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Energy

Why Winners Win and the Value of Geology

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Introduction

Across many industries there is an overwhelming belief that management is the key to financial performance and shareholder value creation. It is the tenet to Warren Buffett's successful investment track-record and examples of this belief abound today in the fight over Dell, the dispute at JC Penny and concerns about Apple following the death of Steve Jobs. In each, a change in leadership is touted as either the tonic for a recovery or the reason for a decline. Such sentiment is not exclusive to technology or retail companies. Currently the public E&P space is seeing unprecedented turnover in management with recent CEO changes at Chesapeake, Sandridge, EnCana, Talisman and Forest, to name just a few. But realistically, how much can the executive suite control? In this research note we break down the drivers of performance and show that in the E&P space it is geology that matters and that few E&P management teams, no matter how experienced they are, can outrun the rocks. Instead, we believe they are better served by focusing on their geology teams and on their ability to stay ahead of the curve.

What Drives Performance?

At its core, the upstream oil and gas business is simple: successful companies find oil and gas cheaply and generate high cash margins. Whether publicly or privately financed, companies that can achieve both these goals, and ideally generate more cash per barrel than it costs to add a new barrel of reserves, have superior capital efficiency, higher returns and better growth. Moreover, companies with a higher cost of adding a barrel of reserves than the cash generated from a barrel of production, are ultimately doomed to decline due to the destruction of capital.

Although we have highlighted two factors, they are not of equal weight because an operator's ability to manage its cash margin is limited. Cash generation is driven by commodity prices - which are out of the operator's control, production costs - which depend on royalties, and lifting costs like water handling and power - which are frequently a matter of physics. As a consequence, there is a relatively small gap in the industry between the best and the worst operators. For example, over 70% of the inter-company variance in netback for a given mix of oil & gas can be accounted for by the commodity price.

In contrast, the ability to find oil and gas cheaply is in the geology team's hands and historically has not been mean-reverting across companies. Data suggests that good explorers tend to remain good and bad explorers remain bad. Geology teams that have identified the winning geological "formula" or who can consistently identify emerging technologies are more likely to continue to be able to do this. Moreover, lessons learned from operating at the cutting edge of exploration are likely to drive new thinking as long as management can maintain focus and capital discipline. Even more important is the fact that oil and gas portfolios resemble super tankers – in that it is nearly impossible to switch directions quickly. Leases can have durations of 3-10 years or even longer if they are held by production and new land positions can take years to build. This means that companies are unable to move to better geologic zip codes quickly, unless driven by an acquisition of better acreage.

While the basic tenets of "generating high cash margins" and "finding oil and gas cheaply" seem relatively simple, it is harder than it should be to compare one company to another using audited financial statements. GAAP measures like return on capital end up being gamed by companies who, to cite only one of many obfuscating methods, overspend on acreage acquisitions that they are later forced to write down, knowing full well that Wall Street models will tend to exclude these write downs as non-recurring special events. Furthermore, adding barrels cheaply is difficult to measure because there are different concepts of what constitutes a barrel. In the past five years the standards of what is considered a "proven" barrel of reserves have been relaxed significantly, including many more "proven undeveloped" or PUD reserves – that is, barrels which are known to exist but which will require significant additional capital to develop. Our preferred measure is to look at only additions of proven developed (PD) barrels – primarily meaning those barrels that are expected to eventually be produced from wells that are already drilled and producing. Combining this concept with cash generated per barrel of production, or netback, yields the "recycle ratio".

The Theory Behind the Recycle Ratio and Relationship With Upstream E&P Cash Flow Growth

The "recycle ratio" is the key to determining a company's ability to grow. We believe this makes it the most valuable differentiator between companies. As you can see in Exhibit 1, the growth rate of a company will be impacted by how much money it has to reinvest, determined by cashflow per barrel, and how efficiently it can reinvest that money, driven by the cost of finding and development – adding new proven developed reserves (PD F&D).

