EMD Energy Economics and Technology Committee Annual Report

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I. Committee Activities

The April 2011 annual report remains as a relatively comprehensive review of many continuing challenges and developments, particularly concerning natural gas and shales. The commentary below is highly selective, emphasizing significant changes and new or overlooked issues that have come into the foreground. It is an evolving document and it is hoped that it will elicit some further comments and contributions from members.

The Committee is represented in the organizing group for an upcoming Geosciences Technology Workshop (Hydraulic Fracturing: New Controversies, New Plays), now scheduled for August 13-15, 2012, at the Green Center, Colorado School of Mines. While covering the basics of hydraulic fracturing, topics of gas and fluid migration, water management, case studies, and regulatory dimensions, the principal perspectives brought by the Committee are topics of the importance of the shales, resource controversies, impacts on supplies, and beating of the bushes to obtain insights into cost components and cost escalation. These will be addressed in an opening (1/2 day) session. Dr. Susan Nash is your key AAPG contact for ongoing information about this GTW. Individuals with drilling/hydraulic fracturing experience can offer insights, even if of a somewhat informal nature, by participating in panels. Dr. Nash and J. Platt would very much like to hear from you.

The Committee is also represented on AAPG's Committee on Resource Evaluation (CORE), under the leasdership of Richard Nehring (Nehring Databases, Boulder CO). It will be very helpful if any interested members of Energy Economics & Technology contact J. Platt with suggestions and comments and/or R. Nehring directly. His aim in offering a formal invitation for participation is to open additional channels in the organization exactly to draw on any relevant expertise of our Committee members. The main topic under examination by CORE is the characterization of unconventional resources, where the geologic and economic/engineering dimensions are necessarily intertwined. From reviewing some initial comments to the committee, it is evident that one essential step will be to recognize what related work has been undertaken on these matters by various sister societies.

II. Energy Economics Commentary

30% of production from shales? The gas industry is in great turmoil, moving as fast as it can to reposition into higher value oil and liquids-rich plays. This causes a sense of impermanence – nothing seems very stable. But an unusual barometer has been developing. This is the amount of gas production derived from shales. It is impossible not to see this share reach (and exceed) 30% without a sense of awe. Chart 1 is EIA's new series on shale gas production, converting near real-time data from Lippman Consulting Energy Insights into dry gas numbers. It is posted in EIA's *Natural Gas Weekly Update*. For 20 months prior to February 2010, Lower 48 onshore gas production (i.e. gross withdrawals, excluding Federal offshore Gulf production) averaged about 56 Bcf/d. The last few months of 2011, this had increased by 12 Bcf/d to 68 Bcf/d. If including the Federal offshore Gulf, overall Lower 48 production increased from 62-63 Bcf/d in January 2010 to 72.5 Bcf/d, an increase of 10 Bcf/d. As shown in the chart, shale production over this period increased from about 11 Bcf/d to 24 Bcf/d. The latter is 35% of EIA's dry marketed gas production estimate (69 Bcf/d) for December 2011.

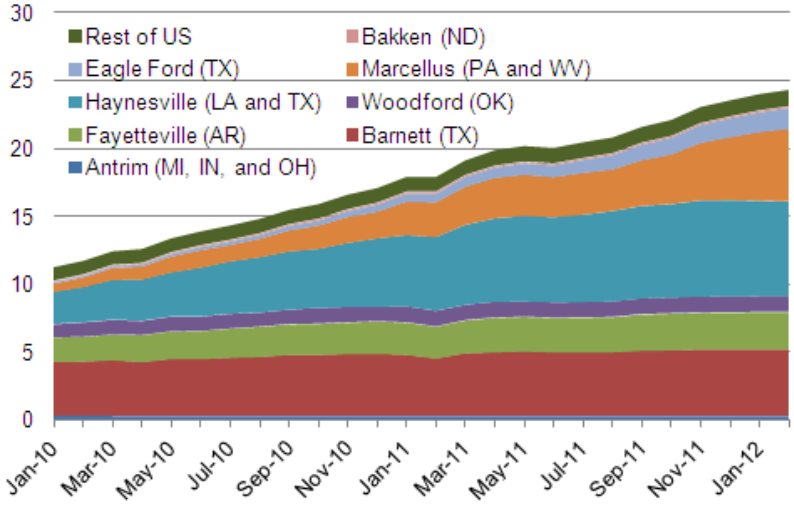


Chart 1. Monthly Shale Gas Production, Jan. 2010-Feb. 2012 (Bcf/d)
Website: EIA, reflecting ross withdrawals converted to dry gas. Data: LCI Energy Insight.

How about almost 40%? The authors of monthly shale gas production tracking in Chart 1 also track all other wellhead gas production. Referring to LCI's estimates, the share of production from shales is almost 39% of gross Lower 48 wellhead production.

Gross Lower 48 Wellhead Production				*Comparison*
	LCI Energy Insight Data			*EIA L48*
	Shale	L48	Shale % of L48	
Dec-11	26.18	69.8	37.5%	*72.49*
Mar-11	27.1	69.9	38.8%	

Source: LCI Energy Insight *Monthly Shale Gas Production Report*, April 2012

Interestingly, LCI Energy Insight is not able to reconcile its measures of gross withdrawals with those reported by EIA. The difference is on the order of 2.5 Bcf/d. If EIA's higher shale gas estimate is correct, the share could be as much as 1.4% smaller. This difference is a quibble and may derive from approximations involved in EIA's simple ratio method of extrapolating from a set of companies' production data. For the reader, a chart with an expanded monthly shale gas production series, by major shale, is included in Appendix Chart A-1 courtesy of LCI Energy Insight. ***Rig Counts.*** Also included is Chart A-2 based on LCI Energy Insight's breakdown of Baker Hughes' rig count information. The Woodford Shale's count has essentially matched one-for-one the Marcellus' growth in Pennsylvania since mid-2009. The Eagle Ford has largely followed in the footsteps on Bakken Oil shale activity, until beginning to exceed it in mid-2011.

Something from nothing – a financial retrospective on shale gas innovation and cumulative value. *Prepared by Dieter Beike, Ph.D. Consultant, Houston.* For the single year 2011, the consulting firm PricewaterhouseCoopers (based on IHS Herold data) reported a shale related Merger & Acquisition (M&A) value of $107 Billon, with the upstream sector alone counting for $59.6 Billion. For the 30 year

period from 1981 (the year of discovery of the Barnett Shale) through 2011, the cumulative value for upstream shale M&A reached $179.3 Billion (calculated by author using the PwC report and data reported by consulting firm KPMG quoting WoodMackenzie data from 2005 - 2010).

Chart 2 (full page) shows how a technology innovation (see point 1), initially driven by the need of a single company to increase its gas supply across its leaseholdings, led to a value increase of its properties from virtually $0 for shale gas acreage to $3.5 Billion for the overall company – after 20 years of incremental innovation work. In 2001 a technology visionary company (see point 2) realized the technological potential, invested in design improvements and developed the Barnett Shale to the most prolific gas producing area in the U.S.

The next 10 years of technology applications was much more dynamic. For the first five years of that period increased technological efficiencies led Early Adopters (i.e. Independent oil companies) to also enter the Barnett Shale before then moving on to other shale plays, leading to a "landgrab of acreage", which resulted in increased leasing costs (see point 3) . During the following three years the first wave of international Oil Majors (who previously had concentrated on LNG imports for the U.S.) entered the "shale gas world" and started to acquire shale gas assets and smaller companies with shale gas know-how. This first phase of investment by "Early Mainstream " philosophy companies resulted in an overall M&A value of $36.2 Billion for the years 2005 – 2008 (see point 4).

The conservative risk-averse mainstream oil Majors had arrived in 2009 (see point 5) when ExxonMobil announced the acquisition of XTO for $41 Billion, leading to a total M&A value of $80 Billion for 2009 and 2010. In 2011 further $59.6 Billion were invested by Laggards (see point 6) that consisted of companies that took advantage of the debt-ridden independents and a low gas price situation in the US with its high gas price differential to Asian markets. Now, increasingly also Austral-Asian companies have announced interest in US acquisitions.

Overall, this innovation developed into a game-changer of supply and demand and related gas prices and led to efforts for its worldwide application, while continuously forcing strategy changes by stakeholders in the gas market. During the period from 1981 through 2011, U.S. shale gas production per year increased from 0.15 tcf to > 5 tcf, as delineated in the preceding observation.

References include: KPMG International: "Shale Gas Outlook: A U.S. perspective" 2011 and Oil and Gas Journal, February 10, 2012: "Unconventional plays likely to drive 2012 oil, gas M&A". Note: an expanded version of this contribution by Dieter Bieke will appear in an SPE paper.

