KIMMERIDGE
Energy

Creeping to a Correction?

Why the US Gas Market May be Poised to Recover

June 2012

Introduction

Over the last 3 years natural gas prices have been in a downward spiral. While oil prices have been supported by a recovery in global demand, the US gas market has instead seen a glut of supply. There are two distinct schools of thought regarding the current environment. The first ascribes the oversupply to a structural shift in the supply curve driven by the development of unconventional shale gas. The other attributes today's weakness to a cyclical trough driven by over exuberant operators growing supply as they chase hot new shale plays despite uneconomic returns. Regardless of which of these is right, supply has continued to rise and inventories are now far above their normal levels.

One of the major points of contention between the two sides of this debate has been the outlook for supply. If the cost structure of gas was permanently shifting downward, operators would be able to continue to increase supply with flat or falling pricing. Others (including ourselves) who believed in a cyclical downturn, continue to propose that eventually producers will be forced to cut back and supply would fall.

While many aspects of the argument are still open for debate, the supply side of the equation seems to finally be turning, and many leading indicators are now showing that gas supply in the US is moderating, if not falling. Taking this data, along with evidence that costs for producers that have continued to rise, suggests that the period that began in 2008 will be remembered as the start of an unprecedented cyclical downturn, but not a structural shift. Moreover, looking forward, demand trends and export capacity expansions lead us to believe the forward curve for natural gas is significantly undervaluing a commodity that will be scarcer soon than is commonly believed today.

Framing the debate: Supply, Demand and the Marginal Cost of Supply

Over time our view on both oil and gas prices have been premised on the belief that despite their volatility, commodity markets function according to the laws of microeconomics. The first aspect of this theory is that over time prices trend around the marginal cost of supply (or the replacement cost). From the deregulation of the natural gas markets in the early 1990s through 1999 the marginal cost of gas supply remained relatively flat. However since 1999 it has been rising, driven by a decline in gas recovered per dollar spent. The second part of our theory has been that prices cycle around this marginal cost driven by near term supply and demand dynamics.

As is evident historically it can be shown that 12 month strip gas prices have cycled around this marginal cost with periods of above and below normal returns. We have used actual reported operator cost data to calculate the marginal cost of supply going back to the 1990's, and this relationship has generally borne out (exhibit 1). Furthermore, using inventory levels versus normal as a proxy for the near-term supply/demand balance has historically yielded a strong relationship with price levels relative to the marginal cost (exhibit 2).

Recent History: Breaking The Trend

Over the past 3 years, the historical trends of cycling around the marginal cost have been replaced by a monotone downward fall. The clearest reasons for this were a unique coincidence of a number of negative factors for the gas market, including a collapse in US GDP which drove down demand for electric power and industrial consumption in 2009. As a result, today this ratio of price relative to the marginal cost of supply is at a record low. This implies a massively oversupplied market, and indeed storage levels are at unprecedented highs.

This elongated trough in pricing has led today's bears on the market to argue that the marginal cost is in structural decline driven by improving capital efficiency and the growth in liquid rich plays. To support this argument analysts point to management commentary regarding improving well performance from technology, statements about lowering drilling costs, and critically the lack of supply curtailments at lower prices. While these all appear to be valid points, the actual underlying data appears to refute the argument. Crucially, the finding and development costs of the industry

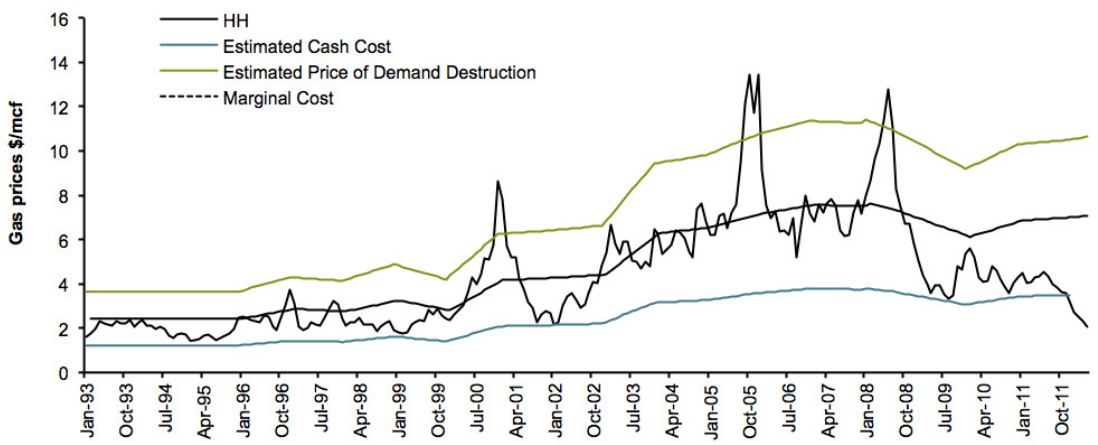

Exhibit 1: US gas prices versus the cash cost, the marginal cost and the price of demand destruction.
Source: Company reports, Bloomberg, EIA and Kimmeridge Research

(essentially capital spent per cubic foot of gas produced) has continued to rise and the marginal cost has not fallen significantly. The reason for this is that despite all of the hype, new plays only show a brief period of capital improvement before the average well declines in quality.

