U.S. Shale Gas

Meet Alaska

Economics of Shale Gas – Impact on Alaska

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Shale Magical Thinking

All difficulties arise from what seems easy.
All great things arise from what is minute.
One who thinks that everything is easy
will encounter much difficulty.

Tao Te Ching

- Less is more: we can produce more oil and gas from shale than was produced from better reservoirs over the past century.
- The United States has enough natural gas to last at least 100 years.
- A shale business model with no barriers to entry except capital, with an infinite supply of cheap gas, and somehow everyone makes a big profit.
- Shale plays can make a profit at less than $5/kcf gas price.
- Gas prices will be low forever because of abundance and low break-even price.
- If shale didn’t make sense, big companies would not be involved.
- Big production volumes prove success.

What is the Debate Over Shale?

- The shale revolution is real. Resources and production volumes are not in doubt.
- But the marginal cost of production is twice the present market price of natural gas.
- Per-well reserves are over-stated by 100%.
- The commercial portion of each play is 10-15% of the area used for resource & reserve estimates.
- If North America invests in greater reliance on natural gas, what happens if the fuel supply proves to be less than we believe or the cost proves to be greater than expected?

The United States has 22 Years of Natural Gas, not 100 Years

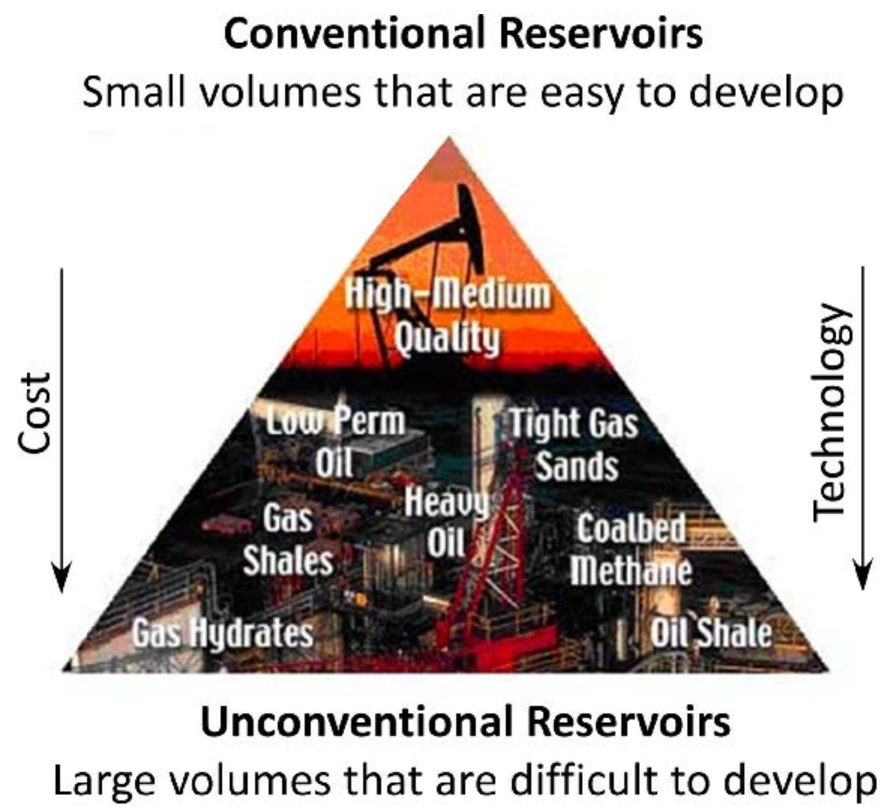
Potential Gas Committee Category	Tcf Gas
Probable resources (current fields)	537
Probable resources (coal-bed methane)	13
Total Probable	550
Optimistic reserve fraction (50%)	225
Years of supply when drilled & developed	10
Proved reserves	273
Years of supply when drilled & developed	12
Maximum years of supply when drilled & developed	22

The myth that the U.S. has 100 years of natural gas comes from confusing resources with reserves.

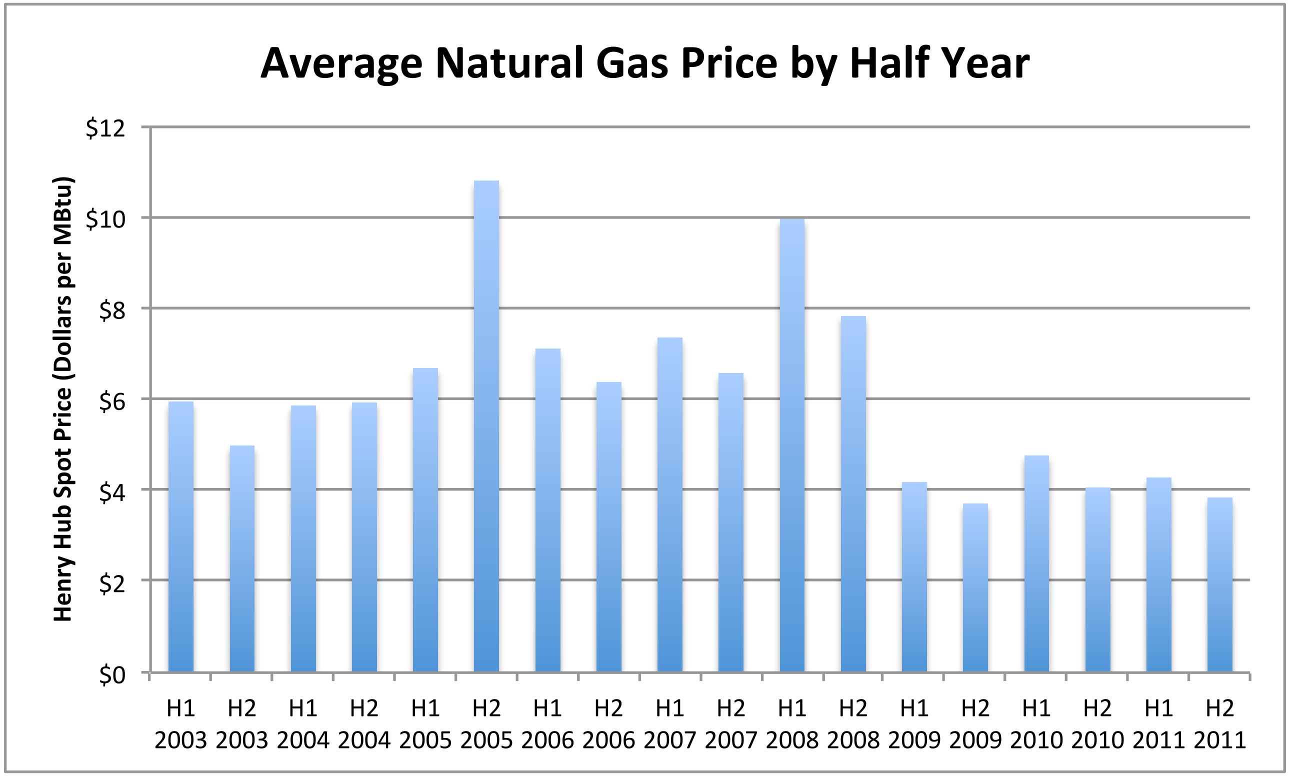
Shale Is Better Than Conventional and Earlier Unconventional Plays?

