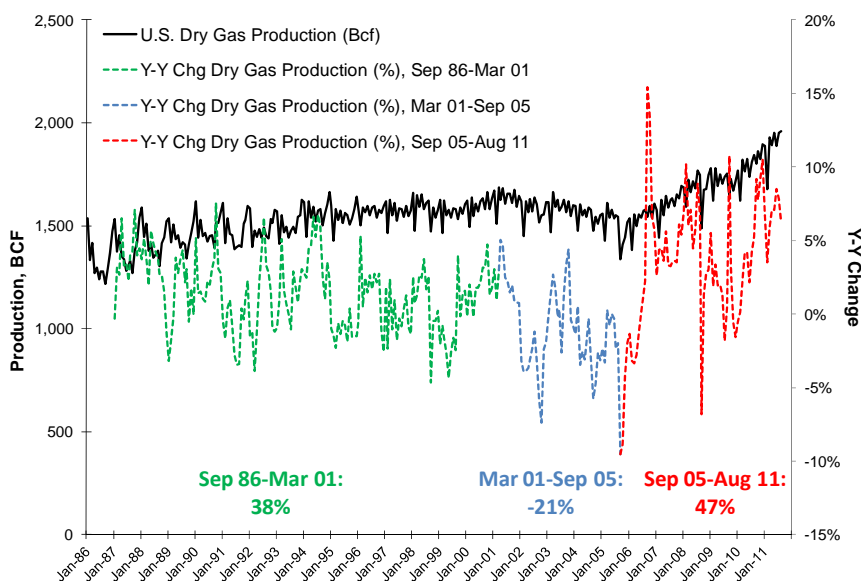
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<sup>23</sup> In the 1990s in speeches and commentary George Mitchell jokingly (?) offered major oil and gas companies airplane tickets to leave the U.S. mainly in response to what many felt was major-company induced higher costs for oil field supplies and service.

point, is “glut”. *Is the U.S. natural gas industry facing a “glubbausage” and if so, what does that mean?*

The size and geographic distribution of U.S. and Canadian shale basins is evident from public domain maps, including those produced by the U.S. EIA and available through portals such as Schlumberger’s.<sup>24</sup> Shifts in U.S. natural gas production are depicted in Figure 8 below, which can be compared with Figure 4 to match production and price “eras”. Year-year declines in production were readily noticeable by the turn of the 21<sup>st</sup> Century. Between March 2001 and September 2005 production had dropped 21 percent (Figure 8). Unlike the 1980s and 1990s, no producer incentives were in the offing for shale gas plays; the robust Henry Hub price signal provided sufficient inducement. Higher prices were reshaping exploration interest and funding. Notably, and importantly, shale basins are almost entirely located on private lands. The ability for early entrants to negotiate directly with surface and mineral owners, paying the going rate in bonuses and royalties, was an important driver for shale gas and oil plays. Private, “fee” minerals is a trait unique to the U.S. Industry insiders will freely admit that had the first wave of shale leases been auctioned by government, the timing and pace of activity would have been much slower and more uncertain.<sup>25</sup> It was not until 2006 that the impact of shale drilling encroached on U.S. production. From that point forward, production gains have been very real albeit with slower growth rates. In any case, the turnaround in U.S. output, coincident with the higher level annual trend in Figure 3, *remains a remarkable story.*

**Figure 8: U.S. Natural Gas Production Eras: 1986-2011**



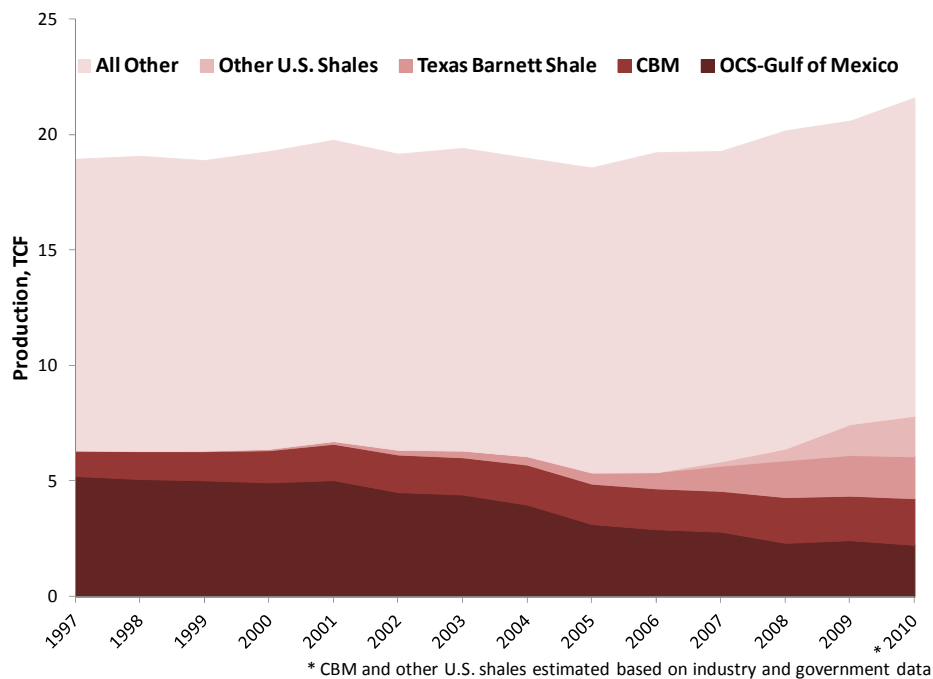
Sources: Compiled by author using U.S. dry gas production data as reported by U.S. EIA. Percent changes are peak to trough.

<sup>24</sup> See [http://www.slb.com/services/industry\\_challenges/unconventional\\_resources.aspx](http://www.slb.com/services/industry_challenges/unconventional_resources.aspx); also see [http://www.slb.com/resources/publications/industry\\_articles.aspx](http://www.slb.com/resources/publications/industry_articles.aspx) for useful technical papers, links and other resources.

<sup>25</sup> Many environmental groups and others less enamored of the “shale gale” will argue that a more measured, government-led process would have been better and avoided current and prospective conflicts over development. Those views ignore attendant inefficiencies and other vagaries that can accompany government leasing programs.

The previous commentary on U.S. upstream business conditions, conventional and unconventional plays, and exploration funding is borne out in the estimates of U.S. natural gas production by source as shown below. The persistent decline in production from the U.S. Gulf of Mexico (OCS) is obvious. Arguments are that without significant new investment in a reasonable time frame, OCS production could erode to a point where U.S. energy security might be hindered. Yet, as will be shown later, the OCS contribution to national natural gas production has been shrinking for some time, although a plateau had been reached by 2010. Deepwater blocks tend to be oil prone and deepwater natural gas handling presents distinct challenges. If the OCS cannot deliver, *could shale production make up the difference?* This is a key point of debate for the longer term. CBM has reached a steady state; there are no expectations for strong gains in the foreseeable future. The shale wedge is split into Texas Barnett production and other shales for comparison.

**Figure 9: U.S. Natural Gas Production by Source**



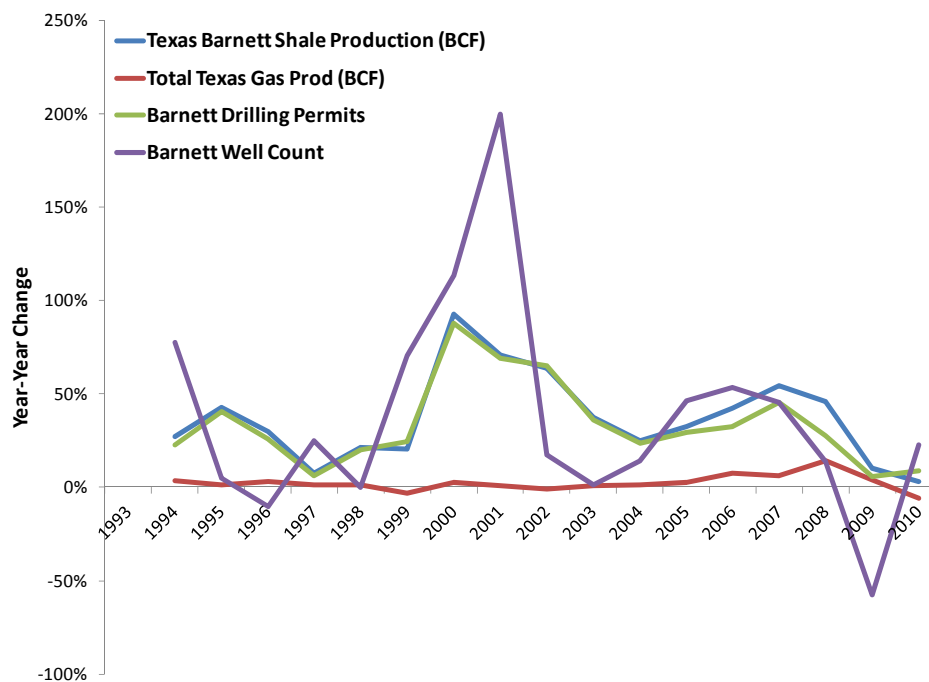
Sources: Compiled by author based on U.S. EIA, U.S. BOEMRE, Texas Railroad Commission industry reports. Author estimates that shale gas production is about 17 percent of U.S. total.

Lessons from the “granddaddy” of the shale plays, the Barnett, are illustrated in Figure 10. Barnett natural gas production and well permits are highly correlated (0.82), production and well count even more so (0.99). A great deal has been learned about Barnett geology, including evidence of microfractures<sup>26</sup> and the role of “conventional” play features such as structural highs and dips that especially define the “sweet spots”. Related to the latter, the role of some rather ordinary criteria – matrix porosity and permeability – in establishing commerciality are increasingly well understood. More will be said further on about reservoir conditions and their implications for advanced drilling and completion research and technology.

<sup>26</sup> See BEG research on fracture systems [http://www.beg.utexas.edu/frac/recent\\_news.php#PubAward](http://www.beg.utexas.edu/frac/recent_news.php#PubAward) and mud rocks, <http://www.beg.utexas.edu/msrl/index.php>, which included the first electron microscopy capture of nanoscale porosity systems.

Another key point of debate is whether other shale basins can be expected to perform as least as well as the Barnett or, in some cases, better. It can be a treacherous step to extrapolate drilling and production experience in one shale basin to another (generally speaking, translating drilling success from any basin and/or location to another is always chancy). The limits to extrapolation have bearing on other aspects of U.S. natural gas industry practice, such as compilation of national outlooks for reserves and production, reserves estimation and reporting, and so on. Nevertheless, accepted relationships for unconventional resource plays are the links between rigs, well completions, and production, as demonstrated for the Barnett in Figure 10. With more wells completed per rig – a strategy for reducing the drilling footprint is to complete multiple laterals per pad or well location – the dependence of production on rig activity will change somewhat. Completing well bores more rapidly and cheaply can affect production positively. The Barnett technology learning curve can inform expectations for other basins and plays, and also points to hurdles producers must overcome to sustain profitability. The Barnett experience suggests that as gas drilling goes, so should natural gas production, for the most part. An important offsetting factor is associated gas production from oil and liquids-directed drilling, which at present in the U.S. is difficult to assess and project.

**Figure 10: Texas Barnett Shale Performance**



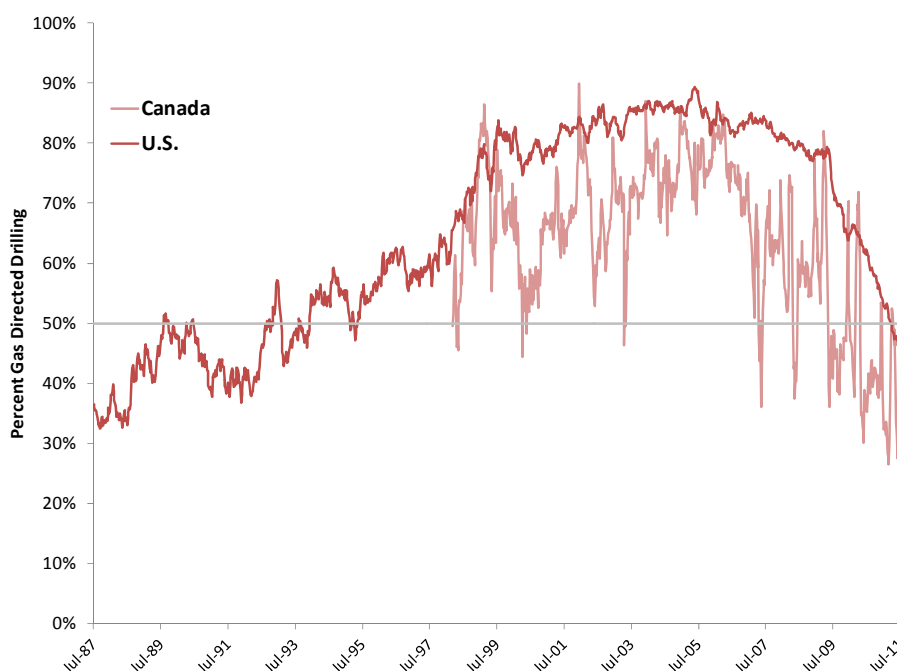
Source: Texas Railroad Commission.

The harsh realities of lower natural gas prices have had a profound effect on drilling in the Lower 48 and Canada. Natural gas-directed drilling, as logged by Baker Hughes, had soared to roughly 90 percent of U.S. rig activity (Figure 11 below). Canada was close behind. The long trajectory toward natural gas drilling dominance seemed to invoke permanence. Yet, in a short space of time, natural gas drilling has fallen below 50 percent in the U.S. and near 20 percent for Canada. Rig stock had followed the previous trend of more dominant gas-directed drilling. The drilling industry had invested in larger rigs capable of the deeper horizons usually targeted for natural gas exploration, and to accommodate the demands of horizontal drilling. Deploying larger gas rigs to shallower oil targets is another factor

inflating finding and development cost structures.<sup>27</sup> The longer equipment is diverted to oil and liquids-rich locations for drilling, and if oil and liquids remain compelling targets, the slower the response time might be when producers react to more favorable natural gas prices.

*A third point of debate, then, is what kinds of delays in responsiveness to higher price signals might be experienced and what might the effects be on natural gas deliverability?* Apart from this query, a bigger question for many is why gas drilling, in the face of chronically low prices, should be happening at all.<sup>28</sup> The initial public offering (IPO) model, in particular, has ensured that financing would drive leasing and drilling strategies. Backers of companies pursuing shale plays have invested on the basis of demonstration of concept. This has meant that companies aggressively lease (at top dollar) and drill (leases are typically “held by production”, spurring action to prove up acreage) and then seek to offload or “flip” their holdings for investment returns. At time of writing, producers are beginning to take some hope in market rebalancing as drilling finally slows in key locations and sampling of production data from states and operators indicates slower growth than the more than 40 percent increase in production since September 2005 as illustrated in Figure 8.<sup>29</sup>

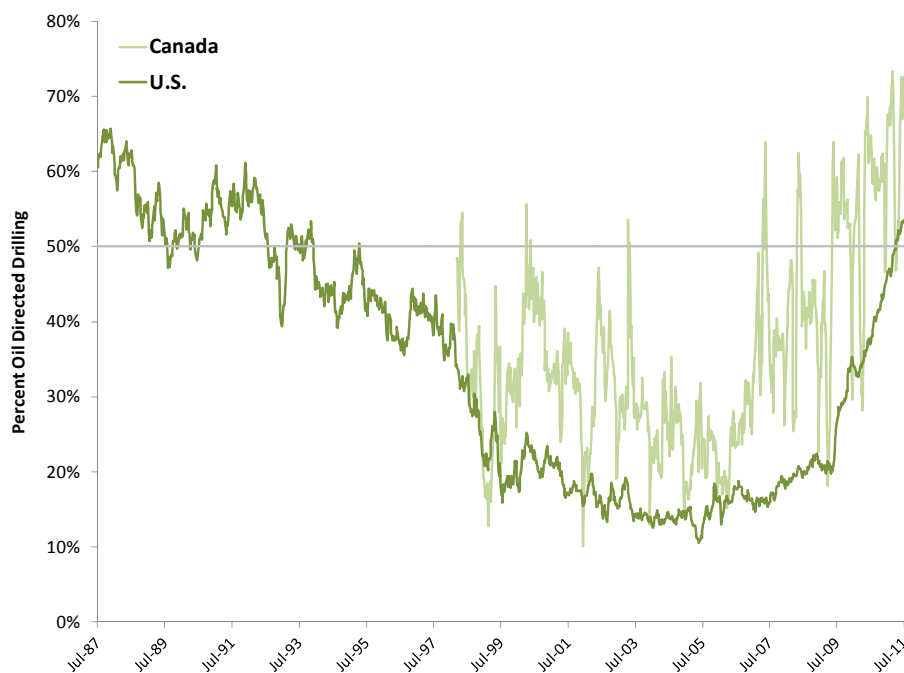
**Figure 11: U.S. and Canada Shares of Gas-directed Drilling**



<sup>27</sup> All based on conversations with drilling companies and other oil field service providers.

<sup>28</sup> Ever forthcoming with commentary, Aubrey McClendon, chairman and CEO of Chesapeake Energy, answered his own question (and presumably his investors’): “Why are we drilling for oil? You hope to do something with your life other than produce \$3 natural gas”. Quote from Hart Energy’s Developing Unconventional Oil Conference and reported in the regular feature “Newswell”, *OilandGasInvestor.com*, July 2011. Onshore shale oil plays are reported to yield as much as 1,000 barrels per day.

<sup>29</sup> Based on information from various investment research houses.



Source: Baker Hughes

### 3.2 The role of finding and development costs

Finding and development costs and trends are the source of much discussion. Relative to the NG 18 lower price deck and current and forward Henry Hub prices, *the critical question is whether finding and development costs, at least in some locations, can tolerate low and persistently low natural gas prices.* How this question is evaluated and, ultimately, answered has huge implications not only for supply development and deliverability, but also for reserves estimation and booking.

Oil and gas finding and development costs are closely linked to price.<sup>30</sup> The highly interactive, complicated cost-price relationship is easily detected during the high price cost-push years; the recent high oil and natural gas price push on shale and other domestic plays is a prominent, and historically significant, example. Importantly, industry activity does not stop during low price periods. Rather, companies “high-grade” their upstream portfolios, dropping projects that cannot be supported by market conditions and pursuing more profitable investments. Thus, leasing in Federal OCS deepwater blocks accelerated during the 1980s. Policy encouragement in the form of the Deep Water Royalty Relief Act was not in place until 1995. In contrast, the first forays into unconventional gas plays happened with stimulus from the Federal Section 29 drilling and production tax credits for wells drilled between 1979 and 1993. The hope was to accelerate development of natural gas supply in the face of production declines and to build interest in the more demanding and expensive unconventional resources. The Section 29 credits were controversial for many of the same reasons that shale plays have become so.<sup>31</sup> Coal seams must be dewatered to reduce pressure

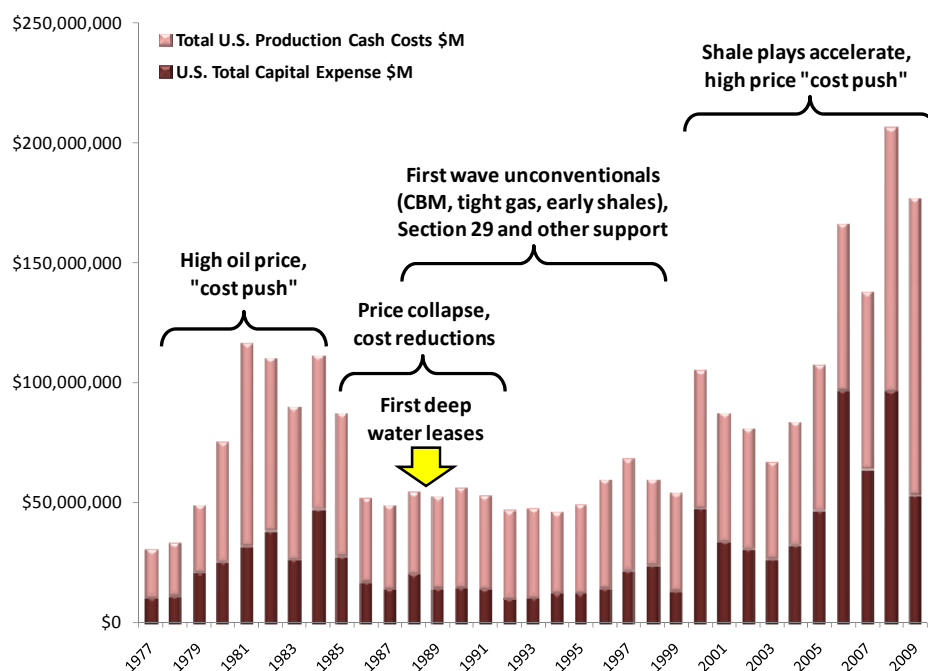
<sup>30</sup> CEE has been conducting extensive research into producer costs and economics, for both oil and gas with emphasis on unconventional plays. See Foss, et.al, 2010 and contact CEE for more information. Any view on oil and gas price levels and volatility must start from supply cost pressures. Paul Horsnell, Barclays Capital, commented in March 2010 that marginal cost sets price, that “producers don’t target projects for a certain price” although they certainly will invest if price signals support profitability. In addition, periods of high multiples attract some degree of “speculative” drilling particularly by new entrants. These practical realities are often ignored as political debates unfold during periods of higher prices and increased volatility.

<sup>31</sup> See <http://www.citizen.org/documents/coalbedfactsheet.pdf> for a prominent example.

and facilitate gas desorption. Concerns revolve around impacts on freshwater aquifers (CBM is typically shallow) and reservoir treatment (hydraulic fracturing and related). In many respects, the battles associated with CBM development have migrated to shale and also enlarged, given the proximity of shale plays to urban areas. Even within industry, and among industry watchers, doubts about the Section 29 program were rampant. For many, the tax credits simply exacerbated the “bubble” to “sausage” effect, depressing natural gas prices for longer than they should have been.

Historical “all in” or “full cycle” breakeven costs for the U.S. industry and production are shown in Figure 12. Costs are expressed in barrel of oil equivalent terms but the main point is to illustrate the distribution of costs between those typically associated with capital expense (“drillbit”) and everything else. The sharp drops in the total capital expense portion, which reflects all source finding and development costs, in 2007 and especially 2009 was largely attributed to the shale play “learning curve”. As producers improved drilling and well completion, higher initial production rates and higher ultimate recoveries per well allowed cost spreading over larger volumes. Figure 12 also bolsters the cost-price linkage, but without addressing direction of influence (cost on price, price on cost; probably coincident).

**Figure 12: Total U.S. Oil and Gas Production Costs**

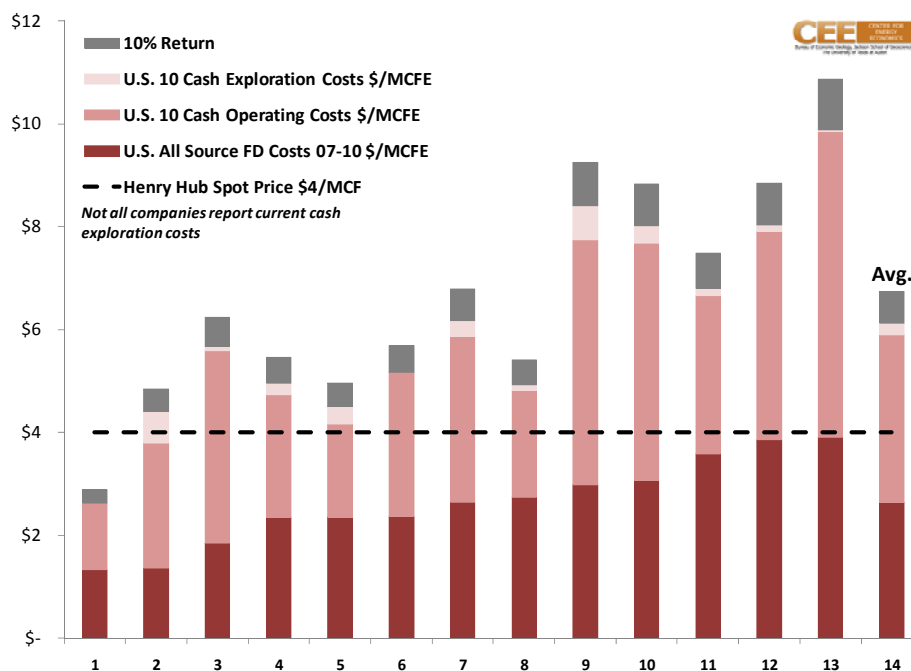


Sources: Compiled by author based on work by Foss and Wainberg using financial data as reported by U.S. EIA, Financial Reporting System, and industry reports.

Full cycle breakeven costs are shown below for a sample of large domestic natural gas operators, including some shale specialists. We use “drillbit” (all source FD costs) and cash operating costs (including income and non-income taxes). When reported, cash exploration costs are indicated. We assume a 10 percent rate of return across the board. “Drillbit” costs are those typically associated with a daily ticket (drilling and completing), usually along with leasing and permitting (full cost basis). Companies carry many other expenses that must be amortized across production. The \$4/MCF or MMBtu assumption is the contemporary psychological indicator in terms of both overall commodity market fundamentals and as a

minimum “hurdle” for entry into shale and other challenging gas plays. It is conventional wisdom that shale gas producers with a \$4/MCF drillbit cost structure can at least break even in a \$4 price market. The analysis depicted below challenges these assertions. For 2010, only one of the operators had total breakeven costs below the \$4. All of the companies had drillbit costs below \$4 but cash cost and return result in all operators but the first being above the \$4 hurdle. The average is close to the \$6 target referenced in NG 18 and in this paper as being most desirable from a producer perspective (\$6.12 and \$6.73 with a return). Drillbit cost tends to be the most commonly quoted estimate of shale gas, and is clearly misleading. That said, a great deal is going on behind FD cost data, not least the benefit of liquids production (if substantial enough, it can fully cover the cost of a well) and the next big push on technology.