Although new shale plays are exciting, our research reveals that each unconventional play undergoes a common evolution. When a new play is discovered, operators initially see a big improvement in capital costs and well performance. Drilling costs in an emerging play can fall 40-50% over the first 100 wells, while well productivity can double as operators identify the core of the play and optimise well completion technology. This improvement causes the sort of headlines that promote the view that the cost of supply is falling. However, the data clearly shows that following this initial efficiency improvement the average well starts to get worse driven by two factors, namely down spacing which recovers less per well due to interference and moving outside the core of the play (for more on why a core exists see "Defining the Core of Shale Plays"). At that point costs per unit begin to rise in each play. This is evident in the Barnett (by looking at EOG's costs), the Pinedale (Ultra Petroleum), the Fayetteville (Southwestern), Woodford (Newfield), Haynesville (Petrohawk) and may now be reaching an inflection point in the Marcellus (Range Resources) – (exhibit 3).

To clarify, our argument isn't that technology is static, or that operators don't get smarter as they learn more about plays. Operators are economically rational so they drill their best prospects first, meaning that the following year they need to drill wells that, from a purely geological perspective, are incrementally less productive.The question for per-unit costs is whether the process of learning is happening faster than the process of geological deterioration of prospects. What our research shows is that in the very first years of an unconventional play the operators tend to learn faster than the geology deteriorates, driving down costs, but that by the third year or so, geology catches up and costs begin to rise.

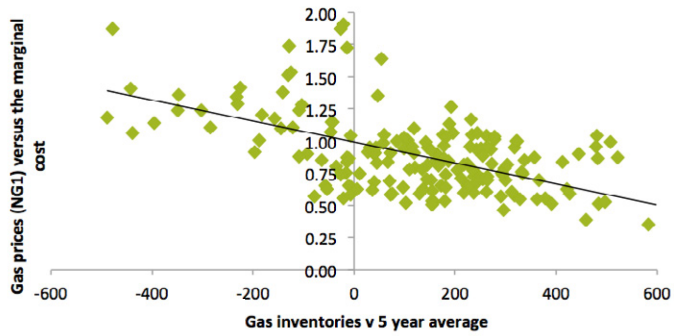

Exhibit 2: US gas inventories over/under the 5 year average versus NG1 gas
Source: EIA, Bloomberg & Kimmeridge Research price over the marginal cost

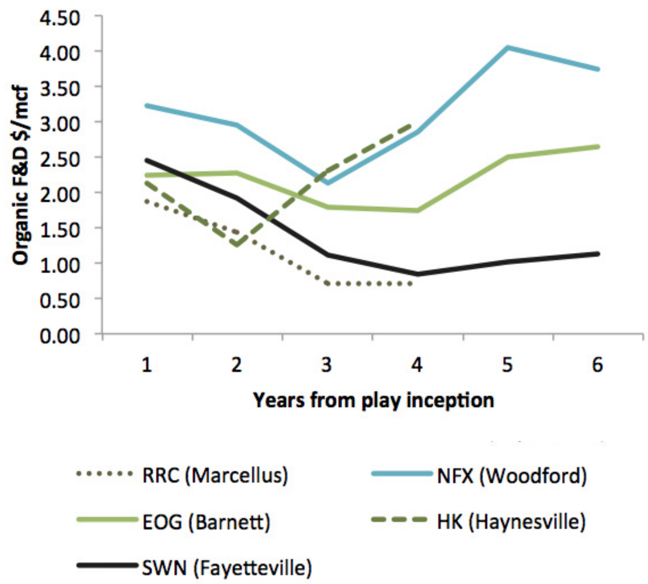

Exhibit 3: F&D trends for key E&Ps in major plays from the year of inception
(Source: Company Reports)

If the Marginal cost remains high, why the delayed impact on supply?

While the adjacent data clearly show that producing gas at today's prices is uneconomic, that hasn't always translated into a supply reduction. To figure out when supply will fall requires a detailed analysis of the connections between drilling, fracking and producing. However, recent data show a significant slowing on the supply side.

Domestic supply: shale, shale and more shale.

As highlighted above the primary driver of growth in the US gas market over the last 4-5 years has been the growth of unconventional or shale gas (exhibit 4).

Shale gas accounted for just 9% of local supply in 2008 but production rose to around 30% of supply or 19 Bcfd+ in 2011, and this is expected to rise further in 2012 with the continued ramp of the Marcellus. Five plays have been the primary contributors of US gas supply growth: the Barnett, the Fayetteville, the Haynesville, the Marcellus and the Woodford, with the Marcellus, Haynesville and Fayetteville being the biggest net contributors (exhibit 5). It is worth pointing out that given the constantly-declining nature of US gas production, growth is necessary every year to offset the lost production. As a result, if shale plays flatten out, overall supply will fall, since shale has been providing all of the growth to offset the base declines.