The journey down the resource pyramid:

- Unconventional gas plays became important as better plays were exhausted.
- Tight sandstone & coal-bed methane were developed first.
- Economics were and are marginal.
- Shale gas is at a lower level on the pyramid.
- Horizontal drilling & fracturing are now routinely used in all unconventional plays.
- **Why should shale plays be more profitable?**



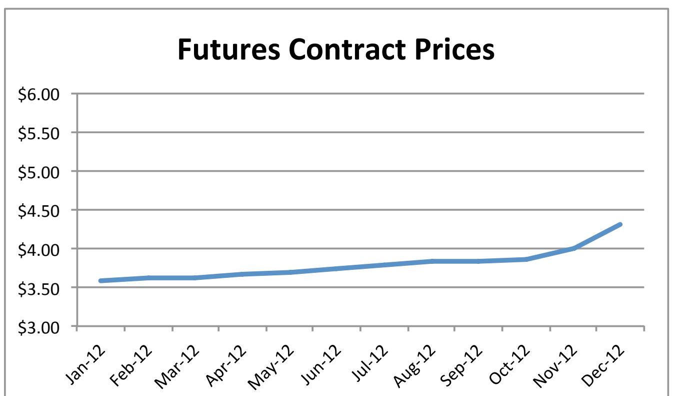
In the Early Years of Shale Plays, the Price Made Sense



- After the price collapse in 2008, hedging allowed profitability.
- For the past 12-18 months, gas prices are too low for profits.
- Magical thinking has created a new story: break-even prices are now lower than market price by the miracle of abundance, newly found efficiency, and the exclusion of major capital costs.

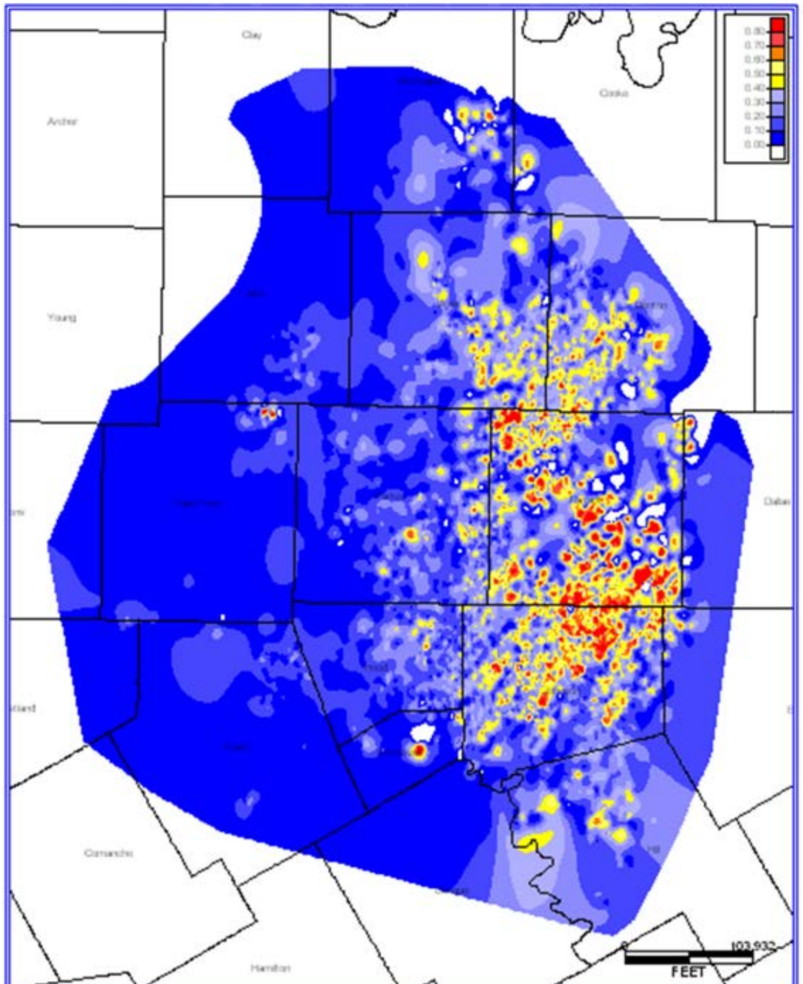
Discrepancy Between Public Statements On Cost of Supply and SEC 10-K filings

TYPICAL SHALE COMPANY COSTS	
	$/Mcfe
Lease operating expenses	$1.00
Gathering & Transportation	$0.50
Production taxes	$0.50
Total Lease Operating Expense	$2.00
General and Administrative Costs	$1.00
Interest expense	$1.50
TOTAL OPERATING EXPENSE	$4.50
Drilling Cost	$2.00
Acreage Acquisition Cost	$1.50
TOTAL UNIT COST	$8.00



- Companies state that shale gas is profitable at market prices less than $5.00 per kcf and, in some cases, lower; yet their average unit cost from financial statements is higher than that.
- If the shale plays are so profitable, why can't the companies pay for drilling & leasing out of cash flow? What about paying down debt?
- Perhaps, operators are losing money but plan on making it up on volume!

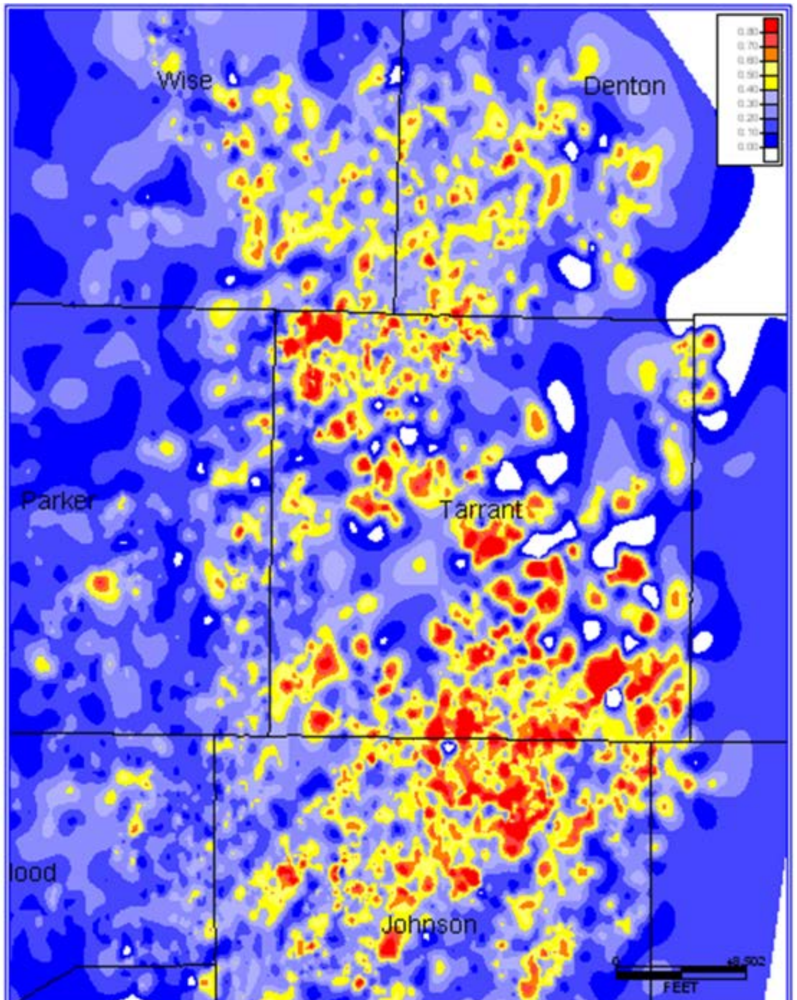
The Plays Always Contract to Core Areas: Barnett Shale Example



