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Drilling Experience and Lessons Learned from Key US Shale Plays

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Abstract

Many thousands of shale gas/oil wells have been drilled in the last few years. Valuable drilling experience has been gained and drilling efficiency has been improving continuously. This paper presents the key drilling experience and lessons learned from several shale plays in the US. Well and drilling data of over one thousand wells from Eagle Ford, Haynesville and Marcellus shale plays were retrieved from a database. Analyses of these drilling performance data offer lessons learned and general guidelines of current drilling practices as well as opportunities for improvement.

The analyses include gas/oil shale failure mechanisms, mud types, drilling performance data such as drilling days or drilling fluid costs versus depth, mud weight, well architectures such as bit sizes, casing sizes and depths of the casing shoe, as well as lateral lengths. A statistical analysis (P10, P50, P90) was also performed to obtain industry-wide drilling performance baselines. Comparisons were made among different mud types on drilling performance and drilling performance among different operating companies. Oil-based mud (OBM) does not always perform better than water-based mud (WBM). For longer wells, it usually takes fewer drilling days for OBM than for WBM. However, for shorter wells and some long wells, certain WBM performs as well as OBM.

The analysis showed that our industry has made clear improvements in drilling efficiency over the years and certain operators perform much better than the industry average. The analysis also showed that there is a large variation in total drilling days for similar well depths and trajectories, indicating there is a large opportunity for improvement. One interesting finding is that the top operators can drill wells in fewer days than industry average even though their drilling fluids costs are slightly more expensive than industry average. The analyses and results provided lessons learned and general guidelines for current drilling practices and opportunities of improvement such as drilling fluid selections, mud weight, and well architectures.

Introduction

Shale gas and oil, often called shale play, has become as a major unconventional hydrocarbon resource in recent years, becoming massive reserves that challenge the largest conventional gas accumulations in the world. Shale play development started in the US, and currently is developing rapidly in other parts of the world, including Argentina, China and Poland, for example. Many thousands of shale play wells have been drilled in the past few years and almost 100% of them so far are in North America. The challenges to shale play drilling and development are many and the top ones are technical, economic and environmental challenges.

On the technical challenges, gas or oil shale is very different from traditional shale and horizontal drilling imposes additional challenges on wellbore stability and drilling fluids. The gas or oil shale is usually not reactive in the traditional sense, but is micro-fractured and highly laminated, which can be easily destabilized by drilling fluids. Additionally, each shale play and the overburdens are different and thus drilling fluids need to be tailored for each formation, not only for the overburden reactive shale, but also for specific shale play. Typical drilling fluids related problems include gumbo shale in the overburden, hole instability and mud losses, solids build-up and hole cleaning, torque and drag, and slow rate of penetration in the long horizontal section (Guo et al., 2012).

Economic challenges are equally important for shale play drilling and development as these shale play wells are often low profit margin wells and the economics depend strongly on drilling and development costs. Increasing drilling efficiency and thus reducing drilling costs are high on the total well cost. Since a large number of wells must be drilled in any shale play development, the cost benefits from drilling efficiency increase will make a large economic impact. Economic and technical challenges are interrelated. For example, some operators can drill two to three times faster than others. As a consequence, some operators make money while others loss money. As an industry, we are still in the early stages of the learning curve for shale play drilling, thus the opportunity of drilling efficiency improvement is real and large.

A third challenge related to shale play drilling and development is environmental consequence of drilling and fracturing fluids because many of the shale plays are in urban locations or environment-sensitive regions and many wells have to be drilled and hydraulically fractured to create production. The public is very concerned with underground fresh water protection and the consequence of multi-stage hydraulic fracturing using very large volumes of water. Environmentally friendly water-based drilling fluids are preferred to oil-based drilling fluids.