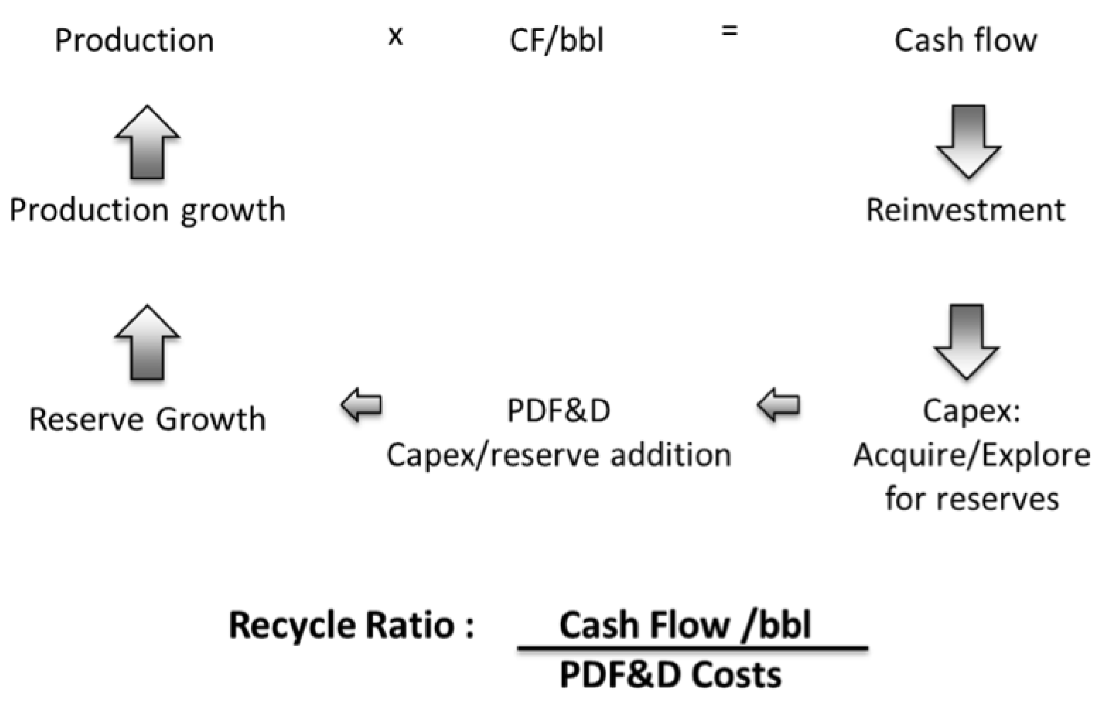

Exhibit 1: Schematic of the drivers of E&P performance

To demonstrate this, consider five companies with comparable daily production and identical realizations (Exhibit 2). While Company A has a $40/bbl F&D cost, Company B has a $20/bbl F&D and Company C has a $60/bbl F&D, driving differing reserve replacement rates and production growth (assuming no addition or subtraction of third party capital). By 2016 this trend in reserve, production and cash flow growth is compounded leading to materially differing values assuming all three traded on similar P/CF multiples. The same dispersion is created by altering cash margin but the impact is less significant, as can be seen with Company D and Company E, a factor that will be discussed in length later.

While clearly simplified, the model demonstrates the key factors at play in the upstream E&P universe: operating cash flow per barrel (CF/boe) and finding and development costs (PD F&D).

	Company A	Company B Lower F&D	Company C Higher F&D	Company D Lower Cash Margin	Company E Higher Cash Margin
Daily Production (barrels per day)	45	45	45	45	45
Annual production (barrels)	16425	16425	16425	16425	16425
BOY Reserves	200000	200000	200000	200000	200000
Reserve life (Reserves divided by production) years	12.2	12.2	12.2	12.2	12.2
Blended oil/gas price $/boe	$70	$70	$70	$70	$70
Cash Margin (% - industry average is 70%)	70%	70%	70%	55%	85%
Cash flow $	$804,825	$804,825	$804,825	$632,363	$977,288
Capex $	$804,825	$804,825	$804,825	$632,363	$977,288
Reserves added	20121	40241	13414	15809	24432
F&D cost per bbl (Capex/reserve additions)	$40.00	$20.00	$60.00	$40.00	$40.00
EOY Reserves	203696	223816	196989	199384	208007
Reserve growth (yoy)	2%	12%	-2%	0%	4%
Reserve Replacement Rate (Reserves added/produced)	123%	245%	82%	96%	149%
2013 Production (if reserve life is constant)	16729	18381	16178	16374	17083
Production growth	2%	12%	-2%	0%	4%
Forecast 2013 CF (assuming constant cash margin)	$819,697	$900,665	$792,707	$630,415	$1,016,414
Cash Flow Growth (%)	2%	12%	-2%	0%	4%
2014E	$834,843	$1,007,917	$780,772	$628,474	$1,057,107
2015E	$850,269	$1,127,941	$769,017	$626,538	$1,099,429
2016E	$865,981	$1,262,257	$757,438	$624,608	$1,143,446
Recycle Ratio	123%	245%	82%	96%	149%
Implied value in 2016 (assuming 5X P/CF)	$4,330,000	$6,310,000	$3,790,000	$3,120,000	$5,720,000
P/CF 2015 E	5.0	5.0	5.0	5.0	5.0

Exhibit 2: Comparison of E&P performance with differing PD F&D and cash margins

Operating Cashflow: A Key Driver, But Fairly Constant in a Flat Commodity World

For most oil and gas companies cash operating margins are relatively hard to control. The majority of costs are tied to realizations, royalty taxes and operating costs (maintenance, power, chemicals and water), over which an operator has almost no control. While SG&A is arguably something that can be controlled, this is relatively insignificant in the context of the capital at work.

As a result few companies can change their cash margin over time or decouple it from the product they produce (Exhibit 4). An analysis of the top 40 E&Ps illustrates this. For example the majority of the differentiation between E&P companies' cashflow per barrel can be explained by their mix of oil and natural gas.

