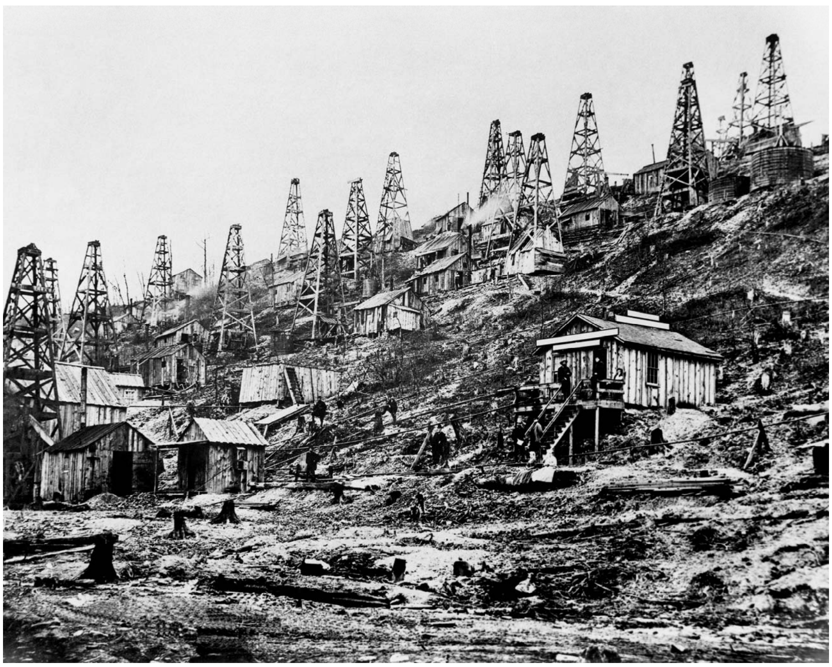
Deutsche Bank
Markets Research

Periodical
Exploration & Production

Date
17 December 2012

North America
United States

Industrials
Oil & Gas Exploration & Production



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F.I.T.T. for investors

Adjusting to an Age of Surplus

The (Un) Sustainability Of US Oil Growth

The growth of US tight oil supply has been the dominant theme in global energy. Supply has surprised to the upside and we expect on trend growth in 2013/14. However, market expectations surrounding the deliverability and sustainability of supply growth are likely peaking. A closer look at field performance suggests well productivity is reaching a plateau and an end to the period of explosive growth is likely to follow. While the key risk is further tight oil discoveries, we see little material and scalable on the horizon. Our outlook is more constructive for longer-dated WTI than consensus and the forward curve, and we expect further differentiation between upstream operators based on asset quality and ability to deliver on production growth expectations.

Deep-dive into North American oil production growth

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Answering the key questions - US oil supply growth.

We have taken a closer look at the trend that has dominated global energy markets. We see domestic crude growth of ~500mbpd annually over the coming 3 years. Our revised view is up ~200mbpd from DB's previous expectations through 2020, but our expectations diverge from consensus by the back half of the decade. Our supply forecast is informed by play and well level results, drilling inventory and economics from the Bakken and Eagle Ford.

Key takeaways from our work

Extrapolating a trend line for tight oil production is dangerous, and we see deliverability from the Bakken and Eagle Ford at the field level peaking over the coming 12-18 months. While longer-term growth rates are attainable at the play level, without further exploration success we think total supply growth will fall short of expectations by 2015+ as well results and rig count have plateaued. There has been a dearth of new resource discoveries that are scalable or material enough to shift our supply forecast. Additionally, a look at play level and industry economics support a view of marginal cost of tight oil supply at ~$80/bbl WTI and we see supply already being rationed from the lower-48 today. While continued robust supply and weakening demand could see sub-$80/bbl WTI prices in 2013, without sustainably higher (>$100/bbl WTI) prices expectations surrounding the scale of the domestic tight oil opportunity is likely to shrink, in our view.

Winner takes all set up for the E&Ps

2012 has seen significant divergence based on asset quality and delivery vs. expectations. We expect more of the same in 2013 and argue for additional scarcity value for the "haves" while the "have nots" are likely to struggle to create value. While 'adjusting to surplus' is likely the near-term focus, once the supply dynamic we outline (limited additional tight oil resource) becomes apparent, we expect those with the track record and assets to deliver to continue to outperform. Key risks are technology and exploration efforts unlocking additional commercial tight oil resource and/or the equity market discouraging supply growth (multiple compression) in the near-term.

Companies Featured	
Anadarko Petroleum (APC.N),USD74.59	Buy
Concho Resources (CXO.N),USD82.39	Buy
EOG Resources (EOG.N),USD118.99	Buy
Noble Energy (NBL.N),USD100.02	Buy
Cimarex Energy (XEC.N),USD56.26	Buy

Valuation and Risks

We see the E&P group broadly at 6.0x forward EV/EBITDA vs. a 7-year average of 6.3x for the group (consensus estimates). We value the large-cap group on both a NAV and target multiple (DACF) basis and at 1x NAV for the mid-cap group. Key risks include execution, higher than expected operating costs, above ground risks (logistics, transport, pricing) and below ground (geologic).

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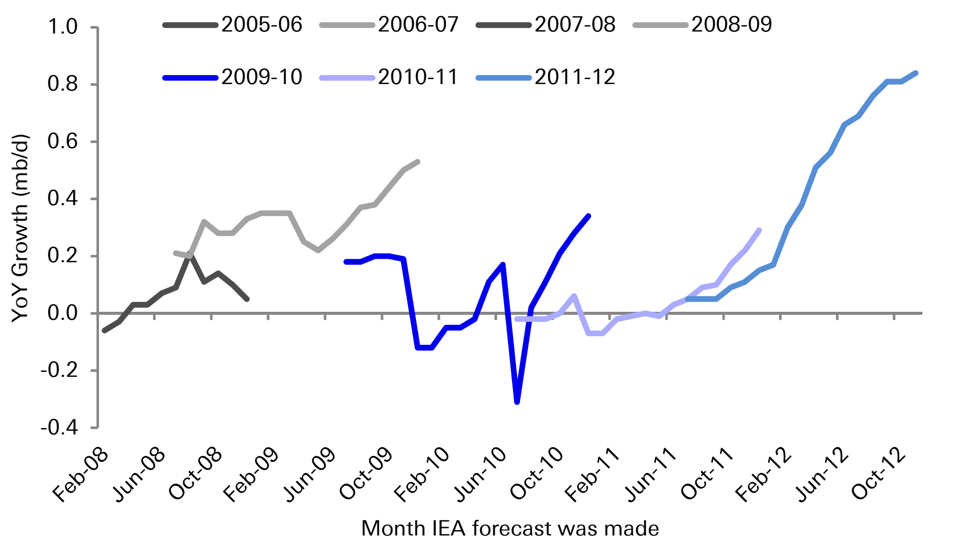
Grasping the Upside Potential

Executive Summary

2012 has been the year of persistent and grinding upside to expectations surrounding domestic onshore crude supply. Driven by 3 major unconventional basins (Bakken, Eagle Ford, & Permian) this supply growth has challenged energy investors to reconsider the supply outlook for crude from a key contributor to non-OPEC supply. As the most significant trend facing energy investors, we set out on a data driven effort to answer two key questions surrounding this outlook.

Figure 1: IEA US Supply Growth Revisions to the Upside



Source: Deutsche Bank, IEA

- What is the sustainability of the supply outlook, how much growth can we expect from established plays and what does well performance at the field level tell us about these multi-year trends?
- What are the economics of this supply growth? With domestic crude prices diverging significantly from global benchmarks (Brent-WTI at $22/bbl), what is the sustainability of the supply outlook at lower prices?

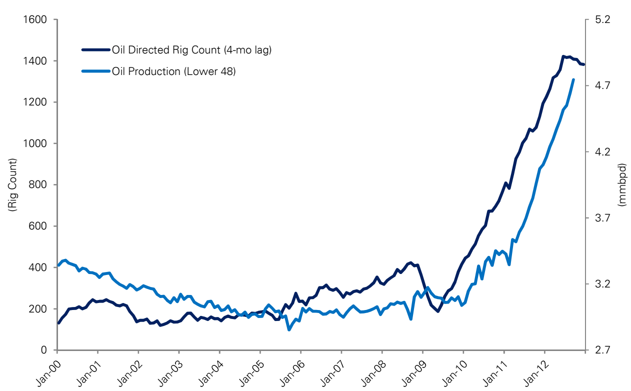
While acknowledging the broad scope of this research effort, our work supports a number of key conclusions.

- We see market expected supply growth in the near-term as well supported. We see ~600mbpd of US supply growth in 2013 (vs. ~700mbpd in 2012). Importantly, our basin level work broadly confirms and supports the conclusions of our colleagues (Sankey, Clark) as outlined in their report "The Future of US Oil" dated February 28, 2012. Our revised North American estimates are ~200 mbpd per annum higher than this previous evaluation of North American supply growth through 2020.
- Expectations surrounding growth over the next 5-10 years is likely peaking. While our expectations are broadly in-line with major forecasters for 2013/14, we see some important divergences by the back end of the decade. A rapid rise in rig count and markedly improving well performance in the early phase of development

from both the Bakken and the Eagle Ford drove accelerated growth, but improvements have slowed from both plays. While drilling efficiencies (move to pads, reducing days drilling) will provide the next lift in productivity, the low hanging fruit has been picked and we expect the period of significant upward revisions to domestic supply growth is in the past. In fact, as the tail wind from the final shift to pad drilling fades post-2013, we expect that base declines and the deterioration of non-core inventory may likely lead to production disappointments. Those looking to extrapolate a trend based on recent performance (12 months) will be mistaken.

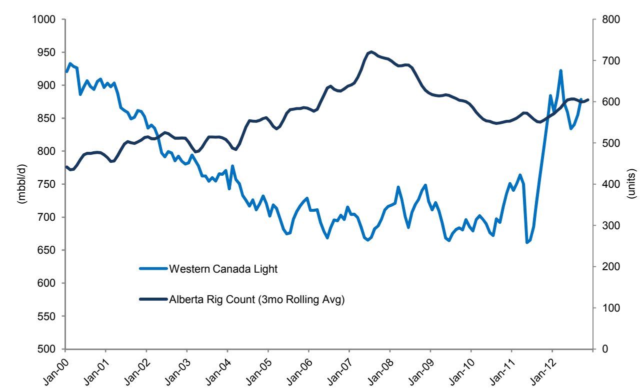
- Exploration in the lower-48 is yielding lackluster results. Beyond the major development plays, no significant (scalable) liquids supply opportunities have been secured over the past 12 months. Activity has shifted towards core development plays and we see little of the scale of a Bakken or Eagle Ford which could be an upward surprise to supply expectations.
- A closer look at field level and corporate economics support the view that ~$80/bbl is the marginal cost of domestic crude supply growth, and we expect supply to react accordingly should prices weaken materially. The top 20 production growth contributors are supplying 75% of growth from North America, and producers are not insulated from prevailing economics.

Figure 2: Lower 48 Crude Production vs. US Oil Rig Count



Source: Deutsche Bank, EIA, Baker Hughes

Figure 3: Western Canadian Light Oil Production



Source: Deutsche Bank, NEB, Baker Hughes

The Haves & the Have Nots

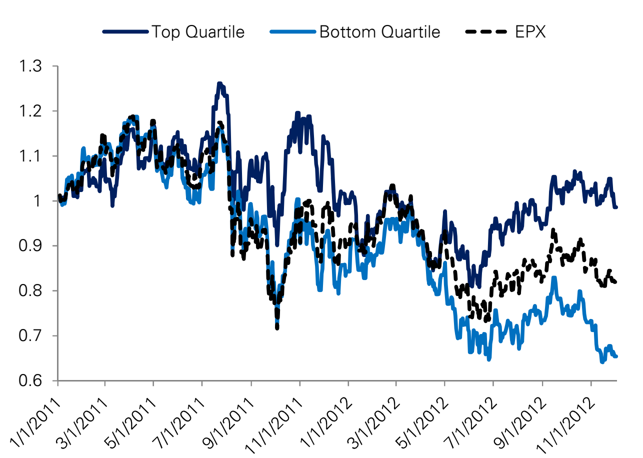
The conclusion of our work is that the industry faces continued above trend crude supply growth over the coming 12-24 months, and in-line of flat domestic demand and the export restriction on crude, this surplus scenario is likely to continue. However, considering evidence from the field level and the attainability of 2015+ growth expectations, we believe scarcity value for the E&Ps is set to rise. The market has severely penalized those without the asset position or track record of execution to grow over the past 12 months, we see this differentiation set to continue. Our view is that those with the right assets (core development positions in established plays) and ability to execute will continue to outperform the sector.

Over past cycles, two underlying themes have proven supportive for all E&Ps, not just a select group.

- Commodity price has healed all ills. Rising commodity prices see increased returns accrue asymmetrically based on operating and financial leverage and skews underlying asset quality.
- New resource plays provide an opportunity to transform the asset base. The industry entered into a significant phase of resource expansion in the 2009-2011 timeframe shifting away from unconventional natural gas towards liquids. This shift saw the accelerated delineation and move to development of major liquids growth plays (Bakken, Eagle Ford). Absent a rising commodity tape, new plays provide opportunity to secure new resource with a differing (improving) return profile relative to legacy assets.

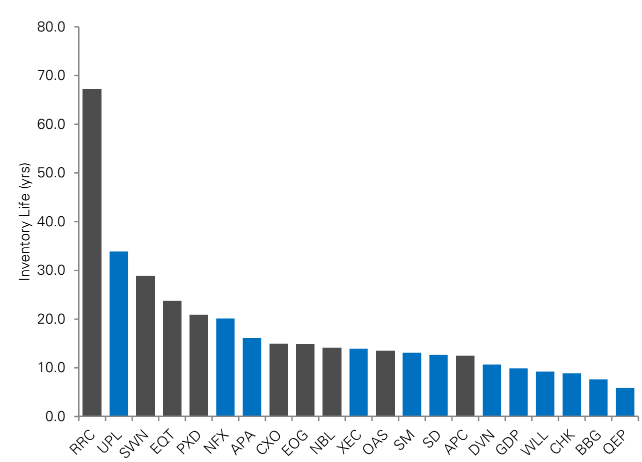
Basing our expectations on a broadly flat outlook for crude prices and modestly rising natural gas prices, we see neither dynamic significantly supporting the industry outlook. Supporting a selective approach towards the group we see neither of the dynamics that have normally attracted investors to the sector; namely rising prices (E&Ps provide leverage to the commodity) or expanding resource (via exploration success).

Figure 4: Expect Dispersion to Continue



Note: Performance indexed to 1 as of January 1st 2011. Top Quartile names include RRC, UPL, SWN, EQT, PXD. Bottom Quartile Names include QEP, BBG, CHK, WLL, GDP, DVN
Source: Deutsche Bank

Figure 5: Activity Adjusted Resource Base



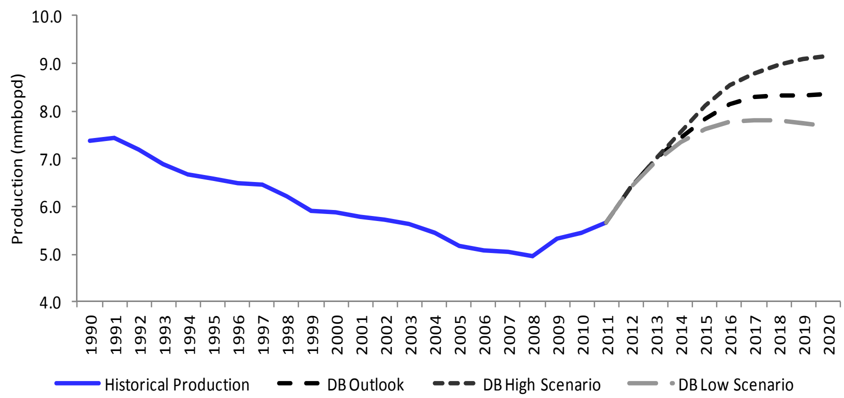
Note: Grey shaded names outperformed the EPX since January 1st 2012
Source: Deutsche Bank

The key risk to this outlook would be higher than expected near-term oversupply which would likely see the equity market discourage production growth, hence compress multiples.

Updated Lower-48 Supply Forecast

After several years of declining production ('90-'05), and a short period of stagnant production ~5MMBopd ('05-'08), US oil looks to be poised for several years of significant growth lead by a resurgence of activity in South Texas, the Williston Basin, and the Permian Basin. Based on EIA data through Sept '12, US oil supply is estimated to grow ~700kbopd in '12 to average ~6,300-6,400Mbopd, a level not seen since the mid-'90s.

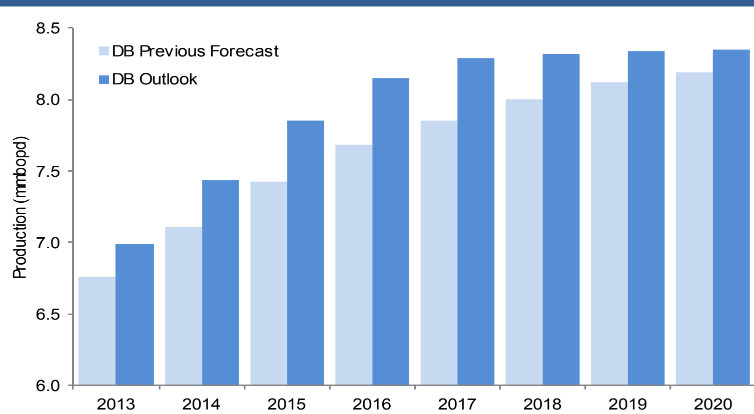
Figure 6: Historical Production From 1990 (mmbopd)



Source: Deutsche Bank, EIA, PIRA

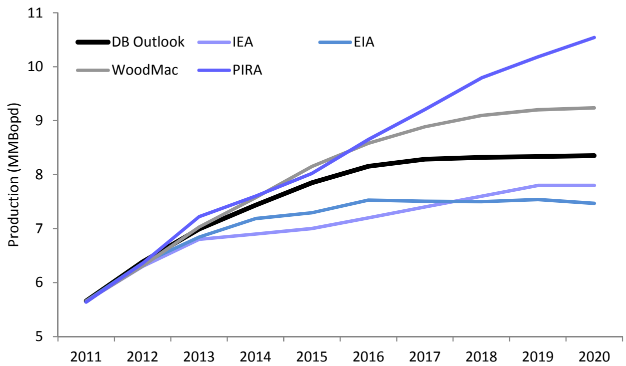
Using our bottoms up analysis of the key drivers for oil supply (Eagle Ford, Bakken, Permian) over the remainder of the decade, our baseline assumptions show US production peaking late in the decade around 8,300-8,400Mbopd, ~200mbopd a year higher than the previous DB forecast, though with a steeper initial incline. While we are broadly in-line with consensus (government agencies and commodity forecasters) estimates through 2014, our forecast divergences through the back half of the decade, as well inventory depletes and base decline sets in. As most forecasts have been revised upwards this year, we have provided an upside estimate should well inventory and recoverable reserves increase. To the downside, we have risked wells for a 10% decline in inventory productive capacity.

Figure 7: DB US Forecast Revisions



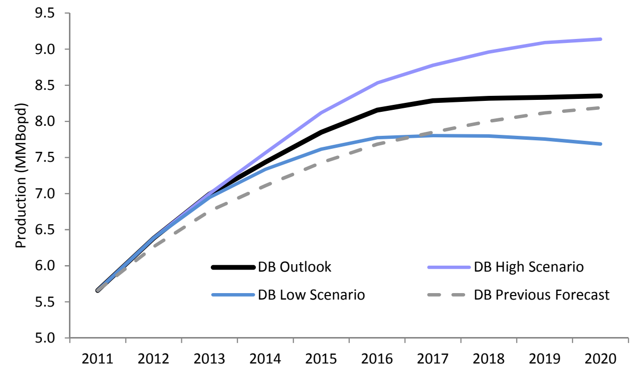
Source: Deutsche Bank

Figure 8: US Crude Oil Forecasts Through 2020



Source: Deutsche Bank, IEA, EIA, Wood Mackenzie, PIRA, Company Presentations

Figure 9: DB US Crude Supply Forecast Through 2020



Source: Deutsche Bank, Company Presentations

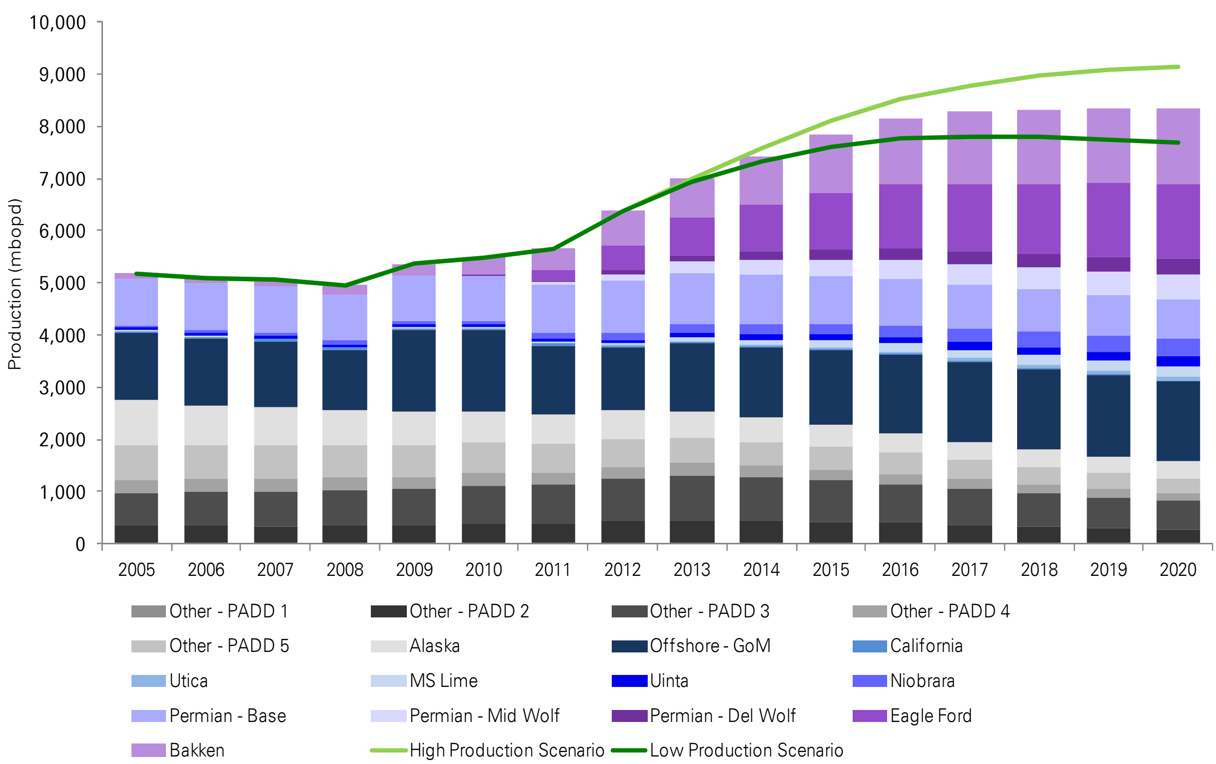
Base Supply Forecast Key Takeaways and Assumptions

- **Eagle Ford production increases to ~1,450mbopd:** After only three years of activity, Eagle Ford oil production has reached ~500mbopd and is estimated to supply ~10% US oil in '13. Our updated Eagle Ford forecast is inline with previous estimates, though we estimate a steeper incline, notably because of higher IP rates (>800boepd vs. 650boped), a higher success rate (95% vs. 90%), and a higher rig count.
  - **Key Assumptions:** We estimate the remaining inventory to be ~25,000 drilling locations available across the oil and wet gas portions of the Eagle Ford, assuming 120 acre spacing. Between the two areas, we have the rig count peaking around 230 rigs in '14-'15, before declining to ~185 in '20, drilling ~24,000 locations (~95% of inventory). Our average well profile in the oil portion of the Eagle Ford has an EUR of ~450MBoe with a 77% oil cut and a $7.5MM drill and complete cost while the wet gas portion has an EUR of 850MBoe with a 25% oil cut.
- **Bakken production increases to ~1,450mbopd:** After years of constrained oil growth due to lack of infrastructure, a ramp in rail and pipeline capacity in '12-'13 has allowed for increased activity, pushing production up to ~750mbopd in '13 from ~425mbopd in '11. We estimate the Bakken to peak around ~1,450mbopd later this decade, up ~200mbopd versus our previous estimate.
  - **Key Assumptions:** In our base scenario, we estimate ~21,200 drilling locations are the remaining inventory based on 320 acre spacing with 200 rigs running through '16 before declining to 150 rigs though '20. Our average well profile has an EUR of ~575MBoe with an 87% oil cut and a $9.5MM drill and complete cost.
- **Permian production increases to ~1,500mbopd:** Permian production has been steady at ~900mbopd '05-'10 before breaking out to ~1,100bopd in '11. The increase in production has been lead by a ~100 horizontal rig pick up since '10 with activity directed towards the Delaware and Midland Wolfcamp basins. The result of the shift change from vertical to horizontal drilling pushes '20 production to ~1,500mbopd, inline with DB's prior forecast.
  - **Key Assumptions:** Our Permian analysis is broken into three sections – Existing base production, Delaware Wolfcamp and Midland Wolfcamp. Our base level of production now declines by 2-4%/yr, which is more than offset by the

increase in Wolfcamp drilling and estimate base Permian production to be roughly equal to Wolfcamp production by the end of the decade.

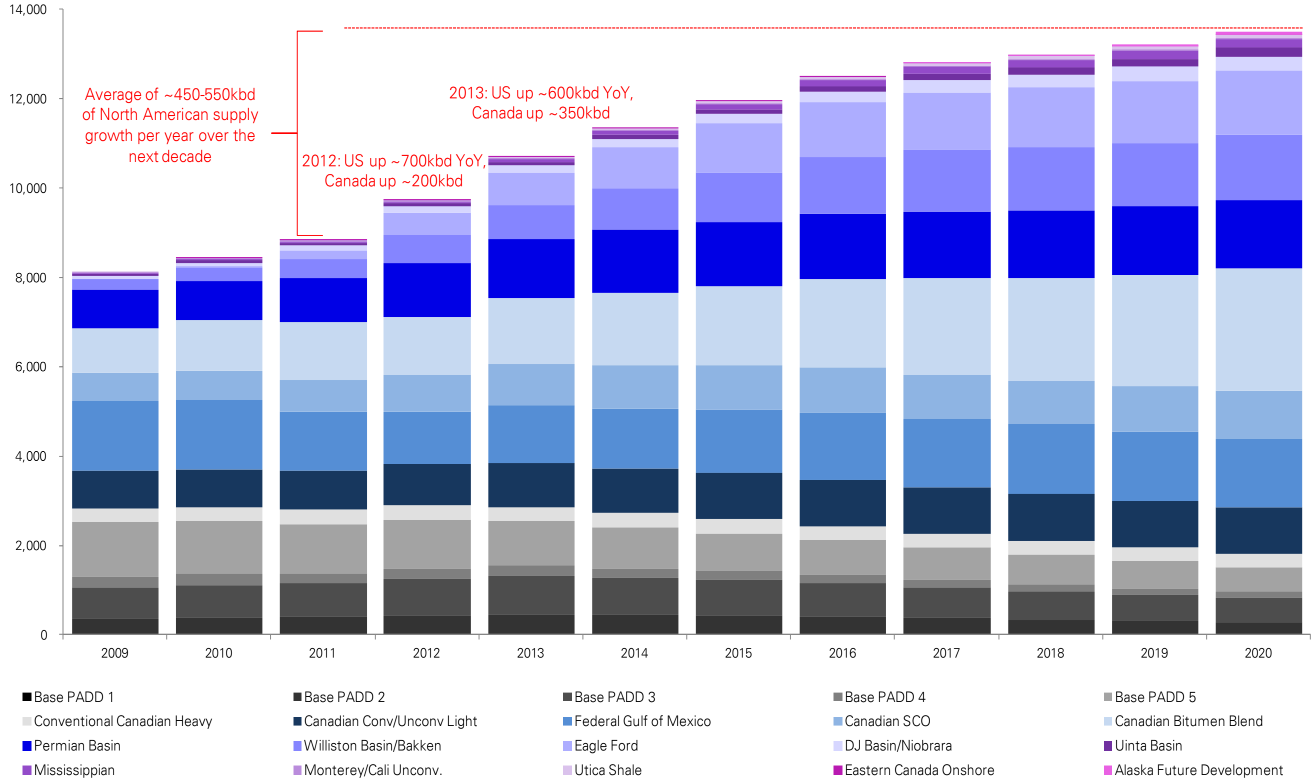
- **Base production declines to ~3,100mbopd:** Current production outside the key unconventional oil plays, declines from ~3,800mbopd in '12 to ~3,100mbopd in '20, as the increase in offshore Gulf of Mexico (deepwater startups) production is offset by normal base declines.
- **Monterey Shale Reduction:** Of the smaller contributions to the overall supply picture (Niobrara, Monterey, Uinta, MS Lime, and Utica), the Monterey sees the biggest change as confidence and activity levels in the play have declined. DB's previous supply outlook had '20 Monterey production of ~190-200mbopd vs. our current forecast of ~20mbopd. The other basins do see changes in our forecast, though they are all within a modest margin of error (~30mbopd).
- **Success Rate of 95%:** While operators are still exploring the boundaries of each unconventional play, we have assumed a 95% success rate across each basin.