**Figure 13: U.S. Natural Gas Average Breakeven Costs (2007-2010)**



Sources: Compiled by author based on work by Foss and Wainberg using industry financial reports.<sup>32</sup>

Our methodology and results are borne out when our results are compared with other reviews of producer costs. For instance, highly respected Bernstein Research noted in a May 27, 2011 advisory to clients that they cannot corroborate “any company’s claim that its fully-loaded cost of production is below \$4 or even \$4.50/MCF.” Moreover, “Excluding land cost and with no return, the average large cap E&P needed \$5/MCF gas to cover its 2010 F&D costs and operating expenses. Including acreage costs and a required return on capital, the required price is easily in the \$6.00s – and this is for the *large* producers.”<sup>33</sup> Analysis of more than 1,957 wells in “sweet spot” locations in the Barnett, Fayetteville, Haynesville,

<sup>32</sup> Methodology based on a presentation to analysts by EOG Resources, September 2010, and related conversations with CEO Mark Papa and others. At the time, EOG estimated industry “all-in” breakeven costs to be \$2.50 per MCFE (MCF equivalent) and \$2.50/MCFE total finding costs, for a total breakeven of \$5.00. With an assumed 10 percent return, EOG’s overall estimate was \$5.50.

<sup>33</sup> Bernstein Research, May 27, 2011, *2010 U.S. Marginal Cost Curve - Oil Floor and Gas Aspiration?* Used with permission. Contact Bernstein Energy, Bob Brackett, Ph.D. (Senior Analyst), [bob.brackett@bernstein.com](mailto:bob.brackett@bernstein.com) for details.



Woodford and Eagle Ford basins<sup>34</sup> found positive economics only for Barnett and Fayetteville for wells drilled during 2008-2009 using a 10 percent discount rate and \$4/MCF, before tax.<sup>35</sup> An extensive review of industry reports and literature indicates the degree of variation in cost basis for producers contingent upon location within basins and presence of liquids. Production from the “liquids window” can yield substantially higher returns.<sup>36</sup> In a new analysis to 2015, Poten & Partners, a leading global oil and gas transport broker and advisor, rates the Texas Barnett as the cheapest of shale plays, on a full cost basis (analogous to our methodology), followed by Fayetteville, Haynesville, Marcellus, and Woodford/Eagle Ford, with other shale and unconventional gas plays kicking in at substantially higher prices. Provocatively, in their analysis, all of the shales are more expensive (on a supply cost basis) than imported LNG, Canadian imports, CBM, Alaskan shipments (were those to happen), offshore production and conventional fields. Their average is comparable to our 2010 estimate, and they expect production cost to slowly increase such that Henry Hub would reach about \$6 by mid decade.<sup>37</sup> Wood Mackenzie, a top energy consultancy historically specialized in upstream oil and gas research, estimates the 2011 full cycle gas breakeven price for U.S. shale basins to be above \$5.50, a slight reduction from their 2009 average of nearly \$6.00. Their cost leaders among the major basins and plays mirror Poten’s and other opinions: the main Barnett basin (which has proved most conducive for non-associated gas production and cost management) and southwestern Marcellus (northeastern U.S.) and Eagle Ford in south Texas, the latter two basins hugely advantaged by prolific oil and natural gas liquids resources.<sup>38</sup> In short, our analysis coincides with a number of external studies and opinions using both producer financials as well as “bottom up” basin, field, and well economics. All indicate a higher rather than lower cost structure for shale plays in general, with better economics in liquids-rich locations.

How did 2010 performance stack up to 2009’s? The 2010 average cost of \$6.12 for the sample of producers represented a slight improvement from the 2009 average of \$6.44 (\$7.08 after return), highlighted in Figure 14. Some reductions were made in drillbit costs, from \$3.06 to \$2.65, in keeping with the “learning curve” and advances in technology application and drilling cost management that are expected of the industry. Cash costs increased from \$3.02 to \$3.25, however, for a number of reasons. These are items such as lease operating expenses, G&A (general and administrative, or overhead) costs, income and non-income (like payroll) taxes, interest on debt, and other costs that are difficult to control. In the demanding world of unconventional resource plays, human resources are difficult enough and many

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<sup>34</sup> See map links in footnote 24 for geographic locations in the United States.

<sup>35</sup> Baihly, et.al, May 2011 and Baihly, et.al, 2010.

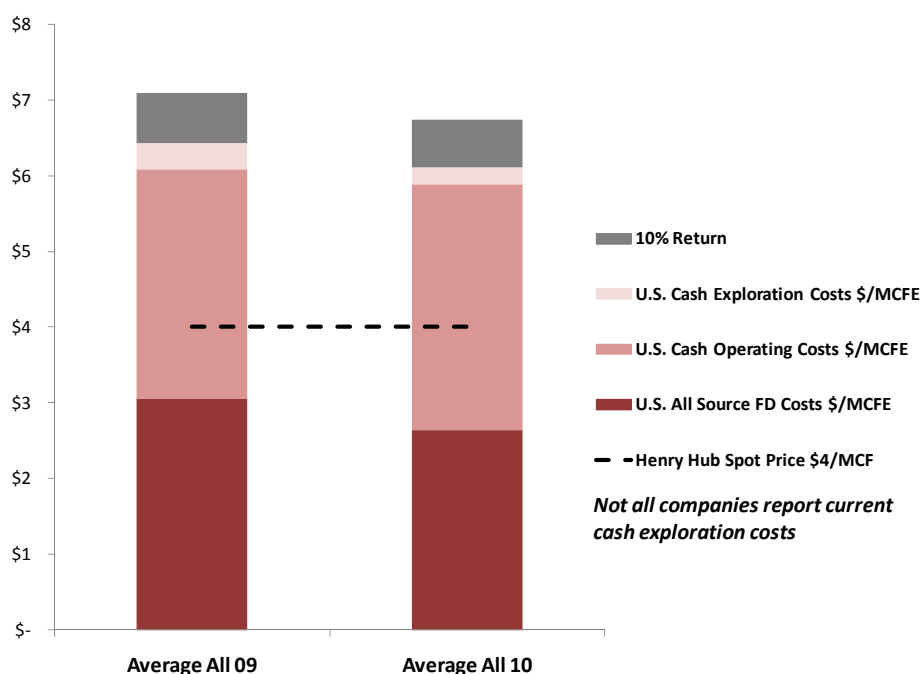
<sup>36</sup> Steve Toon, “Marcellus Momentum”, *OilandGasInvestor.com*, November 2010. “On 95 producing wells, its EURs have jumped from 4.4 Bcfe [BCF equivalent] to 5 Bcfe, raising returns on investment from 50% to 79% (based on \$5 gas). Yields are 3.6 Bcf of gas and 239,000 barrels of liquids. At the same time, Ventura calculates well costs have upticked by about \$500,000 to \$4 million, reflecting extended completions. Since 2009, laterals have lengthened from 2,500 to 3,050 feet, with 10-stage fracture stimulations versus eight before. Plans are for even longer laterals up to 5,000 feet and 17 frac stages. “We’ve made significant improvements in terms of EURs,” he says. “Even though the wells cost more, the rates of return are better. Given where oil and gas prices are today, that liquids component is significant in terms of affecting our economics.” When stripped, ethane can yield \$8/MMBtu or more depending upon oil prices and demand. Based on Nissa Darbonne, “The Ethane Prize”, *OilandGasInvestor.com*, July 2011.

<sup>37</sup> Poten & Partners, *Global LNG Market Review: Can Shale Gas Solve the Post-Tsunami Energy Crisis?*, Society of International Gas Tanker and Terminal Operators Houston Panel Meeting, September 21, 2011. Used with permission.

<sup>38</sup> *Unconventional Gas in Europe – Outcomes & Implications*, presentation to the British Institute for Energy Economics, London, October 10, 2011, cited with permission. Wood Mackenzie also indicates the major European basins as being well above the median post-tax breakeven cost for a large sample of U.S. and Europe locations.

operators had to expand payrolls to add and keep technical professionals. The tendency to leverage up meant larger interest expense. And the entry of larger companies imposed higher G&A expense.

**Figure 14: Total Average Breakeven Costs, All U.S. Natural Gas Producers**

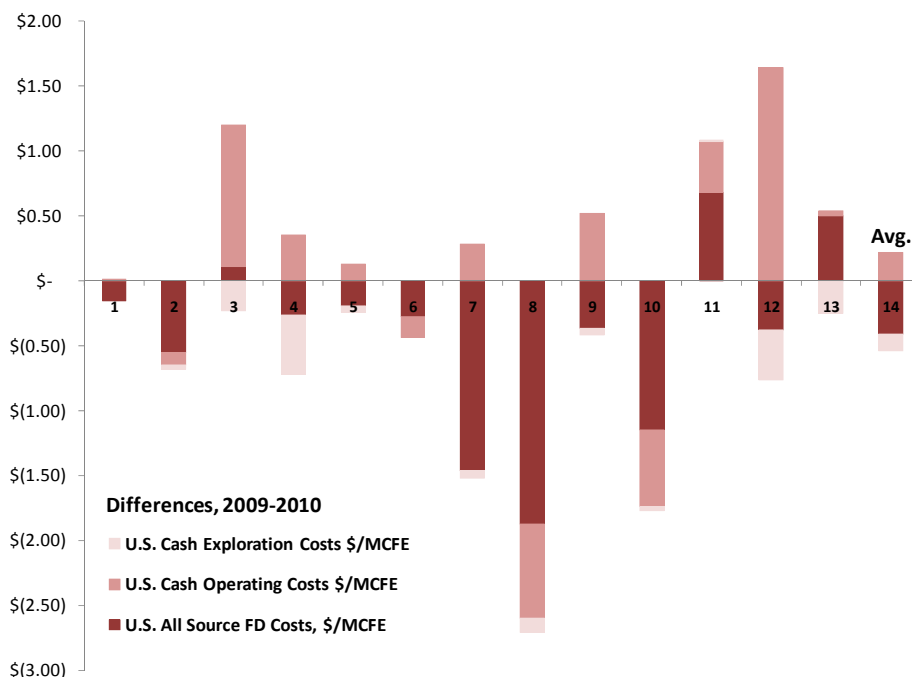


Sources: Compiled by author based on work by Foss and Wainberg using industry financial reports.

When 2009 and 2010 costs are compared across the individual companies, the degree of variability across operators provides interesting insights. Almost all reported some reductions in drillbit costs, in some cases substantial improvements. Not all operators are in all shale basins, or are equally well positioned with respect to leasing. Those companies with more expensive acreage in higher cost plays and/or that paid dearly to enter plays, and especially if they are in plays that are predominantly dry gas, have fewer opportunities to monetize costs. Some companies expanded stock offerings or took on additional debt or had higher cash costs associated with staffing and other items (producers 3, 11, 12 in Figure 13). Merger and acquisition (M&A) strategies work both ways. Companies with higher FD costs can benefit hugely by acquiring low cost specialists (producer 10). The penalty on the flip side comes in greater G&A expense which must be spread across production volumes. Companies that honed their lease positions and were able to drill out all lease obligations are attractive targets for investors still looking to enter the shale businesses, especially if the leaseholds are oil and liquids rich (producer 6). Conquering costs of water management can contribute significant cost advantages (producer 7) as can pushing the entire learning curve through intensive, smaller spaced laterals from common well pads and, if leaseholds allow, drilling much longer laterals.<sup>39</sup>

<sup>39</sup> Because leasing from private land/mineral owners can result in smaller lease blocks, companies often are prevented from drilling out horizontal laterals to optimal distances. The author visited a drill site in Texas in which the lease block configuration limited the operator to roughly 3,000-foot laterals. In one case, the producer commented that their ability to drill 10,000-foot laterals in one basin and as many as 52 laterals from a single well pad in another test location both yielded huge advantages in cost management. As industry

**Figure 15: Change in Average Breakeven Costs for U.S. Natural Gas Producers, 2009-2010**



Sources: Compiled by author based on work by Foss and Wainberg using industry financial reports.

As prices began their downward trajectory in late 2007, producers were able to use hedging to protect cash flows and offset costs. Being able to lock in future sales of natural gas at close to \$6 was a boon for many companies. That kind of hedging strategy has not been available for some time, although other arrangements (collars and so on) can be used to shelter cash flows. However, no more meaningful advantage can be gained than significant overall FD cost reductions. One major producer commented that “rather than waiting for \$6 gas” his company’s goal was to push average, weighted full FD cost (in this case, excluding leasing but including a nine percent cost of capital) to \$3. In a world that “could be permanently \$4”, such an accomplishment would constitute “nirvana”. The dilemmas include sustaining this kind of performance over company portfolios; dealing with service providers on cost; and, not least, understanding and coaxing hydrocarbons from very stubborn rocks.<sup>40</sup>

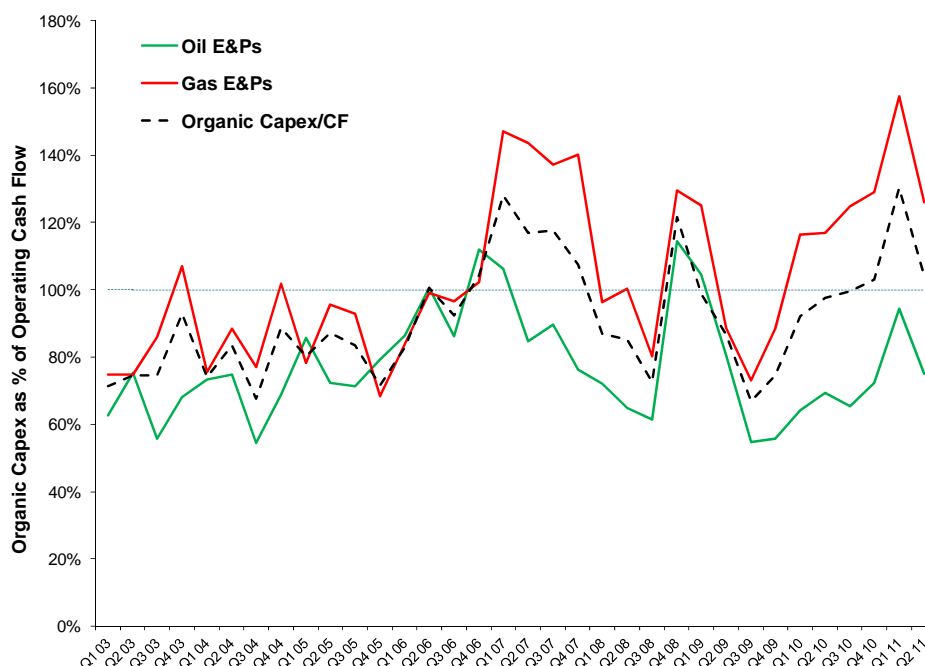
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consolidation gathers pace combining leaseholds as part of that process could help producers to improve drilling efficiencies. Indeed, given the prevalence of highly competitive leasing from private minerals owners and the constraints this often poses on acreage configurations and drilling patterns, the need to drive toward larger, contiguous land blocks may, in fact, induce overall industry consolidation. Shale development experts with strong competencies and hefty balance sheets would emerge as dominant players in basins where they have comparative advantages, bolstering play economics.

<sup>40</sup> Bill Britain, “Oil vs. Gas Transaction Metrics”, *OilandGasInvestor.com*, July 2011 put the future pathway well: “The ‘lease capture’ phase, which has fueled frenetic shale drilling, appears to be coming to an end. Shale joint-venture partnerships, while in the ‘middle innings,’ have less urgent drilling schedules, although liquids-rich shale plays are keeping the gas rig count active. Perhaps the most significant single factor in reducing natural gas supply, and thereby increasing gas prices, is operators’ discovery that reducing initial and early shale-well flow rates can markedly increase estimated ultimate recoveries (EURs). This potential upward price pressure may be lessened, however, as unprecedented teamwork between highly competent unconventional-resource operators and their service-company experts accelerates the learning curve, bringing down the break-even cost in many unconventional plays.”

Our analysis is based on annual financial reports. At time of writing, we are updating for 2011 releases. What are the forward signals? Preliminary looks across 2011 quarters suggests that many producers have missed targets, and that costs for gas E&P are persistently high. Bernstein Research (see Figure 16 below) and other analysts have reported overall E&P capital expense (capex) as being well above operating cash flows, an outcome of lower natural gas prices relative to stiff producer costs. Expectations are that, for smaller companies in particular, analysis of third and fourth quarters will show the pattern continuing.

**Figure 16: E&P Capex to Operating Cash Flow**



Source: Bernstein Research (used with permission)

Expectations are for consolidation in the domestic E&P segment to continue to pick up pace, through 2012 and perhaps beyond, as larger companies enter and expand shale oil and gas plays and mid- and small-sized companies combine. Consolidation reduces the population of players, reduces total spending, and results in a smaller amount of acreage under development as the domestic industry adjusts. Eventually, for the U.S. natural gas balance, less supply will be delivered to the market. As illustrated in Figure 1 at the outset, these conditions reverse when prices and profitability improve.

### 3.3 The decline curve debate and why it matters

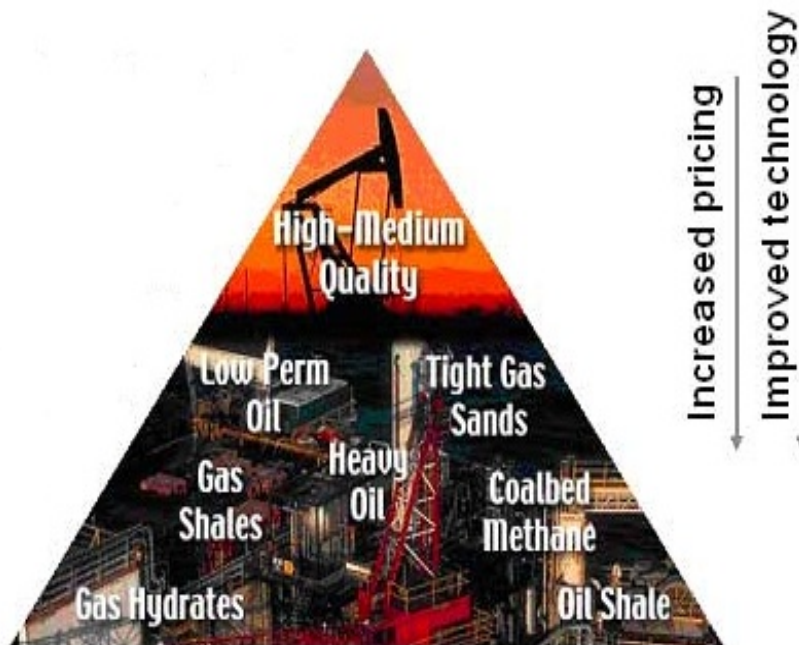
The “blogosphere” is replete with arguments, sometimes virulent, about sustainability of shale plays, particularly shale gas locations, whether producers book reserves properly, whether the emergence of shales means the end to either “peak oil” or “peak gas” theories, and what this all means for longer term supply outlooks. Decline curves – the drop in production that normally occurs once production is initiated – and their relative steepness for shales and other unconventional plays as opposed to conventional reservoirs are at the heart of the matter.

The supply curves represented in Figure 2 for the respective NPC studies are simply summations of individual production curves across thousands, perhaps ultimately millions, of

wells in fields scattered over many different sedimentary basins. As a collection of decline curves – the rate that production diminishes over the life of a well – aggregate supply curves disguise the vagaries inherent in individual reservoirs. Declines are sharper in more difficult and complex reservoir environments. The bane of unconventional resource plays is exactly the battle against declines; enough wells must be initially drilled to fully understand the resource potential in a play; rapidly declining production must be replaced with new drilling; wells may have to be re-treated (i.e., “re-fracked”) in order to sustain production, amortize the leasehold cost, and achieve an acceptable return. All of these put inordinate pressure on cost management. They also dictate cost difference across basins and plays, as noted previously (from the relatively low cost Barnett to high cost Haynesville, for instance).

The “resource pyramid” shown below captures the tradeoffs associated with exploiting unconventional hydrocarbon resources. The potential for large volumes is enormous, given that the earth’s crust is a very large bit of real estate. The unconventional resource plays dominate the mid- to bottom portion of the pyramid and embody higher costs, even with technology advances. Higher prices can provide the kinds of profit margins needed to attract investment capital. Absent higher prices, lower margins imply manageable strategies for higher production volumes with deep cost discipline. The need for scale, sometimes very large scale, quickly becomes evident, presenting many consequences. Whether the risks and uncertainties are public interest concerns on environment or producer concerns about deeper markets that can absorb huge tranches of supply, it is clear that corporate boardrooms and senior professionals and managers will be tested. Bottom line, this is the essence of the unconventional natural gas business as it stands today.

**Figure 17: The Hydrocarbon Resource Pyramid**



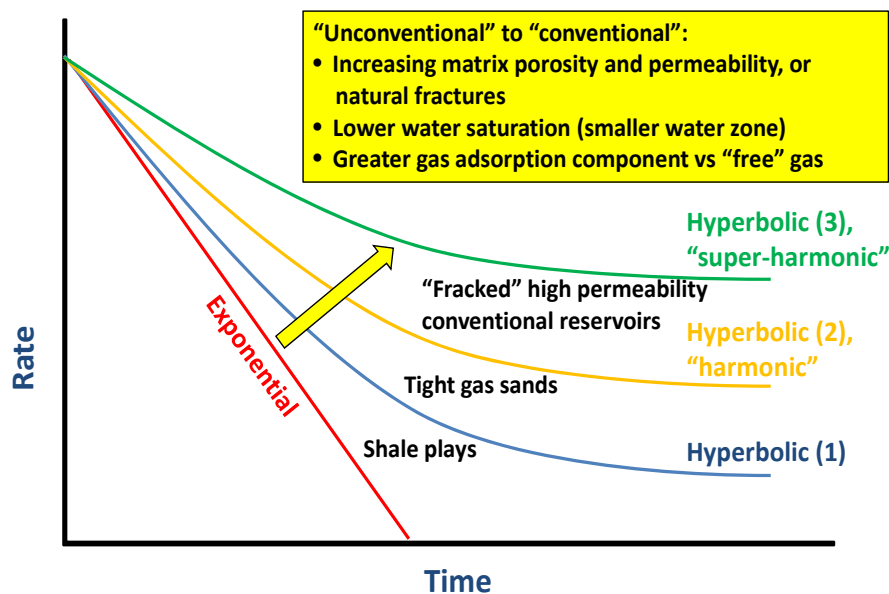
Source: From Stephen Holditch, 2005, “Statistical Correlations in Tight Gas Sands”, American Association of Petroleum Geologists (AAPG) Hedberg Conference Proceedings.<sup>41</sup>

<sup>41</sup> [http://www.searchanddiscovery.net/documents/abstracts/2005hedberg\\_vail/abstracts/extended/holditch01/holditch01.htm](http://www.searchanddiscovery.net/documents/abstracts/2005hedberg_vail/abstracts/extended/holditch01/holditch01.htm)

Depending upon locations and nature of the shale layers, decline rates (the rate at which production declines) can plunge as much as 85 to 90 percent after initial production.<sup>42</sup> For reserves estimation and production planning, the query is what decline rates can be expected. A simplified chart below (Figure 18) illustrates the much more complicated geo-engineering analysis entailed.<sup>43</sup> Wells that decline most quickly are those that must be replaced soonest with new drilling. Once wells are completed and fracked, producers typically hope to gain about five years of production before having to re-enter and re-frack wells. Wells that decline faster and need re-fracking sooner increase the overall cost curve for a location or play.<sup>44</sup> The simplified chart also indicates general differences between unconventional and conventional play concepts. As the prospective subsurface conditions progress to conventional plays, matrix porosity and permeability and/or natural fractures become more evident and traps and seals to retain hydrocarbons in place more critical (although as already indicated, these conditions also help ensure success for unconventional plays). Water zones for conventional plays become smaller and gas adsorption or “free” gas becomes more significant.

**Figure 18: Simplified Illustration of Shale Gas Decline Curves**

*Note: Initial rates set to common value for example only*



*Sources: Author’s compilation.*

<sup>42</sup> Examples are Louise Durham, “Haynesville Hangs In”, OilandGasInvestor.com, March 2011; Steve Toon, “Marcellus Momentum”, OilandGasInvestor.com, November 2010.

<sup>43</sup> Petroleum engineers are busily devising “type curves” that improve reserve estimation and production planning from unconventional resource plays. For a widely cited example, see Ilk, et.al, 2008b. For a user friendly overview of decline curve analysis, see <http://www.fekete.com/software/rta/media/webhelp/c-te-analysis.htm>.

<sup>44</sup> All based on comments from producers and service companies. Re-fracking is one of the more contentious points of debate about shale gas deliverability. One of the well known eclectic thinkers on global oil and gas resources believes that insufficient drilling and production has been done to fully understand unconventional resource productivity and compile forward projections of supply. The need to re-frack sooner rather than later and more often than expected is one of his major concerns.

In a nutshell, and mindful of exceptions, unconventional reservoirs operate at irreducible water saturation as opposed to long transition zones related to tight rocks in conventional traps. For example, a large, conventional offshore GOM reservoir will have much higher initial production rates than typical unconventional plays. Gas content held, or adsorption, is a function of pressure and depth tradeoffs, from low rates at shallow depth to higher rates in deeper zones. For successful unconventional production targets to be achieved, operators need to reduce reservoir pressure significantly to produce adsorbed gas used in gas-in-place (GIP) calculations.

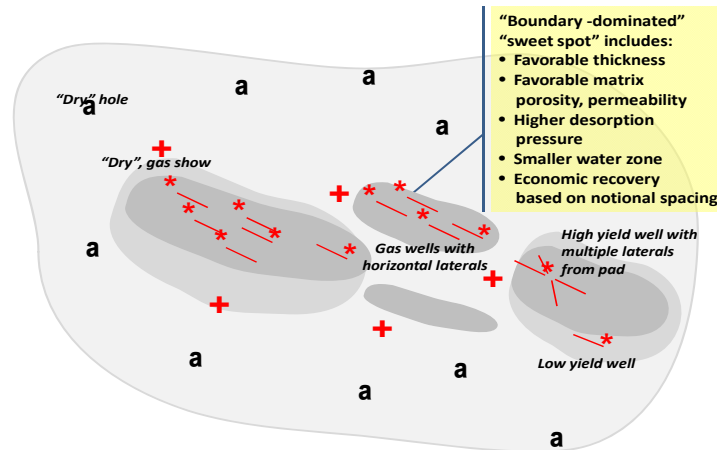
When it comes to hydraulic fracturing, producers often use a “balloon” analogy – the only production volumes that can be obtained are those that exist when the balloon is fully inflated. Thus the need to re-frack, or even to “rubbleize”, with more intensive fracturing and smaller spacing (“downspacing”) between well bores (in some instances, spacings of as little as 250 feet between laterals have been tested, in order to overcome the limitations of the balloon effect.

