KIMMERIDGE
Energy

Green Technology And Fraccing

Closer Bedfellows Than You Might Imagine

June 2013

Introduction

Two tried and tested technologies have been combined, and are changing the landscape in terms of recoverable reserves. Horizontal drilling and hydraulic fracturing are both decades old technologies, but are now seeing widespread use in unconventional plays. However, whilst the media is quick to highlight some of the historical issues with these processes, rarely does it discuss where new technology is taking them.

Fraccing has become a catch-all phrase, both for opponents of the energy industry and within energy circles, for the "new" technology that has dramatically increased North American, as well as global, oil and gas reserves. It is often described as a crude mechanism for forcing rocks to be cracked, and depending on who you listen to, and what data you want to ignore or entertain, the potential cause of widespread drinking water pollution. However, after a decade of being refined and improved, "fraccing", and all the oil service technology associated with it, is much greener than many would have you think. And the new technology being developed is continuing down this path. So could this be the conduit for improving the public persona of unconventional oil and gas?

The objective of the oil industry was never to be anti-green, it merely was marrying a 60-year-old technology with commonplace horizontal drilling, and improvising from there. But the time has come when future oilfield service technology will have to embrace the concerns of the public; in terms of pollution and well density/ footprint, as legislation globally will ensure more environmental regulations and oversight going forward. Therefore, we believe it is worthwhile showcasing the technology that will make a big difference – not just to the recoverability of oil and gas, which has been the main focus of the industry up till now – but as a critical part of the process towards public acceptance.

History Of Fraccing

"Fraccing", whether spelled with a "c" or a "k", is short for hydraulic fracturing-- the process by which fluids are pumped into a pre-perforated well under high pressure, causing the formation around the wellbore to fracture once the rock's critical strain is surpassed. This permits the injection of a "proppant," (usually sand) into the fracture once it has formed. The proppant creates a pathway for the hydrocarbon, which was trapped in the non-connected pore spaces of the reservoir, to escape back into the well bore (Exhibit 1). The commercial application of the technique actually dates back to 1949 and has taken many guises in the past from non-hydraulic fracturing in the 1930s and earlier, using explosives such as dynamite to break open the rocks, to the more common practice of hydraulic fracturing using traditional liquid-based processes.

Well, that may not be entirely the full story, as there is potentially one more extreme application that is worth highlighting. If it is to be believed, the Soviets went to great lengths during the Cold War to fracture the high quality source rock called the Bazhenov Shale in West Siberia (Exhibit 2), as it was widely known to contain a large liquid hydrocarbon component, with potential resources of several trillion barrels. Based on data collected from the USGS (United States Geological Survey) an underground nuclear explosion east of the Ural Mountains in the vicinity of the Salym field during October 1979, was aimed at testing the potential of oil recovery from the Bazhenov shale. No data has ever been released or evaluated that would suggest that this extreme technique actually worked, if it was ever actually deployed.

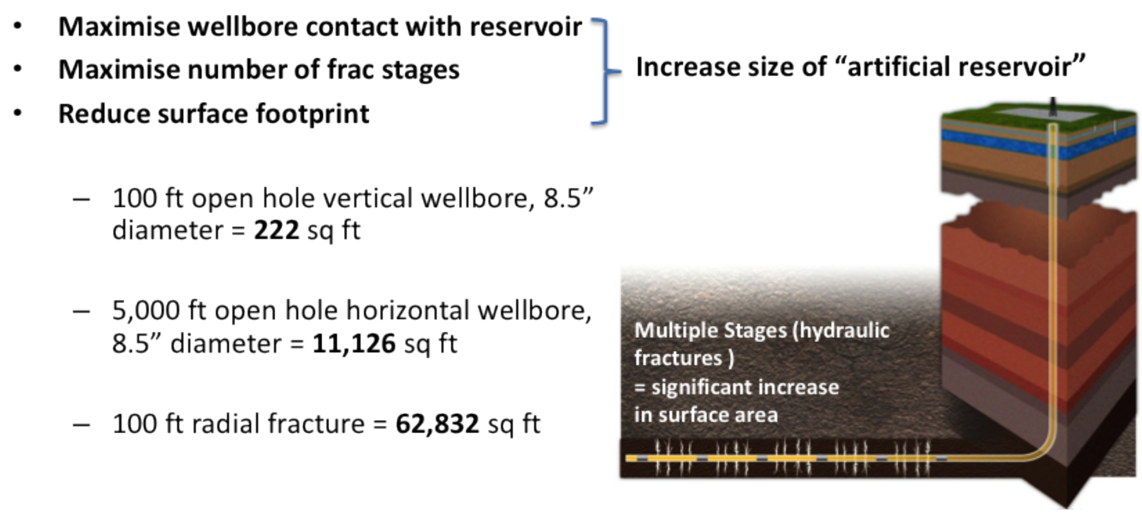

Exhibit 1: The impact of hydraulic fracturing on the surface area exposed to the wellbore. (Source: Baker Hughes)

Today it is not so much the process, but the nature of the fluids used in the fraccing operation that is receiving the most attention. Indeed, the use of acids and other chemicals in the drilling industry is not a new phenomenon either, as they have been used extensively in the oil industry for many decades, without significant issues or public disquiet. Additionally, man-made techniques for fracturing or improving hydrocarbon flow out of rocks are no match for those found in the natural world.

In a study by Davies et al 2012, in which manmade hydraulic fractures were compared to those made by natural faults, the results were surprising. The length of the vast majority of manmade fractures is under 100 m, with a maximum length recorded of 588 m, based on data from several thousand samples, whereas the maximum length of natural fractures in the North Sea and West Africa was 1106m (Exhibit 3a).