Figure 10: US Production Plateaus At 8.3-8.4MMBopd



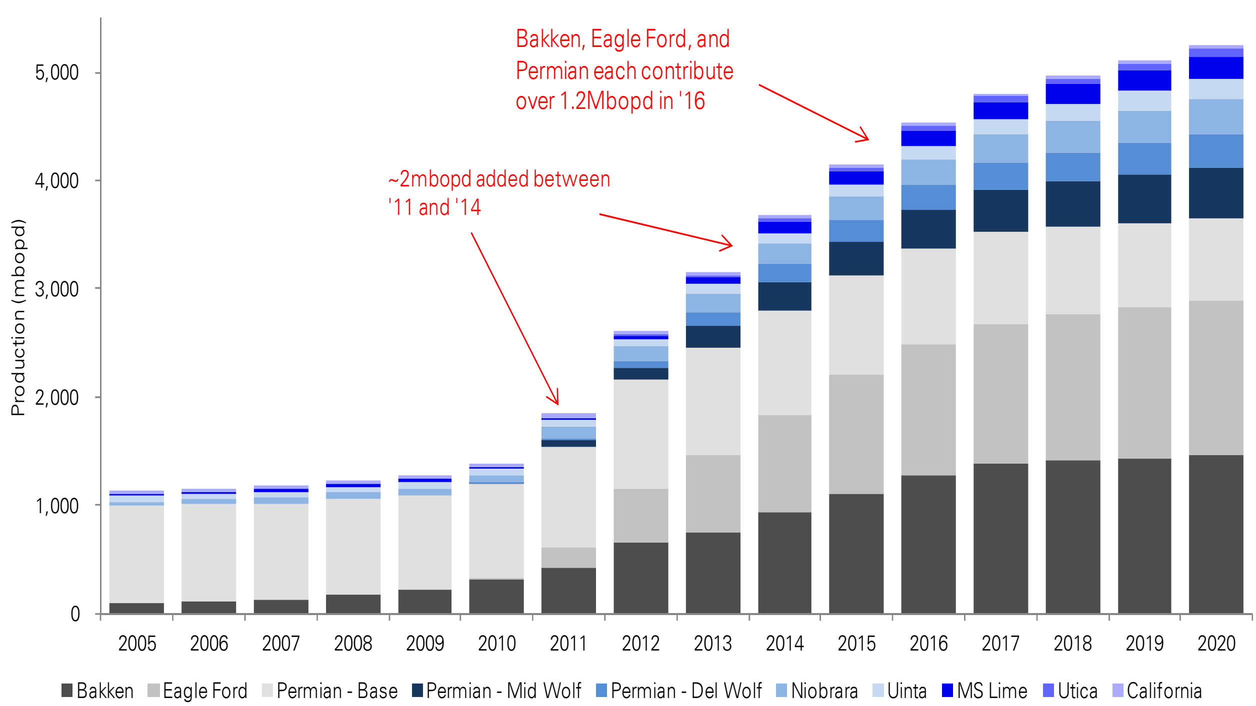
Source: Deutsche Bank, Wood Mackenzie, EIA, IEA

Figure 11: Total North American Supply (Mbopd)



Source: Deutsche Bank, Wood Mackenzie, EIA, IEA

Figure 12: US Supply Growth Drivers



Source: Deutsche Bank, Wood Mackenzie, EIA, IEA

Upside Potential

As revisions to US oil supply have only increased over the past 12 months, we recognize there is potential for future upward bias to our estimates, notably downspacing, technological enhancements, efficiency gains.

To the upside, potential for downspacing across the Bakken and Eagle Ford has the biggest production impact, assuming no degradation to the average well profile or dramatic change in oil prices. In this scenario, we have estimated the Bakken inventory is extended with Three Forks Lower Bench wells (more wells per section) and the Eagle Ford on 80-acre spacing, allowing production to reach infrastructure capacity in both basins, resulting in ~9.3MMBopd US supply by 2020. Our upside estimate also reflects the possibility of the Keystone XL (100mbopd) and Sandpiper (225mbopd) pipeline additions in the Bakken. Risks to reaching our upside scenario estimate are lower crude prices, both on the level of overall supply (Canada is estimated to increase supply by ~2MMBopd from '11-'20) and bottlenecks of pipeline and refining capacity.

Downside Potential

We also see downside potential to our estimates in the '16-'20 timeframe should producers have a lower success rate than our 95%, well performance declines as core area inventory is depleted and the pace of growth slows from HBP acreage (no need to push drilling).

To the downside, the risk of drilling lower quality wells has the biggest impact on production, likely resulting in fewer wells drilled, assuming no upward pressure on oil prices. In this scenario, we estimate the average Bakken and Eagle Ford well declines by 10% from our averages, and as a result, reduces the wells drilled in the '15-'20 timeframe due to lower IRR's. Our low case scenario projects supply to be ~7.8MMBopd in '20, ~500mbopd lower than our base estimate. As with the upside scenario, crude prices are likely to be the major risk to production coming in above our downside forecast, with higher prices offsetting lower estimated ultimate recoveries (EURs).

Understanding US Oil Supply Growth

Pushing the rope

The driver of resurgent domestic energy supply from the US has been the unconventional revolution. Technology (horizontal drilling & multi-stage hydraulic fracture stimulation) has provided the opportunity to extract resource in commercial volumes. While ~20 years in the making, this unconventional revolution has altered the supply dynamics for both natural gas and domestic light crude oil.

Our experience with natural gas supply growth provides a template by which to understand the development of unconventional oil plays. The key to understanding the growth potential of development is the performance of single wells in the field. Producing from tight reservoirs generates hyperbolic decline curves, the benefit of which is high initial production rates and rapid payback of initial investments. Once the resource has been identified and moved to development we see three simple drivers that determine the pace of supply growth.

- **Rising initial production rates.** Optimizing well completions and a better understanding of reservoir characteristics provides the most significant tailwind to production growth in the early stage of development
- **Activity levels.** While a function of available funding & well level returns (plowback of cash flow) the aggregate activity level (rig count, # of wells drilled) is the other part of the growth equation. Rising activity levels with rising initial production rates is the key formula for explosive production growth rates.
- **Efficiency gains.** Due to the repeatability of well results, the industry has moved to a manufacturing process for field development. Once lease terms have been addressed and the resource understood, the final component of growth potential is the optimization of all aspects of delivering production. A key stage for producers as this implies more units of production per unit of capital, production growth has reached a more mature stage by the time optimization is fully completed.

Based on the analysis of multiple plays and fields, our analysis suggests that the peak in production growth coincides with the peak in initial production rates and activity levels. Beyond this point additional activity levels and efficiency gains will support growth at a slowing rate.

A look backwards and forwards at the drivers of US oil supply

Given the time necessary to achieve critical mass in an emerging play (exploration, basin delineation, drilling and infrastructure build-out, etc), the majority of medium-term (3-5 year) production growth is likely to come from already discovered/established basins. Within this group, none are more important for US production growth than the Bakken and Eagle Ford.

Since 2008, combined crude production of the two basins has increased from 176 bpd to 1,150 bpd, representing 20% of total US crude production growth. Nearly 350 rigs currently operate between the two basins, representing 25% of the total oil-focused US rig count, and 32% of the horizontal rig count. Only the Permian compares in size, with 408 rigs currently operating (124 horizontal). The next closest basin from an activity level, the Marcellus operates a far-distant 58 rigs.

Clearly, any analysis of US production growth will hinge materially on the prospects of these three basins. Below, we analyze the historical and future drivers of production growth for the Bakken and Eagle Ford, the sustainability of these factors and the depth of inventory across the basins.

With the caveat that making multi-year forecasts on a type of development that is essentially 3-4 years old is somewhat precarious, a number of noticeable trends are obvious in the data, as early growth drivers (rig count, increasing well performance) slow and industry focus shifts to capital efficiency, cost control and inventory downspacing.

We see segment the development of plays into two discrete phases.

Phase 1: Early stage accelerated growth driven by rising rig count and improving well performance

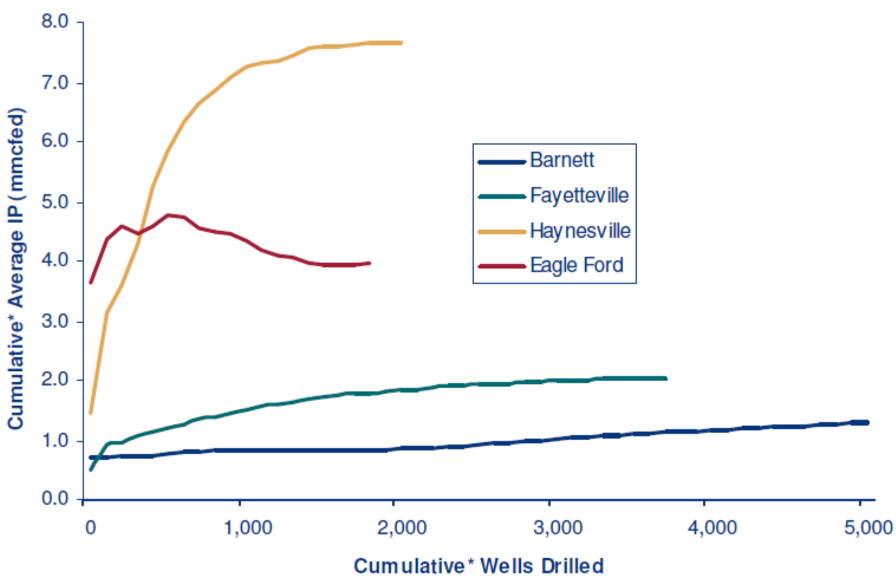
- Oil rig count increased from ~200 to over 1,400 from 2008 to 2012, led by the Bakken (20 to 146), Eagle Ford (0 to 165) and Permian (115 to 399)
- Significant improvement in well performance. Average Bakken IPs increased from ~400 boepd to 1,200 boepd, while Eagle Ford increased from ~200 to 800 boepd Improvements driven by improved reservoir understanding, increasing lateral length and frac stages, larger fracs, etc.
- Shift towards core (pad) drilling further increased average well results. For example, drilling in N. Dakota's two most productive counties, McKenzie and Williams, increased from 20% of well count in 2009 to ~50% YTD in 2012.

Phase 2: As above trends slow, focus shifts towards focus on capital efficiency, cost control and downspacing to increase inventory

- After rapid increases, average well performance has largely plateaued, both in the Bakken (early 2011) and the Eagle Ford (late 2012). Lateral lengths and frac stages are no longer increasing, and rig count has plateaued and rolled over.
- Increasing shift towards pad drilling and loosening of the services market drives gains in capital efficiency, improving industry economics and corporate financials, but with limited ability to prevent a deceleration in growth rate.

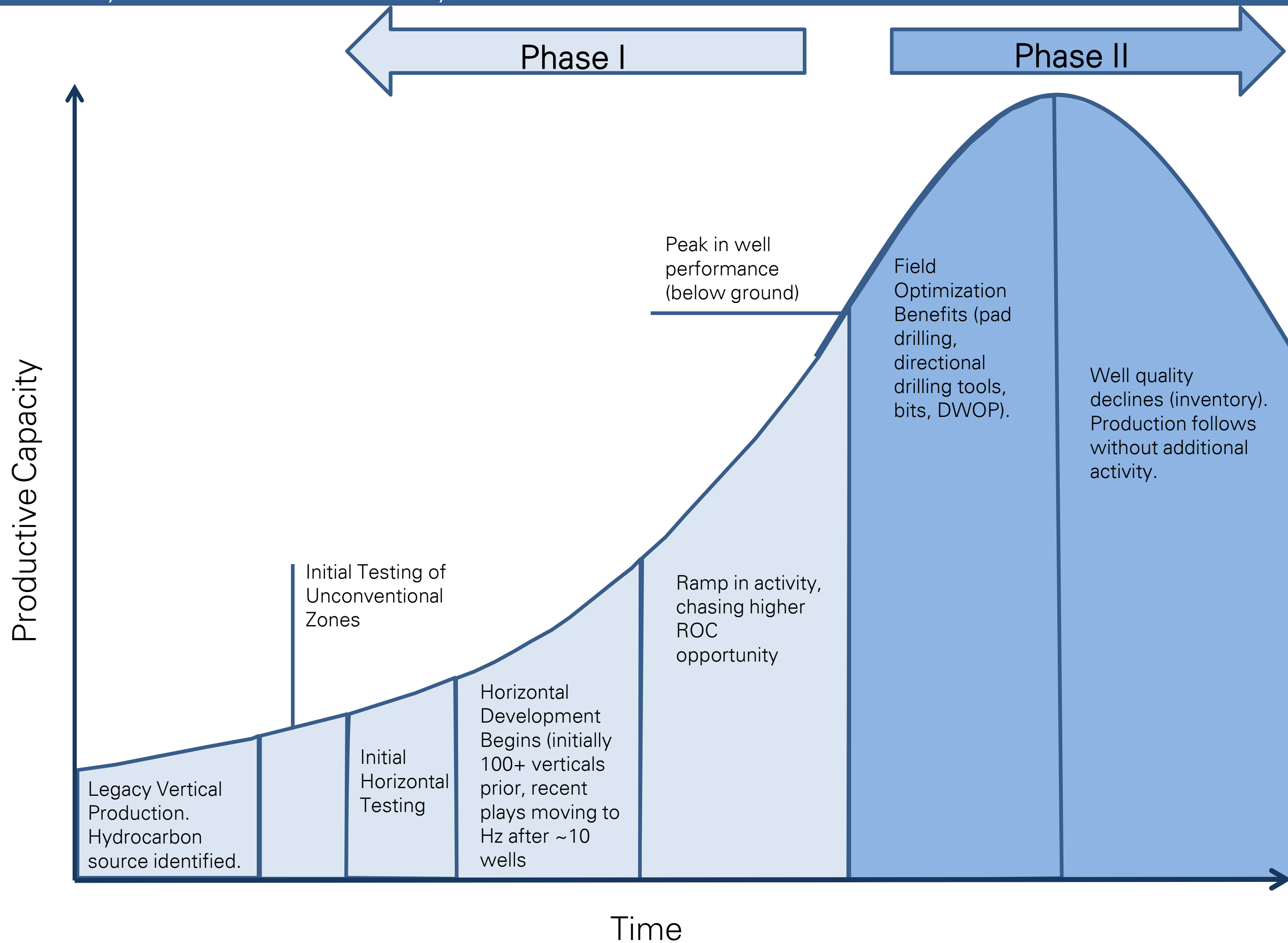
- Sanish and Parshall, as microcosms of the broader industry, demonstrate that when well results cease improving, a steady pace of drilling (Sanish) will result in slowing growth, while any pullback in activity (Parshall) will drive significant declines.
- We see the same dynamics at play in the natural gas plays observed. Discerning the impact of inventory high grading, infrastructure constraints, and lower activity levels can be a challenge. Within we use the experience of the Fayetteville shale in Arkansas to outline a similar dynamic to what we see in the oil plays, the peak in the improvement in initial production rates closely coincides with the peak in production growth.

Figure 13: Industry Learning Curve in Shale Plays has Been Rapid



Source: Deutsche Bank, Wood Mackenzie

Figure 14: Life-Cycle of Unconventional Resource Plays

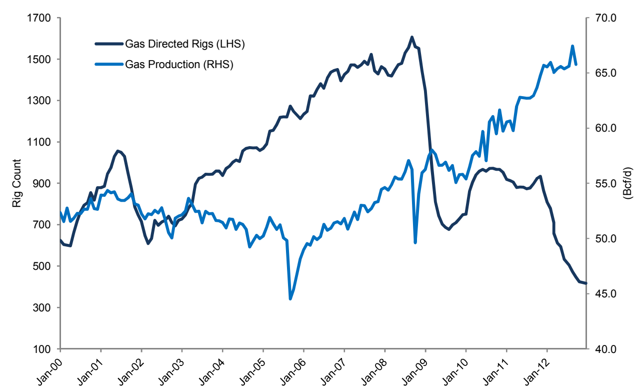


Source: Deutsche Bank

Zero to Sixty in no time: Ramping the oil rig count

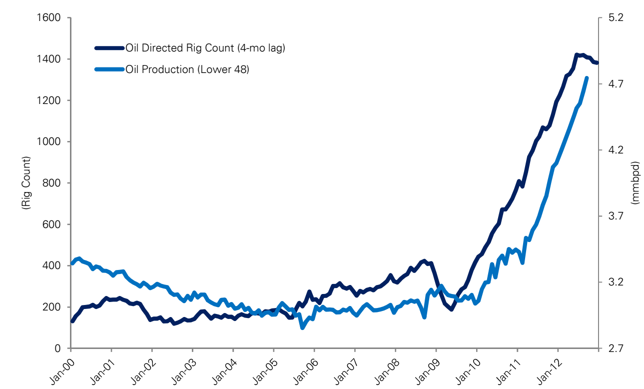
Exiting the financial crisis, the strength of crude oil pricing combined with persistent weakness in natural gas witnessed a wholesale reallocation of capital from natural gas to oil/liquids drilling. From the trough of the market in early 2009, the oil-directed rig count increased from ~200 rigs to over 1,400 rigs earlier this year. Within this growth, the Bakken and Eagle Ford were significant drivers, ramping from 55 to 146 and 0 to 165 rigs respectively.

Figure 15: Gas Production vs. Gas Directed Rig Count



Source: Deutsche Bank, EIA, Baker Hughes

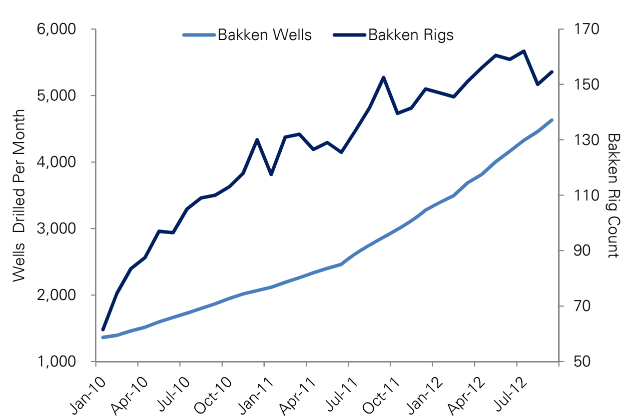
Figure 16: Oil Production vs. Oil Directed Rig Count



Source: Deutsche Bank, EIA, Bake Hughes

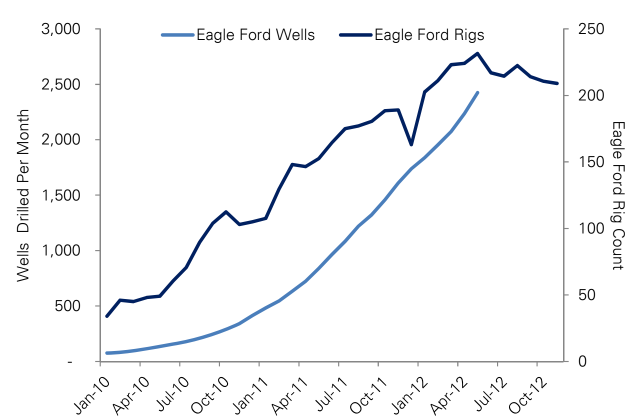
With the rising rig count, number of wells drilled per year has steadily accelerated, providing much of the brute force behind the stellar production growth.

Figure 17: Bakken Rig Count and Wells Drilled



Source: Deutsche Bank, Bloomberg Finance LP, Land Rig Biweekly

Figure 18: Eagle Ford Rig Count and Wells Drilled

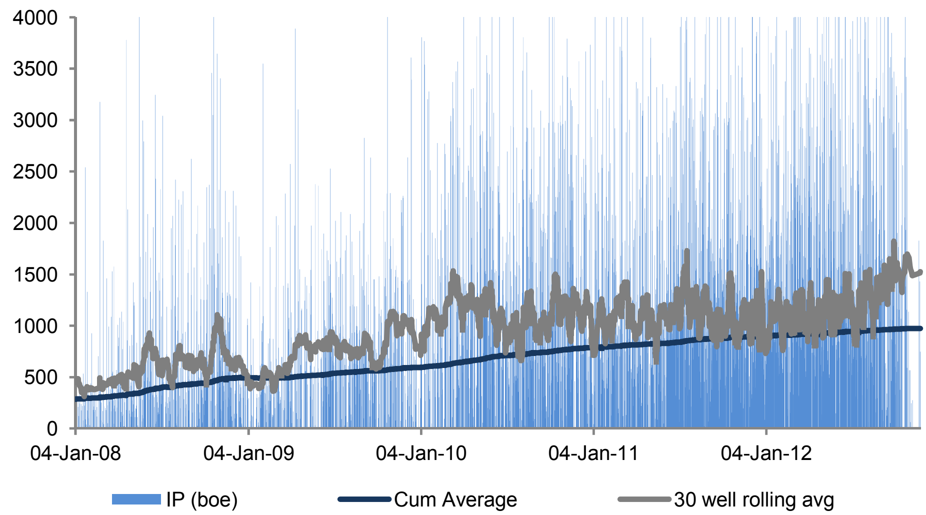


Source: Deutsche Bank, Wood Mackenzie , Land Rig Biweekly

Steady improvement in well performance has been the biggest upside surprise

Although it should not be shocking given the industry's adeptness at driving technological improvement, looking back, one of the more pleasant surprises has been the sheer scale at which well performance has improved. In the Bakken, per well initial production rates (IPs) have more than doubled since 2008, from under 500 boepd to over 1,200 boepd YTD in 2012. We have seen average IPs remain flat since early 2011 with an uptick in recently months driven by the move toward pad drilling. For additional detail, see drilling results over time by county in Figures 104-109 in Appendix B.

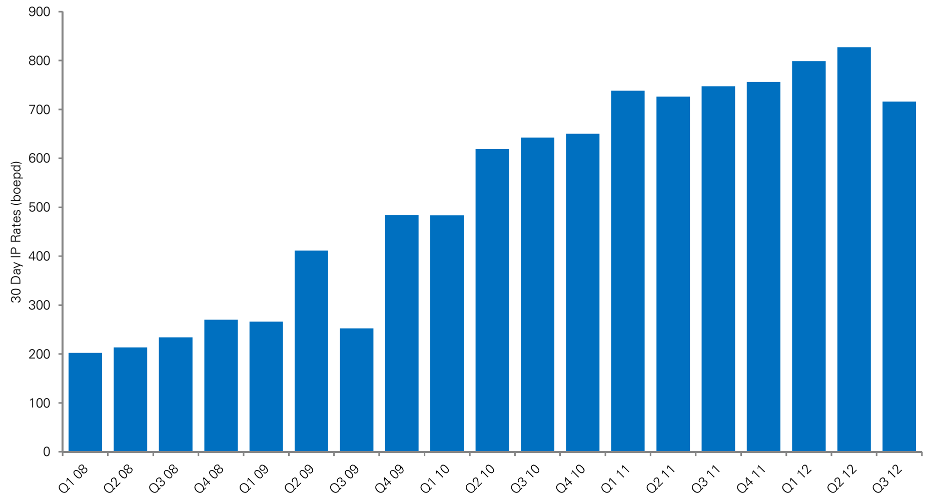
Figure 19: Average IPs in the basin have more than doubled since 2008, but are largely flat since early 2011



Source: Deutsche Bank, NDIC

The story in the Eagle Ford, although complicated by a gradual shift from higher rate gas-condensate wells to lower rate black oil wells, is much the same thing. Since drilling commenced in early 2009, average IPs across the basin have increased from 200 boepd to 800 boped.

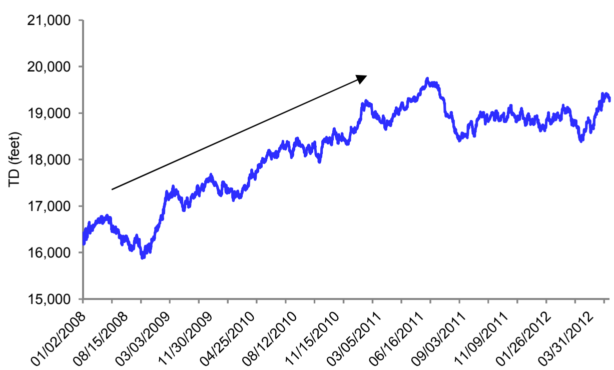
Figure 20: Eagle Ford historical IP time series



Note :IP rates are for Karnes, La Salle, Gonzales, DeWitt, Dimmit, Live Oak, and McMullen counties.
Source: Deutsche Bank, Texas Railroad Commission

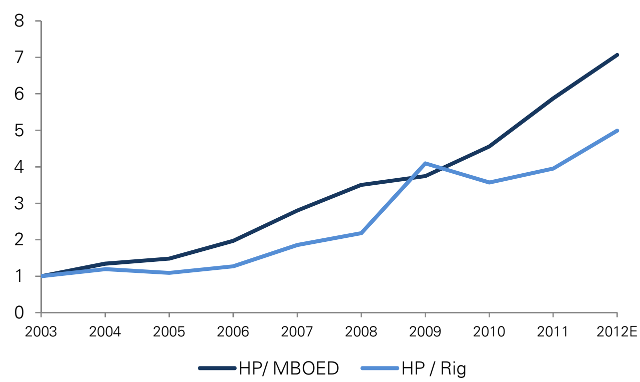
Although a variety of factors have played a role in the improving performance, including technical understanding of the reservoir and improved efficiency/repeatability of well completions, two of the largest drivers have been longer lateral lengths and more/larger frac stages. In the Bakken, lateral lengths have generally doubled from 5,000 to 10,000 ft, while frac stages have increased from ~10 to 30 stages on average, with many wells in the 35-40 stage range.

Figure 21: Lateral length increased from 2008 to 2011



Source: Deutsche Bank, NDIC

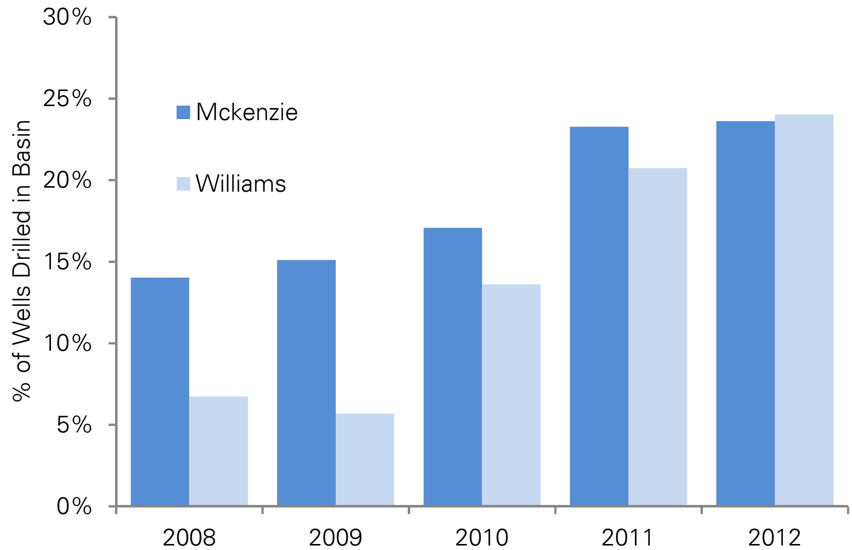
Figure 22: Frac stages & Well Complexity have risen



Source: Deutsche Bank Oil Services Team, Spears & Associates, Baker Hughes

Further, as well results have improved and leasehold requirements have been achieved, drilling activity has increasingly shifted to the most productive areas of the play. For example, since 2010, McKenzie and Williams Counties, which have the highest average IPs in the play, have increased from ~30% to ~50% of drilling activity. When taking a closer look at the individual well data, the increase towards pad drilling, particularly in core areas of the play, is evident in the slight uptick seen in average well IPs in the basin wide data in mid-2012 (see Figure 19). After relatively flat average well results since early 2011, a higher concentration of drilling in some particularly productive fields increased average basin IPs by nearly 100 boepd. We expect that this will remain a factor in 2013 as the shift towards pad drilling continues, although this effect will fade and eventually reverse over the coming 12-24 months dependent upon the pace of development.

Figure 23: Drilling activity shifting towards most productive counties



Source: Deutsche Bank, NDIC

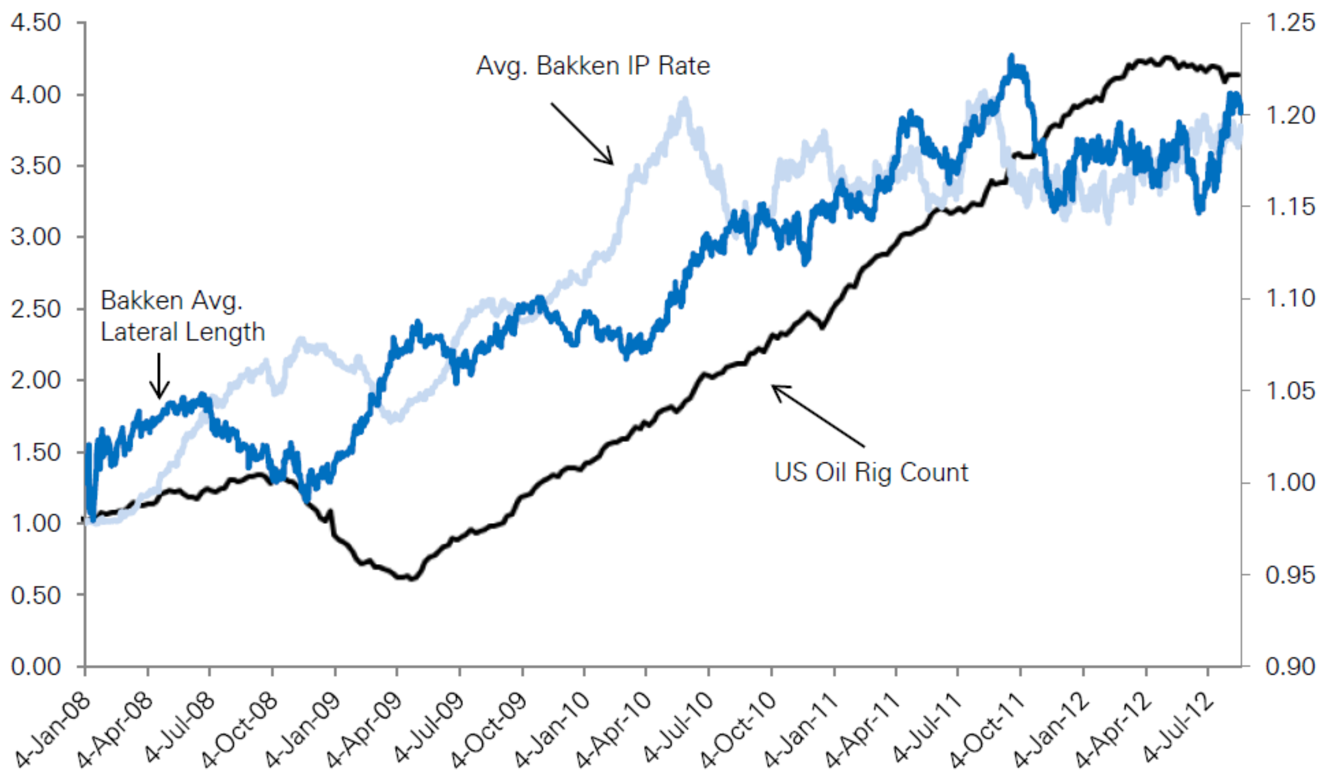
The second leg of improvement likely to focus on capital efficiency, cost control and drilling inventory

Given a proper understanding of many of the drivers behind the rapid growth of 2010-2012, the logical extension is: Are these trends sustainable? And if not, what is the impact on growth as they begin to slow or plateau? What does the second phase of production growth look like in an unconventional play?

While the first (and most accelerated) leg of oil growth was driven by a combination of brute force of capital deployed and technical innovation, the second phase appears to be focused on capital efficiency, cost control and drilling inventory, partially because the low hanging fruit has already been harvested. While history has made us cautious in calling for a moratorium on further technological innovation, the reality is that, for the time being, most of the early growth drivers have plateaued, or at minimum are well into a stage of diminishing returns. And while cost control and inventory duration may be positive for corporate financials and cash flow multiples, neither is likely to prevent a deceleration in the pace of growth across these basins.

A cursory glance at charts in the prior section of rig count, well IPs, lateral lengths, and drilling efficiencies tell a similar story: the rapid improvement from 2008-early 2011 has largely leveled off by 2012. Presented in a single format below, we have included the relative change in each metric, indexed to 2008.

Figure 24: Significant drivers of 2009-2012 growth have slowed, plateaued or rolled over



Source: Deutsche Bank, NDIC, Baker Hughes

The takeaway is not that we anticipate peak production in the near-term, on the contrary, our models indicate production growth through 2020 (and likely beyond). What is dangerous, however, is an extrapolation into the future of the growth rate that we have seen over the past three years, either in growth rate or in absolute number of barrels added. Without the significant contribution of a rising rig count or improving well results (IPs, EURs), we expect that growth will slow, both in rate and barrels added per year, as the declining base grows in size relative to new production.