In pursuing unconventional plays, producers generally must beware of GIP indications that really are just transition zones that are non-commercial (one producer equates the ultimate test of the unconventional resource business to “mining gold in the ocean”). A key question in pursuing plays is how large the GIP estimates might be. A play may require dozens of wells for effective pilot testing and thousands of wells for optimal resource exploitation – ergo the capital cost impediments. Numerous risks and uncertainties must be quantified or otherwise evaluated, including aerial extent of accumulation, ultimate well spacing, and percent of play that ultimately can be developed. Recovery per well (estimated ultimate recovery or EUR) is based on analysis of wells already producing in a play or appropriate analog. This approach presents problems in early phases of pursuit. Downspacing can improve recovery efficiency (increase recovery factors) but result in lower recoveries per well. A distinct problem is one of interference, that reserves estimated for one location inflate those of proximal locations, leading to overstatement.<sup>45</sup> Figure 19 brings these features together to illustrate what a prospective boundary-dominated “sweet spot” might look like within a larger shale gas (or oil) basin geography. The dark gray areas represent “sweet spots”, locations where reservoir qualities are good enough for successful fracking and where EURs are high enough for commercial success. Sweet spots are basin centered, and tend to be influenced by geological factors like regional dip (hydrocarbons concentrate “up dip”), faulting, and presence of anticlines as well as matrix porosity and permeability that enable productive fracking.

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<sup>45</sup> All based on input from professional engineers at recent Society of Petroleum Engineers (SPE) unconventional gas and reserves estimations events.

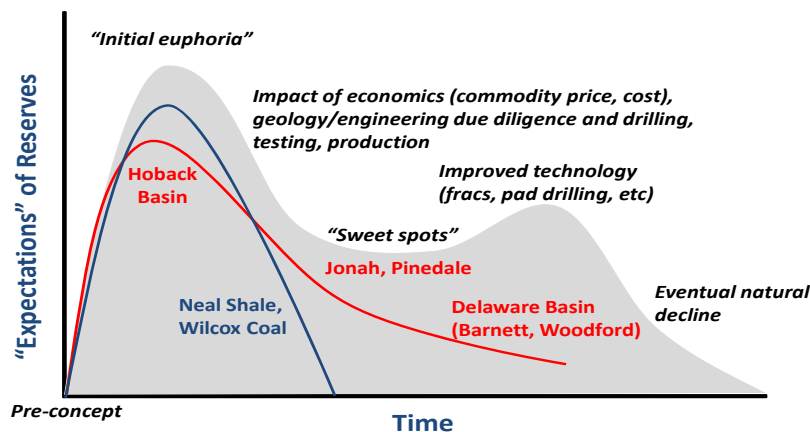
**Figure 19: Simplified Illustration of Boundary-Dominated Unconventional “Sweet Spot”**



Sources: Author’s compilation.

The competitiveness, capital demands, technology requirements, and other aspects of the drive to enter and succeed in frontier plays, like shale gas and other unconventional resource opportunities, leads to a typical pathway for oil and gas extraction. Early results and excitement create initial euphoria. The first waves of production inevitably depress prices (as illustrated in the previous natural gas price eras chart, Figure 4) while, at the same time, “reality checks” associated with geoscience and engineering information, drilling, and testing began to impact results. Eventually, producers coalesce around the “sweet spots” as described above. Importantly, improved technology in sweet spot locations leads to production results that typically exceed early estimates *for those locations*. Natural declines then set in. Also typically, fields produce over longer time frames than expected. Notable examples of this pathway analysis are the Hoback Basin and the Jonah/Pinedale fields in the Rocky Mountains and the Delaware Basin and Barnett fields in Texas (Figure 20). The Neal Shale and Wilcox Coal are examples of plays that did not survive the full test of commerciality.

**Figure 20: Typical Oil and Gas Frontier Play Pathway**



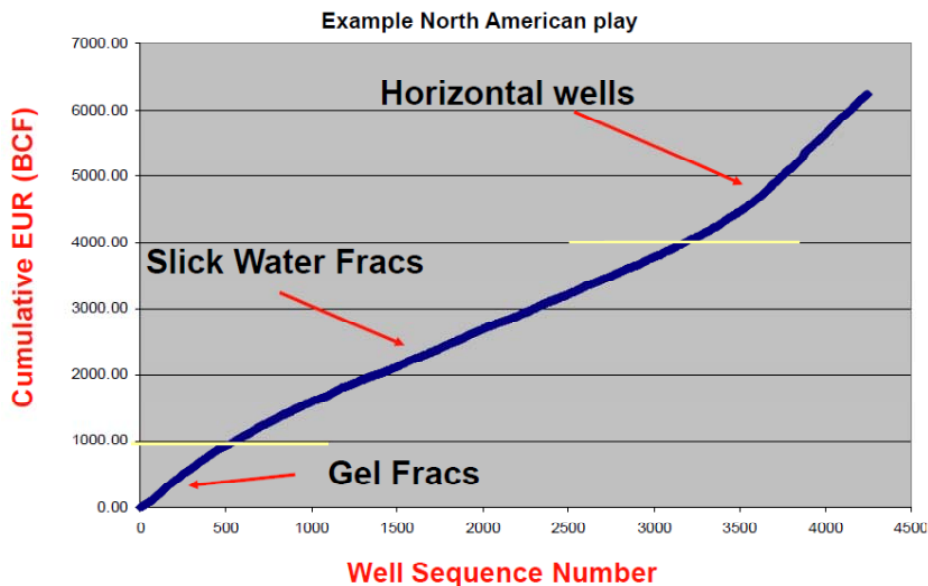
Sources: Author’s compilation.



Given the general depiction of industry-wide play trends presented in this paper, the challenge is building the risk/reward case for investors while making appropriate representations about the probability of success. Reserves may be assigned (or not!) as geologic/engineering due diligence actions proceed and plays are tested. The Hoback Basin is an example of gas saturation but with insufficient measures to be commercial. The only successful portion of the area is Jonah. In that field (a significant development in any case), downspacing to 20 acres between wells was taken to achieve optimal production. With better fracking technology, better proppants (the materials included in frack compositions to keep fractures open and, especially, proppants for micro or even “nano” fractures), and so on producers in fields like Jonah are able to get more out of the sweet spots than thought initially. The result is higher cumulative EUR and attractive play economics for the respective fields. Overall, play concepts emerge, are tested, and reach varying stages of success or abandonment. The U.S. recoverable resource estimate of roughly 1,600 TCF rolls forward continuously as the industry cycles through plays. But companies have to work harder to sustain prospective recoverable resources. The challenge of a more expensive supply curve is whether it shifts inward, as one would expect, or outward over time. Aggregate behavior will depend upon commodity price, availability of substitutes, and other demand side responses. If prices during periods of supply build are low enough for long enough, at some point prospective recoverable resources cannot be classified as such.

As the unconventional resource play story has unfolded, the ability to deliver increasing volumes with technology applications has had the most profound effect on expectations. Figure 21 below shows the impressive progression of EURs as the industry moved from gel fracks to slick water fracks (with the addition of chemicals to reduce friction and enhance fluid flow), and then coupled fracking with horizontal drilling. In all, the combination of technologies and improvements in technology enabled commerciality in shales and other tight rock plays to be achieved.

**Figure 21: Historical Technology Applications**

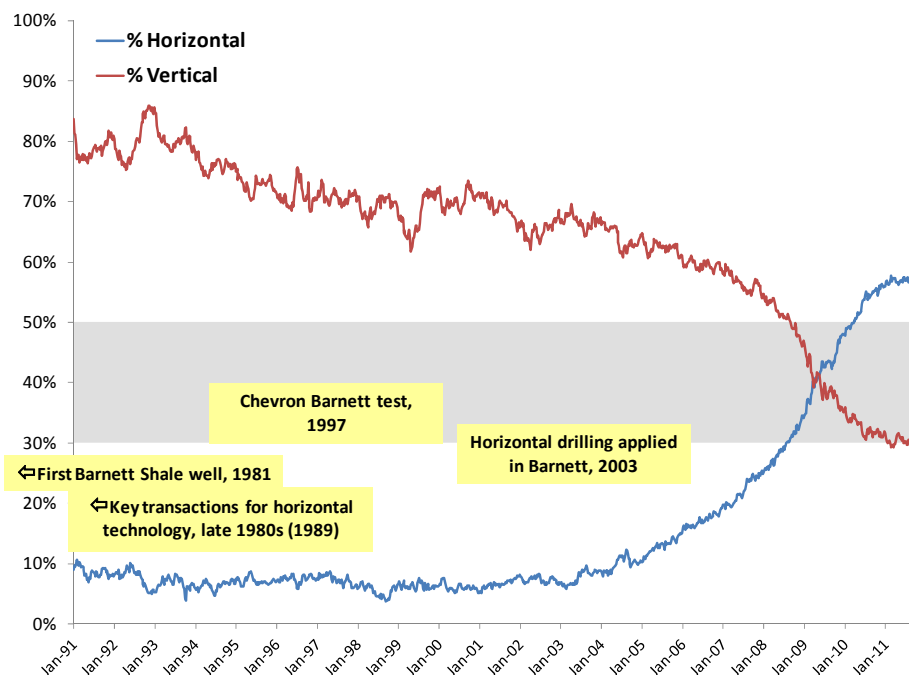


Source: Brown, 2011 based on de Jong, 2007 (unpublished)<sup>46</sup>

<sup>46</sup> As presented by Jeff Brown in *Estimating Prospective Resources in Unconventional Plays*, SPE/AAPG/SPEE Reserves and Resources Estimation and Reporting Symposium, July 2011, Houston. Used with permission.

Technology adaptation takes time. The accomplishments captured in the preceding chart unfolded over roughly two decades of diligent experimentation in the face of strenuous business cycles and conditions. As described earlier, the first, vertical, Barnett wells were drilled in the early 1980s. The first major transactions (mergers and acquisitions) related to horizontal technology occurred in the late 1980s. Directional drilling had been a feature of industry operations for many years before the initial deployment of horizontal drilling tools that enabled full 45 degree turns, measurement while drilling (ability to collect real time information from the subsurface), and geosteering. It was not until 2003 that horizontal drilling was used in the Barnett. In 2008, horizontal drilling comprised 30 percent of the North American market. Horizontal drilling now constitutes the majority of both oil and gas wells drilled in Canada and the U.S., some 30 years later.

**Figure 22: Timing of Horizontal Drilling Market Penetration**

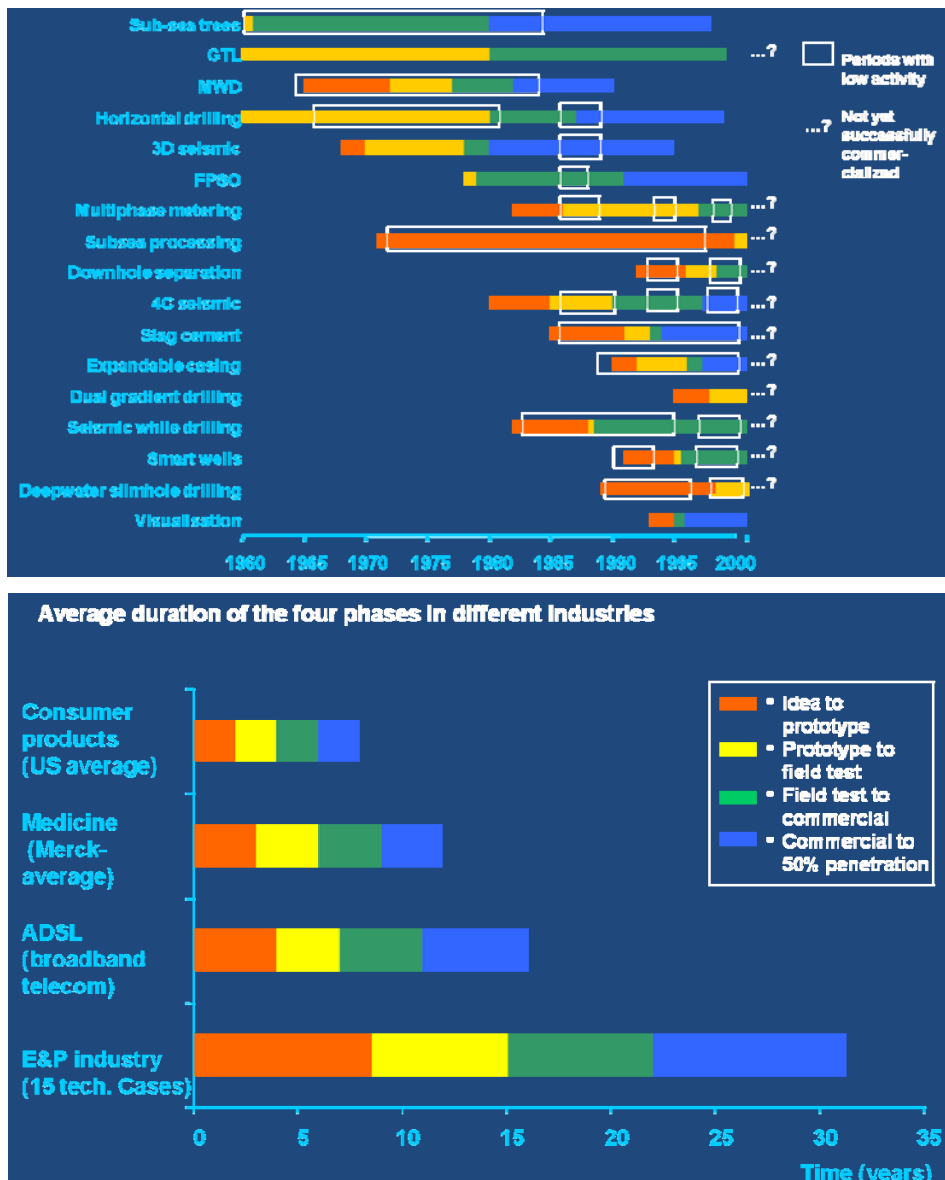


Sources: Baker Hughes and author's records.<sup>47</sup>

For perspective on the history of horizontal drilling application, two views on technology adaptation in the oil and gas industry are provided in Figure 23. View A shows business activity context for comparative stages of development of advanced oil and gas industry technology. View B stacks up oil and gas E&P innovation against other industries.

<sup>47</sup> The author worked on the seminal Baker Hughes 1990 acquisition of Eastman Christensen, which had developed a prototype tool for horizontal drilling and for which Simmons & Company International was advisor to Baker Hughes (SCI also advised Baker International on the merger with Hughes Tool).

**Figure 23: A. Oil and Gas E&P Innovations, Stages and Business Activity (top)  
 B. Oil and Gas E&P Innovations Compared to Other Industries (bottom)**



Source: McKinsey & Company for Shell, 2001 (adapted for NPC 2007 Global Oil & Gas Study).

For people in an industry characterized by long lead times and enormous capital commitments for research, development, and deployment, the application of advanced technologies to yield hydrocarbons from complicated reservoir environments is nothing short of miraculous. This makes public complaints about drilling safety difficult for industry professionals to comprehend and exacerbates the “perception gap” between these professionals, who believe deeply in the economic benefits being created, and their greater audiences, even including civic leaders. That perception gap, however, threatens to add to the financial and business complexities already inherent in the shale gas and other unconventional resource plays and could undermine ultimate success. This would be to the detriment not only of industry players but to the U.S. and, given the worldwide interest in shale plays, other countries as well.

The array of challenges to be met as well as accomplishments is highlighted by the following, which embellish on summary points in the beginning of this paper. “Green well completions” has become the new mantra for the industry. Technology improvements to protect people and the environment are important. The cost and time required for adoption must be borne in mind when building longer term outlooks. Increasing time required to process permits for drilling also increases “cycle time”, increases drilling costs, and delays responsiveness when supply and demand balances are tight.

- A single Eagle Ford well in Texas can require more than 10 million gallons of water to frack.<sup>48</sup> While water use for fracking may pale in comparison to other uses, in particular non-industry uses, water supplies and drinking water safety are some of the more sensitive issues. An estimated 35.8 thousand acre feet (AF) of water was used for fracking in Texas, mainly in the Barnett, in 2008, the most recent data available. This comprised about 63 percent of total water use in oil and gas drilling. Total oil and gas water use for all purposes and throughout the state could reach a peak of more than 150 thousand AF by 2020 and then tail off. This would account for about half of all water use in Texas.<sup>49</sup> To combat both public and regulatory concerns as well as to reduce costs, producers are experimenting with a broad array of water management approaches, ranging from recycling produced water (both water from fracking and water that resides in shale formations) to replacing the “hydraulic” in fracturing with other, non-water media (liquid petroleum gases, LPG, mainly propane or a propane and butane mix are gaining interest).
- Adjustments are not cheap. Fracking regulations could add \$500,000 to the cost of a well,<sup>50</sup> perhaps more if both state and federal actions prevail. Operators argue, rightfully so, that sound well completions using best practices will not communicate with drinking water aquifers. Persistent complaints from citizens along with high profile news coverage and attempts to appraise water well contamination have only added to confusion about what the risks and probabilities of well completion failure might be. In any case, the U.S. EPA launched a frack study to investigate and explore potential oversight, but the announced study plan already has drawn industry criticism.<sup>51</sup> EPA has also proposed to regulate disposal of water that returns to the surface from hydraulic fracturing and that is produced with hydrocarbons, another area of controversy. In many locations, water is reinjected. In other areas, where subsurface geology is not conducive to reinjection, municipal wastewater systems are used. Wide acknowledgement exists that many municipal systems are not capable of handling chemicals, metals and other substances that can be present in water discharge from oil and gas wells.<sup>52</sup>
- During the 2010-2011 legislative session, Texas enacted House Bill 3328 for disclosure of the composition of hydraulic fracturing fluids. The bill enjoyed broad, albeit not complete,<sup>53</sup> industry support. Environmental Defense Fund took a leadership role in

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<sup>48</sup> Adam Connors and Carl Goltermann, “2011: So Far, So Good”, *OilandGasInvestor.com*, August 2011.

<sup>49</sup> Nicot, et.al., 2011.

<sup>50</sup> Susan Klann, “Tudor, Pickering Fracing Regs Could Hike Well Costs by \$500,000”, *OilandGasInvestor.com*, August 1, 2010.

<sup>51</sup> <http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/index.cfm>. For an example of industry response, see the letter submitted to EPA by the American Petroleum Institute, <http://www.api.org/Newsroom/api-responds-to-epa.cfm>.

<sup>52</sup> See, for instance, “Environmental Protection Agency announces plans to regulate water from fracking” by Neela Banerjee, *Los Angeles Times*, October 21, 2011, <http://articles.latimes.com/2011/oct/21/nation/la-na-frack-water-20111021>.

<sup>53</sup> The bill was not supported by service companies, which remain concerned about protecting proprietary intellectual property.

helping to develop the proposed legislation.<sup>54</sup> The bill incorporates use of a public registry for chemical disclosure developed by the Groundwater Protection Council, Interstate Oil and Gas Commission, and industry.<sup>55</sup> The Texas bill has emerged as a model for other states. The goal is to achieve more proactive measures and attain some control over potential regulatory compliance costs.

- Air emissions during drilling operations also have become an irritant. Drilling rigs run diesel generators. Heavy supply and service trucks not only add to local traffic and noise but contribute tailpipe pollutants. But harder to address are methane emissions during well testing and other operations. The EPA has proposed rules including a requirement that producers capture methane during “flowback” operations whenever possible, which the agency views to be of benefit to companies and the industry.<sup>56</sup> EPA’s air quality rules have become highly politicized, and the oil and gas rules have been delayed several times, in keeping with general conflict and tension over the agency’s actions on smog.<sup>57</sup> The lag between associated gas production in active, liquids rich locations and building infrastructure to capture and deliver that gas to the market means, in many instances, gas flaring. Concern about flaring has grown in Texas (Eagle Ford), North Dakota (Bakken) and other places where few or no options exist for handling associated gas production.<sup>58</sup>
- In all of this, industry is tackling how to achieve “real time delivery”, which mainly resides in the backlog of wells drilled by producers as they worked to sustain leases (leases typically require drilling activity and most leases are “held by production”). For example, the Barnett led unconventional well completions in the U.S. for the early part of 2011 even though rig counts have dropped substantially since the heyday.<sup>59</sup> The buildup of backlog largely was an outcome of the huge rush to lease under highly competitive conditions and the obligations leases require. Whether producers would have the same incentives to drill and defer completions in the future is unclear. Likewise, the rush to lease has its own, potentially serious, risks. A ruling by Pennsylvania’s Superior Court has raised questions about the validity of oil and gas leases taken in that state for shale gas development. Unlike other states, Pennsylvania’s oil and gas laws have never been updated to reflect mineral ownership of unconventional resources. In previous disputes, for example, leases were abandoned when oil and gas operators could not legally defend separate title to natural gas associated with coal seams.<sup>60</sup> Similar questions have been raised regarding oil and gas present in shales. In addition, some states like Pennsylvania do not have clear laws on separation of ownership of subsurface minerals and surface

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<sup>54</sup> See *What the World Can Learn from Texas About Frac Chemical Disclosure* by Scott Anderson, May 2011, <http://blogs.edf.org/energyexchange/2011/05/12/what-can-the-world-learn-from-texas-about-frac-chemical-disclosure/>.

<sup>55</sup> <http://fracfocus.org/>.

<sup>56</sup> <http://www.epa.gov/airquality/oilandgas/> and <http://www.epa.gov/airquality/oilandgas/pdfs/20110728factsheet.pdf>.

<sup>57</sup> See, for instance, “EPA delays rules on fracking emissions by a month”, *Reuters*, October 26, 2011 (the third postponement of rulemaking), <http://www.reuters.com/article/2011/10/26/us-usa-epa-emissions-idUSTRE79P5NY20111026>, and “Democrats block bill to delay clean air rules”, *Reuters*, November 3, 2011, on EPA’s overall air quality rulemaking, <http://www.reuters.com/article/2011/11/03/us-usa-epa-senate-idUSTRE7A287720111103>. Republicans and some Democrats along with industry and many state and municipal leaders complain that stiffer smog rules will impact industry and jobs.

<sup>58</sup> See “In North Dakota, Flames of Wasted Natural Gas Light the Prairie”, by Clifford Krauss, *New York Times*, September 26, 2011, [http://www.nytimes.com/2011/09/27/business/energy-environment/in-north-dakota-wasted-natural-gas-flickers-against-the-sky.html?\\_r=1&scp=1&sq=In%20North%20Dakota.%20Flames%20of%20Wasted%20Natural&st=cse](http://www.nytimes.com/2011/09/27/business/energy-environment/in-north-dakota-wasted-natural-gas-flickers-against-the-sky.html?_r=1&scp=1&sq=In%20North%20Dakota.%20Flames%20of%20Wasted%20Natural&st=cse).

<sup>59</sup> Peggy Williams, “E&P Momentum”, *OilandGasInvestor.com*, June 2011.

<sup>60</sup> See “Why gas bonanza is no boon to landowners,” by Don Hopey, *Pittsburgh Post-Gazette*, April 29, 2007, <http://www.post-gazette.com/pg/07119/781909-85.stm>.

land ownership.<sup>61</sup> In a worst case scenario, affected companies would lose all rights resulting in untold losses in assets and reserves downgrades.<sup>62</sup>

- The impact of large companies entering unconventional plays, especially given operating, financial, legal, and regulatory intricacies has injected much needed liquidity into the domestic industry.<sup>63</sup> On the downside are the higher overall cost structures that the larger integrated companies tend to carry, and discussed above in Section 3.2. Also, a question could be raised as to whether major companies might be lightning rods on environment. It is more typical for blame to follow smaller companies and independents, but liability tends to follow large, publicly traded international oil companies (IOCs). Major companies with high profile boards, open shareholder meetings, and greater visibility in the public mindset could generate increased exposure to risk related to “above ground” factors like environment and community disputes for their investors.<sup>64</sup> A contrary question could also be asked: are large companies needed? Speculation has been rife that, following the Macondo oil spill, only the largest companies can handle the steeper environmental protection costs and scrutiny related to the exploration and production segment.<sup>65</sup> Underlying these musings are the high capital cost, high volume-low margin business model drivers already discussed (and described as equivalent to “utility returns”<sup>66</sup>). Investors appreciate the dividends paid by integrated oil companies but also look for growth, increasingly difficult for IOCs given the lack of access to attractive oil and gas volumes around the world. The popular theory is that their return to North American unconventional plays is primarily a search for volumes. The industry has certainly cycled many times before as larger companies lose interest in, and stomach for, higher cost U.S. plays. Regulatory uncertainty, minerals ownership uncertainty, price fluctuations – these and more could work to slow needed consolidation.<sup>67</sup>

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<sup>61</sup> In contrast, Louisiana’s mineral ownership laws are unique in providing clear reversion back to the surface owner if no mineral exploitation activity has taken place within ten years. See, for example, <http://www.haynesvilleshalelandowners.org/hsla/view/faqs>.

<sup>62</sup> Jim Polson and Mike Lee, “Marcellus Gas Producers Face Potential ‘Chaos’ in Pennsylvania Legal Ruling”, *Bloomberg*, September 23, 2011. The ruling was made on September 7 and has received wide coverage. <http://www.superior.court.state.pa.us/opin.htm>

<sup>63</sup> Art Berman, one of the leading questioners on the shale gas revolution, termed the “surprising appetite for joint ventures and acquisitions” in the shale gas plays a possible “stabilizing effect on the distress scenario” of sharp decline curves and low prices and attendant loss of confidence and capital availability. Arthur Berman and Lynn Pittinger, “U.S. Shale Gas: Less Abundance, Higher Cost”, *TheOilDrum.com*, August 5, 2011. <http://www.theoil Drum.com/node/8212>

<sup>64</sup> Sheila McNulty, “Investors demand clarity on shale gas”, *Financial Times*, May 25, 2011. In her reporting, Ms. McNulty cites shareholder votes for transparency on shale gas production of more than 28 percent for ExxonMobil and 41 percent for Chevron at their recent annual meetings.

<sup>65</sup> See articles cited in footnote 66 below.

<sup>66</sup> Sylvia Pfeifer, “Integrated Majors Need to Reinvent Themselves”, *Financial Times Energy Report*, November 2010. Ms. Pfeifer includes a quote from an “industry watcher”: “The big oil companies have become almost like giant utilities” with respect to the very low returns of 10 percent, second to last among the sectors reported in the article and based on data from PFC Energy.

