KIMMERIDGE
Energy

Defining the Core of Shale Plays

Lessons from Cutting-Edge Research
and Practical Experience

Introduction

With the advancement of drilling technology and the ability to produce oil and gas from increasingly low porosity and low permeability rocks, the global oil and gas industry is undergoing a renaissance in onshore exploration and production, exemplified by the rapidly growing production of shale gas and oil in the United States (exhibits 1 & 2).

The focus on long-life resource plays has forced companies to develop a whole new set of skills focused on resource appraisal rather than old-school wildcat exploration.

Shale plays are often identified in mature hydrocarbon basins (see exhibit 3), which may have numerous wells penetrating the source interval, good seismic coverage and a comprehensive understanding of basin geology. Consequently, a significant amount of early de-risking of new plays can be done from the desktop. Combined with the nature of shale plays, this means that actual exploration risk is vastly reduced.

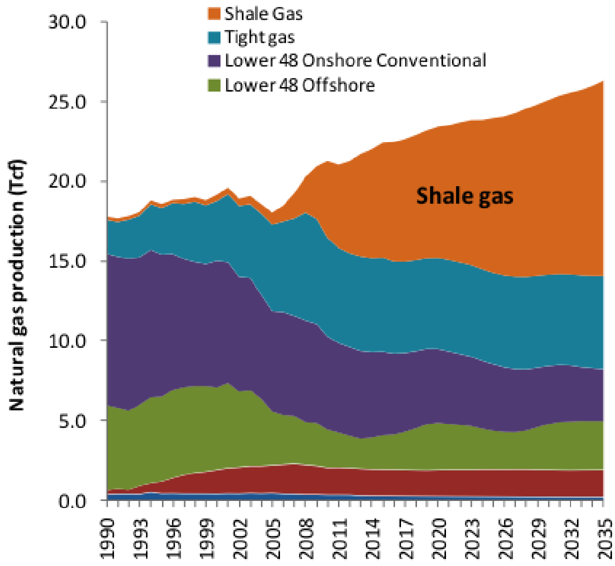

Exhibit 1: Historic and projected US gas production
(Source: EIA and Kimmeridge Energy estimates)

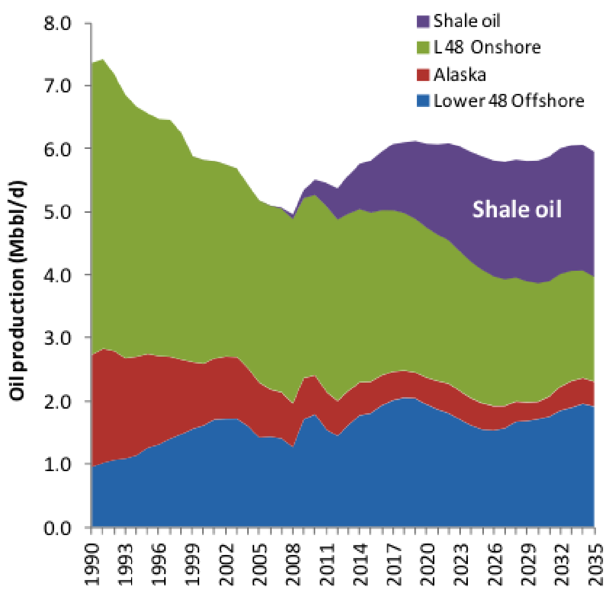

Exhibit 2: Historic and projected US oil production
(Source: EIA and Kimmeridge Energy estimates)

