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Annual Meeting Report - 2011

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March 18, 2011; Rev. April 6, 2011

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Accepting the New Gas Supply Outlook

2010 was marked by continued development and recognition of the role of U.S. gas shales in the U.S. and global energy economies. A most common reference point is the annual natural gas price and production forecast by the U.S. Department of Energy (Energy Information

Administration Annual Energy Outlooks). The record of these forecasts over the five years from 2007 to 2011 (Early Release) spans expectations during the global economic buildup of 2007-2008, the Great Recession particularly during 2009-2010, and the shift in natural gas industry financing along with adaptation to oil-rich prospects reflected in the 2011 Outlook. See Table 1 below:

Table 1. Average Annual Actual and Projected Natural Gas and Oil Prices, Natural Gas Production and Natural Gas Net Imports per EIA Annual Energy Outlooks, 2007-2011

2007 AEO	**2007**	**2008**	**2009**	**2010**	**2011**	**2015**	**2020**	**2025**	**2030**	
$HH Nat. Gas	7.23	7.17	6.60	6.28	5.83	5.46	5.71	6.14	6.52	
$Wellhead NG	6.45	6.40	5.88	5.59	5.17	4.84	5.07	5.46	5.80	
$LS Light Oil	66.71	64.09	60.91	57.47	54.33	49.87	52.04	56.37	59.12	
$Imp. Crude	59.49	57.23	54.21	51.20	48.48	44.61	46.47	49.57	51.63	
NG Prod. 19.70	19.99	19.99	19.93	19.80	20.19	21.41	21.21	21.15		
Net Imports	3.52	3.98	4.35	4.67	4.96	5.76	5.48	5.73	5.59	
>Pipe Imp. ~	2.74	2.84	2.90	2.81	2.64	2.70	1.70	1.23	0.94	
>LNG Imp. ~	0.78	1.14	1.45	1.86	2.32	3.06	3.79	4.50	4.65	

Quantities: Quadrillion Btu or Quads (natural gas). **2005** $/mmBtu (ng) and /bbl (oil). ~ Net pipeline and LNG imports converted from Tcf.

2008 AEO	**2007**	**2008**	**2009**	**2010**	**2011**	**2015**	**2020**	**2025**	**2030**	
$HH Nat. Gas	6.78	7.23	7.35	6.90	6.56	5.87	5.95	6.39	7.22	
$Wellhead NG	6.03	639	6.56	6.16	5.85	5.21	5.29	5.69	6.45	
$LS Light Oil	67.05	83.59	76.96	74.03	71.20	59.85	59.70	64.49	70.45	
$Import. Crude 62.10		72.77	68.32	65.18	62.67	52.03	51.55	55.68	58.66	
NG Prod. 19.55	19.73	19.84	19.85	19.82	20.08	20.24	20.17	20.00		
Net Imports	3.90	3.95	4.05	3.95	4.11	4.13	3.64	3.37	3.26	
>Pipeline Imp.	3.14	3.03	3.03	2.71	2.63	1.96	1.21	0.70	0.34	
>LNG Imports	0.76	0.92	1.02	1.23	1.48	2.18	2.43	2.67	2.91	

Quantities: Quads (natural gas). **2006** $/mmBtu (ng) and /bbl (oil).

2009 AEO *upd*	**2007**	**2008**	**2009**	**2010**	**2011**	**2015**	**2020**	**2025**	**2030**
$ HH Nat. Gas	6.69	8.67	4.20	5.11	5.48	6.16	7.47	7.51	8.83
$Wellhead NG	6.22	7.67	3.88	4.51	4.84	5.45	6.60	6.63	7.80
$LS Light Oil	72.33	99.08	40.52	52.16	65.02	98.88	116.79	122.63	130.92
$Imp. Crude	63.83	96.46	38.75	48.99	61.99	96.77	114.50	116.06	124.36
NG Prod. 19.84	21.05	21.18	20.58	20.37	19.63	20.13	22.55	23.67	
Net Imports	3.89	3.12	2.82	2.41	2.06	1.92	1.92	1.26	0.42

Updated 4/09 for ARRA (Stimulus). Quantities: Quads (natural gas). **2007** $/mmBtu (ng) and /bbl (oil).

2010 AEOr*	**2007**	**2008**	**2009**	**2010**	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**
$ HH Nat. Gas	7.12	8.86	3.49	4.50	5.68	6.27	6.64	6.99	8.05	8.88
$Wellhead NG	6.38	7.85	3.24	3.94	5.02	5.54	5.87	6.18	7.11	7.84
$LS Light Oil	73.93	99.57	59.21	70.30	73.06	94.52	108.28	115.09	123.50	133.22
$Import. Crude	68.69	92.61	56.49	67.40	66.63	86.88	98.14	104.49	111.49	121.37
NG Prod. 19.65	21.16	21.20	20.58	20.03	19.85	20.56	21.93	23.02	23.95	
Net Imports	3.89	3.03	2.83	2.89	2.85	2.44	2.64	2.23	1.89	1.50
>Pipeline Imp.	3.14	2.72	2.40	2.27	2.13	1.32	1.10	0.91	0.96	0.66
>LNG Imports	0.74	0.31	0.43	0.63	0.72	1.12	1.54	1.31	0.91	0.85

* Quantities: Quads (natural gas). **2008** $/mmBtu (ng) and /bbl (oil).

2011 AEOer	**2007**	**2008**	**2009**	**2010**	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**
$HH Nat. Gas		8.94	3.95	4.43	4.48	4.81	5.18	6.01	6.50	7.19
$Wellhead NG		7.96	3.62	4.10	4.08	4.26	4.59	5.32	5.76	6.37
$LS Light Oil		100.51	61.66	78.03	83.21	94.67	108.13	117.48	122.92	125.03
$Imported Crude	93.44	59.04	74.86	80.32	86.94	98.71	107.53	112.35	114.05	
NG Prod.	20.83	21.50	21.88	21.62	22.67	23.62	24.25*	25.35*	26.78*	
Net Imports		3.07	2.73	2.85	2.84	2.87	2.21	1.37	1.03	0.37
>Pipeline Imp.	~	2.75	2.29	2.41	2.38	2.48	1.67	0.99	0.85	0.18
>LNG Imports	~	0.31	0.42	0.42	0.45	0.37	0.52	0.35	0.14	0.14

Quantities: Quads (natural gas). **2009** $/mmBtu (ng) and /bbl (oil). *Notable: No Alaskan pipeline.

~ Net pipeline and LNG imports converted from Tcf; sum does not exactly match total in Quads.

There is a fascinating history represented in this sequence, extracted to highlight just a few changes wrought by the shale-gas revolution. These are:

- ***The sharp decline in projected natural gas prices – precipitous in the most recent forecast***. The estimates for 2020 have progressed as follows ($/mmBtu, Henry Hub): $5.71 - $5.95 - $7.47 - $6.64 - $5.18, a 22% drop in just the past year.
- ***The sea-change in projected domestic production.*** Expected in 2006 (AEO 2007) to gradually increase from 20 Tcf/yr (55 Bcf/d) and then fall slightly 21.1 Tcf/yr (58 Bcf/d) by 2030, the 2030 outlook now is for production to increase to over 69 Bcf/d and remain on an upward track.

- ***Arresting Arctic gas.*** The latest Outlook defers the Alaska gas pipeline over its entire forecast horizon, i.e. not included by 2035, citing the tension of higher capital costs and lower wellhead prices.

- ***The near-evaporation of LNG imports.*** Expected in 2006 (AEO 2007) to climb steadily to 4.5 Tcf/yr by 2025, or over 12 Bcf/d, they are now estimated to reach little more than one-tenth that amount, decline to just 1 Bcf/d by 2025, and continue to fall.

- ***Continuing stratospheric oil prices.*** Giving little ground from the peaks reached after the 2008 global commodities spike (which affected oil, gas, coal, iron ore, and metals), the two indices (low-sulfur light and imported crude oil) have strengthened quite sharply in the short term and remain near or above $100/barrel from 2020 onwards. The sequence forecasted 2011 prices is notable (for LS Light, $/bbl)): $54.33 - $71.20 - $65.02 - $73.06 - $83.21, a 12% increase in the past year. The relationships between declining natural gas prices and increasing oil prices are discussed below.