Although it is difficult, with limited production history, to analyze these trends over the cycle of a field, a number of case studies, are instructive, both in oil (Sanish/Parshall) and gas (Fayetteville).

As rig count growth slows, drilling efficiency picks up the slack

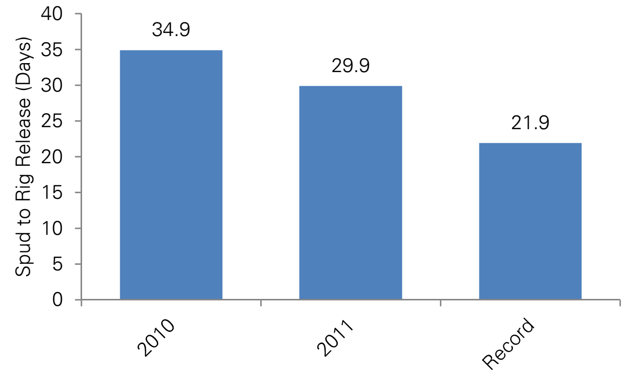
As the oil directed rig count has slowed and rolled over (current level is 1,100, down from 1,195 in May of this year), drilling efficiencies have picked up the slack, allowing the number of drilled and completed wells to continue rising. Driving this increase has been basic improvements in rig and completion technology, improved manufacturing processes and capacity, and the gradual shift to pad drilling. In the Bakken, average drilling days (spud to spud) has decreased from over 50 days in 2010 to 30 days or less currently. In the Eagle Ford, the story is similar, having improved drill times from 14 to 7 days.

The net result of the improvement has amplified the impact of a rising rig count, and in the absence of further rig additions (most company budgets currently forecasting flat rig counts into 2013), will support continued growth in well completions.

Figure 25: Improved Drilling Efficiency (Eagle Ford)

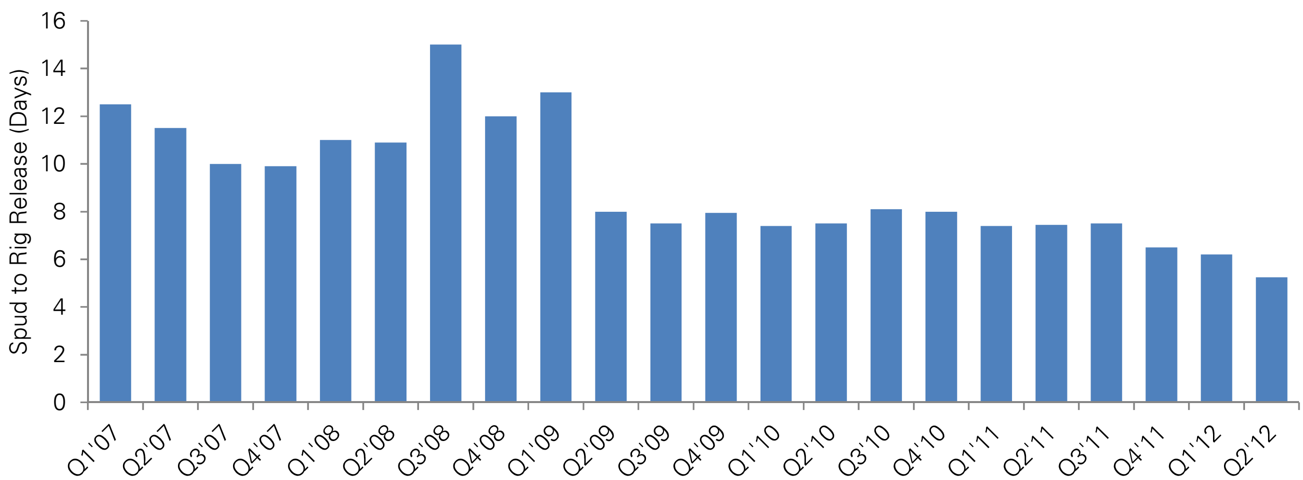
Note: Spud to Rig Release dates from initial drill contact with the ground to rig moving offsite
Source: Deutsche Bank, Anadarko Operations Update

Figure 26: Improved Drilling Efficiency (Permian Unconventional)



Note: Spud to Rig Release dates from initial drill contact with the ground to rig moving offsite
Source: Deutsche Bank, Anadarko Operations Update (Bone Springs)

Figure 27: Improved Drilling Efficiency (Representative Natural Gas Basin)



Note: Spud to Rig Release dates from initial drill contact with the ground to rig moving offsite
Source: Deutsche Bank, Anadarko Operations Update (Greater Natural Buttes)

Figure 28: 2H 2012 Rig Count Efficiency

Company	Ticker	Play	Rig Counts 1H	Rig Counts 2H	Comments
Oasis Petroleum, Inc.	OAS	Bakken	10	10	Will keep the rig count flat and will not ramp the originally planned 12 rigs.
Continental Resources, Inc.	CLR	Bakken	25	19	Company wide, capex increased 30% and prod guidance revised up to 58% from 52% (midpoint) yoy, as rig count falls to 29 from 44 due to drilling efficiencies.
Kodiak Oil & Gas Corp.	KOG	Bakken	6	7	Drilling days has been reduced by 3-5 days per rig. Will not go to an originally planned 8 rigs.
Whiting Petroleum Corp.	WLL	Bakken	20	17	Each rig is now drilling ~12 wells vs. the previous est. of 10 wells.
Anadarko Petroleum Corp.	APC	Eagle Ford	9.5	9	Reduced spud to rig release days to 10.5 vs. 12.4 in Q1.
EOG Resources, Inc.	EOG	Eagle Ford	26	20	Will drill 330 net wells in 2012, up from previous guidance of 300.
SM Energy Co.	SM	Eagle Ford	6	5	Dropping an older less efficient rig.
Chesapeake Energy Corp.	CHK	Eagle Ford	28	25	Efficiency gains have resulted in 15% cost savings per well in Q2.
Marathon Oil Corp.	MRO	Eagle Ford	18	18	Due to drilling efficiencies, MRO will not ramp to 20 rigs as originally planned.
Concho Resources	CXO	Permian	37	33	Previous 2H rig count target was 43. Company anticipates the current target rig count of 33 rigs will be sufficient to deliver within production guidance of 28.7 - 29.8 mboe/d
Cimarex	XEC	Permian	14	14	Flat rig count relative to earlier indications of adding rigs in the Permian during the year.
Pioneer Natural Resources	PXD	Permian	40	30	Vertical rig program ramped down sooner than planned, with the option of dropping an additional 3 rigs. The reduction of rigs is due to the mix of lower commodity prices and greater production from deeper Spraberry wells.
Continental Resources, Inc.	CLR	Cana - Woodford	10	7	Rig count falling due to drilling efficiencies. See above for details.
Cimarex	XEC	Mid - Cont	11	7	Drilling has been outpacing completions, creating a backlog of wells.

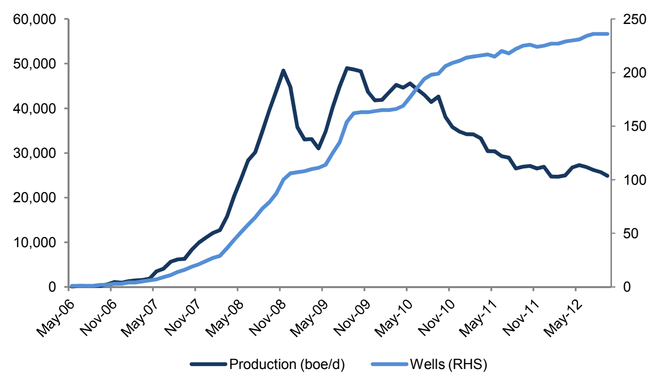
Source: Deutsche Bank, Company Data

Sanish and Parshall - microcosms of the broader basin

For additional insight into the dynamics of future production in the Williston basin, we have examined the history of the Parshall and Sanish fields, which commenced production in 2007 and 2008, respectively. Located at the Eastern edge of the Williston Basin, and enhanced by natural fracturing, the Parshall and Sanish fields have been the premier operating regions of the basin. They are also the furthest along the maturity curve, with Parshall well into downspacing, and Sanish approximately 75% into its forecast drilling inventory.

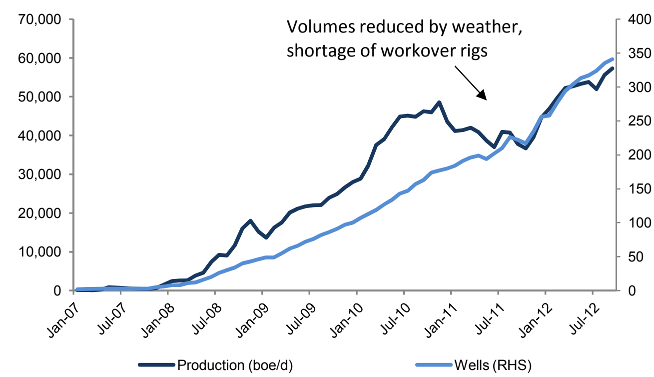
A look at the production history of Parshall and Sanish demonstrate a couple of important trends, neither of which is surprising: 1) Given high declines, a slowing in the pace of drilling will have an adverse effect on production (Parshall), and 2) Even at a steady pace of drilling, growth rate will slow materially as the field matures, from the combination of deteriorating inventory and field declines (Sanish).

Figure 29: Parshall rolled as drilling slowed



Source: Deutsche Bank, NDIC

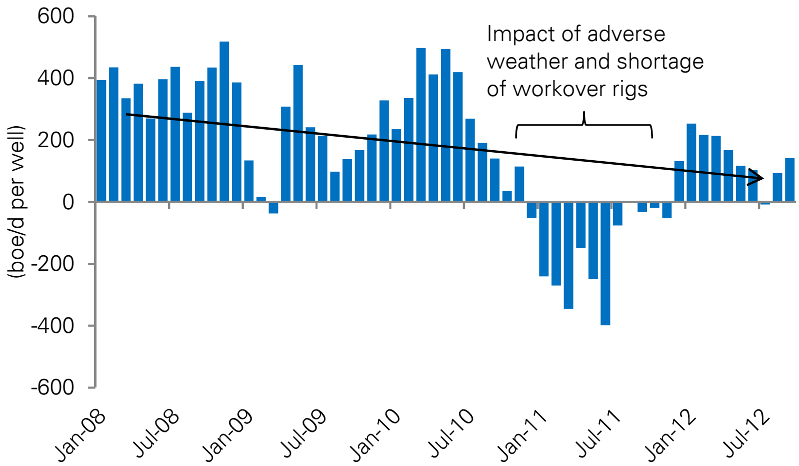
Figure 30: Sanish growth slows as field matures



Source: Deutsche Bank, NDIC

Important to consider, producers have more recently shown some success returning to core fields particularly in the Bakken to drill in-fill wells. In the case of EOG Resources, one of the dominant operators in the Parshall field, the effort has been to return to the field and drill 320 acre wells (vs. 640 acre spacing initially). Recent results suggest that wells are highly economic, and the most recent frac approaches (initial wells drilled 3-4 year ago) are improving recovery from both new and existing well bores. This is a clear indication of the duration of quality oil resource, as recovery rates are increased in prospective areas. While highly accretive and attractive investment opportunities, we do not expect this type of field revitalization to significantly address the trends outlined above. While Parshall field declines are likely to be shallowed and even stemmed, additional recovery is unlikely to return the field to growth. Due to the desire to begin water flooding the field, we expect EOG Resources to accelerate downspacing efforts in the year ahead with an inventory of ~100 downspaced wells a priority.

Figure 31: Volume growth per well slows as the field/inventory matures (Sanish)



Source: Deutsche Bank, NDIC

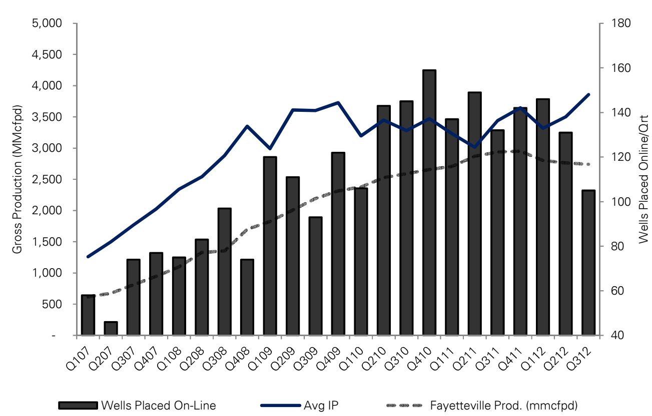
It's Not Just an Oil Thing

The impact of peaking well productivity on total field production growth is not just a dynamic witnessed in oil plays. The hyperbolic decline curve of unconventional wells, drilled in faster succession with improving individual well characteristics created explosive growth in natural gas just as it did in the Bakken and Eagle Ford. In a similar trend, the peak in initial production rates was the peak in production growth rates. Incremental growth beyond this point must come from more activity, drilling, and wells.

The Fayetteville shale in Arkansas provides a good case study in this dynamic. While a play that enjoyed preferential economics vs. other early shale plays (Barnett, Woodford) the play also benefitted from the significant learning curve achieved in previous plays. Due to its discrete size and limited participants (field development was dominated by Southwestern Energy, XTO Energy, and Chesapeake Energy) the play provides a clear look at the dynamic outlined above. As outlined below based on disclosure from Southwestern, production grew rapidly as increasing numbers of wells were drilled, however the key driver was a continual move higher in the initial production rate (as indicated by 30 day initial production). Concurrent to a plateau in initial production rate (horizontal leg and fracs were likely optimized) the pace of production growth began to slow. Further, production growth was supported by a higher quality of drilled wells with increasing lateral length, however production growth never returned to its peak rate apparent when all drivers were moving in the right direction.

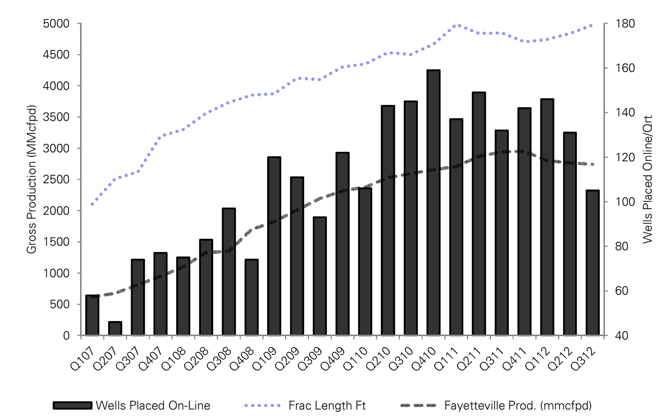
More recently, initial production rates have been on the incline again due to the 'high-grading' of locations at Southwestern works to drill its best (most economic) wells in the field due to lower commodity prices. This uptick in initial production rate (achieved via cherry picking the best locations) has been offset by a falling rig & well count. Accelerating production growth is likely in the past for the Fayetteville as improving incremental initial production rates and accelerating the well would likely require a further high grading of locations which would in turn shrink the inventory of economic wells.

Figure 32: Production Growth Slows Once IPs Plateau



Source: Southwestern Energy, AOGC, Deutsche Bank

Figure 33: More & Longer Wells Do Not Offset



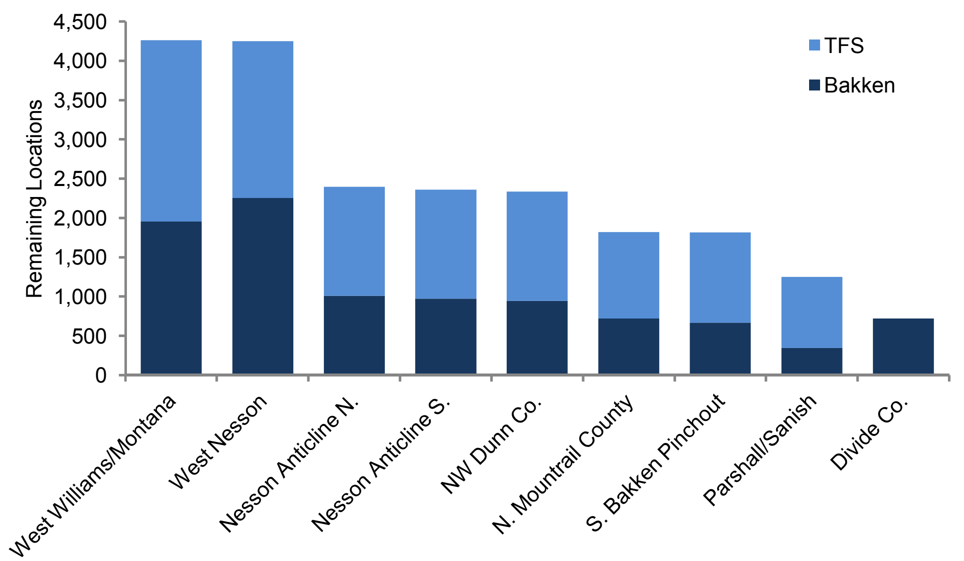
Source: Southwestern Energy, AOGC, Deutsche Bank

Inventory - Piecing together one of the final pieces of the puzzle

While trends in rig count and well performance may dominate the pace of production growth, *sustainability* will largely be determined by inventory: As development progresses, the industry (and investors) will increasingly wrestle with the amount and quality of remaining inventory, and the question of when declining quality of inventory become evident in deteriorating well performance.

In order to put some context around sustainability of growth, we have estimated inventory levels in both the Bakken and the Eagle Ford. In the Bakken, using Wood Mackenzie, we have estimated prospective acreage across the Williston Basin (~4.6 million acres), which has been divided into nine different regions. Average well spacing across each of the regions has been assumed (generally 3-4 wells per drilling unit in each horizon, Middle Bakken and Three Forks), adjusted for currently producing wells in each region. We estimate current remaining drilling inventory of ~21,000 wells, or approximately 10 years of drilling inventory at the current pace of drilling.

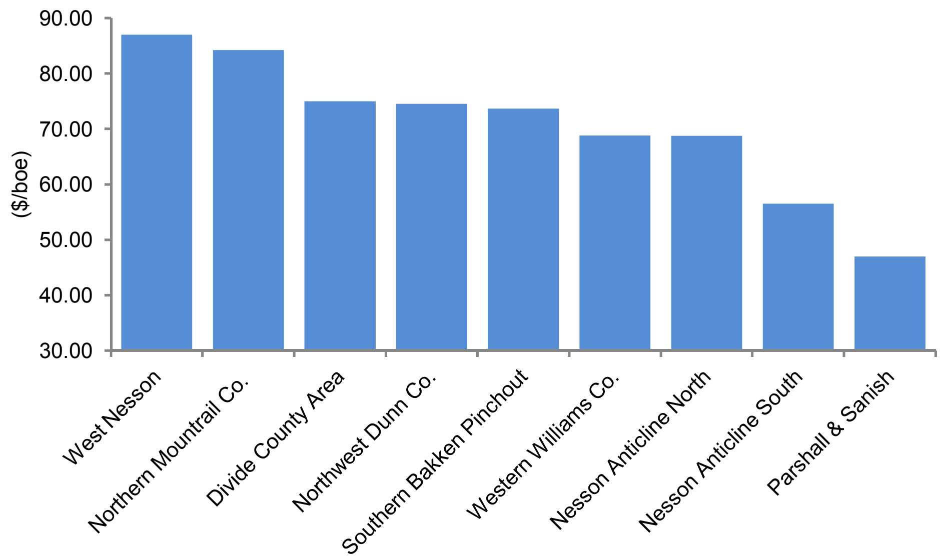
Figure 34: Remaining inventory by operating area



Source: Deutsche Bank, Wood Mackenzie

Based on projected EURs (calculated from historical production data in each region), and estimated well costs, we can estimate the average breakeven oil price (single well economics only) associated with each bucket of inventory. As would be expected, the area just to the west of the Nesson Anticline and the northern operating regions (North Nesson and Divide County) require the highest breakeven oil price, with core areas near Sanish and Parshall winning the award as most economic.

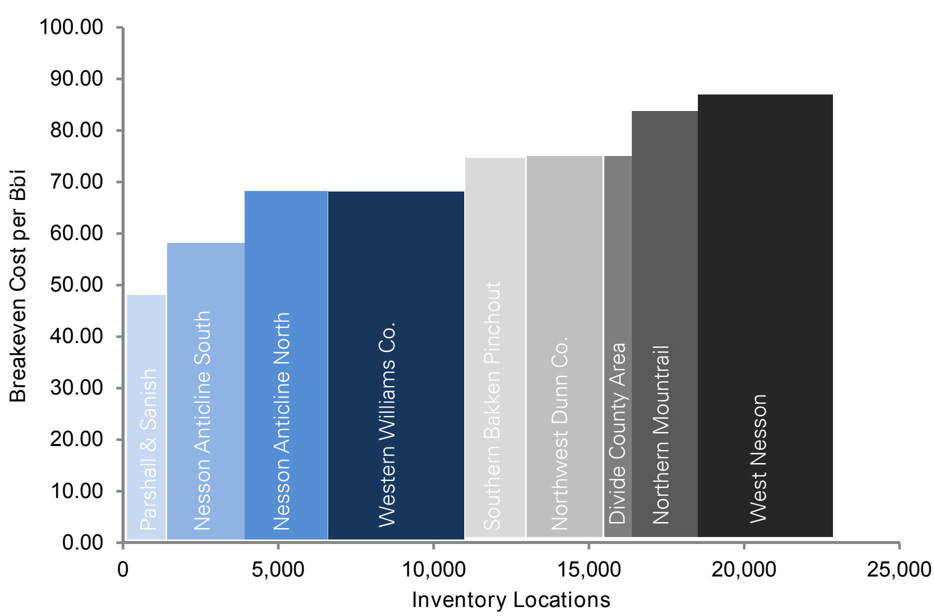
Figure 35: Single well breakeven price by sub-play



Source: Deutsche Bank, Wood Mackenzie, NDIC

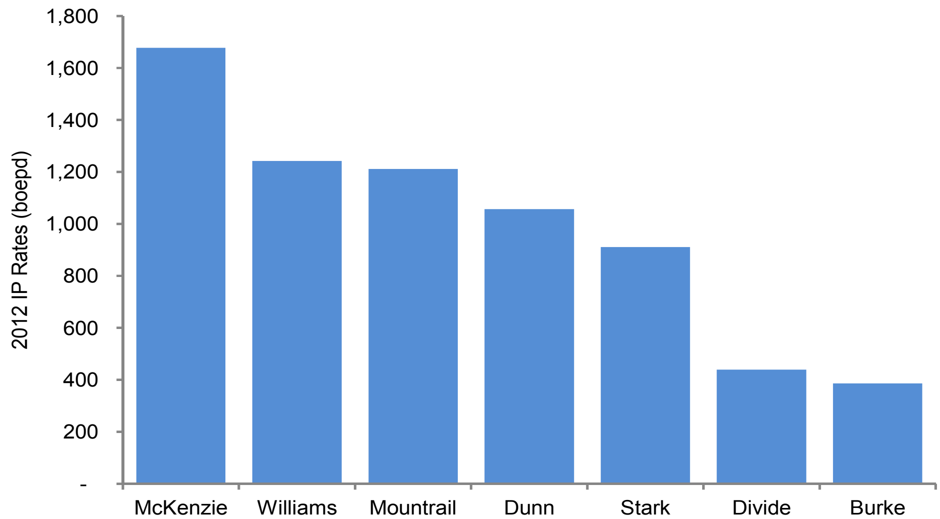
By combining the two, we can create a "cost curve", showing the oil price necessary to support each incremental tranche of inventory (on average). Unsurprisingly, the exercise shows a relatively wide range of average economics across the play, with less than 5 years of inventory remaining below $75/bbl. It is important to note, however, that these single well economics are unburdened for the cost of acquiring inventory, supporting overhead (G&A) expenses, interest payments or infrastructure costs, which would driven actual "breakeven" economics significantly higher.

Figure 36: Breakeven cost curve by relative inventory



Source: Deutsche Bank, Wood Mackenzie, NDIC

Figure 37: IP Rates Not Created Equal

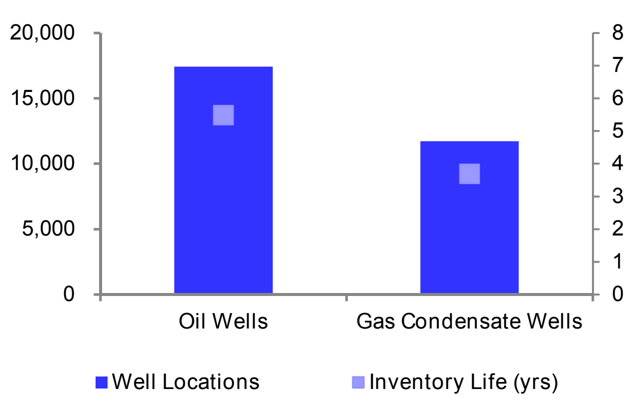


Source: Deutsche Bank, NDIC

From a high level, we are still very early in the development drilling process, having drilled no more than 20% of total inventory, and probably much less, as downspacing progresses (Fig. 36). However, with drilling increasingly shifting towards the core areas of the basin, we are likely to see a gradual deterioration of results a couple of years out as we move further down the quality spectrum. While the dynamic may result in an underestimation of near term production, as we have seen to date, but an overestimation of potential growth in the latter half of this decade.

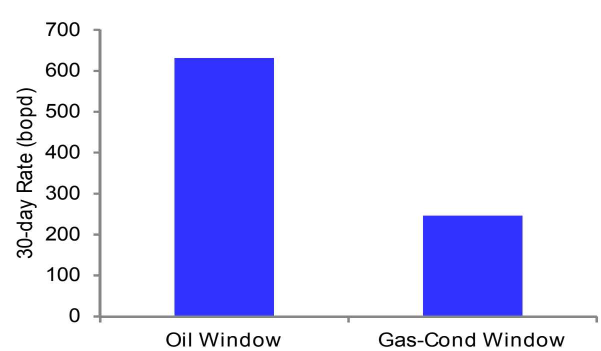
Eagle Ford inventory paints a similar picture. Based on an estimation of approximately 5.0 million acres in the basin (~2.3m acres in the oil window and 1.6m acres in the gas-condensate window), and an average well spacing of 120 acres, we estimate liquids focused inventory of ~29,150 in the play, of which roughly 60% is in the oil window. At a current rig count near 200, drilling over 3,100 wells/year, we see just under 10 years of inventory life at 120 acre well spacing. Similar to the Bakken, there is a wide variance in quality of the inventory across the play, particularly in the rate (or share) of oil produced. Despite high returns, wells in the gas-condensate window produce 60% less oil than wells in the oil window.

Figure 38: ~9 years of inventory at 120 acre spacing



Source: Deutsche Bank

Figure 39: 60% less oil production in Gas-cond window



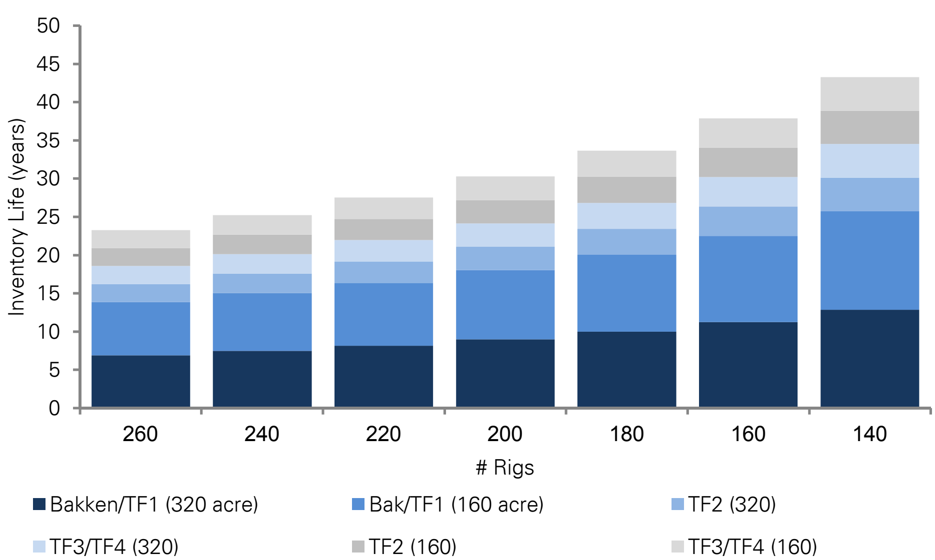
Source: Deutsche Bank

Upside risks abound on inventory – but will it impact pace, or just duration?

Of all of the dynamics discussed to this point, inventory levels are the most likely to surprise to the upside. While our analysis largely gives risked credit for 3-4 wells per drilling unit in the Middle Bakken and the 1st Three Forks, momentum is building behind the potential to downspace even further, with additional horizons potentially productive as well in the 2nd 3rd and 4th Three Forks. Continental Resources is leading the charge in this regard, with initial results promising in the 2nd and 3rd TFS (1,023 boepd, 1,396 boepd and 953boepd initial production rates) and an ongoing pilot program testing 160 acre spacing (ie. 8 wells per drilling unit). While downspacing and lower benches may only be prospective across part of the total basin acreage, the increased inventory may meaningfully impact sustainability.

We would argue, however, that unless increased inventory is associated with a higher level of eventual rig activity, the additive locations will have little impact on pace of growth, but will mainly serve to prolong the onset of eventual declines – particularly given the potential degradation in additional locations (Ryder Scott Co. LP, reservoir consultants, currently estimates 30% loss of reserves at the 8th well in a drilling unit, while downspacing is also more likely in fringe, rather than core, acreage).

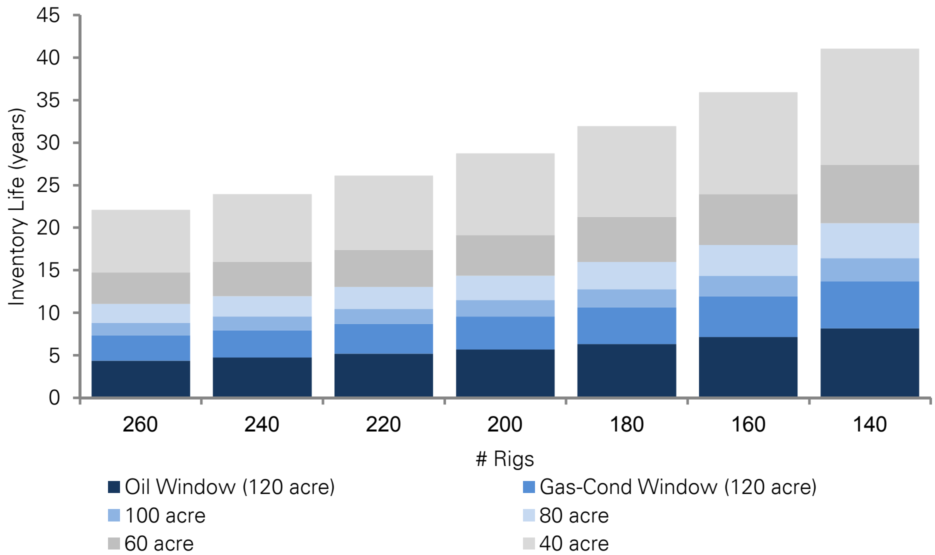
Figure 40: Bakken: Downspacing, Lower Benches and Rig Count vs. Inventory Life



Source: Deutsche Bank, NDIC, Wood Mackenzie

In the Eagle Ford, although we assume 120 acre spacing in our base case, large parts of the core have are already indicating likely development spacing of closer to 80-100 acre spacing, with some regions even testing as tight as 40 acre spacing. The impact on inventory is dramatic, with inventory life shifting from 9.6 years at the current rig count to 14.4 years at 80 acre spacing.