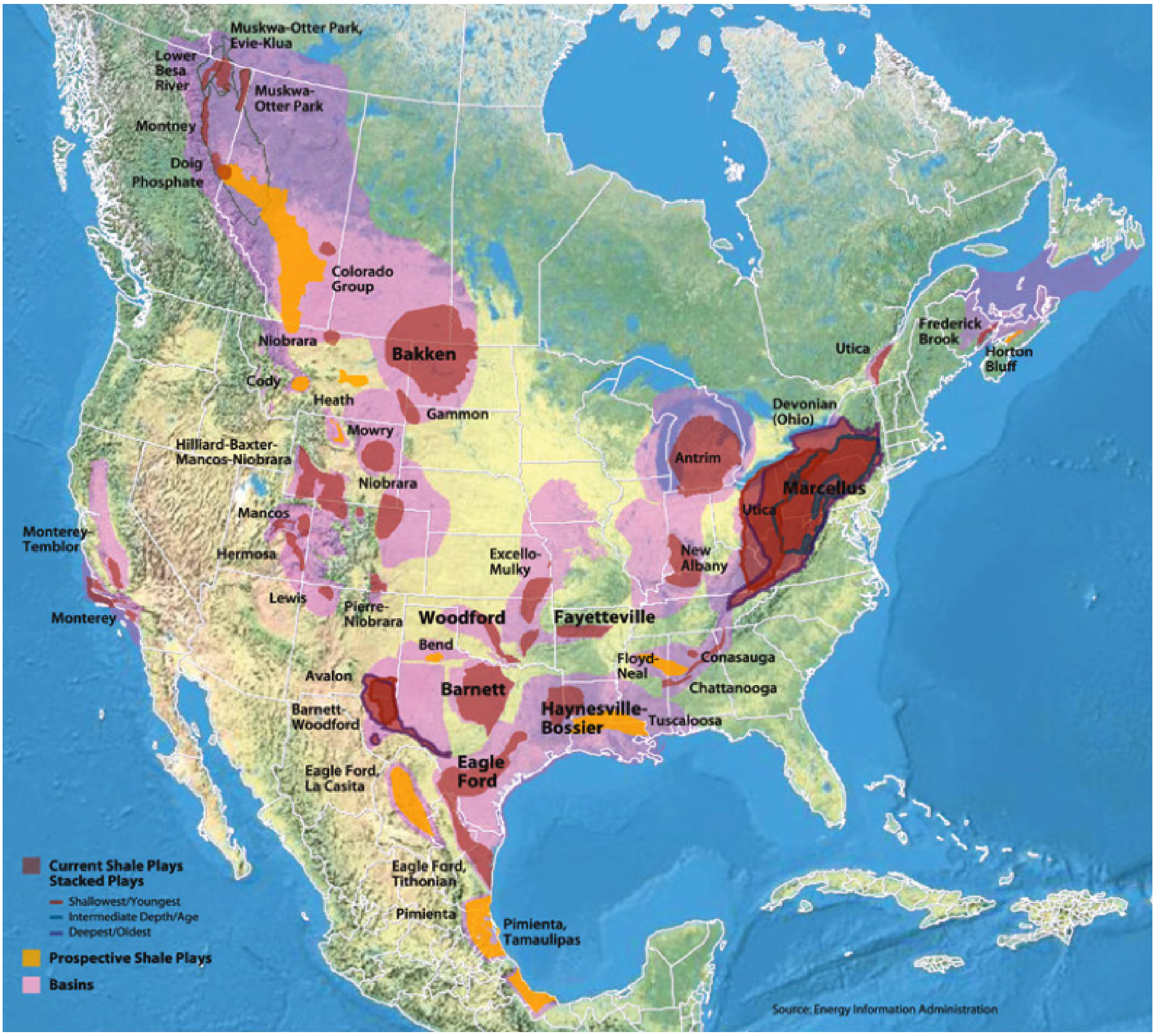

Exhibit 3: North American basins and shale plays (Source: EIA)

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Rapid Evolution of Industry's Understanding of Shale Plays

The industry's understanding of shale gas plays is relatively mature, based on over a decade of success in various plays like the Barnett, Haynesville, Marcellus, Woodford and Fayetteville. In contrast, the industry's understanding of shale oil plays is fairly nascent, with the only proved and developed plays being the Bakken, Eagle Ford and to a lesser extent the Niobrara.

Therefore, the newest frontier, and current focus of the industry due to low US gas prices, is shale oil. But, with a limited number of proven plays, the formula for success is still being defined. Indeed, the idea that oil could be produced directly from shales was almost unthinkable a few years ago – many believed that the Bakken, the first successful shale oil play was unique and was more akin to a hybrid shale play with production only possible from the dolomitic Middle Bakken, which is essentially a conventional reservoir rock sandwiched between two shales.

Industry's knowledge has expanded not only in terms of what can be produced, but also with respect to the uniformity of these plays. In the beginning, the industry consistently argued that unconventional resources were manufacturing plays. However as each of these plays has evolved it has become increasingly clear that this is rarely the case and that there is a high degree of heterogeneity across the plays driven by variation in geological inputs. This in turn meant that each play has, over time, been divided into a core where these elements or factors optimally overlapped and a non-core portion where certain geological elements were missing.

Furthermore given the fact that a light oil molecule is typically 10-20 times larger than a methane molecule, it is even harder to extract oil than gas from tight rocks such as shales. As such, in shale oil plays the impact of variations in porosity, permeability and mineralogy are accentuated. This means it subsequently becomes even more important in tight oil plays to lease within the core, since flow rates and economics will be markedly better in the core versus the fringes of the play.

So the key first step for companies is to identify the "core" before wells have been drilled and lease this acreage early to minimize entry costs. Identifying the core after many wells have been drilled is relatively easy, as it is simply the area where wells are most economic (i.e. highest flow rates for standard well completions).