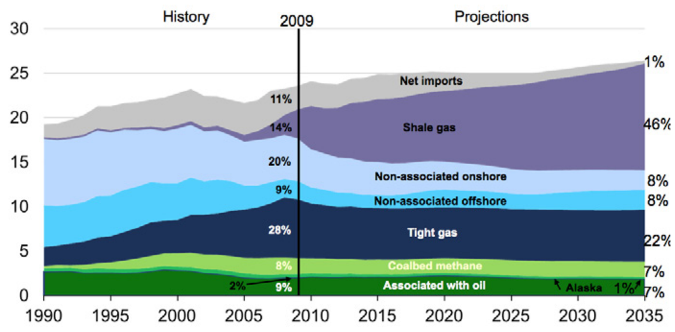

Exhibit 4: US Dry Gas production, trillion cubic feet per year
(Source: EIA, Annual Energy Outlook 2012 Early Release)

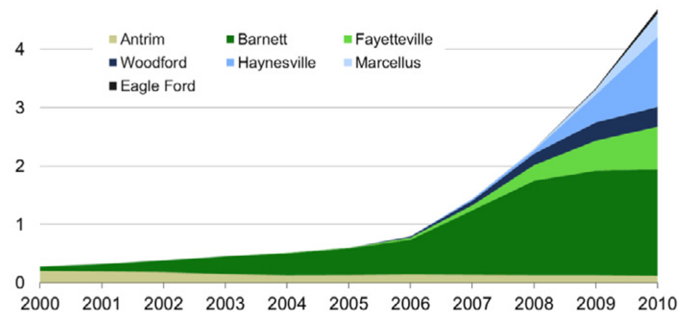

Exhibit 5: Annual Shale Gas Production (dry) trillion cubic feet per year
(Source: Lippman Consulting, Inc. gross withdrawal estimates as of March 2012 and converted to dry production estimates with EIA-calculated average gross-to-dy shrinkage factors by state and/or shale play.)

The Barnett

While the Barnett shale is the "granddaddy" of the industry, recent production growth in the Barnett has all but stalled (exhibit 6 & 7).

To a certain extent this reflects the maturity of the play. As highlighted above, the core of any new unconventional play is targeted first. As this is drilled out operators are forced to downspace or to move out of the core of the play where the per unit economics gradually degrade. Given the extended history of drilling in the Barnett the majority of core locations have now been drilled. What is perhaps more interesting in terms of estimating whether the play will remain flat or decline, is the trend. While the production of the play held flat from 2009 -2012, due to the backlog of drilled to be completed wells and the growth in frac stages per well, recent permit data (down 50% on an annualised basis) and rig data (down 30%) suggests even holding production flat will be challenging over the next 12-24 months.

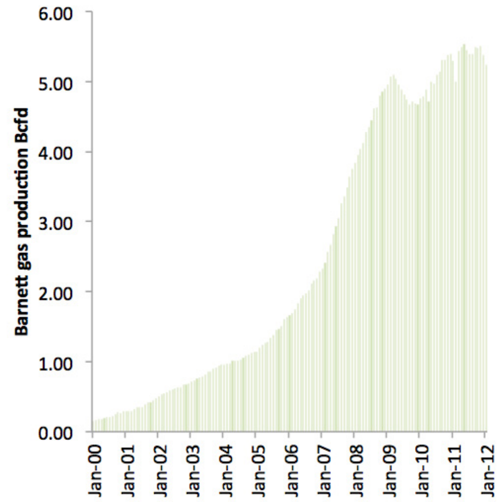

Exhibit 6: Daily gas production from the Barnett Shale (Bcfd)
(Source: EIA & Texas Railroad Commission)

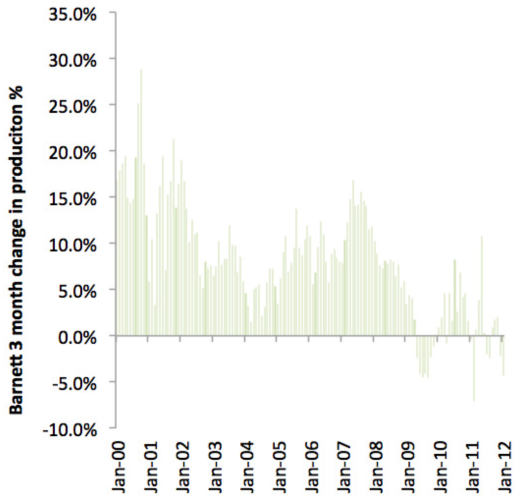

Exhibit 7 : 3 Month change in gas production from the Barnett Shade
(Source: EIA & Texas Railroad Commission)

The Fayetteville

The Fayetteville has been another source of gas growth within the US, and one of the lowest cost sources of supply. Since 2007 production has grown from an average of 0.25 Bcfd, to almost 2.8 Bcfd. However based on early 2012 figures it appears to be approaching its peak. Not only has the major operator (Southwestern - exhibit 8) started to report rising F&D but initial data for the beginning of 2012 shows production growth slowing to 8% (or a net addition of just 200mscfd or 0.3% of the US gas market), and is expected to slow to circa 3% in 2013 given the drop in the rig count and permitting activity (exhibit 9).

The Haynesville

While the Barnett and Fayetteville have been major players in the shale space no asset has been more confusing than the Haynesville. This reflects two issues. The first is that none of the major operators in the play has reported attractive returns in their audited financials and secondly that the field has appeared inelastic to price despite this. Indeed one of the only things that has been clear is that operators in the Haynesville have been drilling for reasons other than actual positive returns.

Looking first at the cost assumptions it is hard to see why anyone is drilling. For example in the final year of being an independent company (2011) Petrohawk, which was essentially a one asset company, reported total upstream costs (excluding interest expense of circa $1/mcf) of $5/mcf (exhibit 10). Even excluding the sunk costs of drilling the gas wells, Petrohawk's total variable costs still topped $2.59/mcf, which is a full 10% above today's gas price. Put plainly, at today's gas price Petrohawk's average well would lose money on a cash basis and drilling a new well would double this loss.