Based on this empirical data, the probability of a stimulated hydraulic fracture extending vertically for more than 350m is 1% (Exhibit 3b). With most oil industry fraccing activity occurring at least 1500m below freshwater aquifers, the fracture itself should not be a problem. Therefore it is almost impossible for fractures formed by man-made activity to propagate into aquifers under these parameters. But that does not mean that the industry should stop improving the technique or making it more palatable for the public.

Additionally many hydraulic fracturing operations are routinely monitored using micro-seismic techniques. Each frac "stage" is "listened to" by an array of highly sensitive geo-phones, suspended in nearby observation wells. Every micro-seismic event (crack) can be measured and recorded and positioned relative to the wellbore (Exhibit 4). It is therefore possible to observe the extent and effectiveness of the fraccing operation and to optimize subsequent operations to take advantage of the natural stresses that already exist in the deep rock structure as part of its geological evolution. This data can also be used to control the extent of the fractures.

Indeed, real-time microseismic monitoring is useful for alerting the operator to approaching hazards such as faults, as well as providing information useful for the optimization of subsequent treatments.

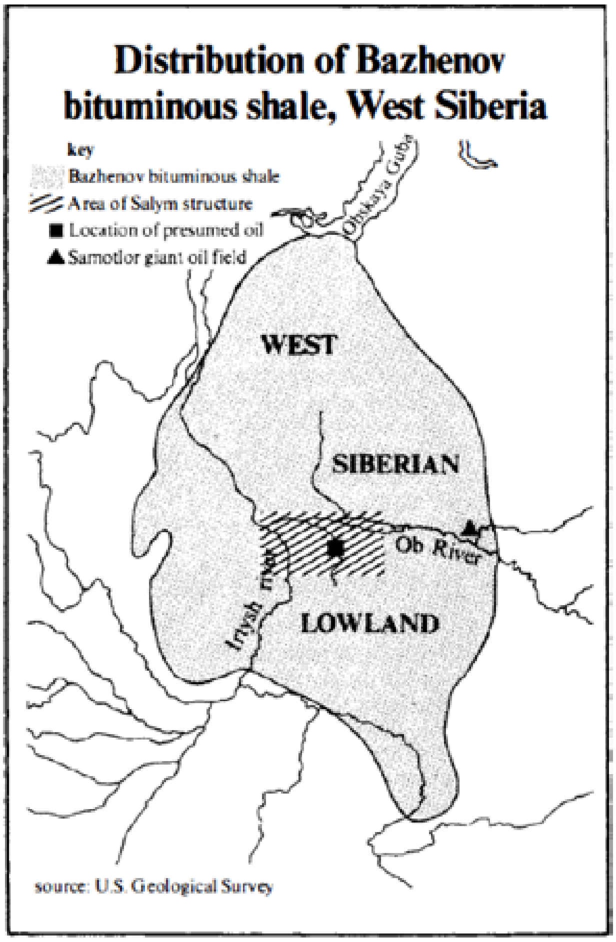

Exhibit 2: Early analysis (circa 1979) of the Bazhenov Shale in W. Siberia by the USGS and the potential feature (hashed) that may have been targeted by a peaceful nuclear explosion. (Source: EnergyInsider by William Engdahl, Dec 30th 1980)

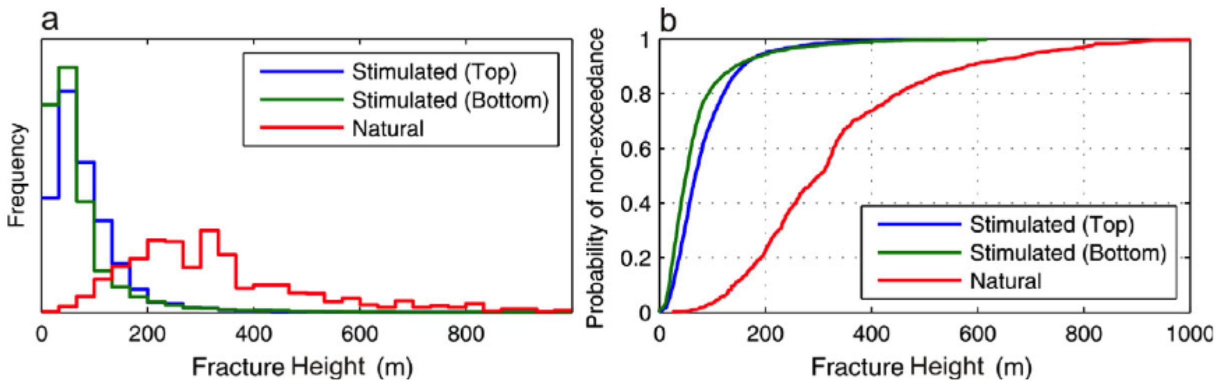

Exhibit 3: a) Frequency or the height of man-made and natural fractures b) Probability of fractures not exceeding a certain length. (Source: Davies et al 2012)