Shale Gas' Boom of Expectations

A number of studies were released in 2010 which portrayed trajectories of escalating shale gas production. One of the more accessible and prominent of these was *The Future of Natural Gas – An Interdisciplinary MIT Study*, Interim Report:

(http://web.mit.edu/mitei/research/studies/naturalgas.html).

The Figure below forms the basis for the comparative plotting of several such projections. The study is careful to point out that the projection is one of "production potential" for the five major shale plays, assuming drilling at 2010 levels for twenty years, and is therefore not an integrated economic forecast of gas production. Earlier in the year, EPRI completed a private analysis, reflecting data as of the last quarter of 2009, which yielded a more conservative view but which was based at the time on ongoing activity and productivity of the major shale plays (red line). The MIT study leaped into higher territory, with levels exceeding 20 Bcf/d by 2015. A study by Rice University projected a slightly lower ramp rate, almost matched by Deutsche Bank's US projection (both studies issued in September 2010). Shortly thereafter, Lippman Consulting developed an estimate for the "Big Six" shales, namely the Big Five plus the Eagle Ford. Surprisingly, this estimate eclipsed MIT's production potential, but represents much the same thing – it is the trend if the industry continues current development plans rather than

suffers a correction. For this reason, it should probably be viewed as an upper bound and open to considerable uncertainty once the current wave of financing plays out during 2011-2012.

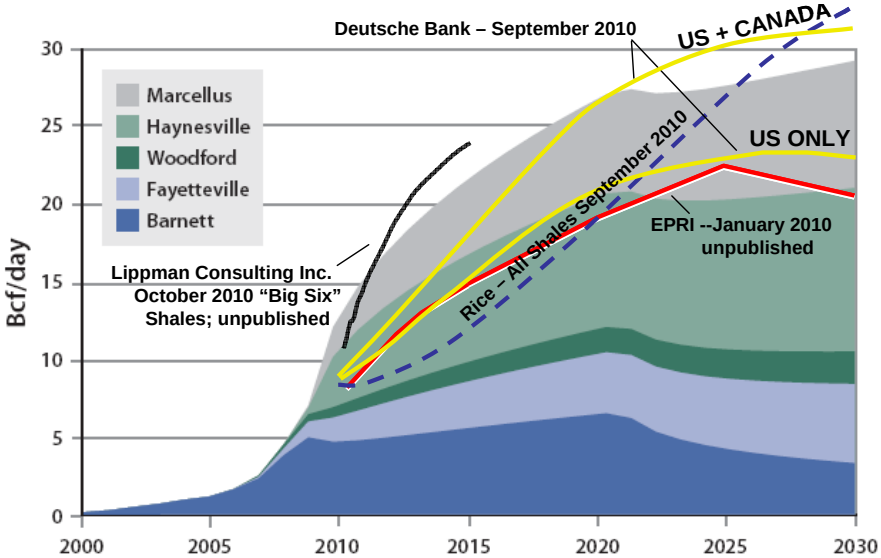


Figure 1 - Estimates of Shale Production or Production Potential

Notes. Base Projection (area shading): MIT's "Potential Production Rate that Could Be Delivered by the Major U.S. Shale Plays Up To 2030 – Given Current Drilling Rates and Mean Resource Estimates". Used by permission. Additional Estimates (lines) EPRI, Rice, DB, LCI.

How Quickly Things Have Changed: The Forward Curve in 2010

The futures market, not unlike the weather, is a force to which all must respond. While a notoriously poor predictor of prices, it encapsulates immediate expectations and defines business risk. Most interesting about the futures market in 2010 were, not just its shifts in the short term, but the way it reflected an easing in the thinly traded longer term as well (i.e. five to eight years). It is in response to the new realities presented by this market that companies were forced to shift assets, seek partners, and shore up cash flows during 2010. Shifts in asset portfolios had begun over a year ago and escalated during the year.

Referring to the price in the figure below, at the high point of the global commodities "supercycle" in June 2008, shortly after spot prices had touched $13/mmBtu, futures prices tracked a narrow band between $10 and $11/mmBtu out to 2018 (gray line below). A year later spot prices had fallen below $4.00 and the band had dropped between $7 and $8/mmBtu (blue line). By January 2010 the band had dropped further, principally at the "front end", spanning $6-nearly $8/mmBtu (green line). The front end continued to weaken through June, dropping to $4.50, while the back end (2018) moved down gradually to $7.25/mmBtu (dashed blue line). Subsequently, the gas futures prices collapsed over the full period to 2018. By October, the front end had weakened further, below $4.50 in 2011 and remained trapped within the $5-6.00/mmBtu band out to 2018.

To sum up, in ten months the entire curve dropped $2.00 or 33% for 2010 (from $6.00 to $4.00) and 23% for 2018 (from nearly $8.00 to $6.00). Once past the winter, the record has

been one of relentless negative price pressures on producers throughout most of the year, a reframing of prices during much of the current decade, new attitudes about natural gas driving capital investment planning by some major consumers (electric utilities), and the imprimatur of the soft market view by the EIA in its most recent Annual Energy Outlook.