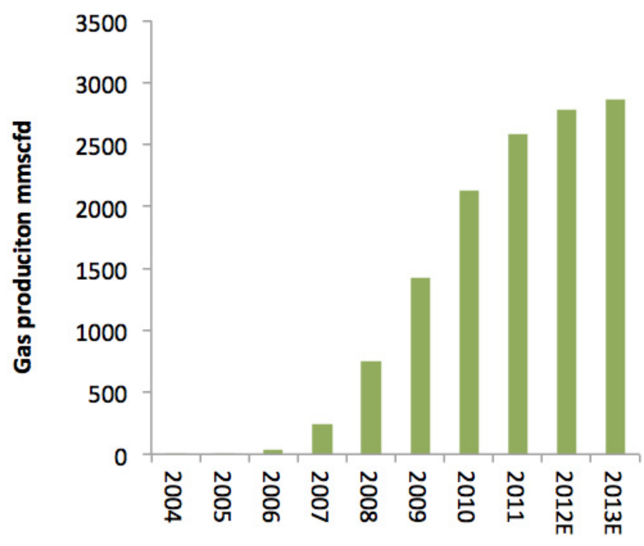

Exhibit 8: Arkansas Oil and Gas Comission
(Source: Fayetteville shale gas production (2004-2013E))

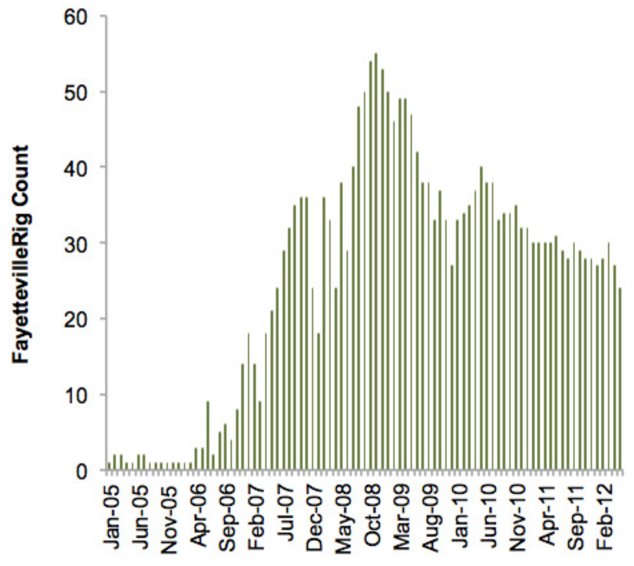

Exhibit 9: Smith Company Report
(Source: Fayetteville Shale Rig Count)

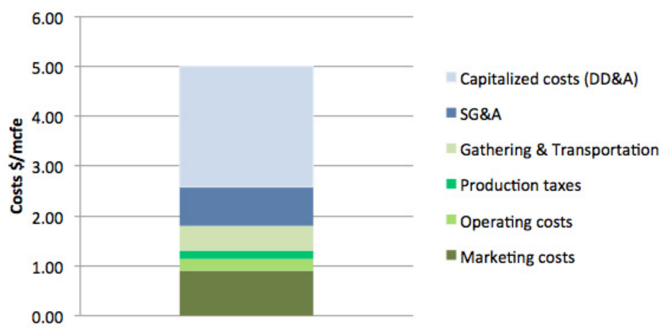

Exhibit 10: Petrohawk 2011 operating costs (per mcf)
(Source: Company Reports)

Despite the lack of profitability, it appears three factors helped drive production since 2009:

- Hedges that keep production economic (for example Petrohawk realized $5.89/mcf in 2011)
- Drilling to hold leases (the net cost of writing off the lease $10M was greater than the loss on drilling at a $3/mcf gas price, $5M)
- A backlog of drilled but not yet completed wells

At this point, almost all of these factors appear to have dissipated. For example over the last 6-12 months the forward strip price of gas has collapsed, rendering hedging largely ineffective. At the same time drilling to hold leases has been in decline as evidenced by activity, while the backlog of drilled but not completed wells also appears to have fallen based on reports from the department of natural resources (down from 400 to 250) and the drop in days between permitting and drilling (exhibit 11).

This drop in permitting and drilling appears to be having an impact on production in Louisiana. Since November 2011 the state has seen production decline from 9.09Bcfd to 8.17Bcfd in March (exhibit 12). Furthermore based on permitting/drilling data that shows the drilling in progress has halved since January this rate of decline should only accelerate.

The Marcellus

Of all the major gas plays that have the potential to continue the net oversupply in the market the Marcellus remains the greatest risk. This is due to the fact that costs are genuinely low, the play is early in its development and it is geographically large. However, even here the data appears to be increasingly supportive of at least a moderation in activity. Specifically total production at least as measured in the EIA's 914 data for other states (Pennsylvania doesn't release monthly production data) has decelerated and some of the early indicators have turned. For example the rig count in the play is down for the first time in 2 years (down 20% from the peak), while permits issued are down 46% from the peak and wells drilled are down 40% (exhibit 13). Whether this is enough to moderate production remains to be seen. Based on the last month's supply data it appears that the category of "Other State" production did plateau.