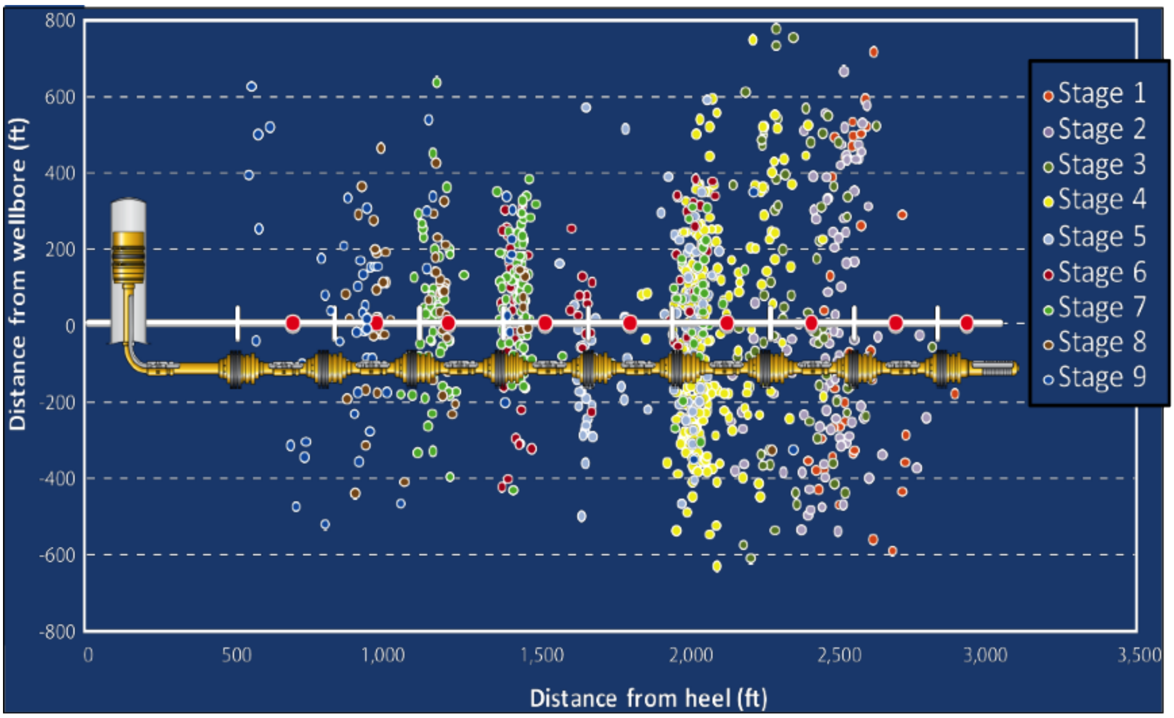

Exhibit 4: The micro seismic response of different frac stages with each bubble associated with the propagation of an individual fracture. (Source: Baker Hughes)

So, the new technology known as fraccing can be summarized in a few sentences. In contrast to conventional oil exploration, in situations where the hydrocarbons have not moved very far or have been trapped by the hydrocarbon-generating source rock itself, and are usually not pressure-supported by water, the theory is that more hydrocarbons will flow if a greater surface area of the reservoir rock can be connected into the wellbore. By drilling horizontal sections along the reservoir formation and by forming fractures that spread away from the wellbore, this modern drilling and completion technology creates higher oil flow rates in "tight" reservoir rocks (typically the shale source rocks and adjacent formations). Effectively the technology is inducing the hydrocarbon that is trapped in the small, poorly connected pore spaces to flow into the wellbore, through man-made pathways. By drilling the optimum number of wells, based on the rock volume the new fractured wells are draining, a tight or unconventional reservoir can be cost effectively developed over a wide area.

In theory this is relatively straightforward; however, although lower scale variations on this technology have been used for decades, the current process of high volume hydraulic fracturing has created a fair degree of controversy. In particular, the public and politicians have for a number of years expressed their concern over the possibility of contamination of drinking water aquifers; the process' high demand for water in many areas that are stressed for water in the first place; and the footprint of many rigs on the landscape.

What Are The Environmental Issues And What Are The Oil Service Companies Doing About It?

Three critical areas appear to be at the centre of the environmental debate on fraccing and the use of new drilling technology: the high use of water in the fraccing process; possible groundwater contamination; and the high drilling footprint of historic unconventional operations. Of course, there are many other issues that relate to wider energy policy. For example, more drilling leads to significantly more gas reserves being exploited instead of pursuing wind and solar alternatives. However, the focus of oil companies has been to create fraccing operations that eliminate any potential of groundwater contamination by using non-toxic fluids and by drilling fewer wells whilst still draining the same area underground.

To look at what oil service players are doing to tackle these issues, Kimmeridge recently met with representatives of Baker Hughes at their Celle research and development facility near Hannover, the location of Kimmeridge's exploration licences in the Lower Saxony Basin in northern Germany.

The Christensen Diamond Products manufacturing plant opened in Celle, Germany, in 1957 (later to be incorporated into the Baker Hughes group in 1990). The facility manufactured diamond core heads and drill bits and later expanded to make downhole drilling tools. In 1977, the Celle engineering and manufacturing team introduced the Navi-DrillTM line of downhole drilling motors and also the industry's first steerable motor system and the AutoTrakTM rotary steerable closed-loop system. As Baker Hughes is one of the three largest oil service companies in the world and has been at the forefront of unconventional technology for many years, we asked what they had been working on, and what the oil industry could expect from the oil service world in the near future? To summarize, three themes emerged from our discussions.

Theme 1: Fraccing without being overly reliant on water

Most unconventional operations involve the use of multistage hydraulic fracturing treatments that pump millions of gallons of fluid into a wellbore to connect it to as much of the shale's natural fracture network as possible, while at the same time propping open the newly created fracture. However, recently there has been an increasing focus on using gas and liquids, such as propane, as the mechanism to fracture the rock versus water. Taking as much water out of the equation as possible has two potential benefits: namely, the lower demand for water, which could be used for farming, etc, and the lower potential of groundwater contamination.

Baker Hughes' VaporFrac system pumps an ultralightweight proppant mixture directly into a high-pressure nitrogen or carbon dioxide gas stream that goes into the wellbore. Unlike the traditional hydraulic process, the technique creates a flow stream that is 94 to 96 percent gas, which significantly reduces freshwater requirements, the use of chemical additives, postfrac cleanup time and water disposal costs. In addition, the efficient process minimizes equipment requirements, thereby limiting truck traffic on local and lease roads.

This system has actually been trialed in New York state, which is currently under a fraccing moratorium, but permission was given to use the technique on a vertical well with just 80,000 gallons of fluid (instead of millions of gallons in a typical fraccing operation). New York state regulators also needed assurance about the exact chemical composition of the fluid and gas system that would be used to carry the proppant prior to the initiation of operations so that they could evaluate it (something that we believe will become common place in the industry very soon).