Even companies with the largest deviation from the trendline (Exhibit 5) show trends which are primarily based on crude quality as opposed to drivers that management can control. For example CNQ's cashflow per barrel is $13 lower than the trendline, but this predominantly reflects a lower quality of crude sold (in essence cash flow should be adjusted for crude API). On the other end, Gulfport performed well above the trend given its disproportionate exposure to Gulf Coast (Brent and therefore higher priced) crudes. Overall, the data demonstrates that the average absolute deviation in cash flow per barrel versus commodity mix projected CF is $4.36/boe, or just 16% of the average CF/boe.

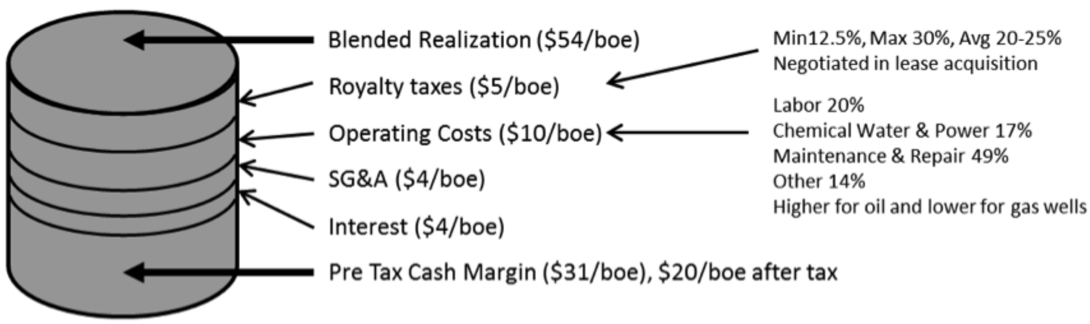

Exhibit 3: Breakdown of a barrel

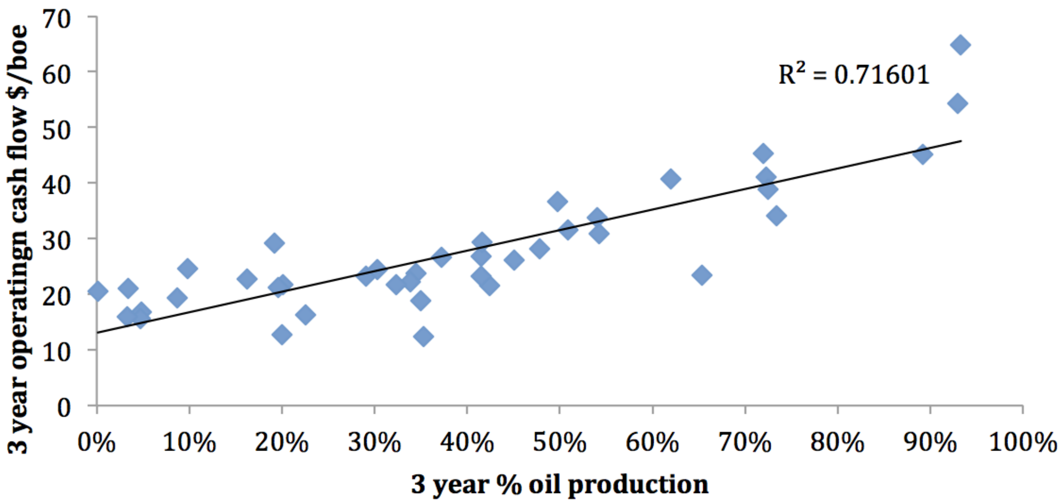

Exhibit 4: Correlation of operating cash flow versus commodity exposure

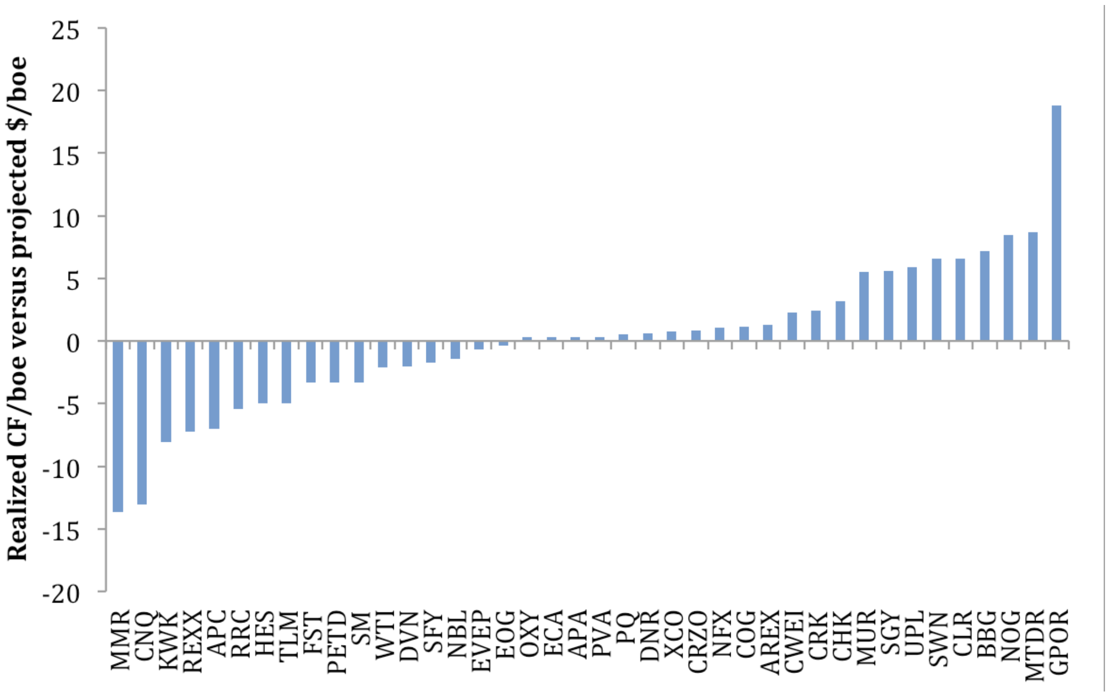

Exhibit 5: Deviation of CF/boe versus commodity adjusted estimate

Variation in F&D: The True Driver is the Rocks

In contrast to operating cash flow per barrel, proven developed finding and development costs (PD F&D) are subject to considerable variance (Exhibit 6). Even averaging reserve addition trends over the last three years shows that the spread between the best and worst performers is significant at nearly $100/boe (this excludes two companies that had negative net additions of proved developed reserves over 2010-2012).

Moreover there is virtually no correlation in F&D trends to commodity exposure, because geologically it's not necessarily easier or cheaper to find a barrel of oil than finding a mcf of natural gas. This in turn suggests that other factors drive this key metric.