Therefore, early-entrants need to develop skills to identify the potential core, based primarily on geological and geochemical parameters. Much of this skill set derives from historic research and knowledge of source rock quality, which during the era of deepwater exploration in the 80s and 90s, took a backseat to seismic-led exploration focused on structure. With this new style of hands-on exploration (rather than seismic workstation exploration), geochemists have a more prominent role to play.

Typical parameters of interest are kerogen type, TOC, hydrogen index, mineralogy, porosity, permeability, pressure, thickness, maturity, etc, most of which are obtained from geochemical analysis, and are fundamental to understanding shale plays.

Defining the core

After extensive drilling and de-risking of a play, it is relatively easy to define the core (see exhibit 6). It is simply the area of the play where wells produce the highest return on capital employed. More specifically, it is a combination of the wells with highest initial production rates (IP)and estimated ultimate recovery (EUR) potential because of the best geology, and the best initial price per acre and royalty terms. Often high IPs are the only metric used to assess the core areas of a play.

In a mature play like the Barnett, where completion methodology has become consistent over time (e.g. the length of the horizontal wellbore and the number of frac stages are similar between different wells), then IP rates alone can define the core.

However, in a new play with no/little drilling and no/little production history, the core must be defined pre-drill in advance, using geoscientific and economic parameters, to optimize a company's leasing strategy.

In simple terms, the core is where the overlap of geological and geochemical characteristics are optimal and thus wells drilled there should produce the best well economics.

Shale plays are gradational in nature (see exhibit 5), with a variety of thicknesses, depths, TOC, mineralogy, maturity, etc, across the play fairway, which can be many thousands of square miles. The core of the play occurs where the confluence of these different parameters is optimal. So for example, a confluence of good thickness, high TOC, requisite maturity, high porosity, suitable mineralogy, etc, is most likely to offer the best development economics across the play, although this needs to be proven through subsequent drilling and de-risking.

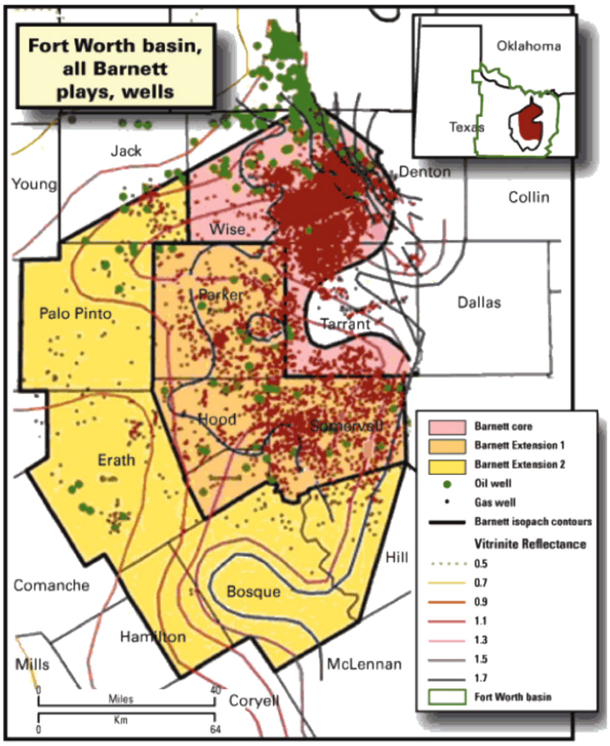

Exhibit 4: Barnett shale play in the Fort Worth basin
(Source: Advanced Resources International and EIA)

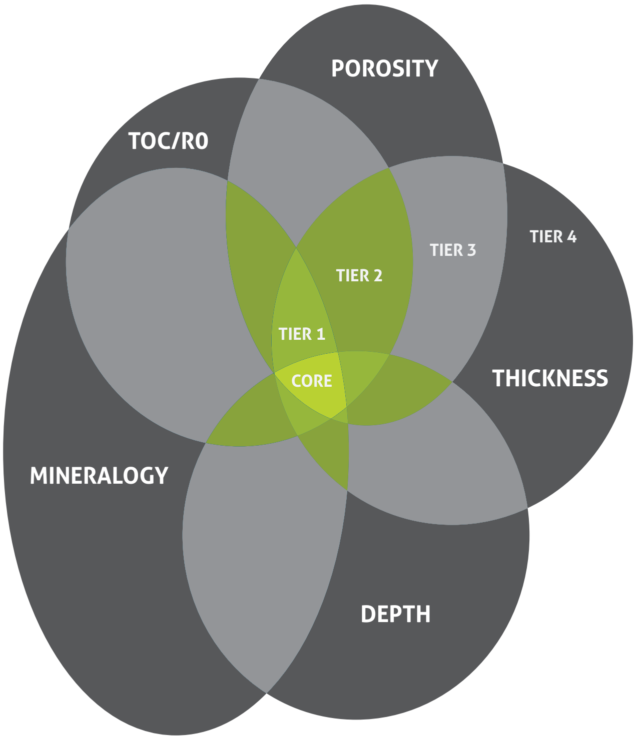

Exhibit 5: Gradational nature of shale plays
(Source: Kimmeridge Energy)

Furthermore, we should caution strongly that looking at characteristics such as TOC or thickness in isolation, is virtually meaningless when assessing quality of plays. For example, a shale with average TOC of 10% may seem prospective, given no other data, since TOC>2% is the generally accepted lower cut-off for a "good-quality" shale.