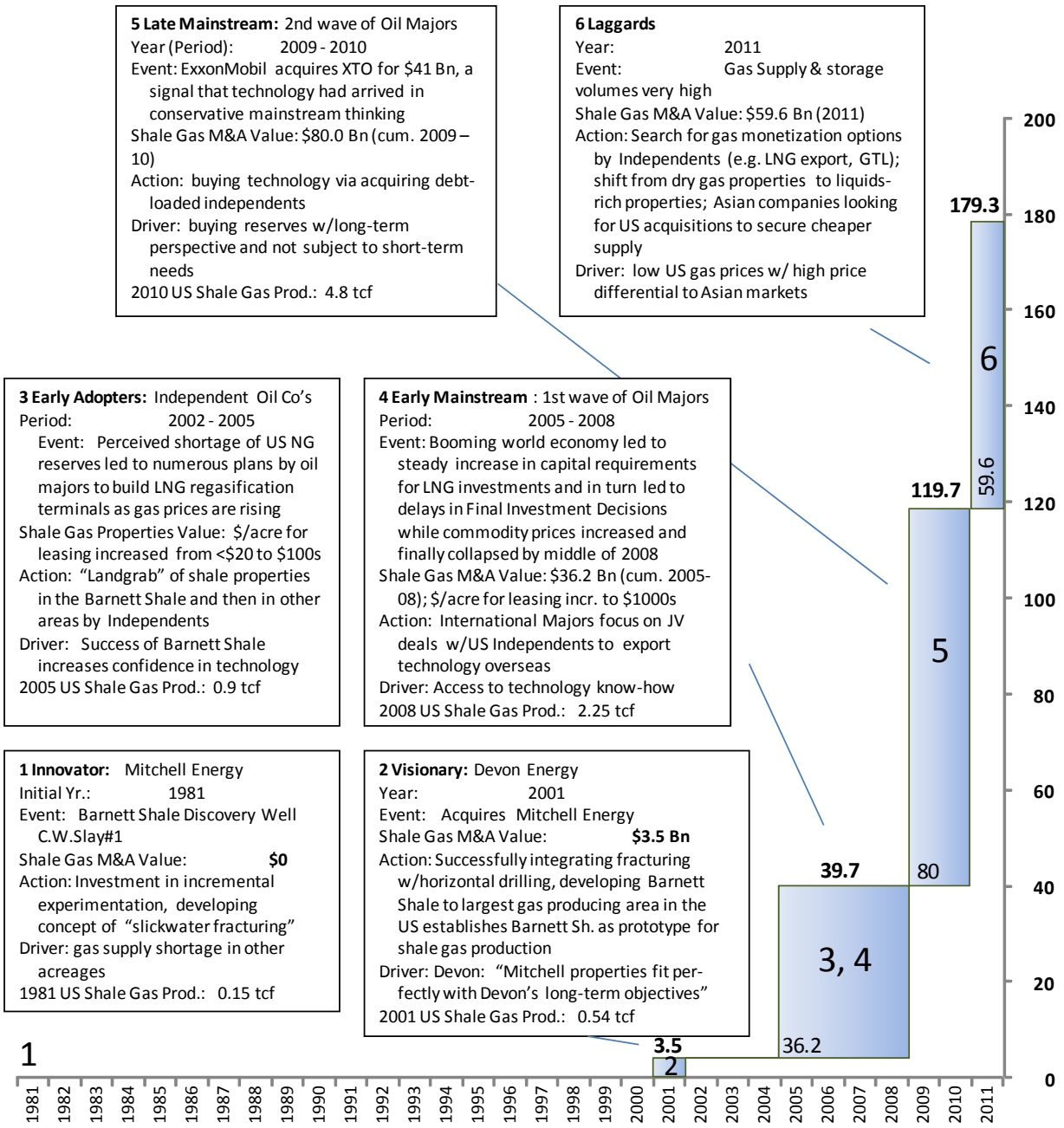


Chart 2. Cumulative Upstream M&A ($Billions)

It's the supply curve, stupid! With poetic license from the iconic phrase of the 1992 Clinton-Bush election campaign, the new supply curve of natural gas -- about which there is no absolute agreement, and which remains obscure in its proprietary details – is the dominant lasting feature of the emergence of the gas shales. A host of considerations can distract from the new realities. At the end of the day, the matter is one of "much more" gas or "much, much more" gas. MIT's *The Future of Gas* report (draft in 2010, final in 2011) shoes this tellingly, with the shale curve added in Chart 3. MIT relied on their own work as well as ICF's Hydrocarbon Model.

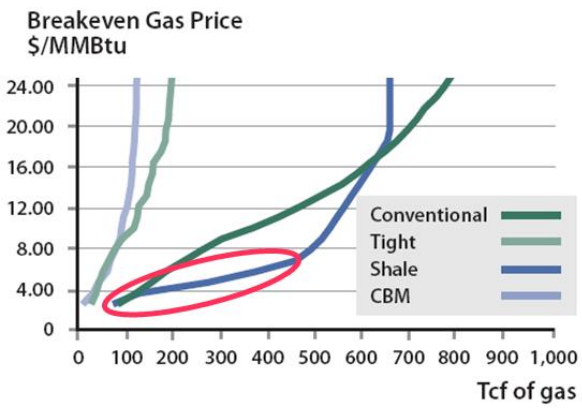


Chart 3: Shales Add an Entire New Supply Curve at Lower Costs Than Other Sources of NG
Source: MIT, *The Future of Natural Gas*, 2011. CBM=coal bed methane, Tight = tight gas sands.

MIT's evaluations were consulted by the National Petroleum Council in constructing its evaluations of North American supply. NPC's lower (i.e. leftward) curve assumed current technology and represented the mean of a number of resource and cost assumptions. Its advanced technology case pushed the curve far to the right, with high resources pushing it farther still. This family of three curves along with others addressing either U.S. or North American supplies are summarized in Chart 4, along with NPC's estimates of the range of cumulative demand from 2010-2035. The California Energy Commission employed the Rice World Trade Model in developing its curve, increasing the supply by over 60% or 400 trillion cubic feet at the $5.00/mcf price level compared to its assessment of four years earlier (CEC *2011 Natural Gas Market Assessment: Outlook in Support of the 2011 Integrated Energy Policy Report*, September 2011). Deloitte's curve was presented in Made *in America: The Economic Impact of LNG Exports from the United States*, October 2011. Energy Ventures Analysis' curve, distinct methodologically from the others, was included in research provided to the Electric Power Research Institute (EPRI, *Mitigation of Energy Market Risks*, December 2010. 1019825).

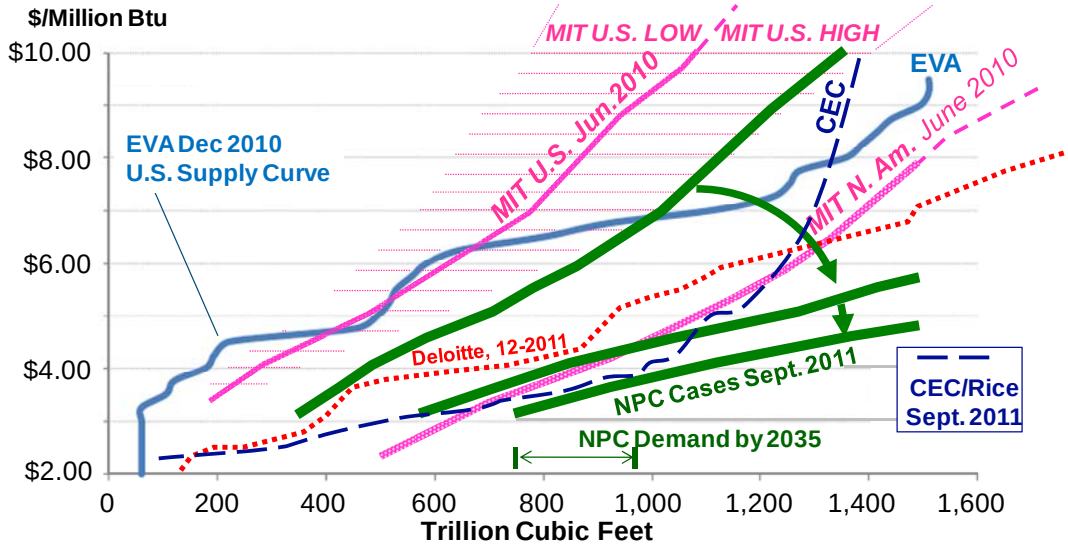


Chart 4: Comparison on Selected U.S. and North American Natural Gas Supply Curves

In considering this array of ample to abundant supply, a "flat supply curve" is nevertheless not a recipe for flat prices – although it does reshape equilibrium expectations. As always, the jittery market will track faster-moving phenomena: shifts in investment (rig counts/gas-directed drilling) and the yearly battle of storage filling/withdrawal/weather. Yet even here, the shales are redefining what is meant by jittery (volatility).