Figure 41: Eagle Ford: Downspacing vs. Inventory Life



Source: Deutsche Bank

The Economics of Unconventional Development

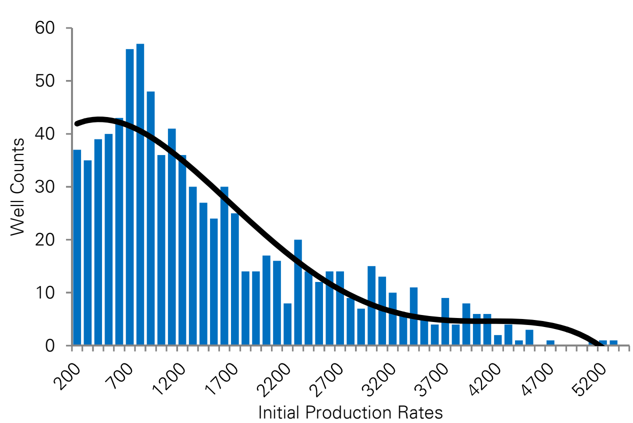
Project and well level economics provide the linkage between production trends witnessed across the industry and the producers that are generating this growth. The primary focus of this report is the unconventional oil resource opportunity and what the life cycle of unconventional plays and single well results suggest. However, project and well level economics provide an important underpinning of the supply equation.

Our work continues to support the view that marginal cost for unconventional light oil supply approaches $80/bbl WTI. Further, we see an important differentiation between single well returns and corporate level decision making and cash flow which further informs this view that $80/bbl will act as a near-term point of resistance for WTI supply. Below we outline project level returns and corporate funding outlooks for major North American liquids growth contributors which support a view that supply growth will slow if prices do not hold ~$80/bbl levels on a sustainable basis.

Half-cycle returns belie true project economics

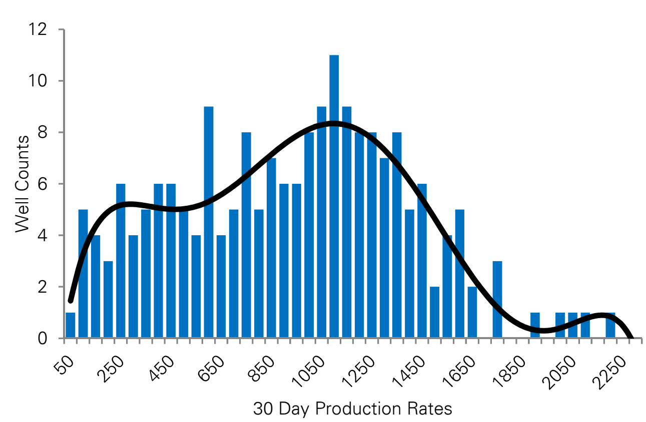
In a commodity market where supply can meet demand, expectations are that prices will fall to marginal costs. As a result, we focus on 'half-cycle' returns at the well level for unconventional plays. This analysis includes direct costs (capital and operating) and net resource capture over the expected production profile of a single well. This analysis includes nothing for either cost of leasehold acquisition, corporate overhead, dry hole and science/learning expense of initial wells. This analysis also considers 'average' well economics as representative across a play. While the benefits of unconventional development are the predictability and repeatability of wells, well level results suggest more significant divergence between results.

Figure 42: Bakken Observed Initial Production Rates



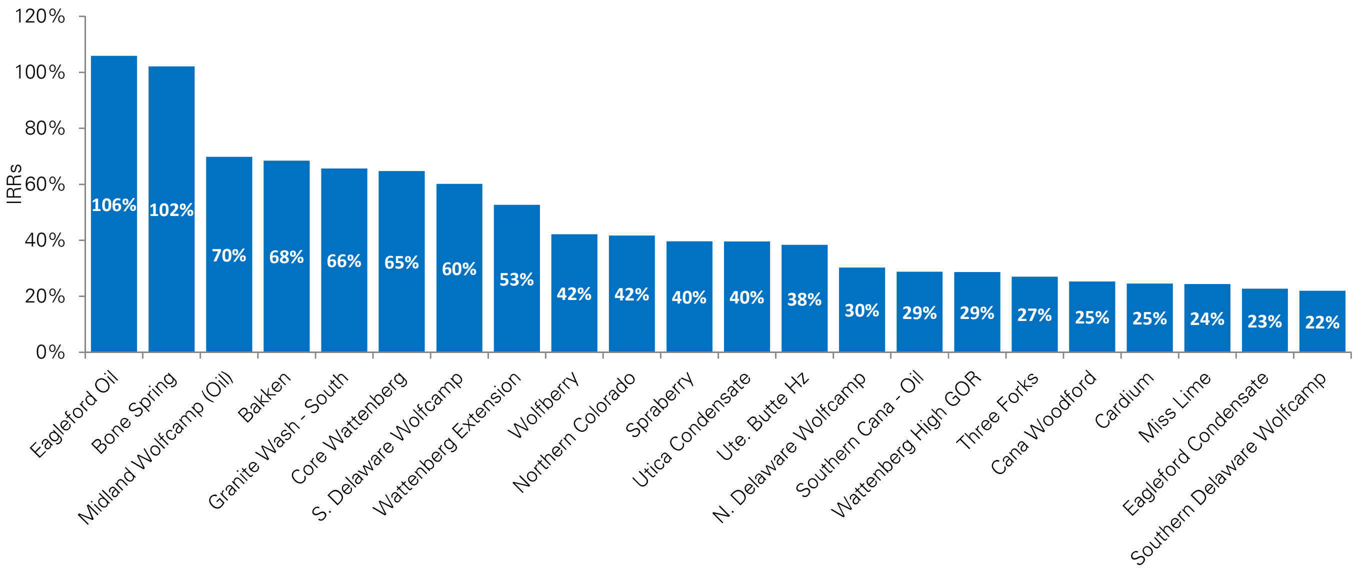
Note: Data per NDIC for Mackenzie Ct. North Dakota
Source: NDIC, Deutsche Bank

Figure 43: Eagle Ford Observed 30-Day Production Rates



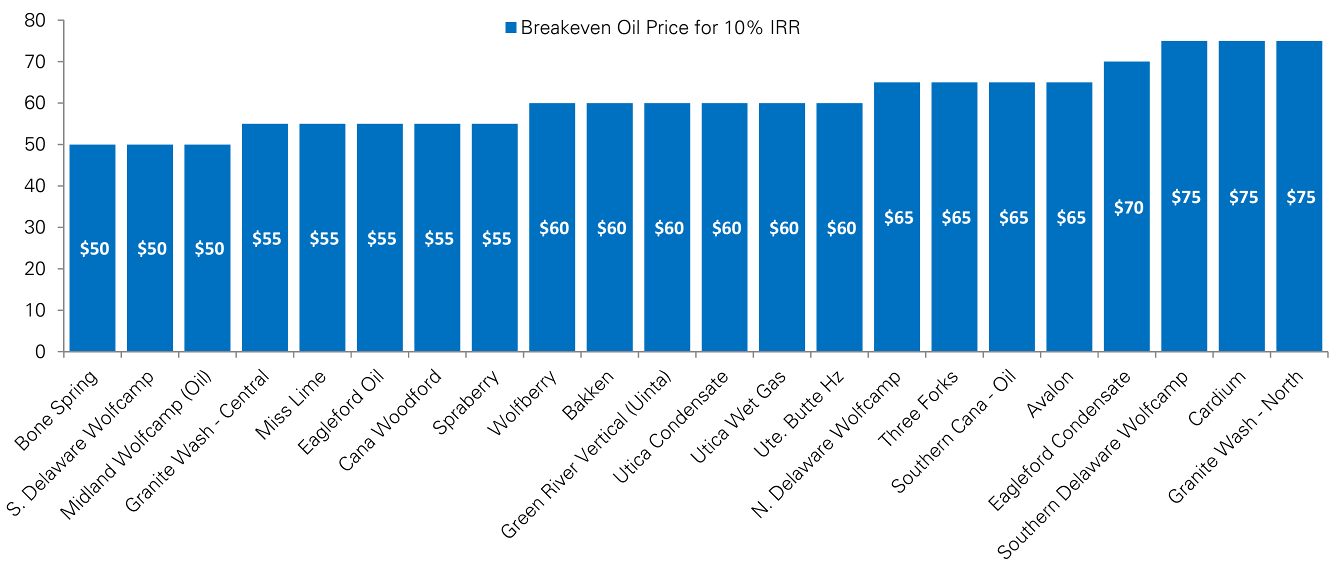
Note: Data per Texas Railroad Commission, DeWitt Ct Texas.
Source: Deutsche Bank, Texas Railroad Commission

Figure 44: Single Well Returns – Only half (cycle) of the story



Note: Based on single well economics. Assumed commodity pricing of 90/bbl, $4.00/mmbtu, and NGLs at 40% of WTI.
Source: Company Reports, Deutsche Bank estimates

Figure 45: Single Well Breakevens ($/bbl WTI for a 10% IRR)

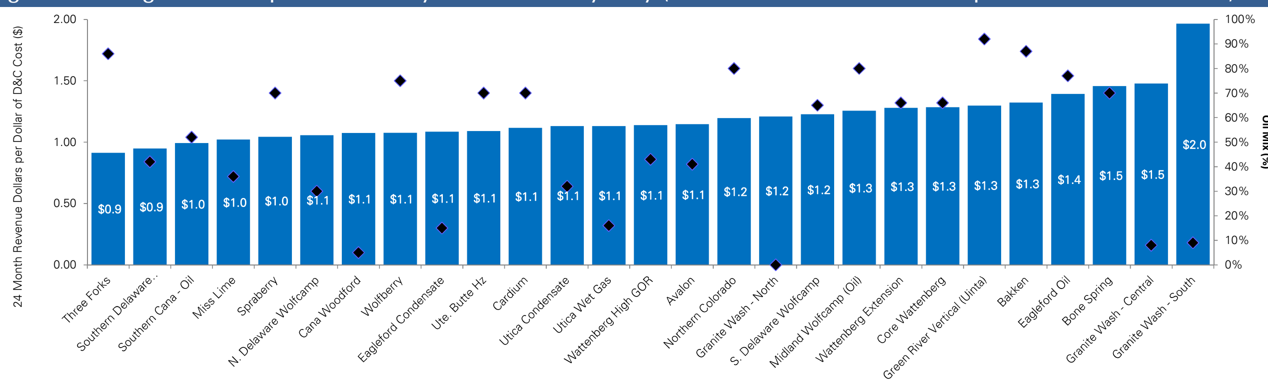


Note: Based on single well economics. Assumed commodity pricing of 90/bbl, $4.00/mmbtu, and NGLs at 40% of WTI.
Source: Company Reports, Deutsche Bank estimates

Building growth on a base of unconventional production creates a number of challenges for the industry, which is important to consider in regards to economic decision making. First, the hyperbolic decline curve of tight reservoirs (oil or gas) create a challenge to growth. Single well profiles decline rapidly from high initial production rates. While positive for net present value as wells achieve payout rapidly (vs. linear, lower rate wells) the challenge is to build and grow a production base from the sum of high decline wells. This dynamic contributes to two factors that serve to limit and reduce returns from the unconventional upstream. First, the prerogative to grow production and cash flow means capital commitments extend far beyond a single well and into a multi-year developments. Second, capital is reluctantly withdrawn from plays when returns compress as production declines are likely to rapidly ensue.

Diverging commodity prices have also created a challenging environment for the upstream as the production mix is a significant driver of underlying economics. At the well level, the commodity mix also has an impact on flow rate and the ultimate net present value of the resource (gas & NGLs will flow at higher rates, but contribute lower value). In addition, the production decline characteristics outlined above, this dynamic is a significant driver of capital efficiency for the upstream. Below we outline capital efficiency in terms of capital deployed vs. revenue generated over the first 24 months (2 years). At the assumed commodity prices (approximating the current forward curve) the highest efficiency ($/revenue) is still generated by higher rate liquids (NGL) wells vs. many of the oil focused plays in our sample size. Accelerating returns and capital efficiency continues to remain a key driver for the equities and an area of market focus.

Figure 46: Single Well Capital Efficiency and Oil Mix by Play (24 Month Revenue Dollars per Dollar of D&C Cost)



Note: Based on single well economics. Assumed commodity pricing of 90/bbl, $4.00/mmbtu, and NGLs at 40% of WTI.
Source: Company Reports, Deutsche Bank estimates

Building a full-cycle understanding of returns

As producers never drill single unconventional wells, producers must bear entry costs for new plays, and absorb corporate overhead, returns should be considered on a project basis inclusive of these important cost drivers. Beyond corporate level cash flows (which we outline below) we consider project level economics at the play level fully burdened by full-cycle cost elements. While most E&Ps operate in multiple basins, which increases costs and can dilute returns, we consider a project development of a single play. Major assumptions are outlined below.

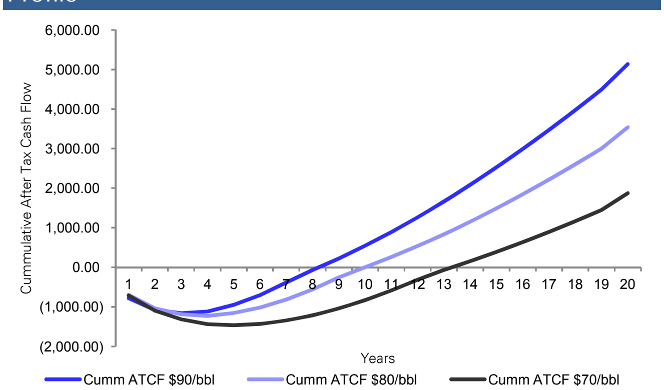
- In the Bakken, we assume the acquisition of 200k net acres for an entry cost of $2,500/acre (lower than current market but representative). We assume average West Williston well economics of $9 mm drill & complete costs for ~600 mboe EUR. We assume a fixed $10/bbl price differential vs. WTI. In terms of other costs we assume $100 mm over the first 4 years of development for infrastructure costs (gathering and transport) and assume a 5% of sales ($3.50/boe) as corporate overhead / G&A expense.
- In the Eagle Ford, our model assumes a comparable $2,500/acre entry cost for a 200k net acre position. We assume transition zone economics (~33% oil / NGL / natural gas split). We assume average well economics of $8 mm drill & complete costs for ~1,000 mboe EUR. We assumed realizations flat to WTI for crude pricing and a 60% discount to WTI for NGLs. In terms of other costs we assume $100 mm over the first 4 years of development for infrastructure costs (gathering and

transport) and assume a 5% of sales ($2.50/boe) as corporate overhead / G&A expense.

Reflecting some of the difference we outline between single well economics and total development programs this approach yields divergences in terms of unlevered after-tax IRR. Our fully burdened (all entry & overhead costs applied to single well of a program) reflect a 35% IRR in the Bakken and a 56% IRR in the Eagle Ford (at $90/bbl and $4/mmbtu flat commodity price). On a total project basis these returns fall to 18% and 24% respectively, reflecting the impact of overhead, entry costs, and replacing production declines.

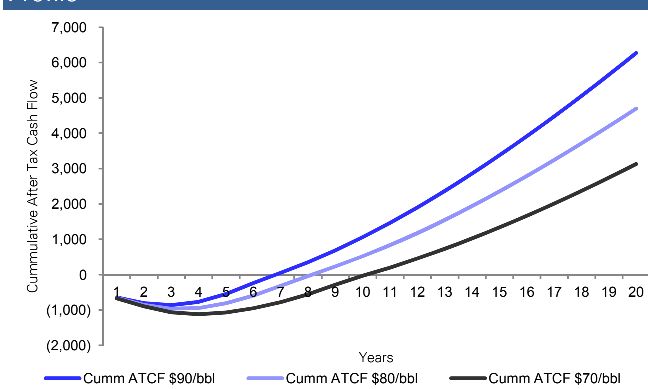
A more transparent view of the economics of unconventional development comes from the cumulative cash flow profile of our project model. Burdening the projects with the same costs (entry, overhead) and considering sensitivity to lower oil price. This analysis highlights the challenge to full cycle returns created by the growth by acquisition model in E&P, in our view. High entry costs create higher hurdle rates of return for incremental well economics and the timing of development which must deliver on expectations. Acquired resource places the onus of execution on management teams. In terms of cumulative cash flow, below we outline the cumulative cash flow (undiscounted) associated with our project models. Importantly, sensitivity between our base case expectations (reflected in our NAVs today) of $90/bbl and the lower-end of expectations closer to $70/bbl shows significant impact to project breakeven. Bakken payback periods in this scenario are hurt by our assumption of a fixed transport cost ($10/bbl) vs. a % of WTI analysis. The impact of these and other fixed costs means that cash flow breakeven at $80/bbl is 8 years while $70/bbl is 12 years. Eagle Ford continues to benefit from geographic locations (access to preferred crude and NGL markets on Gulf Coast) and as a result shows lower sensitivity to lower commodity prices. $70/bbl realizations limit project payback to 9 years vs. 5 years at $90/bbl.

Figure 47: Bakken Project Co. Cumulative Cash Flow Profile



Note: Development assumptions include 10 Rigs drilling LT, with 28 days drilling per Well. We assume $4 flat gas price.
Source: Deutsche Bank

Figure 48: Eagle Ford Project Co. Cumulative Cash Flow Profile

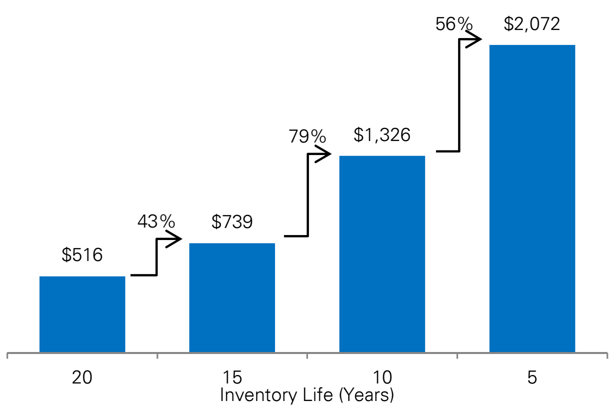


Note: Development assumptions include 10 Rigs drilling LT, with 30 days drilling per Well. We assume $4 flat gas price.
Source: Deutsche Bank

Inventory Optimizations also an Important Consideration

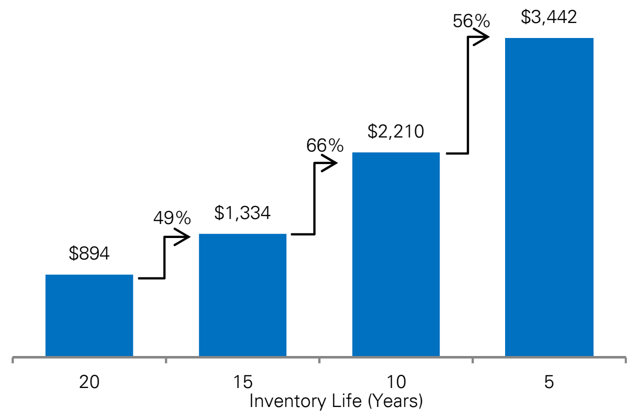
In considering the value creation potential of an unconventional play, an important consideration is the perceived inventory of future drilling opportunities. In order to maximize present value, producers must consider the right development plan to bring forward resource in consideration of a number of constraints including capital, rigs, labor, infrastructure etc. Resource that is economic but not in the foreseeable horizon of achievable drilling targets, is likely considered for divestiture. Below we outline a number of potential acceleration scenarios based on the same project economics outlined for the Bakken and Eagle Ford above. While more resource, faster is always more NPV accretive, we find it of note that rapid acceleration entails diminishing returns (moving below 10 years of drilling inventory, will see the rate of NPV accretion slow) while perhaps a nuanced point surrounding resource development, we would also highlight that reserve life is a key contributor to valuation multiples for the E&Ps for the same reason. Producers are incentivized to protect inventory of drillable and accretive locations, particularly if other plays or resource is yet to be secured. Simply, we expect producers to work towards accelerating resource to a point approaching ~10 years of drilling inventory in major plays, and to maintain activity levels thereafter. This is consistent with our expectations surrounding the inventory of drillable locations in unconventional plays such as the Bakken (~16k locations, 1,700 annual wells drilling) and Eagle Ford (33k locations, 2,500 annual wells drilling).

Figure 49: Bakken Project NPV – Acceleration Scenarios



Source: Deutsche Bank

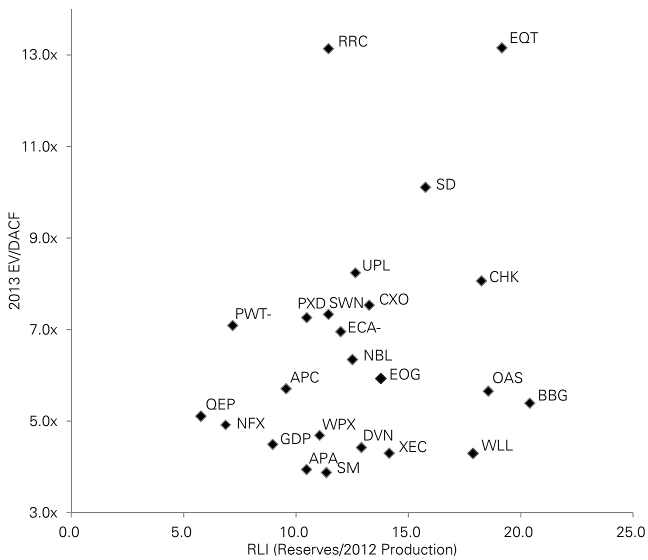
Figure 50: Eagle Ford Project NPV – Acceleration Scenarios



Source: Deutsche Bank

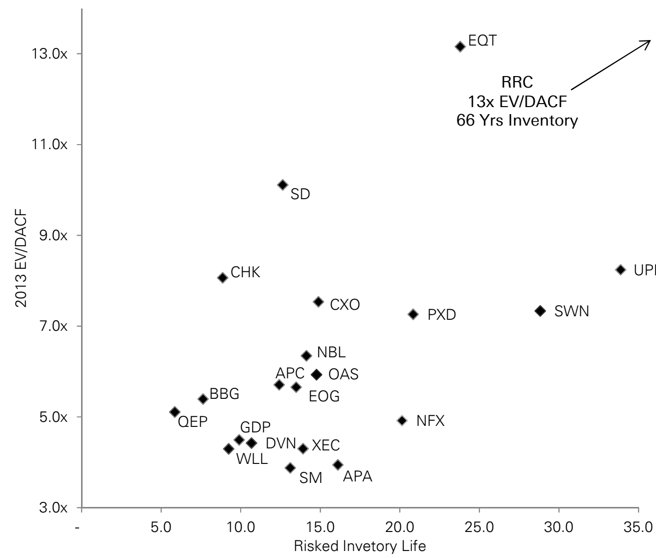
Below we underpin the view that reserve life and inventory life (of re-investment projects) is a key driver of valuation in the equity market. Below we show 2013 valuation multiples based on consensus estimates vs. both the reserve life of proved reserves (year end 2011 proved reserves / 2012 total production) and relative to our evaluation of the risked inventory life of our coverage group based on current expected drilling activities.

Figure 51: EV/DACF vs. RLI



Note EV/DACF is based off consensus estimates. While RLI is calculated using 2011 Reserve Disclosures divided by 2012E Production:
Source: Deutsche Bank, Factset, Company Presentations

Figure 52: EV/DACF vs. Risked Inventory Life



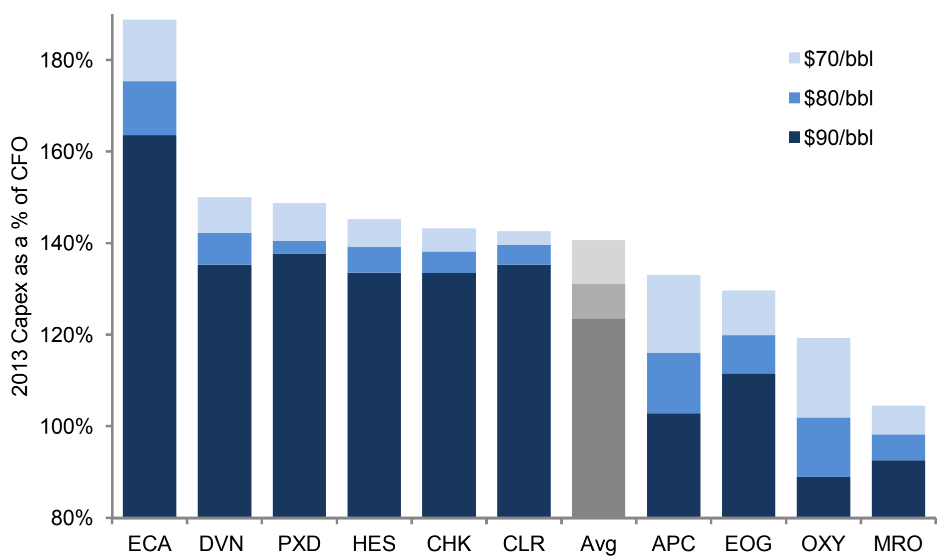
Note EV/DACF is based off consensus estimates. While Risked Inventory Life is calculated using company disclosed acreage values, drilling days, as well as DB rig assumptions and acreage risking
Source: Deutsche Bank, Factset, Company Presentations

Bringing it to the corporate level.

Our final consideration in terms of unconventional economics and the sustainability of US liquids growth is corporate level returns and cash flows. Our survey of 83 public entities includes North American liquids forecasts for 65% of the total market and the vast major of market growth. A further evaluation of this growth suggests that the top 20 producers account for 75% of total expected production growth from across North America.

While capital remains available from a number of sources (capital markets, asset sales, joint ventures) we selected the 10 largest growth contributors to North American liquids growth in 2013. While we have excluded major projects (oil sands, offshore Gulf of Mexico) from our sample, we have stress tested the expected capital expenditures of this subset of producers. Based on consensus expectations for 2013 capital expenditures for this group of producers, we have forecast organic cash flow under a $70/bbl, $80/bbl, and $90/bbl pricing scenario. While some of the more significant, well capitalized, and profitable contributors to domestic liquids growth, this sample shows capex budgets are likely balanced (~120% of organic cash flow) at $90/bbl in the aggregate for 2013, and commodity pricing below this level for a prolonged period may drive downward revisions to the capital expenditure (and resulting production growth) outlook.

Figure 53: The reality of funding liquids production growth



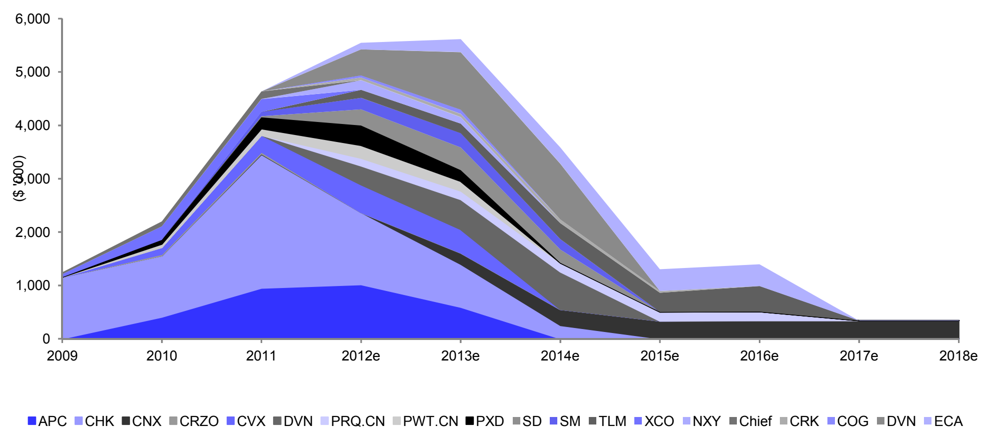
Note: 2013 Capex is based on Factset consensus. CFO is calculated with $90, $80 and $70/bbl
Source: Deutsche Bank, FactSet

Sensitivity to Commodity Price Set to Rise for North American E&Ps

A further consideration surrounding industry funding has been the significant number of joint ventures secured in North America. Domestic producers have tapped this market to secure funding for the early stage of development of both oil and natural gas plays. The significance of these structures, is that they provide stable funding (commitments broadly independent of prevailing commodity price) over the term of the initial period. This "carried capital" is effectively a capital subsidy for domestic producers which can be expected to reduce economic sensitivity in terms of development plans.

We continue to see fewer of these joint ventures signed and this suggests this capital subsidy will begin to wane over the coming 12-18 months. We see 36% lower capital subsidies by 2014 vs. the peak of subsidized capital we expect in 2013 at $5.6 Bn. This implies more economic sensitivity to commodity prices in terms of drilling plans on a go forward basis for North American unconventional producers.

Figure 54: <$25 Bn in Joint Venture Capital Has Subsidized Activity in North America



Source: Company Reports, Deutsche Bank

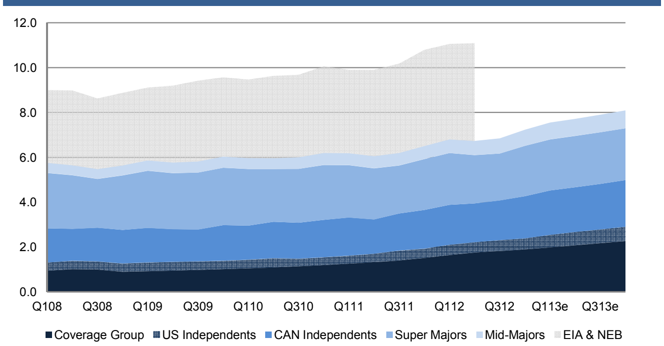
What does the Producer Data Say?

As upstream analysts, we are often asked to link the macro trends identified with what is being witnessed at the corporate level. Linking the macro data (total crude and NGL production) to what the producers are reporting and expected to report is a key step in this regard. While not all production is in public hands or even reported and consensus production forecasts can be a challenge for small producers, the trendline growth expectation is an important consideration in our analysis of domestic liquids supply.

The survey draws from 83 North American liquids producers, including SuperMajors, MidMajors, and small independents. We track actual and forecasted liquids (oil + NGLs) production for all producers in the sample using DB estimates where available and Factset consensus estimates for the remainder. Production reported by US producers is grossed up by 15% to account for produced volumes dedicated to royalties and not reported by US producers. Meanwhile, for Canadian producers, we use the gross (pre-crown royalty) production numbers. Our survey outlines the following.