However, source rocks are rarely if ever made up of one type of organic matter – typically a source rock will contain a combination of kerogen types I, II, III and IV, and there are even types within types, such as type IIS, which indicates a sulphur-rich marine source rock that has a lower activation energy than a normal type II source rock, but produces higher sulphur oil.

Consequently, a shale with average TOC of 10%, but made up primarily of Types III (woody/coaly) and IV (inert) kerogen will be moderately gas prone and not make a good shale play, despite the high TOC. This is because a large percentage of the organic matter is not convertible to hydrocarbons, due to a low hydrogen content (indicated by the rock eval derived hydrogen index or directly measured atomic H/C ratio). Additionally, a predominantly type III source rock would be a coal, so more akin to a coal-bed-methane play, rather than a shale play.

Therefore, it is crucial to understand the optimal interaction and combination of these various factors in order to delineate ex-ante the potential core of a new play. Acknowledging and risking one's knowledge gaps, for example in a play where mineralogy data is missing, should be a fundamental part of the investment screening process for potential new shale plays.

Even parameters that seem fairly straight-forward, such as depth (given that the shale is mature), cannot be simply interpreted as "shallower is better" due to lower well costs. For example, a shale that sits in the early oil window at shallow depth due to uplift, in a basin that is heavily faulted, is probably less valuable than a shale that sits at greater depth in the peak oil window in a tectonically quiet basin.

Why? - Because peak oil window maturity results in a higher transformation ratio, more oil produced and higher saturation, and typically higher pressure. Additionally, with limited faulting, primary migration is restricted, allowing more oil to remain in-situ within the source rock, which can also increase geopressuring. Greater depth also increases pressure, helping flow rates, but increasing well costs, so there are clearly trade-offs that affect play economics. Understanding such trade-offs and defining the optimum convergence of different factors is key to being able to successfully define the core.

Worked Example – Paris Basin Liassic Shale

The Paris Basin in France is the first international play to be recognized as a Bakken analogue. Although political and environmental opposition to fracking have slowed development of the play, we believe it is promising from a geological perspective, and it makes a useful example in highlighting the process for defining the core, pre-drill.

Over 2000 wells have been drilled in the Paris Basin, and despite only modest historic production of around 300 million barrels of oil, the basin is well studied, particularly from a geochemical standpoint, with techniques such as rock eval pyrolysis pioneered by the Institut Francais du Petrole (IFP), which owns the trademark Rock Eval™.

The basin is known to have three primary petroleum systems, with three Liassic source rocks, the most important of which is the Toarcian Schistes Carton. Several hundred wells have penetrated this interval, and extensive geochemical data is available on the Schistes Carton, enabling significant desktop analysis. The Schistes Carton is a type II marine shale, with high TOC, high HI and oil mature at depths of over 1800m in the Paris Basin (see exhibit 6).

Since the tectonic setting of the Paris Basin is very quiet and the structure simple (it is an intracratonic basin like the Williston Basin that contains the Bakken shale play), we can define the areal extent of the play as the area where the Liassic shale has been deposited and lies deeper than 1800m.

The next step is to identify areas of superior geological and geochemical parameters, in order to home in on the potential core.

Maturity maps of the Liassic Schistes Carton source rock (see exhibit 7 - pg8) show a Tmax range of 430-445 (~0.55-0.85 Ro%). All areas where maturity is >0.55 Ro% will have produced oil, but areas of higher maturity ~0.75-0.85 Ro% will be in the peak oil window, and will have generated more oil and have higher saturation.