Harsh adjustments to oversupply. 2012 promises to be the year in which low gas prices will have caused a chain of events to actually begin to depress natural gas production. In the last annual report, much attention was given to financing arrangements (joint ventures, drill carries) that promoted production regardless of price. This year is very different. Numerous companies have been reporting a turn toward liquids-rich plays and toward oil exploration. Expect a great deal of commercial research to report out who is making these announcements and what impacts may be expected, eventually, on supply. As an example, the factors at play are delineated in Credit Suisse's March 9, 2012 short term assessment, *US Natural Gas Reservoir: When Will Supply Turn?* (Analysts A. Jayaram, S. Revielle, and J. Stuart). Due to shifts in drilling activity, CS expects the sharpest production declines will be in the Haynesville core and Barnett (-3.2 Bcf/d by year end), whereas the greatest increases are expected from the Marcellus (+1.4 Bcf/d). On top of this, announced shut-ins by just three companies could amount to -1.35 Bcf/d. The subtotal of this activity and cutbacks is a -3.0 Bcf/d adjustment. But working in the opposite direction is associated gas from liquids-rich plays, especially the Eagle Ford, Granite Wash and Permian plays, estimated by CS at adding 1.5 Bcf/d. With total supply possibly dropping only 1.5 Bcf/d, their market outlook remains bearish.

Collateral damage extends to:

<u>Gas Producers</u>

- distressed producer balance sheets
- write downs of reserves

<u>Power Sector</u>

- low electricity prices (with impacts on net revenues for power producers)
- low margins on coal-fired and nuclear generation
- stresses on operating budgets, and other financial consequences
- weakening business conditions for wind projects and other generation, even though subsidies for wind do not terminate until the end of the year

Lower energy (natural gas) costs are not a bad thing. This certainly depends on one's perspective. Offsetting the negatives are consumer and other macroeconomic benefits of lower-priced natural gas, especially important in the environment of historically high gasoline prices. This is a topic that warrants close economic analysis, although there are a host of lags and complications with counterfactual analysis of this type (i.e. what the effects would have been if prices had not collapsed). NETL (National Energy Technology Laboratory) has done research on the opposite: the impact of high oil prices [*A Decade of Economic Change: Fuel Prices and Households*, G. Pickenpaugh and P. Balash, Feb. 2012 working presentation]. The nearly linear collapse of natural gas prices since mid-summer 2011 from $4.00+ to

$2.00+ (April 2012) has been remarkable enough, but it has been even more remarkable in light of the absence of seasonal increases. The latter translates into a new view of price volatility and crossover effects of lowered power prices. From a consumer point of view, price collapse translates into a building-up of savings (or the prospect of this) over time. For a sense of scale, winter national consumption averages about 85 billion cubic feet per day (Bcf/d). Assuming an eventual decrease in expenses of at least $2.00/thousand cubic feet, the consumer benefit amounts to $170 million per day, $1.2 billion per week and $15-20 billion over 3-4 winter months.

Jaw-dropping storage figures. There's no other way to put it. Emergence from the withdrawal season (end of March) with some 750 Bcf above the norm in storage acts as a wet blanket going into the summer (Chart 5). Just how much lower than $2.00/mmBtu might prices fall? And if prices cannot balance physical supply, will pipelines have to place limits on producing gas? Rock-bottom prices will likely have little effect on usage until after summer heat waves when power sector gas units have greater spare capacity – a pattern of ever-greater "shoulder month" use that has developed every year since 2008.

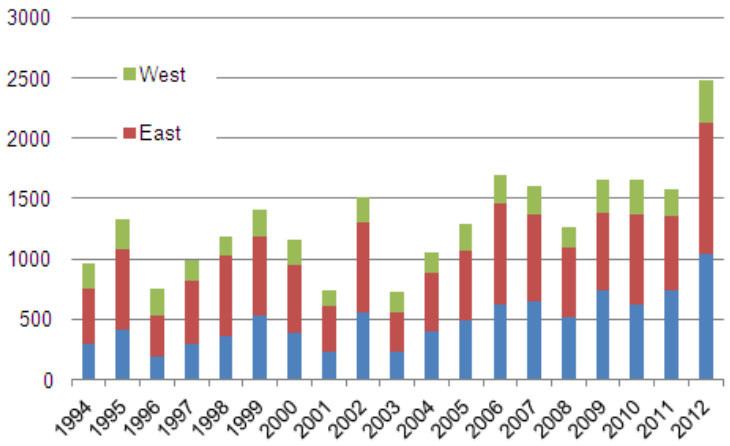


Chart 5. Natural Gas Storage: End of March Levels

Source: EIA Natural Gas Weekly Update, 5 April 2012. West, East and Producing area (blue) storage levels are delineated.

EIA's popular weekly portrayal of the gas storage situation is shown in Chart 6. What this does is effectively and starkly show how far ahead of normal – over 2 months – is the status as of Friday, March 30th (per EIA's Natural Gas Weekly of April 5th), effectively the end of the withdrawal season.

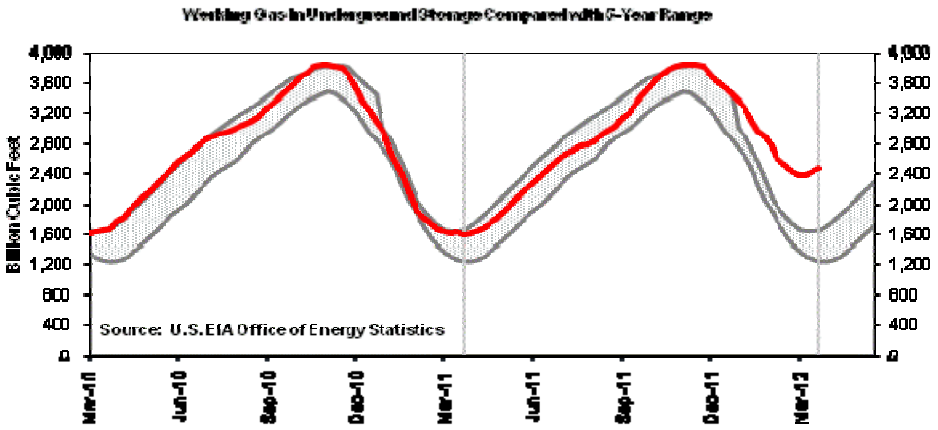


Chart 6. Natural Gas Storage and Trends, 2010-2012

Source: EIA Natural Gas Weekly Update, 5 April 2012. Working gas in underground storage; vertical lines are current and prior year.

Catalysts for gas demand: cheap gas and expensive oil. Our prior Committee report touched on the movement of the oil-gas price ratio into new territory where, in the long run (per the EIA's 2010 Annual Energy Outlook), it appeared the ratio would settle at around 17 (WTI $/bbl divided by natural gas Henry Hub in $/million Btu). That view, a historical anomaly, has not only been reinforced but now looks tame (Chart 7). In recent days, natural gas spot prices have fallen to $2.00/mmBtu or lower and oil prices have held over $100/bbl, a ratio of over 50! Adjusting for Btu parity, oil is 8.5X more expensive than natural gas. This sets in motion a number of "feedback" effects – namely, measures to take advantage of U.S. natural gas vs. oil as a feedstock and lower cost energy source (refining, petrochemical industries, steel, Gas-to-Liquids, LNG exports, and activities in transportation). These developments are among the most notable of the past year. The huge Hovensa refinery on St. Croix in the Virgin Islands closed, unable to compete with Gulf refineries having access to low cost natural gas. Methanex mothballed a methanol project in Brazil to take advantage of low cost natural gas in Louisiana instead, and simple mid-Continent refineries are able to handle the better quality shale-play oils now being produced (D. Pursell, Tudor Pickering, April 2012). Collectively these kinds of developments could drive incremental growth more than events in the power industry.

The power industry is generally assumed to represent the largest segment of natural gas demand growth, with an early surge due to displacement of existing coal-fired generation and replacement of retiring coal plants by mid-decade or some years thereafter. The upward pressure on demand and prices, however, will be somewhat muted by the great extent to which displacement has already been occurring since late 2008 and essentially uninterrupted and climbing ever since.

The long term view, incorporated in the National Petroleum Council study *Prudent Development – Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*(September 2011) is illustrated in Appendix Chart A-3. It illustrates that most of the uncertainty in national demand is the uncertainty in power sector developments, with 2030 power sector demand ranging from 19.2 to 35.3 Bcf/d. The 800 pound gorilla is the natural gas vehicle market, although few see this moving rapidly beyond fleet applications at the present time (a good technical/economic analysis of the most promising

segments of the transportation market is included in MIT's *Future of Gas* report, 2011; the NPC study indicates potential direct use of gas in a high case of 2 Bcf/d – thus not a very high number; D. Pursell, Tudor Pickering Holt, describes transportation as the "Holy Grail" of emerging gas markets, April 2012). Considerable research will (and should) be devoted to tracking these developments. This process began in earnest with Senate Committee on Energy & Natural Resources hearings on LNG exports on November 8, 2011.

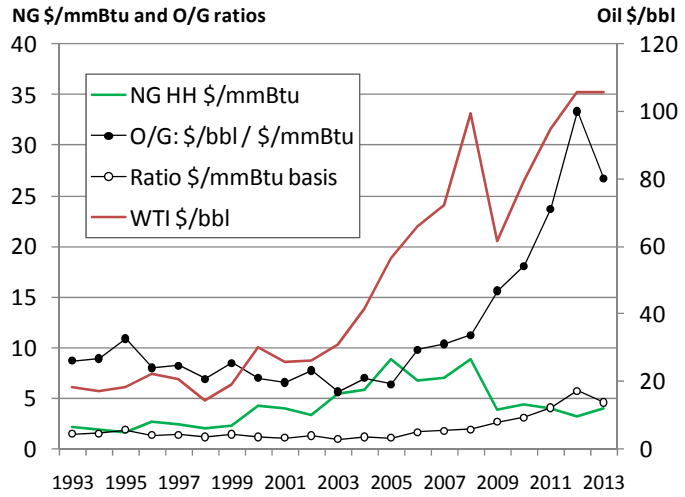


Chart 7. Oil to Gas Price Ratios: The Trader's Ratio and Btu Parity Ratio

Source: EIA Short Term Energy Outlook – interactive table builder. Actual: 1993-2011; forecast: 2012-13.