First-year cumulative production for Barnett horizontal wells.
Source: HPDI.

- Commercial portion of shale plays always contracts to a core or core areas.
- Red areas will be commercial @ $6/kcf, yellow areas may become commercial at higher prices, blue areas are non-commercial.
- Core areas have the optimum combination of rock properties, organic carbon richness, thermal maturity, natural fracturing, etc.
- Core areas represent approximately 10-15% of the total play.

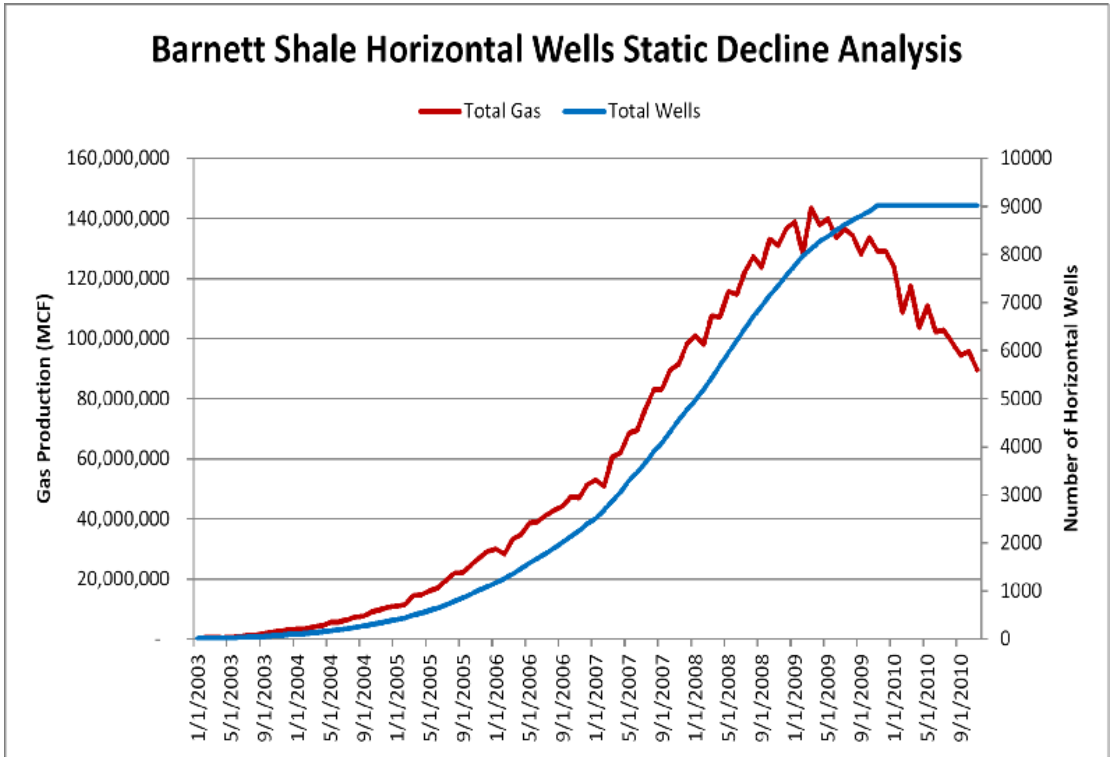
Even Within Core Areas, Performance is Uneven



First-year cumulative production for Barnett horizontal wells. Source: HPDI.

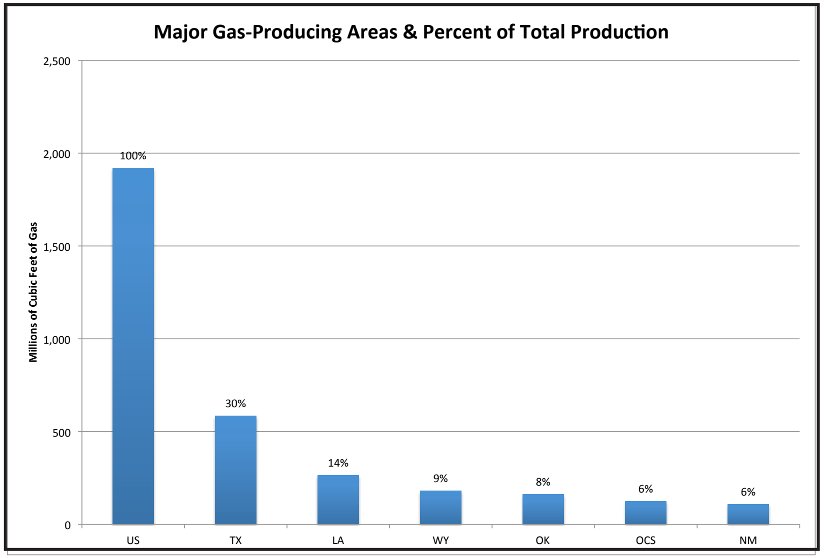
- Drilling in core areas is risky. Commercial success is not a given.
- Despite admission that shale plays are not “manufacturing” operations, expectations for future production do not account for the heterogeneity that we see.