In this paper we collected and analyzed drilling data from over 1000 US shale play wells to give a clear picture of the current industry practices on the technical, cost and environmental challenges in shale gas and oil drilling and development. Drilling data from Eagle Ford, Haynesville and Marcellus were analyzed in detail. The analyses of these drilling performance data not only offer the current drilling status and guidelines, but also offer recognition of opportunities for improvement in shale play drilling. A comparative analysis was performed between oil-based and water-based drilling fluids. A statistical analysis (P10, P50, and P90) was also performed to evaluate industry-wide drilling performance such as drilling days for wells of various depths. Comparisons were made among different drilling fluid types and different operating companies.

Shale Plays Are Different

Shale plays are different in two key aspects. The first one is that gas or oil shale is very different from traditional, swelling or reactive shale and the second aspect is that each shale play is different from the other. The industry knowledge and experience in dealing with shale are mostly on overburden and reactive shale, rather than oil or gas shale. The laboratory and well-site testing techniques for evaluating fluids and shale interactions and dealing with shale instability do not apply to oil or gas shale. Additionally, each shale play is different from the other. Eagle Ford shale is different from Haynesville, Haynesville shale different from Marcellus.

Shale reaction with drilling fluids is a complex problem and there is no single method for solving this complex problem. Over the years, the drilling and drilling fluids industry has developed various lab testing techniques to address shale-fluids interaction problems (Friedheim et al., 2011). Each testing technique is developed to evaluate a single attribute or to address a specific problem. However, when we put these testing results together, they present a holistic approach and are effective for identifying and managing shale-fluids interaction issues. Shale is a very complex rock and varies greatly. Fig. 1 shows a rough grouping of shale reactivity potential, varying from highly reactive shale, to moderate reactive shale, to low reactive shale such as oil or gas shale.

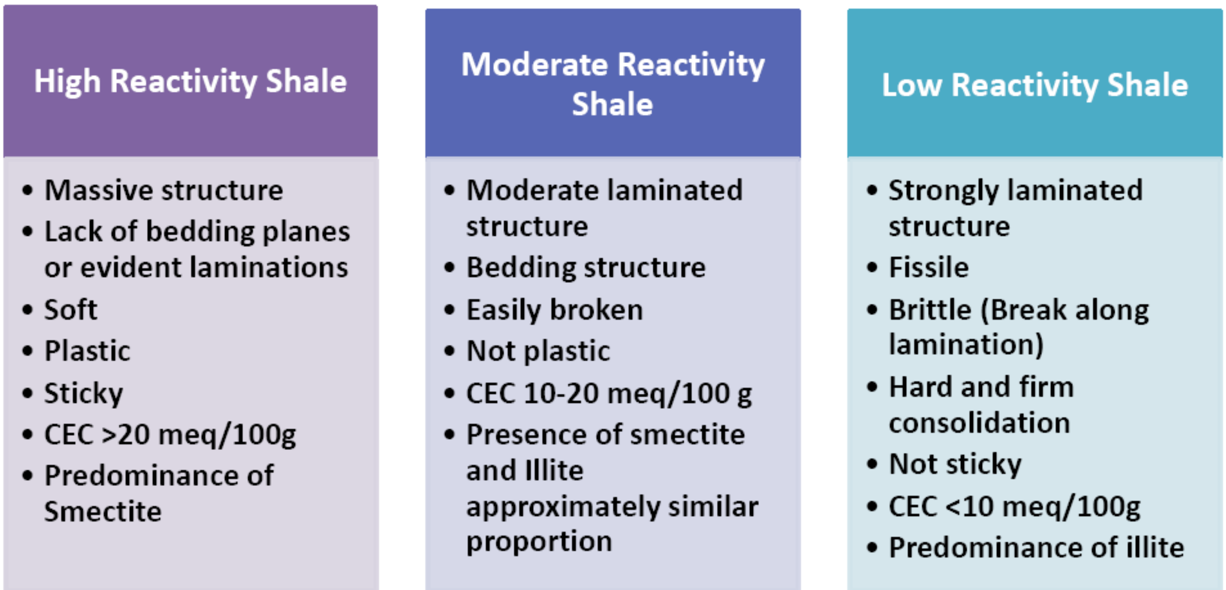

Fig. 1 – A rough classification of shale reactivity potential (after Gomez et al., 2006).