<sup>67</sup> See Steve Toon, “Deal of the Year: Making the Elephant Dance”, *OilandGasInvestor.com*, August 1, 2010 on the ExxonMobil acquisition of XTO (Crossttimbers). Jack Randall of Randall and Dewey, a reserves certification consultancy, is quoted as saying, “The shales were a game-changer but they are capital intensive to exploit”. Analysis of the 2009 acquisition credits capital intensity, technical requirements, depressed gas prices as challenging the XTO growth company design and limiting value added possibilities as drivers for the transaction. Following the merger, ExxonMobil’s worldwide total acreage in unconventional plays topped eight million. Regarding business models: “There appears to be a dichotomy between corporate managements’ strategies and the investment community’s expectations regarding North American natural gas. The former seem focused on long-term production growth, while the latter is more concerned with near-term return on capital employed and free cash flow.” Tamar Essner, “Capital Flows Back to Gas”, *OilandGasInvestor.com*, January 2011.

- Finally, the search for solutions on all fronts has recharged research,<sup>68</sup> a positive development that other countries should enjoy as well.

### 3.4 *Thoughts on conventional production – Gulf of Mexico (GOM)*

Whither the conventional plays, those at the top of the hypothetical, simplified decline curve in Figure 18? It is widely known, and discussed, that many conventional dry gas plays with attendant exploration risk will not attract investors in the current low price environment (notwithstanding the development risk associated with unconventional plays, as lined out in the previous section). From Figure 9, about 70 percent of 2010 U.S. dry gas production comes from conventional reservoirs; about 14 percent of conventional reservoir production comes from the Gulf of Mexico OCS. The sharp drop in gas directed drilling noted in

Figure 11 encompasses not only shale gas plays but also conventional prospects. The main target for discussion is offshore Gulf of Mexico, which fell from a 27 percent share of total U.S. dry gas production in 1997 to 9 percent by 2010 (

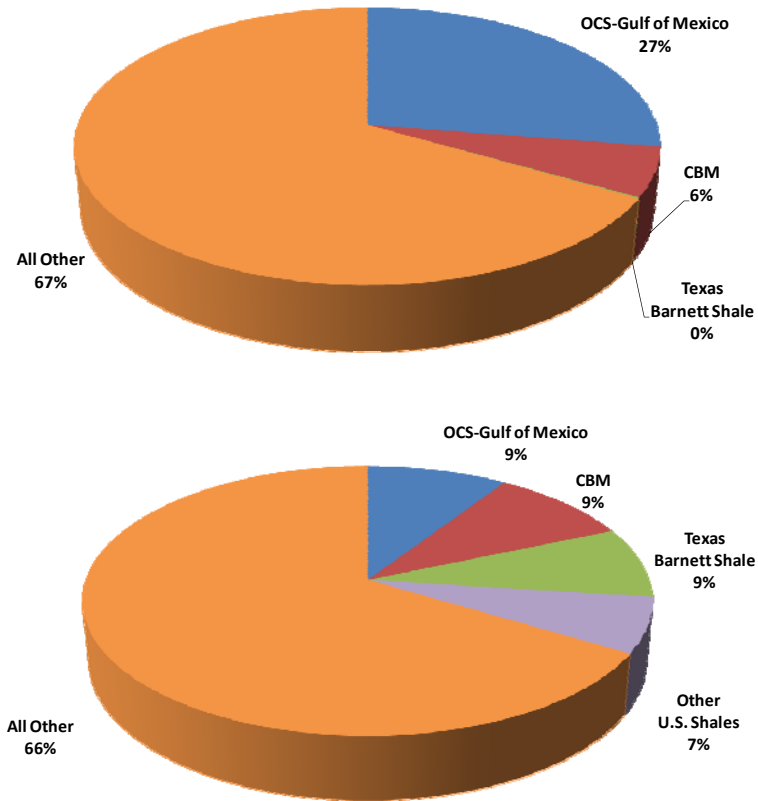
Figure 24) and could drop further. Gas production from the overall Federal OCS (including Pacific and Alaska) has dropped more than 3 TCF over the same period (Figure 25). GOM oil represents 96 percent of U.S. OCS total production (including the Gulf, Pacific and Alaska), and GOM natural gas 98 percent of the total. Thus, any attention to the health of U.S. offshore production centers on GOM activity given that region's dominance as a producing bloc. In describing Figure 18 I make the point that GOM reservoirs are typically high yield conventional fields; production rates are such that drilling needs to happen to replace produced reserves. Amid the debate about how best to proceed post-Macondo and whether or not the GOM is returning to a semblance of normal industry activity, major discoveries have been made, pushing the number of super giant, one billion barrel recoverable oil fields to four.<sup>69</sup>

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<sup>68</sup> In addition to references mentioned in this paper, see the University of Texas Bureau of Economic Geology unconventional resources web site, <http://www.beg.utexas.edu/resprog/unconv.php> and <http://www.cpge.utexas.edu/nge/> for UT's Petroleum and Geosystems Engineering unconventional natural gas research. Examples of other major university programs contributing to unconventional resource research are: Texas A&M University's Global Petroleum Research Institute, <http://www.pe.tamu.edu/gpri-new/home/index.htm>; Penn State engineering, <http://www.pnge.psu.edu/>, Marcellus outreach <http://www.marcellus.psu.edu/> including <http://extension.psu.edu/naturalgas> and <http://www.msetc.org/>; Potential Gas Agency at Colorado School of Mines, <http://www.potentialgas.org/> and <http://www.mines.edu/Potential-Gas-Committee-reports-unprecedented-increase-in-magnitude-of-U.S.-natural-gas-resource-base> which serves as the main clearinghouse for industry, government, and research collaboration on U.S. natural gas resource assessments.

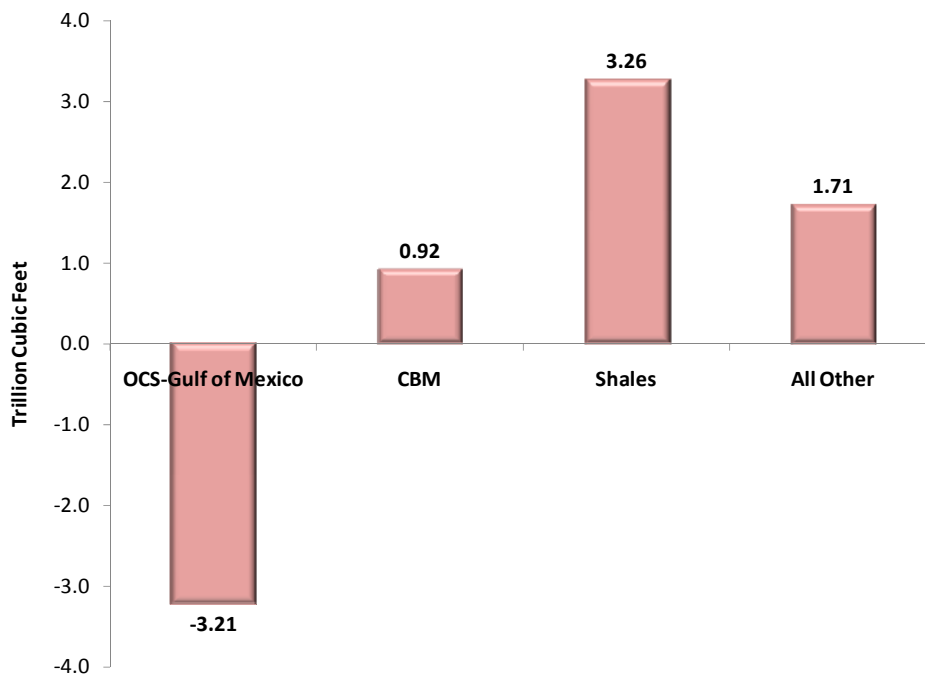
<sup>69</sup> Russell Gold, "Oil Drilling Rebounds in Gulf After Spill", *Wall Street Journal*, September 15, 2011 provides a generally optimistic take. See Letters, September 22, 2011 for a rejoinder by Representative Jeff Landry of Louisiana. Rep. Landry writes that deepwater permits are running 39 percent below monthly for the past three years and shallow water permits 80 percent lower than historical averages.

**Figure 24: 1997 (top) and 2010 Shares of U.S. Dry Natural Gas Production**



Source: estimated and compiled by author using data from U.S. EIA and BOEMRE.

**Figure 25: Change in U.S. Natural Gas Production by Source, 1997-2010**

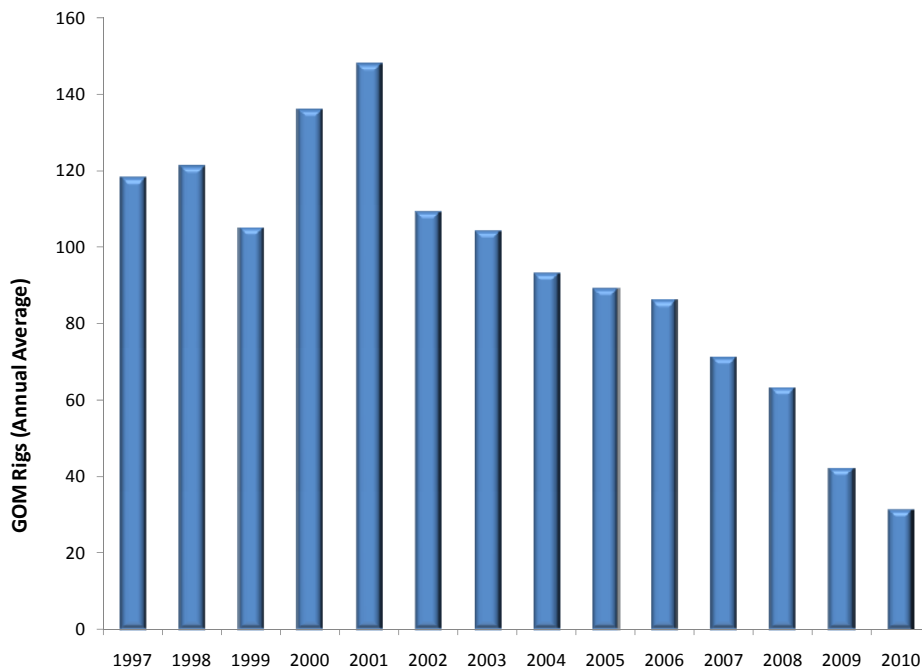


Source: estimated and compiled by author using data from U.S. EIA and BOEMRE.



The future indicators for OCS production deliveries are not heartening, but rig activity has, in fact, been falling for some time, largely because of cost, complexity, and competing opportunities. In addition, as companies have pushed into deeper waters, fewer rigs will run as a matter of course. Unlike shale plays, correlations of rigs to production are inconsequential in the case of oil (10 percent), and but more important for natural gas (49 percent).

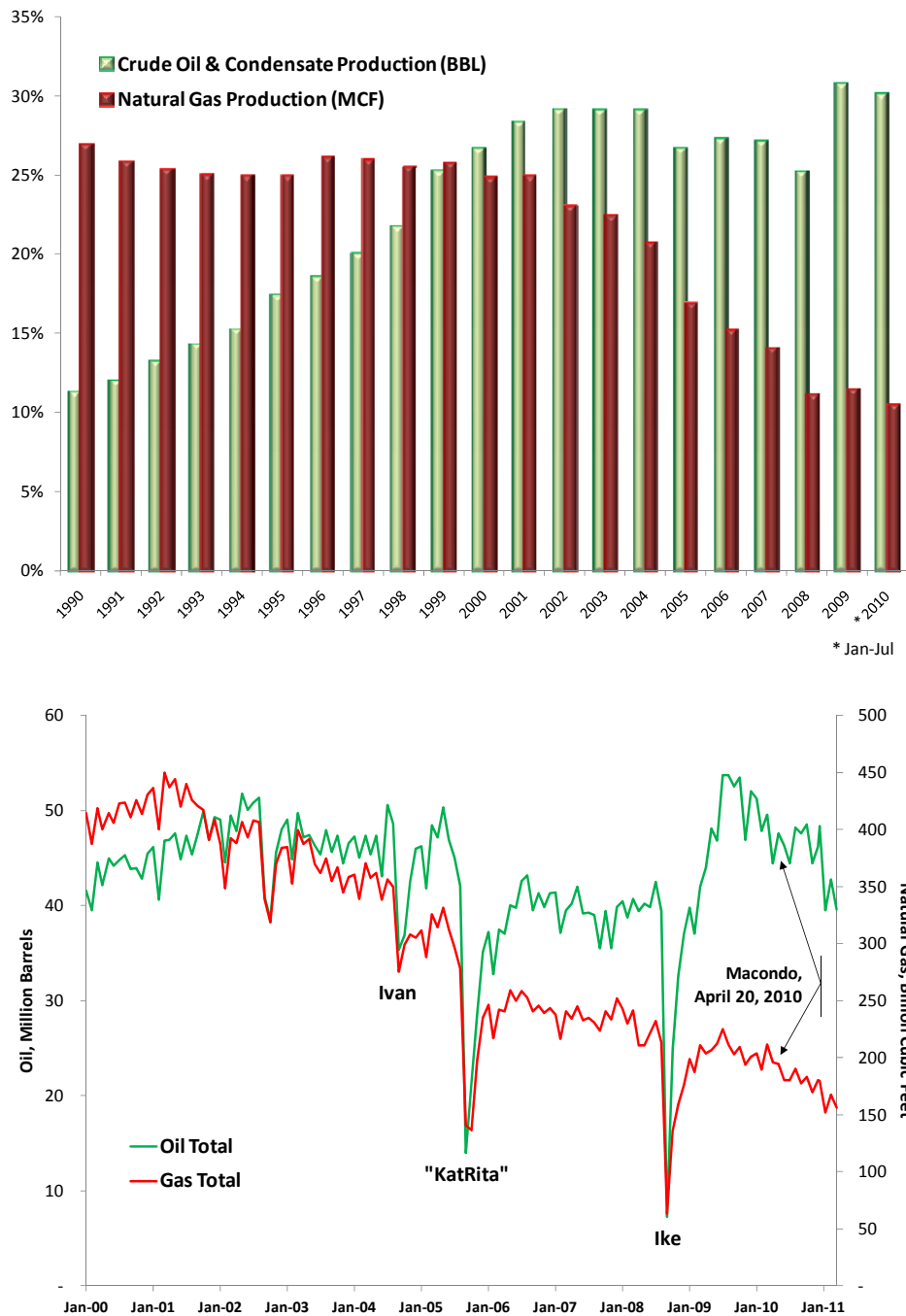
**Figure 26: GOM OCS Rig Activity**



Sources: Baker Hughes

The already mentioned “oil proneness” of the GOM OCS is shown in the charts below. More gas is found through deeper drilling in shallower waters where subsea pipelines and facilities are easier to attain. In 2010, the 6 TCF Davy Jones discovery ushered in what many thought might be a new era of ultra-deep, below salt Gulf shelf drilling.

**Figure 27: OCS Production as Share of Total U.S. in Percent (top) and Actual Volumes (bottom)**



Source: U.S. BOEMRE

Many view hurricane risk to be a strike against offshore natural gas deliveries, and indeed, as shown earlier in Figure 5, and more closely in Figure 27 above, hurricane events can exert sharp disruptions. Yet, offshore regions in North America and worldwide offer some of the most alluring prospects for high impact, material reserves and production rates with conventional reservoir features. It is difficult to argue that these integral components of supply portfolio diversity should not be pursued.

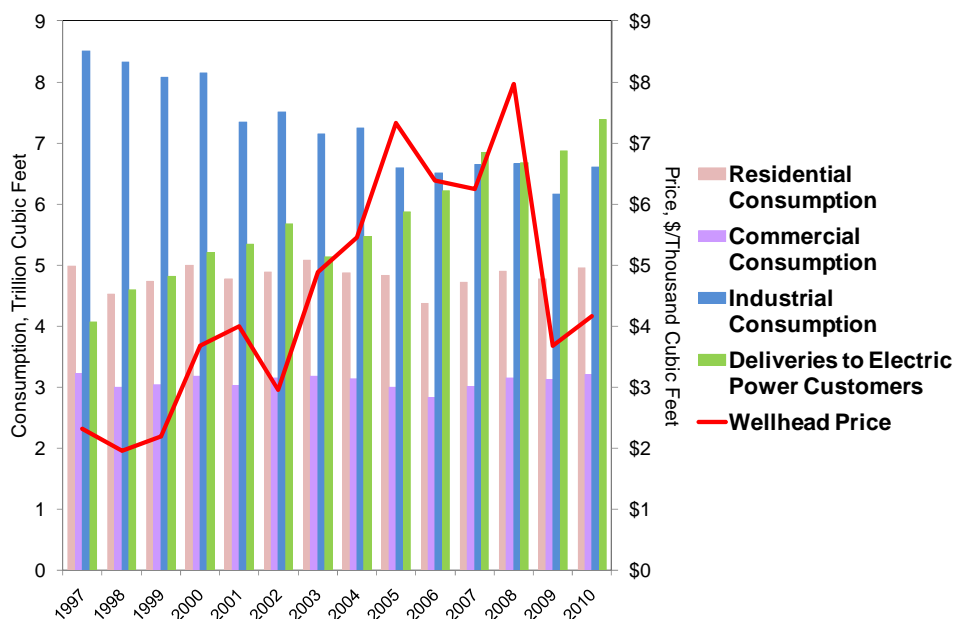
## 4 Demand side drivers, storage, and other midstream infrastructure

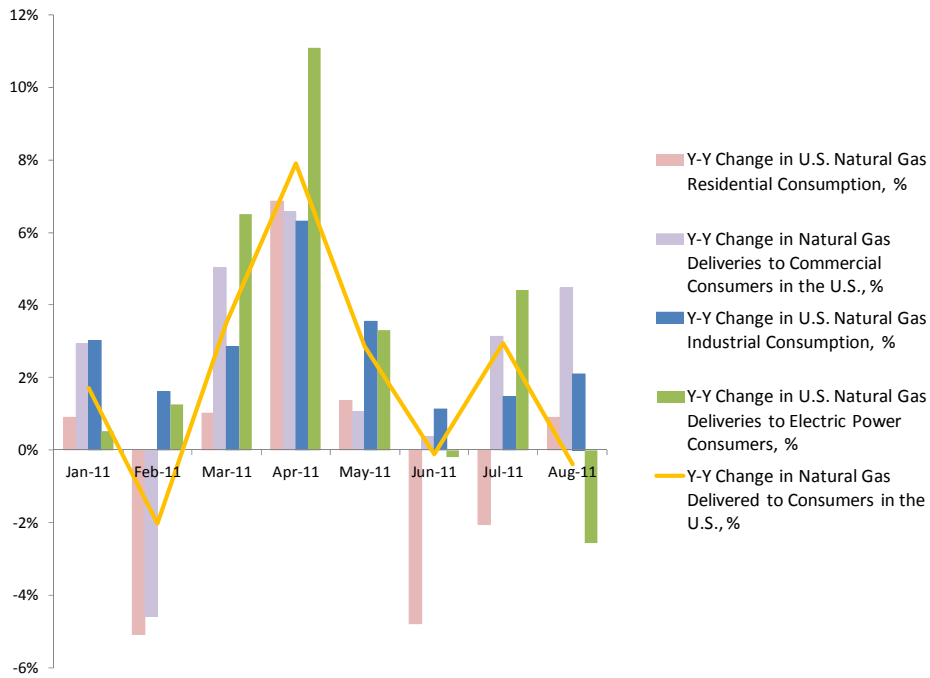
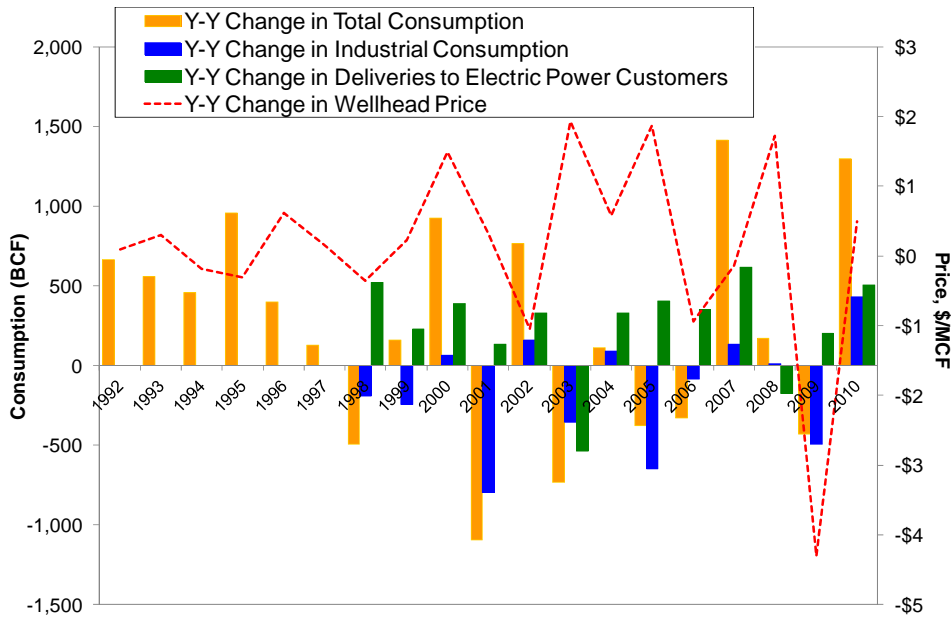
### 4.1 Searching for sustainable demand

To round out discussion toward 2020 views, I revisit the detailed analysis of demand from NG 18 with targeted updates along two main lines – the potential shift in the role of industrial use as companies move to take advantage of abundant NGLs, and the effect of renewables as the new, upper boundary for natural gas prices in the power sector. It is useful to look back to Figure 3 and observe that U.S. natural gas consumption in 2010 increased only incrementally above the 1970s peak. The long history of experience is a testament to the challenge of building demand growth over the past 40 some years. Certainly the future could be different; indeed, fundamentally, this is what the industry hopes to change. It will not be easy.

Figure 28 provides three looks at U.S. natural gas demand, with annual data, annual change, and year-year change for the 2011 monthly data thus far. Consumption in 2010 was not unreasonable, given overall economic conditions and uncertainties, and consumers and customers have benefitted considerably from lower natural gas prices and attendant cost savings. But demand has not been able to keep up with current levels of production and storage. Following NG 18, and as expected, natural gas deliveries to electric power generators now exceed those to industrial facilities, topping 50 percent during 2011. Across months, the pattern of industrial relative to electric power deliveries varies somewhat depending upon seasonal effects, but the general long term trend appears to be well established. Moreover, gas deliveries for power are less sensitive to price, a point raised in NG 18 and to which I return below. Of concern is the lack of growth in new electric power load, which translates into fierce competition among generation fuels and technologies for a static pie. Moreover, economic dislocation has impacted the bottom lines of power utilities, complicating responses to regulatory constraints that would hasten the retirement of older coal generation units, creating more room for natural gas at the electric power burnertip.

**Figure 28: U.S. Demand for Natural Gas by End User**  
(top, total annual; middle, annual change; bottom, Y-Y change in 2011 monthly)

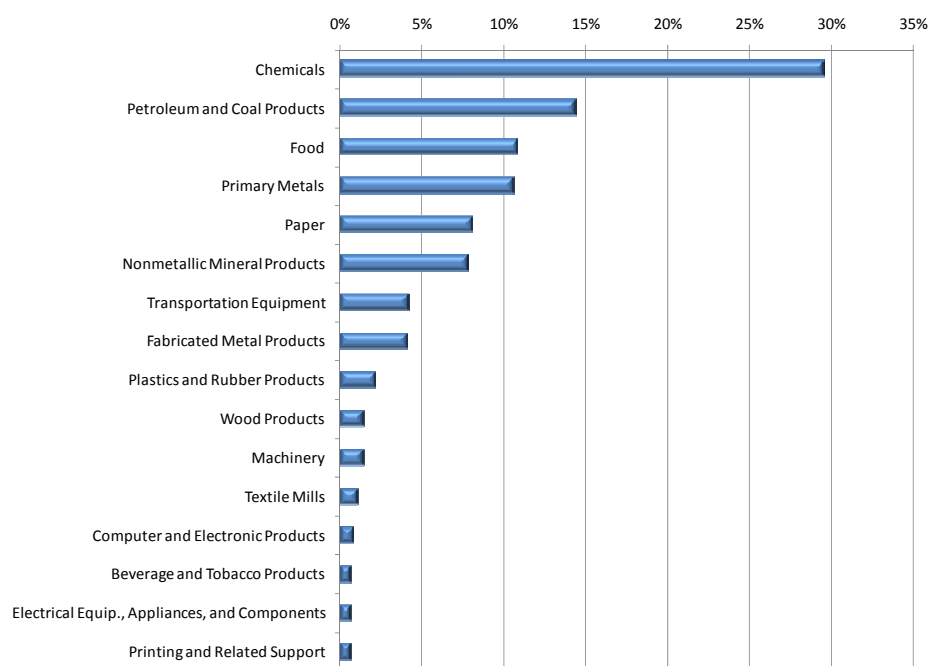




Source: analysis based on U.S. EIA data

Looking first at industrial load, natural gas is used at industrial facilities for fuel, as raw material feedstocks, and for power generation for both self use and external sales. Refining, petrochemical, and chemical end users comprise the dominant share of industrial natural gas consumption, historically and to the present. Petroleum refining alone accounts for more than one-third of industrial natural gas use.