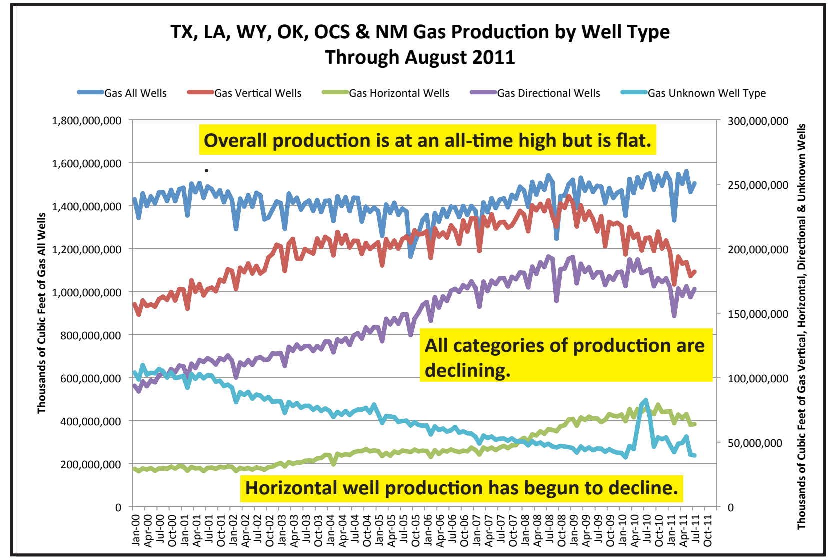
Why Reserves are Over-stated—Decline Rates are Higher than Anticipated



- Annual decline is 44 percent.
- This means that to keep production flat, new wells must be continually drilled.

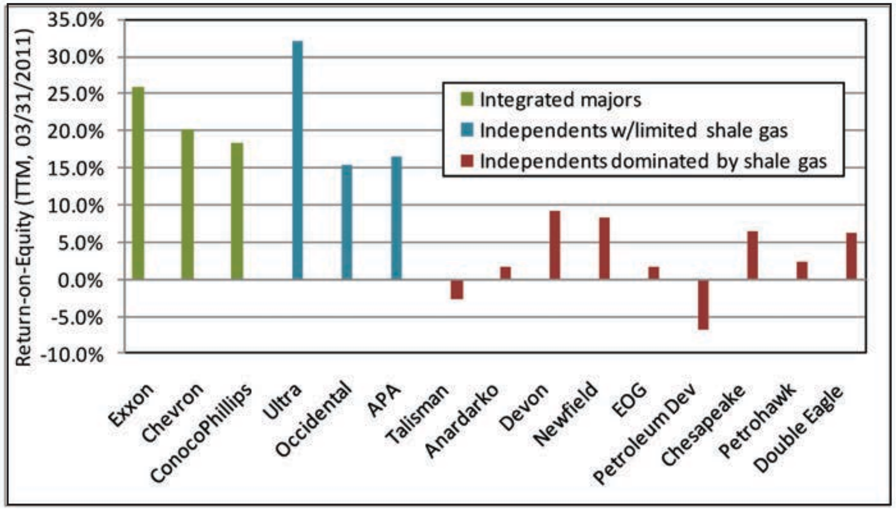
The Expectation of Abundance Cannot Be Sustained



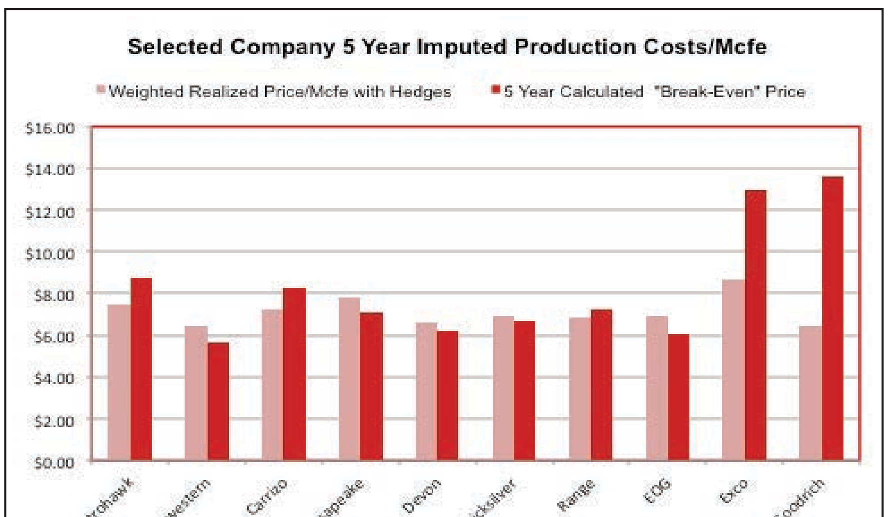


• 75% of U.S. natural gas production is from 5 states & the offshore Gulf of Mexico.
• Gas production from these areas is flat.
• All conventional and non-shale unconventional gas production is declining.
• Horizontal well production is declining.
• Is there an optimistic outcome to this scenario for natural gas supply?

Shale Math: Poor E&P Performance in Shale Gas Plays



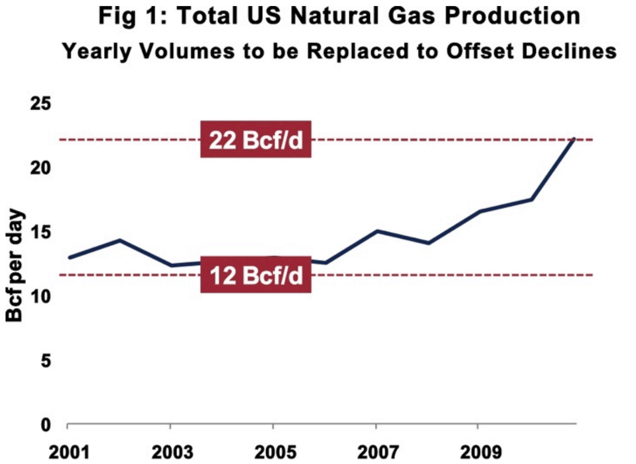
From Economides et al, 2011



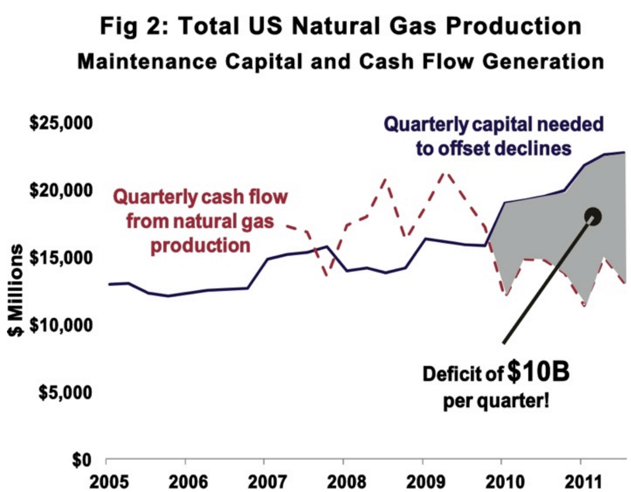
From company publications

- Companies with strong shale emphasis have poor return on equity, limited retained earnings.
- Creative accounting gives the impression of profitability.
- Shale E&Ps need Joint Ventures to fund capital expenditures.
- Also need to hedge forward volumes to get an uplift but benefits are declining: the game has changed.
- For majors, shale plays are a way to replace reserves and are a small part of their portfolio.
- Gas price will rise over time and is a good long bet.
- Energy is a strategic consideration for have-not countries in Asia and Europe.