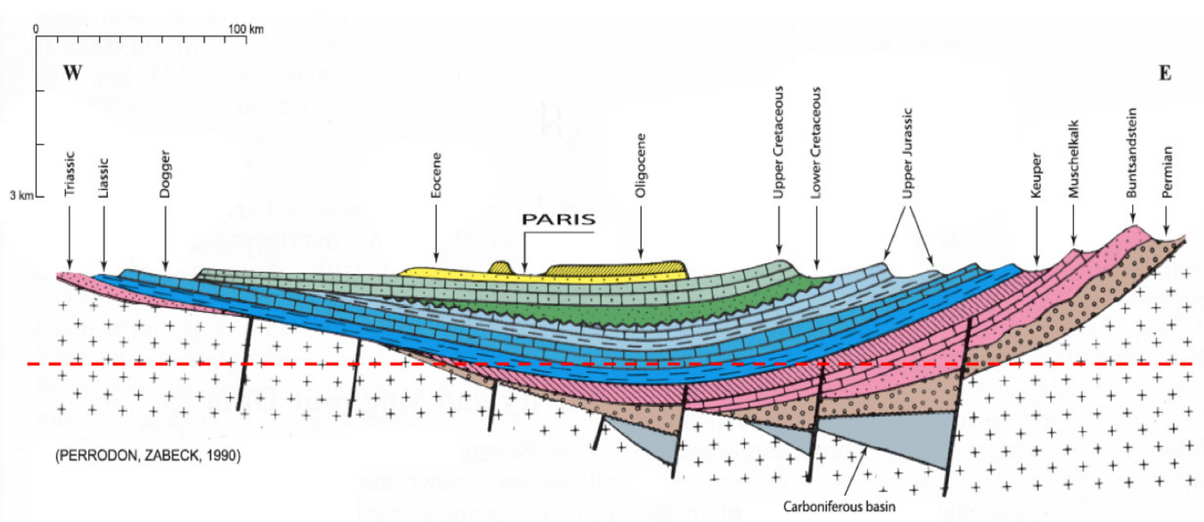

Exhibit 6: Cross-section of Paris Basin (Source: IFP and Kimmeridge Energy)

Additionally, intense generation of oil typically results in geopressuring of shales due to the volumetric expansion of kerogen transformed into oil. This causes natural fracturing, which can enhance porosity and permeability, aiding in the produceability of the shale.

Another important attribute is thickness, which varies from around 5-65m for the Schistes Carton (see exhibit 8), as well as TOC. Greater shale thickness (as long as the TOC is high enough) provides more organic material for transformation into oil, and also more storage capacity.

Thus, the pre-drill core of the play geologically is the overlap of areas of peak oil window maturity, highest original TOC, highest original HI, greatest shale thickness, highest porosity and permeability, and suitable mineralogy for well completion, as this is the area most likely to deliver the best well economics. Broadly speaking, the core should lie in the depocentre of the basin, where the Liassic is thickest and deepest.

Furthermore, an analysis of historic wells indicates that the Liassic shale in the prospective basin centre is over-pressured, with several wells that flowed/kicked/showed oil from this interval. This includes two modern vertical and hydraulically fractured development wells drilled by Vermillion into the Liassic shale, which produce a combined 60 bbl/d. Consequently, the core of the play has been reasonably well constrained prior to extensive drilling to test the play.

Due to the above-ground issues in France, such as strong environmental opposition and the ban on hydraulic fracturing to develop shale plays, there are clearly other factors that are very important to consider in the investment process. However, the above example gives an overview of what it takes to define the core pre-drill.

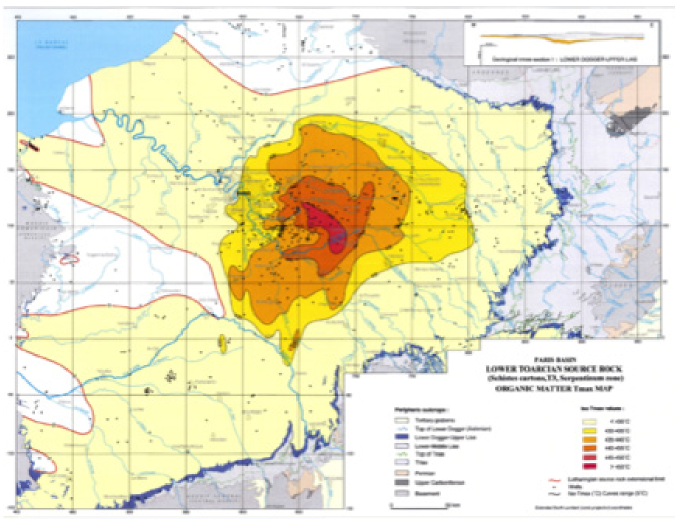

Exhibit 7: Maturity map of Toarcian in Paris basin (Source: IFP)