Controversies over extent and impacts of LNG exports. The matter of LNG exports has raised concerns over how this could drive up domestic prices. The USAEE and the Senate Committee on Energy and Natural Resources are sources of materials on the subject, in addition to filings before the Federal Energy Regulatory Commission. Approval is supposed to be largely automatic when the trade involves signatories to Free Trade Act agreements. Selected impact assessments are summarized in Chart 8. These impacts are all rather modest, which is not surprising considering that LNG exports represent an incremental source of demand within a very large overall market. World oil prices are not transmitted in any direct way to the US wellhead. Cheniere's sales agreements are a case in point. It has negotiated deals for output from four trains with BG, GAIL (India), Gas Natural (Spain) and Kogas (Korea), each a 3.5 million metric ton per year, 20 year undertaking. Prices (per public information on the BG deal) are 115% of Henry Hub plus $2.15/mmBtu. The Final Investment Decision is pending. These are very large and financially challenging (risky) projects. The highest market impacts were found in the Energy Information Administrations assessments, particularly for levels of 12 Bcf/d (not shown). Their "low and slow" case (6 Bcf/d by 2020, included in the chart) may better reflect the risks confronting these projects. Like much else in this report, the matter needs and will receive attention and much will be learned if, and as, projects move forward.

ICF – Digested from FERC filings

Facility	Analyst	Summary of Analysis	Price Impact ($/MMBtu per Incremental Bcfd of Exports)
Sabine Pass	Navigant Consulting	5 cases examining different levels of U.S. demand and LNG export ranging from 0 to 2 Bcfd	$0.18 to $0.30
Cove Point	Navigant Consulting	7 cases examining different levels of U.S. demand and LNG exports ranging from 2.7 to 7.1 Bcfd	$0.10 to $0.30
Freeport	Delloite	Single scenario, with and without 1.5 Bcfd of exports	$0.02
Lake Charles	BGNA	Based on long-run cost curve; filing cited price impacts from 0 to 12 Bcfd of exports.	$0.02 to $0.04

Source: ICF, LNG Exports from North America: Economics and Market Impacts , United States Energy Association , December 6, 2011. Harry Vidas, Vice President . ***Used by permission.***

Deloitte "Made in America", Dec. 2011	**6 Bcf/d :**	**$0.22/mmBtu**
EPRI Newsletter (EVA Inc. est.), Oct. 2011	**1.5 Bcf/d :**	**$0.05/mmBtu**
EIA, Dec. 2011: 6 [to 12] Bcf/d scenarios	**6 Bcfd "slow" :**	**$0.52 ave, $0.70 peak year impacts**

Chart 8. Price Impacts of LNG Exports – Selected Estimates

Hydraulic fracturing costs. The industry lacks a [non-proprietary] tracking index of land well completion costs, although this kind of information does appear sporadically and individuals in the business occasionally can provide anecdotal "evidence" on cost trends. An example of the latter is an observation that HF costs per stage had essentially doubled in the year or so preceding spring 2011, reaching about $175,000 or $1.75 million for a ten-stage frac. At about the same time (June 21, 2011), staff writer Trey Cowan, Rigzone, surveyed Eagle Ford operators ("Costs for Drilling the Eagle Ford", www. Rigzone.com). He found drilling and completion costs to range from $5.5 to $9.5 million. His summary estimate was drilling, $2.4 million, and completion, $4.0 million, and he observed that the industry was moving toward a large number of stages per lateral (15-20), which would drive completion costs even higher. Day rates (drilling) were approximated at 35 days at $20,000/day or $700,000 total, the largest component of drilling costs (29%). Stimulation was far and away the highest cost component of completion costs, $2.76 million (70%). This corresponds to $184,000 per stage (at 15 stages). He noted that rigs with higher horsepower and thus capable of completing longer laterals command a premium. Anecdotally, in just the past 4-5 months component costs (frac cost per stage and service costs) have started to come down, though this is offset by more stages per well and resulting, better overall performance (D. Pursell, Tudor Pickering, April 2012).

In broad terms, the past year has seen movement out of Marcellus, PA into Utica/Pleasant Point, OH , movement out of Haynesville, LA and TX into Eagle Ford , TX, and continued movement into North Dakota. Some of this movement is captured in Appendix Chart A-2.

While not a direct index of drilling and completion costs, the fortunes of oilfield services and drilling companies might be correlated. Chart 9 plots the relative share performance of a handful of oilfield services and U.S. onshore drilling companies, along with indices of natural gas and oil price changes.

These charts begin in January 2009, the year Haynesville production surged and the first year of the Great Recession.

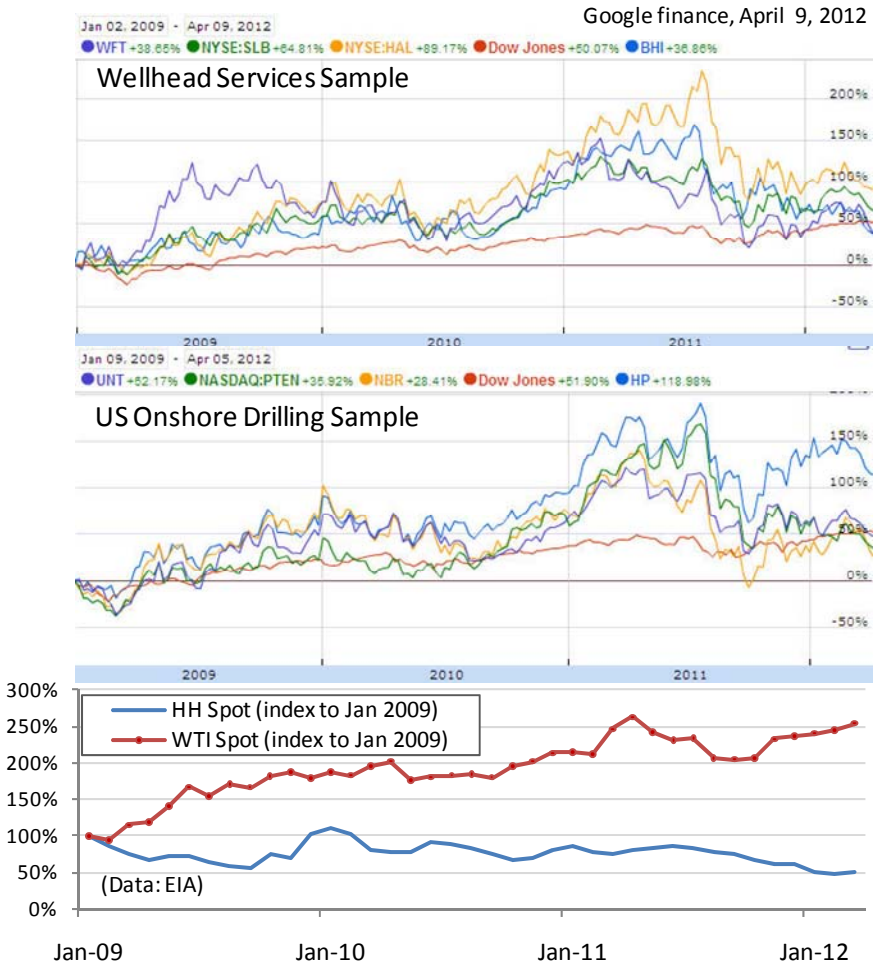


Chart 9. Price Indices of Oilfield Services and US Onshore Drilling Companies

Source. Companies: Google Finance; oil-gas prices: EIA Short Term Energy Outlook – interactive table builder. Notes. Service Companies: (1) Weatherford WFT, Schlumberger SLT, Halliburton HAL and Baker Hughes BHI. Drilling Companies: (2) Unit Drilling UNT, Patterson-UTI NASDAQ:PTEN, Nabors Industries NBR and Helmerich & Payne HP. Energy prices: Monthly through March 2012.

Price Cycle Dip Does not Deter Global Coal Industry. A scan of coal producers' investor presentations, e.g. Arch Coal, Alpha Natural Resources, Peabody Energy and BHP Billiton, is a convenient means to track essential developments in U.S. and global thermal and metallurgical coal markets. While such documents are aimed at informing investors of companies' strengths in the face of adversities, they usually define the principal forces shaping the industry. Coal prices have generally been on a decline since early- (international) to mid- (US) 2011, dragging down share prices which tend to track the commodity markets as indicated in Chart 9. Chart 10 tracks met coal prices. Principal themes reflected in these documents are that:

- Coal will remain a very important and growing energy source even in the context of substantive growth in other energy sources for the foreseeable future (various 2030-35 forecasts).