Shale Math: The Drilling Treadmill



Sources: HPDI, ARC Financial Research



Sources: HPDI, Company Reports, ARC Financial Research

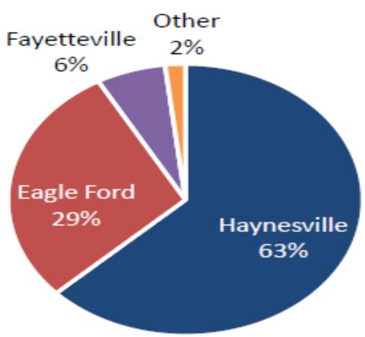
- Conventional gas decline rate was 23% in 2001.
- Annual replacement requirement was 12 bcf/d (total consumption 54 bcf/d).
- Current annual decline rate is 32%.
- Annual replacement requirement is 22 bcf/d (total consumption 65 bcf/d).
- $22 billion/quarter needed to maintain supply based on analysis of 34 top U.S. publicly traded producers.
- Cash flow for the same companies is $12 billion/quarter.
- Capital shortfall is $10 billion/ quarter.

Shale Math: Industry IRR Claims

Capital Spending and Returns

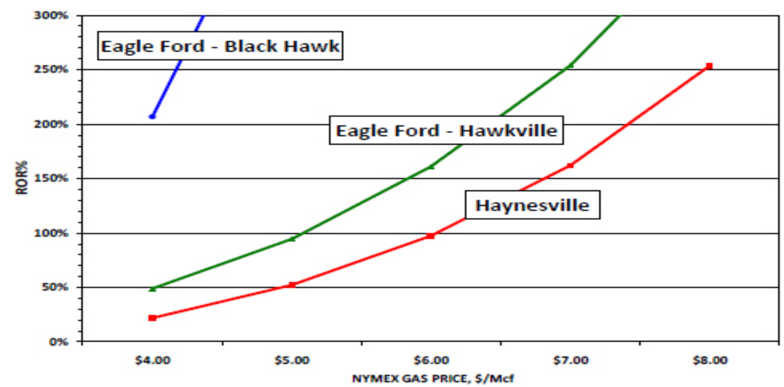
- HK's Black Hawk, Hawkville, and Haynesville fields provide excellent returns even in $4.00 gas market
- Eagle Ford Shale economics driven by liquids component

2010E D&C Capex Breakdown



$1,350 million

ROR (%) by Core Area



Note: Costs include drilling and completion, royalties, LOE, gathering, transportation, production taxes, and connection expenses. 12

Petrohawk's August 2010 Investor Presentation

- When has any business (other than crime) generated 20%-50%-210% IRR?

Shale Math: Industry IRR Claims

•Petrohawk's 2008 SEC 10K Filing, Pg 26

At December 31, 2008, the ceiling test value of the Company's reserves was calculated based on the December 31, 2008 West Texas Intermediate posted price of $41.00 per barrel adjusted by lease for quality, transportation fees, and regional price differentials, and the December 31, 2008 Henry Hub spot market price of $5.71 per million British thermal unit (MMbtu) adjusted by lease for energy content, transportation fees, and regional price differentials. Using these prices, the Company's net book value of oil and natural gas properties would have exceeded the ceiling amount by approximately $1.0 billion before tax, $574 million after tax, at December 31, 2008. Subsequent to year–end, the market price for Henry Hub gas and West Texas Intermediate oil did not increase. Accordingly, the Company recorded an approximate $1.0 billion full cost ceiling impairment at December 31, 2008.

•Petrohawk's 1st Qtr 2009 SEC 10Q Filing, Pg 12

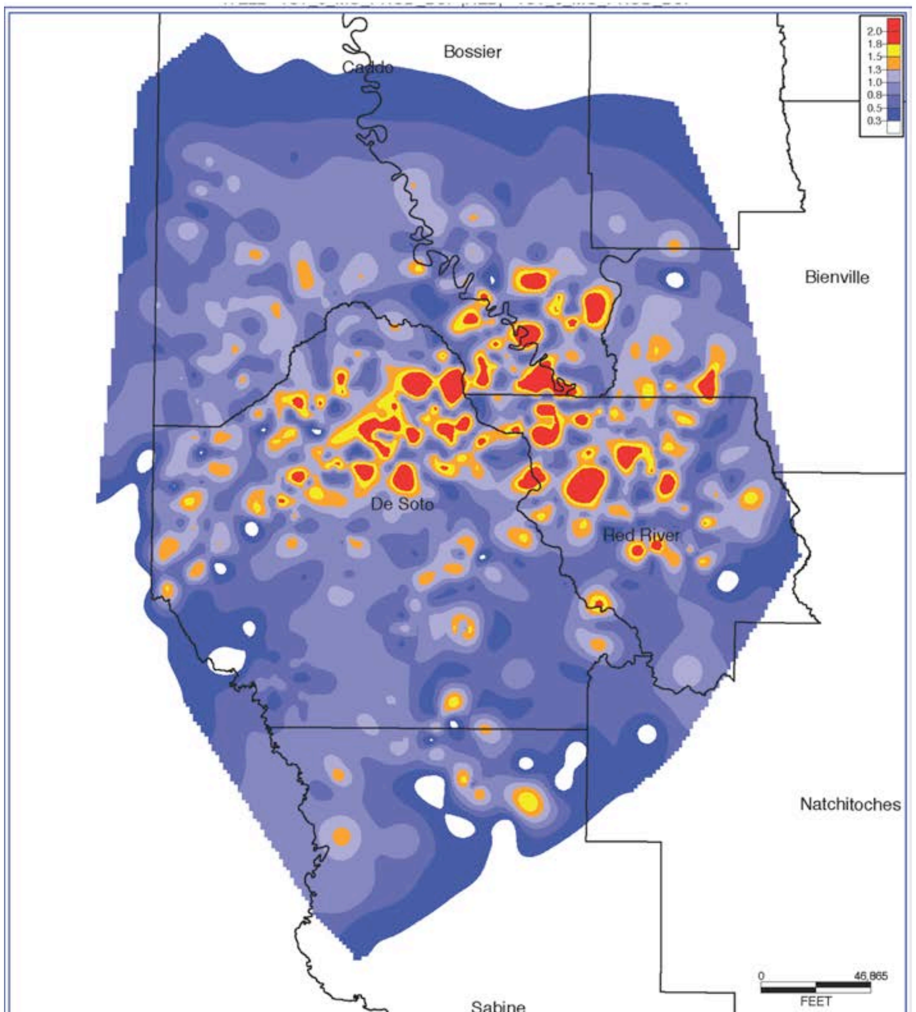
At March 31, 2009 and December 31, 2008, the ceiling test value of the Company's reserves was calculated based on the March 31, 2009 and December 31, 2008 West Texas Intermediate posted price of $49.66 and $41.00 per barrel, respectively, adjusted by lease for quality, transportation fees, and regional price differentials, and the March 31, 2009 and December 31, 2008, Henry Hub spot market price of $3.63 and $5.71 per million British thermal units, respectively, adjusted by lease for energy content, transportation fees, and regional price differentials. Using these prices, the Company's net book value of oil and natural gas properties exceeded the ceiling amount by approximately $1.7 billion and $1.0 billion before tax, $1.1 billion and $574 million after tax, at March 31, 2009 and December 31, 2008, respectively. Accordingly, the Company recorded approximately $1.7 billion and $1.0 billion in full cost ceiling impairments at March 31, 2009 and December 31, 2008, respectively, before tax.