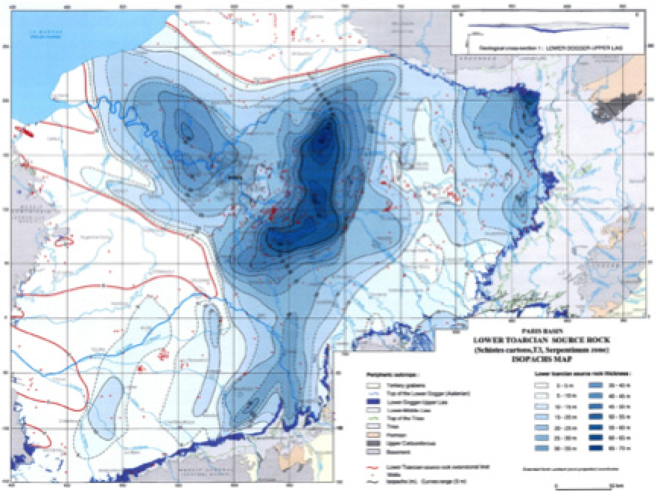

Exhibit 8: Isopach map of Toarcian in Paris basin (Source: IFP)

Defining the Core Post-Drill

Once a play is developed, and a sufficient number of wells have been drilled to generate a dataset with IP rates for standardised completions across a play, it is fairly straight-forward to define the core. This is something we have developed within Kimmeridge Energy over the last few years, and currently we have around 10000 wells in our North American frac-completion database.

For the oldest shale play in the US, the Barnett shale, we can compare the pre-drill core counties targeted for leasing, with the post-drill core based on IP rates for horizontal wells (see exhibit 9).

Notably, our technical team Roxanna recognized the extension of the Barnett shale play into Johnson County in 2005, and it proved to have some of the highest IP rates across the play.

Interestingly, a map created by Jarvie et al. in 2006 showing the Hydrogen Index-derived transformation ratio for the Barnett shale (see exhibit 10), shows that the eastern extent, including Tarrant, Johnson, Wise and Denton counties should be most prospective for shale gas. This is because transformation ratios in the range of 80-100% indicate that the shale has reached sufficient thermal maturity for secondary cracking of oil to gas.

Clearly other factors, such as rock mineralogy, porosity and permeability affect flow rates, so the eventual core was defined by the optimal overlap of these different factors that resulted in the best well economics.

Notably, there is a material divergence in well economics between the core and fringes of a play. Well performance and economics can often be orders of magnitude different, which drives a huge discrepancy in investment returns between core and fringe acreage. Consequently, it is crucial for early entrants to define and lease the expected core of the play in order to ensure the best returns. In the next section we use a simplified example of two wells, one core and one non-core, to highlight this difference in economics.

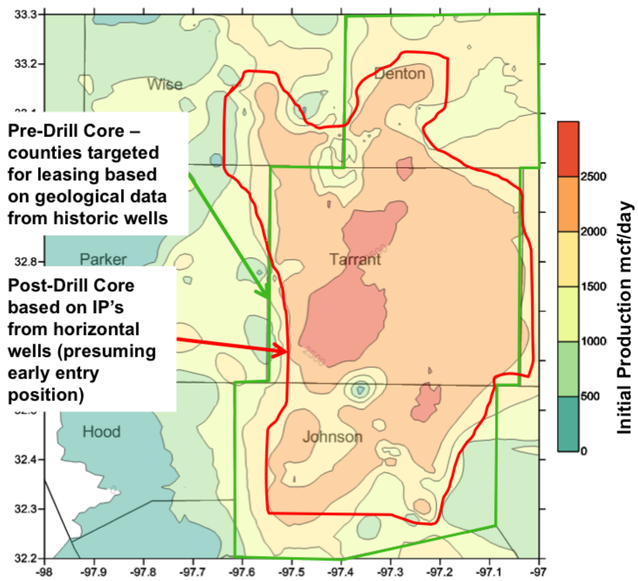

Exhibit 9: IP map of core of Barnett shale play
(Source: HPDI and Kimmeridge Energy