**Figure 29: 2006 Natural Gas Use as Percent Industrial Energy Demand**



Source: based on EIA's 2006 Manufacturing Energy Consumption Survey (MECS)<sup>70</sup>

As noted at the outset of this paper, industrial demand for energy has largely been marked by the strong forces that have buffeted manufacturing in the U.S. for decades. Since NG 18, a marked change comes from the idea that natural gas abundance, and especially NGLs abundance, might help revitalize some of the industrial base. Building industrial demand for NGLs has caused some to term this the “liquids prize”. There is a widespread view that “the ethane-to-market opportunity is not fully monetized” and that conversion of NGLs to plastics and higher value products could attract significant interest. With ethane costing about 46 percent of crude oil, a flurry of announcements has been made. Greenfield petrochemicals facilities for ethylene are being proposed and discussed, as well as expansions to existing facilities along the Gulf Coast. Transportation options for NGLs are being raised in tandem. A “Marcellus to Manufacturing” task force has been constructed. Along with these developments are new steel facilities to support industrial growth as well as oil and gas drilling needs, and new manufacturing for hydraulic fracturing inputs, including development of new materials to meet the aforementioned growing preference for “green completions”.<sup>71</sup>

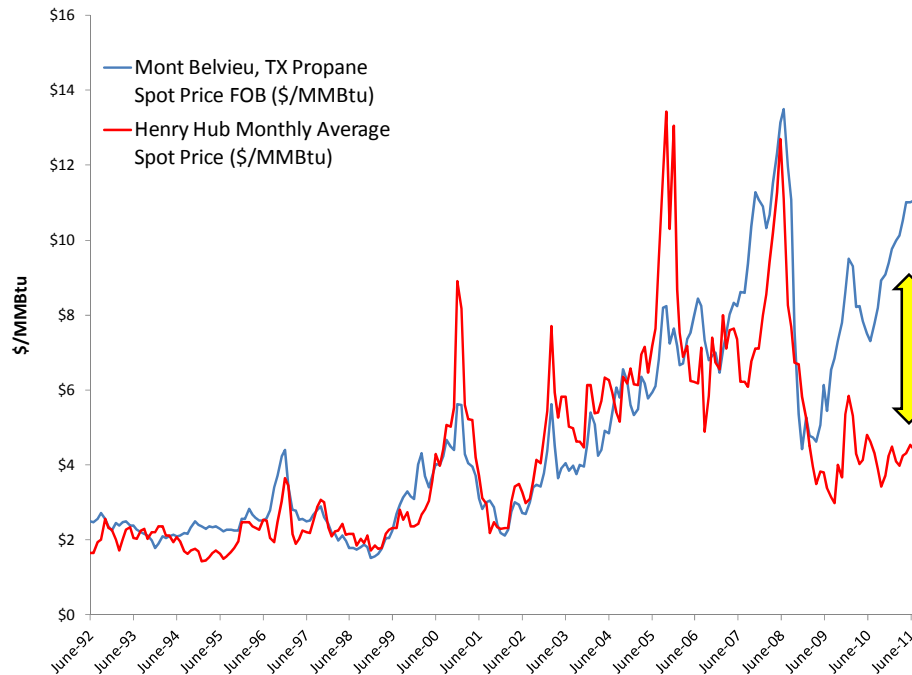
The NGLs dynamic will be tricky. Large volumes of NGLs production from shale plays could depress NGL prices if insufficient offtake (demand) and transport capacity evolve quickly enough, further discouraging liquids-driven drilling investment and eventually reducing dry gas supply. A hard fall in oil prices could narrow the differential with ethane and other NGL molecules, inducing switching back to oil. NGLs have been “upside down” to methane in the past. Most recently, for an extended period during 2003-2005, natural gas outpriced propane. At the peak differential, natural gas was roughly 12 percent more valuable than propane (MMBtu equivalence). Higher Henry Hub prices and demand for

<sup>70</sup> At present, EIA is surveying 2010 manufacturers. The 2010 survey is likely to show some changes with possible declines in overall energy and natural gas use associated with recession (and reduced industrial production), but increased natural gas use in petrochemicals as low prices lure back some end users (such as methanol).

<sup>71</sup> See Darbonne, footnote 3336. Also see Gregory Meyer, “Shale Gas Boosts U.S. Manufacturing”, *Financial Times*, September 19, 2011.

methane induced the inverted pricing. The relationship is usually methane being lower valued. In a nutshell, the prevailing trend of NGLs to be much more highly priced than natural gas but still cheaper than oil provides strong incentives for NGLs offtake but sustains NGLs focused drilling. Along with the prevailing high oil to gas price differential and oil directed drilling, the result is overproduction of methane as associated gas and depressing Henry Hub price.<sup>72</sup>

**Figure 30: Comparative Natural Gas and Propane Prices**



Sources: Analysis by author based on CME and U.S. EIA price formation.

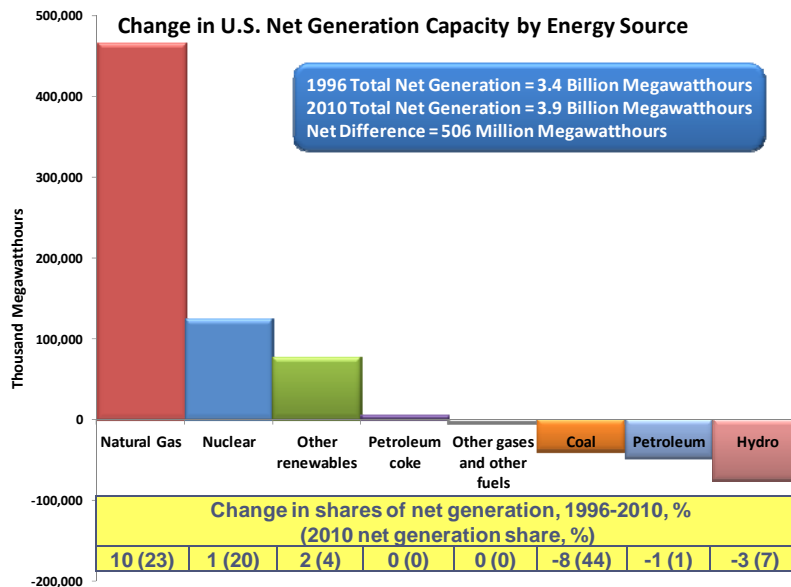
In NG 18 I touched on the links between electric power and natural gas price and price volatility as remarked in the opening sections. Make no mistake: the Holy Grail for the natural gas industry is large baseload power generation commitments with coal displacement. A great deal of pressure is being exerted on the coal industry and utilities with large coal generation fleets by environmental regulators and groups; the latter exerts influence through regulatory proceedings not only for generation but also transmission, successfully blocking new high voltage lines that would carry electricity from coal units, and agitating against mining in numerous states. Increasingly, the coal producers and generators look resigned to eroding market share going forward.<sup>73</sup> A bone of contention is that while most of the investment capital in power generation has flowed to natural gas capacity additions, natural gas generators continue to capture only a fraction of the market (23 percent in 2010 to coal's 44) even while gaining share in power sales (10 percent between 1996 and 2010). To many minds, increasing the share of natural gas-fired electric power is the single easiest solution if a "carbon constrained" world is reality. Faced with considerable roadblocks to achieving a

<sup>72</sup> See "Propane, Ethane Gains Deepen Natural Gas Glut," by Christina Buurma and Morning Zhou, Bloomberg, January 12, 2011, <http://www.bloomberg.com/news/2011-01-12/propane-ethane-price-gains-deepen-natural-gas-supply-glut-energy-markets.html>. Their analysis emphasizes the importance of liquids for improved shale drilling economics.

<sup>73</sup> Coal producers are trying to offset domestic market share loss with exports, but environmental and civic groups are also opposing expansions of existing and construction of new west coast export capacity (Asia Pacific being the magnet for sales).

reasonable cost structure for zero or near-zero coal plants, electric utilities have been flocking back to natural gas as the preferred solution. Complicating the achievement of base load dispatch for gas generators, and increased use of gas generation in total, is the push to integrate renewables.

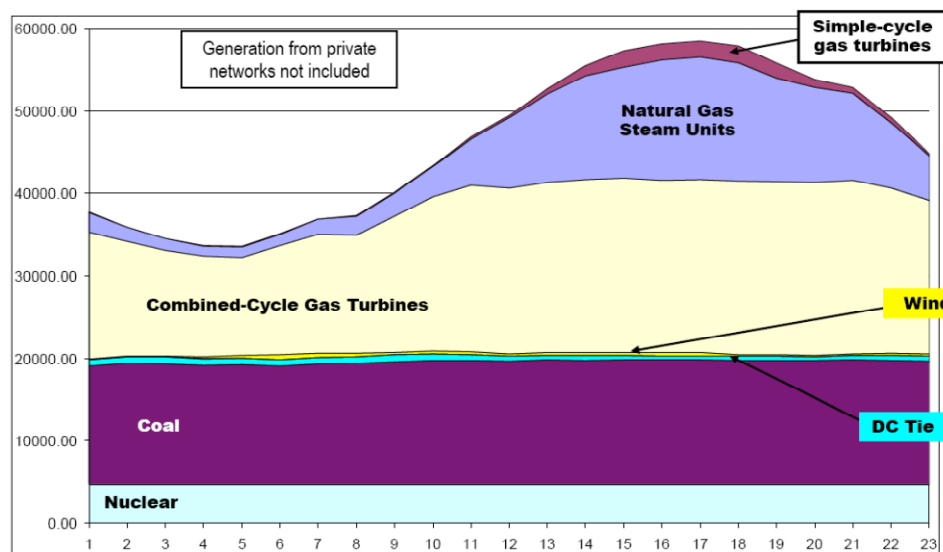
**Figure 31: Electric Power Capacity Additions, 1996-2010, and Shares**



Source: estimated and compiled by author based on U.S. EIA data.

When renewable energy sources are added to the mix, natural gas generation – which already tends to be dispatched on the margin for peak use – becomes even more marginalized as a “load following” resource. This is because gas generators are the cheapest to build and easiest to run on an as-needed basis. When the wind doesn’t blow, gas units kick in to balance the market. The clearest example of implications from this system has occurred in Texas, which has aggressively developed wind (enabled by Federal subsidies in the form of production tax credits or PTCs) and has competitive wholesale and retail electric power markets. A typical dispatch curve for Texas is shown below.

**Figure 32: Texas Electric Power Dispatch Example**

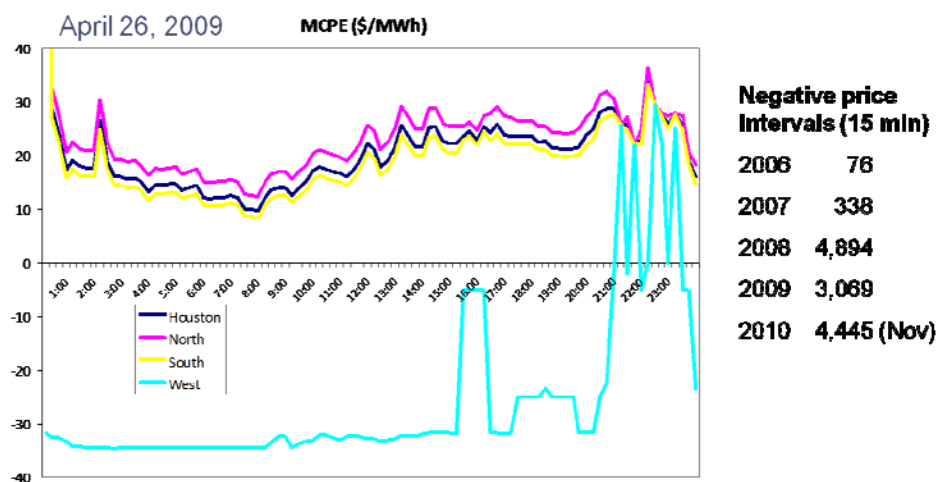


Source: Electric Reliability Council of Texas

Note that steam and simple cycle units tend to be dispatched mainly for peak periods. Efficient combined cycle gas turbines (CCGT), the technology of choice throughout most of the U.S., run base load to some extent as well as serving peak needs. Problems are encountered when wind projects need to dispatch in order to achieve sales that can qualify for PTCs. A representative day is shown in Figure 33 along with historical negative price intervals – those times when wind projects dispatch to the full extent of PTC value (roughly \$30 per MWh). In sum, whatever generation can be obtained from wind projects, given the diurnal nighttime pattern of West Texas winds, is offered to the grid at ever-lower prices until operators achieve dispatch, are able to claim PTCs and satisfy investors (who finance wind and other renewables projects on the basis of federal supports). Dispatch from wind projects has had the perverse effect of displacing both natural gas and, surprisingly, coal units, creating disruptions in the marketplace and undermining financial returns for the displaced units. Because many natural gas generation projects were acquired or developed when natural gas prices were high, and thus are dependent upon higher electricity prices to sustain profit margins, the combination of lower natural gas prices and wind dispatch has exerted a double “whammy” on their returns. In addition, running gas generators as load following, balancing units to wind is neither the most efficient use of natural gas nor the cleanest. Emissions are higher from the gas units, as are gas fuel requirements.<sup>74</sup>

The market distortions experienced in Texas will abate somewhat as the new nodal market design is implemented, and more information revealed about transmission congestion and capacity requirements. Wind projects have been particularly disadvantaged by transmission constraints, but the cost of transmission additions along with all attendant environmental and public acceptance factors (high voltage transmission is one of the most difficult kinds of infrastructure locate and approve in the U.S.) introduces new, pervasive uncertainties.

**Figure 33: Impact of Wind Dispatch in Texas**



Source: analysis by Gülen (BEG-CEE/UT) based on data from ERCOT (unpublished).

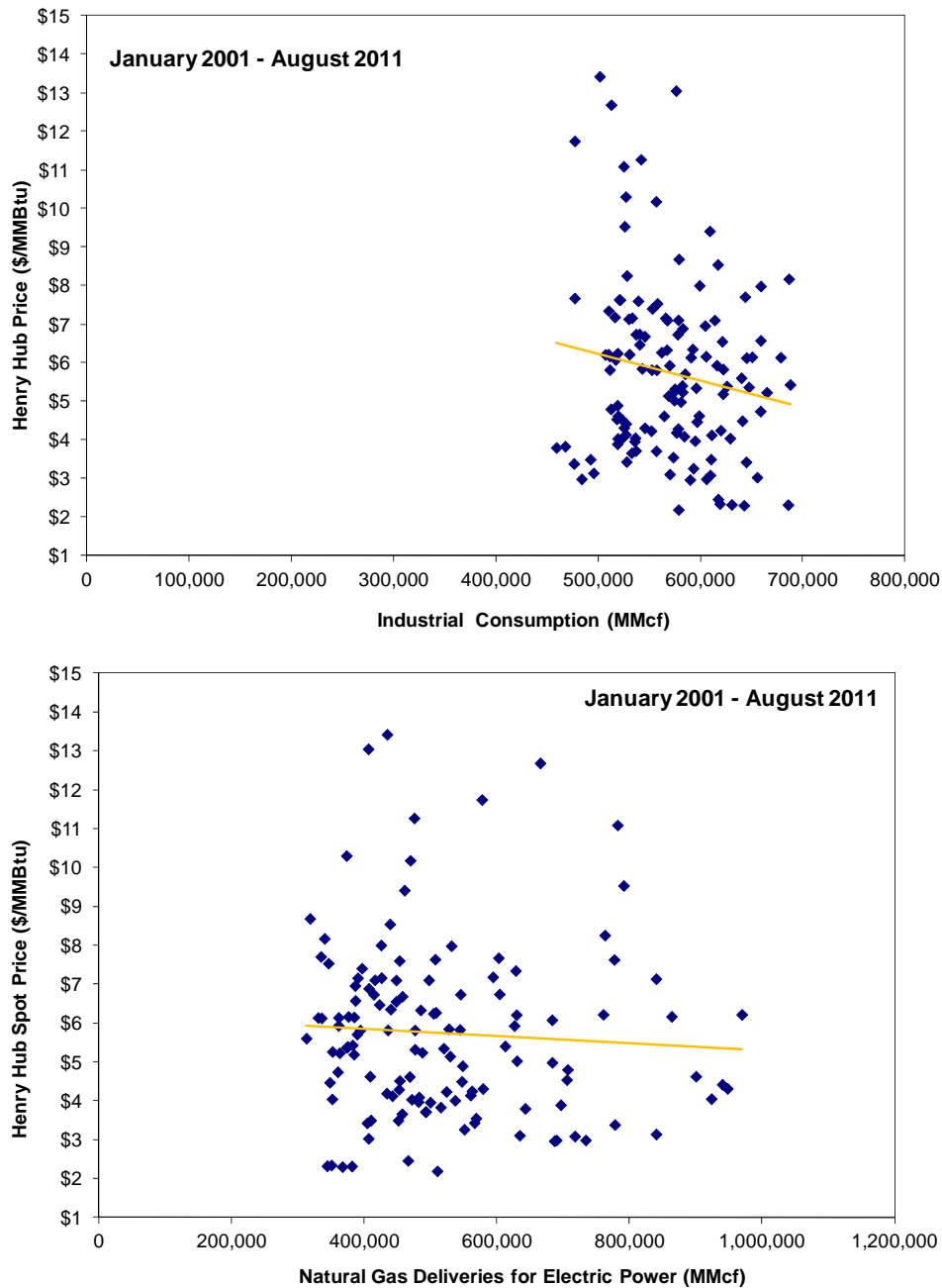
In NG 18, I included charts that correlated natural gas consumption in the industrial and electric power segments with price; Figure 34 provides an update of those charts. Industrial natural gas use clearly tracks the expected relationship – consumption increases at lower prices. Electric power deliveries are much less sensitive. This is almost certainly a seasonal effect. In cold and hot regions, peak seasonal demand for electric power places a “call” on

<sup>74</sup> A scientist at a U.S. national lab commented in a spring 2011 meeting that running natural gas generation units for spinning reserves to follow renewables made no environmental or economic sense.



natural gas units and thus an upward push on natural gas prices, even when supplies are ample.

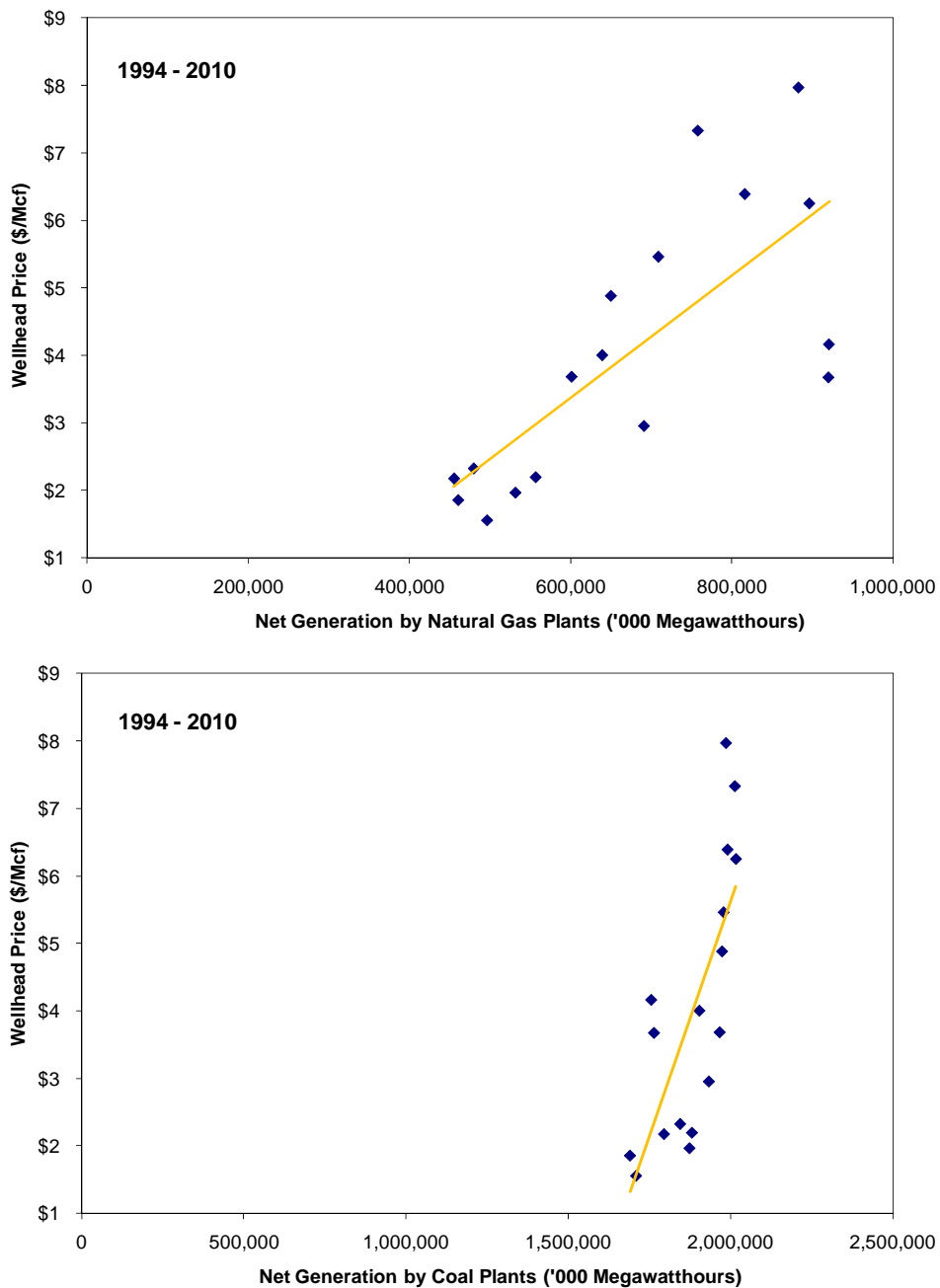
**Figure 34: Natural Gas Deliveries to Industrial (top) and Electric Power (bottom) versus Price**



*Source: analysis by author based on U.S. EIA data.*

Likewise, if natural gas units are running on more costly fuel, coal units will benefit. This results in the widely accepted outcome that coal sets a floor for the natural gas price (although coal producers and generators are both sacrificing profitability in the current low natural gas price environment).

**Figure 35: Net Generation by Natural Gas (top) and Coal (bottom) Power Plants**



Source: analysis by author based on U.S. EIA data.

Strong proponents of wind power argue that wind “disciplines” natural gas prices because “wind can bid in at zero or negative prices”, benefitting customers. They view renewables as a source of “stable pricing” whereas natural gas is characterized by inherent price volatility.<sup>75</sup> The stabilizing price, of course, comes at a hefty taxpayer cost given the much higher expense for wind generation on a per Btu basis as compared to dense fossil fuels, and the greater expense of subsidized generation. From the natural gas perspective, the intermittent nature of renewables increases volatility in the system, since daily and seasonal swings in electric power demand, mainly from residential customers, already create variability. The efficiency drag of turning gas generation units on and off (even with more efficient CCGT),

<sup>75</sup> Comments by a notable advocate of wind in Texas at a public forum during a panel debate with the author, August 2010.

consequent higher costs for operations, and higher costs for fuel during periods when gas generation units must run are the major source of volatility to customers. Public pressure and activist interest in renewables makes a fundamental shift away from renewables unlikely, at least in the foreseeable future. Without a climate policy, the main arguments are that renewables provide a “no regrets” strategy for reducing GHG. Proponents of natural gas make the same argument, and add that reliability of gas generation is greater. Renewable energy advocates counter that linking nighttime wind power with daytime solar can solve the reliability constraint (a significant caveat is lack of viable, commercial scale energy storage options for balancing and security). If renewable energy continues to expand as a share of electric power generation, the effect in the wholesale markets could be to effectively cap natural gas prices if PTCs remain in effect. The link between subsidies and investment in renewable energy is strong. At times when PTCs have been allowed to expire, investment in wind and solar projects in the U.S. has collapsed. Links in Europe and elsewhere are equally profound and all are heavily impacted by adverse economic conditions.

Lastly, an option for using NGLs is in the electric power generation fuel stream. Ethane and other molecules can be used for power generation with burner adjustments. Thoughts along these lines already permeate the discussions surrounding prospective shale gas production locations.<sup>76</sup> The option of using NGLs for power generation can help to accelerate NGLs monetization and ensure that lack of offtake is not a drag on overall shale gas productivity in plays like the Marcellus. Dual fired generation has diminished in the U.S. with aggressively rising oil prices; petroleum has had little impact in the power segment (Figure 31) and fuel switching has had little or no impact on natural gas prices, especially since 2006. Orders for dual fired generation plants are on the upswing given the shift in the production slate. Greater use of liquids could, in some key locations and mindful of smog controls, re-introduce fuel switching dynamics should enough capacity be developed. In the past, fuel switching set a ceiling for natural gas price in some instances.<sup>77</sup>

How will directions in electric power use and competitiveness for natural gas play out? Since 1997, electric power load in the United States grew 20 percent based on U.S. EIA retail sales data. But growth stopped in 2007; between 2007 and 2009, electric power sales sunk four percent as recession took hold. Sales recovered in 2010 but the result for the full time frame is a zero percent gain. Using monthly data, sales between January 2009 and July 2011 increased 16 percent, but from August 2010 to July 2011 sales declined by one percent. Since 1949, net generation of electricity has grown almost unabated. Recessions and other effects dented power demand and output, most notably during the 1980s as utilities reeled from oil shocks and the first big adjustment in the U.S. fleet were made – replacing oil with coal and lignite and making large nuclear investments, all during ferocious inflation and interest rate conditions. In the category of “this time is different”, many analysts and electric power industry experts and professionals feel that the long term future for electric power demand is flat, at best. These impressions are in spite of a seemingly endless appetite for electronics goods and internet access and applications and even in the face of speculation about market penetration of electric vehicles and plug in hybrids. These outlooks include the effects of environmental regulation as well as pressure to encourage demand side management, both of which open doors to everything from renewable energy to “smartgrid” innovation and other transmission and distribution efficiencies. (These opinions also parallel broad views on demand for refined products in the U.S.) That is quite a changed world. Yet, the utopian vision encapsulated in renewables/smartgrid deployment is difficult to achieve

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<sup>76</sup> Jeannie Stell, “Marcellus Methane”, *OilandGasInvestor.com*, April 2010.

<sup>77</sup> See NG 18 discussion on fuel switching.

and remains long in the future. Thus, it is a safer bet that gas will displace coal, significantly, in spite of antipathy by some large customers.

As producers have struggled to push strategies for deepening natural gas demand, a popular beneficial use to promote is transportation. Total natural gas use for vehicle transportation is only about one-tenth of one percent of total U.S. consumption. While there is evidence of growth, clearly a long haul lies ahead to push natural gas into transport use in a meaningful way. I will not delve into that segment here; there is little initiative for investment in the massive infrastructure that would be required for natural gas vehicle (NGV) refueling in the mass market, and little incentive for auto makers to divert attention from electric vehicles (although the higher energy density of natural gas ought to be more attractive). The oil to gas price differential should be a strong incentive for development but given the lack of motion, one can only presume that NGV transport is not meant to be on a large scale. Trucking, marine transport, and other options are, however, under active scrutiny, with LNG engine designs (better engine performance and range) and associated LNG infrastructure for long-haul highway truck refueling expected to provide nice niche markets. Already, regional truck fleets and fleet refueling by municipalities for waste management and utilities for maintenance and emergency vehicles constitute the bulk of transportation use. Because of the oil to gas price differential, many observers expected more interest in gas to liquids (GTL), especially in light of high profile projects around the world. For that option, the Henry Hub price signal is likely still too expensive with too much uncertainty about the persistence of oil and gas price spreads.<sup>78</sup>

#### **4.2 Midstream opportunities, and anxieties**

To move natural gas from field to market requires pipeline transportation across state boundaries (interstate) and within states (intrastate) as well as storage to manage daily and seasonal fluctuations. Some estimates are that upwards of \$200 billion will be required to re-jig the U.S. midstream segment to accommodate production shifts and changing flows.<sup>79</sup> However, the midstream segment has been heavily impacted by adverse business conditions for the “volatility loving” market makers mentioned in Section 2. As this paper was being completed, ratings agencies were reviewing the impact of diminished basis differentials and competitive pressure on transportation rates from large pipeline capacity additions (including compression to increase capacity in existing facilities) that have already entered service. Attention also is focused on revenue losses among the pipeline affiliated storage, marketing, and trading businesses. While, thus far, the pipeline segment is much better off than it was during the energy merchant collapse, there are many consequences for the investment requirements that lie ahead should credit quality deteriorate.<sup>80</sup>

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<sup>78</sup> Sasol announced a feasibility study associated with Southwest Louisiana production. See “Louisiana chosen as site for proposed GTL facility,” *Engineering News*, October 21, 2011, <http://www.engineeringnews.co.za/article/proposed-gtl-facility-for-the-us-2011-10-21>. In both public and private statements, Sasol has repeatedly emphasized natural gas feedstock cost as the main hurdle for development. The potential location in Calcasieu Parish suggests that feedstock could likely come from the huge Davy Jones discovery. See Section 4.4.