Although one of the benefits of the VaporFrac system is its minimal chemical footprint, it does use a few additives, such as surfactants to improve its proppant-carrying capacity, but Baker Hughes' (BJ) SmartCare team had also developed fluids and chemicals that were non-toxic for use in the well. It was found that the fraccing performance of VaporFrac compared favorably with other low-water stimulation techniques, as the proppant mixture had additional mass that helped create a fracture, which would have been challenging in nitrogen-only fracs. In addition, the patented BJ LitePropTM ultralightweight proppants were easier to transport into a fracture than conventional sand, improving the resulting (propped) fracture area.

The operation in New York, although only conducted on a vertical well, focused on two zones more than 2,000 ft (609 m) deep in the Marcellus shale, using 40,000 lb of LiteProp ultralightweight proppant, 7 MMcf of nitrogen and less than 20,000 gallons of water. The operator reported the results exceeded expectations, with initial production, limited by the vertical nature of the hole, of 200 Mcf/d and sustained production of 150 Mcf/d after four weeks of extended flow. The results would have been much more impressive if a horizontal well with 10 stages (rather than 2) had been drilled, however, the operation proved that this fracturing process has huge potential.

Another technology with great potential to mitigate the use of water in fracturing operations, is gelled LPG (typically propane or butane). A Canadian company called GASFRAC licensed the technology for gelled LPG from Chevron in 2006, and then designed and patented the process for gelled LPG fracture stimulations. After an initial period of rapid growth and deployment of its technology, including a long term contract with Husky Energy, GASFRAC underwent a period of declining share price performance due to poor management and the crash in the US gas market, which has largely overshadowed the potential of its technology.

However, we believe there is sufficient evidence to suggest that its technology has great potential to replace traditional hydraulic fracturing methods. A good summary of the advantages of LPG fracs is offered by D.V. Satya Gupta of Baker Hughes: "There are many advantages in using liquefied petroleum gases for hydraulic fracturing if it can be done

GASFRAC summarizes the advantages of its technology as follows:

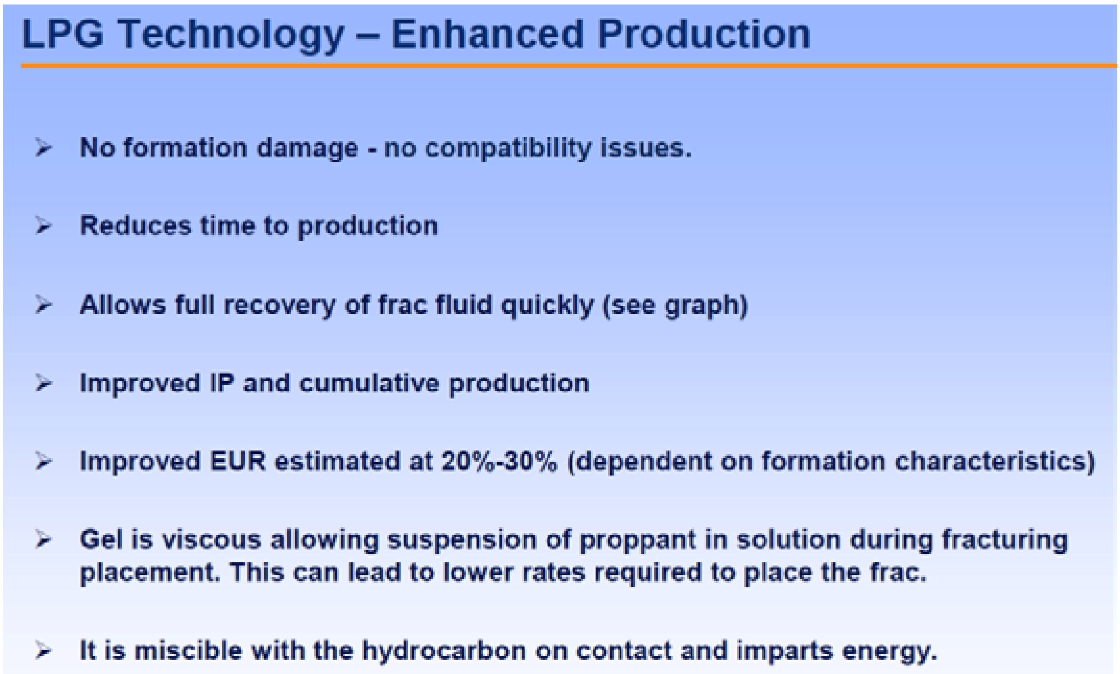

Exhibit 5: The Advantages of LPG fracs. (Source: GASFRAC corporate presentation)

safely. The properties of density, viscosity and surface tension with complete solubility in formation hydrocarbons are very beneficial. Recovery of the LPG very nearly approaches 100%, clean up, is very rapid (often within 24 hours), phase trapping is virtually eliminated, and LPG properties allow for extended shut-in times without detriment. Additionally, direct flowback to an available pipeline can be readily achieved. The result is a potential cost-effective stimulation with effective fracture lengths, excellent post-treatment production and the potential for zero flare clean-up."

GASFRAC achieved much of its initial revenue growth in Canada, but has struggled more to penetrate the US market. However, that is changing with the signing of large new customers such as Shell and Apache. Several case studies evidencing the benefits of LPG fracs have been provided by GASFRAC for plays in Canada, notably the McCully Gas Field and Ansell Cardium horizontal play (Exhibit 6).

Additionally, Kimmeridge has collected well completion data for the Niobrara tight oil play in Colorado, which also suggests that significant benefits versus hydraulic fracturing can be achieved with gelled LPG fracs (Table 1). Quicksilver was an early customer of GASFRAC and deployed its technology in the Niobrara horizontal oil play to boost IP rates and EUR. Based on data for Niobrara oil wells in Moffat Co., it is clear that gelled LPG (butane) offered better results on average than, water-based fracs, nitrogen-fracs and unstimulated wells. Specifically, average IP was higher, no water was produced, and less fracture fluid and proppant was used.