- China drives global use of both metallurgical coals and steam coals, with India a distant second. Producers track China's urbanization and materials use (in some cases to the provincial level) and projections vs. performance in achieving goals set in Five Year Plans. China is on track to consume 5 billion metric tons/yr, substantially higher than the 3.9 Bt level in its 2011-2015 or 12th Five Year Plan (as projected by Peabody). Consumption growth is shown in Chart 10. Most is driven by power generation, with some 240 GW of new coal-fired generation projected over the next five years, the torrid pace of 0.9 GW per week. Arch, on the other hand, sees 118 GW of coal-fired plants under construction 2012-2015 in China and 97 GW in India, with additional capacity in planning stages. Regardless, the epicenter of growth is China and India.
- With respect to China's impact on global markets, the important figures are net coal imports. China is foreseen to increase net imports by 175 million metric tons between 2011 and 2016, 100 million tons of which are thermal coal. This would double net imports. India in the same period is seen to increase imports by 100 million tons, 70 million tons of which are thermal coal. This would nearly double its net imports. 2011 total imports by the two countries are ~170 million tons and ~115 million tons, respectively. Projections from Peabody Energy.
- The supply-demand balance over the next five years is likely to remain tight, a condition know as a "deficit" in the seaborne coal trade amounting to 65-70 Mt (million metric tons) per year 2013-2106. About 60% of the total is metallurgical, 40% thermal, as projected by Arch. This condition supports continued short term growth of US coal exports.
- US Central Appalachian coal production is continuing to decline dramatically, with strength maintained in met coal. For example, from 2008 to 2012 (as projected by Arch), met coal grows from 56 to 88 M short tons while thermal coal shrinks from 315 to 199 M tons.
- Use of Powder River and Illinois Basin coals is increasing, in part aided by growing exports.
- US port capacity to enable exports is increasing, including ports capable of moving Powder River Basin coal to Asian markets. By 2016, total capacity could reach 270 million short tons, some 2 ½ times greater than 2011 capacity, with western ports reaching the 50 million ton level. As of September 2011, the "netback" price of PRB coal from West Coast ports compared to comparable Indonesian coal was found to be about twice the ~$14/short ton US mine price. Attractive to producers or shocking to buyers, this spread is sensitive to global price fluctuation.

Ironically, it is the U.S. coal industry that has been buffeted by global forces, a factor in the coal-gas price discrepancies that have fueled coal's displacement by natural gas, whereas natural gas has become increasingly isolated from global forces (except through shifts in competitiveness of US industries that rely on natural gas as fuel or feedstock, and except – a big exception – from natural gas' historic price linkage to oil in Asian and to lesser extent European markets). An implication is that informed energy professionals must keep track of global coal developments to understand coal-gas competitiveness in end use (e.g. the power industry). And even though the US is in a physical retreat from consuming LNG, European energy professionals in particular must keep track of US natural gas and related developments to understand the US export of "price depression" into global fuel markets.

References include company presentations to the Howard Weil Energy Conference, March 26, 2012, and to Coaltrans in Beijing, April 17, 2012.

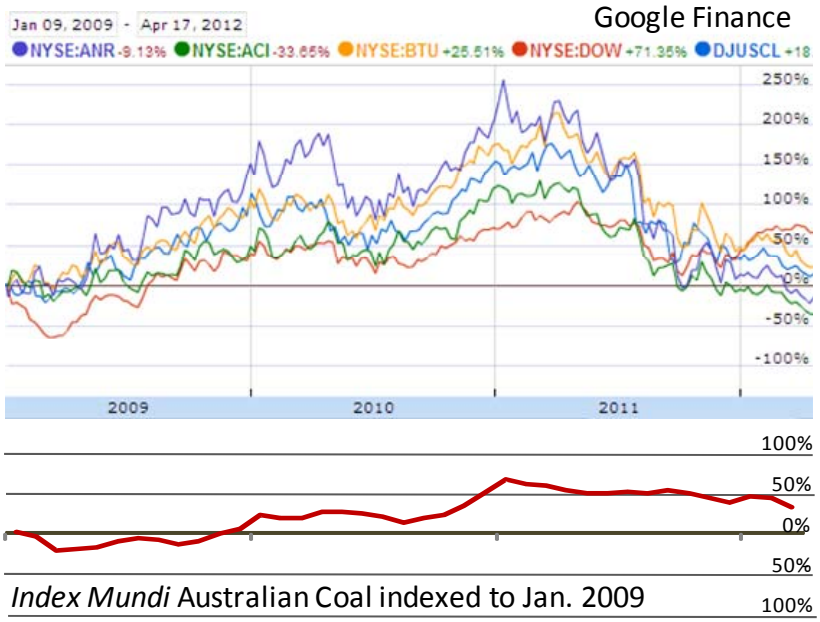


Chart 9. Coal Company Indices and Australian Coal Price Index 2009-2012

Source. Companies, Google Finance: Alpha Natural Resources, ANR; Arch Coal, ACI; Peabody Energy, Btu; Dow Jones, DOW and Dow Jones US Coal Index, DJUSCL. Coal Price Index: derived from Index Mundi Australian thermal coal price series. www.indexmundi.com Selected absolute prices (US$/metric ton): Jan. 2009 $85.71; March 2012 $112.59; peak in Jan 2011 $141.94.

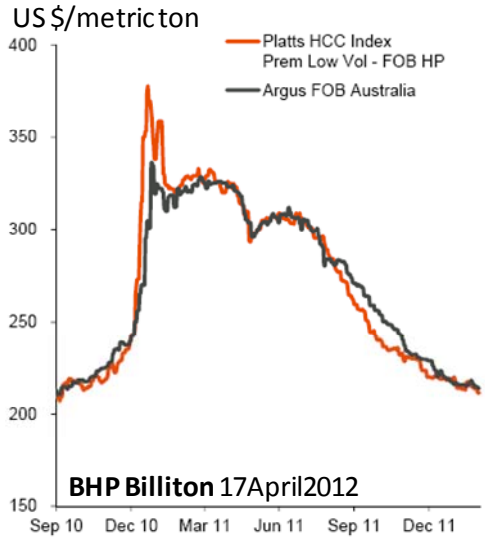


Chart 10. Metallurgical Coal Price Trends from BHP Billiton

Source. *Developments in the coking coal market*, V. Burns, BHP Billiton, Coaltrans, Beijing April 17, 2012. http://www.bhpbilliton.com/home/investors/reports/Documents/2012/120417_CoaltransBeijing.pdf

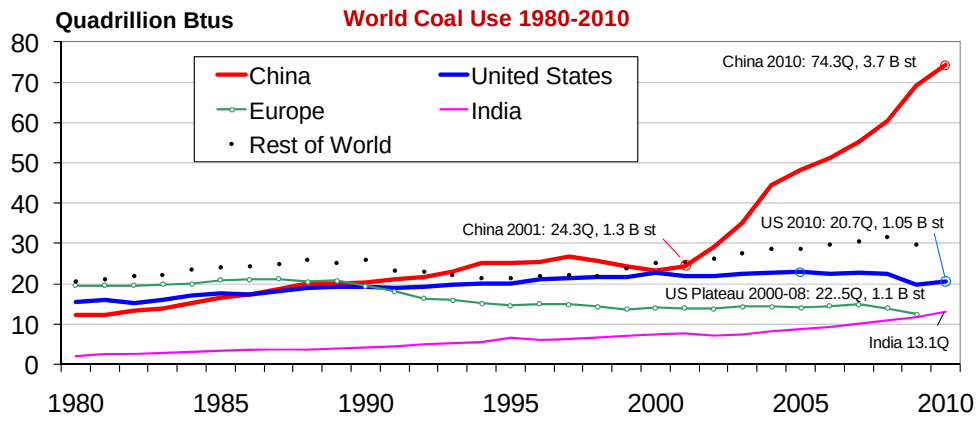


Chart 10. Global Coal Consumption by Principal Region/Country, 1980-2010
www.eia.gov/cfapps/ipdbproject/iedindex3.cfm?tid=1&pid=1&aid=2&cid=&syid=1980&eyid=2010&unit=QBTU

IV. Imagining Alternative Scenarios of Natural Gas Market Evolution over the Remainder of the Decade

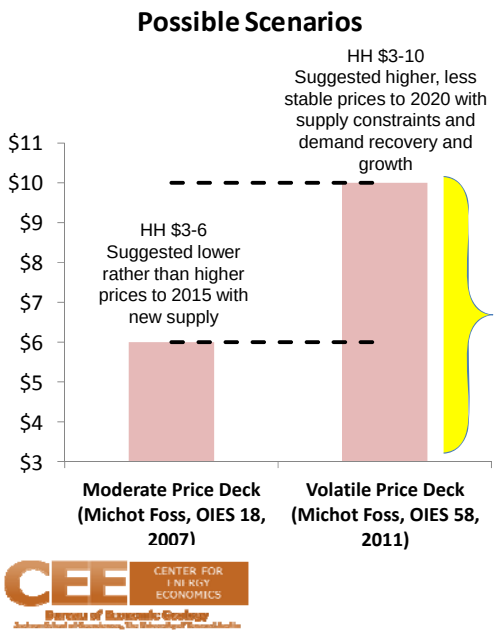
Prepared by Michelle Michot Foss, Ph.D. Chief Energy Economist and Head of the Bureau of Economic Geology's Center for Energy Economics, Jackson School of Earth Sciences, The University of Texas at Austin.