Because of these differences the shale-fluid reaction mechanisms and thus the shale instability or failures are different. For highly to moderate reactive shale, shale swelling is the major shale instability problem. For low reactivity shale, including gas or oil shale, fracture development and shale failure along the laminations (see Fig. 2) are the major shale instability problem when the shale reacts with drilling fluids. The drilling and wellbore instability problems caused by fracture development along the laminations are many such as hole cleaning, pack-offs, torque and drag problems. This is because the shale fails in the manner shown in Fig. 3 and the cuttings are thin and sharp initially and then may be ground along the wellbore into small pieces like coffee grinds (see Fig. 4, for example). Coffee-grinds like cuttings are difficult to be recovered from shakers and they contaminate the mud easily, causing high mud costs and mud recycling or disposal costs.

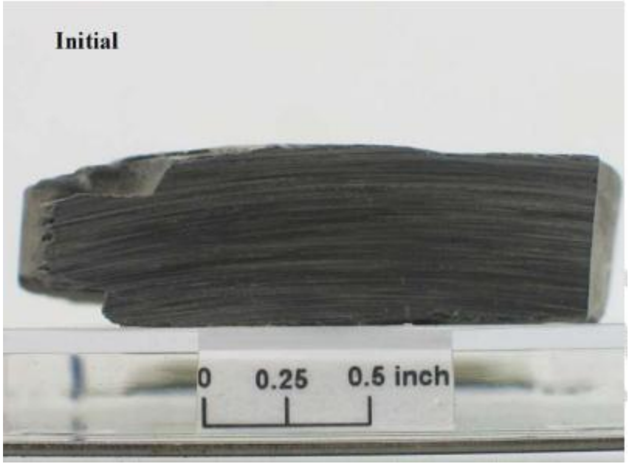

Fig. 2a – A low reactive shale sample before contacting with a drilling fluid.

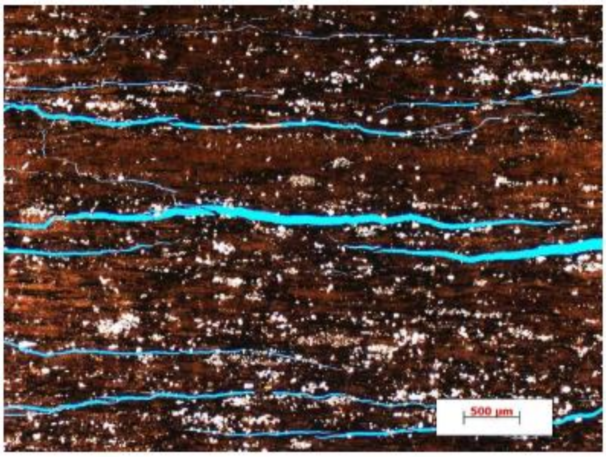

Fig. 2b – Fractures along the laminations developed when the shale sample reacts with the drilling fluid.

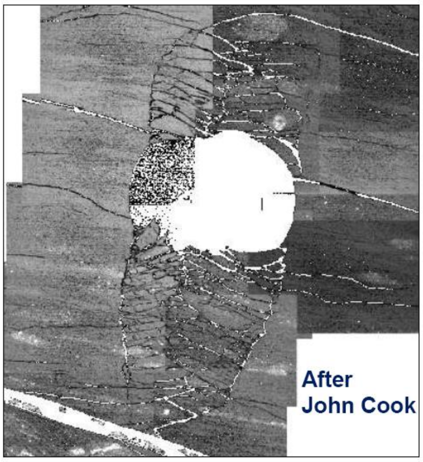

Fig. 3 – An experimental study of bedding and lamination effects on wellbore failure, after John Cook of Schlumberger.