•Petrohawk's 2009 SEC 10K Filing, Pg 34

As of December 31, 2009, using the West Texas Intermediate unweighted 12-month average price of $57.65 per Bbl for oil and the Henry Hub unweighted 12-month average of $3.87 per Mmbtu for natural gas, our net book value of oil and gas properties exceeded the ceiling amount. As a result, we recorded a full cost ceiling impairment before income taxes of approximately $106 million, $65 million after taxes. The Company also recorded full cost ceiling impairments before tax at March 31, 2009 and December 31, 2008 of $1.7 billion and $1.0 billion, respectively. As ceiling test computations depend upon the calculated unweighted arithmetic average prices, it is impossible to predict the likelihood, timing and magnitude of any future impairments. Depending on the magnitude, a ceiling test writedown could negatively affect our results of operations.

- Yet Petrohawk had $1.7 billion in impairment write-downs.
- This means that their true IRR was less than 10%.
- Which statements are true?

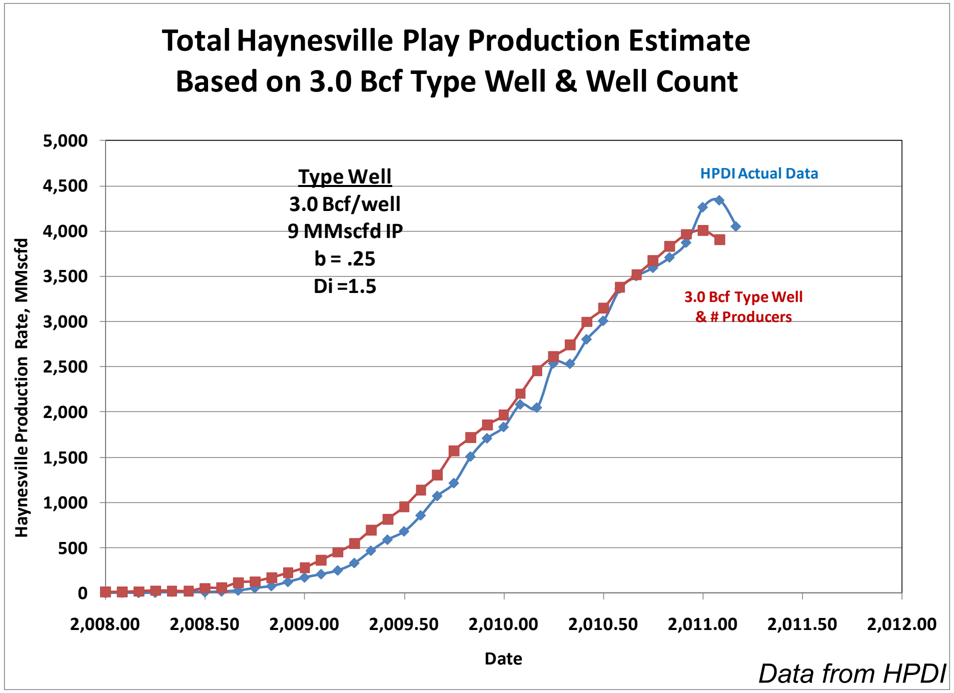
The Haynesville Shale Play has contracted to small core areas (in red)



First 6-month cumulative production for Haynesville Shale horizontal wells. Data source: HPDI

- Less than 20% of the play has the potential to be commercial.
- EUR has not met early expectations that this would become the largest gas field in North America.

Total Haynesville play production estimate

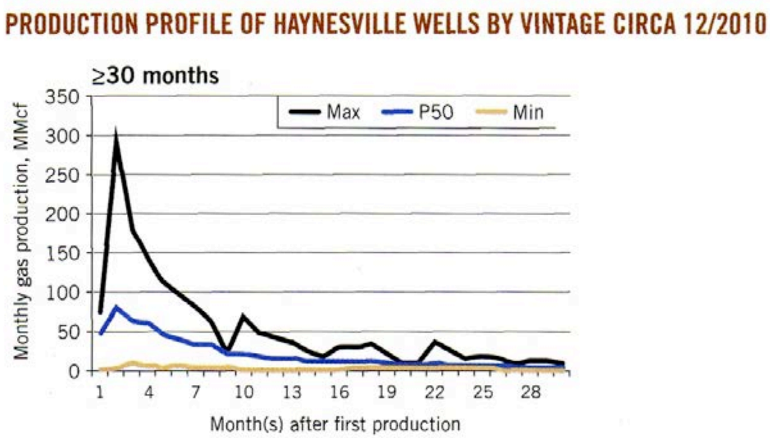


Overall Average EUR - Calculated Break-Even Gas Price for 8% Discount Rate								
	Barnett		Fayetteville		Haynesville		Marcellus	
	Full-Cycle	Point-Forward	Full-Cycle	Point-Forward	Full-Cycle	Point-Forward	Full-Cycle	Point-Forward
Break-Even Gas Price, $/mmBtu	**$8.75**	**$5.63**	**$8.31**	**$5.06**	**$8.68**	**$6.80**	**$7.84**	**$5.61**
EUR/Wel (Bcf/Well)	1.34	1.34	1.19	1.19	3.00	3.00	2.00	2.00
Well Cost ($mm)	$3.50	$3.50	$2.80	$2.80	$9.50	$9.50	$5.50	$5.50
Royalty	22.5%	22.5%	22.5%	22.5%	22.5%	22.5%	22.5%	22.5%
Land* ($/acre)	$5,000	$0	$5,000	$0	$5,000	$0	$5,000	$0
Expense (LOE, G&T., G&A ($/net mcf)	$1.50	$0.75	$1.50	$0.75	$1.50	$0.75	$1.50	$0.75
Severance Tax	7.50%	7.50%	$0.11/mcf	$0.11/mcf	7.50%	7.50%	0%	0%
F&D ($/net mcf)	$4.92	$3.37	$4.78	$3.04	$4.87	$4.17	$4.99	$3.56
Total Cost ($/net mcf)	$6.41	$4.12	$6.42	$3.93	$6.37	$4.92	$6.03	$4.31

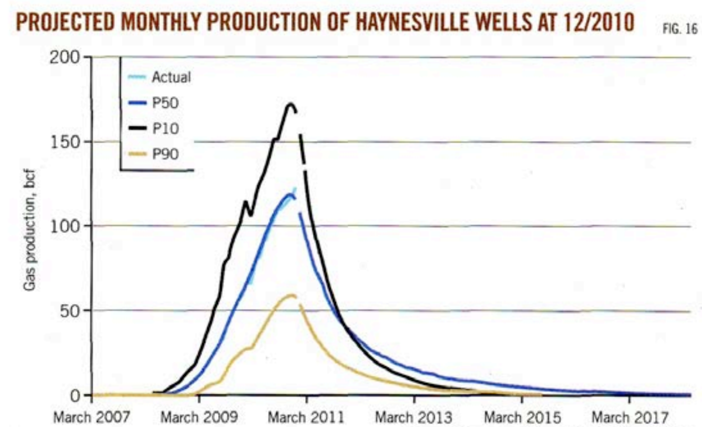
* *Land cost assumes 169-acre spacing and 50% of leased land developed*

The play will not be profitable until gas prices are more than $7/mcf.