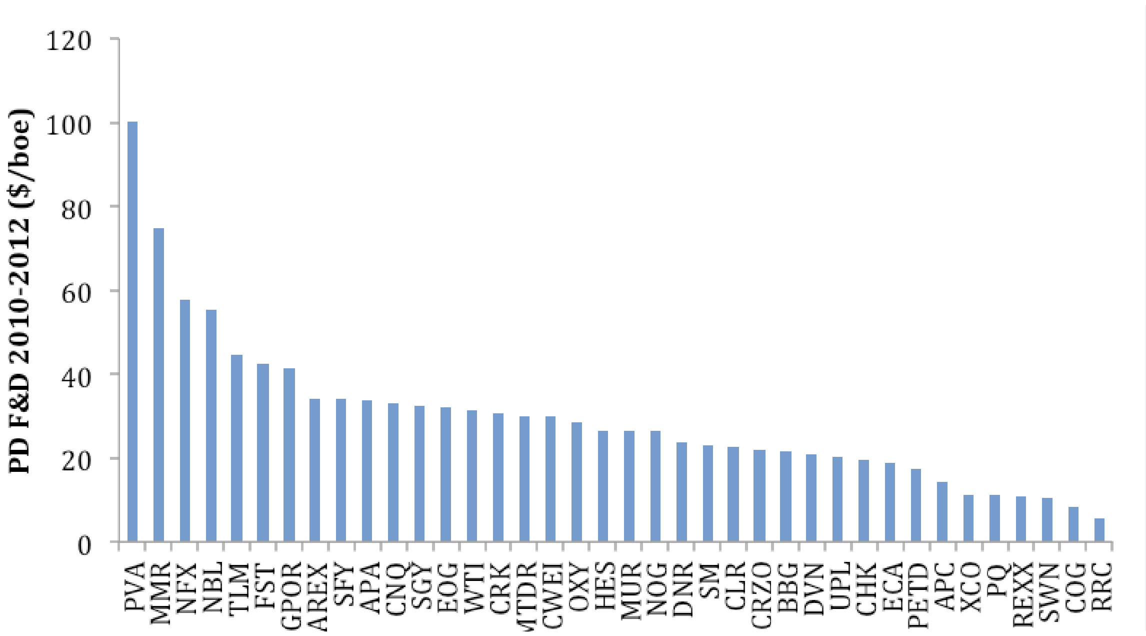

Exhibit 6: 3 year PDF&D of the peer group

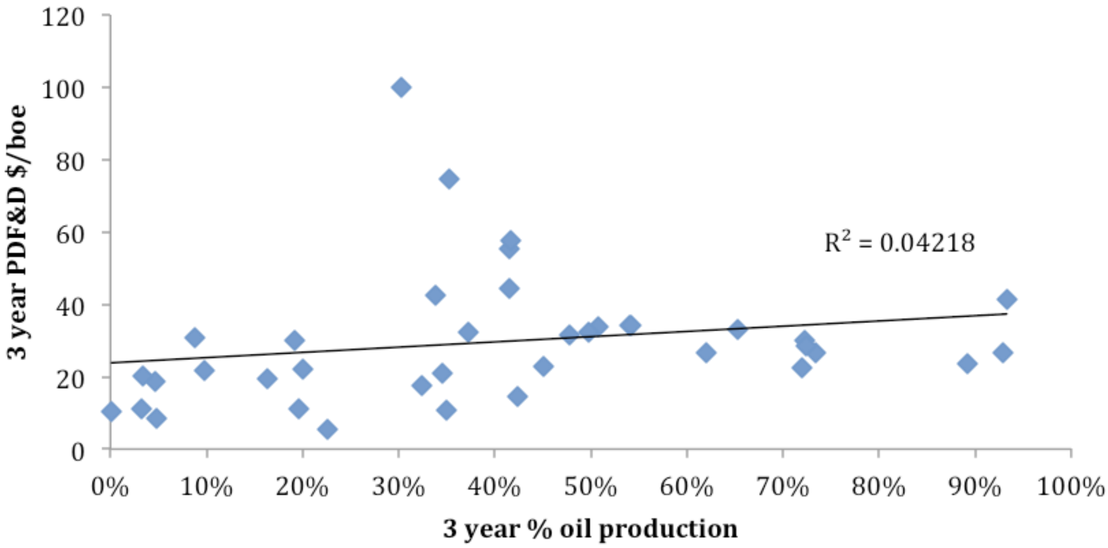

Exhibit 7: Correlation PDF&D to commodity exposure

The Drivers of Divergence

So why is there such great difference between companies on this metric? To answer this question, we break down PD F&D into its two main constituent parts:

- The capital cost of drilling, completing and tying in a well
- The size of the reserves added from the associated well (EUR)

For instance, if in the Permian an operator spends $10 million drilling, completing and connecting a new Wolfcamp horizontal well that has an estimated ultimate recovery (EUR) of 600,000 boe, the company in question will have a PD F&D of $16.6/boe (10,000,000 / 600,000).