Editor's Introduction: In Dr. Foss' role as a contributor to the Committee on Energy Economics & Technology, she chose to provide a capsule synopsis of essential observations that she developed in her December 2011 paper "The Outlook for U.S. Gas Prices in 2020: Henry Hub at $3 or $10?". This was published by the Oxford Institute for Energy Studies (OIES) as **NG58**. It revisits the subject of her initial paper for OIES prepared in 2006 and published in 2007, "United States Natural Gas Prices to 2015", **NG18**. NG58 is available from this link: http://www.oxfordenergy.org/wpcms/wp-content/uploads/2011/12/NG_58.pdf In today's environment the paper puts forth the radical notion that some factors could drive the gas market to much higher levels within a relatively short number of years – while adhering to the caution that there remains considerable uncertainty in any such speculations. – J. Platt

The major factors identified in NG 58 are summarized in the chart below. Generally speaking, the goal is to help readers understand what needs to go right (not wrong) in order to preserve the production gains that have been achieved. There is, of course, no way to guarantee "lower prices". However, there are two points that need to be considered going forward.

- ***A robust resource base does not protect either producers or customers from variation in price***. We have been extending and increasing the U.S. oil and gas resource endowment for 40 years. In that time, we have had any number of events in which disruptive price events. The key question is how much more exposure, and how much more disruptive, would these disruptions have been without our resource wealth? Any economic analysis or "look back" that attempts to assess the importance of U.S. production on, for instance, gasoline prices, needs to incorporate this reality: *How much worse off would we have been, or would we be in future, if we don't responsibly develop our hydrocarbon base?*

- ***Deliverability is critical.*** *How much supply can be placed in the market at any one time?* Obstacles that complicate the process of resource identification-conversion to proved reserves-establishment of production-delivery of supply should be the focus of attention. From a geoscience perspective, of most importance is the below-ground R&D. But from an operational perspective, issues run the gamut: producer finance and business models; environmental oversight and public acceptance; market development and demand; field-to-market linkages; and the price signals that capture all of these dynamics.



Key Drivers for Scenario Differences

Variable	Moderate	Volatile
Shales	Full deliverability	Reality check
Non-shale	Recovery	Declines
Policy, regulation	Favorable	Unfavorable
Economic recovery	Weaker	Stronger
Gas-fired power	Slow increase	Rapid increase
Industrial	Modest growth	Strong growth
Midstream, downstream bottlenecks	None	Many
Oil:gas spread	Wider	Narrower
Gas industry business model	Lower price, higher volume	Higher price, lower volume

Chart 11. Key Variable Driving Lower and Higher Price Scenarios -- Looking Ahead from 2007 to 2015 vs. from 2011 to 2020 . See www.oxfordenergy.org

Shifting business models? Ultimately, industry needs to establish a workable "business model" for long term sustainability of unconventional plays. Especially with re-entry of large IOCs (international oil companies) to the domestic E&P scene, the question is what needs to happen in order to keep them, and their financial heft, in the "development game". All discussions with the large production leaders indicate that cost management in the shales (and other unconventional plays) entails a **high volume model** (see Chart 11). Large production volumes allow producers to bring down unit costs. The trade off, invariably, is lower rather than higher price and, probably, lower rather than higher profit margins (but perhaps higher revenues over the longer term). This business model is in direct conflict with public perception and acceptance of high density drilling and more intense upstream activity, overall. Obstacles that impact "cycle time", i.e., that increase delays and costs will ultimate result in a lower volume model and commensurately higher prices (with, perhaps, stronger profit margins but less opportunity over the longer term because of constraints to resource development).

Tax treatment risk. Producers can probably absorb the risk and uncertainty associated with things like environmental regulation. They have less capacity to absorb impacts from changes in tax treatment. Examples from producers suggest that elimination of intangible drilling credits (IDCs) in a play like the

Bakken would render all of the marginal production uneconomic. Activity would collapse to the "sweet spots". Loss of production from marginal acreage would remove *tranches* of supply from the marketplace. The result, for both oil and gas, would be upward pressure on price and increased volatility during periods of robust demand.

Cost trends. Since NG 58 (December 2011), producer cost tracking from corporate financial data reveals some interesting, if challenging, trends. Producer costs show some improvement, on average, over 2010, based on a sample of producers as delineated in Chart 12. We use full, breakeven, all source finding and development cost plus cash cost, including lease operating expense, general and administrative (G&A), income and non-income taxes, net interest expense, and other costs.

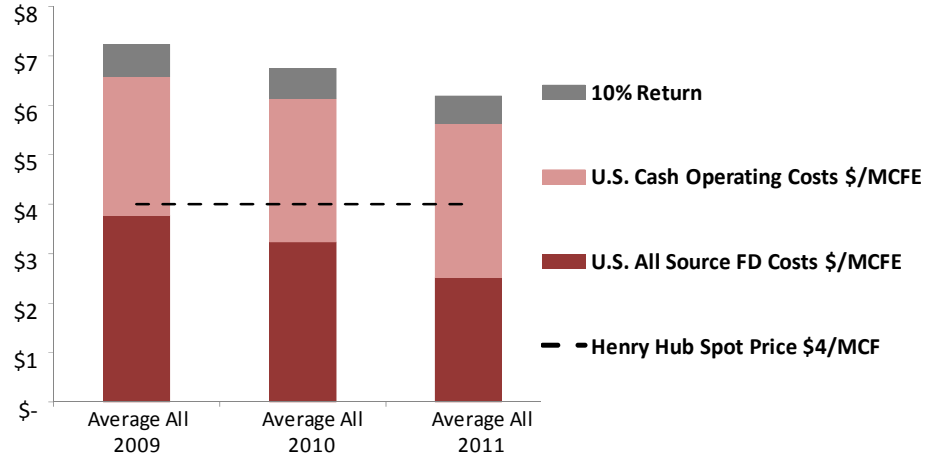


Chart 12. Average Full Breakeven Cost Trends (sample of 16 producers)

Signal of tightening – proved undeveloped production. Performance across the largest producers (natural gas equivalent basis) is uneven. Several reduced costs through acquisitions and the opportunity to spread cost across newly booked proved undeveloped production (PUD). PUD bookings declined sharply between 2010 and 2011, a consequence of both timing and completion of acquisitions and the erosion of natural gas prices (affecting both drilling activity and acreage and drilling locations held in inventory). This trend is outlined in Chart 13. PUD is important because these holdings represent supply that can be delivered most quickly to the marketplace.

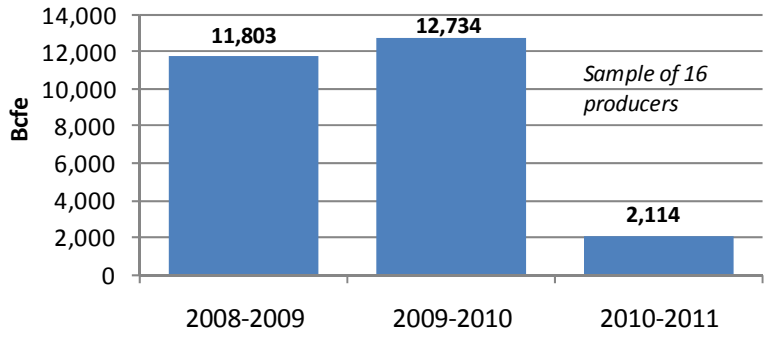


Chart 13. U.S. PUD Bookings Trend (sample of 16 producers)

Storage detail. Rather than track natural gas storage within a five year range, it is more revealing to track storage using the difference between weekly reported working gas in storage and a rolling five-year average. The strongly bearish storage conditions for most U.S. regions are shown in Chart 14.