Total Haynesville play production estimate



From Kaiser and Yu (OGJ 5 Dec 2011)



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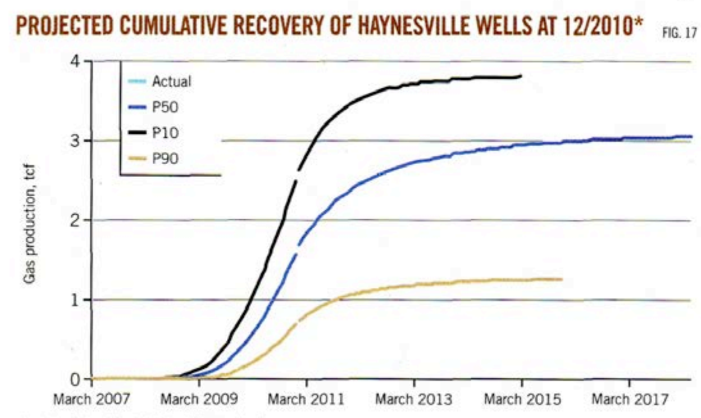


From Kaiser and Yu (OGJ 5 Dec 2011)

New LSU Haynesville Study (OGJ 5 Dec 2011)

- Production growth due to continual drilling of new wells and concentrating in the core area.
- 80% of EUR produced in first 2 years production.
- Individual well EUR P_{10} 4 bcf – P_{50} 3 bcf – P_{90} 1.2 bcf .
- Projected field EUR: 3 – 9 tcf (200-800 wells/3 years).
- This field was advertised as 250 tcf in 2006.

Joint Ventures in Shale E&P: Importance in defraying capex

Sellers:

- Provide cash and drilling carry.
- Shale players always need cash to make the next play.
- Help defray cost of land position.
- Cause wells to be drilled that otherwise might not be.
- Reduce seller's net asset value.
- JVs reflect the reality that shale players do not have adequate financial resources to develop leases that they have acquired.
- Reflect inability to find other funding sources.

Joint Ventures: Expectations of international Players in U.S. Shale Market

Buyers:

- Reserve replacement is a key driver.
- No other perceived options for scalable resources.
- Enter the North American natural gas market.
- Opportunity to enter emerging plays.
- Hard assets when low confidence in currencies, equity or bond markets.
- Technology Transfer: learn horizontal drilling and hydraulic fracturing techniques.
- Capital insignificant for major players.
- Unlike shale companies, only a small part of a broader portfolio.
- Strategic for energy have-nots.
- Higher gas prices anticipated in future.
- Chuck Prince at the dance.

Rational Decision-Making: Capex-to-Cashflow Ratios

Ticker	Share Price as of 12/19/11	Mkt Cap ($B)	EV ($B)	1-Year Change in Price	Production 3Q11 (kboepd)	Gas as % of Production	Cash Margin ($/boe)	Debt to Total Cap	Capex to Cashflow
RRC	59.45	9.4	11.2	39%	89	76%	20.62	43%	860%
SM	68.08	4.5	5.1	23%	77	61%	27.91	28%	368%
KWK	6.35	1.2	3.2	-55%	71	82%	6.95	65%	321%
TLM	11.75	11.7	15.4	-44%	324	60%	36.97	28%	282%
CRZO	24.27	1	1.6	-21%	20	88%	18.81	56%	275%
XCO	9.48	2.1	3.8	-51%	90	98%	18.35	50%	207%
CHK	22.06	14.7	29.5	-5%	554	83%	25.18	42%	196%
GDP	12.17	0.5	1	-27%	19	89%	14.84	77%	190%
COG	72.05	7.8	8.9	97%	91	95%	20.49	37%	174%
WLL	43.93	5.3	6.5	-23%	71	17%	49.04	29%	173%
UPL	28.68	4.6	6.4	-39%	101	96%	27.57	52%	159%
CRK	14.78	0.7	1.5	-33%	48	96%	18.35	41%	158%
NFX	35.89	4.9	7.9	-49%	134	59%	33.06	44%	156%
ROSE	41.89	2.3	2.4	15%	26	49%	31.57	29%	143%
PXP	32.25	4.6	8.4	7%	105	52%	28.99	52%	135%
EOG	95.57	26.3	30.1	4%	427	62%	30.48	29%	133%
PXD	81.38	10.2	12.7	-4%	128	48%	30.39	33%	133%
XEC	59.8	5.3	5.6	-32%	99	56%	33.18	10%	133%
DVN	59.05	24.4	26.8	-19%	661	66%	22.72	30%	128%
SFY	28.23	1.2	1.7	-29%	28	53%	32.87	33%	122%
FST	12.26	1.4	3	-66%	54	73%	18.34	61%	121%
SWN	32.66	11.6	12.9	-9%	233	100%	18.26	26%	117%
CNQ	0.09	0	0	-39%	547	37%	40.37	30%	112%