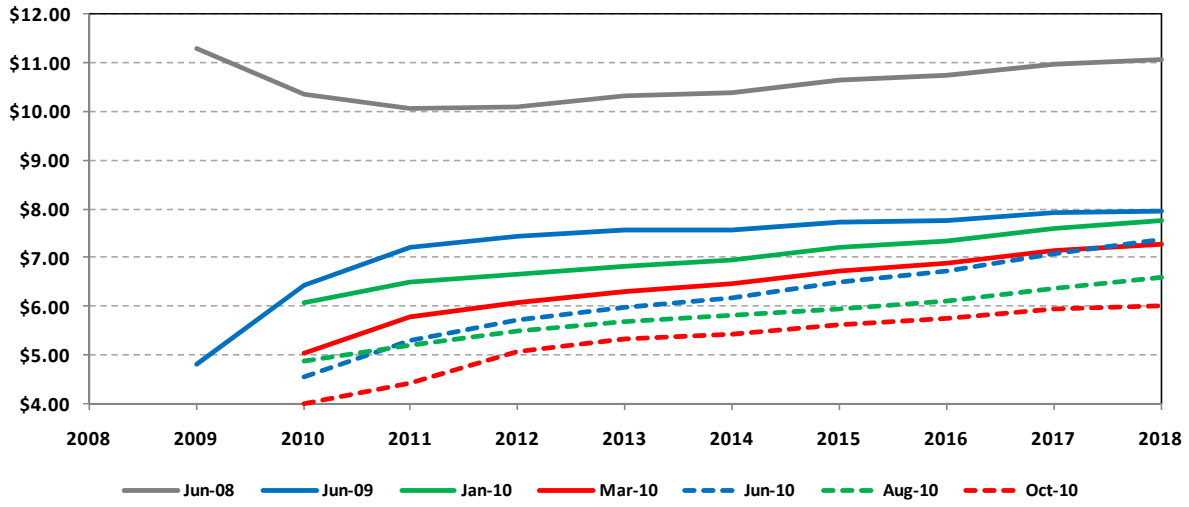


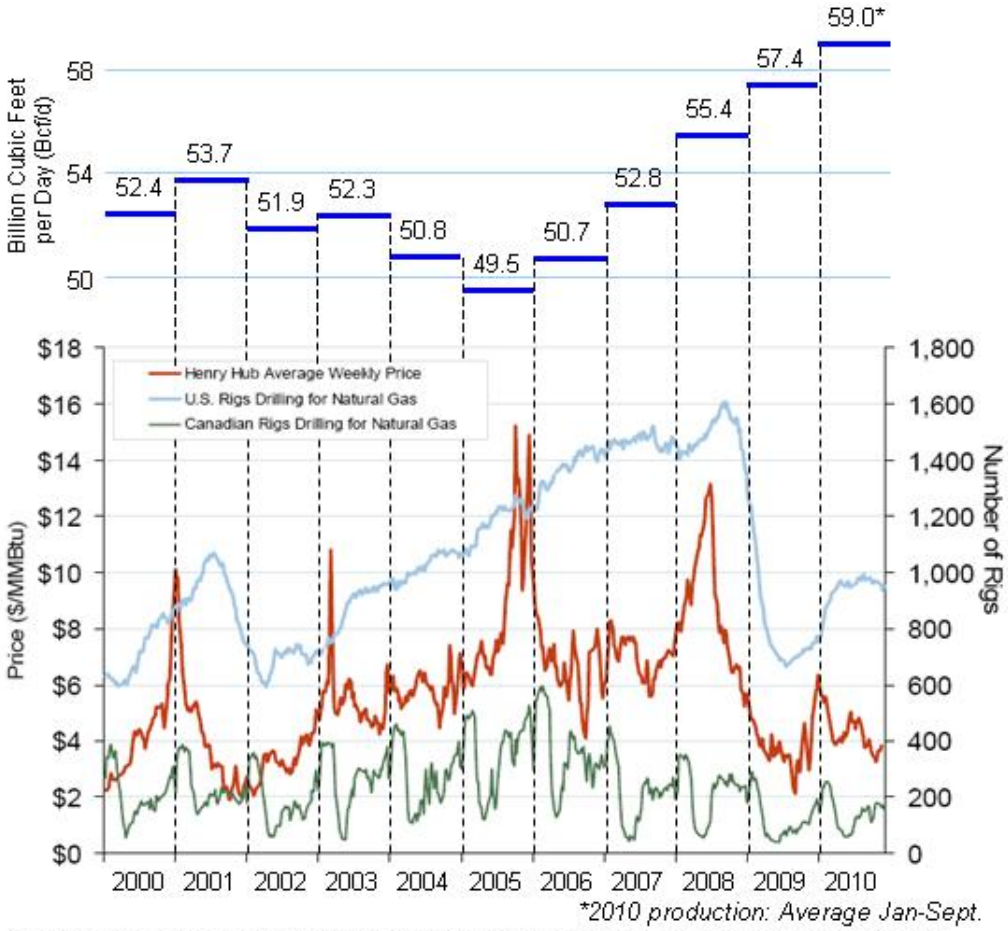
Figure 2 - The March (Down) of the Forward Curve in 2010: NYMEX Henry Hub Futures Prices

Source. S. Thumb, Energy Ventures Analysis, in "2009 Experiences: Impact on the Natural Gas Industry", EPRI-EEI Annual Seminar on Power Technology, Fuel Supply and Market Risk, Dec. 14-15, 2010. From the EPRI Publication – *Unprecedented Generation Shifts: The 2009 Experience and Implications for the Power, Coal and Natural Gas Industries.* Part I: Welcome to the Future: Lessons from Coal-Gas Switching, Renewables Penetration and Generation Response to Recession, 1021123. Dec. 2010

Decoupling Natural Gas Production and Prices

Over the short to intermediate term, one of the most notable developments has been the decoupling of natural gas production from market price signals. While this decoupling is not a sustainable phenomenon, what it means is that drilling and production levels, normally price-responsive, have actually risen as prices have declined. This novel phenomenon is evident in the trend of 2009 and 2010 production, illustrated in the figure below. It violates long-established notions of "effort-yield" relationships and complicates production forecasting.

A host of factors are behind this divergence from expected and typical economic behavior. These factors include: (1) greater productivity of individual unconventional wells, due the vast majority of natural gas wells now being horizontal wells, longer laterals (up to about 7,000 feet) completed, and more numerous stages of fracking per lateral, (2) development of numerous wells from a single drilling site or well pad, (3) necessity to drill prospects in order to fulfill terms for holding the leases ("held by production"), (4) joint venture financing arrangements in which partners acquire a position by carrying most of the costs of drilling, (5) heightened value of oil/liquids production associated with natural gas in some fields, and (6) above-market income from production hedged at higher prices.



Source: Production data (top): EIA (Monthly Energy Review); Price-Rig chart (bottom): Federal Energy Regulatory Commission, derived from *Platts* and *Baker Hughes* data, updated Dec. 8 2010

Figure 3 - 2000-2010 Trends in Price, Rig Activity and Production.

Probably the most notable factor of all these is the role played by joint venture financial arrangements. In a perverse irony, low prices force cash-strapped owners of shale acreage to divest or obtain partners who underwrite a large fraction of drilling costs in order to secure their position, thus increasing production in the opposite direction of price signals. Drawing on an EPRI research project, the table below summarizes transactions (principally joint ventures and acquisitions) involving shales in the U.S. and Canada. The level of activity during 2010 is breathtaking. The dollars involved were estimated by EPRI's investigator to leverage about $38 billion in drilling costs. Yet this mechanism is not a sustainable means to drive investment in an industry. The table underscores how very unusual 2010 has been with respect to financing upstream activity and represents the scale of financing which will come under tension during an inevitable correction.

Table 2 - Transactions Involving North American Gas Shale Plays

	Date	New Entity	Original Holder of Acreage	Shale Play	Upfront Cash ($MM)	Drilling Carries ($MM)	Total ($MM)	Comment	Cost Metric ($/Acre)
1	Nov-10	Chevron	Atlas Energy	Marcellus	$3,200		$3,200	Acq	
2	Nov-10	Exxon	Ellora Energy	Haynesville	$695		$695	Acq	$15,109
3a	Oct-10	Statoil	Enduring Resources (private)	Eagle Ford	$529		$529	JV	$10,897
3b	Oct-10	Statoil	Talisman	Eagle Ford	$178		$178	JV	$9,622
3c	Oct-10	Talisman	Enduring Resources (private)	Eagle Ford	$529		$529	JV	$10,897
3d	Oct-10	Talisman/Statoil	Enduring Resources (private)	Eagle Ford-prod&plt	$268		$268	JV	
4	Oct-10	CNOOC	Chesapeake	Eagle Ford	$1,080	$1,080	$2,160	JV	$10,801
5	Oct-10	Barclays Bank	Chesapeake	Barnett	$1,150		$1,150	Prod. Payment	
6	Sep-10	S. Korean Invest. Firm (Antinum Marcellus I)	Gastar Exp.	Marcellus	$30	$40	$70	JV	$9,551
7	Sep-10	Sumitomo	Rex Energy	Marcellus	$64	$52	$116	JV	$8,964
8	Aug-10	Mitsubishi	Penn West Energy	Horn River & Montney	$808	$190	$998	JV	$7,255
9	Aug-10	Blue Stone O&G(private	Abraxas	Eagle Ford	$75	$25	$100	JV	$15,095
10	Aug-10	Reliance	Carrizo	Marcellus	$340	$52	$392	JV	$6,258
11	Jun-10	Exco Resources	Southwestern Energy	Haynesville	$355		$355	Acq	$17,750
12	Jun-10	CNPC	Encana	Horn River & Montney	$1,900		$1,900	JV	
13	Jun-10	KKR	Hilcorp	Eagle Ford		$400	$400	Finance	$10,000
14	Jun-10	Reliance	Pioneer	Eagle Ford	$266	$879	$1,145	JV	$12,002
15	Jun-10	Shell	KKR/East Resources	Marcellus	$4,700		$4,700	Acq	$7,231
16	May-10	Unknown	SM Energy	Haynesville		$87	$87	JV	$9,506
17	May-10	Williams	Alta Resources	Marcellus	$501		$501	Acq	$11,929
18	May-10	Shell	Unknown	Eagle Ford	$1,000		$1,000	Acq	$4,000
19	May-10	BG	EXCO Resources	Marcellus	$800	$150	$950	JV	$2,905
20	May-10	Talisman	Common Resources	Eagle Ford	$359		$359	Acq	$7,180
21	May-10	BG/EXCO	Common Resources	Haynesville	$446		$446	Acq	$14,867
22	Mar-10	Kogas	EnCana	Horn River & Montney		$1,100	$1,100	JV	$7,774
23	Mar-10	Reliance	Atlas Energy	Marcellus	$340	$1,360	$1,700	JV	$14,167
24	Mar-10	BP	Lewis Energy	Eagle Ford	$200		$200	JV	$5,000
25	Feb-10	Mitsui	Anadarko	Marcellus	$100	$1,400	$1,500	JV	$15,000
26	Jan-10	Total	Chesapeake	Barnett	$800	$1,450	$2,250	JV	$33,333
27	Jan-10	Exxon	XTO	All 5 major plays	$41,000		$41,000	Acq	
28	Jan-10	Consol	Dominion	Marcellus	$3,480		$3,480	Acq	$6,960
29	Jan-10	Newfield	TXCO Resources	Eagle Ford/Pearsall	$217		$217	Acq	$723
30	Jan-10	Anadarko	TXCO Resources	Eagle Ford/Pearsall	$93		$93	Acq	$1,163
31	Jan-10	Exxon	Penn General Energy	Marcellus			$0	JV	
32	2009	Morgan Stanley	Trianna Energy	Marcellus			$0	Finance	
33	Dec-09	Sumitomo	Carrizo	Barnett	$16		$16	JV	$12,266
34	Jul-09	BG	EXCO Resources	Haynesville	$655	$400	$1,055	JV	$17,583
35	Jul-09	KKR	East Resources	Marcellus	$350		$350	Finance	
36	Jun-09	Williams	Rex Energy	Marcellus	$33		$33	JV	$1,500
37	May-09	Eni	Quicksilver	Barnett	$280		$280	JV	$3,598
38	Mar-09	Shell	Encana	Haynesville	$580		$580	JV	
39	Nov-08	Statoil	Chesapeake	Marcellus	$1,250	$2,125	$3,375	JV	$5,769
40	Sep-08	BP	Chesapeake	Fayetteville	$1,100	$800	$1,900	JV	$14,074
41	Jul-08	Shell	Duvernay	Montney	$5,900		$5,900	Acq	
42	Jul-08	BP	Chesapeake	Woodford	$1,750		$1,750	Acq	$19,444
43	Jun-08	Plains	Chesapeake	Haynesville	$1,650	$1,650	$3,300	JV	$30,000