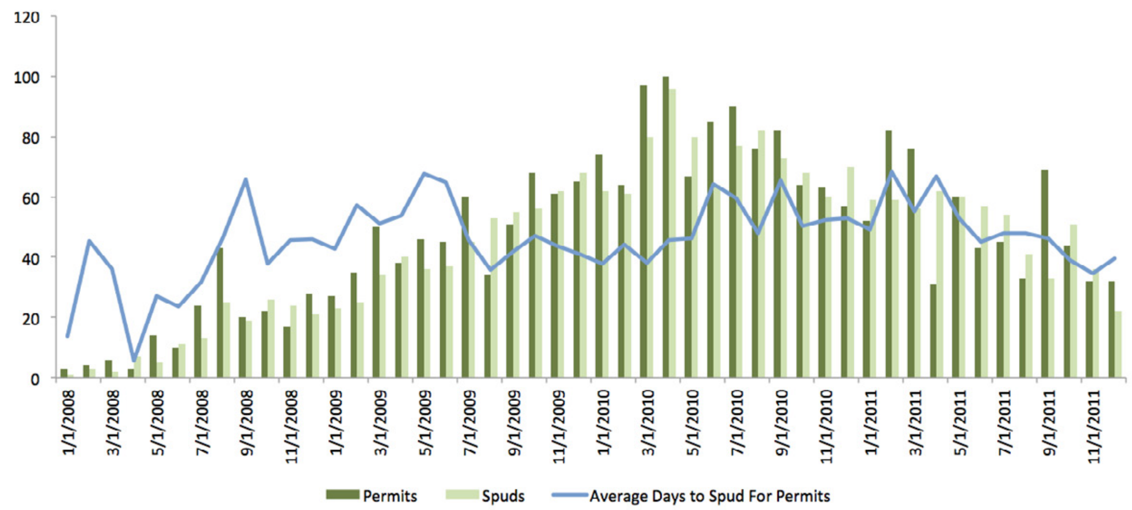

Exhibit 11: Haynesville permits to drill, wells spudded and time to spud
(Source: Source; Louisiana Department of Natural Resources)

The overrated influence of liquid production

One of the other explanations given for why gas production won't fall in the US is that some gas is produced from wells that are drilled primarily for oil, or natural gas liquids (NGLs). While this is partially true, the numbers, and impact appear to be grossly exaggerated and we think gas produced from liquids wells has not been a major contributor to the growth over the last 3 years. For example in the Bakken Shale, where wells are drilled for oil, total gas production is now only 0.39 Bcfd up from 0.15 Bcfd in the late 90's, or an incremental 0.2% contribution to the market over 15 years. Although the Eagleford is more significant, this is still relatively small versus the major gas plays.

For example even in the most liquid rich play, the Barnett the data is deceiving. For while the Barnett has an average liquid content of 17% and gas production of 5.4 Bcfd, it is incorrect to assume all wells have 17% liquid content. Rather a small minority of wells have a high liquid production while most are dry. As a result it appears, based on our calculations that only 0.8-1 Bcfd of Barnett gas is from "wet" wells .

The impact of drilling to hold leases, and international JV's

Two other factors have been critical in delaying the response of the US gas market. While these are hard to quantify they have been drilling to hold leases and the impact of joint ventures (JV's). Looking first at the impact of drilling to hold a lease it is clear that at certain economic thresholds this makes sense for operators, especially public ones who are spending investors' capital. For example if an operator signed a lease in the Haynesville for $10,000 an acre they would face a $6.4M write down if they do not drill a 640 acre unit. In comparison even drilling a $10M well and returning just $4M makes sense when you factor in the option value of another 3 well locations on that 640 acre unit, not to mention the avoidance of a write down and potential reserve additions. Given the price of some leases touched $20,000 an acre in the peak of 2008 (and had 5 year term) it is understandable that many operators continue to be incentivized to drill uneconomic wells through to mid 2013.

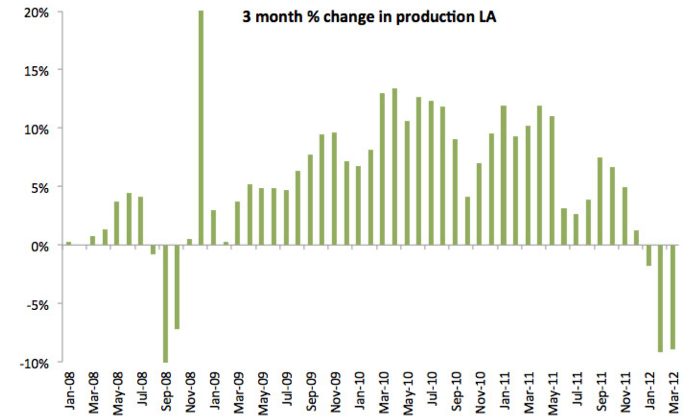

Exhibit 12: 3 month change in Louisiana gas production
(Source: Louisiana Department of Natural Resources)

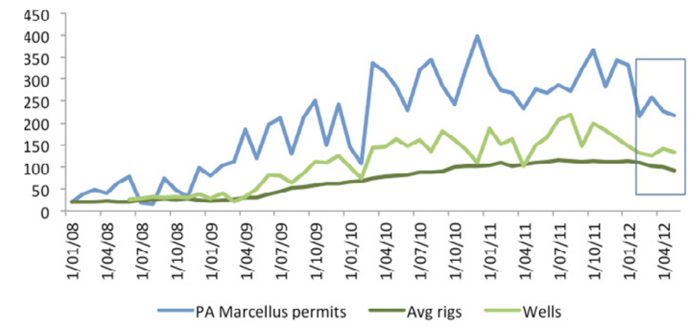

Exhibit 13 : Marcellus shale permits, rigs and wells drilled
(Source: Pennsylvania Department of Environmental Protection
& Smith Company Reports)

Another driver has been the billions of dollars of capital infused into the industry through joint ventures with multi billion dollar well carries. These have effectively meant the selling company (most often the operator) can drill for free with their new partner's money. Coupled with the time limits to spend this capital, it has meant that in many cases the operator can drill through their program irrespective of the fact that their funding partner is generating no or a negative return. Once again the peak of this frenzy (at least on the gas side) appeared to be in 2007/8 and 2009. As such many of these are now rolling off, removing the incentive for uneconomic drilling.