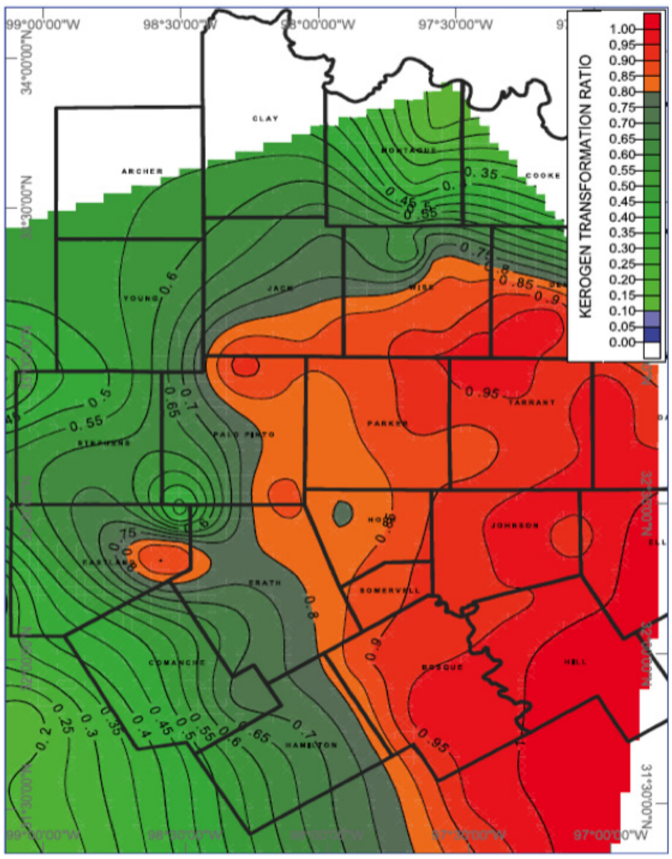

Exhibit 10: Transformation ratio for Barnett shale play
(Source: Jarvie et al., 2006)

Core vs Non-Core Economics

In the adjacent map (exhibit 11), we compare two fictional wells – one in the core of the play in Tarrant county with an assumed IP of more than 2.5 mmcf/d at depth of around 6,500ft; and a non-core well in Parker county with assumed IP of <1.0 mmcf/d at a depth of roughly 5,500ft.

If we assume that the lateral length of a 7-8 stage frac in the Barnett shale is around 3,500 ft, the total length of these two wells becomes 9,000 ft for the non-core well and 10,000 ft for the core well. Consequently, the cost of these two wells will not materially differ, since we assume the same lateral length and completion methodology – therefore we assume a cost difference of $250,000.

Assuming constant inputs, such as royalty rate of 16.67% and gas price of $5/mcf, and the only difference being well costs and well performance (IPs and EURs), we can see a material difference in play economics for wells drilled in the core versus the fringe (exhibit 12).

Furthermore, it is more than likely that having correctly identified and leased the core early, the average $/acre and royalty rate will be lower than on the fringes of the play, which tends to be leased later by competitors after the play has gained momentum, following promising initial results. Indeed, adjusting royalties for acreage in the core down to 12.5% increases the NPV to $2.6m and the IRR to 40%.

The preceding example highlights the critical importance of identifying and leasing the core of the play since well economics (as measured by NPV and IRR) differs by orders of magnitude between the fringe and the core.

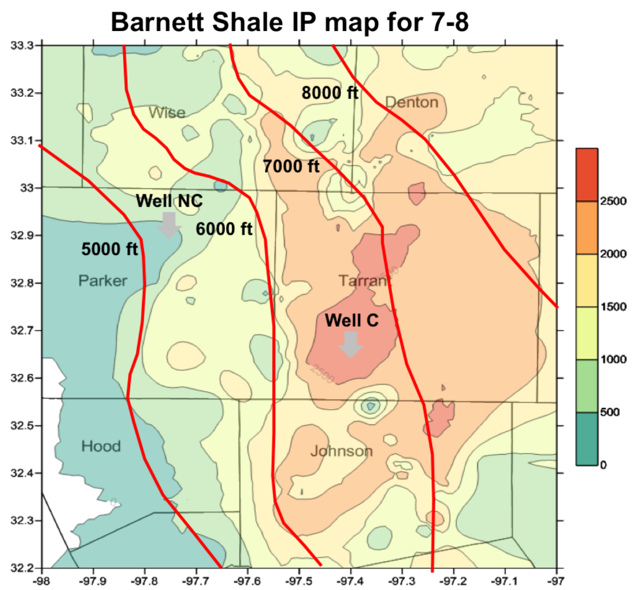

Exhibit 11: IP & depth map for core of Barnett shale play, with dummy wells (Source: HPDI and Kimmeridge Energy)

	Well NC	Well C	Delta
County	Parker	Tarrant	
Play area	Fringe	Core	
Depth (ft)	5500	6500	***1000***
Lateral Length (ft)	3500	3500	*0*
Frac Stages	7-8	7-8	*0*
Est. Well Cost ($m)	3.25	3.5	*0.25*
IP (mmcf/d)	0.8	3.0	*2.2*
EUR (Bcf)	1	3.75	*2.75*
NPV ($m)	-2.16	2.0	*4.16*
IRR	-2%	30%	*32%*

Exhibit 12: Modelled economics of core vs. non-core (Source: Kimmeridge Energy)

Factors that may help explain the divergence in well performance and economics between Tarrant and Parker counties are:

A. Thickness of the Barnett shale is 300-500 ft in Tarrant county, but typically only 200-250 ft in Parker (see exhibit 13).

B. Thermal maturity in Tarrant county ranges from Vr 1.3-1.7% (dry gas window), but only Vr 1.1-1.3% (wet gas window) in Parker (see exhibit 14).