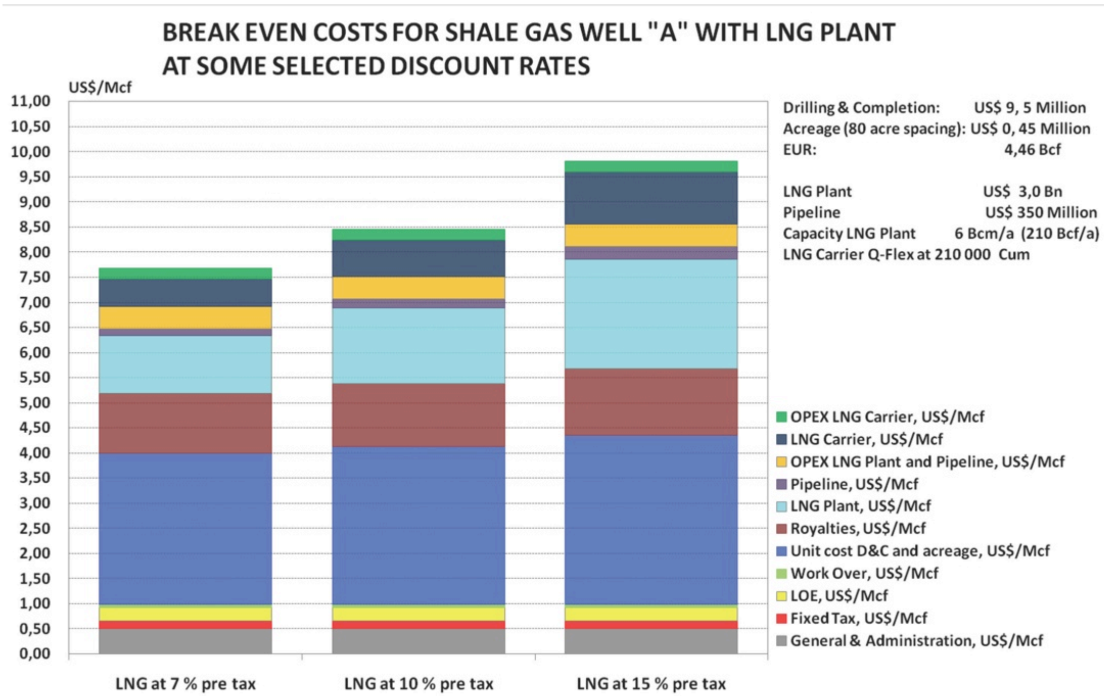
Source: Corporate Reports, Capital IQ, and Bernstein Analysis

- Unsustainable capital expenditures will limit capability to deliver on supply.
- Service cost acceleration will compound this limitation.
- Further constraints on cost-of-capital will limit options.

Viability of LNG Export

- High cost of U.S. supply compared to exporting nations (Qatar, N. Africa, Norway, Trinidad).
- Incremental cost to transport U.S. gas to European markets is $2.50/kcf more than from Qatar.
- BG & NGF-Cheniere deals shows that there is a perceived supply shortfall for European market.
- Development of spare capacity to support exports would crush short-term spot prices.
- LNG exports would compete with other sources of demand and increase long-term domestic prices to uncompetitive levels for exports.

Horn River Shale – Kitimat LNG: Implications for Alaska

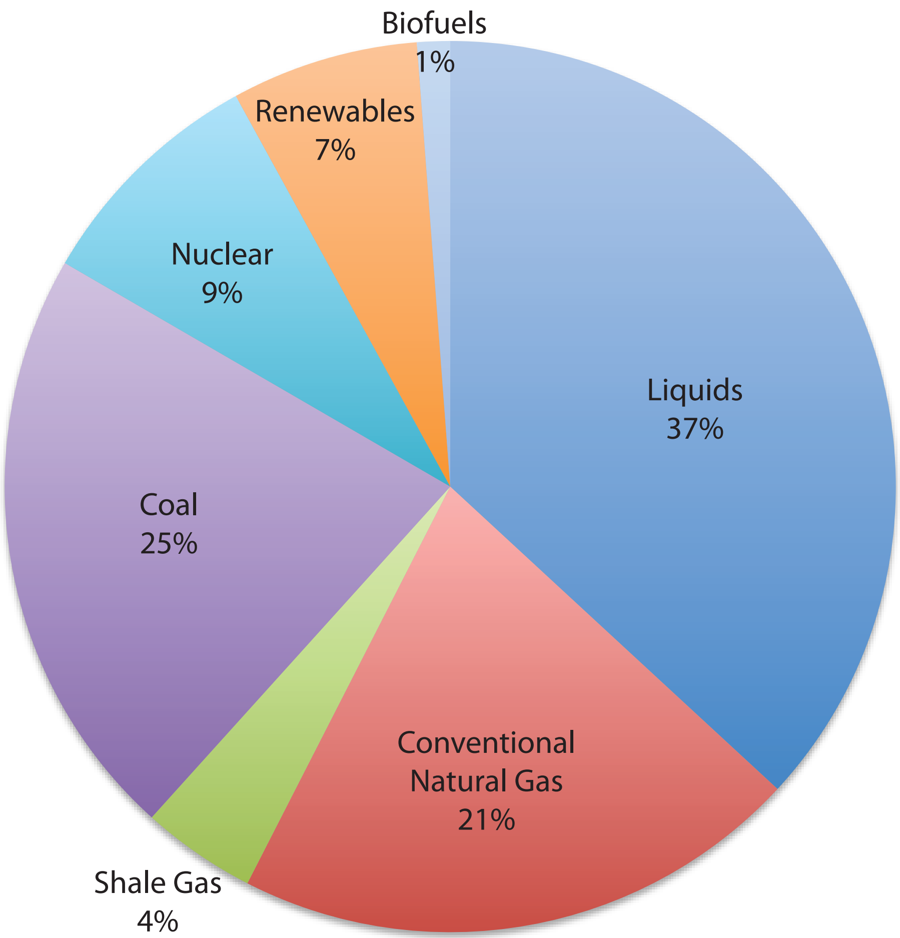


- Using Core Haynesville Shale EUR (4.5 bcf), and published Horn River well, pipeline and LNG (train + transport) costs, the project will not be economic until gas price is above $8.50/mcf.
- Export of North Slope gas depends on cost and year-round access.
- Export of shale gas depends on rates and reserves of shale plays.
- Geography favors Alaska LNG export but Asian market price is not the entire story.

Environmental Concerns

- Hydraulic fracturing is safe if done correctly: no evidence of aquifer contamination from fracturing fluids.
- Methane contamination of aquifers, gas venting and waste water disposal are legitimate concerns.
- Regardless of the merit of environmental concerns, perception is everything. Environmental issues will be an obstacle that adds cost and time to shale development.
- Venting and methane contamination via legacy vertical wells not a problem for Alaska.

Can natural gas reduce dependence on foreign oil?



Data from EIA

- Natural gas was 25% of U.S. primary energy mix in 2010.
- Shale gas was ~4% of total energy mix—is this really a **game-changer?**
- Will natural gas eliminate U.S. dependence on foreign oil (Pickens, etc.)?
- 3% of natural gas used for transportation.
- 72% of liquids used for transportation.
- Natural gas and crude oil are used differently & are not interchangeable without massive, long-term equipment changes.

U.S. Shale Gas Magical Thinking: What It Means

- A tremendous amount of capital has been bet on shale and much of this is in the form of debt.
- A new paradigm in land and completion costs has forever changed the domestic E&P business.
- There is very little shale production history so the outcome is uncertain.
- It is unclear that shale gas production will support even short-term expectations of abundance.
- Capital expenditures exceed cash flow for most companies.
- Full-cost and off-book accounting mask the weak performance of most shale-dominated companies.
- There is great uncertainty about reserves, and most are undeveloped.
- Yet, the prevailing view is that success is certain.
- There are considerable risks in magical thinking.

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