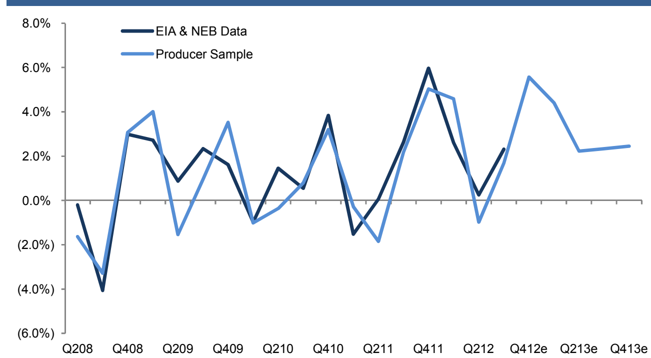
- We compare total production from our survey with macro data released by US (EIA) and Canadian (NEB) energy data sources. Our sample accounts for ~65% of total liquids production across North America and the quarterly production trend of our sample provides a good fit relative to state data.

Figure 55: North American Sample Growth Ahead of Total Market Growth



Source: Company Reports, EIA, NEB, Deutsche Bank

Figure 56: Trend Suggest Growth to Peak in 4Q12



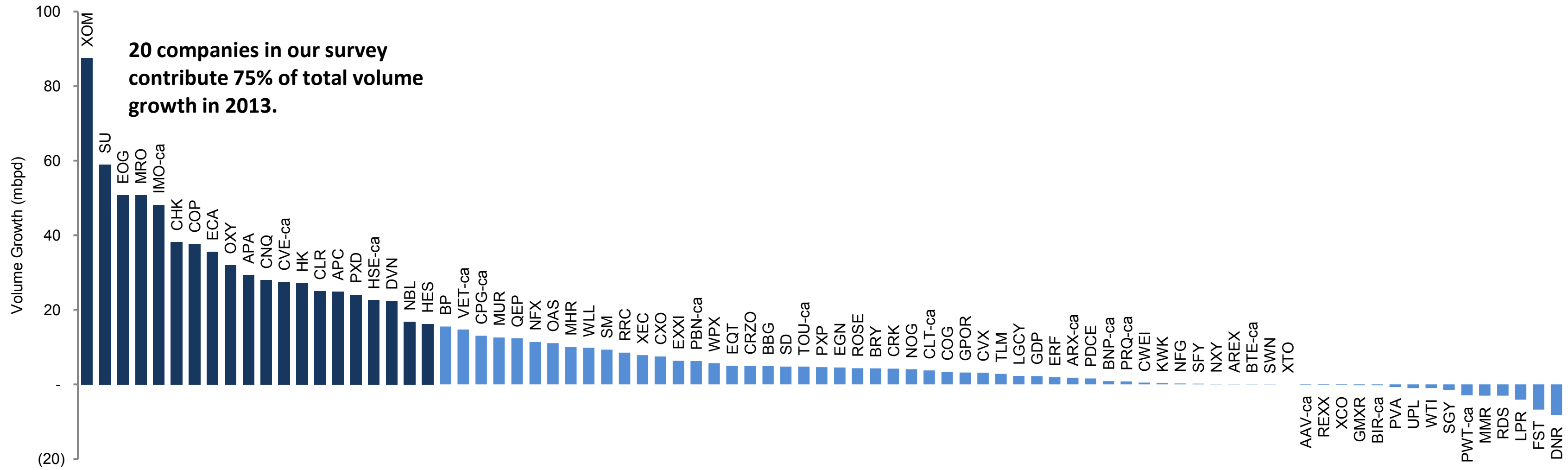
Source: Company Reports, EIA, NEB, Deutsche Bank

- DBe & street estimates reflect robust liquids growth for 2013. The sample shows growth of 1.0 mmbpd (13%) in 2013 vs. 2012 after posting 0.7 mmbpd (11%) growth in 2012. Government agencies and commodity forecasters project average 10% 2013 growth for US crude. Compared to our sample, of 13% growth for US and Canadian liquids growth (crude & NGLs), the data indicate significant growth from Canada (oil sands) and NGLs. The trend suggests that on a quarterly growth rate basis, production growth will peak in 4Q12 before moving lower in 2013e.

- The main contributors to volume growth skew toward the large independents in 2013 top 20 companies contributed 75% of growth. In 2012, the top 20 companies contributed 80%. While the smaller independents look to contribute more to volume growth, the concentration is a strong indicator that the future of oil growth will be driven mainly by the select 20 producers. Production developments for these producers will be a strong forerunner of future oil growth.

- Noting the evolution between 2012 and 2013 growth contributors, EOG Resources and Chesapeake Energy were the highest contributors in 2012. For 2013, our survey shows that Exxon and Suncor take over as the leading contributors, supported by major oil sands projects coming on line in 2013. Exxon's Kearl oil sands project will initially produce 110 mbpd in 2013 and will expand to ultimately produce 345 mbpd. With an expected 40 year project life, Kearl is an example of the long life span of oil sands projects and the significant volume which can be produced from successful projects. However, oil sands projects require considerable lead times as Kearl was in the works since 2009 and will only now begin production. Going forward, we expect the large independents will most likely continue to be the main drivers in liquids growth with lumpy contribution from the oil sands.

Figure 57: Growth Contribution Highly Skewed to the Large Independents



Source: Deutsche Bank, FactSet

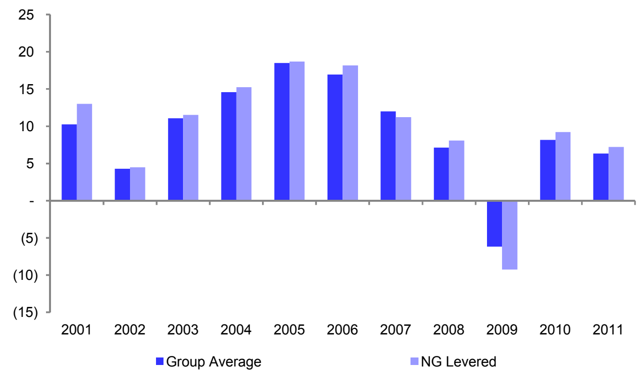
Why it's Not Natural Gas All Over Again

One of the more discomforting aspects of our call is the very recent example of the natural gas supply glut in North America. The example provides a direct analogue where excess returns were ground to zero via an industry driven by marginal economics with little capital discipline and a fragmented supply base. The easy analogy has been to look at natural gas for an example of an industry that was generating excess returns for multiple years, the profit incentive encouraged investment and further research, and ultimately the resource (shale plays) and technology (horizontals / hydraulic fracturing) were developed and supply of the commodity followed. We think there are number key reasons why the history of the natural gas supply glut in North America is unlikely to be replicated in crude oil.

With the benefit of hindsight, the natural gas supply glut was the perfect confluence of industrial economics, technology, and cyclical change. The implications for both the industry and the market have been significant. It should not be forgotten that as recently as 20 years ago, it was unclear if the industry could supply adequate natural gas despite secular demand growth. The supply base consisted of associated gas (from oil production), the Gulf of Mexico shelf which looked to be able to supply ample quantities at low costs, and more conventional onshore sources in areas such as the gulf coast. Further, the North American market looked to be dependent upon LNG imports over the coming decades to balance domestic demand growth. In the face of stagnant supply (despite rising upstream activity levels) and rising demand (primarily from the electricity generation sector) the price signal to the market was higher to incentivize additional supply.

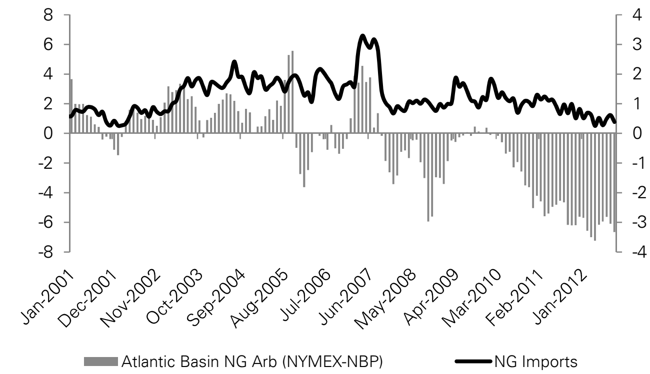
- Higher prices created a prolonged period of above trend returns for the industry. This not only created an incentive to generate more supply to the industry, but a significant subsidy to expand the productive capacity. Importantly, this period of above trend returns was apparent for multiple years (2004-2007) before a supply response (and demand collapse) occurred.
- The inability to grow domestic supply and the linkages to global prices provided a further premium to domestic natural gas prices relative to the domestic cost of production. Important to consider, in this period, LNG imports were key to balancing the market and as a result prices to compete for international supply were required. The Atlantic basin natural gas price arbitrage was an important driver of excess returns for the industry, as NYMEX prices needed to rise to encourage imports in the 2005-2007 timeframe.

Figure 58: A Sustained Period of Excess Returns



Note: Industry ROIC. Sample includes APA, APC, NBL< EOG, CHK, DVN, RRC, SWN, NFX, UPL, ECA
Source: FactSet, Deutsche Bank

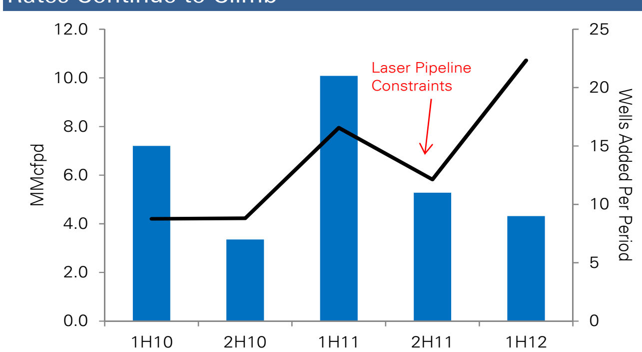
Figure 59: Linkage to Global Prices



Source: Bloomberg Finance LP, Deutsche Bank

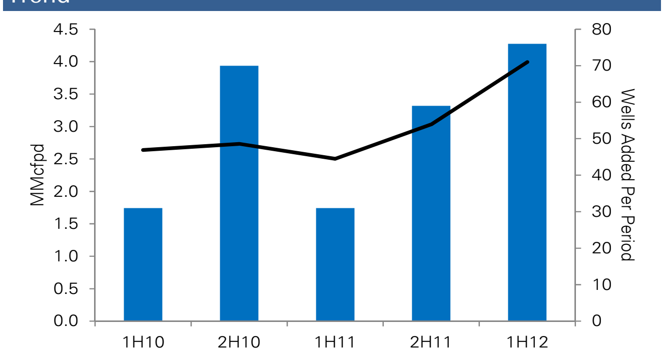
Beyond pricing dynamics, an important aspect of the supply growth for natural gas has been the anomalous and outsized efficiency gains of the Marcellus. Far beyond the collapse in natural gas prices, the industry focused unconventional learnings on a resource that already had locational benefits close to Northeast demand market but also clear geologic benefits. Importantly, well data continues to show improvement in initial production rates for Marcellus producers, a key driver of supply growth and economic viability. We see no analogy for domestic oil plays as of yet, and while a significant sustained improvement in Eagle Ford or Bakken initial production rates on a well basis bear watching, it is the Marcellus that has primarily contributed to the prolonged glut in domestic natural gas and is singularly responsible for the further reshaping of supply dynamics for North American natural gas.

Figure 60: Cabot's Susquehanna Ct. Initial Production Rates Continue to Climb



Source: PA DEP, Deutsche Bank

Figure 61: Range Resources Results Reflect a Similar Trend



Source: PA DEP, Deutsche Bank

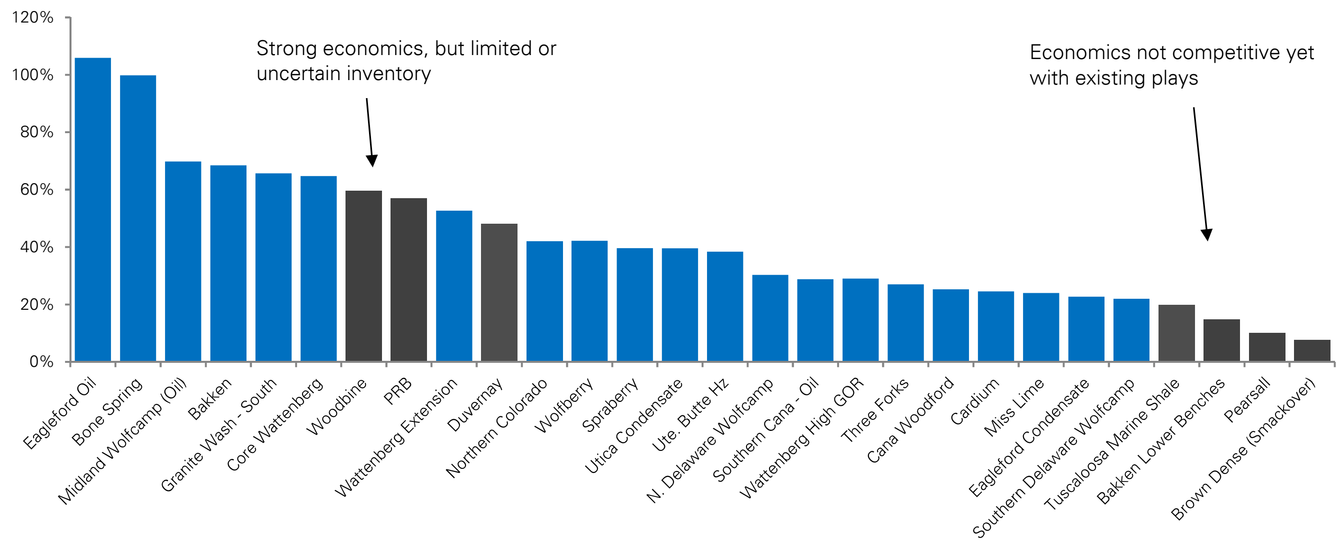
Finally, the pain in gas has been prolonged as the subsequent boom in oil drilling and production served to distort the supply/demand dynamics of the natural gas market. Despite a collapse in the dry gas rig count, as one would expect in the current environment, natural gas production has remained stubbornly resilient, partially because of the tremendous amount of natural gas growth from oil production as associated gas, or supported by NGL pricing. In this scenario, gas was produced effectively as a byproduct, entirely immune to price response. Crude oil production, however, should respond more readily to price signals and shifts in activity level, as there is no secondary source of crude production as an industrial byproduct.

Looking for the Next Leg - Exploration plays failing to gain traction

Although existing plays in the Bakken, Eagle Ford, Permian and others will continue to drive the lion's share of growth in the medium term, maintaining the next leg of growth post-2015, or at minimum driving upside to crude production outlooks, will largely depend on successful exploration and derisking of emerging plays. However, despite the feeling that we are awash in crude, exploration has been largely unsuccessful (or at least uninspiring) over the past 18 months.

In order to figure meaningfully in future activity levels, emerging basins need to provide sufficiently attractive scale (footprint), and competitive economics. A brief look at a cross-section of emerging basins and exploration plays in the industry reveals a set of assets that either offer insufficient scale, are gassier than originally expected, or likely require a structurally higher oil price.

Figure 62: Exploration plays challenged by poor economics or limited/uncertain inventory



Source: Deutsche Bank, Company Presentations

Figure 63: Exploration Plays

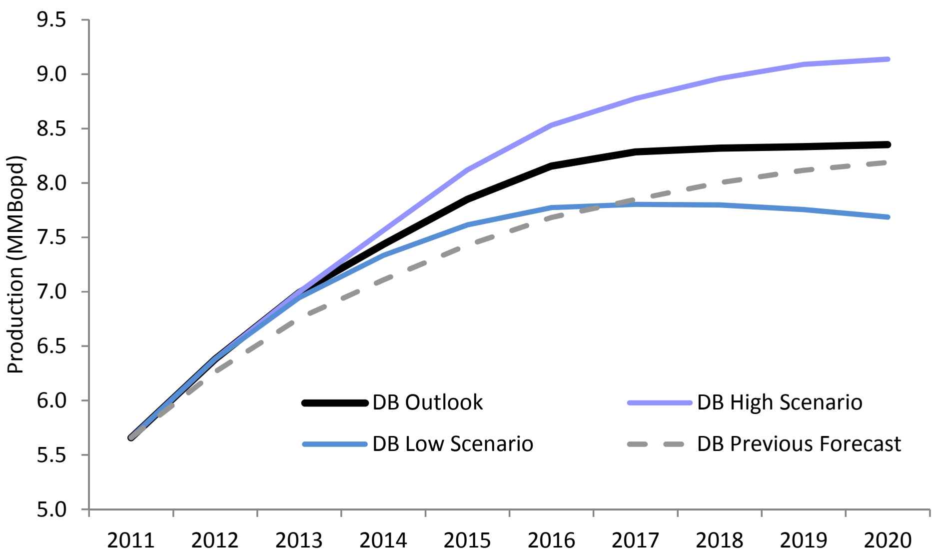
Exploration Plays	Expected Well Profile: Gross EUR (Mboe)	Expected Well Profile: D&C ($MM)	Exposed Companies		What's happened…	What to look for…
TUSCALOOSA MARINE SHALE	550-600	$10-12	GDP	EOG	ECA: Anderson 17H-1 933boepd 30-day IP	GDP: 4Q12 - Results from Denkmann 33H #1
			ECA	HK	ECA: Weyerhaeuser 73H-1 740boepd 30-day IP	GDP: 1Q13 - Results from Crosby 12H-1
			DVN	COG	DVN: Thomas 38H-1 402boepd IP	ECA: Q3 - Results from Weyerhaeuser 60H #1
					DVN: Murphy 63H-1 408bopd	ECA: 4Q12 - Results from Ash 31-1H
					DVN: Weyerhaeuser 14H-1 670bopd 20-day IP	HK: 1Q12 - Results from Broadway 1H
						EOG: 1Q13 - Results from Dupuy Land Co #1
WOODBINE	450-500	$6-8	CHK	ZAZA	DVN: Mathis 2H 956boepd IP	ZAZA: Late-Nov - Results from Stingray A-1H
			ECA	DVN	CXPO: 3 wells with 1,000boepd+ IP rates	ZAZA: Potential JV announcement
			CXPO	APA	CXPO: Payne 1H 1,014boepd 100-day avg rate	HK: 4Q12 - Will have first 6 wells turned online
			HK		ECA: Jgresham 2H, 249boepd 30-day IP rate	CXPO: Results from Upchurch #1H (only toe has tested)
BAKKEN LOWER BENCHES	450-500	$9-11	OAS	QEP	CLR: Sunline 11-1TF 1,023boepd IP	CLR: '13 - 4 pilot areas to test 2-4 lower bench zones
			EOG	CLR	CLR: Charlotte 2-22H (TF2) 1,396boepd	
			NFX	HES	CLR: Charlotte 3-22H (TF3) 953boepd	
			WLL	MRO		
			SM	OXY		
			KOG			
S. TX PEARSALL	450-500	$9-11	GDP	CHK	COG: Chipitlin 1H 1,400boepd (Frio County)	GDP: 1Q13 - Drilling first operated well
			SM	PXD	Blackbrush: Pals Ranch 11H 1,837boepd IP (Frio County)	COG: Completing 2nd well, drilling 3 additional wells
			APC	COG		
			NFX	HK		
			EOG			
LOWER SMACKOVER BROWN DENSE	300-500	$7-10	SWN	COG	SWN: Drilled 6 wells to date, with peak flow tests up to 420bopd 50 degree API oil plus rich gas	SWN: Late-Nov - Doles (6th well) and BML (3rd well) online
			EOG			SWN: Johnson (4th well) and Dean (5th well) re-entered
PRB MULTIPLE PLAYS	450-550	$6-7	QEP	BBG	CHK: 3 recent wells with peak IP rates of 1,700-2,000boepd	CHK: 4Q ops update
			CHK		QEP: 3 Sussex wells with peak IP rates of 580-1,600boepd	BBG: 1Q13 - Results from 1 Frontier and 1 Shannon well
			DVN		BBG: Horizontal Shannon well 30-day IP 429boepd	QEP: 1Q13 - Hardy 12-27-39-74SXH results (Sussex)
MARMATON	450-500	$3-4	QEP	COG	COG: 5 operated wells with IP rates of 650-2,000bopd	COG: Q412 - Results from first 2 extended laterals
			CHK		QEP: 3Q12 - 4 wells with 300boepd 24hr IP	QEP: Potential sale of acreage
DUVERNAY	850-1,600	$14-16	ECA	TLM	ECA: Tested 4 wells with 3 WOC.	ECA: Upcoming wells (12-04HC, 06-09HZ, more licensed)
			PWT	XOM	XOM: Acquired CLT.TO for C$3.1B	
			CVX		Drilling activitiy weighted toward Kaybob. Recent results range from 6.0 mmcfpd (with 109 bbl/mmcf) to 2.0 mmcfpd (with 80 bbl/mmcf)	
NORTH UTICA SHALE/POINT PLEASANT	300-1,100	$6-9	RRC	COG	RRC: Encouraged by 1st well	HK: 1Q13 - Results from 3 wells in NW PA
			HK			RRC: 1Q13 - Results from 2 wells in NW PA

Source: Deutsche Bank, Company Reports

Key Risks

In regards to domestic onshore oil production, the trajectory that we have outlined and expect is on a course unlikely to be altered significantly in the near-term (2-3 years). Upside and downside risk to this trajectory is likely to be driven by well level performance. Continuing to monitor well results from the Bakken and Eagle Ford will be the important drivers, as our view remains that the trajectory of initial production rates is the single largest driver of growing production rate. A sudden improvement in well results would see more rapid near-term production growth and would likely pressure WTI prices below our view of marginal cost ($80/bbl) as spending plans for major producers are in place.

Figure 64: DB Crude Supply Forecast Through 2020



Source: Deutsche Bank

On a longer term basis we see two key risks, one surrounding resource and the other technology.

The key risk to supply growth on a 3-5 year view would be the delineation of a material and scalable oil resource play. As outlined within we do not see a play of the scale or scope (>50 horizontal rigs drilling) to materially alter the trajectory of our 5-10 year view on supply. While exploration efforts and the activity of the industry bear watching, the exploration plays we see on the horizon are either sub-optimal scale (not broadly repeatable) or are missing a technical breakthrough to become economic. Importantly, with industry activity focused on known resource opportunities and returns for the upstream already under pressure, we see activity surrounding exploration and technical development as already being curtailed industry wide.

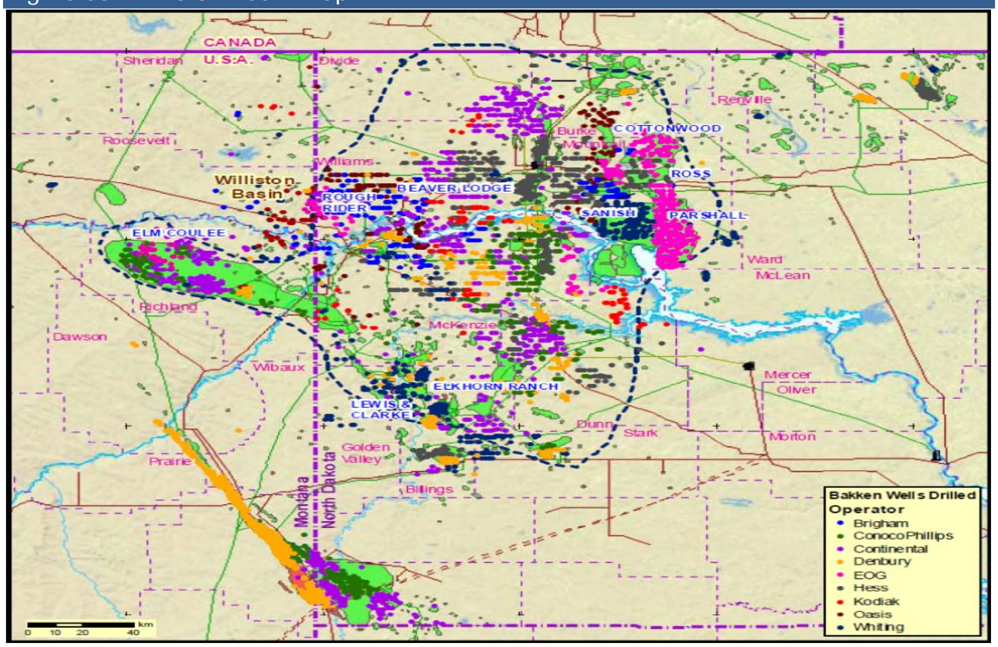
Technology a significant wildcard. Drilling and completion technologies have progressed significantly. With few barriers to entry across the industry and service providers acting as a conduit to share drilling techniques and tools development has been rapid. In many ways resource in existing hydrocarbon basins in the lower 48 provides a call on technology over time as new advances will continue to increase recovery rates (and expand understand of oil in place).

Oil Basin Background

Williston Basin - Bakken

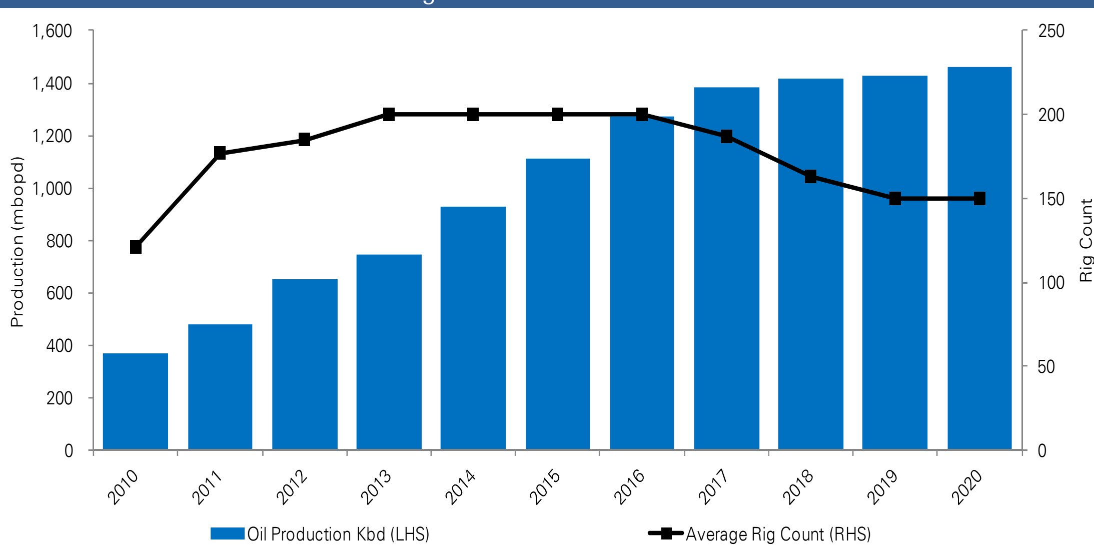
The Bakken Formation is one of the largest continuous oil formations in the world and accounts for ~10% of US daily oil production. The play spans western North Dakota and eastern Montana in the United States and parts of Saskatchewan and Manitoba in Canada. It is located primarily in the Williston Basin.

Figure 65: Williston Basin Map



Source: Deutsche Bank, Wood MacKenzie

Figure 66: Estimated Bakken Production And Rig Count Estimate



Source: Deutsche Bank, Wood MacKenzie, BHI Rig Count, NDIC

History

Recoverable resource estimates for the Bakken continue to increase as scientists and engineers learn more about the geology and structure of the formation. Improvements to technologies such as extended reach horizontal wells and multistage hydraulic fracturing have also contributed to recoverable resource growth.

Amereda Petroleum's Clearence Iverson well drilled in 1951, is the first known production from what became known as the Bakken formation two years later when the formation was mapped and named after Montana farmland owner, Henry Bakken. In the mid-90s, the Elm Coulee field in eastern Montana was discovered, indicating significant oil accumulation in the middle Bakken member, and ~10 years later, EOG Resources drilled the Nelson Farms 1-24H well, demonstrating horizontal wells with fracture stimulation could produce high initial flow rates and commercial recoveries (EURs.) Continental Resources opened up the possibility of Three Forks drilling in 2009, when the Mathistad 2-35H well proved that the Bakken and Three Forks formations are separate reservoirs and can be produced independently.

With the basin rig count increasing and completions commonly reaching 40 stages by mid-2011, North Dakota overtook Alaska to become the second largest producing oil state behind Texas.

Geology

The Bakken Formation is a combination of gray sandstone and silt beds, sandwiched between two radioactive black shales. It occurs at the Devonian/Mississippian boundary and is present throughout much of the western interior of North America. The Bakken is made up of three distinct sections; the upper, middle, and lower members are collectively known as the "Bakken Pool" with the bulk of operator interest focused on the middle member.

The current drilling target of most operators is not a pure shale, but largely a silty sand and shale-rich dolomite with low porosity. The middle member, based on fossil analysis, can be divided into three sub-units. Geology is highly variable and maximum thickness approaches 90 feet. It becomes sandier as it thickens. Discrete sand zones are present in the shallowest portions of the Middle Bakken. Hydrocarbon saturation is over 60% in this member.

In 1995, the USGS estimated that the Bakken held 151 million barrels of recoverable oil, much lower than the 3.7 billion barrels recoverable reported in 2008. The USGS is in the process of reassessing the formation's reserve potential and will release results in late 2013. Operators have increased recoverable reserves by improving drilling and completion methods.

Per well reserves estimates increased substantially when companies began lengthening lateral legs (horizontal sections) of the well. Many Bakken wells now have laterals reaching 10,000 feet. Spacing began in the play at 1,280 acres per well, but operators are currently averaging 640 acres and are looking to further downspace with pilot programs planned through 2014 by EOG Resources, Continental, and other operators.

Well Data And Economics

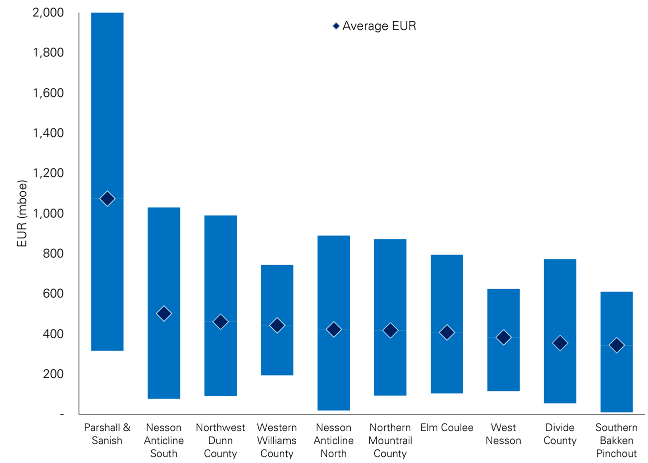
The economics for the Bakken are a balance between cost control and the potential ultimate recovery from each well, which is highly dependent on location. EURs can range from 200MBoe to well over 1,000MBoe, though average Bakken wells are in the 450-650MBoe range. Wells average ~$9.5MM to drill and complete, but can vary tremendously depending on length of lateral, material usage, and location as well. The amount of sand and ceramic proppant used to fracture each well is increasing, as 10,000 foot laterals and 40 fracture stages become common. However, the increased implementation of pad drilling is reducing costs, in some instances, upwards of $1MM/well.