Combined domestic supply outlook

Combining the outlook for these major plays, with flattening or declining production trends in all gas shales except the Marcellus, we expect US total production growth to slow though the year. While the recent government data has shown volumes falling, we remain more conservative and expect volumes to grow in 2012, albeit by only 3%. If this is indeed the case, and it does not assume acceleration in the decline in the Haynesville, Barnett or a flattening of the Marcellus, then total volumes would also be down 3.3% from the peak of production and would be heading into 2013 effectively in decline.

Conservatively it also appears reasonable to assume that this decline would continue in 2013 even if only at the same rate (of 3%). More likely unless the rig count reaccelerated before year end this rate of decline would accelerate in the early part of the year, moderating if prices rebounded.

Putting it All Together: If Supply is Declining, What Does it Mean for the Balance of US Gas?

To gauge the impact of supply flattening or decline on the overall market, it is necessary to understand the major swing factors for the US gas market. As of 2011 the US gas market was supplied primarily through domestic production (88%) with the rest coming from imports primarily from Canada through pipelines. On the demand side the balance is mixed. In 2011 4.1 Bcfd was exported (or 6%) and the rest was consumed by residential homes (20%), commercial users (13%), industrial end users (28%), and electric power plants (32%).

On the demand side, residential and commercial demand are driven by weather, with a standard deviation of only 1-2% per year outside weather factors. In contrast, industrial demand has been twice as variable as domestic supply and power demand has had a standard deviation of 6% of the market over the last 5 years. Historically industrial demand has been the most elastic to higher prices. At the same time, power demand has also been sensitive to pricing, since gas is the incremental source of supply at low prices at the expense of coal on both a secular and cyclical basis.

The swing in these factors determines in a given year whether the market will be oversupplied or undersupplied, and thus whether prices will be above or below the marginal cost. What is also noticeable from this data is the volatility in price. For example a net swing of daily oversupply from +/-1 Bcfd (equivalent to 1.5% either way) takes prices from 0.7-1.3x the marginal cost. This is significantly more volatile than the oil market and reflects the captive nature of the market.

Based on this data, we can understand the drivers of the extended trough that is currently being observed in pricing. In 2008 supply grew by 3 Bcfd but this was more than offset by a large decline in net imports driven by strong oil prices and strong global LNG pricing, coupled with better weather demand (exhibit 14). In 2009, however, as the US and global economy collapsed demand dropped some 1 Bcfd. This was partly offset by a drop in imports but not by supply which continued to grow. While the economy and demand recovered somewhat in 2010 and 2011, supply continued to accelerate. As such the market remained wildly oversupplied despite rebounding demand.

On the negative side if operators were looking for relief in 2012 there has been little to cheer with supply through March up 9% and demand broadly flat. However, on the positive side the data does suggest that the pricing of the last 3 years can be explained by cyclical supply/demand factors (which can be corrected through rational economic behaviours) rather than a secular trend in the cost base.

The Outlook for Imports and Exports

As seen in exhibit 14, one of the key factors in the outlook for the US gas market is the net impact of imports and exports. Critical to this is the outlook for Canadian pipeline imports and LNG exports. With respect to Canada the area has consistently been a high cost region for gas production and continues to be so. As a result production has been in steady decline. Compounding the impact on the US, domestic gas demand in Canada has continued to grow. The net result has been a steady decline in imports from 10.5 Bcfd of imports in 2007 to 8.5 Bcfd in 2011, a trend we expect to continue albeit at a slightly moderated pace.

Beyond pipeline imports, the outlook for exporting LNG from the US could be a game changer for the North American gas market (albeit to date only a fraction of the proposed export options have been fully approved). At the earliest, this could start to impact the market in 2015, when the first export terminals open. In the US the first project set to go ahead is Cheniere Energy's Sabine pass, which has been approved for export and has to date signed offtake agreements for 2.1 Bcfd of its 2.4 Bcfd of capacity. The same progression is happening north of the border in Canada, where a terminal at Kitimat is being designed and constructed with 1.2 Bcfd of exports.