<sup>79</sup> North American Midstream Infrastructure Through 2035 – A Secure Energy Future, ICF for Interstate Natural Gas Association of America (INGAA) Foundation, June 28, 2011, <http://www.ingaa.org/File.aspx?id=14900>.

<sup>80</sup> Based on a proprietary report by Standard & Poor’s, *The Shale Gas Boom Brings Growing Pains for U.S. Pipelines*, October 27, 2011. While S&P left its ratings of reviewed pipeline and storage companies “relatively stable” their report points to many caution flags of classic midstream overextension, as large capacity increases work against profitability. In a previous revision, S&P had downgraded Rockies Express to negative from stable.

In the main, drilling shifts to oil and NGLs at locations outside of the Gulf Coast, with associated gas being a major contributor to natural gas deliveries, require midstream infrastructure investment for transport and storage of both liquids and associated gas. A great deal of positioning is underway in that regard, already with winners and losers.<sup>81</sup> This is especially true in locations like North Dakota and Texas (Eagle Ford) that are being scrutinized for gas flaring with oil production and for ethane offtake in locations where NGLs are abundant.

Historically in the U.S., many more pipeline proposals are floated than projects built. Downward revisions on initial field reserves estimates and disappearance of supporting price spreads between producing and consuming locations (basis differentials) can discourage final investment decisions. Head-to-head competition to expand service where basis differentials results in eroding pipeline profitability (“contestability” is much more common than typically thought and has influenced regulatory oversight, especially at the federal level). Major new lines have been built to support production flows from the Rockies, Barnett and other western plays to eastern and western consuming centers, as well as within regions, such as transportation within/around Marcellus states. Of more interest are the broad realignments of pipelines that many feel will be needed to accommodate changes, possibly profound, in gas flows relative to existing infrastructure. The prevailing Lower 48 gas pipeline routes are from the Gulf Coast and southwestern U.S. to the east and west coasts, and from Canada east to the northeastern U.S. Closely watched are pipelines proposed to support transport to coastal locations (an indicator of potential LNG exports); pipelines for regional loads that would compete with traditional routes (especially in the Marcellus); status of newly built west-to-east lines such as Rockies Express (to the northeastern U.S. where Marcellus production is upending Rocky Mountain deliveries); and capacity that would displace long established Canadian exports.

The preponderance of pipeline projects are directed toward eastern markets.

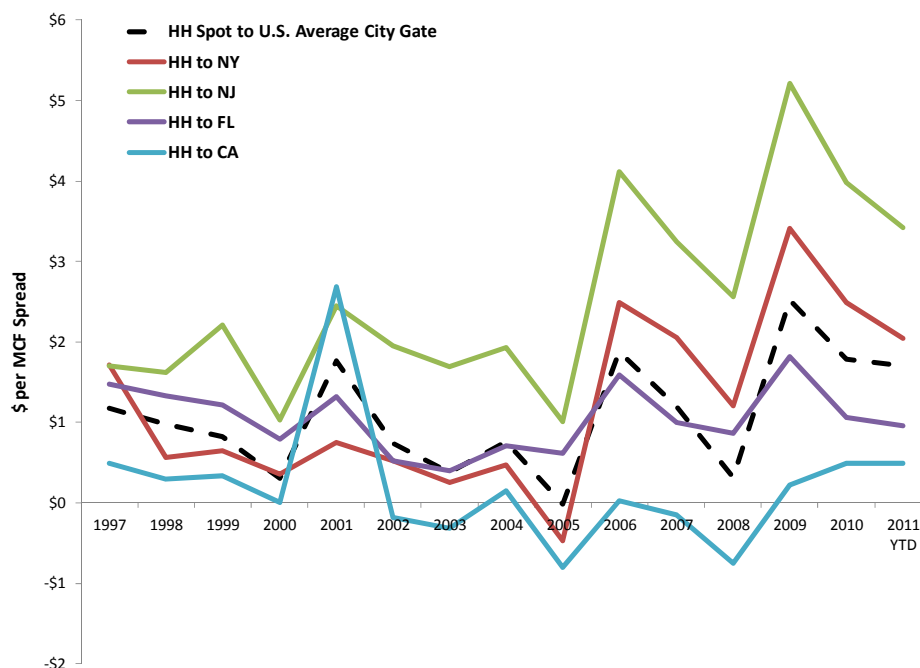
Basis differentials between Henry Hub and selected U.S. city gates, where local utilities typically take title to natural gas for delivery to final customers, are providing plenty of impetus for new pipeline additions (Figure 36). This is especially true for the large load centers in the northeastern U.S. Florida also offers an attractive target. California and the West do not offer attractive spreads but conditions could change dramatically in the future as those states continue to force coal-fired power generation out of their markets. Most of the FERC approved and built projects have been in the “Marcellus neighborhood” (Appalachian states, Pennsylvania, New York and New Jersey). A handful of projects targeted Florida and the southeastern U.S. by pulling midcontinent production across the southeast, linking major shale basins with other producing locations along the way. Until the current recession, demand provided a pull on gas apart from the push by producers to connect new supplies with markets. Demand has been driven in part by an increase in heating degree days in recent years for the U.S. as a whole and the northeast in particular, and cooling degree days in the south mainly as a result of population shifts. Florida has long been a difficult location for gas pipeline additions, largely because of the dominance of coal-fired generation operated by large public utilities under cost of service ratemaking. Florida also was a location where,

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<sup>81</sup> Kinder Morgan’s acquisition of El Paso’s huge pipeline asset base, announced in October 2011, has received most attention. In one notable development, lack of interest in a proposed KM (El Paso)-Spectra Energy liquids pipeline to the Gulf Coast resulted in the project sponsors cancelling that development. See “El Paso’s Marcellus ethane pipeline not in the cards” by Anya Litvak, *Pittsburgh Business Times*, November 7, 2011, <http://www.bizjournals.com/pittsburgh/blog/energy/2011/11/el-paso-marcellus-ethane-pipe-not-cards.html>. Takeaway capacity to the Gulf Coast would compete with proposals for regionally based ethylene and other NGLs projects.

during the 1990s, market power for pipelines was less well pierced by contestability.<sup>82</sup> Improvements certainly have been made since then, pulling Florida’s average city gate price below the U.S. average price. Of note in Figure 36 is the spike in basis differential between Henry Hub and California. Part of the disruption to natural gas markets that year (2001) stemmed from a pipeline explosion and outage in New Mexico, a good example of what can happen when midstream constraints happen while supply-demand balances also are tight.

**Figure 36: Basis Differentials, Henry Hub Spot to U.S. Average and Selected State Average City Gates**

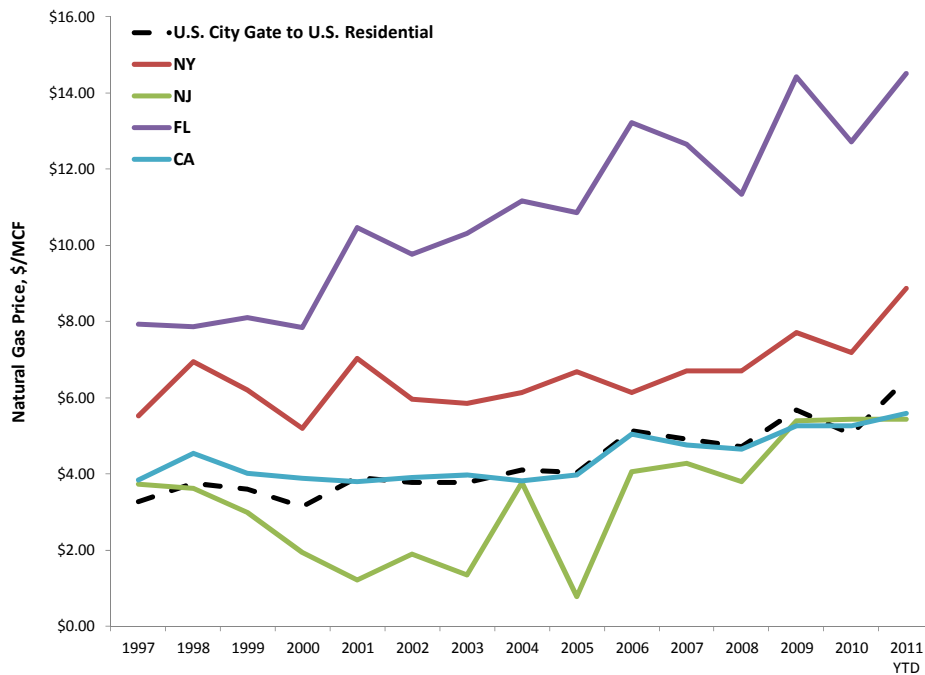


Source: Author analysis based on U.S. EIA data.

For all of the softening of natural gas prices in the U.S., prices in large load centers remain stubbornly high. Pennsylvania and Illinois (Chicago) city gate differentials to Henry Hub are nearly as robust as the New York and New Jersey differentials shown here, if not more. Delivered prices to residential users also are high and, in many locations, increasing in spite of supply abundance. As illustrated in Figure 37, using the difference between city gate and delivered prices to residential customers in different states and the U.S. average, this is partly a function of local distribution system costs, partly the transfer of pipeline expansion costs to customers, and partly driven by the expense of building midstream capacity in states and locations where resistance to new infrastructure is strong and urban densities and geography make infrastructure expensive.

<sup>82</sup> I reviewed the impact of contestability in FERC decision making as part of dissertation research in 1995. See Foss, *U.S. Natural Gas in the 21<sup>st</sup> Century – Adjusting to the New Reality*, University of Houston, 1995.

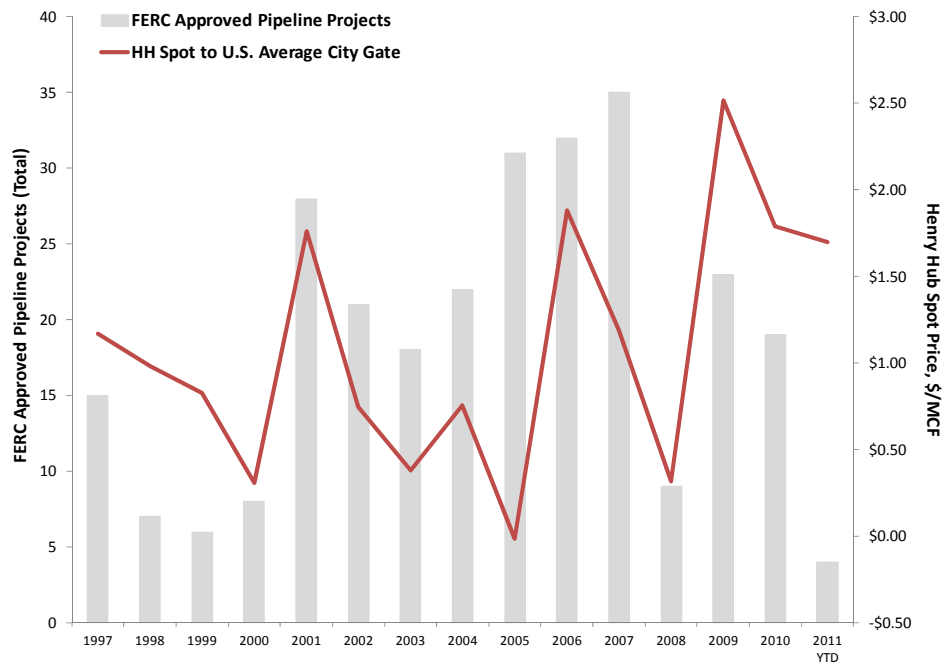
**Figure 37: City Gate to Residential, U.S. Average and Selected States**



Source: Author analysis based on U.S. EIA data.

Figure 38 compares the Henry Hub and average U.S. city gate price differential to the total of FERC approved pipeline projects. The general tendency of FERC regulators – with oversight for interstate pipelines – seems to be to approve projects when spreads are rising. Of interest is the decline in approved projects even as strong differentials persisted during 2009-2011. (FERC approvals for 2011 are year-to-date through May; it is unlikely that full year data will deviate from the observed drop off.) Results during these most recent years reflect changing market conditions: diminishing spreads; new projects entering service (in particular in the state of New York, pushing down basis differentials shown in Figure 36 above); declining revenues with increased competition. FERC project approvals also reflect a fundamental shift in the kinds of projects pursued, illustrated in more detail below.

**Figure 38: FERC Approved Projects and Henry Hub-U.S. Average City Gate Basis Differential**

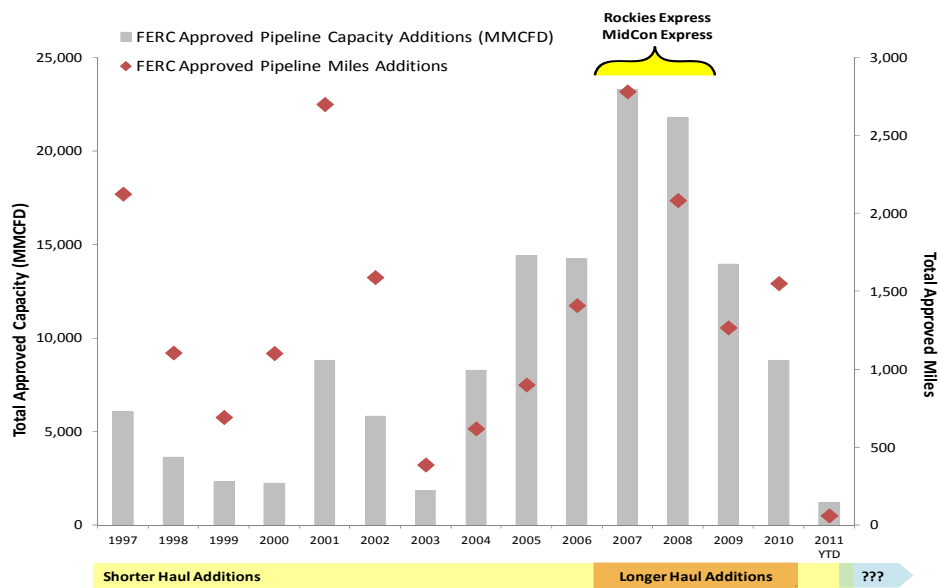


Source: Author analysis based on FERC data.

Figure 39 and Figure 40 show FERC approved pipeline capacity and miles, and growth in capacity, miles, and compression since 1997. Large, new long haul pipelines were commissioned to bring Rockies and shale production to eastern markets. The future of these pipelines, in particular Rockies Express, looms large in the face of uncertainty about future gas flows. Generally speaking, a marked shift occurred to certify long haul projects in response to surging natural gas prices and deep discounts for production that was locked up in the middle of the Lower 48. Attention has shifted back to shorter haul de-bottlenecking, for both interstate and intrastate projects. Figure 40 provides a powerful illustration of changing focus for midstream developers and operators. When growth in compression exceeds that of capacity and mileage, this is a general indication of investment to rehabilitate existing facilities rather than build new ones. Adding compression is a relatively cheap tactic for responding to market conditions and expectations. During 2010-2011, in particular, compression has been the focus for investment.

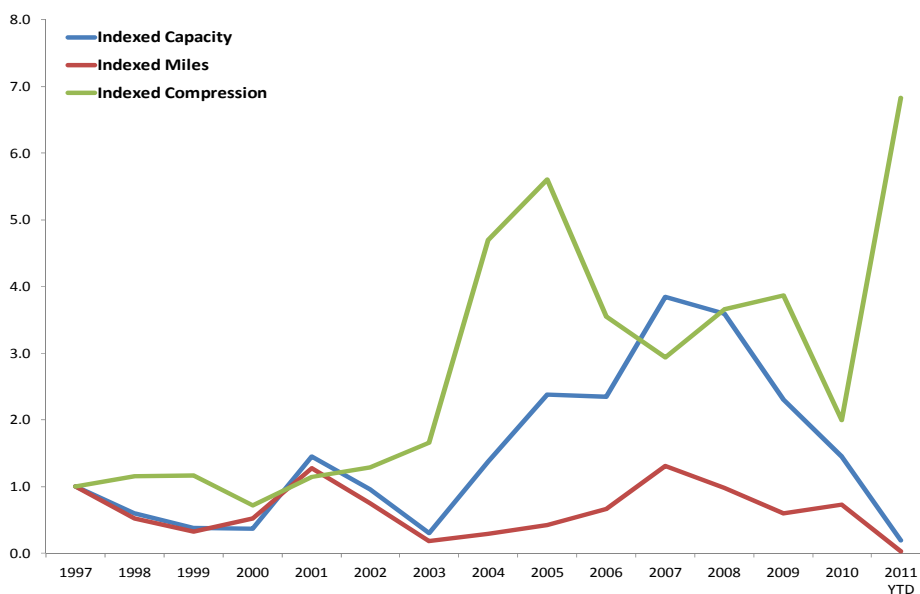


**Figure 39: Trends in Pipeline Capacity versus Miles Additions**



Source: Author analysis based on FERC data.

**Figure 40: Trends in Capacity, Miles, and Compression (HP) Additions**



Source: Author analysis based on FERC data.

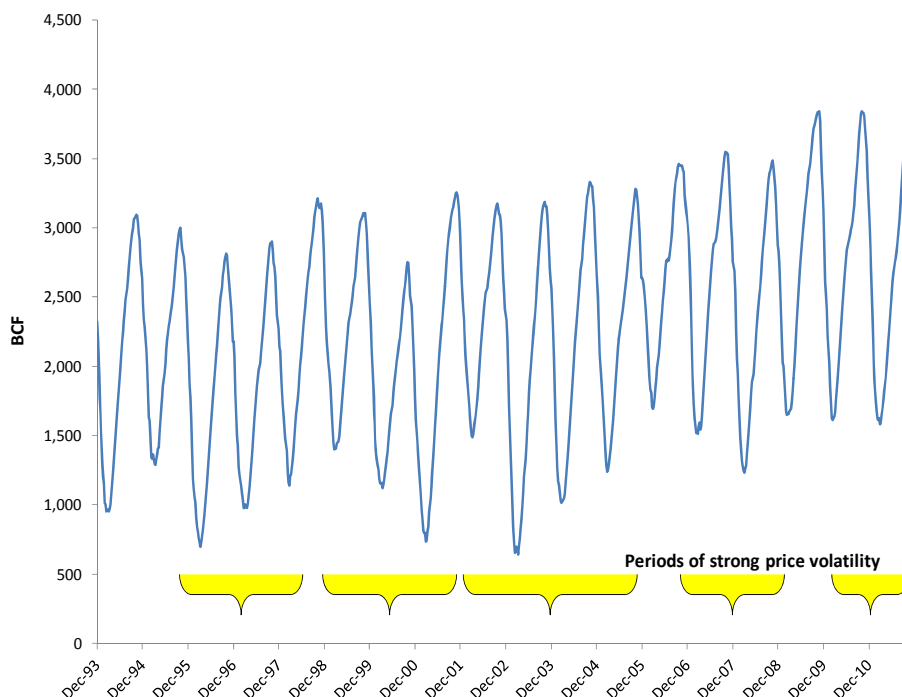
How expensive is it? Marcellus and Appalachian region projects are especially costly, a consequence of terrain, sensitive watersheds, and dense urban corridors. One project to reverse gas flow from Staten Island to Manhattan and bring additional Marcellus production to New York City will cost \$850 million for 16 miles of 30-inch pipeline (with new right of way) and three compressor stations. The roughly \$53 million cost per mile exceeds every estimate for an Alaska gas pipeline.<sup>83</sup>

<sup>83</sup> Texas Eastern, with three firm shippers (Chesapeake Energy, Consolidated Edison, and Statoil) based on FERC filings and industry trade information. See also Gurfinkel, et.al, 2006.

Much money has also been directed toward storage. Storage is a powerful fundamental driver for natural gas prices. Storage facilities are developed and operated on the basis of intrinsic, forward commodity price; asset values; and the difference between intrinsic and total value and extrinsic (time) value. Storage value is higher when price uncertainty is greater, such as when seasonal differences are larger, when it takes longer for “mean reversion” (for market prices to fall back to a longer term equilibrium), and so on.<sup>84</sup> Low price volatility can undermine storage, affecting returns for storage developers and operators and associated trading activities. Large storage capacity additions have been made in response to E&P activity and results but were initiated two to three years ago, when expectations about forward prices, volatility and seasonal spreads were different than the low price and price volatility manifest since then.

As might be expected, the routine pattern in the U.S. is for producers to inject gas into storage when prices are falling, and for net withdrawals to increase when prices are rising. Working gas in underground storage, the major component consisting mostly of salt caverns and depleted fields, usually peaks in October-November and falls to its lowest point in March-April. Shifts in U.S. natural gas market conditions can easily be discerned from storage activity. The less gas remaining in storage in March-April, the stronger price signals usually must be in order to attract supply for reinjection (Figure 41 “bottoms”). The larger the injections on a year to year basis, the bigger the downward impact on price (Figure 42, net injections relative to price change; periods of price volatility in Figure 41 correlate to high volatility periods in Figure 6).

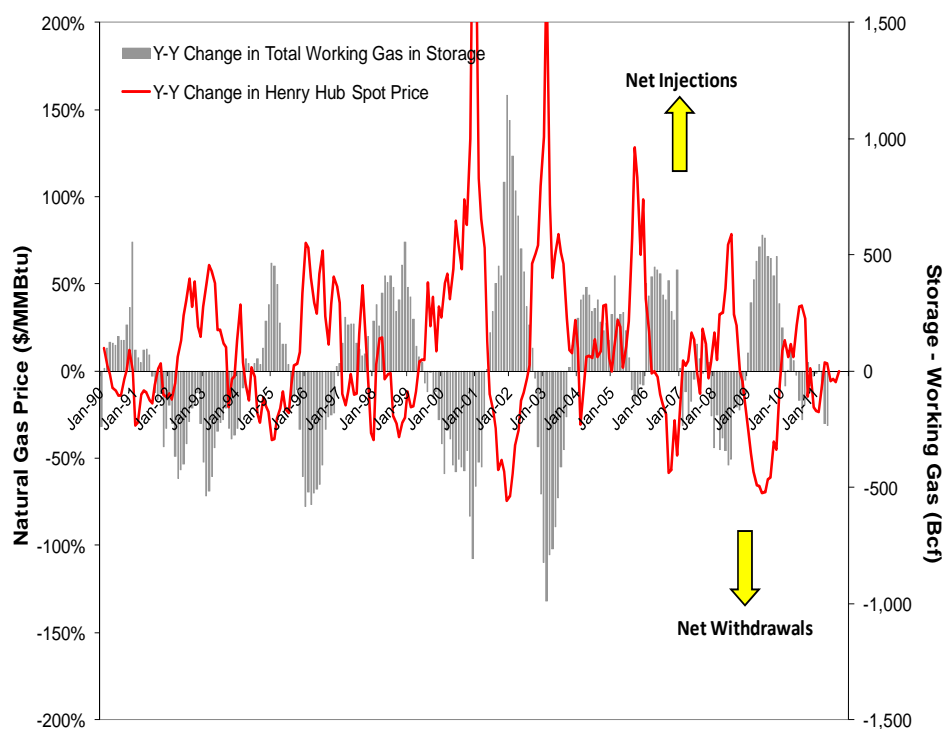
**Figure 41: Working Gas in Storage**



Source: analysis by author based on U.S. EIA data.

<sup>84</sup> Midstream assets are often bundled into master limited partnerships (MLPs). MLPs with the highest risk/reward profile tend to be more highly valued in unit price. Comments on volatility and impact on various natural gas segment businesses come from a variety of industry and financial sources.

**Figure 42: U.S. Storage Net Injection, Net Withdrawal Patterns**

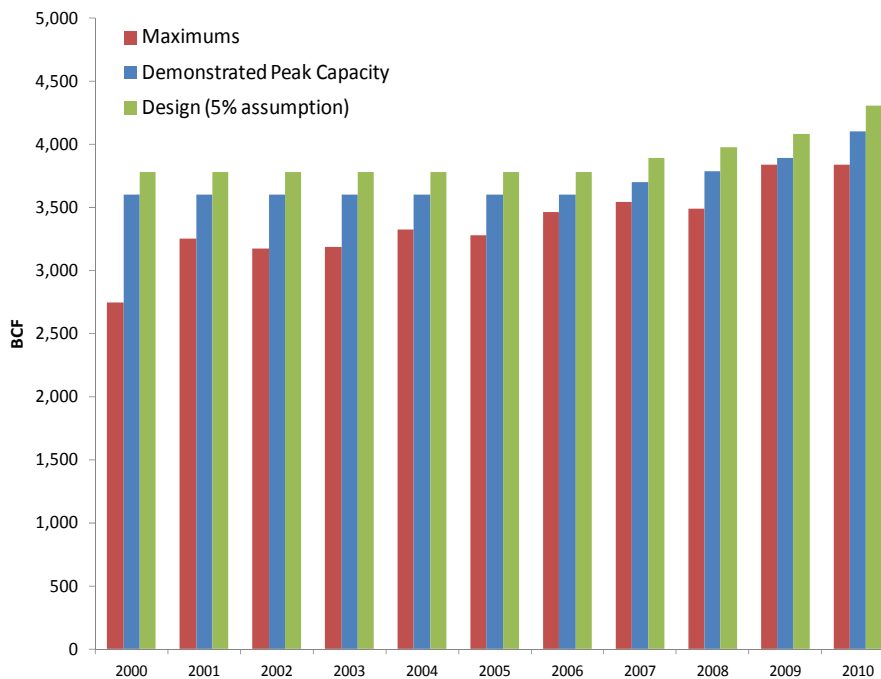


Source: analysis by author based on U.S. EIA data.