Source: EPRI, *Unprecedented Generation Shifts: The 2009 Experience and Implications for the Power, Coal and Natural Gas Industries*, Dec. 2010, 1021123. Table developed by Energy Ventures Analysis, Inc.

Decoupling Oil and Natural Gas Prices

Over the past year, any rules of thumb for how natural gas prices should "behave" relative to oil prices have been tossed to the wind. While volatility of either fuel might cause this ratio to fluctuate, the most striking thing is how this ratio has moved into new territory, not just now, but in the forward curve and in long term forecasts.

At strict Btu parity, a ratio of about 6:1 would be expected – at 5.8 million Btus per barrel, $40/bbl oil would lead to $7.90/mmBtu. Discounting strict parity, a reasonable view of this "netback" mechanism (established by price-sensitive consumers able to switch between natural gas or oil) had been to expect that gas might settle at about 80% of parity, leading to a ratio of about 7.25 and corresponding in this example to about $6.50/mmBtu gas prices. This ratio is the dashed line on the figure below. In 2009 this ratio set a record at 24:1 – reflecting both

spiking oil (which was higher in 2008) and falling natural gas prices. In 2010 it averaged about 18:1. The futures markets portray the ratio in the high teens over most the next five years. The Annual Energy Outlook forecast, already discussed, suggests a ratio of about 20:1 for the next 20 years (e.g. the low-sulfur light oil price divided by the Henry Hub price). 2010 might then be said to be a watershed year marking an historic change in this relationship and in long term expectations for oil and gas prices. A permanent weakening of the relationship represented by these ratios has a number of implications to E&P, to fuel and technology choices, and to the sustainability of oil-linked gas pricing internationally. It also spurs gas-to-liquids developments, discussed below.

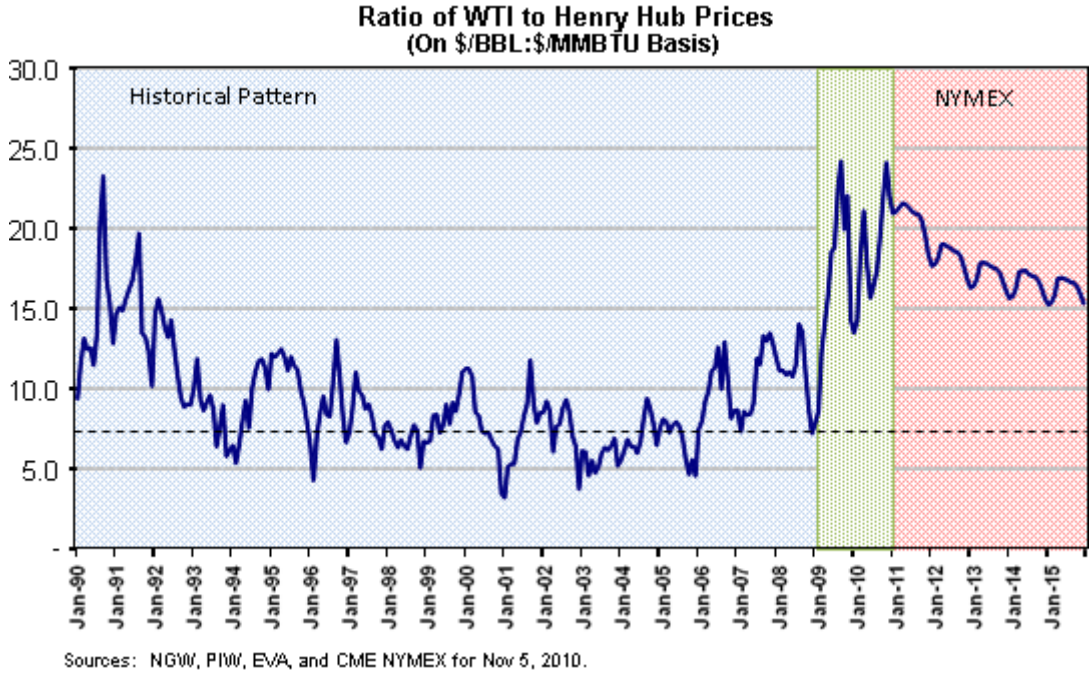


Figure 4 - 2000-2010 Trends in Price, Rig Activity and Production.

As of March 2011 energy trades have pegged the ratio at 25.3 (WTI:HH spot) and 24.2 (NYMEX crude futures: NYMEX HH futures, March 18, 2011).

Learning from the Recession

Events brought about by the Recession have had profound impacts on the electric sector and the gas industry, with somewhat more muted impacts on the coal industry due to the vintaging of coal transactions and the buffering effects of coal inventories.

Fuel Use Impacts in the Power Sector. The Electric Power Research Institute has completed an economic analysis of the impacts of the Recession on the fuel and power industries.[1] The Recession, with related adjustments, represents an almost unimaginable shock to the electric industry. The events can be viewed as terribly perverse "economic experiment" which offers

[1] EPRI, *Unprecedented Generation Shifts: The 2009 Experience and Implications for the Power, Coal and Natural Gas Industries*, Dec. 2010, 1021123.

empirical evidence into the strengths and vulnerabilities of different types of generation. Electricity demand fell 5% in 2009 compared to 2007. As is well known, the industrial sector (amounting to 27.4% of total demand in 2007) was particularly hard hit, experiencing a 14.2% decline. The impacts were not felt uniformly across the country, but rather were most severe in the Atlantic Coast (WV, VA, NC and SC), East North Central (WI, MI, IL, IN and OH), and Southeast (KY, TN, MS, AL, GA), falling -12.5%, -10.1% and -9.8% respectively.

Table 3 below gives a synopsis of impacts on generation between 2008 and 2009, splitting the country between east and west. Of greatest interest are the two biggest changes: eastern coal generation experienced the brunt of the Recession's impacts, dropping 14.5%, and eastern natural gas generation increased 15.3%. This is exactly the opposite of what one might expect in a severe recession year. The explanation lies in the historically anomalous and surprisingly prolonged flip flop in the relative competitiveness of coal and natural gas generation.

Table 3 - Changes in Fossil and Other Electric Generation, 2009 vs. 2008

	Eastern Power Generation GWh				Western Generation			
	2009	**2008**	**Change**	**Percent**	**2009**	**2008**	**Change**	**Percent**
Coal	1,089,337	1,274,785	(185,448)	-14.5%	658,402	692,008	(33,606)	-4.9%
Natural Gas	385,672	334,478	51,194	15.3%	451,754	463,949	(12,195)	-2.6%
Oil	14,146	19,653	(5,507)	-28.0%	867	1,149	(282)	-24.5%
Pet Coke	6,897	8,014	(1,117)	-13.9%	4,581	4,640	(59)	-1.3%
Fossil Total	**1,496,052**	**1,636,930**	**(140,878)**	**-8.6%**	**1,115,604**	**1,161,746**	**(46,142)**	**-4.0%**
Nuclear	608,748	619,306	(10,558)	-1.7%	188,004	186,902	1,102	0.6%
Hydro	83,141	65,450	17,691	27.0%	185,800	186,429	(629)	-0.3%
Renewable	28,094	24,105	3,989	16.5%	84,531	72,503	12,028	16.6%
Pumped Storage	(5,154)	(6,930)	1,776	-25.6%	809	640	169	26.4%
Other Gases	532	776	(244)	-31.4%	2,575	2,423	152	6.3%
Other	6,100	5,986	114	1.9%	980	846	134	15.8%
Non-Fossil Total	**721,461**	**708,693**	**12,768**	**1.8%**	**462,699**	**449,743**	**12,956**	**2.9%**
Total	**2,217,511**	**2,345,626**	**(128,115)**	**-5.5%**	**1,578,300**	**1,611,491**	**(33,191)**	**-2.1%**

Coal's Loss was, to an Unprecedented Degree, Natural Gas' Gain.