Figure 67: Bakken Well Profile

Well Profile		Production Profile:	
Avg Well Cost ($MM)	$9.5	Oil/Condensate	87%
Typical EUR (Mboe)	574	NGL	3%
30 day IP (boe/d)	950	Gas	10%
Initial Decline Rate	37%		
Terminal Decline Rate	7%	Avg Drill Time (days)	40
b factor	1.2	Well Spacing (acres)	640
IRR ($90/$4/30% WTI)	56%		

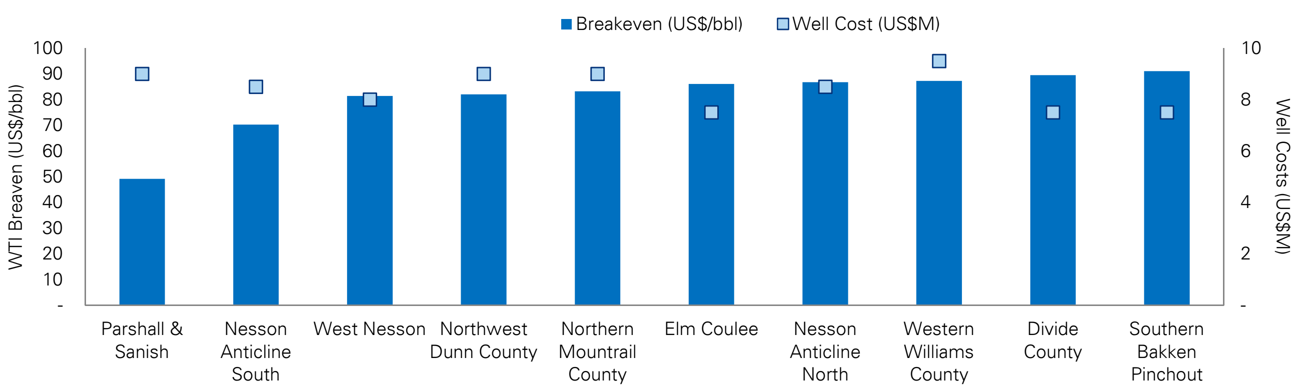
Source: Deutsche Bank, Company Reports, Wood Mackenzie

Figure 68: Bakken EUR



Source: Deutsche Bank, Company Reports, Wood Mackenzie

Figure 69: Bakken Breakeven Cost By County



Source: Deutsche Bank, Wood Mackenzie

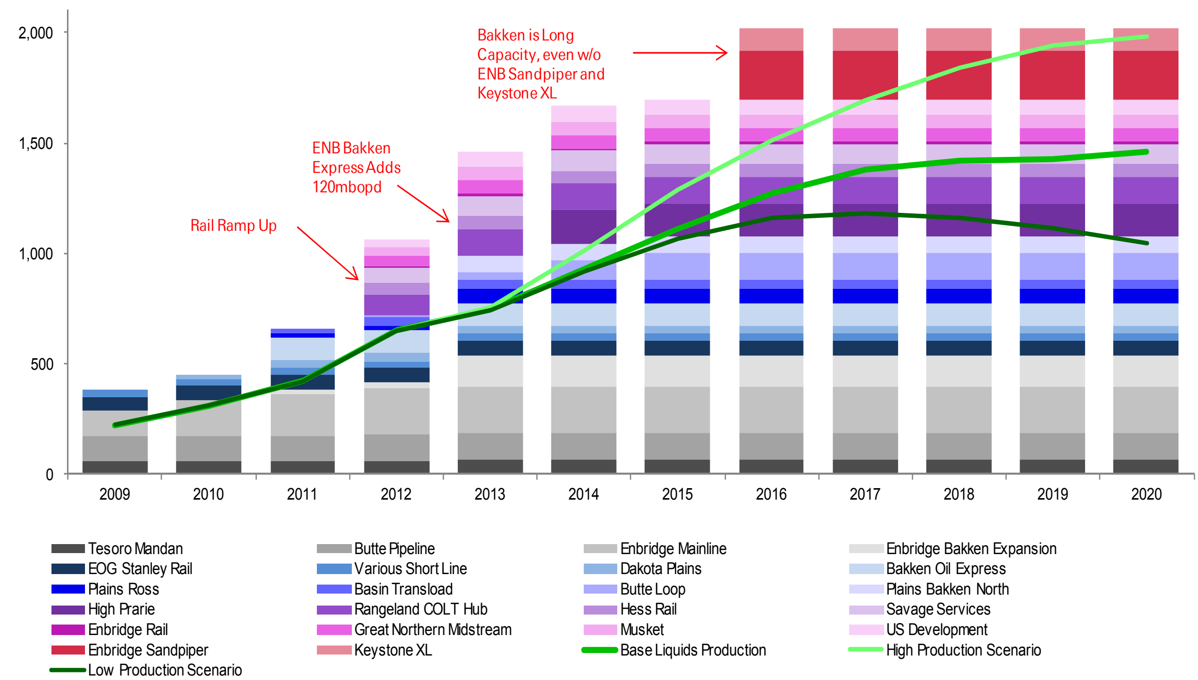
Infrastructure

The challenge of transporting oil from the well site also impacts the economics of Bakken development. Pipeline capacity was a constraint, so operators began using more rail capacity to ship liquids to refineries. Approximately 60-65% of oil is now shipped via rail, enabling operators to increase takeaway capacity and access a higher sales price on the Gulf Coast. Due to regional pricing dynamics, economically transporting crude to the gulf coast (achieving LLS prices), has proven more attractive relative to the oil-congested WTI hub at Cushing, Oklahoma.

Production from the Williston Basin has increased from 200,000 bpd in 2007 to around >700,000 bpd currently. This unprecedented and unexpected growth in production means that existing inter and intra-state pipeline capacity quickly reached capacity. Within the play the majority of crude in the Bakken is transported by truck. For transport out of the basin, rail is currently the swing mode of transport. Rail is a more expensive option than pipeline but it does allow operators to access the higher Light Louisiana Sweet (LLS) crude prices.

While shipping crude by rail can cost US$15-20/bbl, compared to US$8-9/bbl by pipeline, costlier transportation methods have been justified by better prices at more distant refineries. As a result, railcar demand has risen significantly, as operators place large orders for tanker cars and cars capable of shipping large amounts of proppant. There is anecdotal evidence that some operators are waiting up to a year to secure the tank cars necessary to get their crude out of the basin.

Figure 70: Infrastructure Project Additions Provide Ample Capacity To Grow

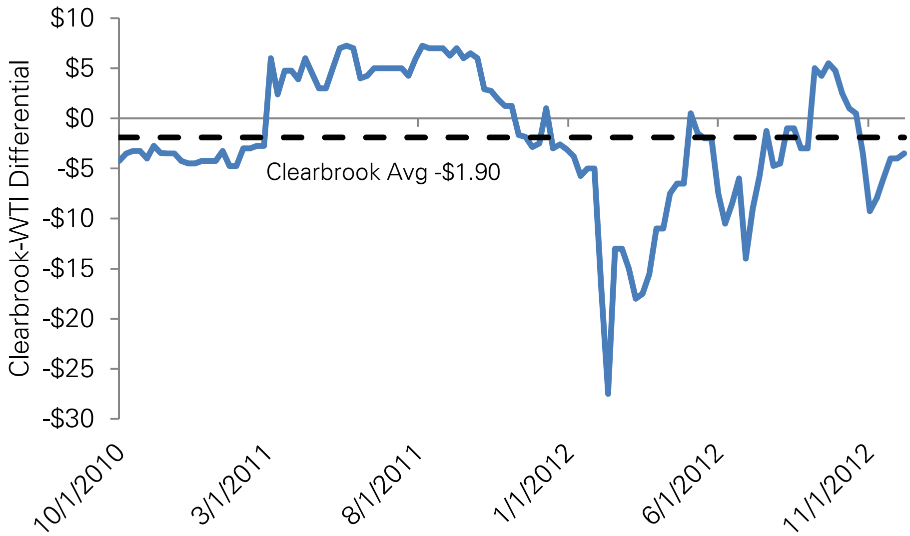


Source: Deutsche Bank, Company Reports, , North Dakota Pipeline Authority, Wood Mackenzie

Pricing

While Bakken producers now sell crude at various locations, Clearbrook, MN, it is the index for basin production. A tight market through mid '12 generally kept the Bakken-Cushing differential in the -$10-15/bbl range (pushing as high as $28/bbl at points), but the start up of several rail facilities, capable of taking production to the East, West, and Gulf Coasts, has relieved market tightness and briefly turned differentials positive in Sept '12. With the ability to rail crude to higher price points, producers can now receive LLS pricing (WTI +$15-20/bbl) less rail transportation costs ($15-20/bbl) or WTI less pipeline costs ($8-10/bbl).

Figure 71: Clearbrook-WTI Differential



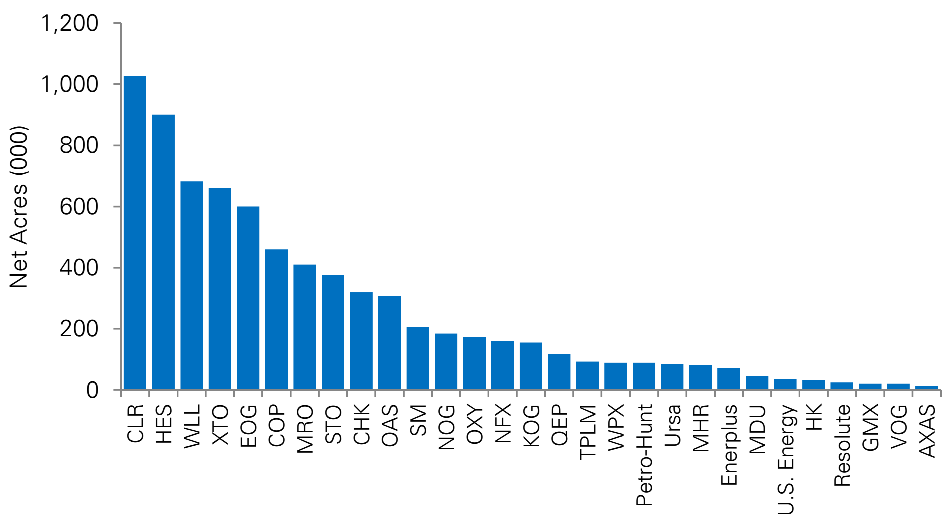
Source: Deutsche Bank, Bloomberg Finance LP

Companies

The Bakken has been well established for several years, with Continental, EOG Resources, and Hess as the largest producers. Oasis Petroleum, Kodiak Oil and Gas, Whiting Petroleum, and ConocoPhillips are also notable producers, all anticipated to produce over 20,000boepd.

Continental Resources is the largest producer and leaseholder in the Williston Basin. After the acquisition of Samson's Divide County, ND acreage, Continental will hold over 1MM net acres across the Bakken, with an estimated EUR of 600MBoe in ND and 400MBoe in ND for the Middle Bakken.

Figure 72: Company Acreage Holdings



Source: Deutsche Bank, Company Presentations

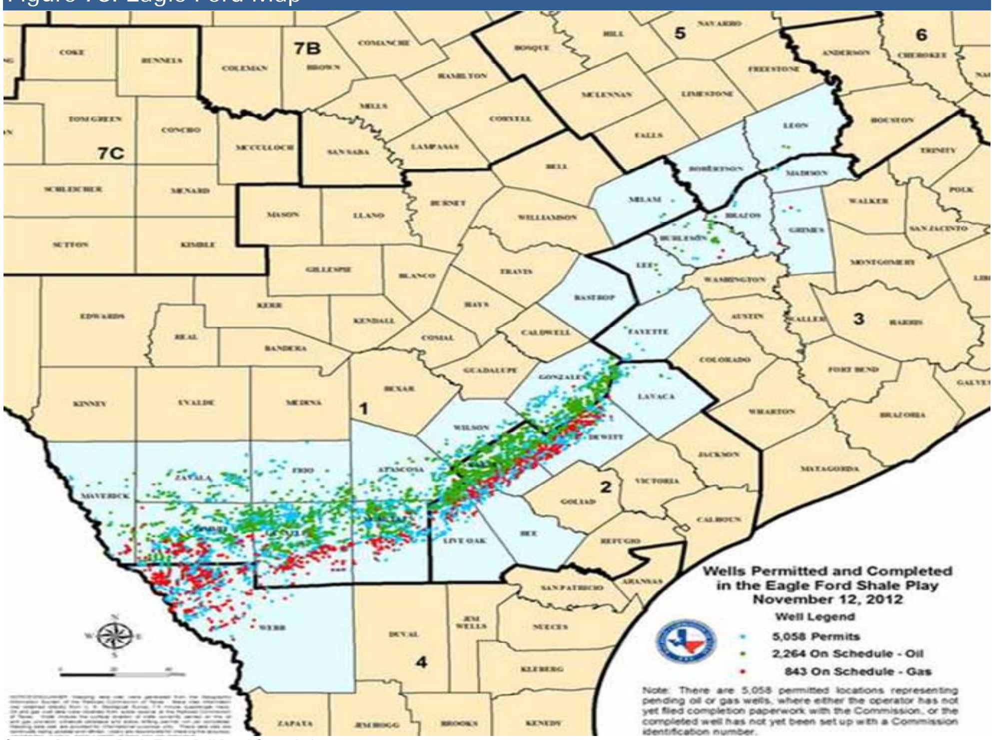
What To Look For

Beyond cost reduction, Bakken operators are now looking to expand the longevity of the play by testing the lower Three Forks benches, downspacing, expanding the limits of old fields (such as Elm Coulee), and beginning to test the potential for secondary and tertiary recovery. Continental has taken the lead in exploring the lower Three Forks benches with 2 operated wells to date, both flowing over 950boepd. Plans are to drill 14 lower bench tests through '14. Additionally, Continental has several pilots to test downspacing, potentially up to 14 wells per 1,280 acre unit. Finally, operators are beginning to rail more crude than pipe, potentially reducing differentials to WTI on a sustainable basis.

Maverick Basin - Eagle Ford

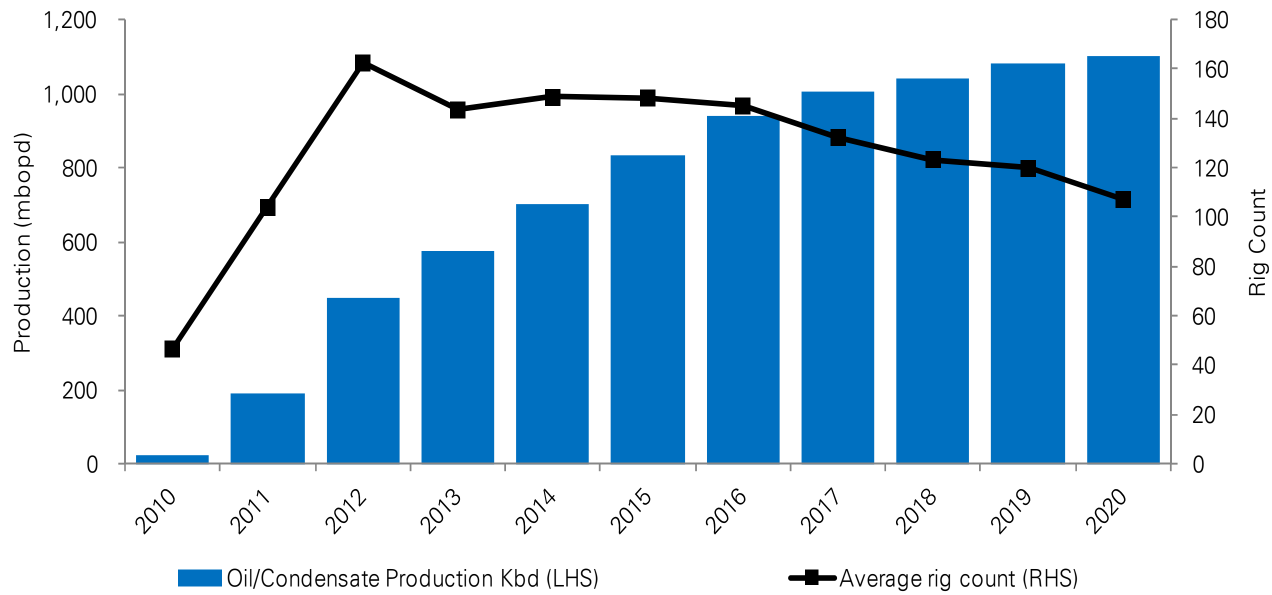
The Eagle Ford Shale is a rapidly developing resource play in South Texas with the trend stretching from the Texas/Mexico border near Maverick County, parallel to the coastline, into central Louisiana. The Eagle Ford is now in its fourth year of development and like the Bakken, is now a major contributor to US oil supply (10%). While there are three "windows" to the play (oil, gas-condensate, dry-gas), operator focus is clearly on development of the liquids sections and where we focus our analysis.

Figure 73: Eagle Ford Map



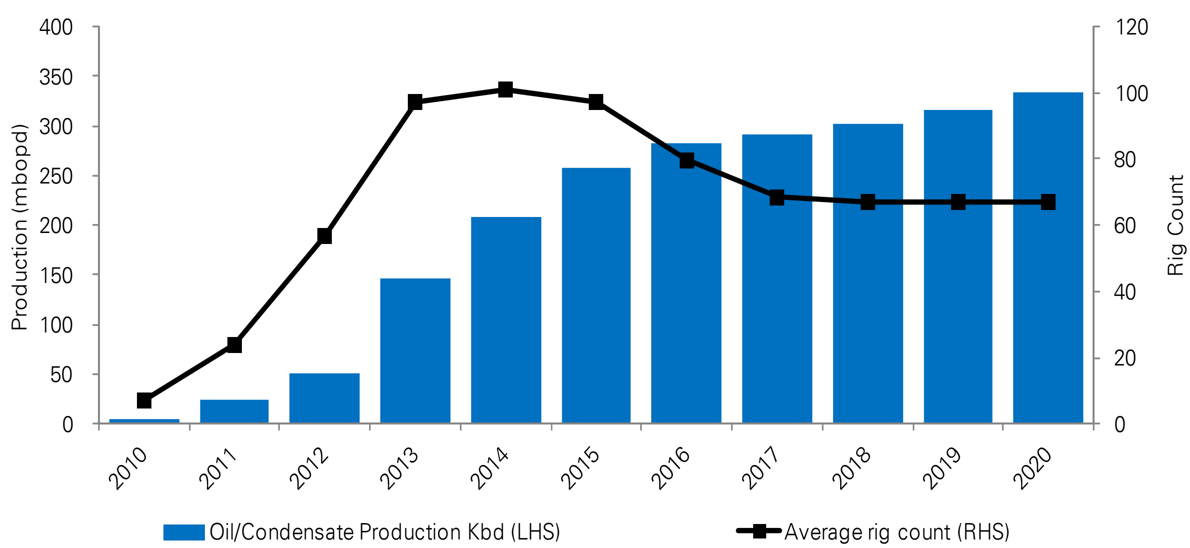
Source: Deutsche Bank, Texas Rail Road Commission

Figure 74: Eagle Ford Oil Window Production and Rig Count Estimate



Source: Deutsche Bank, Wood Mackenzie, BHI Rig Count

Figure 75: Eagle Ford Wet Gas Window Production and Rig Count Estimate



Source: Deutsche Bank, Wood Mackenzie, BHI Rig Count

History

The Eagle Ford formation was routinely penetrated in the 80's-90's after the initial round Austin Chalk and Edwards wells failed, but the formation was not singled out until 2008. Commercial gas activity began post Petrohawk's success with the STS #1 well in LaSalle County flowing 9.1Mmcfepd, followed by the Dora Martin #1 well 14 miles to the southwest, testing 8.3Mmcfepd. Oil drilling began around the same time with Apache testing wells in Maverick County.

The big change for the market's view of the Eagle Ford came in early '10 with EOG Resources announcing 505,000 net acres of leasehold in the oil window, changing the market focus of Eagle Ford from more of a gas play to liquids focused growth. This led to a rapid increase in the rig count and a significant pick up in M&A activity. In 2012, EOG Resources and Marathon Oil announced several high rate wells, including a few over 4,000bopd plus NGL's and natural gas.

Geology

The Eagle Ford Formation wraps around the northeast-trending San Marcos Arch in Texas, outcropping in Dallas County and acts as a source rock for shallower formations such as the Austin Chalk and Woodbine. The commercial section of the play is a smaller, deeper area to the southwest. Specific to the oil window of this multi-phase asset, the northern boundary is located along the Pearsall arch in Frio County. Most oil activity to date has been southwest of the furthest northeast edge of the Karnes trough. The trend is more gas prone south of the Edwards Reef Trend.

The play is bound by the Austin Chalk above and Buda formation below. It is estimated that the Eagle Ford was deposited roughly 30 miles from the shoreline, where water depth was near 330 feet. There was virtually no tectonic activity during the time of deposition.

A key characteristic of the play is its inconsistent geology, mainly due to structural deformation. Total organic carbon (TOC), thermal maturity, porosity and thickness metrics all show significant ranges. In general, the Eagle Ford Shale is thickest in the Maverick Basin area (southwest, up-dip) and thins over the San Marcos Arch (northeast). Local uplift is primarily due to the influence of the Chittim anticline. Near LaSalle and McMullen counties, the gross to net pay ratio in very specific areas can be above 90%.

Well Data And Economics

Liquids production and reservoir quality varies greatly in the Eagle Ford and operators are having difficulty defining exact liquids and gas boundaries within the formation. EURs can range from 200MBoe to well over 1,000MBoe, though average wells in the oil and gas-condensate window are in the 400-600MBoe range. Ranges in drilling and completion costs exist across the play, with current industry estimates ranging from US$5.5-9.5 million. This range depends on multiple factors such as depth, lateral lengths, and the number of hydraulic fracturing stages employed. Early Eagle Ford wells were completed with 10-stage hydraulic fracturing stages that used 2MM pounds of proppant with most common practices now performing 15-20 stages fracture stimulation treatment with 4MM pounds of proppant.

Figure 76: Oil-Condensate Well Profile

Well Profile		**Production Profile:**	
Avg Well Cost ($MM)	$7.5M	Oil/Condensate	77%
Typical EUR (Mboe)	454	NGL	11%
30 day IP (boe/d)	820	Gas	12%
Initial Decline Rate	35%		
Terminal Decline Rate	7%	Avg Drill Time (days)	25
b factor	1.2	Well Spacing (acres)	120
IRR ($90/$4/30% WTI)	106%		

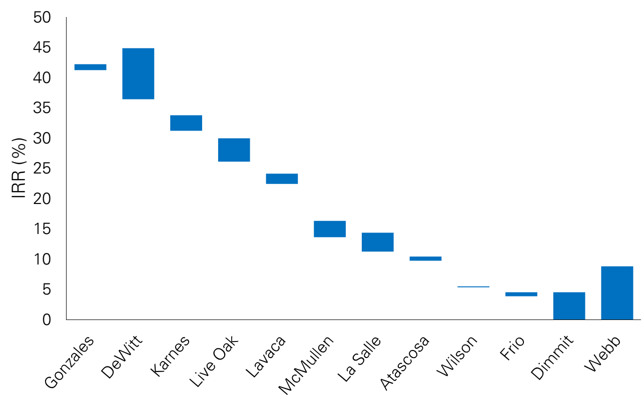
Source: Deutsche Bank, Company Presentations, Wood Mackenzie

Figure 77: Wet Gas Well Profile

Well Profile		**Production Profile:**	
Avg Well Cost ($MM)	$7.5M	Oil/Condensate	15%
Typical EUR (Mboe)	850	NGL	32%
30 day IP (boe/d)	983	Gas	53%
Initial Decline Rate	25%		
Terminal Decline Rate	7%	Avg Drill Time (days)	25
b factor	1.4	Well Spacing (acres)	120
IRR ($90/$4/30% WTI)	23%		

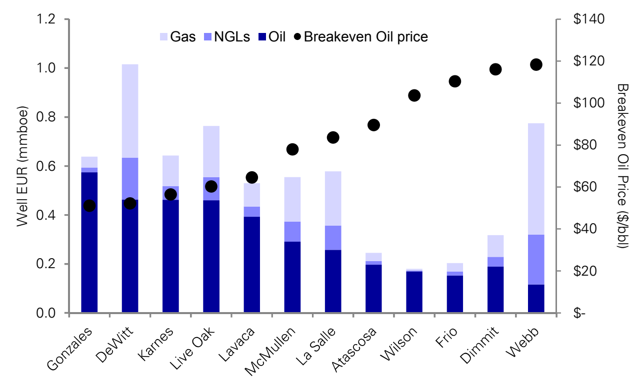
Source: Deutsche Bank, Company Presentations, Wood Mackenzie

Figure 78: Eagle Ford County IRRs



Note: Assumes WTI at $95.34, $82.80, $85.00, $and $85.51 in '12-'16
Note: Assumes Nat Gas at$2.88, $3.74, $4.34, $4.78, and $5.02 in '12-'16
Source: Deutsche Bank, Wood Mackenzie

Figure 79: Eagle Ford EUR and Breakeven Oil Price



Note: Assumes NGLs are priced at 30% of WTI
Note: Assumes Nat Gas at$2.88, $3.74, $4.34, $4.78, and $5.02 in '12-'16
Source: Deutsche Bank, Wood Mackenzie

Infrastructure

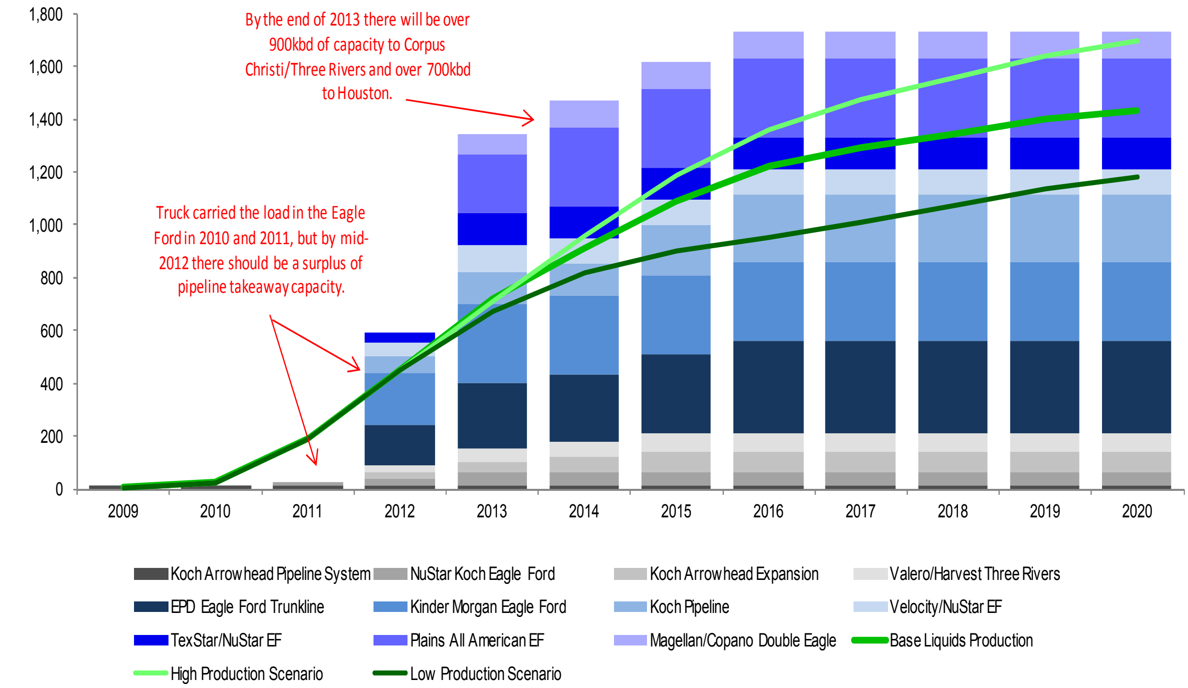
Located in Texas on the Gulf Coast, the Eagle Ford is able to take advantage of its proximity to refineries in Corpus Christi and Houston. The short distance to the Gulf Coast refineries reduces costs and allows for more transport options. Barges are available to transport on the inter-coastal waterways in addition to pipelines, rail, and trucks. In spite of these advantages, the Eagle Ford does face challenges as a result of the volume of crude, condensate and NGLs that require processing in the Gulf Coast refineries.

Crude Oil Projects

Several projects are being constructed to facilitate the movement of the crude and condensate production. While these projects are being completed, trucks continue to serve as the intermediate logistics solution. Enterprise Products with the Eagle Ford Crude Oil Pipeline, stretching from Lyssy to Sealy Texas will have a capacity of 350 kbpd with interconnections to Seaway Pipeline and to the new 5 million barrel Echo Terminal in Houston. Another new addition has been the Kinder Morgan condensate pipeline, starting in Eagle Ford and terminating in Pasadena, Texas. This line has a capacity of 300 kbpd of condensate and connects with a new condensate splitter to process this light material.

Additionally, Koch in partnership with NuStar and Arrowhead will provide 200 kbpd of capacity allowing either consumption in the refineries or marine shipment. Connections to storage as well are being made available in the Corpus Christi area. Lastly Plains All American has a pipeline project to carry Eagle Ford crude and condensate to Corpus Christi as well with nearly 300 kbpd of capacity. These projects together should be able to manage the near term requirements for Eagle Ford crude and condensate production takeaway.

Figure 80: '12-'13 = Significant Capacity Additions

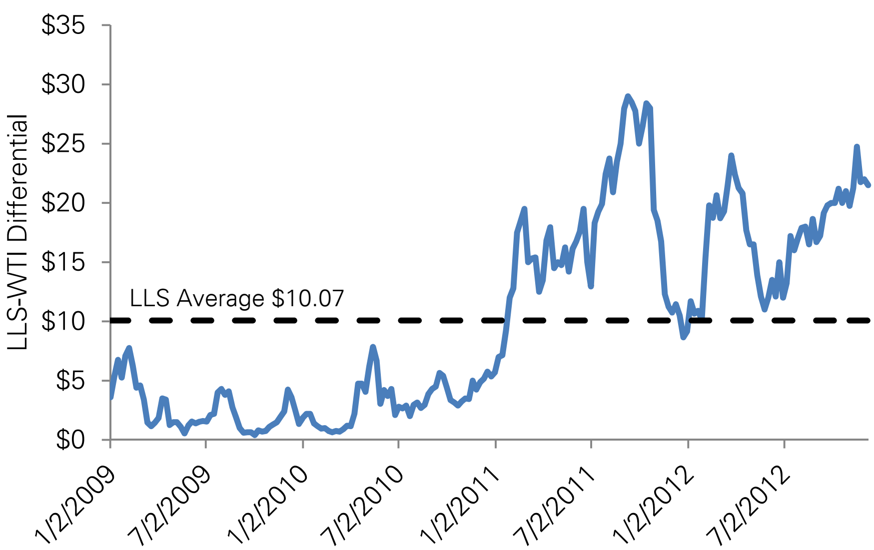


Source: Deutsche Bank, Wood Mackenzie, Company Presentations

Pricing

After two years of trucks carrying the transportation load, several new pipelines set to come online in through '14, providing infrastructure relief and the ability to sell crude at WTI or premium Gulf Coast prices. Rail capacity is also being adding, providing additional flexibility depending on spreads.