Between 2006 and 2011 about 370 BCF of working gas design capacity was added to the system to bring total peak capacity reported by EIA to 4,388 BCF. This capacity is net of retirements of older, marginal fields, mainly in the producing regions. Apart from underground storage, small LNG storage facilities operated by pipelines and utilities typically contribute annual peaks of about 5 BCF. U.S. EIA, which reports the closely watched weekly storage survey, usually assumes a five percent overage between demonstrated peak capacity and design capacity that can be safely used. Both are shown in Figure 43 along with the maximum amount of gas stored each year (peak winter storage). As of November 2011, the more than 3,800 BCF of working gas stored represents close to 90 percent utilization of demonstrated peak capacity (86 percent) and a new historical high. Storage drives perceptions and expectations about short term natural gas prices. With available capacity filling up, and given winter 2011-2012 projections of a snowy north but warmer, drier south, large amounts of working gas remaining in storage during the spring 2012 “shoulder months” would mean less available capacity for continued production and imports in the face of a persistent weak economy. Henry Hub could bottom out below \$3 in that case.<sup>85</sup> At the time this paper was completed, analysts were revising outlooks for 2012 prices, noting downward pressure and with uncertainty about winter heating loads in mind.

<sup>85</sup> At least one midstream executive interviewed believes Henry Hub could bottom out at about \$2.60. That executive also charts a possible forward top of about \$10 during this paper’s time frame.

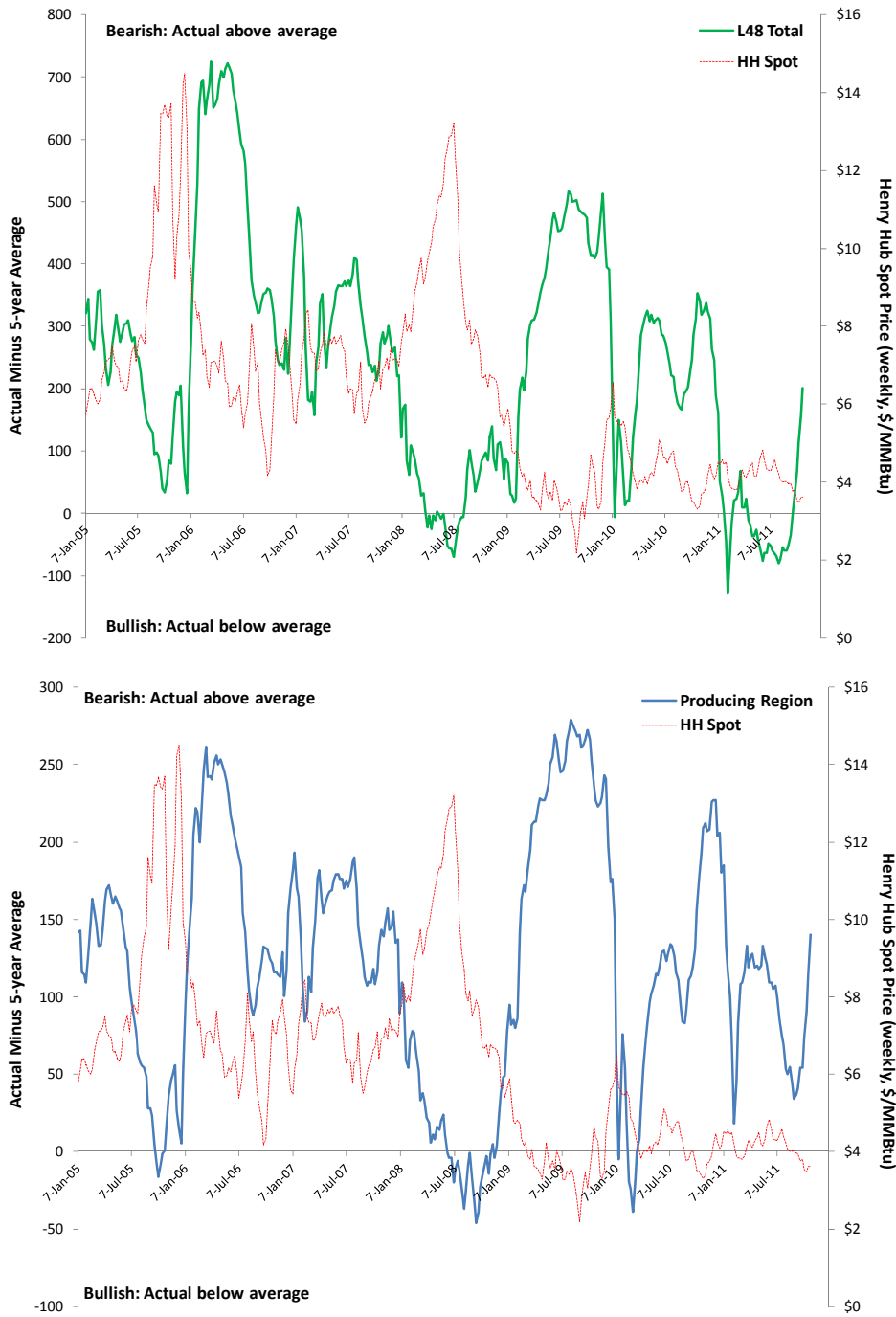
**Figure 43: Natural Gas Underground Storage Capacity and Maximum Levels**

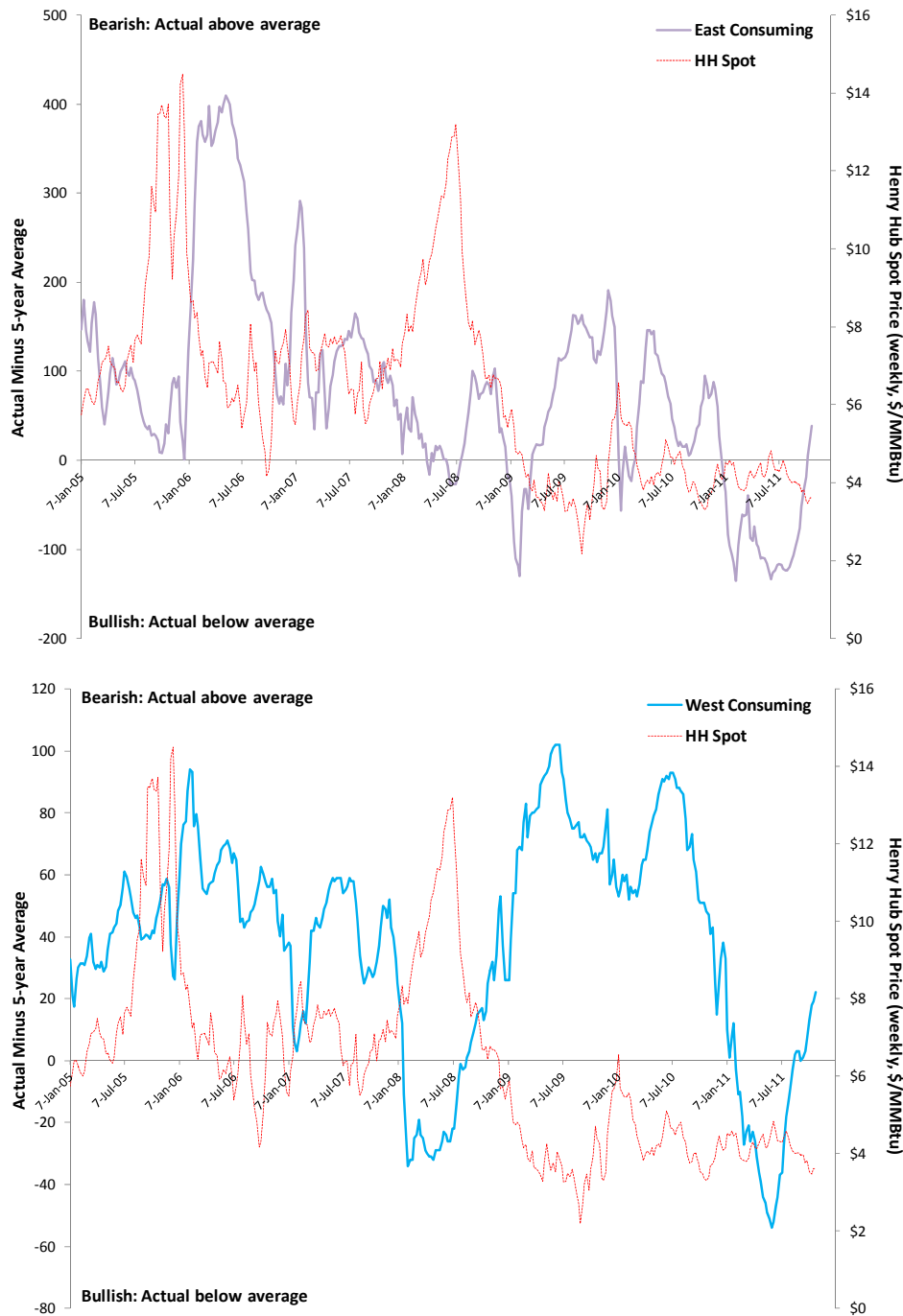


*Source: analysis by author based on U.S. EIA data.*

This short term outlook is reinforced by trends in working gas storage, comparing actual, weekly reported levels to a rolling five-year average for each week. The four charts in Figure 44 show the Lower 48 total and producing, East consuming, and West consuming regions. The historical interaction between storage levels and price over the past six years is clear: pronounced “bearish” conditions for price when differences between actual, weekly reported levels and the five-year average are rising and positive, and “bullish” when differences are falling and negative. A period of declining differences, including negative bullish differences in the producing region, during 2011 contributed to somewhat stronger natural gas prices. However, no price spike was experienced, in distinct contrast to 2008. During the latter half of 2011, for the Lower 48 and across all regions, actual levels of working gas in storage have been rising quickly above the five-year average.

**Figure 44: U.S. Natural Gas in Storage, Actual to 5-year Average for Lower 48 (top), Producing, East Consuming, West Consuming**





Source: analysis by author using U.S. EIA data.

Several observations and questions can be put forth. Why didn't prices move more sharply upward during 2011 when, overall, the Lower 48 was in bullish territory? And shouldn't the more bullish east and west consuming regions be impacting natural gas prices? Both regions have been experiencing a declining trend in actual-average differences since mid-2009. With less "slack" in working gas storage, price firmness should be expected. The bulk of storage investment typically is made near production fields and along the Gulf Coast (the producing region), which also is most conducive to large underground facilities (especially salt domes from which gas can be released quickly into the market). During 2011, producing region storage was in bearish territory, offsetting pressures from the consuming regions. And, indeed, an argument could be made that the bullish trends in the east and west (mainly weather related) kept prices from collapsing. These differences are suggestive of longer term

patterns and indicators, and provide clues to future market balances and prices. Perceptions about storage are evolving, given additions to capacity. The roughly four trillion cubic feet of storage is large and compelling. At some point price will reflect tension associated with that balance but many take these outcomes as supporting indicators for a lower price volatility future. “Volatility loving” businesses, as described in Section 2, are actively shifting strategies in response to the perceived “stable price” future.<sup>86</sup> However, as demonstrated in the preceding paragraphs recapping demand (Section 4.1), recession effects are powerful and are masking market fundamentals. Given that reality, there should be many caution flags going forward.

A related question is whether storage is actually needed in the east with more shale gas available proximate to demand centres. A fundamental shift of this sort would make sense for the east but not the west. The thinking is that ability of producers to complete wells held in “inventory” in the Marcellus and other shale basins (the “just in time” manufacturing component of the shale production business) will balance the market. A number of factors would be at play in that scenario, including financing, availability of crucial drilling and fracking services, and flexible environmental oversight, raising the issues of timing and needed price signals to attract producers back to non-associated, dry gas acreage when deliverability from those locations is necessary to balance the market. Is there a possibility that, if east region storage is used less because of anticipated production from regional shale plays that then does not materialize, customers and consumers could face abrupt changes in price? This is a fair question to add to the mix. An added complication is whether investment in traditional Gulf Coast producing region storage could be throttled back in light of Marcellus/east region dynamics, and what the implications might be. This would come about as a logical response to changing production patterns and potential “reversal” of pipeline flows, i.e., the east region becoming less dependent upon gas flows from the Gulf Coast, as well as less attractive market models for storage developers (absence of price volatility). There is, of course, mountains of storage capacity at Gulf Coast LNG import terminals but no serious discussion, as yet, of using those facilities for domestic storage per se.

Clearly, basis differentials over the years have signaled a need for midstream investment and the industry has responded. However, it is not clear what the future opportunities for midstream investment flows will be. Basis differentials can close quickly once new facilities and other improvements enter service. Once built, expensive pipelines and storage can be quickly stranded by market dynamics (witness Rockies Express). Uncertainties about how best to match NGLs to markets and forward prices and differentials, delays in public approvals, geologic risk, and assorted other threats can all combine to foster lags in midstream investment that could accelerate upward pressure on price.

## **5 Summary and conclusions – Henry Hub prices at 2020: \$3... or \$10?**

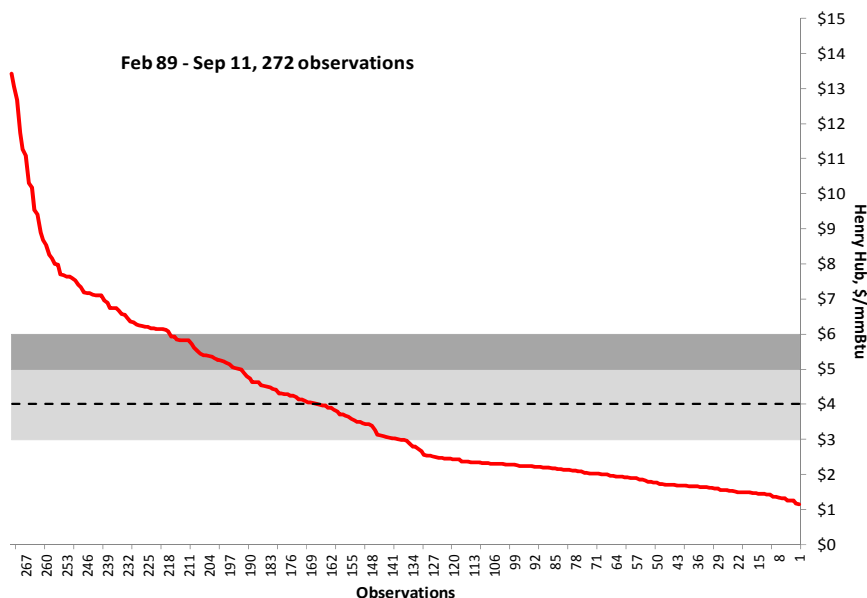
In NG 18, I emphasized the low historical occurrence of natural gas prices higher than \$5-6. Even with the robust prices that were reached between 2006 and 2008, natural gas mainly continues to occupy a price deck below the \$6 price cited as “preferred” in NG 18 and, as noted in this paper, still the target price for sustainable natural gas drilling. Indeed, a hallmark of the U.S. natural gas marketplace is the extent to which high volatility accompanies low price periods. This has everything to do with relative supply-demand

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<sup>86</sup> A Houston marketer remarked that her company is moving into renewables given the absence of natural gas price volatility, one of many such signals (and an ironic one in light of gas price volatility induced by renewables).

balances, low substitutability of natural gas for other energy fuels (the phenomenon of “natural gas competing best with itself” as I termed it in NG 18; “gas-gas” or “gas-on-gas” in industry phrasing), and the lumpiness of supply investment cycles as shown at the outset of this paper (Figure 1). Figure 45 below updates and refreshes the frequency distribution as published in NG 18. Of 272 observations, 138 are less than \$3, 166 are less than \$4 (a crucial psychological barrier), 193 are less than \$5, 217 are less than the preferred \$6 level, and 240 less than \$7, the price many believe is most favorable to renewables for the power sector. Even though natural gas market participants have relatively brief experience with higher price regimes, political reactions can be counted upon to match episodes of volatility. A common refrain is that “volatility is relative.” Even so, a shift in price from 2011 (and possibly 2012) lows around \$3 to a deck that can support gas directed drilling and deliverability (\$6 and above) would entail a considerable change in price level and almost certainly an increase in price volatility because, in all likelihood, such a shift would be accompanied by supply-demand tightness, the main driver for price volatility. A higher price spike would bring both higher volatility and a higher price level.

**Figure 45: Historic Natural Gas Price Distribution Based on Monthly Data**



Source: Author analysis based on CME and U.S EIA data. All prices are money of the day.

What major conclusions can be drawn from my exploration of natural gas prices and markets in this paper for forward price views and scenarios?

- The long and short histories of Henry Hub prices demonstrate many periods of adjustment to supply-demand balances with varying price levels and periods of price volatility that reflect changes in fundamentals. U.S. markets are dynamic; relatively “wide open” as a result of regulatory restructuring of the natural gas industry and the broad diversity in players and funding sources; and, still for the most part, conducive to industry responsiveness when price signals and profit margins warrant investment. As in all aspects of American life, political conflict regarding how much and what kind of oversight government jurisdictions should have over myriad aspects of business activity, from drilling to end use, from environmental to financial, is adding risk and uncertainty that could impact responsiveness in the future.
- Drilling success in response to the high price signals in the 2000s has yielded a surge in production from new plays, particularly shale plays. Combinations of technologies –



horizontal well completions with multi-stage hydraulic fracturing, subsurface “intelligent” drilling tools, and many other advances – have enabled extraction of hydrocarbons from tight rocks that, in lower price environments and without technology inducements, were unproductive. Costs for shale plays – both oil and gas – remain stubbornly high but the strong premiums for oil and NGLs over natural gas make the economics in these plays much more attractive. As a result, drilling activity in both the U.S. and Canada has shifted rapidly away from natural gas wells to liquids. Natural gas supply additions initially were from non-associated or dry gas acreage. Now, additions are mainly from associated gas produced in liquids rich locations (crude oil and NGLs). Continued leasing activity in liquids fairways and drilling to meet leasehold obligations is keeping associated gas production high, further suppressing prices. Conventional plays such as offshore Gulf of Mexico (deep water and deep shelf prospects in shallow water) have been less attractive if the main hydrocarbon to be produced is methane. Thus, new production from shale basins must cover for declines and lack of additions from conventional prospects.

- Cost, negative margins, and other factors like environmental management will complicate natural gas production until price signals are more supportive. Environmental issues range from water consumption and water quality protection with hydraulic fracturing to air emissions, gas flaring, and local nuisances such as noise and dust that rile communities.
- Natural gas customers and consumers have been enjoying considerable savings over the past few years from lower natural gas prices, a bright spot in an otherwise stilted energy demand context. Recession effects since 2007 have flattened natural gas demand, especially in the major customer segment of electric power generation. Competition among electric power fuels and generation technologies has intensified. Industrial demand has some bright spots as lower natural gas prices and attractive NGLs have stimulated interest. But incremental new natural gas demand is difficult to build. The emphasis on renewables – which captures a public passion that natural gas lacks – creates volatility in both the electric power system and natural gas prices because of intermittency and lack of viable, commercial, large scale energy storage solutions. As a result, growth in renewables could set a ceiling for natural gas generation and wellhead netbacks, if the Texas experience translates to other states and regions.
- Storage has expanded and can better absorb injections from producers, but the lack of natural gas price volatility during 2010-2011 has adversely affected many midstream market participants, raising interesting questions about the role of and sustainability of “volatility loving” entities in restructured, more competitive commodity industries. The distinct, contrary trend in storage data during 2010-2011 – conditions that would be strongly bullish for natural gas prices based on history – is also indicative of the countervailing forces of production surplus and slack demand. Economic recession may be masking many fundamentals that would, ordinarily, enable consumption to soak up excess production and build upward support for prices. However, the view among many is that low and stable prices even in the face of bullish drivers will be the norm going forward.

Not addressed in this paper are the specific ways in which financial and physical markets are converging and how this convergence can make commodity prices more volatile. Other work performed by CEE, past and forthcoming, captures these new dynamics.<sup>87</sup> In Section 2, I

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<sup>87</sup> See *The Future Landscape of Energy Trading* at [http://www.beg.utexas.edu/energyecon/thinkcorner/Energy\\_Trading\\_Foss.pdf](http://www.beg.utexas.edu/energyecon/thinkcorner/Energy_Trading_Foss.pdf). Foss and Gülen, 2011, previously referenced was prepared upon request by U.S. EIA on the basis of *Future Landscape*.

mention the investor interest in commodities for portfolio diversification and risk/reward. Commodities have long been considered an asset class, but mainstream investors now have direct access to commodity markets in ways they did not have previously. Through exchange traded funds, hedge funds, and other avenues, mainstream investors can take positions that reflect bets on forward commodity prices. We believe that as participation has grown (open interest in oil, gas, and other traded commodity derivatives has skyrocketed over the past ten years) the tendency of non-commercial investors to accelerate price movements up or down contributes to both price levels and volatilities. Non-commercial interest waxes and wanes depending upon attractiveness of other, competing opportunities. Many argue that investors can gain exposure to commodity risk by holding shares of companies in the commodities industries, but that also means investors are exposed to variation in management style and quality. Investing in commodity derivatives provides a more direct conduit to the commodity market. There is much to comment about on this front, and much to learn. Suffice it to say, short of outright bans or highly restrictive rules (such as very stiff margin requirements) it is unlikely that the commodity trading genie will be stuffed back into the bottle. It simply would impact too many interests.

I also have not discussed LNG. Separate work is underway and is forthcoming on U.S. and global LNG patterns.<sup>88</sup> As domestic production surpluses have grown, and in the face of underutilized and expensive LNG import capacity, of most interest has been prospects for exports of U.S. natural gas via LNG. Even at the low Henry Hub price deck during 2011 and possibly through 2012, LNG remains expensive when sourced from the U.S. Associated gas production offers the most attractive option, and is driving speculation about industry activity, export applications, certifications for liquefaction, and public and political interest and scrutiny. The current choices most often mentioned are Eagle Ford associated gas production in Texas through Gulf Coast; Marcellus associated gas production through Cove Point. Most observers feel that the clearest case can be made for stranded shale gas production in Canada's British Columbia basins (Big Horn, Mounteney), given the attractiveness of Asia Pacific markets. Some proponents of U.S. Northwest Pacific LNG import terminals are hinting about LNG exports of Canadian production, but the import projects already faced significant hurdles. Success of export strategies will hinge on the pace and timing of market balance adjustments. A sharp and prolonged increase in Henry Hub price in response to tighter supply-demand conditions and cost structure of shale gas drilling could easily strand expensive new LNG export facilities. Potential exporters also need to be mindful of U.S. energy politics. While open markets for natural gas are important and enticing, it is common for proponents of any one outcome to fall prey to mixed messaging and opposition. Immediately following news of a Gulf Coast transaction, pundits and bloggers linked LNG exports, and potential increases in price and benefits to producers, with the assorted controversies surrounding shale drilling. Nor are some gas customer groups happy about potential price pressures that could accompany exports.<sup>89</sup> The most

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<sup>88</sup> Contact CEE, [energyecon@beg.utexas.edu](mailto:energyecon@beg.utexas.edu) for information.

<sup>89</sup> The roughly \$8 billion transaction for Cheniere to supply 3.5 million tons of LNG to BG received considerable coverage. For example, see "RPT-Cheniere and BG ink \$8 bln deal to export U.S. LNG", by Edward McAllister, Reuters, October 26, 2011, <http://www.reuters.com/article/2011/10/26/lng-cheniere-idUSN1E79P0N120111026>. For an example of reactions, see "Massive Natural Gas Export Deal Inked by BG Group, So Much for Industry's 'Domestic Energy' Claims" posted by Brendan DeMelle, October 28, 2011, [http://www.huffingtonpost.com/brendan-demelle/massive-natural-gas-expor\\_b\\_1062696.html](http://www.huffingtonpost.com/brendan-demelle/massive-natural-gas-expor_b_1062696.html). For an example of customer responses, see American Public Gas Association's stance on risk of higher natural gas prices, <http://www.apga.org/i4a/headlines/headlinedetails.cfm?id=820>. APGA and American Gas Association are taking distinctly different positions on LNG exports; see posting from July 2011 at [http://www.pressaction.com/news/weblog/full\\_article/agaexports07092011/](http://www.pressaction.com/news/weblog/full_article/agaexports07092011/) for analysis. Industrial Energy Consumers of America, <http://www.ieca-us.com/>, also opposes LNG exports. As noted in Section 5, industrial

commercially viable option for Lower 48 exports is Atlantic basin shipping and sales to Europe. Panama Canal widening will not support the larger LNG vessels needed for most Pacific basin shipping routes. With Europe as the export target, that begs the question of Europe's own markets and pricing structures. Any meaningful move away from oil indexed gas and LNG supply contracts would make U.S. exports less competitive. Given the need to pull Europe out of its economic doldrums, natural gas market restructuring on the continent and especially the prospect of cheaper gas supply for electric power should trigger action.<sup>90</sup> For that matter, Asian customers and especially Japan would benefit hugely from LNG supply contract reform. The argument that oil indexing satisfies supply security can only go so far for so long, given today's economic dislocations and prospects for a slow recovery. Prospects for LNG – whether imports to balance U.S. markets in future or exports of U.S. production to monetize surplus production – also hinge on global LNG supply conditions. Countering the forces that could break the link between gas supply contracts and oil are the interests of large exporters in maintaining their oil index premiums.<sup>91</sup> Finally, many producing and exporting countries are becoming “gas short”, a result of maturity in their resource endowments and/or real growth in demand for natural gas at home. Sovereign resource owners increasingly are compelled to use their natural gas reserves and production for national economic development, especially in the Middle East-North Africa (MENA) region where stability can only be attained through more concerted economic development and in countries like Nigeria where strong pressures to build domestic demand are driving national and energy politics.

These last comments on oil-indexed gas contracts raise the specter of high oil prices, which I also have not touched on. It is difficult to find sympathetic views for softer oil markets. Oil supply cost curves are stubborn, Asian demand is stiff, Middle East geopolitics are complicated. Other than a Chinese economic meltdown, most oil market participants and observers do not have scenarios for disruptive oil price drops. And yet – new supply is on the horizon at a time when the global economy is tentative. A new twist in the Middle East fabric relates to tactics toward Iran. Many believe that the best instrument for countering Iranian influence, especially in sensitive Iraq, where much new oil production could be sourced, is lower oil price. Lower oil prices would be a direct hit on one of the most oil export revenue dependent governments in the world. For those who view Iran as the source

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customers are benefitting from lower natural gas prices and believe exports may exacerbate price risk and uncertainty. Good coverage on the LNG export debate is provided in “LNG export plans pit producers against North American gas users” by Shawn McCarthy, *Globe and Mail*, November 2, 2011, <http://m.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/lng-export-plans-pit-producers-against-north-american-gas-users/article2223127/?service=mobile>.