An operator has considerable control over both these items, although EUR has a much wider standard deviation between operators. Looking first at the numerator, capital costs of drilling are highly sensitive to days to drill, mobilization costs and frac costs. Over time an operator who has scale, drills year-round, understands the geology and keeps consistent rig teams working can lower costs anywhere between 10-50%.

However, operators in the same play show little variation in well costs, once adjusted for depth and lateral length of the completion. A good example of this is again in the Permian (Exhibit 9). Despite well

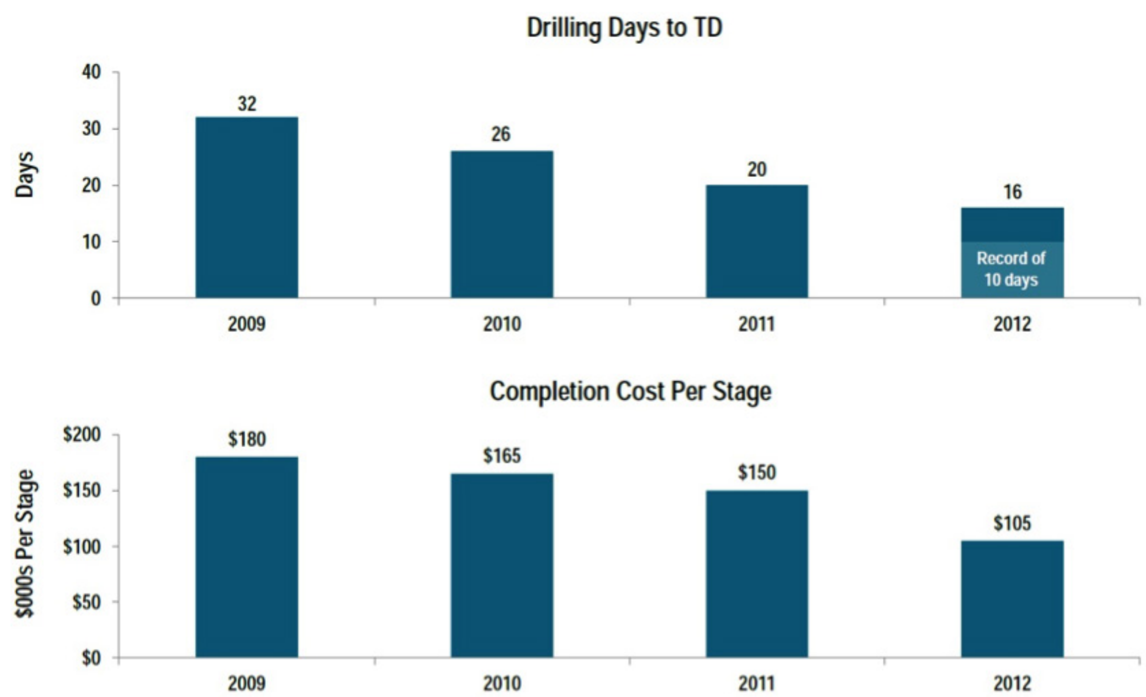

Exhibit 8: Cabot days to drill and completion costs per stage in the Marcellus

completion techniques seeing considerable variation due to operators testing new completion "styles" the majority of operators are guiding to similar (within 5-15%) costs.