Supply (Bcfd)	2006	2007	2008	2009	2010	2011	2012E	2013E	2014E	2015E
Gross Withdrawals	**64.5**	**67.6**	**70.2**	**71.4**	**73.5**	**78.3**	**80.3**	**77.9**	**80.2**	**83.4**
From Gas Wells	49.3	46.8	42.8	40.8	57.1					
From Oil Wells	15.2	15.9	15.7	15.9	16.4					
From Shale Gas Wells	0.0	0.0	6.3	9.3						
From Coalbed Wells	3.6	4.9	5.4	5.4						
Repressuring	8.9	10.0	10.0	9.6	9.4					
Gases Removed	2.0	1.8	2.0	2.0	2.3					
Vented and Flared	0.4	0.4	0.5	0.5	0.5					
Marketed Production	**53.2**	**55.3**	**57.8**	**59.3**	**61.4**	**66.2**	**67.0**	**65.0**	**67.0**	**69.6**
Natural Gas Processed	40.2	42.9	42.0	43.6	44.8					
Extraction Loss	2.5	2.5	2.6	2.8	2.9	3.2	3.2	3.1	3.2	3.4
Dry Production	**50.7**	**52.8**	**55.2**	**56.5**	**58.4**	**63.0**	**63.8**	**61.9**	**63.7**	**66.3**
Imports	**11.5**	**12.6**	**10.9**	**10.3**	**10.2**	**9.5**	**8.8**	**8.2**	**7.6**	**7.1**
Pipeline	9.9	10.5	10.0	9.0	9.1	8.5	7.8	7.2	6.6	6.1
LNG	1.6	2.1	1.0	1.2	1.2	1.0	1.0	1.0	1.0	1.0
Exports	**2.0**	**2.3**	**2.6**	**2.9**	**3.1**	**4.1**	**4.1**	**4.3**	**4.3**	**4.5**
Pipeline	1.8	2.1	2.5	2.8	2.9	3.9	3.9	3.9	3.9	3.9
LNG	0.2	0.1	0.1	0.1	0.2	0.2	0.2	0.4	0.4	0.6
Net Imports/exports (Bcfd)	**9.5**	**10.4**	**8.3**	**7.3**	**7.1**	**5.3**	**4.7**	**3.9**	**3.3**	**2.6**
Total Consumption	**59.4**	**63.3**	**63.8**	**62.8**	**65.1**	**66.8**	**67.4**	**65.8**	**69.0**	**71.0**
Lease and Plant Fuel	3.1	3.4	3.3	3.5	3.5	3.8	4.1	4.1	5.1	6.1
Lease Fuel	2.1	2.4	2.4	2.5	2.5					
Plant Fuel	1.0	1.0	1.0	1.0	1.0					
Pipeline & Distribution Use	1.6	1.7	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9
Delivered to Consumers	**54.7**	**58.2**	**58.7**	**57.4**	**59.8**	**61.1**	**61.3**	**59.8**	**62.0**	**63.0**
Residential	12.0	12.9	13.4	13.1	13.1	13.0	10.4	11.7	12.5	12.5
Commercial	7.8	8.3	8.6	8.5	8.5	8.7	7.3	8.5	8.5	8.5
Industrial	17.9	18.2	18.3	16.9	17.9	18.5	18.0	17.5	18	18.1
Vehicle Fuel	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electric Power	17.0	18.7	18.3	18.8	20.2	20.8	25.6	22.0	22.9	23.8
Net balance	**0.7**	**-0.1**	**-0.3**	**1.1**	**0.4**	**1.6**	**1.1**	**-0.1**	**-2.0**	**-2.2**
Price v marginal cost	0.95	0.95	1.22	0.64	0.63	0.52	0.66	1.02	1.59	1.65

Exhibit 14: Summary of US gas supply & demand
(Source: EIA & Kimmeridge Research)

Not only are these projects material to the US gas market but it should also be noted they are highly competitive on the global LNG cost curve, even if North American gas prices were to rise far higher, say, to $7/mcf (exhibit 15).

As a result by 2016/17 North America could be exporting (assuming pricing is attractive) 2-3.6 Bcfd of LNG, or 5% of all North America's current production. In addition there are a further 10 projects planned which could double or triple this number by the end of the decade.

Demand dynamics

Finally, the other major swing factor for the gas market is demand. Fundamentally, the debate over demand comes down to two factors namely the secular trend in gas fired power generation growth and the trend in industrial demand. On the Industrial side a large percentage of consumption is in fertilizer production, steel, aluminium and petrochemicals where natural gas prices are a key input to the economics. When prices are low these industries generate materially higher margins (especially against other production reliant on LNG or oil linked pricing) and increase consumption (2010,2011) but when prices rise margins are squeezed reducing consumption (2008, 2009). While no one indicator is a perfect marker for the outlook for industrial demand, history has shown that the ISM forward manufacturing order book has been a good indicator (exhibit 16). This currently suggests that industrial demand should moderate in 2012 associated with the moderation in GDP and the potential for a global slowdown in GDP. In our base case we model a reduction in demand in 2012 and 2013 of 0.5 Bcfd each year.

Last but not least turning to electric power demand there are two near term drivers of consumption. The first is the secular trend for shutting down coal fired power generation driven by environmental regulation. The second is short term gas switching demand driven by price that may or may not be reversible if natural gas prices recovered. To date these together have led to a 30% increase in consumption or 5.14 Bcfd. The significance of this number is considerable. If weather normalized in 2012 and/or 2013, utility demand remained the same and supply was flat, then the market would rapidly fall into a 3+ Bcfd deficit, which would be more than enough to return the market to normal or even below normal inventories.