However, the gelled butane (LPG) completions did show considerable variability in results, which could reflect both inconsistent completion efficacy and/or lateral heterogeneity of the Niobrara formation. However, the Niobrara is notoriously heterogeneous with characteristics such as thermal maturity, porosity and thickness

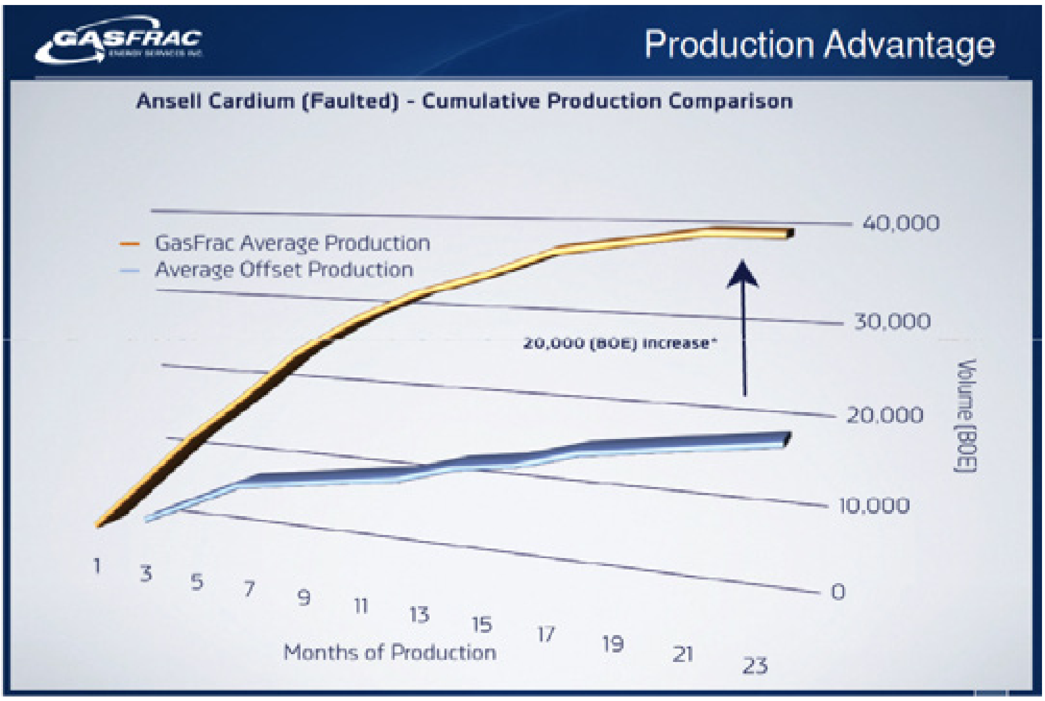

Exhibit 6: Estimated uplift in production from using GASFRAC's LPG technology in the Ansell Cardium oil play. (Source: GASFRAC corporate presentation)

changing significantly over relatively short distances (Exhibits 7 & 8), which has resulted in highly variable well results. Consequently, we believe that the variability in results for gelled LPG completions in this Moffat Co. dataset is more likely to be driven by the geology than the technology.

Overall, we believe that GASFRAC's technology is promising, given positive comments from operators (Husky, Quicksilver and Chevron), new large customers (Shell and Apache) and compelling initial case studies in Canada and the US. However, no large oil service company has yet to develop similar technology or attempted to acquire GASFRAC (as far as we know), and widespread E&P industry uptake of LPG fracs has yet to occur. This is potentially due to lingering concerns over the safety of LPG fracs, despite an excellent safety record for GASFRAC's operations. Widespread use of LPG fracs will only occur once a large public dataset of LPG frac completions is available to prove technological efficacy, safety and economics.

Theme 2: Green fraccing fluids

Many of the risks associated with groundwater contamination in fraccing operations have historically been due to above ground spillages and the inadequate cementing of the upper part of the borehole where it passes through shallow aquifers. As mentioned earlier, it is impossible for man-made fractures at depth to propagate far enough vertically through the overlying rock to reach shallow aquifers. However, to diminish all potential risks associated with groundwater contamination, non-toxic frac fluids are being developed by oil service companies.

Typically the make-up of a standard frac fluid contains a small amount of chemicals such as acids. These fluids are required as they help to open up fractures and breakdown the "cement" that binds the reservoir particles together,