With this in mind it becomes clear that the primary driver of F&D is EUR per well drilled and, by default, the underlying geology. There is a tendency to assume that this means that companies can be rated by the basins they are in. For example, if Company X is in a new play with drilling costs of $5 million and reserves per well of 500,000 bbl then the company will have a $10 PD F&D. If Company Y is in another region where well costs are double, at $10 million with similar EUR of 500,000 bbl, it will have a PDF&D of $20/bbl. For investors these differences on a basin-by-basin basis appear easy to determine. After all multiple players release results from each basin, leading the sell-side in particular to put each play on a cost curve based on its EUR or F&D.

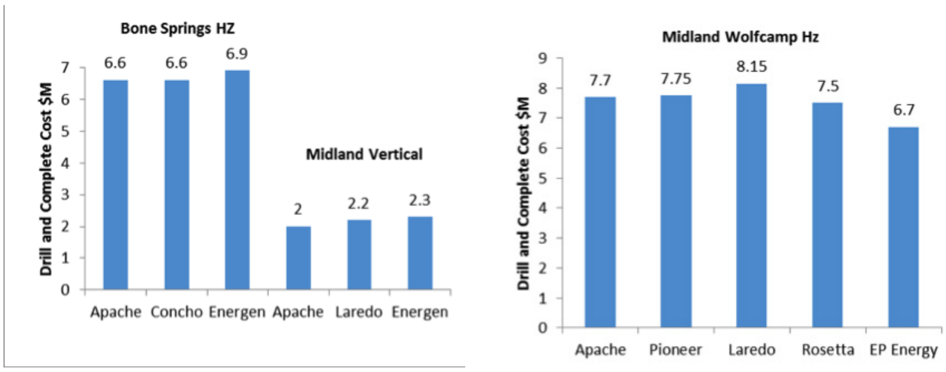

Exhibit 9: Estimated drill and complete costs for operators in the Permian Basin

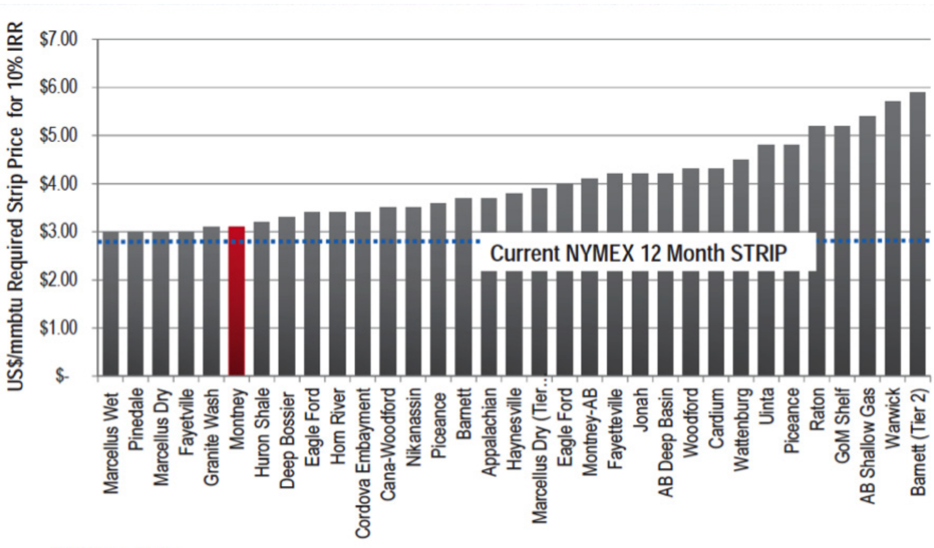

Exhibit 10: North American cost curve for major unconventional plays (Morgan Stanley)

However, this analysis is flawed and determining winners is significantly more complicated. The reason is that the differentiations between companies based on EUR per well are very likely to occur within the very same play. Companies can't simply be understood based on which plays they are in; their EUR, F&D, and performance will be determined by their geologic position within basins as well.

The reasons for this are many. Unlike conventional oil and gas exploration which is a series of binary outcomes, the unconventional exploration business is gradational. In many ways each unconventional oil or gas play represents a Venn diagram of factors such as depth, thermal maturity, pressure, total organic carbon content (TOC), thickness, porosity, permeability and mineralogy to name but a few elements (Exhibit 11). Where these elements optimally overlap or co-exist represents the "core" of any play and if specific elements disappear the average well performance drops.