Figure 81: LLS-WTI Differential

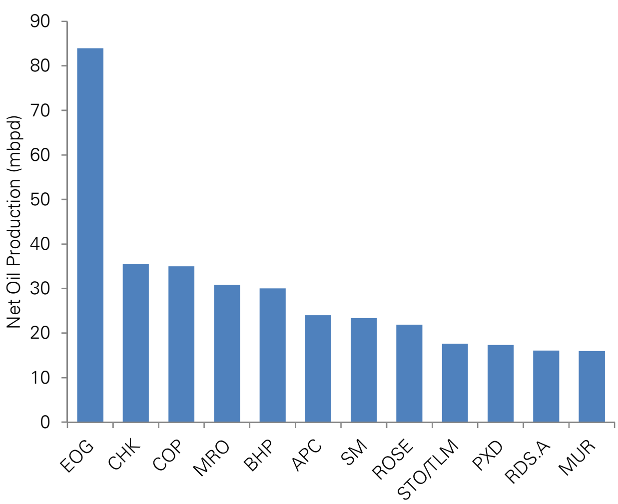


Source: Deutsche Bank, Bloomberg Finance LP

Companies

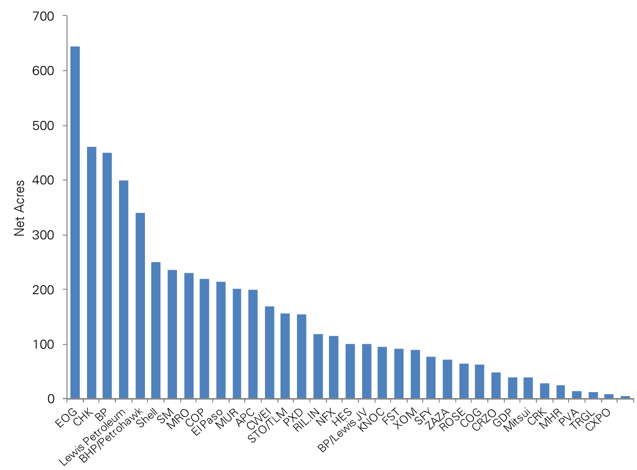
While operators have grown production rapidly since '09, EOG Resources remains the clear leader in oil production, more than Chesapeake Energy and ConocoPhillips, the second and third largest crude producers, though several producers are rapidly increasing activity. Marathon Oil and BHP Billiton are notable producers who are rapidly ramping up activity, each with plans to spend over $1.5B+/yr for the next 3-5 years.

Figure 82: 3Q12 Selected Company Oil Production



Source: Deutsche Bank, Company Data

Figure 83: Net Acreage Per Company



Source: Deutsche Bank, Company Data

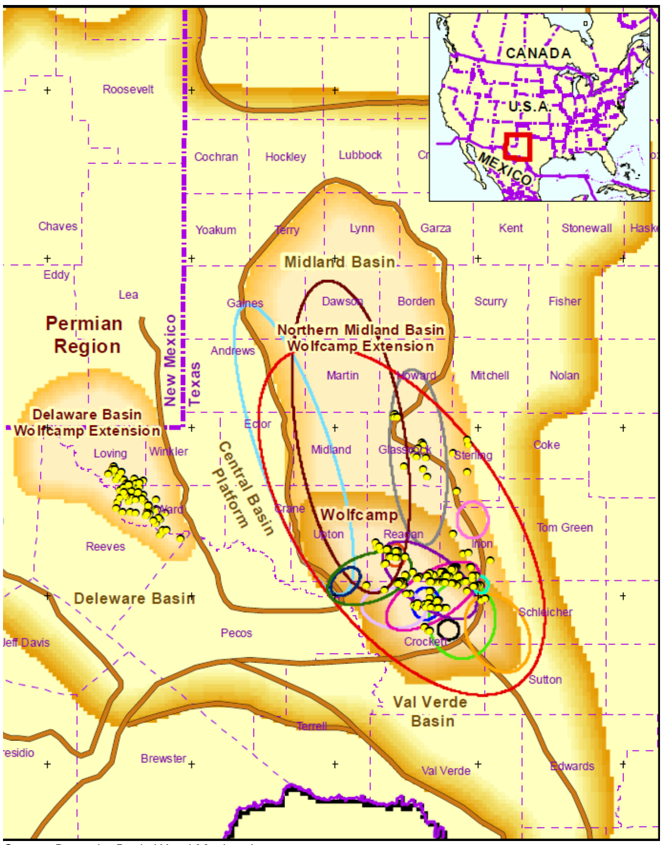
What To Look For

While moving into development mode, operators are still looking to increase the resource potential of the basin by conducting downspacing pilots and testing additional formations. In '13, we anticipate hearing results of five 40-100 acre and five 40-80 acre spaced pilots Marathon Oil has conducted. Additionally, we anticipate an update on Pearsall Shale activity in the basin from Cabot Oil and Gas (not covered), EOG Resources, Goodrich Petroleum, private operator Blackbrush Oil & Gas, and others over the next several quarters

Permian Basin – Wolfcamp and Bone Springs

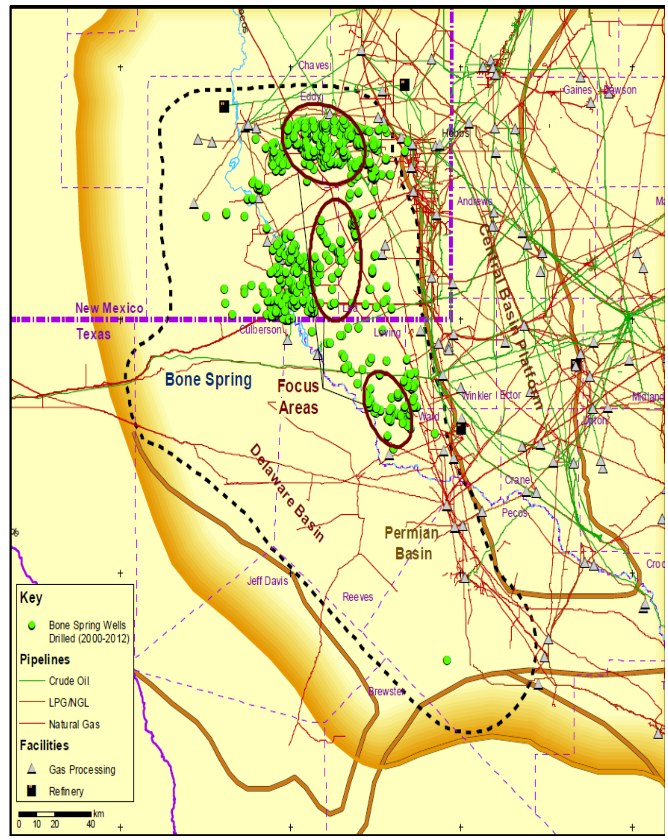
The Permian Basin in West Texas and south-eastern New Mexico has been producing oil for almost 100 years through conventional vertical drilling. In the past several years, a few unconventional, horizontal plays have emerged. The Wolfcamp Shale, along with the Bone Spring/Avalon and Cline Shale, will drive production growth in the Permian.

Figure 84: Midland Wolfcamp Map



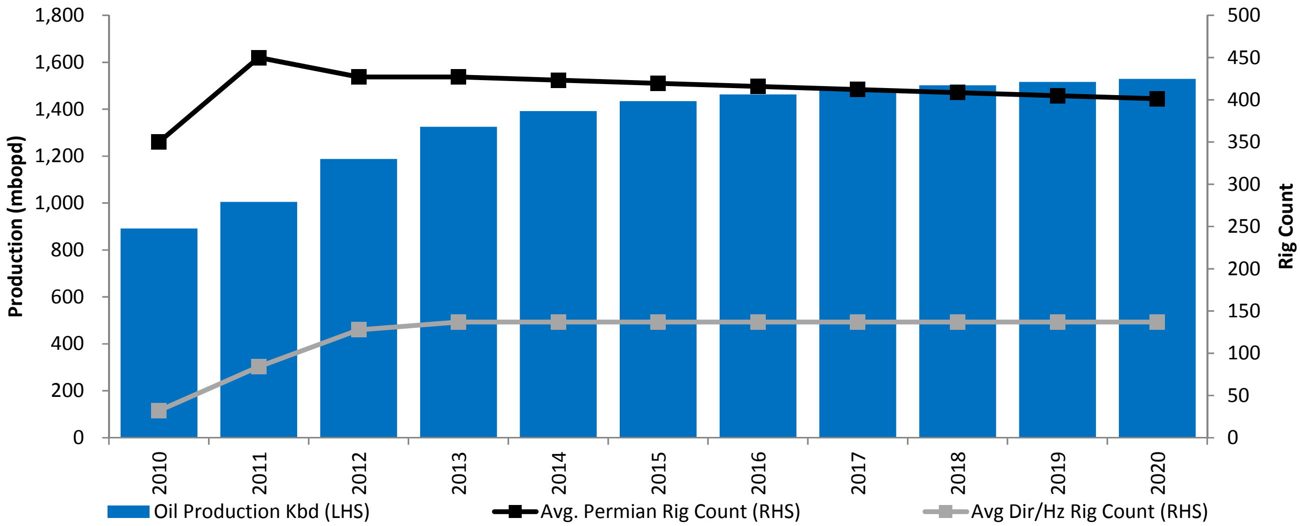
Source: Deutsche Bank, Wood Mackenzie

Figure 85: Delaware Bone Springs Map



Source: Deutsche Bank, Wood Mackenzie

Figure 86: Permian Production and Rig Count Estimate



Source: Deutsche Bank, Texas Rail Road Commission, Wood Mackenzie

History

The Permian Basin has a long productive history, but operators originally disregarded the Wolfcamp Shale in the southern Midland Basin as it was thought to be thin or absent in this region. It was assumed that the shale was not part of the basin deposits and instead extended across the Ozona Arch to the southern edge of Crockett County and middle part of Sutton County. Prior to the recent pickup in activity, operators drilled into the Canyon, Strawn, and Ellenburger formations, which, now comingled with the Wolfcamp Shale, became known as the Wolfberry Play. As companies re-evaluated historic technical data, it was determined that the Wolfcamp Shale was present in a 1,000–1,500 foot thick stacked column.

While Approach Resources (AREX, not covered) began collecting data beginning in 2004, the first horizontal well in the Wolfcamp was drilled in 2009 by Broad Oak Energy (now part of Laredo Petroleum, not covered) in Reagan County, TX. As drilling activity has increased between 2011 and 2012, operators have been able to increase initial production rates from 300 boepd to over 1,000 boepd.

In the Southern Delaware Basin, Occidental Petroleum began drilling Bone Springs wells in '06, followed by Chesapeake Energy in '07. Majors re-entered the basin this year with the acquisition of Chesapeake's 1.09MM acres to Royal Dutch Shell and Chevron for ~$3.6B or ~$3,300/acre.

Geology

Wolfcamp

The Permian-age Wolfcamp Shale is present across the entire Permian region in Texas and New Mexico, with varying geological characteristics. The Wolfcamp is a hybrid system of interbedded, normally pressured carbonates and shales. The carbonate layer is oil-rich and can have associated silica content of 35%. It is located below the prolific Spraberry sands. Key geologic attributes are maturity and thickness; the play is situated in a peak oil generation window, and in places, is 1,450 feet thick.

The Wolfcamp Shale is an oil-rich carbonate and shale play in the southern Midland Basin in the Permian. Here the play is comprised of four intervals: labelled as the

Wolfcamp A, B, C or D. The Upper and Middle or the A, B, and C horizons are thought to have similar geological characteristics (TOC, and permeability). Most activity has focused on the Wolfcamp B with operators testing the A and C intervals. The D bench, also known as the Cline Shale by some operators, is found at depths close to 10,000 feet, and is thought to be gassier.

In the Midland Basin, the Wolfcamp Shale is bounded to the east and west by the Eastern Shelf and Central Basin Platform respectively, where it is replaced by thick, massive carbonate debris flows. The depth varies across the basin while the Wolfcamp B target zone thickness is fairly consistent except towards the basin edge where it thins out.

In the north of the Midland Basin, past Reagan and Glasscock counties, the carbonate source rock thins and becomes less mature. Thermal maturity is not significantly impacted by depth. To the south, the Ouachita Uplift turns the Wolfcamp into a shallower and more fractured play. In the Delaware Basin, the Wolfcamp Shale is deeper, sitting below the Bone Spring Formation. Here, the shale is expected to have higher gas content than the main southern Midland Basin play area.

The reservoir has high permeability in the core part of the play. The Wolfcamp has a high TOC in the oil window. Cores from the play have shown up to 25% clay content. In addition, the formation has a high concentration of natural fractures which run vertically and trend northeast to southwest, which operators are leveraging by drilling the horizontals with a north-south orientation.

Bone Springs

The Delaware Basin is located west of the Central Basin Platform (home of the prolific Yates field) in the greater Permian region. The Delaware is significantly deeper than the Central Basin Platform (CBP). Deep channels running off the CBP slope sourced much of the sediment throughout the Delaware. The basin is bound by two shelves, a fold belt to the south, and a platform to the west.

The Bone Spring play is a significant internal in the Delaware and is comprised of a set of Permian-aged sandstones and carbonate interbedded mudstones and shales. It is a massive gross vertical sequence containing both conventional and tight unconventional targets.

There are three benches within the Bone Spring. Benches two and three are located beneath the Avalon Shale (sometimes referred to as Bone Spring 1st Bench). Each Bone Spring bench is roughly the same thickness 150 m (500 ft) as the standalone Avalon section. Additionally each subsection has both a sand and carbonate zone. Deeper benches are significantly overpressured; the gradient can reach up to 0.75 psi/ft. All the Bone Spring zones sit above the well-known Wolfcamp tight oil play

The Bone Spring formation is a sequence of three stacked sandstone intervals - 1st, 2nd and 3rd Bone Spring - that include organic-rich mudstones, interbedded siltstones, shales and detrital limestones and dolostones. In parts of the play the 1st interval is intermingled with the Avalon Shale. The Avalon Shale tends to be more mature and gassier than the Bone Spring. It is more prevalent in the western portion of the play. Unlike most plays, the deepest areas of the Bone Spring are most prospective for oil. The play is deepest in the east, and gradually gets shallower as it moves west.

Well Data And Economics

Drilling and completion costs are expected to decrease as the play moves from pilot to development wells. The typical pilot well in the Wolfcamp currently costs US$8.0-9.0 million, while most operators are expecting a development well to cost US$5.5-6.5 million. We assume an average Wolfcamp well will cost US$6.5-7.0MM, with almost 80% due to completion costs. Pad drilling and stacked laterals could help bring down single well costs while improving recoveries. Operators have improved production by increasing the number of fracture stages and lateral lengths. We assume a typical well is completed with 25-35 fracture stages and a 7,500 foot lateral though some operators are now utilizing lateral lengths of as much as 9,000–10,000 feet.

Figure 87: Midland Wolfcamp

Well Profile		Production Profile:	
Avg Well Cost ($MM)	$6.5	Oil/Condensate	42%
Typical EUR (Mboe)	449	NGL	30%
30 day IP (boe/d)	500	Gas	28%
Initial Decline Rate	18%		
Terminal Decline Rate	6%	Avg Drill Time (days)	25
b factor	1.2	Well Spacing (acres)	160
IRR ($90/$4/30% WTI)	22%		

Source: Deutsche Bank, Wood Mackenzie, Company Presentations

Figure 88: Delaware Wolfcamp

Well Profile		Production Profile:	
Avg Well Cost ($MM)	$7.0	Oil/Condensate	80%
Typical EUR (Mboe)	577	NGL	10%
30 day IP (boe/d)	600	Gas	10%
Initial Decline Rate	35%		
Terminal Decline Rate	5%	Avg Drill Time (days)	25
b factor	1.7	Well Spacing (acres)	160
IRR ($90/$4/30% WTI)	70%		

Source: Deutsche Bank, Wood Mackenzie, Company Presentations

Bone Springs

Most activity has been focused in the Northern Bone Spring targeting all three intervals, though activity is moving south. IP's first averaged ~340 boepd with gas content less than 35%, though several companies now report IP rates in each of the 2nd and 3rd intervals of between 500 and 600 boepd with a higher liquids mix. Like the Wolfcamp, wells are estimated to be ~$7MM, though depending on whether an operator goes to the 1st or 3rd interval, the cost can vary from $5-9MM.

Figure 89: Bone Springs Well Profile

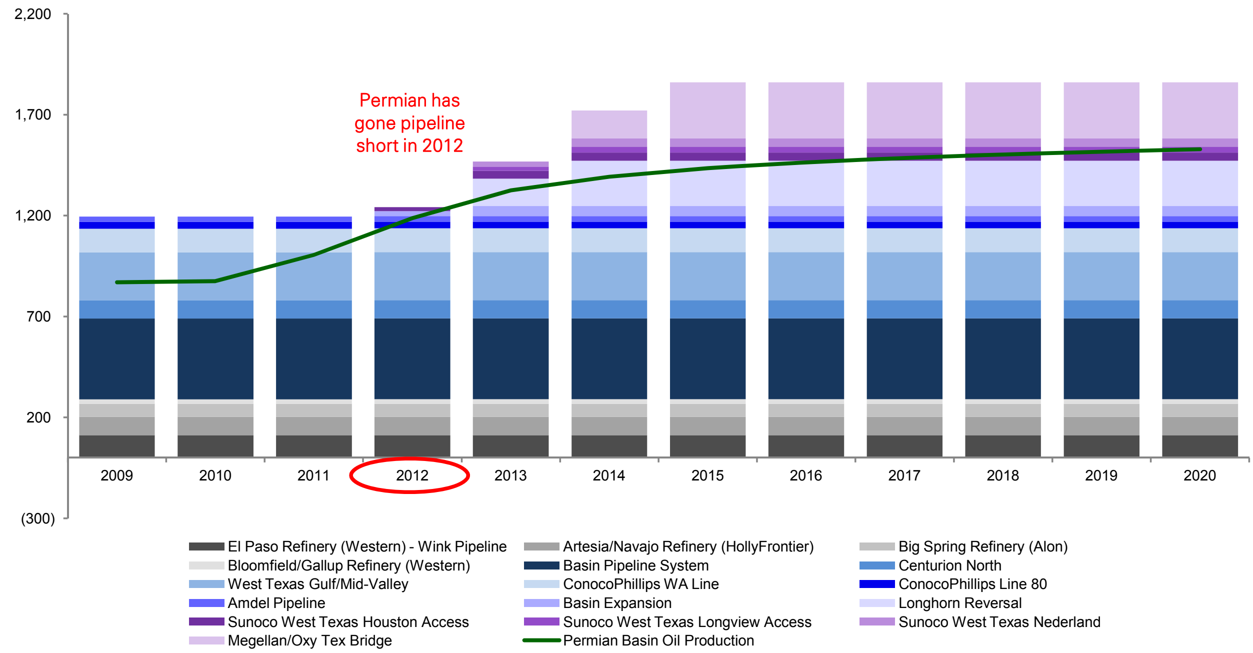
Well Profile		Production Profile:	
Avg Well Cost ($MM)	$6.5	Oil/Condensate	70%
Typical EUR (Mboe)	600	NGL	6%
30 day IP (boe/d)	600	Gas	24%
Initial Decline Rate	33%		
Terminal Decline Rate	6%	Avg Drill Time (days)	25
b factor	1.7	Well Spacing (acres)	160
IRR ($90/$4/30% WTI)	65%		

Source: Deutsche Bank, Wood Mackenzie, Company Presentations

Infrastructure

The Permian Basin is an established oil and gas producing region and has a well-developed transportation network. Currently there is enough capacity to get the products out of the Permian, but if activity increases as expected, companies will have to plan additional projects to meet the supply. Thus far, operators and midstream companies have been proactive in planning for additional pipelines to account for this increased activity in the Permian, and no delays are currently expected.

Figure 90: 300kbpd Tex Bridge Pipeline In '14 Relieves Tight Crude Capacity



Source: Deutsche Bank, Wood Mackenzie

Crude in the Permian mostly flows east to Cushing, Oklahoma, or to the Gulf Coast. The Basin System, operated by Plains Exploration (PXP, not covered), is a major route for transporting crude oil from Midland, Texas, to Cushing with the other major pipeline that runs to the Gulf Coast is the West Texas Gulf. Permian crude will face competition from other tight oil plays sending crude to Cushing as well as to the Gulf Coast. However, three major pipelines are planned to start in 2013 and 2014 that will be able to move the crude to the Gulf Coast. In addition, EOG Resources is constructing a rail facility that will be able to transport oil to the Gulf Coast. These lines and rail are expected to take the majority of the increased production from the Wolfcamp Shale.

Companies are investing in refurbished mature lines as well as reversing pipelines to carry crude from the Permian to the Gulf Coast. Magellan's Longhorn Pipeline reversal from El Paso to Houston, Texas, is expected to be completed in 2013. The first phase will have a 135,000 bpd capacity, with the second phase adding 90,000 bpd. Sunoco has also announced plans to do this for the Permian Express Pipeline. The pipeline will initially have a capacity of 90,000 bpd with a possible expansion to 350,000 bpd in 2014. The third major pipeline proposed by Magellan and Occidental is the 300,000 bpd BridgeTex. The line is expected to open in mid-2014.

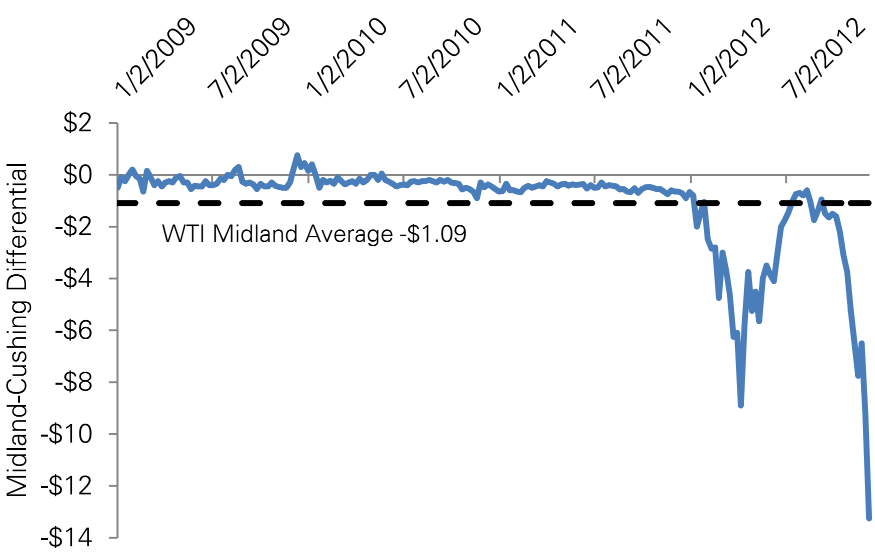
Operators will also use rail as well as pipelines to get crude to the Gulf Coast. EOG Resources is building a rail system to transport crude from the Wolfcamp to an unloading facility in St. James, Louisiana.

Although there is main line oil and gas capacity available, some operators have had issues with gathering systems and have had to truck crude to market. Some of these facilities have increased transport costs by up to US$10/bbl. As pipelines are built, these costs are expected to come down to US$3/bbl.

Pricing

Crude in the Permian mostly flows east to Cushing, Oklahoma, pricing at WTI-Cushing, or to the Gulf Coast, pricing at various, and currently positive differential index points. After years of stable production and a relatively flat differential to Cushing, the recent increase in production has made the infrastructure capacity extremely tight, pushed differentials above $10/bbl at times of refinery outages or pipeline maintenance. With the start up of the Longhorn Reversal in '13 and Tex Bridge in '14, some market tightness will be relieved, though still susceptible to increases in differentials with any outages or maintenance.

Figure 91: WTI Midland-WTI Cushing Differential



Source: Deutsche Bank, Bloomberg Finance LP

Companies

Wolfcamp

Pioneer Natural Resource is a leading leasholder in the play with ~800k net acres prospective. In early 2013, Pioneer expects to secure a joint venture covering 200k net acres in the Southern portion which will provide significant development clarity. EOG Resources is the leading operator, with 57 wells currently drilled into the play and a position of 130,000 net acres. In 2012, EOG has operated 3-5 rigs in the play, targeting the Wolfcamp benches in Reagan, Irion, Crockett and Schleicher counties. EP Energy (formerly El Paso) holds 138,000 net acres in the play in Crockett, Reagan, and Upton counties. The company entered the play in 2010 by leasing almost 123,000 net acres in the September 2010 University Lands Lease Sale. EP Energy has approximately 20 producing wells from the Upper Wolfcamp.

Bone Springs

Cimarex is the leading driller in horizontal wells in the Bone Spring, with over 170 wells drilled to date and now reports average New Mexico 30 day IP rates of 590 boepd compared to 260 boepd in 2008. Cimarex currently has six rigs dedicated to New Mexico and four drilling in Texas, second only to the 17 Concho Resources operates in the Delaware Basin. Concho Resources bolstered its Delaware Basin position through its acquisition of Three Rivers Operating in July 2012. The company holds over 330,000 acres in the Delaware Basin, of which it estimates over 300,000 is prospective for the Bone Spring. To date, Concho has focused its efforts on the Northern Delaware Basin in Lea and Eddy counties in New Mexico.

What To Look For

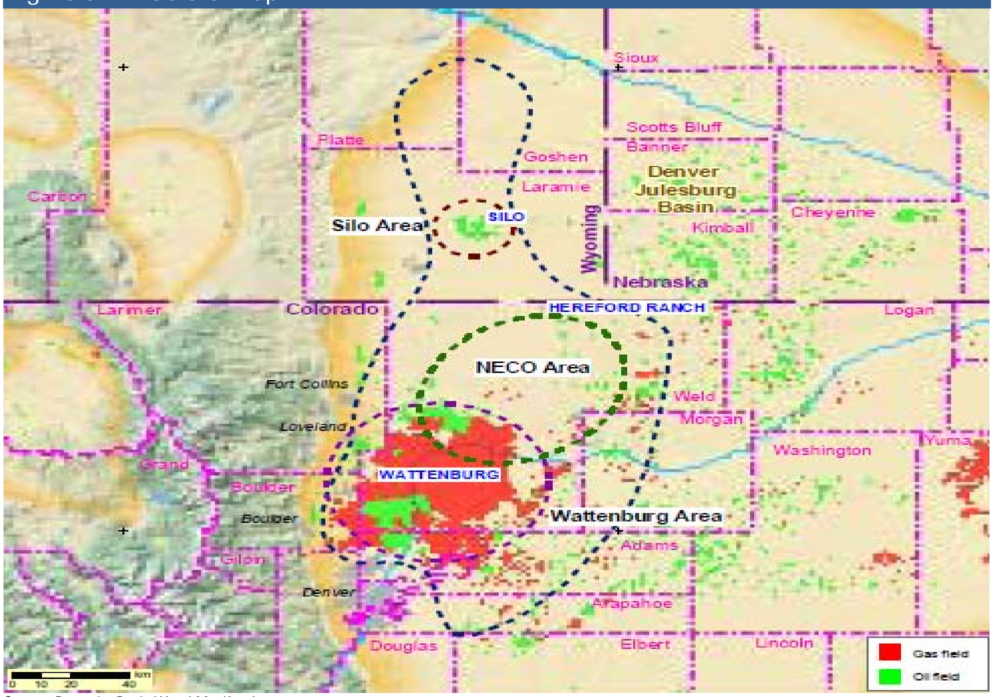
In the Wolfcamp, almost 600 new horizontal well permits having been issued in the last year. As the play moves from exploration to development for most operators, we expect costs to decrease by over US$1 million per well. With up to four separate horizons possible in the Wolfcamp Shale, well results testing each of these will be important. Operators are planning to test stacked laterals targeting two benches at a time in 2012 and 2013.

In the Bone Springs, activity in the region is going to spread south where there are over 100 permits outstanding. Drilling in the northern portion of the play will continue, but as operators begin to understand the southern portion, activity will ramp up in this region of the play. More data and complete studies will help operators monetize the large potential of the southern portion.

Denver-Julesburg Basin - Niobrara

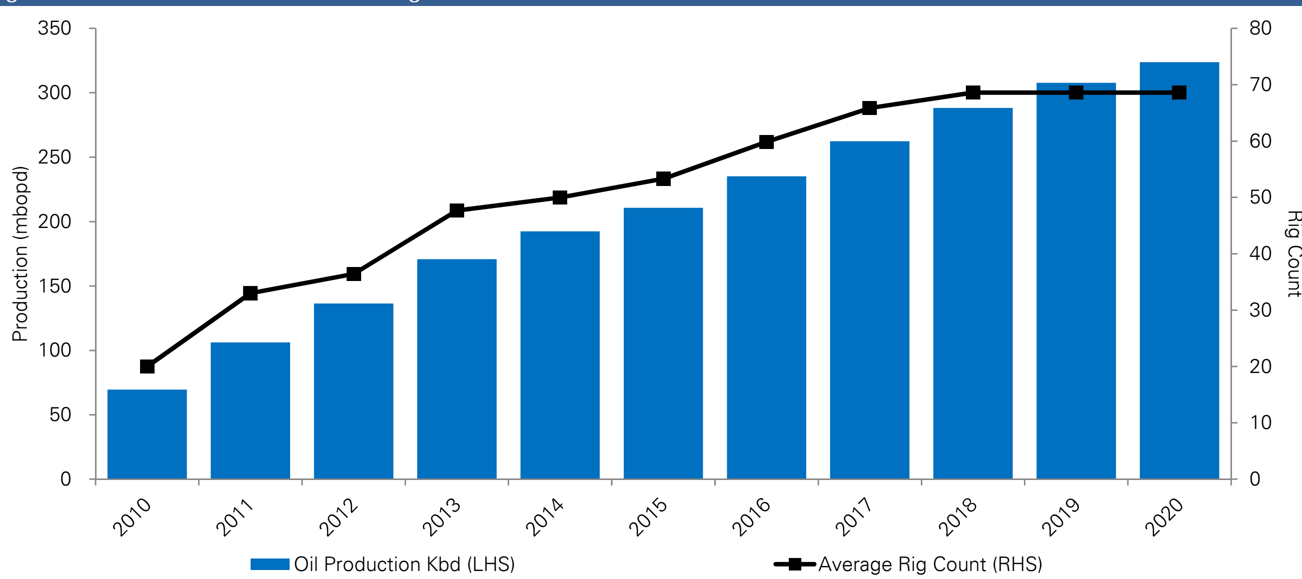
The Niobrara is a low-cost liquids play, highly competitive with other liquids growth basins (Permian, Williston, Maverick) in the lower-48. We expect the play will continue to compete for capital in the current commodity price outlook and after 3+ years of industry activity, infrastructure is reaching critical mass to support meaningful production growth.