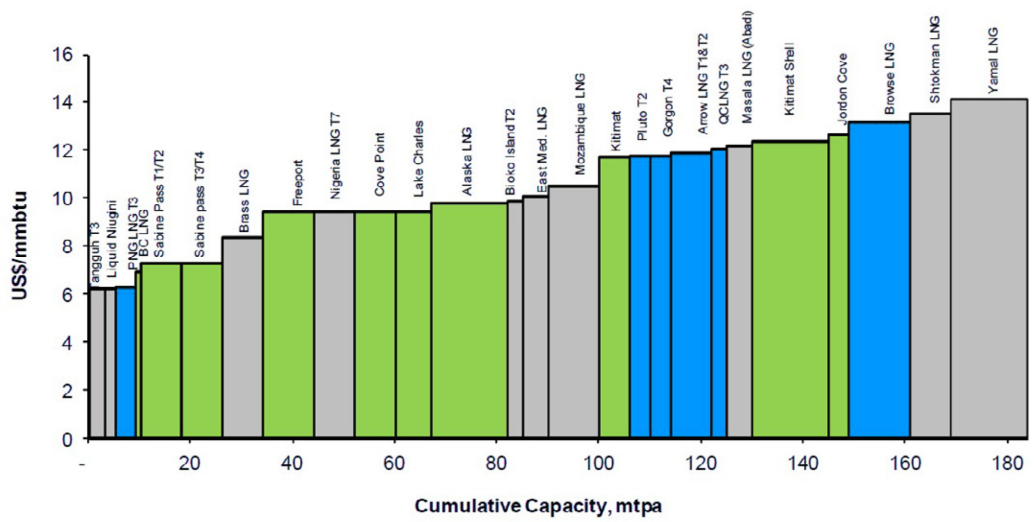

Exhibit 15: Cost curve for Global LNG supply at a $7/mcf Henry Hub gas price (Source: Bernstein Research)

Recent work by Hugh Wynne our former colleague at Sanford Bernstein gives perhaps the most detailed breakdown on these two factors in a piece entitled "Clash of the Titans: Has Gas Production Growth Met Its Match in Utility Gas Demand?" In it he noted the economic incentives to switch to gas fired power generation especially below $3.50/mcf and the constraints on this (the unutilised capacity of the gas fired generation fleet which is large and the distance between these plants and the coal fired plants that are being reduced). Ultimately this relationship means that economics will continue to dominate the outlook for gas demand from utilities but that in theory it could rise by as much as 9 Bcfd. While we do not model anywhere near this number, as it would presume trough pricing and would be incompatible with the cost of supply, we do assume a 4% secular growth in demand from 2009 to 2013, which we believe is a conservative assumption on the long term substitution effect.

As such the outlook for power demand remains critical to the debate. Specifically we believe that looking at the 2012 market there are 2 very clear end members:

- Bull case: Weather normalizes, supply flattens (if not declines) and power demand remains within 2-3 Bcfd of 2012 levels. Under this scenario the gas market would be net undersupplied, and while inventory would need to be "burnt off" prices should recover to the marginal cost by YE.
- Bear case: Weather normalizes but as residential and commercial demand picks up power demand falls (presumably as prices recover to $4-5/mcf). Drilling activity also resumes albeit slowly moderating supply declines to keep prices in the $3-4/mcf range.

Lastly but not least, while there isn't a major debate about the outlook for residential and commercial demand but that isn't to say that they aren't important; it's simply because consumption levels are determined by weather, which is highly unpredictable.

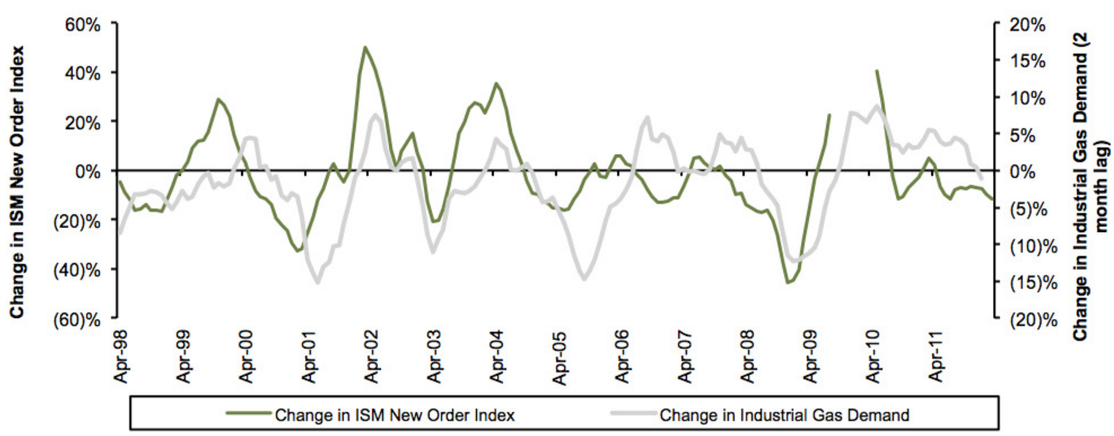

Exhibit 16: Change in ISM forward manufacturing order book v change in industrial gas demand (Source: EIA & ISM)

What Does the Balance Look Like In 2012?

The outlook for gas pricing remains controversial. However a bottom up analysis of the market suggests that the extended cyclical trough that has persisted from 2009 may now be turning the corner. Key factors behind this are:

- The recent decline in production in key states
- The continued decline in imports
- The continued switching of utilities from coal to gas
- In 2015+ the growth in LNG exports

Specifically, in 2011 the market was net oversupplied by 1.6 Bcfd. In 2012 (based on data so far reported) we believe consumption is likely to be up 0.6 Bcfd, while supply will grow 0.8 Bcfd and exports will fall 0.6 Bcfd, ultimately reducing the net oversupply by 0.4 Bcfd to 1.15Bcfd. However if weather were normal in 2013, and supply moderates as expected, then residential and commercial demand would be 4 Bcfd higher, sending the market into deficit.

While timing these remains challenging (especially the net changes in the utility market), we see light at the end of the tunnel and believe that when prices do rebound the natural scepticism built up over the last 3 years will mean the market is slow to react on the other side most likely leading to a price spike above $7/mcf.

References

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