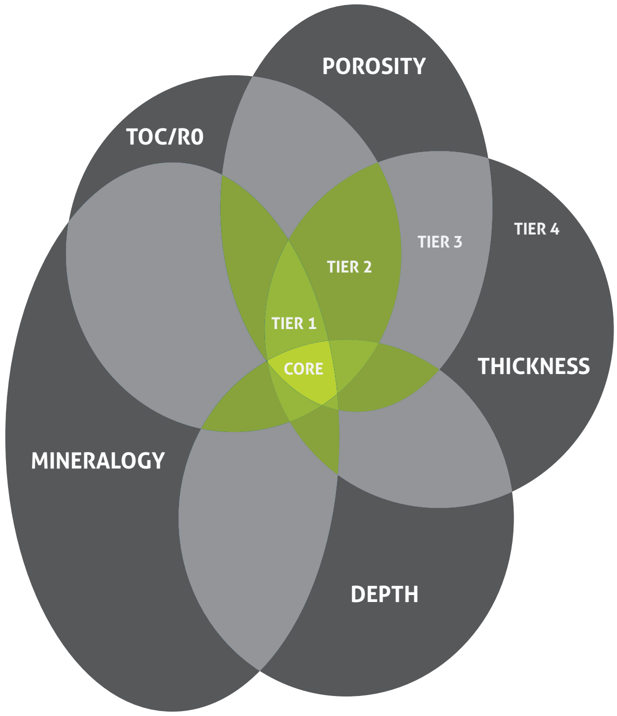

Exhibit 11: Schematic of overlapping drivers of EUR

As we discussed in our previous research piece (Defining the Core of Shale Plays), this is consistent across all plays, but perhaps the most well-studied example is the Barnett in the Fort Worth Basin, Texas. (Exhibit 12).

Data from the Bureau of Economic Geology at the University of Texas shows the significance of this, by mapping projected production (or EUR) for each 640-acre unit of the Barnett, based on well results to date. This normalizes for completion technique and projects each assuming a 4,000 foot lateral. What is notable here is that from the core of the play (>4.3 Bcf) to the fringe (<0.5 Bcf) the EURs vary by almost a factor of 10. Assuming that well costs are broadly similar at around $3 million this implies that the F&D for the play varies from $6/mcf to $0.75/mcf, explaining the spread in reported results (Exhibit 6).

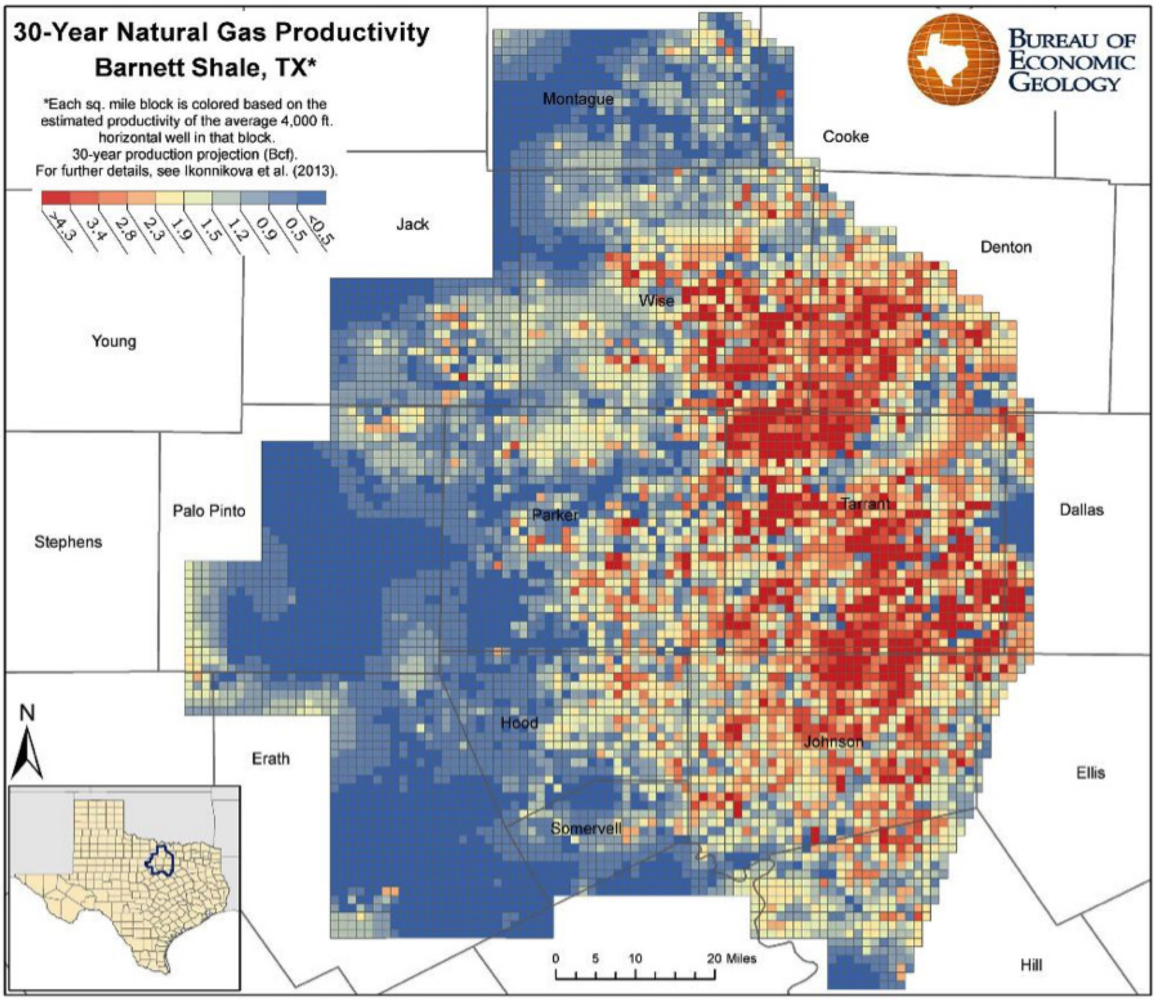

Exhibit 12: Estimated 30 year productivity per section based on comparable well completion.