Greater thickness of the shale in Tarrant provides more gas-in-place for the same surface area. And dry gas window thermal maturity in Tarrant versus wet gas window in Parker, implies more dry gas generated in Tarrant. Additionally, since dry gas (methane) molecules are smaller than oil/condensate molecules, this implies higher flow rates and recovery rates in Tarrant.

Furthermore, other factors such as mineralogy, porosity, permeability and in many cases structure (such as the water rich Ellenburger unconformaity), are also likely to drive a difference in well performance between the core and fringe.

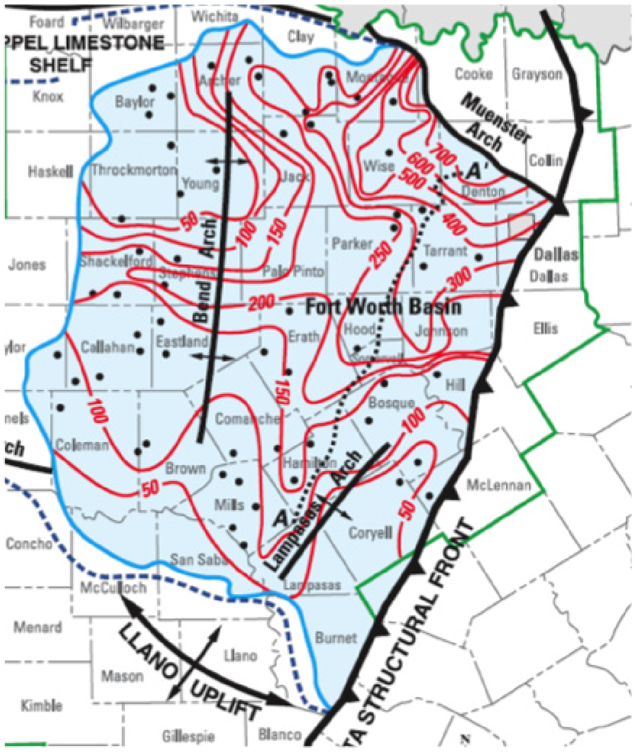

Exhibit 13: Barnett shale isopach map (Source: DOE)

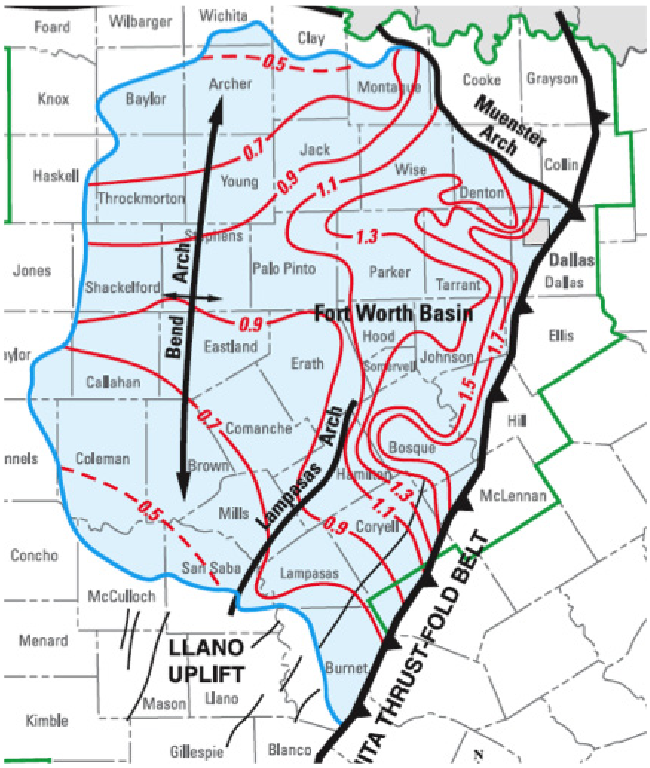

Exhibit 14: Barnett shale vitrinite reflectance map (Source: DOE)

Conclusion

Identification of the core of a developed shale play, such as the Barnett, is a relatively simple statistical exercise based on mapping out standardised well completions and well economics. In simple terms, the core is where wells are most economic.

The real challenge comes from identifying the core pre-development, which is much harder since it based on mapping out the area that is believed to have the optimal convergence of geological factors, such as TOC, maturity, thickness, depth, etc. At Kimmeridge, we believe the key to understanding the next break-out play is the ability to take these input factors of existing plays and determine their relationship to adjusted IPs from our proprietary database. This, in turn, relies on scientific knowledge of shale plays, industry experience and plenty of due diligence.

The vast superiority of investment returns for core acreage versus fringe acreage, makes early identification and leasing of the core critical for companies in any new shale play. Therefore, it is essential to have a team in place with the requisite technical skills and industry experience to identify the core pre-drill, as well as the discipline and focus to optimise investment returns.

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