The next table summarizes changes in generation between 2007 and 2009 (these are larger than shown the preceding table because the recession began in 2007 and 2008 generation had already started to decline). Focusing on the flip flop ("fuel switching"), coal demand declined 33.8 million short tons while gas demand gained a boost of about 1.3 billion cubic feet per day. This boost is the bright side to gas' depressed prices.

Table 4 - Changes in Fossil and Other Electric Generation, 2009 vs. 2008

Change in Coal Generation (GWh), 2009 vs. 2007

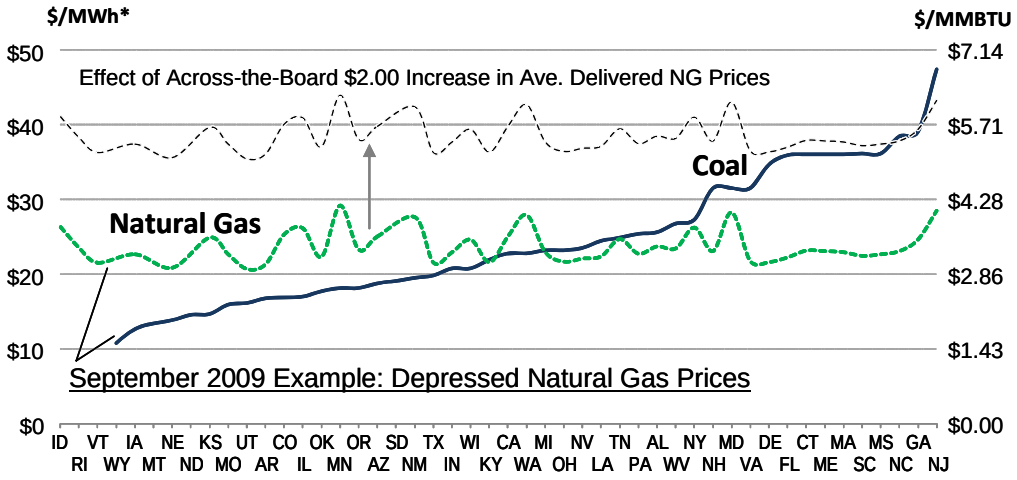
	EAST	WEST	TOTAL
η in Coal Gen. (GWh)	(225,444)	(30,956)	(256,400)
η in Coal Gen. due to:			
Decreased Demand	(138,420)	(27,426)	(165,846)
Fuel Switching	(67,922)	(7,440)	(75,362)
Non-Fossil (Wind, Nuc, Hyd)	(18,570)	(1,587)	(20,157)
Other	(531)	5,497	4,965

2009 Eastern Coal Generation Lost to Switching to Nat. Gas Gen.

	Coal Gen. (GWh)	Tons of Coal (1000 Tons)	Volume of Gas (BCFD)
Northeast	5,630	2,950	0.11
MPJD	14,171	7,445	0.26
East North Central	2,884	1,602	0.05
Atlantic Coast	10,787	5,402	0.20
Southeast	25,608	11,851	0.48
FRCC	8,843	4,528	0.17
Total East	67,922	33,778	1.27

Source. EPRI 1021123. See footnote 1.

The mechanisms behind this unusual state of affairs are principally the current oversupply of natural gas depressing prices, highly efficient gas generating equipment, and robust coal costs in the East (a combination of high mining costs and global pressures in the seaborne thermal and especially metallurgical coal trade). A snapshot of this competition translates fuel into electric power production costs in the following chart. This represents a month in which natural gas prices were especially low (September 2009). The natural gas price is more uniform across the country than coal costs, but they can rise and fall quite precipitously in the short run due to the short term price indexing used in the gas market. With just a two-dollar increase in natural gas prices, natural gas' economic edge all but vanishes. While winter prices and winter peaks in the northeast typically preclude gas' displacement of coal generation, market information suggests those peaks will be the exception and for a time the norm will be continued displacement.



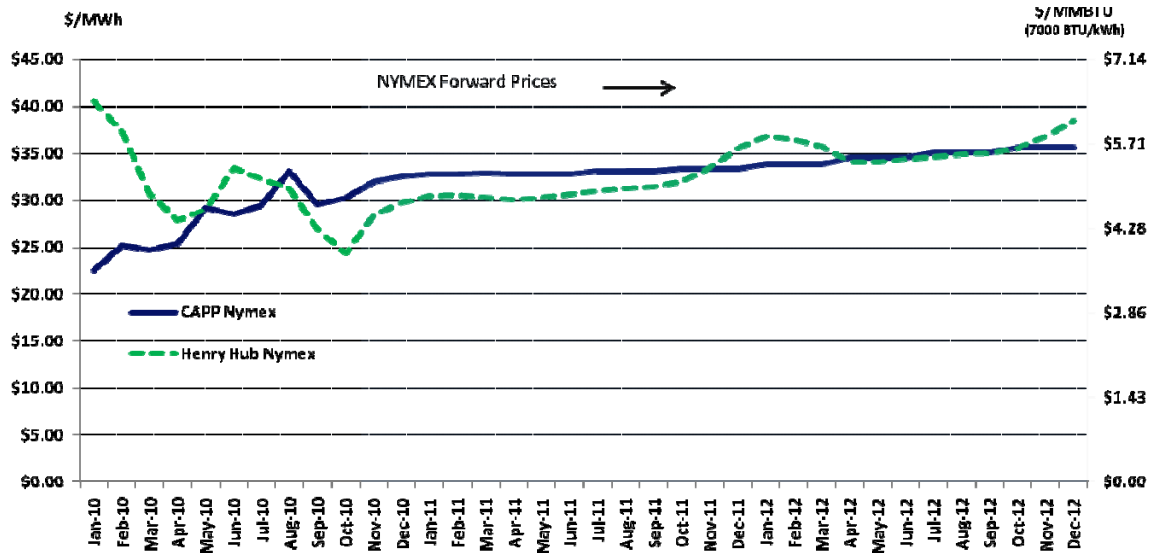
*Conversion of average delivered fuel costs to $/MWh at 7,000 Btu/kWh for natural gas and 10,500 Btu/kWh for coal.

Source. EPRI 1021123. See footnote 1.

Figure 5 - Average Costs of Coal and Natural Gas Generation by State in One Month

Outlook is for Continued Hyper-Competition between Coal and Natural Gas Generation in Segments of the Eastern U.S.

It is not possible to pick a specific trigger price at which natural gas displaced coal generation, as this occurs over a range of prices and takes into account local delivery circumstances and costs (for both coal and natural gas), the actual efficiencies of generating units (both coal and natural gas), environmental penalties which vary seasonally, and other factors. But it is helpful to look at the forward curves (the strip of futures prices) for natural gas and coal to obtain a general indication of how "the market" is anticipating conditions to evolve over the next six to twenty-four months. The Henry Hub is the most liquid index. And a useful reference for Eastern coal prices is the New York Mercantile Exchanges strip for Central Appalachian coal. At the end of 2010, these relationships indicated the anomalous coal-gas price relationships will continue for at least one to two years, punctuated by winter gas price spikes. As in the preceding figure which converts fuel prices into power generation costs, the next figure shows the futures prices in the same manner. The implications are that the power sector will continue to use above-average amounts of natural gas and coal-fired generation will remain hard pressed. The latter signifies very tough business conditions for coal-fired power generators.



Source: NG Weekly, United Power Coal Prices, NYMEX Coal and Gas Futures at 12/6/10; in EPRI 1021123. See footnote 1.