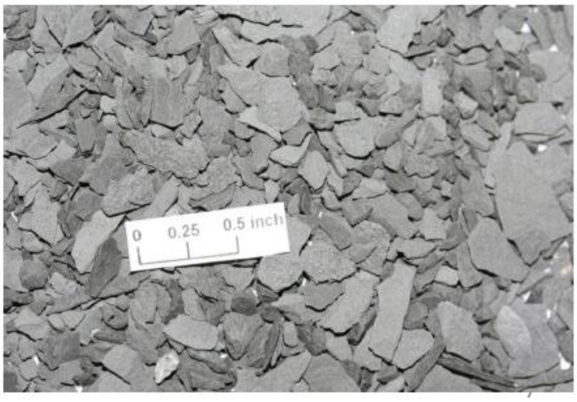

Fig. 4 – Thin and sharp cuttings collected from a Marcellus well. Cuttings from Eagle Ford wells are often like coffee-grinds

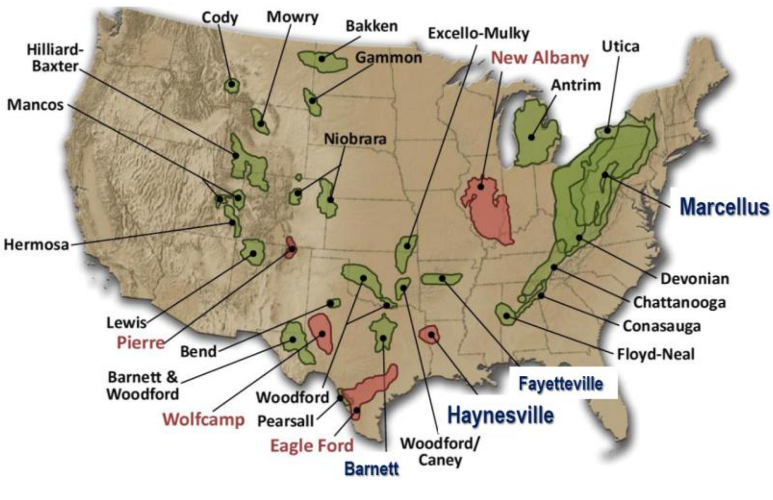

Fig. 5 – Key shale plays and their locations in the US.

Highlight of Key US Shale Plays

Fig. 5 shows the map and locations of the key US shale plays. Table 1 highlights the differences among the key shale plays in the US. For example, Haynesville shale is a high temperature and high pressure reservoir, while Fayetteville shale is a low temperature and low pressure reservoir. Eagle Ford and Marcellus are in between. The data shown in Table 1 are much generalized and should be taken with caution. For example, Eagle Ford shale encompasses a very large area about 50 miles wide and over 400 miles long from the southwestern part of Texas to just south of Dallas. Some region of Eagle Ford shale is high temperature and high pressure, while other region is not high pressure or high temperature. Eagle Ford shale has three thermally aged areas: the northern edge of the play rich in oil, the middle section with gas condensate, and the southern-most edge consisting of a dry gas window.

Table 1 – Highlight of Reservoir and Drilling Parameters for Key US Shale Plays

Haynesville Shale ➢ Depth = 10,500 – 13,500 ft TVD ➢ MW = 15 – 16 ppg ➢ Temperature = 300 – 325° F	**Eagle Ford Shale** ➢ Depth = 6,000 – 14,000 ft TVD ➢ MW = 10 – 12 ppg ➢ Temperature = 200 – 250° F
Fayetteville Shale ➢ Depth = 1,000 – 7,000 ft TVD ➢ MW = 9 – 10 ppg ➢ Temperature = ~130° F	**Barnett Shale** ➢ Depth = 6,500 – 8,500 ft TVD ➢ MW = 9.5 – 10.5 ppg ➢ Temperature = 180 – 220° F
Marcellus Shale ➢ Depth = 6,000 – 8,500 ft TVD ➢ MW = 12 – 14.5 ppg ➢ Temperature = ~180° F	**Bakken Shale** ➢ Depth = ~11,000 ft TVD ➢ MW = 10 – 11 ppg ➢ Temperature = ~150° F

Key US Shale Play Drilling and Drilling Fluids Performance Analyses and Results

Drilling and drilling fluids data from over one thousand shale play wells were retrieved from a drilling database. Among them, there are 203 horizontal wells from Eagle Ford shale play drilled by over 30 different operators, and similar number of wells and operators from Haynesville and Marcellus shale plays.