<sup>90</sup> OIES has considerable research on European gas supply contract pricing and restructuring. See *Is There A Rationale for the Continuing Link to Oil Product Prices in Continental European Long-Term Gas Contracts?*, Jonathan Stern, OIES, NG19, April 2007 <http://www.oxfordenergy.org/wpcms/wp-content/uploads/2010/11/NG19-IsThereARationaleFortheContinuingLinkToOilProductPricesinContinentalEuropeanLongTermGasContracts-JonathanStern-2007.pdf>; *Continental European Long-Term Gas Contracts: is a transition away from oil product-linked pricing inevitable and imminent?*, Jonathan Stern, OIES, NG34, September 2009, <http://www.oxfordenergy.org/wpcms/wp-content/uploads/2010/11/NG34-ContinentalEuropeanLongTermGasContractsIsATransitionAwayFromOilProductLinkedPricingInevitableandImminent-JonathanStern-2009.pdf>; *The Transition to Hub-Based Gas Pricing in Continental Europe*, Jonathan Stern and Howard Rogers, OIES, NG 49, March 2011, <http://www.oxfordenergy.org/wpcms/wp-content/uploads/2011/03/NG49.pdf>.

<sup>91</sup> Just in time to stir the pot, see “Gas Exporters Seek ‘High’ Prices as They Cooperate on Supply, Projects,” by Robert Tuttle, Anthony DiPaola and Wael Mahdi, *Bloomberg*, November 15, 2011. <http://www.bloomberg.com/news/2011-11-15/natural-gas-exporters-seek-high-prices-as-they-cooperate-on-supply.html#>

of instability in other Gulf countries, containing Iran might be preferable to the current stance of buying internal stability through petrodollar spending. In any case, any driver that narrows persistent spreads between oil, NGLs, and natural gas would throw almost any forward view or scenario on natural gas prices into disarray.

Given the large array of drivers and factors covered in this paper, how will these play out through the end of this decade? What forces could keep natural gas prices lower rather than higher? What could upend expectations and create new price pressures? Models are only as good as the assumptions and data inputs that go into them and even then, models can only inform users about possible outcomes. Scenarios are most useful for understanding the present. Given these two well accepted adages, thinking about future pathways and outcomes should be nuanced. As in NG 18, a summary table can be built of key signposts. For all of the added complexity, risk, and uncertainty, including recession effects and upcoming national elections, the forward looking statements revolve around a selection of high priority conditions as shown in Table 3, which expands on Table 1 using the analysis in this paper.

**Table 3: Competing Viewpoints on Natural Gas - Revisited**

<b>“Gas Short” – Tendency Toward \$10</b>	<b>“Gas Long” – Tendency Toward \$3</b>
<ul style="list-style-type: none"> <li>❖ Reality check on shale play fundamentals               <ul style="list-style-type: none"> <li>➤ Geology less attractive, high development risk stymies progress especially during low price time frame</li> <li>➤ Cost increase resulting from environmental management</li> </ul> </li> </ul>	<ul style="list-style-type: none"> <li>❖ Shale plays deliver expected volumes               <ul style="list-style-type: none"> <li>➤ Cost management plans succeed for both shale oil and shale gas plays</li> <li>➤ Shale oil production provides robust yields of associated gas “byproduct”</li> </ul> </li> </ul>
<ul style="list-style-type: none"> <li>❖ Gulf of Mexico chronically under-produces               <ul style="list-style-type: none"> <li>➤ “Oil proneness” of deep water blocks and oil directed investment</li> <li>➤ Price continues to be unattractive for deep shelf</li> <li>➤ Continued uncertainty surrounding post-Macondo regulatory regimes and oversight</li> </ul> </li> </ul>	<ul style="list-style-type: none"> <li>❖ GOM recovery proceeds apace               <ul style="list-style-type: none"> <li>➤ Regulatory framework more conducive to accelerated drilling activity</li> <li>➤ Natural gas production stabilizes</li> <li>➤ Solutions achieved for monetizing offshore gas production, including deep shelf</li> </ul> </li> </ul>
<ul style="list-style-type: none"> <li>❖ Policy, regulatory imperatives and costs outweigh upstream business fundamentals</li> </ul>	<ul style="list-style-type: none"> <li>❖ Policy, regulatory imperatives and costs are manageable, upstream business fundamentals win out</li> </ul>
<ul style="list-style-type: none"> <li>❖ Robust economic recovery               <ul style="list-style-type: none"> <li>➤ Rapid erosion of current supply surplus</li> </ul> </li> </ul>	<ul style="list-style-type: none"> <li>❖ Weak economic recovery               <ul style="list-style-type: none"> <li>➤ Prolonged gas supply overhang</li> </ul> </li> </ul>
<ul style="list-style-type: none"> <li>❖ Power sector demand increases strongly               <ul style="list-style-type: none"> <li>➤ More gas use for baseload (coal displacement, nuclear roadblocks) offsets renewables impact</li> </ul> </li> </ul>	<ul style="list-style-type: none"> <li>❖ Power sector remains slack               <ul style="list-style-type: none"> <li>➤ Slow economic recovery holds back demand</li> <li>➤ Highly competitive dispatch, gas remains largely a marginal fuel with delays in coal retirements and accelerated renewables dispatch</li> </ul> </li> </ul>
<ul style="list-style-type: none"> <li>❖ Industrial demand grows               <ul style="list-style-type: none"> <li>➤ Lower gas prices spur long term offtake commitments for both NGLs and methane</li> </ul> </li> </ul>	<ul style="list-style-type: none"> <li>❖ Industrial demand remains modest               <ul style="list-style-type: none"> <li>➤ Recession impacts and cost of developing large scale NGLs offtake</li> </ul> </li> </ul>
<ul style="list-style-type: none"> <li>❖ Midstream (processing, pipelines, storage) constraints create classic bottlenecks and</li> </ul>	<ul style="list-style-type: none"> <li>❖ Few midstream constraints               <ul style="list-style-type: none"> <li>➤ Accepted regional models, particularly</li> </ul> </li> </ul>

“Gas Short” – Tendency Toward \$10	“Gas Long” – Tendency Toward \$3
contribute to upward price pressures, sometimes sharply ➤ Delays in public approvals add to high costs and impact capital investment flows	for the Marcellus region and including public approvals, evolve to accommodate production flows and associated midstream requirements
❖ Domestic LNG exports have price impact ➤ U.S. must compete heavily for and pay dearly for LNG to address any supply-demand imbalances ➤ Less LNG supply available worldwide as domestic demand in producing/exporting countries takes off	❖ Domestic LNG exports do not develop or, if launched, have no price impact ➤ LNG supply worldwide remains robust ➤ Restructured, mainly European gas and LNG supply contracts create more competitive pricing on gas indexes
❖ Oil:gas price spreads narrow ➤ Less pressure to renegotiate international gas supply contracts	❖ Oil:gas price spreads remain wide ➤ Increasing pressure to renegotiate gas supply contracts, gas exporters resist
❖ U.S. natural gas industry business model – <i>high price, low volume</i> ➤ International majors stay in the game for liquids with modest investment in nonassociated gas	❖ U.S. natural gas industry business model – <i>low price, high volume</i> ➤ International majors pursue large scale upstream investments to support downstream offtake commitments, including LNG exports as part of global value chains

Building scenarios for continued lower prices or a bump to a higher price deck are complicated by contradictory forces. Lower prices attract demand; any constraint on supply in the face of rising demand (economic recovery, coal generation plant phase outs, and so on) could tighten market balances and introduce upward price pressure. Higher prices attract drilling and while \$6 seems to be the comfort zone, it remains unknown what price level might be needed to attract drilling back to non-associated gas plays. While natural gas, and other commodities, generally have followed oil price trends, natural gas has done so even as spreads widened. Whether or not spreads persist is a question that complicates scenario building. Policy inducements have considerable impact on the U.S. energy scene. Industrial customers that worry about exports of domestic gas production via LNG also tend to be more agnostic about use of natural gas for power generation. They also worry that substantial deployment of natural gas for power use would make their own gas purchases more expensive and have long argued that gas combusted for power wastes valuable feedstock for critical materials, and that power can be generated from many sources and technologies. Wide spreads and the perception that wide spreads will persist undermines these arguments. If nothing else, the scenario builder should expect a continued high degree of fragmentation in U.S. energy politics vis-à-vis natural gas with conflict across groups and interests and shifting positions as perceptions change.

Perceptions do change, but they also tend to stay the same in one important respect. The “gas short” versus “gas long” debate is old and permeates the political and industry landscapes, even as the underlying conditions and preconditions are altered. As noted, perceptions shifted from natural gas as a “no regrets” response to climate concerns to a more confrontational context over drilling as lower gas prices clashed head on with philosophical support for renewables. Now, methane and other GHG emissions from well completions and the natural gas supply system are a target for regulatory oversight along with other aspects of natural gas resource development. Even if unintended, the potential outcome of regulatory

oversight in the form of higher prices would bolster flagging prospects for renewables and satisfy those concerned about climate with a lower level of development and use of a fossil fuel. “Gas short” plays more happily to those interests and fits the post-fossil fuel paradigm much more comfortably. “Gas long” is, simply, inconvenient.

What about the organizational and logistics structure of the Lower 48, or more broadly, the North American marketplace? Currently, producers in the Marcellus and surrounding shale plays take prices that are netbacks based on transportation cost from Henry Hub to sales locations in the Marcellus region. Why should that continue to be the case? If Marcellus region production volumes become as large as projected, given proximity to load centers why wouldn’t or shouldn’t a separate, financially liquid hub and natural gas contract emerge?

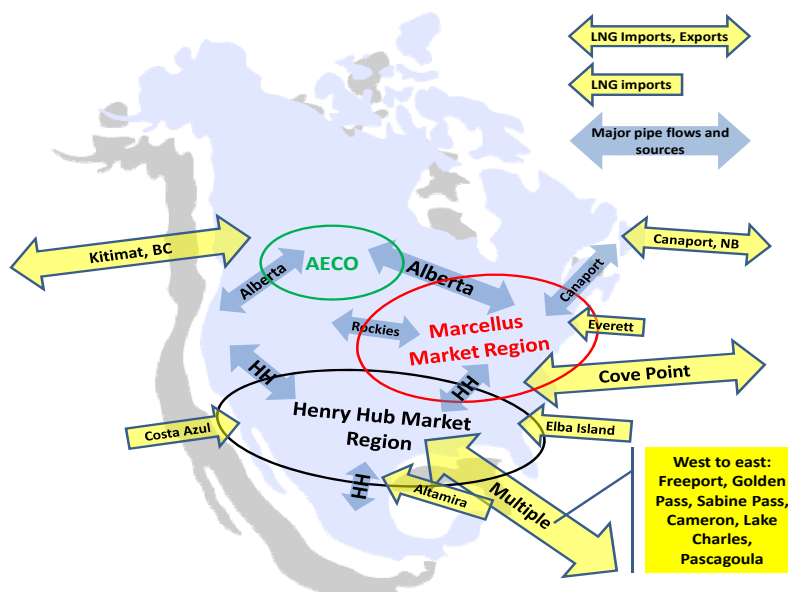
Figure 46 provides a rough schematic (not to scale) of major North American natural gas and LNG flows, including probable locations for LNG exports if those were to happen. Generally speaking, the Henry Hub market region encompasses the (still) dominant concentration of onshore and offshore oil and gas producing fields (historically important onshore producing locations along the Louisiana-Texas Gulf Coast, in East Texas, Oklahoma, and West and South Texas along with the new shale plays, extending from the Eagle Ford in South and West Texas east to the Barnett, Haynesville in Louisiana and Fayetteville in Arkansas). The region is defined by Henry Hub and other key market hubs and centers, long established long distance pipeline routes to the West Coast and Northeast and more recent offtake in the southeastern U.S. (also served by the Elba Island LNG import terminal off of Georgia<sup>92</sup>) and new routes to Florida. The largest concentration of LNG import capacity resides along the Gulf Coast.

The “Marcellus” region is so named for simplification; other emerging shale plays are incorporated but the Marcellus is the dominant geological feature. The Marcellus region is dominated by the huge northeastern and Midwest industrial load centers but, importantly, little real growth in load has occurred in either one during recent years although significant bottlenecks (constraints on expanding pipeline capacity in dense northeastern urban corridors) and pockets of demand have driven midstream investment. More robust load growth has taken place in the south. Consequently, including the currently distressed housing markets in the southeast, gas (and power) loads have been heavily impacted in the “sand states” of Florida, Arizona and Nevada where housing was most overbuilt and overpriced. Natural gas production from the Rockies mainly flows to the Midwest and Northeast, with the new Rockies Express pipeline built in response to the large basis differentials that had existed between northeast city gates and Rockies producing fields, historically priced well below Henry Hub. In addition to the mid-Atlantic (Cove Point LNG terminal in Maryland), the Northeast region also has access to global markets via the Everett LNG receiving terminal in Massachusetts, which remains a vital gas supply point for winter season heating needs in New England but for which no flexibility exists to add export capacity. The Marcellus region historically also has been served by Canada, with the northeast anchoring the huge TransCanada west (Alberta) to east pipeline system. LNG import capacity is installed at Canaport in New Brunswick; deliberations are underway regarding whether exports of possible shale gas production abundance from both eastern U.S. and Canadian locations could be added. The Canadian hub in Alberta (AECO) also is often discounted to Henry Hub. Internal debottlenecking within the province helped to dissipate basis differentials somewhat.

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<sup>92</sup> El Paso personnel have indicated that no plans are under consideration for LNG export capacity at Elba Island.

**Figure 46: North American Natural Gas Marketplace Structure**



Sources: Author's compilation.

U.S. and North American market centers and hubs tend to develop where they make sense – where production, storage, and pipeline takeaway capacity are aggregated and trading can be supported. Henry Hub is the oldest market center, established in 1988. The concentration of capacity served by Henry Hub made it the logical choice for the traded natural gas futures contract. The U.S. EIA notes that, “By 1998, 36 market centers had been established within the U.S. natural gas pipeline grid. By 2003, however, 13 of these had closed their doors as the concept matured and those that were unable to develop a trading base were eliminated. Currently, 24 market centers in the United States provide hub services to customers, the majority of which are located in the States of Texas and Louisiana.”<sup>93</sup> At the height of energy merchant activity, market centers emerged where traders and marketers were attempting to create new concentrations of liquidity. It is true that trading activity at several locations was suspect. However, looking at U.S. and North American natural gas dynamics today through the lens of the energy merchant era begs the question of Henry Hub remaining the sole contract point in future.<sup>94</sup> If Marcellus production becomes as large and dominant as some posit, if facilitating storage and pipeline takeaway capacity are developed, and if Atlantic Basin supply-demand connections are forged through LNG import/export arrangements, then there is no reason why a well-financed hub and contract could not be created. These conditions present “lots of ifs” but make a key, and seemingly forgotten point: nothing is set in stone when it comes to the North American natural gas market framework. More will be said about North American markets and price dynamics in the forthcoming OIES book, *The Pricing of Internationally Traded Gas*.<sup>95</sup>

<sup>93</sup> From EIA's 2008 market center and hub update, published in 2009. See

[http://www.eia.gov/pub/oil\\_gas/natural\\_gas/feature\\_articles/2009/ngmarketcenter/ngmarketcenter.pdf](http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2009/ngmarketcenter/ngmarketcenter.pdf)

<sup>94</sup> To a query from peer reviewers about why a Marcellus hub and contract have not yet been established, two observations should be kept in mind. First, Marcellus production must be firmly established, which entails a level of public acceptance not yet achieved. Second, if Enron were still in existence, I have no doubt that engineering a Marcellus hub would already be in the works. A distinct cluster of expertise constituted by Enron and its competitors was lost when the company and the energy merchant era imploded.

<sup>95</sup> Nothing is new under the sun. Having dreamed up Figure 46 I find that others are clearly contemplating a possible split between Marcellus and Henry Hub. See *Unconventional Midstream: Making Connections*,

To sum up, if the Henry Hub price curve remains near \$3, LNG exports of domestic production look very competitive at anticipated prices in Europe. If the Henry Hub price curve is raised and a higher price event or set of events happens, such that a \$10 spike is tenable, then exports look out of the question. The exception could be Asia with the most logical route being from western Canada (or Alaska, if backers of an “all Alaska” solution for monetizing North Slope natural gas with a pipeline to Cooke Inlet won out). A future price level that could accommodate a \$10 price spike also could be more attractive to LNG imports. At this point, it is important to note that throughout 2011 and, in fact, back to 2008 U.S. LNG imports appear to have settled into a “baseload” stage with receipts and send out of about 1 BCF per day, in spite of soft market conditions. This is half of the 2007 peak of about 2 BCF per day, leaving the U.S. LNG industry where it is. It is also a small share of the huge 60-plus BCF per day marketplace. Nevertheless, intentions by some developers and exporters to meet their commitments and, for some countries, to maintain their U.S. market presence; the obligations of long term supply contract arrangements; the need to maintain cryogenic conditions at LNG terminals – all play into maintaining LNG flows.

The upshot to my analysis is a viable scenario in which some developers are successful in securing support and financing for LNG export strategies and facilities but by mid-decade, when these projects are anticipated to come on line, prices could shoot up with LNG imports responding accordingly. It could be argued that the push for LNG exports is about “jobs, jobs, jobs” during a stubbornly down economy, but that simply pits potential exporters against job creators in domestic manufacturing. Are exports needed in order to preserve and sustain a domestic natural gas industry? Many arguments are being made on that front<sup>96</sup>, but that line of reasoning simply reiterates what everyone knows – there is too much gas for demand, it has been relatively easy for producers to shift money and attention to liquids plays, and while the results are volumes of associated gas entering a soft market the diversion of capex away from non-associated gas drilling ensures a correction on down the road. With economic recovery, that correction could come sooner rather than later. Finally, might all of this cause significantly greater volatility, with prices moving between a \$6-10 range? The analysis I’ve conducted suggests that such an outcome could be in the realm of possibilities. A combination of any number of factors, as presented in Table 3 above, could support this scenario: a geology reality check for both shales and offshore, demand push from coal retirements (especially with policy inducements), economic recovery – taken all together, these factors could swamp the “gas long” view. Natural gas demand for power generation popped the 1990s gas supply bubble, setting up dynamics for the surge in shale investment and production.

In closing, it is worth reflecting on the billions that have been spent and could be spent on natural gas strategies. Companies and their investors must navigate between belief in spreads and the reality of amortizing long term capital investments through a foggy and unknown future. Black swans permeate the random walk. Agility, optionality, and flexibility are highly valued but cost real money. For all of these reasons, it is worthwhile to be circumspect about the Henry Hub price trajectory to 2020.

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Unconventional Oil and Gas Center, February 10, 2011 regarding the concept of using Transco’s Leidy storage center to foster a new Marcellus hub. <http://www.ugcenter.com/>.

<sup>96</sup> For example, see [http://www.navigant.com/~media/Site/Insights/Energy/NG\\_Notes\\_Mar2011\\_Energy.ashx](http://www.navigant.com/~media/Site/Insights/Energy/NG_Notes_Mar2011_Energy.ashx). In the March 2011 circular, the authors note: “The health of our gas industry is at risk more from a real and growing domestic oversupply coupled with a lack of markets than it is from an undersupply potentially attributed to domestic exports.”



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## APPENDIX I: NG 18 HIGHLIGHTS

The table below provides highlights on conclusions and underlying assumptions from NG 18 as well as eventual outcomes for comparison.

NG 18 Conclusions	Assumptions	Outcomes
<i>Supply, Cost, Price</i>		
<p><i>“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 U.S. is entering, albeit in a bumpy way, a new period of natural gas surplus.”<sup>97</sup></i></p>	<ul style="list-style-type: none"> <li>• Emphasis on unconventional gas plays in the Rocky Mountains and East Texas (Barnett Shale production was drawing attention); Canadian unconventional gas plays; Gulf of Mexico (GOM) deepwater as well as deeper drilling in shallow water locations</li> <li>• Also under discussion industry-wide was the potential for a pipeline solution to carry Alaska natural gas production into the Lower 48</li> </ul>	<ul style="list-style-type: none"> <li>• Domestic production from shale gas plays accelerated, with shales plays now constituting 16 percent of total domestic production</li> <li>• A major oil spill in the U.S. Gulf of Mexico (GOM) has threatened a key, conventional production province</li> </ul>
<ul style="list-style-type: none"> <li>• Widespread belief that a reasonable marginal cost of supply was \$6/MCF</li> <li>• <i>“The pressure to effectively ‘prove up’ new technologies and supply, and to reduce costs on a unit basis of production is huge. 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...If the current high rates of drilling persist and if success is achieved, a ‘Section 29’ type of effect could occur. In this scenario, rapid deployment of E&amp;P [exploration and production] financial capital and technology, along with strong</i></li> </ul>	<ul style="list-style-type: none"> <li>• Strong price signal and associated expectations would drive investment in both domestic drilling and LNG import capacity</li> <li>• Higher natural gas prices would continue to impact consumption, mainly for industrial users</li> </ul>	<ul style="list-style-type: none"> <li>• Market price peak of \$13 and perceptions that higher price “deck” would prevail accelerated drilling investment, most prominently in North American shale gas plays</li> <li>• Build up in domestic production along with demand reductions (higher price and economic deterioration)</li> <li>• Lower price deck, falling below \$3 during August-September 2009 and remaining close to \$4 most of the time since then</li> </ul>

<sup>97</sup> NG 18, page 33.

NG 18 Conclusions	Assumptions	Outcomes
<p><i>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.</i>"<sup>98</sup></p>		
<ul style="list-style-type: none"> <li>• LNG could constitute a second possibility for how a new gas bubble might form</li> <li>• <i>"If LNG cargoes arrive in abundance because of favourable Henry Hub pricing relative to other Atlantic Basin markets, a hefty downward push could occur."</i><sup>99</sup></li> <li>• Only a 50 percent utilization of LNG receiving capacity might be necessary to re-balance the Lower 48 marketplace</li> <li>• <i>"U.S. gas market fundamentals would have to support such a scenario (i.e., abundant gas inventories in storage, stronger domestic production, and so on)"</i><sup>100</sup></li> <li>• LNG must be competitive in a wholesale electricity price band reflecting extensive inter-fuel dynamics with coal setting a floor and natural gas on the margin</li> </ul>	<p>LNG would be a price taker in the U.S. and LNG cargoes could contribute to gas-on-gas competition</p>	<ul style="list-style-type: none"> <li>• Cargo receipts surged from roughly 86 to nearly 99 billion cubic feet (BCF) during March-August 2007<sup>101</sup></li> <li>• With the dramatic increase in domestic production, even less LNG was needed than assumed thought</li> <li>• The combination of doubling or tripling LNG receipts between 2006 and 2008 and the nearly one-quarter jump in domestic production from 2006 to present served to accelerate downward price pressure</li> </ul>

<sup>98</sup> NG 18, page 26.

<sup>99</sup> NG 18, page 35.

<sup>100</sup> NG 18, page 35.

<sup>101</sup> Based on U.S. Energy Information Administration, or U.S. EIA, data

NG 18 Conclusions	Assumptions	Outcomes
<i>Demand and price</i>		
<ul style="list-style-type: none"> <li>• “A hallmark of the U.S. natural gas marketplace is the extent to which gas is most competitive with itself.”<sup>102</sup></li> <li>• “The near-parity for electric power and industrial consumption represents the most fundamental shift in the natural gas marketplace...natural gas consumption for power generation may overtake natural gas for industrial use...natural gas pricing at the margin will be driven much more by gas-fired power”<sup>103</sup></li> </ul>	<ul style="list-style-type: none"> <li>• Natural gas prices would likely reflect demand driven by efficient electric power use rather than influence from other demand segments (specifically price-sensitive industrial customers)</li> <li>• Electric power would set the price of natural gas at the margin given competition among generation fuels and technologies</li> <li>• Fuel switching with oil not a compelling factor for the electric power segment</li> <li>• Challenges exist to continuing or increasing use of coal for power generation</li> </ul>	<ul style="list-style-type: none"> <li>• Natural gas utilization for electric power generation now roughly one-third of total end user consumption</li> <li>• Rollback in coal development as a result of environmental pressure and lack of consensus on climate change policy</li> </ul>
<i>Environment</i>		
<ul style="list-style-type: none"> <li>• “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 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.”<sup>104</sup></li> </ul>	<p style="text-align: center;">Uncertainty regarding public acceptance of more intense domestic drilling and political conflict surrounding climate legislation.</p>	<ul style="list-style-type: none"> <li>• “Gasland effect” on drilling, ranging from local disturbances to broader regional and national debate on hydraulic fracturing and other issues<sup>106</sup></li> <li>• Lack of consensus on climate legislation with increased opposition to coal provides new impetus for natural gas fired power generation as “no regrets” strategy</li> </ul>

<sup>102</sup> NG 18, page 35.

<sup>103</sup> NG 18, page 15.

<sup>104</sup> NG 18, page 26.

<sup>106</sup> Reference to the movie *Gasland*, which has had widespread affects. See <http://www.gaslandthemovie.com/>. For a taste of the debate surrounding *Gasland*, see Energy in Depth, <http://www.energyindepth.org/http://www.energyindepth.org/> and specifically <http://www.energyindepth.org/2010/06/debunking-gasland/>. For a thorough and provocative treatment of the myriad debates regarding hydraulic fracturing, see the report by Tudor Pickering Holt and Reservoir Research Partners, [http://tudor.na.bdvision.ipreo.com/NSightWeb\\_v2.00/Handlers/Document.ashx?i=2ac12b4d442943a090b8b0a8c8d24114](http://tudor.na.bdvision.ipreo.com/NSightWeb_v2.00/Handlers/Document.ashx?i=2ac12b4d442943a090b8b0a8c8d24114).

NG 18 Conclusions	Assumptions	Outcomes
<ul style="list-style-type: none"> <li> <i>“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.”<sup>105</sup></i> </li> </ul>		<ul style="list-style-type: none"> <li>Political conflict on climate along with drilling related issues complicates outlook</li> </ul>

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<sup>105</sup> NG 18, page 31.