Figure 6 - Coal vs. Gas Prices 2010 to 2012

Export LNG? Gas-to-Liquids? Success in unconventional shale gas development is leading to new business structures: Moving down the LNG value chain and oil-indexed pricing (by Dieter Beike, Ph.D., Independent Consultant)

The post-2008 natural gas market environment – described on the one hand by decreasing natural gas prices, a global economic recession and worldwide decline in natural gas demand, and on the other hand by a sharp increase in shale gas production in the regional North American market – resulted in a natural gas oversupply that triggered shifts in the international liquefied natural gas trade. LNG imports into the North American market, whose prospect triggered numerous applications for building re-gasification terminals on all coasts of North America in the mid 2000's, were now being displaced by domestic shale gas production. Facing significantly increasing production and natural gas reserves and weakening gas market demand and prices, independent E&P shale gas producers were forced to investigate strategies for gas monetization.

This impetus resulted in efforts to tie shale gas production areas to oil-indexed liquefied natural gas markets in Asia or to transform shale gas via gas-to-liquids processes (GTL) to diesel, kerosene or jet fuel. Both approaches are highly capital intensive, requiring in the first case the development of an LNG value chain anchored in a liquefaction facility, and in the second case the construction of a processing facility that is lacking in examples of commercially successful predecessors. The approaches are very different or "diverse", as they would use entirely different sets of asset classes (e.g. investments in process technology) in order to achieve gas monetization.

In the case of shale gas to LNG, high capital costs are being weighed against opportunities for arbitrage trading to take advantage of typically significantly higher gas prices in Asian LNG and European gas prices vs. North American Henry Hub gas prices. A substantial, sustained

price spread could justify the high capital investment. An added consideration is geographic diversification into new gas markets.

Table 5 - New Heights in U.S. vs. UK Natural Gas Price Spread

Yr-Month	NYMEX HH	ICE NBP	Spread
11-Apr	4.17	10.05	-5.88
11-May	4.25	10.19	-5.95
11-Jun	4.32	10.27	-5.95
11-Jul	4.39	10.22	-5.83
11-Aug	4.42	10.31	-5.88
11-Sep	4.44	10.17	-5.74
11-Oct	4.49	10.82	-6.33
11-Nov	4.67	11.36	-6.69
11-Dec	4.92	11.85	-6.94
12-Jan	5.05	12.06	-7.01
12-Feb	5.04	11.92	-6.88
12-Mar	4.98	11.45	-6.47
12-Apr	4.83	10.71	-5.88
12-May	4.86	10.49	-5.63
12-Jun	4.89	10.34	-5.45

Source: LNG Gateway, March 18, 2011. www.lnggateway.com

In the case of gas-to-liquids, the resulting product diversification would tie the original gas product to a new business line, i.e. the transportation sector.

Commercial Examples.

These approaches rely on evolving business structures. New partnerships across industry segments are developing, pairing operational excellence of the upstream company with an application-driven approach to end-markets. This business model can be initiated at various points along the value chain. In case of shale gas to LNG, two upstream companies (EOG Resources and Apache) initiated the reclassification of a facility originally planned to import LNG (re-gasification terminal) to export LNG, in order to facilitate the export of western Canadian Horn River shale gas deposits. This is the Kitimat facility in British Columbia. The same approach was taken by owners of three existing re-gasification terminals (Freeport LNG and Cheniere LNG on the US Gulf coast and Dominion Resources on the US East Coast (Cove Point) re-gasification terminal. These facilities suffered from serious under utilization due to lack of LNG imports. Further down the value chain, we've seen the end-user rather than the producer drive similar investment. Korean KOGAS is partnering with Canada's Encana to move its shale gas into the LNG export market. Likewise, Australia's merchant bank Macquarie is bolstering project end-use expertise by joining with Freeport LNG to market potential shale gas as LNG.

In the case of gas-to-liquids, Canadian Talisman joined with South Africa's SASOL to develop Montney shale gas deposits to produce transportation fuels. Even though this conversion loses about 40% of the energy value, at times of high oil prices and low natural gas prices, oil products derived from natural gas could be cheaper on a unit basis than those derived from crude oil. The climbing and possible permanent shift in the oil-to-gas price ratio was discussed previously.

Additional Considerations.
Critical for both approaches is the role of the shale gas producer as an efficient low cost gas provider. Major (international) LNG facilities often have favorable economics due to large liquids production, a type of revenue that would be missing for dry gas producers. Liquefaction and shipping costs typically determine the competitiveness of such plants for given markets. Completion of the widening of the Panama Canal by 2014 would greatly support U.S. Gulf Coast producers aiming to serve Asian markets. However, in the U.S. regulatory issues could hinder shale gas to LNG export development, as capping of exports to a certain volume limit could occur under fluctuating market conditions through a legislative process. In this case, an early mover approach could be advisable for any of the contenders. GTL, by contrast, can be viewed as a different type of refining process. Its primary challenge is to compete in terms of $/daily barrel of capacity; however, transportation of the product itself would not require any new technology.

Investment in such gas monetization processes would require an expanded management skill set from independent shale gas producers. The complexities of such arrangements would focus on a number of elements:

- Pricing structures of international markets will need to be understood.
- Gas supply agreements will have to include end user market stipulations.
- EPC (engineering, procurement and construction) contracting strategies for yet to be built facilities will have to be developed.
- Financing arrangements will have to satisfy possible project financing structures.

Addendum – Costs. Timely and public information on costs of liquefaction and transportation is scarce, although these costs are certainly a focus in any private financing arrangements for the projects referenced here. Insight into shale gas to LNG economics comes from James T. Jensen's recent presentation to the Beijing Energy Club, February 18, 2011 in Shanghai, "Natural Gas Pricing: Current Patterns and Future Trends".

The figure below shows three estimates of costs for the chain of steps beyond initial gas supply costs. That chain (liquefaction, transportation, re-gasification, and a smaller geographic adder "European basis") was nearly $5.00/MMBtu in 2009 and its level is linked to prices of natural gas and oil in the forecast year 2020. For example, that chain is indicated to be as low as $4.50 (with gas supply prices below $5.00/MMBtu in 2020) to nearly $6.00 (at a gas supply price of $8.00/MMBtu). The current $6-7.00 spread in today's Gulf/U.K. markets is an attractive lure for such projects, provided it holds up. Perhaps not surprisingly, developers have suggested financial success would occur at much lower spreads.

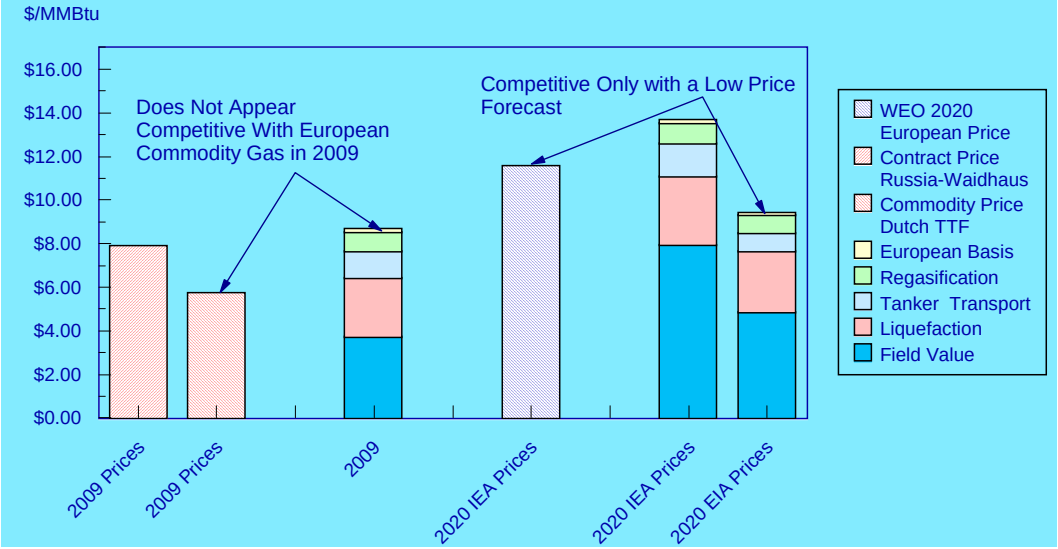


Figure 7 - Principal Liquefaction and Transportation Costs for a U.S. Gulf Coast LNG Export Facility to Supply Europe Source: J. T. Jensen, Natural Gas Pricing: Current Patterns and Future Trends, Feb. 2011. Used by permission.