Eagle Ford Shale

In Fig. 6, we plotted the true vertical depth versus the total measured depth from the 203 Eagle Ford shale wells. As shown in Fig. 6, the true vertical depth of the Eagle Ford shale play varies from approximately 5,000 to 15,000 ft TVD. The lateral or horizontal length of these wells varies from 4,000 to 6,000 ft. Most of the horizontal wells targeting the Eagle Ford shale were drilled with OBM. As shown in Fig. 7, only 38 wells (19%) out of total 203 horizontal wells were drilled using WBM while most of the rest were drilled with OBM. Because of the large variation of Eagle Ford shale depth and reservoir pressure the mud weight used in drilling Eagle Ford wells has a large variation too. Fig. 8 shows the mud weight range used in drilling Eagle Ford wells, where the squares represent OBM while the triangles represent WBM.

OBM and WBM perform similarly when the wells are not too long, and OBM performs better than WBM when the wells are long. Fig. 9 shows the total average drilling days versus total measured depth for OBM and WBM. As shown in the figure, when the total measured well depth is less than 12,000 feet, there is little difference between OBM and WBM. However, OBM performs better than WBM mud when the well length is greater than 12,000 feet. For example, the industry average with OBM is about 27 days for drilling a 16,000 ft depth well, while it takes about 36 days with WBM. Table 2 shows the statistical results of total drilling days versus well depth for both water-based and oil-based drilling fluids. For instance, in Table 2, for wells with a total well depth of approximately 16,000 ft drilled with WBM, we have P10 = 26, P50 = 36 and P90 = 50 days. This means that less than 10% of the wells were drilled in less than 26 days, 90% of the wells were drilled in less than 50 days, and the most likely drilling days were around 36 days. As seen from the data, more drilling days were spent on the same footage with WBM comparing to OBM; this was more pronounced at greater depths.

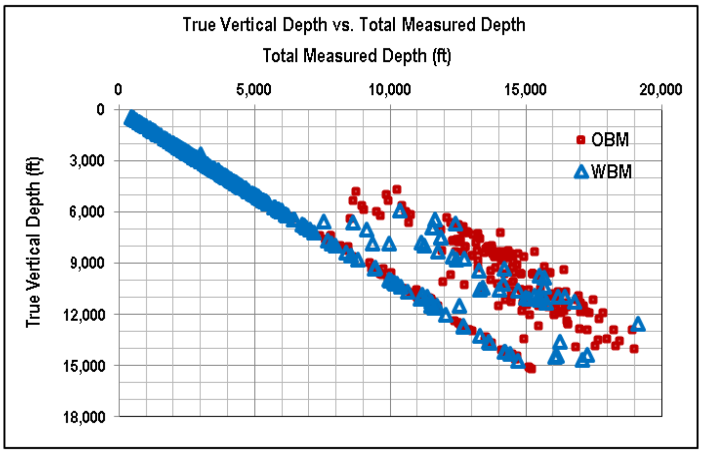

Fig. 6 – Depth range of over two hundred Eagle Ford shale play wells drilled between 2008 and early 2011.

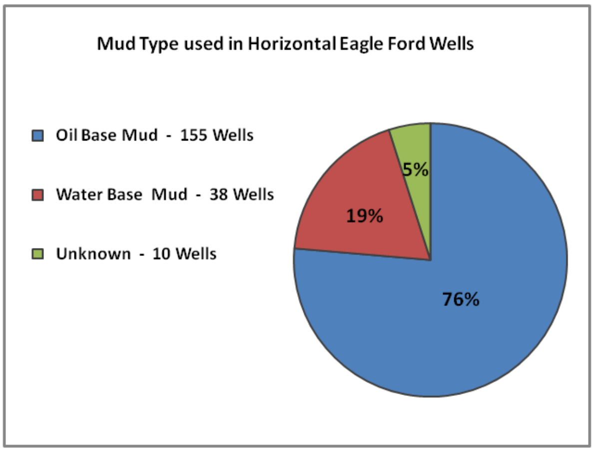

Fig. 7 – Distribution of drilling fluids types for the horizontal Eagle Ford wells.