Well name	Operator	County	Top Nobrara depth (ft)	Wellbore Completion Date	Test Date	IP oil (bbl/d)	IP gas (mcf/d)	IP (boe/d)	IP water (bbl/d)	Oil API	Gas BTU	Frac stages	Frac fluid	Frac fluid (gals)	Proppant type	Proppant (lbs)
Bret Granbouche 24-02H	Quicksilver	Moffat	6,810	21/10/2011	19/01/2012	576	492	658	0	41	1250	na	Gelled butane	735,126	20/40 CRC sand	686,560
PIRTLAW PARTNERS Ltd #24-33	Quicksilver	Moffat	5,980	21/08/2012	26/11/2012	283	410	351	289	43	1323	3	Slickwater/ Linear Gel	1,147,136	20/40 Ottawa + 20/40 CRC sand	1,013,100 + 153,100
SIMOES #12-30	Quicksilver	Moffat	6,673	5/30/2012	10/07/2012	165	145	189	79	42	1368	4	Water	786,303	Not specified	794,500
Stoddard 33-30	Quicksilver	Moffat	6,787	07/08/2011	06/01/2012	114	360	174	0	39	na	na	Gelled butane	364,842	20/40 CRC sand	540,000
ELLGEN #11-10-1	Gulfport	Moffat	6,028	26/09/2011	02/03/2012	82	100	99	0	42	na		no stimulation			
ALLEN #44-8 #1	Gulfport	Moffat	6,356	03/09/2007	07/10/2007	83	46	91	0	37	1236		no stimulation			
STATE #41-14-1	Gulfport	Moffat	7,023	na	30/12/2011	57	0	57	0	40	na		no stimulation			
WEBER FEDERAL #32-04	Quicksilver	Moffat	6,139	27/06/2012	31/07/2012	36	126	57	64	42	1280		"Fluid"	301,518	20/40 White + 20/40 CRC sand	199,008 + 154,540
MOFFAT #22-11-1	Gulfport	Moffat	6,079	24/02/2012	29/11/2011	43	0	43	2	40	na		no stimulation			
PIRTLAW PARTNERS LTD #14-03	Quicksilver	Moffat	6,322	na	15/12/2011	40	0	40	0	50	na	na	Gelled butane	375,190	20/40 CRC Sand	626,000
STATE #33-15	Gulfport	Moffat	6,723	14/09/2009	20/10/2009	38	14	40	0	39	na		no stimulation			
Gamma State #14-15D	Quicksilver	Moffat	7,338	08/11/2008	17/06/2010	10	140	33	12		1252		N2 + X-linked Gel	627,144 cf + 3,429 bbls	20/40 sand	301,592
WEST DANFORTH #5A-4-3-95	Gulfport	Moffat	7,393	na	29/08/2009	15	17	18	0	38	na		no stimulation			
ANTIETAM 11-12D	Quicksilver	Moffat	9,710	09/09/2007	28/01/2008	0	105	18	0	na	957	na	N2	357,000 scf	20/40 sand	103,866
Roundup #22-24D	Quicksilver	Moffat	7,900	03/06/2011	26/09/2012	9	41	16	10	43	1300	1	Water	222,894	40/70 Ottawa sand	79,300
SD FEDERAL 24-9DL	Entek	Moffat	6,515	22/09/2011	16/12/2011	10	20	13	0	40	1561	na	"treated fluid"	29,652	various sand	35,520
Ridgeview #32-16-1	Gulfport	Moffat	7,118	01/10/2012	30/11/2012	12	0	12	0	40	na		no stimulation			
BATTLE MOUNTAIN FEDERAL 14-10L	Entek	Moffat	6,033	02/08/2011	09/12/2011	10	10	12	0	40	1435	na	"treated fluid"	73,416	various sand	27,180
Average Ips (boe/d)																
Gelled butane								**291**								
Water								**103**								
N2								**25**								
Other								**108**								
no stimulation								**51**								

Table 1: Well Completion data for Moffat Co., Colorado, in the Niobrara tight oil play. (Source: COGCC database and Kimmeridge Analysis)

therefore increasing the formation's permeability and allowing hydrocarbons to flow. Chemicals also can help the proppants (sand, ceramics etc.) go into the fractures to hold them open.

To accommodate fraccing operations in areas that are environmentally sensitive, oil service companies have increased their efforts to firstly identify appropriate chemicals that are not toxic, and develop chemicals that can be substituted for those found in current fraccing operations. For example, the Baker Hughes chemical evaluation processes and the use of the SmartCareTM family of environmentally responsible chemicals and products (Exhibit 8), are strictly screened to meet or exceed environmental regulations with minimum effect on performance. In some recent industry trials, everyday food additives (such as guar gum that is used in tootpaste) have also been used as gelling agents, replacing some traditional fraccing chemicals.

By focusing from the outset on the ecotoxicological properties, the Baker Hughes SmartCareTM process can identify hazardous properties early, so that the ongoing development of new and better products can happen quickly.

The evaluation of the chemicals is managed by the Baker Hughes Environmental Services Group – a team of chemists and toxicologists charged with asking a number of questions, such as: What is the

Log 10 Deep Resistivity (maturation of lower source facies)

Thickness of storage facies (B Bench N460)