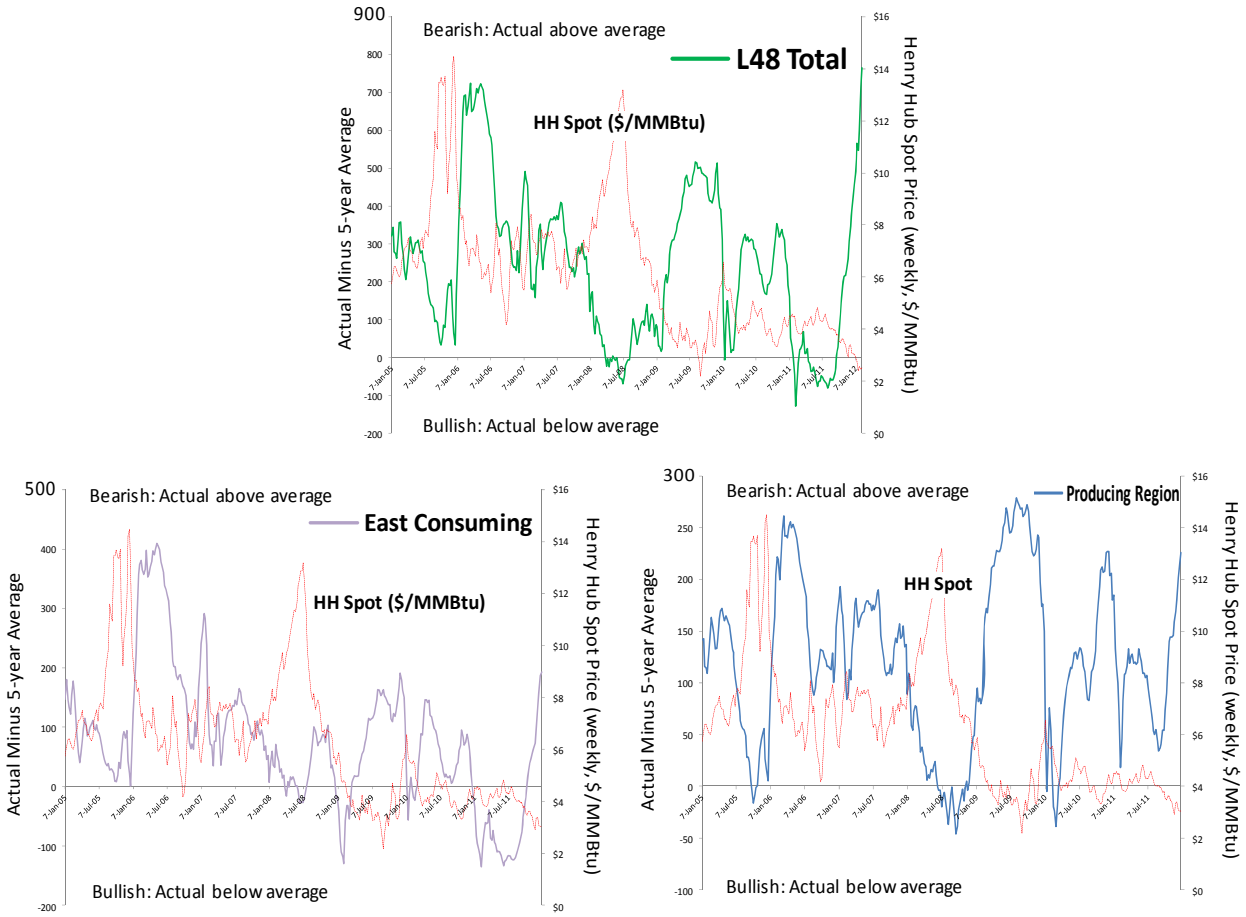


Chart 14. Natural Gas Storage Detail

GOM production declines are a concern. A major concern remains Gulf of Mexico production. With the shift in activity to deepwater locations, the GOM became "oil prone". Both oil and natural gas production has fallen off. The trends in oil and gas production are illustrated in Charts 15 and 16. Shale plays can make up some of the difference, but given the low ebb of the GOM, any disruption in shale output would create the potential for disruptive tightness in the U.S. supply-demand balance.

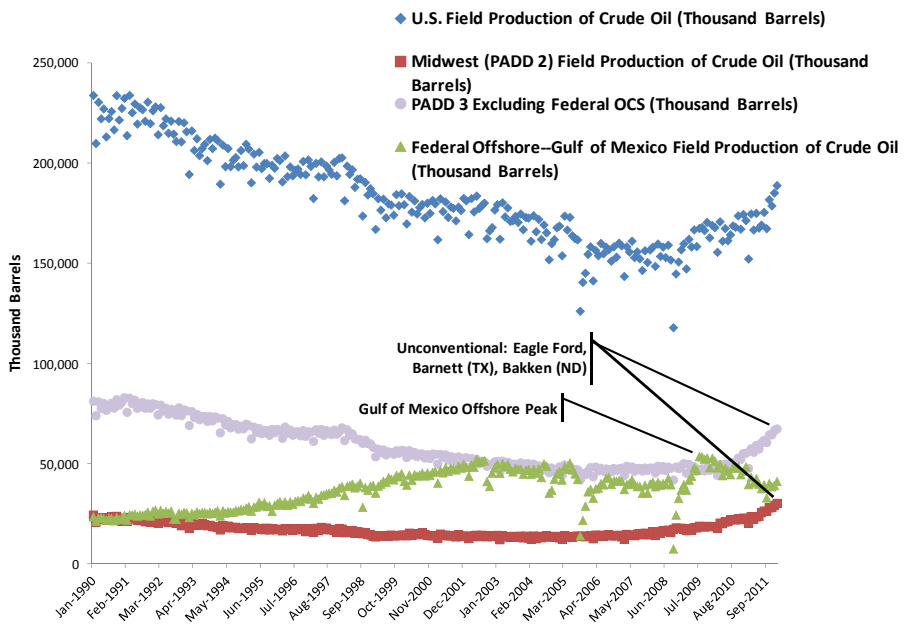


Chart 15. The U.S. Crude Oil Production Renaissance and Some Components

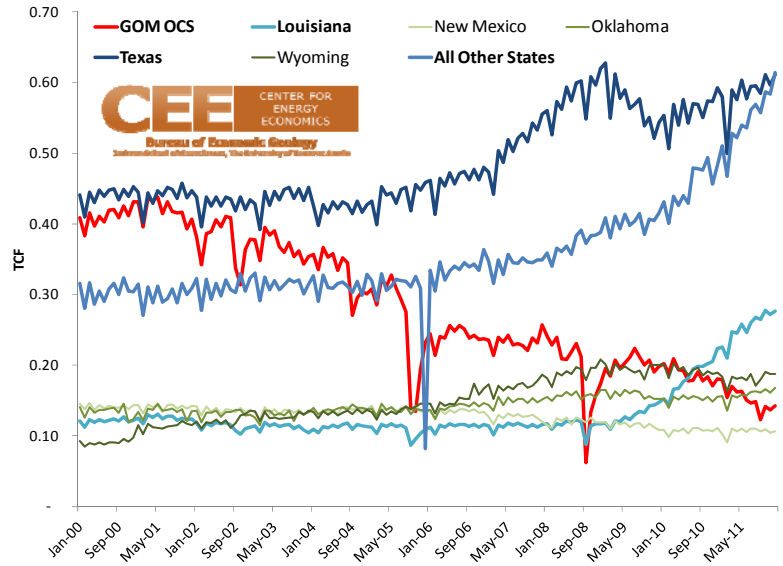


Chart 16. U.S. Natural Gas Production Detail

A further concern is data. The Energy Information Administration (EIA) is not picking up production declines that are becoming apparent in states. EIA also is more than a year behind in tracking natural gas production from states other than major producers. Selected state data are presented in Charts 17 and 18 (Texas and Louisiana).

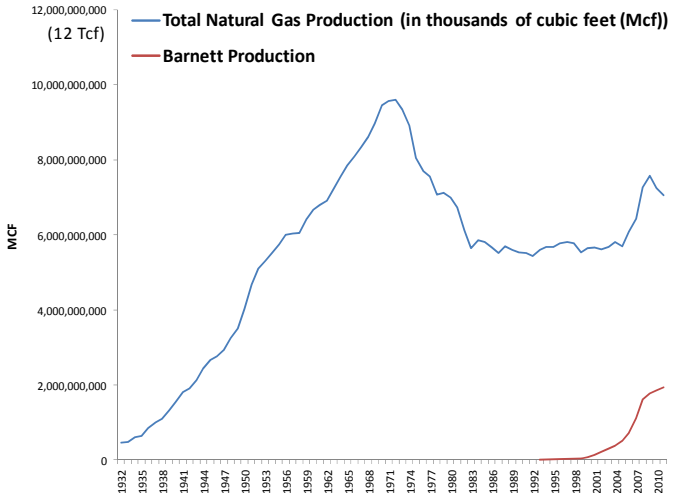


Chart 17. Texas Railroad Commission Natural Gas Production 1932-2011

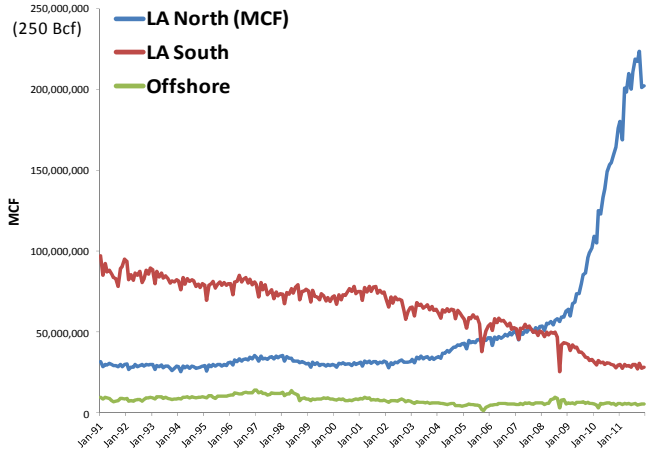


Chart 18. Louisiana Department of Natural Resources 1991-2011

IV. AAPG August 2012 planned Geosciences Technology Workshop: Hydraulic Fracturing – New Controversies, New Plays

Scheduled at the Colorado School of Mines, Golden, Colorado, August 13-15, AAPG is hosting a workshop on the controversies and science around hydraulic fracturing, extending from understanding the basics of fracturing to questions and evidence of migration of fluids and gases to regulatory dimensions. A number of individual plays will be highlighted and some new and extensive industry research will be featured. Dan Arthur of ALL Consulting, a firm with voluminous research related to shale developments and public concerns, is helping to organize the event along with a pool of members from AAPG's EMD. The University of Texas' Energy Institute's recent and relatively comprehensive review of science-based research on hydraulic fracturing will also be represented. Key contributors include representatives from Resources for the Future and Duke University's Nicholas School, both of which are