Examples of Shale Property Economic Analysis: Living with $4.00 or Needing $7.00? [2]

The tight gas market that prevailed during most of 2010 was "the mother of invention", leading to productivity gains (e.g. additional frac stages per lateral, continuing economies from pad drilling), alternative financing (e.g. the joint ventures discussed previously), alternative completion practices (lower initial volumes), and so on. In this section, we examine how alternative assumptions about key price drivers can affect the economic evaluation of shale prospects. Our approach is to illustrate calculations of "break even" natural gas prices – the price a producer requires under normal financing to sustain development and production. *Every part of this discussion is open to inputs from individuals close to the various shales. We welcome contributions from readers to clarify the performance and economic factors.*

BREAK EVEN GAS CALCULATIONS

We understand that companies, analysts and consultants maintain a variety of proprietary approaches to assessing gas-field economics. The list here represents one such collection of variables and it likely represents a higher level of abstraction than used by operating companies.

PLAY

Play / Part of Play. It has become common to differentiate parts of plays by their production or geographic characteristics. The best economics are found in the "Core". The Non-Core segment may be treated collectively or broken out into regions with descending quality, e.g. "Tier 1" and "Tier 2". The newer Eagle Ford play may be broken out into areas with higher and lower liquids contents (a combination of high value condensate and lower value natural gas liquids). Current oil prices are a major driver of the popularity of this play. Even the Eagle Ford "dry' wells are roughly on a part with the Marcellus, which has the greatest liquids

[2] George Lippman, Lippman Consulting Inc., kindly provided illustrative cost and performance factors and an economic framework to enable this discussion.

content of the Big Five (Barnett, Haynesville, Fayetteville, Woodford, and Marcellus). Yet we can expect considerable variation over the vast region spanned by the Marcellus. With the arrival of the Eagle Ford, the top shales are now known as the Big Six. Most of these are broken down further, e.g. the Barnett North with its greater liquids contents, or the Texas Haynesville as contrasted with the Louisiana core and non-core portions of the Haynesville.

PRODUCTION

Gas production – initial years. Some estimators examine a well's initial production rate at its 30-day point and apply decline rates thereafter. Others might estimate average production over the first year and specify declines on an annual basis. One estimator known to EPRI uses data and judgment to specify average annual production by year for an initial period of years, the argument being that the sharp falloff in production over the first years of a well is not representative of later declines. Most of the new shales do not have a sufficiently long history to inform estimation of decline rates beyond about three years, leading then to the Barnett as a possible proxy. See top chart, next page.

Gas production – later years. At some point, the step downs in production will be expected to reach a ***constant decline rate***, such as 15% per year. At this stage, production levels are important to total field output when summed up over hundreds of wells, but this production typically does not have a significant impact on breakeven price calculations. Exceptions may occur as new completion techniques are applied, causing notable performance gains in mature plays. See bottom chart, next page.

Condensate and natural gas liquids production rates. Liquids associated with what are principally natural gas wells may be expected to conform to gas production levels, such as barrels per million cubic feet. Condensate is oil stripped off at the well and is valued at oil prices. NGLs (methane, ethane, propane, butane and other hydrocarbons) will be removed at a gas processing plant. In the Gulf, they may be go into dedicated NGL pipelines or be used locally. In the northeast, the pipeline infrastructure for NGLs is in a state of flux; one issue still to be resolved in the northeast, apparently, is whether NGLs will be combined or whether lines dedicated just to ethane will be developed. NGLs are typically priced at about half the price of oil.

The current era of low natural gas prices is bringing greater and greater attention to liquids. The "wet" region of the Eagle Ford may have about 35 bbls condensate and 30 bbls NGLs per mmcf. The other regions drop off in comparison, though their break even prices may not follow this uniformly because of very different gas productivities across the different plays. The "dry" region of the Eagle Ford is, comparatively, still quite wet. Although its oil production may fall off considerably to only 10 bbls/mmccf, its NGL content may fall only marginally to 25 bbls/mmcf. The Barnett spans a wide range of characteristics. The Barnett core is dry, say 1 bbl condensate (oil) and 7 bbls NGL per mmcf. This is also typical of the Haynesville and the Arkoma part of the Woodford. Other parts of the Barnett are comparable to the Eagle Ford in NGLs but lower to much lower in condensate (e.g. 4-8 bbls/mmcf). Data and assumptions on these products are an important part of any break even analysis.

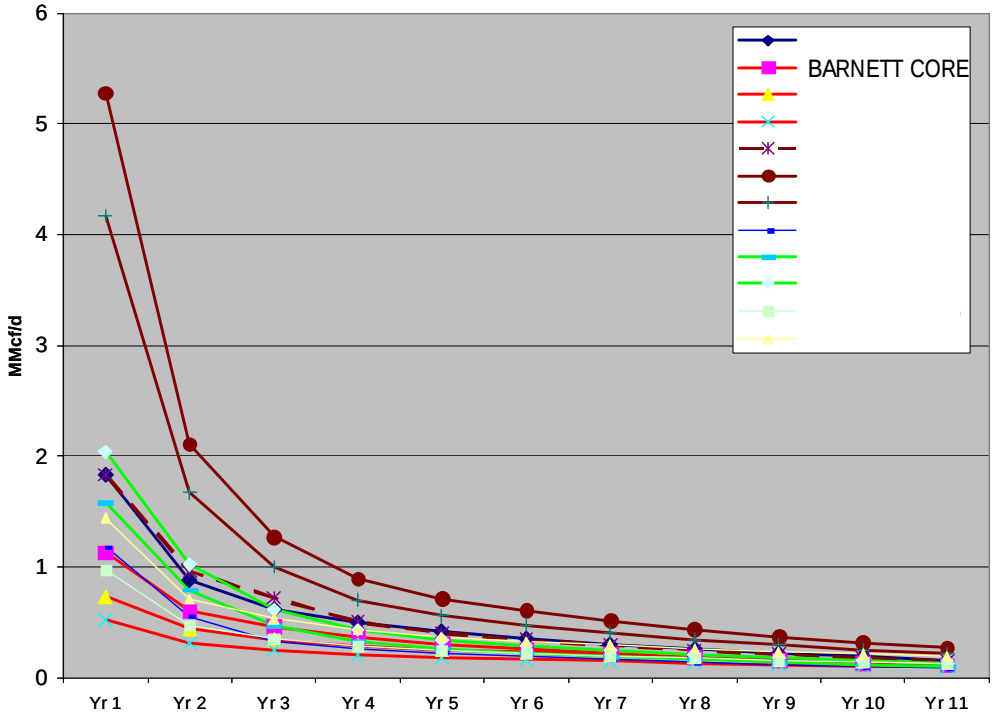


Figure 8 - First Years' Production for Big Six Shale Plays

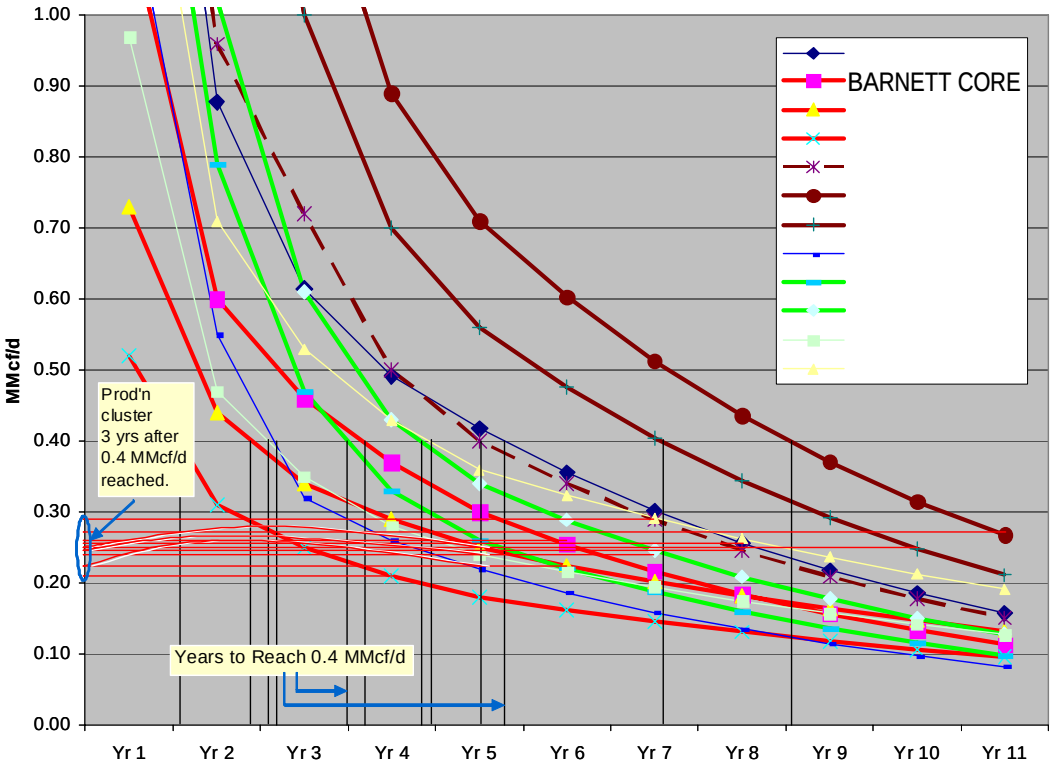


Figure 9 - Clustering of Long-Term Production Rates across Big Six Shale Plays

PRICES

Price assumptions. In break even analyses, condensate and oil prices will be inputs, or used to measure sensitivities. For condensate, $/bbl. For NGL, $/bbl.