Figure 92: Niobrara Map



Source: Deutsche Bank, Wood MacKenzie

Figure 93: Niobrara Production and Rig Count Estimate



Source: Deutsche Bank, BHI Rig Data, Company Presentations

History

Prior to horizontal drilling in the Niobrara, the formation was initially targeted for oil in and around the Silo field in Laramie County, Wyoming, and tight gas in the Wattenberg field. Operators first used vertical wells in the Silo field in the 1980s and began applying horizontal laterals in the 1990s. Horizontal laterals enabled operators to maximize recoveries by accessing more of the formation's natural fractures. In total, approximately 180 wells were drilled during the 1980s–1990s into the Silo field, recovering over 10 mmbbl in crude oil. Activity waned in the mid-1990s following a drop in oil prices, and as operators struggled to drill economic wells outside of the field's core area.

In the 2009/10 period, the Niobrara saw significantly heightened industry expectations. Initial expectations for a blanket deposition and repeatability across larger areas were not met by early drilling results. Initial industry expectations were set high by EOG Resources' Jake 2-01H well in Weld Ct. which produced 50,000 bbls in the first 90 days of production. Acreage values followed higher expectations for the play, and we see these expectations having peaked with the Chesapeake / CNOOC JV in January 2011 ($4,750/acre) and Marathon Oil / Marubeni JV in April 2011 ($5,000/acre). Soon after, step out wells drilled away from the core of existing producing fields at Wattenberg (CO) and Silo (WY) proved challenging and activity levels slowed.

Recent activity suggests that Niobrara is gaining strength as well results continue to improve and extension areas are being delineated and acreage data points support an indication of improving economics and expectations industry wide. In the most recent Colorado state lease sale, Bonanza Creek Energy (BCEI- not covered) acquired 5,640 net acres in the play for $59.5MM (5 annual payments of $11.9MM) or ~$10,550/acre. Just to the east of Wattenberg, Carrizo Oil & Gas (CRZO, not covered) announced a JV with India Oil and Oil India last week, selling a 30% interest in 61,500 net acres for $82.5MM, split $41.25MM cash / $41.25MM carry, or ~$4,470/acre undiscounted.

Geology

The Niobrara is a chalk formation with up to four benches spanning across Colorado, Wyoming, New Mexico, Kansas, and Nebraska. However, the resource is not uniform across the play with the richest, more organic, and deeper source rocks found in Colorado. Operators are currently focused on the productive B and C chalk benches due to their high resistivity with the Codell Sandstone, and Greenhorn Limestone also holding potential. Current OOGIP estimates are in the 25-30mmboe/section with 160 spacing recovering 3-6% and the possibility of 80 acre spacing should yield recoveries in the 6-12% range. The challenge of the Niobrara has been the complex geology, as its heavily faulted and naturally fractured, making it a challenge to operators trying to utilize the same drilling and completion techniques throughout the play. However, updated resistivity mapping and imaging technology is helping to greatly improve recoveries.

Four focus areas are emerging in the Niobrara play with high variability within areas in terms of prospectively (acreage risk) and liquids mix. Within the core of the Wattenberg field which has been developed for a number of decades, there is a geothermal anomaly where the pressure gradient changes significantly. This has provided much of the liquids rich gas charge that has been the primary producing focus until very recently. Horizontal drilling within the developed core of the field, drilled to avoid existing vertical wellbores has proven successful. Higher GOR wells here have been typified by lower oil content (~20%). Moving from this high EOR to areas around the rim of Wattenberg has show oil content rise to ~40-45%. Current focus activity is in the Wattenberg extension areas to the Northeast. Here the oil content has been found to increase again (~65%) while the area has proven challenging due to geo-hazards (faults) and the need to determine the contribution of natural fracturing. Finally, the NECO (Northeast Colorado) areas have exhibited the highest liquids cut of all wells (~80%) in the play, but are further challenged due to limited infrastructure and the need for extensive 3-D seismic.

Well Data and Economics

Well results across the play have been mixed, with many operators drilling sub-economic wells near a top-performing field. The lack of consistency in the formation's fracture patterns leads to difficulty staying in the pay zone, and a handful of operators exited the play. Despite this, the Niobrara is working for a few core operators (notably Noble Energy, NBL and Anadarko, APC) and overall drilling and spend in the play is increasing.

The play has developed into two core areas, Wattenberg and the Northeast extension. While both areas offer compelling economic returns, operators are shifting focus to the oily extension area as the core Wattenberg area remains constrained by gas and NGL infrastructure.

Figure 94: Core Wattenberg High GOR Economics

Well Profile		Production Profile:	
Avg Well Cost ($MM)	$4.7	Oil/Condensate	66%
Typical EUR (Mboe)	290	NGL	10%
30 day IP (boe/d)	750	Gas	24%
Initial Decline Rate	60%		
Terminal Decline Rate	6%	Avg Drill Time (days)	25
b factor	1.2	Well Spacing (acres)	320
IRR ($90/$4/30% WTI)	29%		

Source: Deutsche Bank, Company Presentations

Figure 95: NECO Extension Low GOR Economics

Well Profile		Production Profile:	
Avg Well Cost ($MM)	$5.3	Oil/Condensate	80%
Typical EUR (Kbbls)	294	NGL	5%
30 day IP (bbl/d)	620	Gas	15%
Initial Decline Rate	45%		
Terminal Decline Rate	6%	Avg Drill Time (days)	25
b factor	1.2	Well Spacing (acres)	320
IRR ($90/$4/30% WTI)	65%		

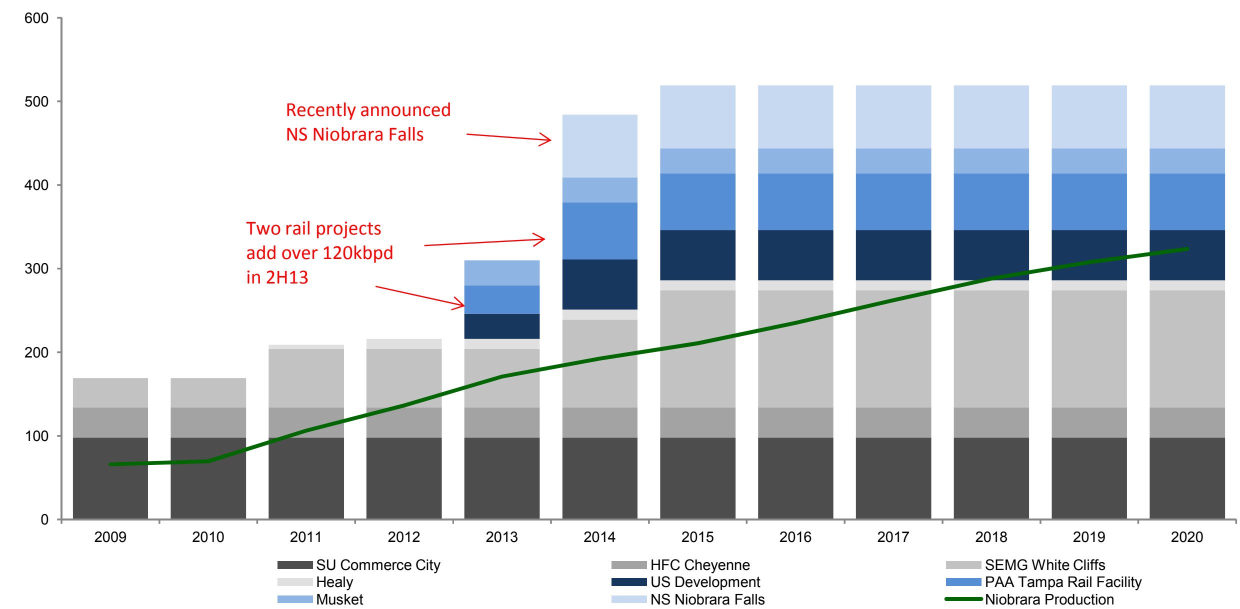
Source: Deutsche Bank, Company Presentations

Infrastructure

Locally, crude from this area has gone to Suncor's 98kbpd refinery in Commerce City, CO and Holly Frontier's 52kbpd refinery in Cheyenne, WY, though ~30% of the Cheyenne facility processes 30% heavy Canadian crude.

Current oil export out of Wattenberg is ~100-125kbpd with expansion plans in place to increase capacity over ~300 kbpd by 2015. The primary crude export pipeline is the 70 kbpd White Cliffs Pipeline, operated by Rock Rose Midstream (RRMS), a newly created MLP by SemGroup (SEMG) and is owned by SEMG (51%), Plains All American (34%), Anadarko (10%), and Noble Energy, NBL (5%). The pipeline takes Niobrara crude from Platteville, CO down to Cushing, OK, where 250,000 barrels of storage are leased from Rock Rose. White Cliffs is currently holding an open season, closing on Oct 22, for another 80-90kbpd of capacity with a 1H14 in service date. Additional export capacity via rail down to the Gulf Coast, taking over 60kbpd, is anticipated to be in service in 2H13.

Figure 96: 2014 Sees Significant Capacity Adds to the Niobrara



Source: Deutsche Bank, Company Reports

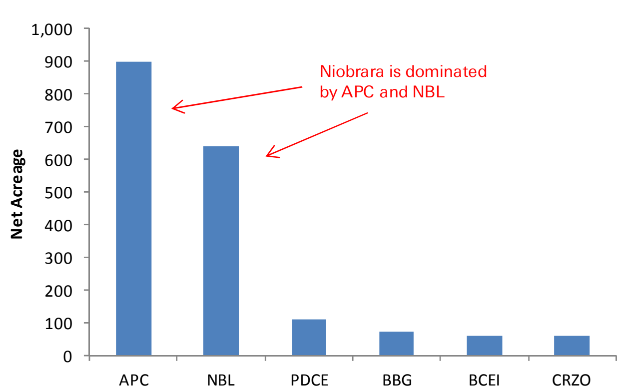
Pricing

Like the Permian Basin, the DJ Basin has local refinery capacity taking most of the current supply, with the White Cliffs pipeline for export to Cushing. However, unlike the Permian, producers benefit from excess capacity with new rail projects and an expansion of White Cliffs in '14 to provide future outlets.

Companies

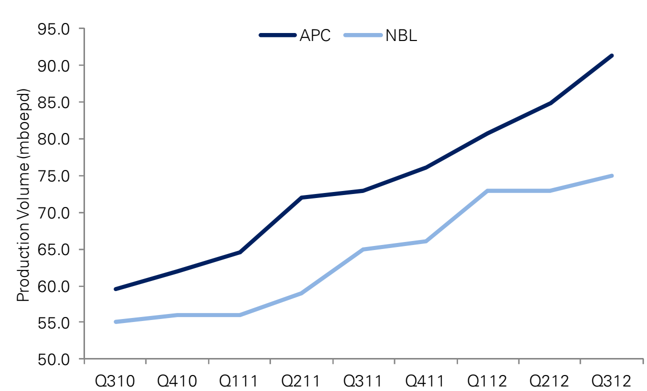
Noble Energy and Anadarko are the two dominant producers in the DJ Basin, though several smaller companies are increasing activity, notably Bill Barrett, PDC Energy, (PDCE, not covered), Bonanza Creek Energy (BCEI, not covered), and Carrizo Oil & Gas (CRZO, not covered). Of note, Anadarko reached 100mboepd of production in 4Q12, while Noble Energy recently announced a ramp in drilling activity from ~200 wells in '12 to 500 wells in '17.

Figure 97: APC and NBL Hold Dominant Positions



Source: Deutsche Bank, Company Presentations

Figure 98: Production Trends For APC and NBL



Source: Deutsche Bank, Company Data

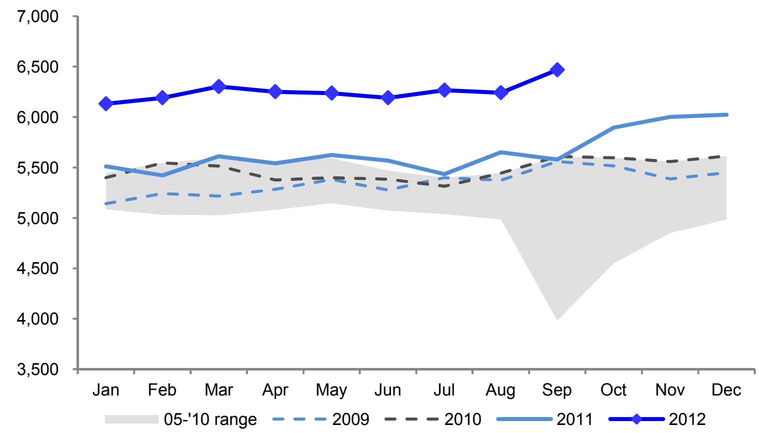
What To Look For

Although 160-acre spacing is the current base case across the play, downspacing could have a significant impact on inventory assumptions, particularly in the higher oil-cut acreage to the northeast. Noble Energy has two pilot programs testing 80-acre spacing (all 9 wells above type curve after 6 months) and 40-acre spacing, with greater clarity expected by 1H 2013. Producers are also testing multiple zones (Niobrara B & C, Codell) and expect tests to better define the opportunity. While Noble Energy is testing in the extension areas, Anadarko is particularly positive on Codell potential in the western extent of Wattenberg.

Appendix A

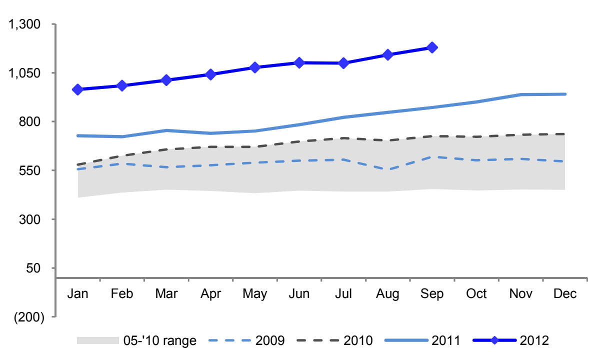
Historical Production

Figure 99: Total US Production (mbopd)



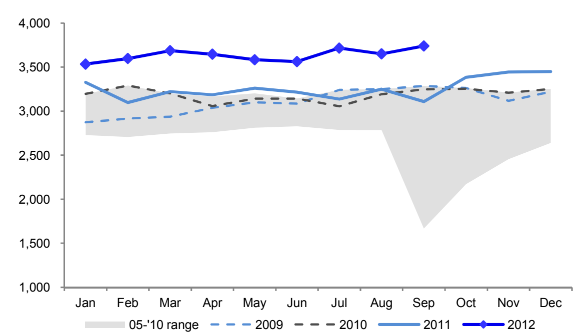
Source: Deutsche Bank, EIA

Figure 100: PADD 2 Production (mbopd)



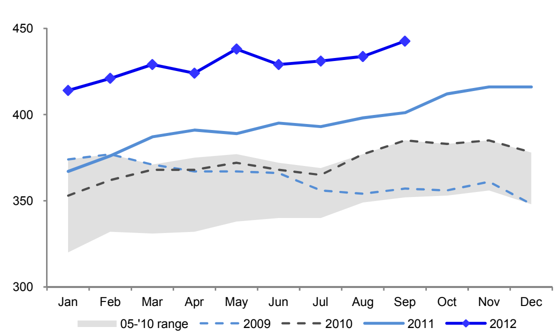
Source: Deutsche Bank

Figure 101: PADD 3 Production (mbopd)



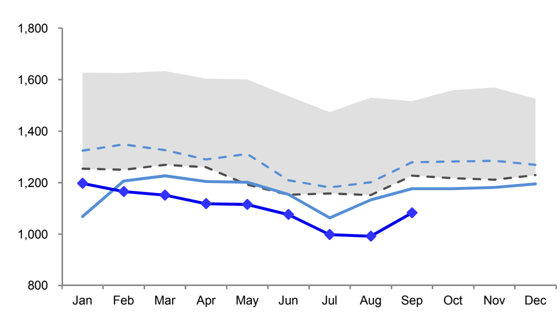
Source: Deutsche Bank

Figure 102: PADD 4 Production (mbopd)



Source: Deutsche Bank

Figure 103: PADD 5 Production (mbopd)

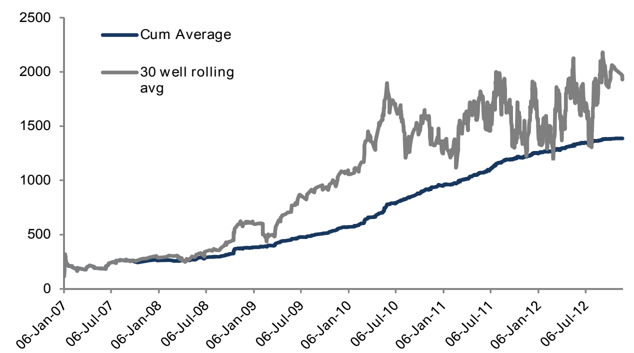


Source: Deutsche Bank

Appendix B

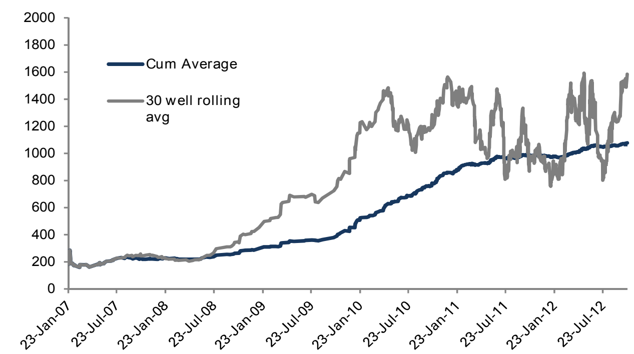
Bakken IP rates by County

Figure 104: McKenzie IP Rates



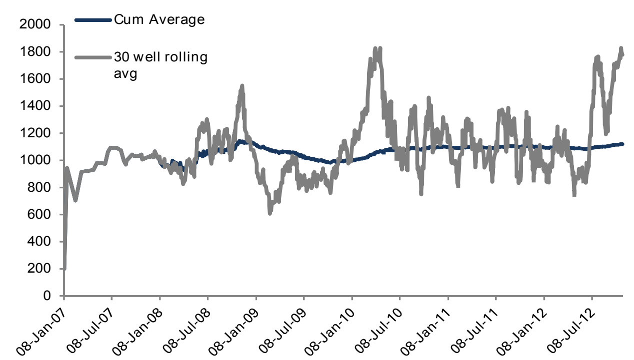
Source: Deutsche Bank

Figure 105: Williams IP Rates



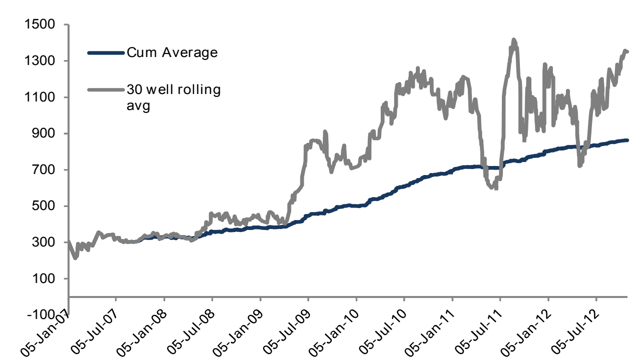
Source: Deutsche Bank

Figure 106: Mountrail IP Rates



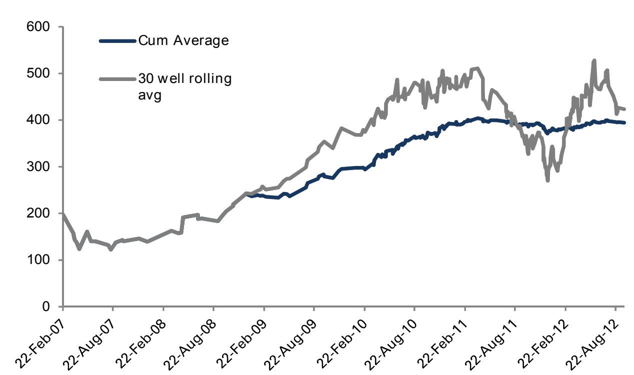
Source: Deutsche Bank

Figure 107: Dunn IP Rates



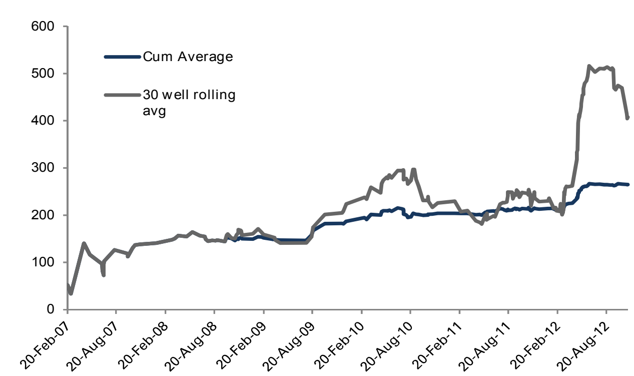
Source: Deutsche Bank

Figure 108: Divide IP Rates



Source: Deutsche Bank

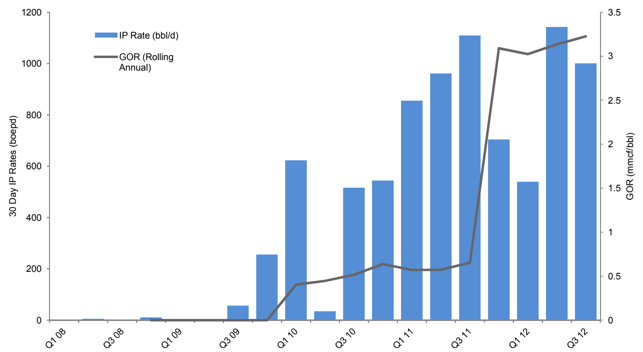
Figure 109: Burke IP Rates



Source: Deutsche Bank

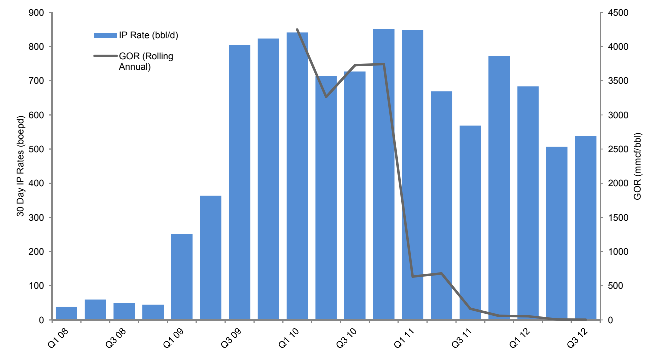
Eagle Ford IP rates by County

Figure 110: Gonzales



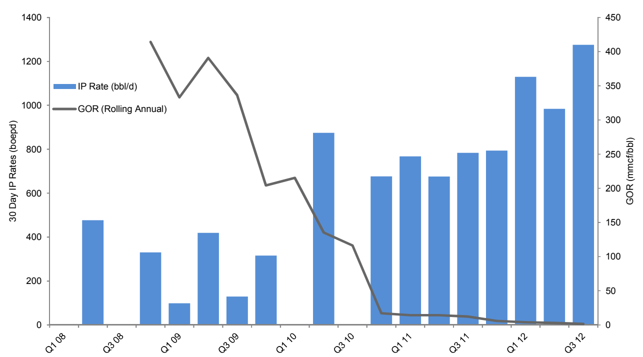
Source: Deutsche Bank, Texas Railroad Commission

Figure 111: La Salle



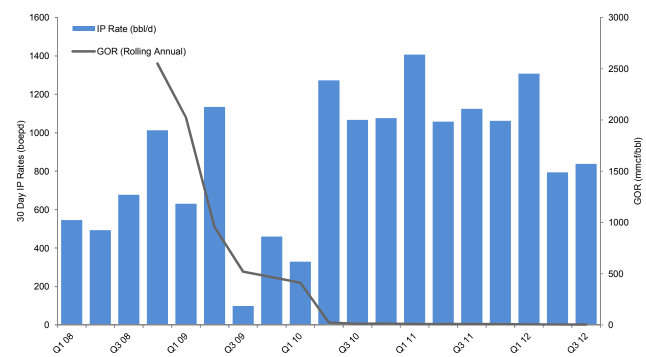
Source: Deutsche Bank, Texas Railroad Commission

Figure 112: Karnes



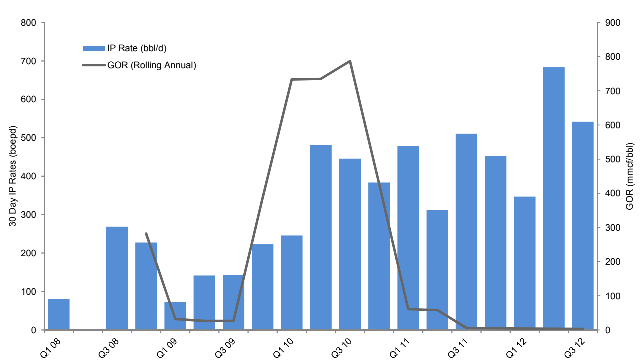
Source: Deutsche Bank, Texas Railroad Commission

Figure 113: DeWitt



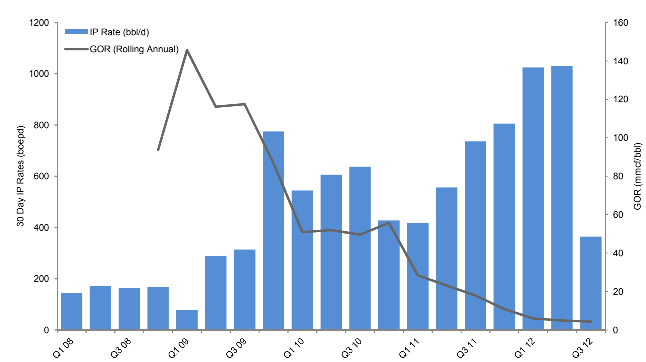
Source: Deutsche Bank, Texas Railroad Commission

Figure 114: Dimmit



Source: Deutsche Bank, Texas Railroad Commission

Figure 115: Live Oak



Source: Deutsche Bank, Texas Railroad Commission

Appendix C

North America Oil Supply

Figure 116: North America Oil Supply (mbopd)

Crude (mbopd)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Bakken	90	110	129	176	223	310	423	650	744	930	1,113	1,273	1,381	1,417	1,425	1,459
Eagle Ford	0	0	0	0	0	24	190	500	720	908	1,090	1,222	1,294	1,342	1,401	1,434
Permian - Base	910	900	890	880	870	858	925	1,005	985	952	917	881	847	814	784	755
Permian - Mid Wolf	0	0	0	0	0	13	60	120	212	271	317	355	388	418	446	471
Permian - Del Wolf	0	0	0	0	0	4	20	62	128	170	201	227	250	270	287	304
Niobrara	36	44	52	65	66	70	106	136	171	192	211	235	262	288	308	324
Uinta	51	52	53	54	55	56	58	62	79	94	110	125	142	158	175	193
MS Lime	22	23	23	23	24	17	22	34	66	98	124	145	164	180	195	208
Utica	0	0	0	0	0	0	1	6	20	32	40	46	52	57	64	72
California	28	29	30	32	34	35	52	36	29	26	24	23	23	22	22	22
Other - PADD 1	23	22	21	21	18	21	22	22	22	22	20	19	17	16	14	13
Other - PADD 2	331	325	318	339	344	363	373	410	431	418	401	381	351	323	297	273
Other - PADD 3	612	639	661	667	692	736	751	819	860	834	800	752	692	637	586	539
Other - PADD 4	253	261	256	238	236	245	226	235	235	223	210	193	177	163	150	138
Other - PADD 5	677	656	633	621	595	578	540	529	492	458	426	396	364	335	308	284
Alaska	864	741	722	683	645	601	572	555	505	459	418	380	351	335	327	334
Offshore - GoM	1,282	1,299	1,277	1,152	1,559	1,551	1,318	1,199	1,295	1,347	1,428	1,499	1,529	1,545	1,545	1,529
Total US	**5,179**	**5,101**	**5,065**	**4,951**	**5,361**	**5,482**	**5,659**	**6,382**	**6,993**	**7,435**	**7,850**	**8,154**	**8,285**	**8,321**	**8,334**	**8,352**
Canada																
Oil Sands	1,185	1,350	1,440	1,473	1,642	1,794	2,001	2,115	2,409	2,601	2,758	2,983	3,147	3,280	3,516	3,817
WCSB	985	965	954	939	871	879	917	1,025	1,059	1,103	1,132	1,142	1,148	1,140	1,137	1,129
East Coast	305	304	369	342	268	284	273	215	242	206	216	212	217	236	227	216
Total Canada	**2,475**	**2,618**	**2,763**	**2,754**	**2,781**	**2,957**	**3,192**	**3,354**	**3,710**	**3,911**	**4,106**	**4,337**	**4,512**	**4,656**	**4,880**	**5,162**
Total NAM Supply	**7,654**	**7,719**	**7,828**	**7,705**	**8,142**	**8,439**	**8,851**	**9,736**	**10,704**	**11,346**	**11,955**	**12,492**	**12,797**	**12,977**	**13,214**	**13,514**
Annual US Change		-78	-36	-114	410	121	177	723	612	442	414	305	131	36	13	18
Annual NAM Change		65	108	-122	437	297	411	885	968	642	609	536	305	180	237	300

Source: Deutsche Bank, EIA, CAPP

Appendix 1

Important Disclosures

Additional information available upon request

For disclosures pertaining to recommendations or estimates made on securities other than the primary subject of this research, please see the most recently published company report or visit our global disclosure look-up page on our website at http://gm.db.com/ger/disclosure/DisclosureDirectory.eqsr

Analyst Certification

The views expressed in this report accurately reflect the personal views of the undersigned lead analyst about the subject issuers and the securities of those issuers. In addition, the undersigned lead analyst has not and will not receive any compensation for providing a specific recommendation or view in this report. Stephen Richardson/Ryan Todd

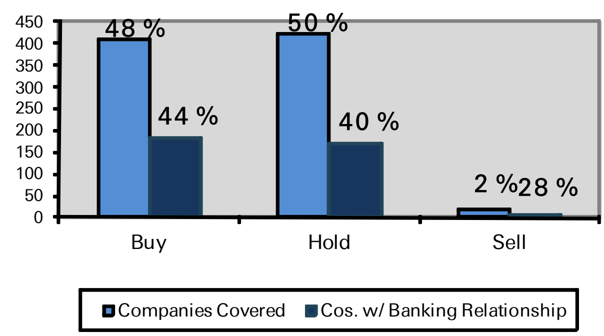
Equity rating key

Buy: Based on a current 12- month view of total share-holder return (TSR = percentage change in share price from current price to projected target price plus pro-jected dividend yield) , we recommend that investors buy the stock.
Sell: Based on a current 12-month view of total share-holder return, we recommend that investors sell the stock
Hold: We take a neutral view on the stock 12-months out and, based on this time horizon, do not recommend either a Buy or Sell.
Notes:

1. Newly issued research recommendations and target prices always supersede previously published research.
2. Ratings definitions prior to 27 January, 2007 were:

    Buy: Expected total return (including dividends) of 10% or more over a 12-month period
    Hold: Expected total return (including dividends) between -10% and 10% over a 12-month period
    Sell: Expected total return (including dividends) of -10% or worse over a 12-month period

Equity rating dispersion and banking relationships



North American Universe

Regulatory Disclosures

1. Important Additional Conflict Disclosures

Aside from within this report, important conflict disclosures can also be found at https://gm.db.com/equities under the "Disclosures Lookup" and "Legal" tabs. Investors are strongly encouraged to review this information before investing.

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