Implications for Investors and Operators Alike

We have shown above that superior performance by geology teams can yield better cashflow growth. And while it is logical that rising cash flow growth delivers greater value creation, it should not be taken for granted that this is automatic. Proving this requires an analysis of public stocks since private sales data on cash flow growth and exit prices are patchy and unreliable.

Looking at the top 40 North American E&Ps, 32 have been in existence the last three years and have had positive recycle ratios. Within this group there is strong evidence to suggest that recycle ratios drive cash flow growth and share price performance (Exhibit 13). Furthermore, the data indicates that improving recycle ratios lead to expanding multiples, creating a compound effect.

To put this into perspective, if an investor over the last three years bought names that had recycle ratios of 1.5x or higher then on average the group was up 62% (there were seven such companies). In contrast those names with recycle ratios below 1.0x were down 22%.

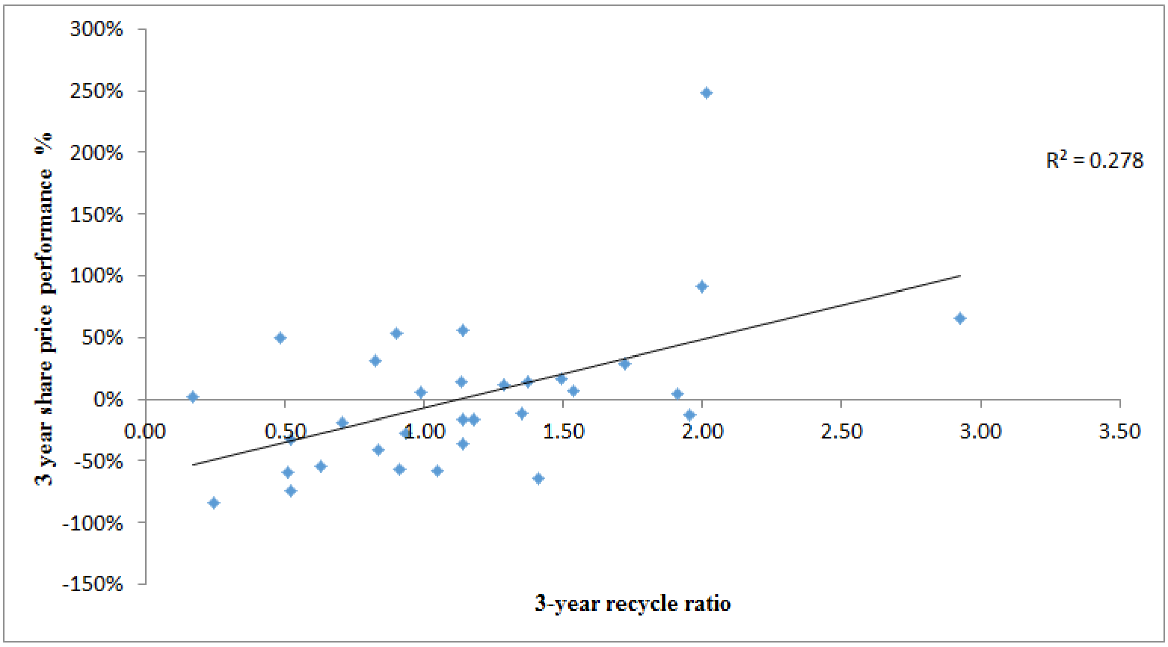

Exhibit 13: Correlation of recycle ratio of share price performance (last 3 years)

Conclusions

The above data suggests that over time the market for investing is indeed rational and the best performers are those that can find oil and gas cheaply and generate high cash margins (i.e deliver a high recycle ratio). In an environment of rising commodity prices, the key element is the change in commodity price and cash flow per barrel, which masks the relevance of F&D. In contrast, in flat or declining commodity price environments F&D differentiation becomes key.

Given the lack of control over commodity prices and the relative inability of investors to predict them, the data suggests that the key to performance is not operational efficiency in controlling production costs or driving down the cost of drilling, since these benefits are reaped by all players equally. Instead, what matters is being in the right geology. Unfortunately for both public and private investors it is very hard to figure out where that is, especially if the ambition is to make it there before competitors or other investors. In the private sphere the emphasis to date has been on sticking with winning teams. The assumption has been that a geology team that has done it once can and will do it again. There is a fair amount of data to support this view, although finding proven teams at a reasonable price is clearly difficult in the current environment. In the public sphere the data implies that winners will continue to win and losers will tend to lose and that any company turnaround must be premised on a shift to better geological areas. Moreover, low multiple stocks are frequently value traps that deserve to be trading at low multiples and high multiple stocks are often the best performers. At least until the geology runs out.

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