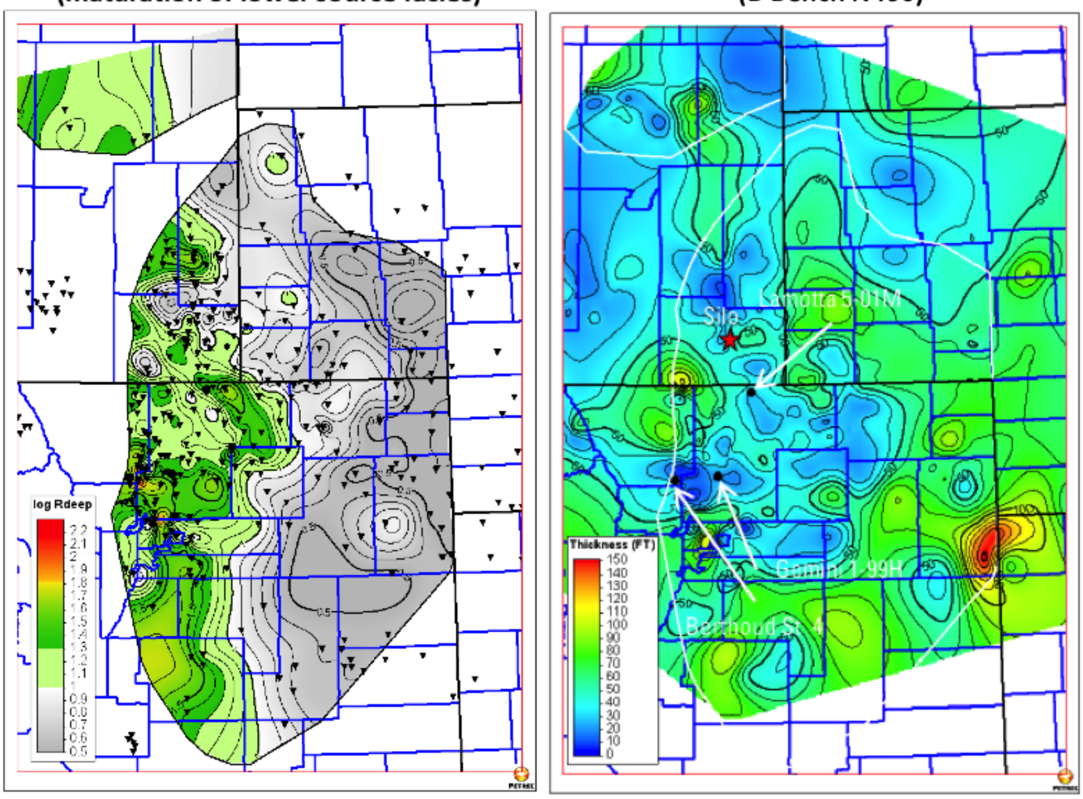

Exhibit 7: Log 10 Deep Resistivity as a proxy for thermal maturation. Exhibit 8: Log-derived thickness of the B Bench reservoir facies within the Niobrara formation. (Source: "Stratigraphy and Petrophysical Characteristics of the Niobrara Formation in the Denver Basin, Colorado and Wyoming", Luneau et al. (2011))

potential impact of this chemical on people and the environment? Is this chemical sustainable? Can another chemical offer a better environmental profile and deliver the same performance? How can we help improve oil and gas production without harming people or our environment?

Indeed, once a product is within the SmartCare family, it has been thoroughly examined and rated according to accepted regulatory and industry standards. Indeed, Kimmeridge believes that it will be a standard regulatory requirement going forward for companies to disclose the chemicals they are proposing to use in the fraccing operation prior to the initiation of the activity (similar to proposals in the current legislation that is being debated in Illinois).

Theme 3: Lower drilling footprint

Currently, areas and communities that have not experienced significant oil industry activity in recent decades can also be concerned that unconventional field development could mean a "forest" of oil rigs on the landscape. Indeed, it is easy to sympathize with these worries, as any photographs of Bakersfield in California or Baku in Azerbaijan do not look particularly attractive (although neither does a large windfarm). This view has also not been helped by the experience from the early years of the unconventional industry in the Barnett play in the Fort Worth Basin in Texas. Here, as the oil service industry was developing its technology and evolving its processes, it was commonplace for wells to be drilled on a 40-acre spacing or less. However, recent activity in the Bakken play in the Williston Basin in North Dakota and Montana, suggests that as the lateral lengths of wells have increased, along with the number of frac stages, wells on a 640 and 1280 acre spacing are becoming typical of the development of the play. This is not to suggest that more wells will not be drilled in the future to fully "drain" the oil, but at least initially, there can be considerable distances between wells compared to the practices of over a decade ago. Indeed, the typical practice now

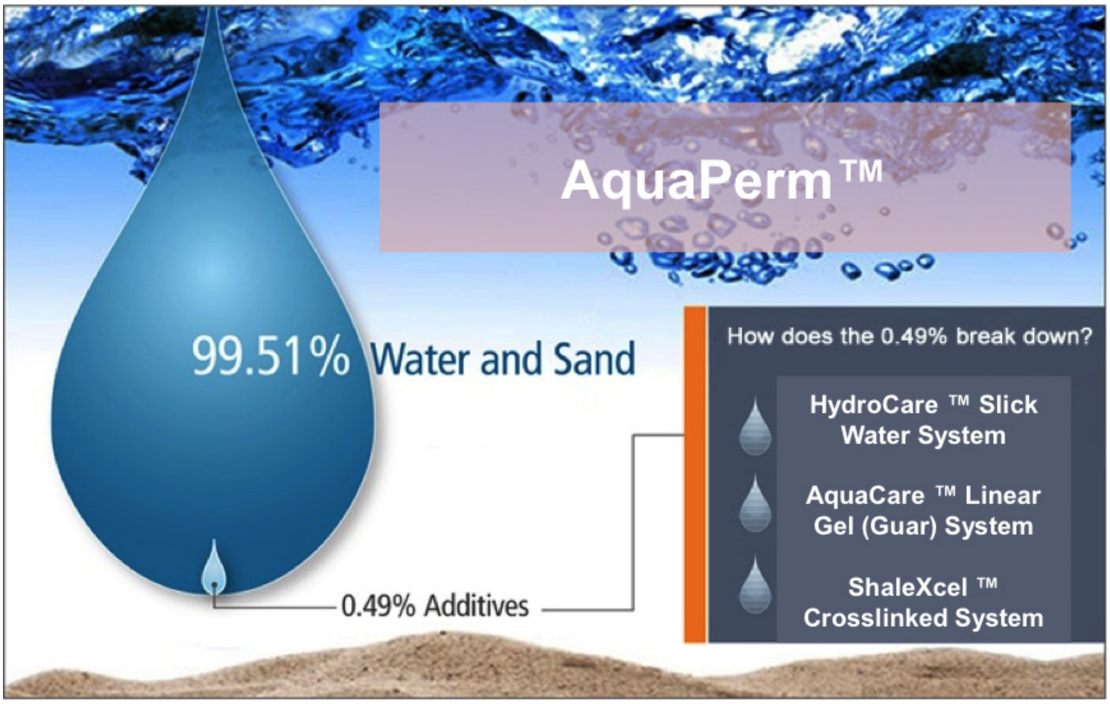

Exhibit 9: The composition of frac fuilds using non-toxic additioves. (Source: Baker Hughes)

is for multiple wells to be drilled from the same pad (much like offshore platforms where up to 60 directional wells are drilled from the same platform), minimizing the surface footprint.

In a recent academic paper (Kennedy et al 2012), scientists at Baker Hughes believe that efficient field development could be achieved with fewer wells and less surface impact if the industry did a better job of understanding the reservoir and planning up front. The authors report that despite improvements and optimizations over the last decade, a closer look at well performance reveals that not all wells are producing optimally, largely due to only a limited number of the multiple hydraulic fracture stages contributing to the total production from the well.