engaged in extensive multidisciplinary programs. Of interest to the Committee, the GTW will open with a session on the importance of shale gas and on some of the apparent or real controversies about the extent of the resource/characterization of supply. See Appendix Chart A-4. Individuals from the USGS, the Energy Information Administration, Pennsylvania State and the Potential Gas Committee may be able to participate, although the plans as of mid-April, 2012 are not yet finalized. Contacts include Susan Nash, AAPG, Jeremy Platt (representing this committee), Doug Peters (AAPG DPA and EMD), Steve Testa (EMD President), Paul Morgan (Colo. Geological Survey) and, as mentioned, Dan Arthur (ALL Consulting).

Appendix

	Barnett Shale (1)	Wood-ford (1)	Fayette-ville (1)	Haynes-ville (1),(2)	Eagle Ford (1)	Marcellus (1),(3)	Other Shale (1)	Total
Jan-07	2,331	138	99	97	0	28	1,254	3,949
Jan-08	3,835	358	437	98	0	51	1,377	6,156
Jan-09	5,001	821	1,110	443	6	164	1,417	8,962
Jan-10	4,791	982	1,813	2,616	144	440	1,492	12,278
Jan-11	5,431	1,212	2,384	5,746	710	2,525	1,668	19,676
Feb-11	5,110	1,185	2,355	5,952	763	2,635	1,668	19,668
Mar-11	5,581	1,168	2,421	6,457	852	2,862	1,668	21,010
Apr-11	5,661	1,203	2,536	6,745	906	3,043	1,733	21,827
May-11	5,730	1,130	2,541	6,935	974	3,096	1,733	22,140
Jun-11	5,656	1,157	2,544	6,893	1,021	3,010	1,733	22,015
Jul-11	5,640	1,159	2,574	7,062	1,130	3,426	1,755	22,746
Aug-11	5,673	1,149	2,572	7,319	1,260	3,403	1,755	23,131
Sep-11	5,800	1,184	2,673	7,481	1,398	3,717	1,755	24,007
Oct-11	5,827	1,191	2,704	7,549	1,473	4,027	1,779	24,550
Nov-11	5,927	1,197	2,694	7,766	1,606	4,631	1,779	25,600
Dec-11	5,930	1,204	2,703	7,771	1,682	5,107	1,779	26,176
Jan-12	5,937	1,213	2,714	7,681	1,742	5,504	1,801	26,591
Feb-12	5,947	1,217	2,726	7,598	1,794	5,808	1,801	26,891
Mar-12	5,958	1,222	2,738	7,618	1,822	5,941	1,801	27,101

Chart A-1. LCI Energy Insight Shale Gas Production Trends through March 2012

Note: Data for most recent months subject to revision after assimilation of emerging state reports. Used by permission, G. Lippman, LCI Energy Insight, April 10, 2012.

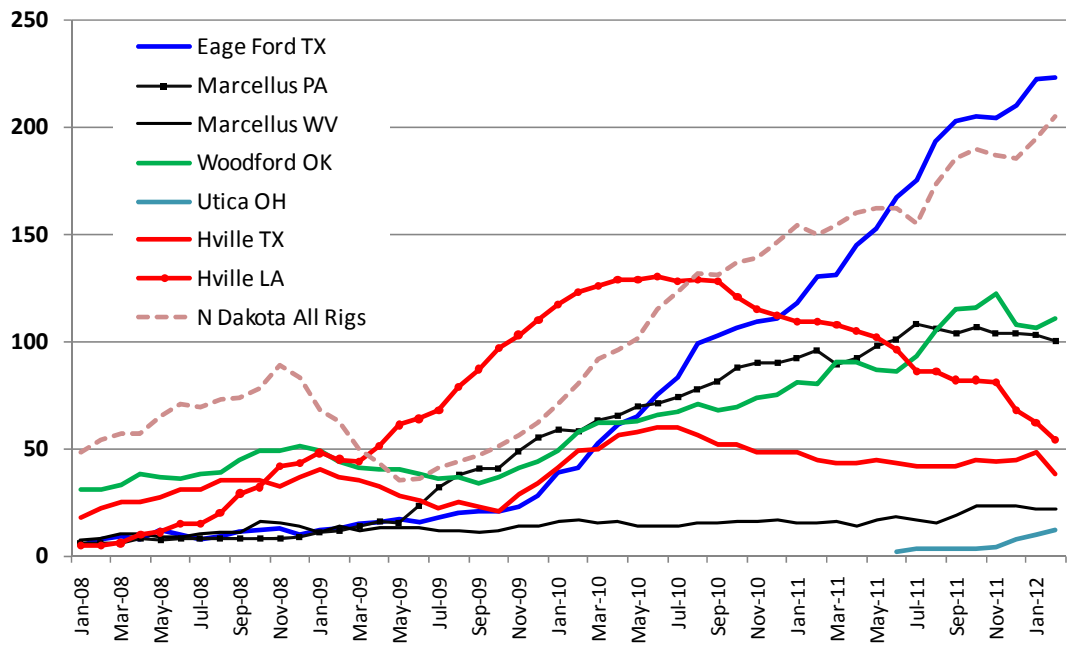


Chart A-2. LCI Energy Insight Selected Shale Play Rig Counts based on Baker Hughes Data (with North Dakota Oil Rig Count Added)

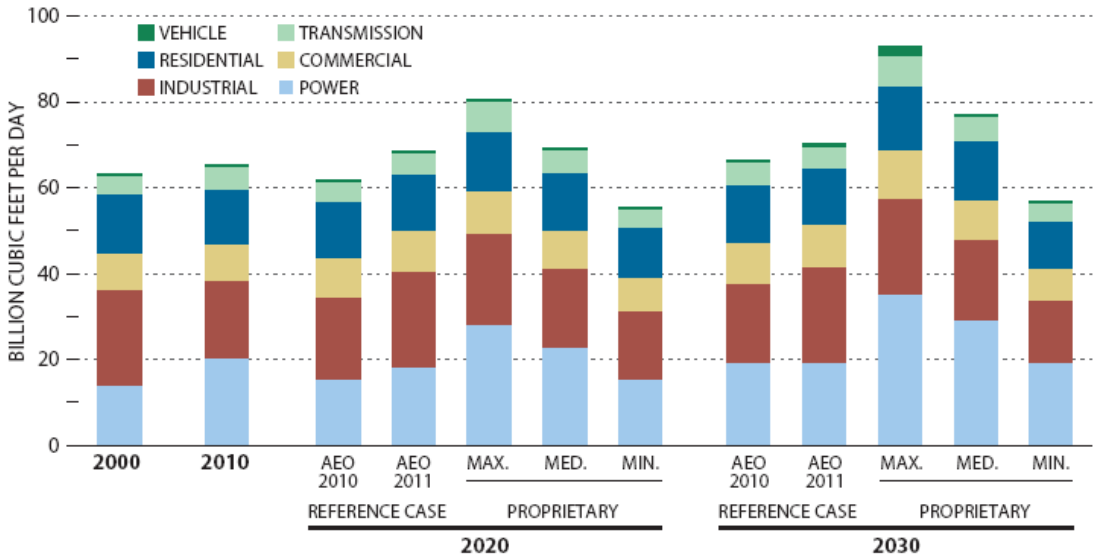


Chart A-3. US Natural Gas Demand – Ranges of Forecasts as Assessed by National Petroleum Council
Note: "Proprietary" refers to results of NPC's third-party analysis of a number of proprietary forecasts from the industry, consultants, and others. From Chapter 3, Natural Gas Demand, NPC study, 2011.

US Proven NG reserves (dry)

Tcf

	All NG	Shales Only	Shales % of Reserves
2004	193		
2005	204		
2006	211		
2007	238	23	10%
2008	245	34	14%
2009	273	61	22%
2010			
2011			

2010 ff
Extensive Activity (++)
vs. Price Collapse (-) = ?

Shales Only

Unproven technically recoverable resource **(TRR)**

AEO2012*	AEO2011*	Change
482 Tcf	**827** Tcf	-345 Tcf
Marcellus **141** Tcf (29% of sh.)	**410** Tcf (50% of sh.)	-269 Tcf
Utica **16** Tcf (2% of sh.)		

*Energy Information Administration Annual Energy Outlook, reference cases

Chart A-4. EIA's Evaluation of Natural Gas Reserves and Unproven Technically Recoverable Resources

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