Price of natural gas: This is the break even price which will be calculated as an output, not an input.

LAND COSTS and TAXES

Acreage – acres per well.. This may be set by the state or by operators based on drainage areas per well. While pad drilling brings economies to drilling and completion costs, the number of wells across a region will reflects these policies and calculations. The acreage cost will need to fold into the cost per well on a tract the cost, also, of undrilled or undrillable acreage also acquired at the time of leasing; thus, a view of the scale of a broader development effort involving multiple well and potentially thousands of acres is necessary for developing an estimate of land costs. A typical assumption is drainage of about 80 acres per well. The number shrinks to 40 acres for the densely-drilled Barnett.

Land cost per acre ($/acre). These vary greatly with the market and the state of development of a play. At present, values might range from $1,000-$3,000 per acre, with the higher production natural gas or wet plays at the high end and non-core or lower-quality plays at the low end.

Royalty rate (% of gross revenues). These range from 15% to 25% across the Big Six.

Severance tax (% of gross revenues). These range from 5% to 7.5% across the Big Six. In several states horizontal wells are exempted for the first two years, or until "payback" of all or 50% of D&C costs is achieved for "high cost" wells. In Texas, the rate is between 0% and 7.4%, depending on the well's costs compared to its peers. In Louisiana, the full rate is 16.4 cents per mcf and, for oil, 12.5% of value – which translate into about $0.16/mmBtu for natural gas and, at $84/bbl, about $1.75/mmBtu for oil/condensate.

DRILLING AND OPERATING COSTS

Drilling and completion costs. This is the most significant big-ticket cost item in any economic evaluation. Drilling and completion costs are incurred up front, in the first year. Sophisticated economic models may calculate these costs from detailed inputs ranging from rig rental rates to the target shale depth. Across the Big Six, D&C costs range from about $2.5-3.0 million in the Barnett and Fayetteville to $4-5 million in the Eagle Ford, Fayetteville and Marcellus to $7 million or more in the Haynesville.

Hydraulic fracturing costs. These may be incorporated in D&C costs or broken out separately. They are included in the indicative D&C costs presented here.

Fixed operating costs/year ($ thousands). These represent field and home office administrative costs and some fixed costs such as capital costs of pumping units. They will typically be uniform for an operator across a field. They are relatively low across the Barnett

and may be about 50% higher or $18,000 per year for wells in the other shales. Like many cost considerations, this is not an area of great price transparency.

Variable operating costs ($ per mcf). These costs vary depending on the need for pumping units, for example, or for water disposal or treatment. Normative costs might be about $0.50 per mcf in your model, whereas a developer might use cost assumptions of $1.40 per mcf for the Haynesville Core, D&C costs of $9 million, and even include lower production rates. All else being equal, your model would calculate far a far higher B.E. price, yet the developer may somehow report a B.E. price the same as yours. We've seen such a case and simply cannot explain it. Such examples suggest that transparency regarding all essential assumptions is lacking and that there is more leeway in approaches to economic analysis than one might expect.

Water acquisition and treatment costs. As noted, water used in fracking will be incorporated in D&C costs, whereas water produced on a routine basis during the operation of a well will be incorporated in variable costs.

FINANCIAL ANALYSIS – YEARS TO BREAK EVEN, CASH FLOW, ETC.

Among the many measures important to financial analysis are break even prices, rates of return, and years to break even. The ***break even price*** calculation will incorporate all the preceding variables, yet will require a decision on the ***number of years to break even***. Different periods of time will result in very different prices, yet this too is an area of limited transparency.

The ***rate of return*** may be an output, provided one inputs all the pertinent costs, production variables, and prices received, or it may be an input, such as 10%, to be used in break even price calculations when all considerations except the price are assumed to be known.

Additional layers of sophistication in economic valuation come from incorporating financial arrangements reflecting different costs of money (for shares of debt) and different discount rates (for equity investments in play development). *We invite readers to weigh in on this topic with examples they are able to share.*

Illustrative, simplified economic analyses show:

(a) ***Huge importance of production in the early years.*** This places outsize importance on initial production rates and the pattern of rapid decline before a well reaches steady state. Insights into month to month trends and operator practices regarding maximizing production versus choking back production for various reasons must be considered. The latter is claimed in the trade press to result in greater overall recovery while reducing the volumes entering a weak market.

(b) ***Huge importance of drilling and completion costs***. As the big ticket item with the greatest impact in any given play on break even prices or years to break even, it is no surprise that recent financial arrangements with investors underwriting drilling costs is such a compelling driver of development and production.

The following table illustrates some of the cost relationships based on simplified economic modeling that contrasts the mature, dry core of the Barnett Shale and oil/NGL-rich portion of the Eagle Ford. These represent a small example of the variety of shales and economic questions one might wish to examine.

Table 6 - Illustrative Economic Sensitivities for the Barnett Core and Wet Eagle Ford.

Sensitivities	Barnett Core Example	Eagle Ford Example ("Wet")
B.E. reference	~$4/Mcf (~6.50 outside core)	~$3.50
If 25% lower prod'n in first three years:	Need $0.75/Mcf higher price	Need $1.25/Mcf higher price
If D&C $ 20% less:	Cuts payback to 5 vs. 11 yrs	Cuts payback to 4 vs. 11 yrs
If D&C $ 20% more:	Need $0.70/Mcf higher price	Need $1.00/Mcf higher price
If zero condensate:	Need $0.07/Mcf higher price	Need $2.07/Mcf higher price
If oil price up $10/bbl:	-	Cuts payback to 6 vs. 11 yrs
If oil price down $10/bbl:	-	Need $0.35/Mcf higher price

Questions/Uncertainties

- How will a correction in gas oversupply appear in the market? What price uplift might be expected? How long would this period last? Is lower natural gas price volatility the "new normal" because of the shales' growing share of unconventional production? The winter of 2010-2011 is an example of extreme cold weather not translating into significant increases in index prices outside of the northeast. Is this the harbinger of things to come? Likewise, is hurricane risk sufficiently muted by the geographic dispersion of shale production that the pattern of seasonal price risk is now substantially different than in the past?
- Economics of shale – beyond the immediate future. After some adjustment period, what "equilibrium" or sustainable price level is likely? This needs to take into account in some explicit fashion (a) depletion/movement to non-core areas), (b) improvements in technology/practices, (c) revisions, controversies and possibly improved estimates of EUR, (d) completing wells using market-responsive ("choked" or reduced initial output) production rates, (e) access/permit and cost aspects of evolving environmental regulations, (f) high prices and/or price volatility of oil and NGLs, (g) shifts in financing practices, e.g. joint ventures, drill carries, and their shrinkage over time, and (h) other. It also needs to take into account the strength of demand…
- Gas demand: Doldrums or Accelerating? Industrial demand is recovering under the low prices now envisioned. The electric sector is using more gas for economic reasons, but this prospect is not sustainable once gas prices move into equilibrium from oversupply. A more sustainable wedge of gas use in the power sector will come from environmental policies targeting coal generation. How will these forces in industrial sector, which also faces a wave of environmental regulations, and the electric sector play out over the next five years or so?

- Skyrocketing oil prices. This is a huge topic, which we would like to tee up “for next time” and encourage readers’ input.
- Iron/steel (“Oil Country Tubular Goods”) and hyrdrofracturing/services costs. These areas merit attention by the Committee and we encourage readers’ input.