It has been a common practice over the past decade to go through a trial and error process around the number and nature of fracture stimulations in a developing play to get a completion strategy that works. Then such a methodology is usually rolled out "cookie-cutter" style over the rest of the play, with limited appreciation for the how the reservoir can change over short distances. This practice is driven by inadequate data collection in the early wells of the play, the changing operators, as well as the desire to get costs down very quickly and turn the operation into a manufacturing process.

Baker Hughes, however, proposes that by using modern data gathering techniques in the first wells and by building a subsurface geo-mechanical "model" a "customized" hydraulic fracture design for each individual well will yield significantly higher production benefits over a longer time. Reservoir properties vary significantly, not only vertically, but also aerially along the lateral length of the horizontal borehole, which creates additional challenges for the "optimum" fracture design.

Indeed, it is evident that one size does not fit all, with each of the commonly researched shale plays in the US having been fractured in different fashions (Table 2). This data partly reflects the evolution in technology, with the Eagle Ford having more frac stages than the early Barnett play, but it is also down to the different geology in each area.

	Bakken	Barnett	Eagle Ford	Haynesville	Marcellus
Avg. MD, ft	17,535	10,873	14,643	16,566	10,722
Avg. TVD, ft	10,207	7,331	9,392	11,941	6,937
Horiz Perfed, ft	7,401	2,788	4,311	4,355	3,331
Avg. ft /stage	550	450	270	325	275
Avg. BHP, psi	5,310	4,213	7,550	10,870	7,650
Avg. rate BPM	24.8	73.3	81.6	71.2	83.5
Avg. No. Stages	13	6	16	13.3	12
Avg. No. Stages/day	3.4	1.9	2.6	1.9	1.5
Amt Prop / Stage, lbm	160,300	286,000	292,600	357,800	399,500
Amt Prop / Well, lbm	1,998,000	1,515,000	4,304,000	4,675,500	4,425,600

Table 2: Typical Fracturing Treatments of Some of the Major Shale Plays. (Source: Kennedy et al 2012)

Some degree of customization would likely increase production per well. This appears to be backed up by recent data from production logging tools that Baker Hughes suggests indicates that on average only 40% of fracs contribute to the total production from a well. The possible cause of this is a limited understanding of the reservoir prior to fraccing, as the frac placement probably does not intersect some of the natural fractures in the well, and the reservoir quality, such as TOC levels, or thermal maturity, of the source rock may have been low at the locations where the fracture stages were placed.

Therefore the data would suggest that more care should be taken initially to understand the geology and the reservoir characteristics of the source rock using a multidiscipline approach across all geoscience areas (geology, geochemistry, petrophysics, rock mechanics, geophysics etc.), in order to increase the productivity of individual fraccing operations and hopefully reduce the footprint of unconventional operations on the surface.

Summary

Hydraulic fracturing has attracted a lot of negative attention in the media over the past ten years, and this has not gone unnoticed by the oil service industry. A considerable effort is being made to tackle the image of unconventional technology through:

- development of non or limited hydraulic fracture operations that lower water usage and limit potential water contamination;
- developing non-toxic additives for the fracture process;
- and by improving the productivity of each well that should lead to the reduction of the surface drilling footprint.

Whether these advances will quiet the critics of the process or not is uncertain; however, we see this as part of an essential evolution of the technology, which is likely to run hand in hand with increased regulation aimed at improving the environmental record of the industry

Notice & Disclaimer

- This document and all of the information contained in it, including without limitation all text, data, graphs, charts (collectively, the "Information") is the property of Kimmeridge Energy Management Company, LLC or its affiliates (collectively, "Kimmeridge"), or Kimmeridge's licensors, direct or indirect suppliers or any third party involved in making or compiling any information (collectively, with Kimmeridge, the "Information Providers") and is provided for informational purposes only. The information may not be reproduced or redisseminated in whole or in part without prior written permission from Kimmeridge.
- The Information has been derived from sources believed to be reliable but is not guaranteed as to accuracy and does not purport to be a complete analysis of any security, company or industry involved. The user of the information assumes the entire risk of any use it may make or permit to be made of the information. NONE OF THE INFORMATION PROVIDERS MAKES ANY EXPRESS OR IMPLIED WARRANTIES OR REPRESENTATIONS WITH RESPECT TO THE INFORMATION (OR THE RESULTS TO BE OBTAINED BY THE USE THEREOF), AND TO THE MAXIMUM EXTENT PERMITTED BY APPLIABLE LAW, EACH INFORMATION PROVIDER EXPRESSLY DISCLAIMS ALL IMPLIED WARRANTIES (INCLUDING, WITHOUT LIMITATION, ANY IMPLIED WARRANTIES OF ORIGINALITY, ACCURACY, TIMELINESS, NON-INFRINGEMENT, COMPLETENESS, MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE) WITH RESPECT TO ANY OF THE INFORMATION.
- Information containing any historical information, data or analysis should not be taken as an indication or guarantee of any future performance, analysis, forecast or prediction. Past performance does not guarantee future results. Opinions expressed are subject to change without notice.
- None of the Information constitutes an offer to sell (or a solicitation of any offer to buy), any security, financial product or other investment vehicle or any trading strategy.
- Kimmeridge Energy Management Company, LLC is a Registered Investment Adviser. Nothing herein is intended to constitute investment advice or a recommendation to make (or refrain from making) any kind of investment decision and may not be relied on as such.
- The Information has not been submitted to, nor received approval from, the United States Securities and Exchange Commission or any other regulatory body.

Contact Kimmeridge

New York
400 Madison Avenue,
Suite 14C, New York, NY 10017

London
Thornton House, Thornton Road
London, England SW19 4NG

Houston (Roxanna)
952 Echo Lane, Suite 364
Houston, TX 77024

info@kimmeridgeenergy.com