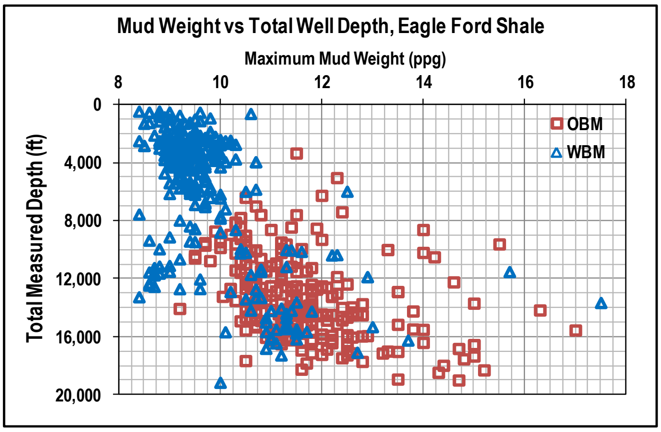

Fig. 8 – Mud weight range in Eagle Ford shale.

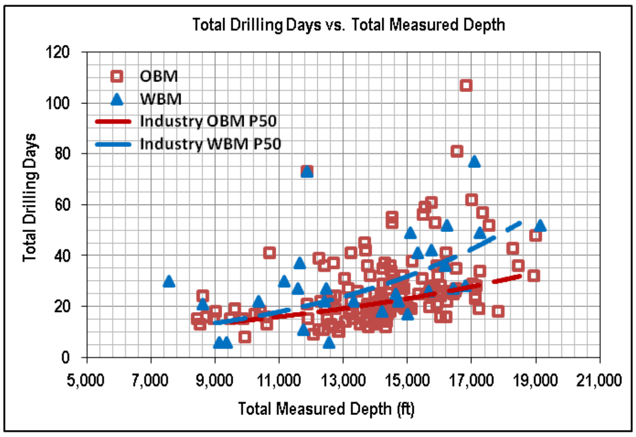

Fig. 9 – Drilling days versus total well depth with water-based and oil-based drilling fluids.

Table 2 – Drilling Days vs Total Depth

WBM				OBM			
TD (ft)	P_{10}	P_{50}	P_{90}	TD (ft)	P_{10}	P_{50}	P_{90}
9,000	5	14	26	9,500	9	15	22
12,000	6	26	38	12,000	10	15	37
14,000	17	20	44	14,000	14	21	36
16,000	26	36	50	16,000	19	27	58
18,500	n/a	59	n/a	18,500	18	32	55

The industry, on the average, has made clear continuous improvements in drilling performance over the years and certain operators perform much better than the industry average. Looking at the overall drilling performance, generally, an improvement or a decrease in number of drilling days, can be observed between 2008 and 2011 (Fig. 10). Fig. 10 also shows a bigger range and scattering in drilling days of 2008 and 2009. However, in 2010 and 2011, the drilling days for the same depth seem to have stabilized as more and more experience is gained in the field. Another example of clear drilling performance improvement is for Fayetteville wells from 2007 to 2011, the average drilling days was reduced from 17 to 11 days, while the average lateral length was increased from 1400 feet to over 4000 feet. One interesting observation is that some operators can drill wells in much fewer days than industry average even though their drilling fluid cost is slightly more expensive than industry average. Fig. 11 shows the average drilling days for different depths with OBM based on 155 wells investigated. Drilling days of the top performing operators are also shown in Fig. 11 for the same depth. As seen from the plot, operators D and B drill around 12,500-ft long wells in about 10 and 8 days respectively which are 8 and 10 days less than the industry average respectively. Similarly, operator C drills around 14,000-ft long wells in about 15 days which is roughly 6 days below the industry average. This means that there are still large opportunities to improve and decrease the industry average to even fewer drilling days.

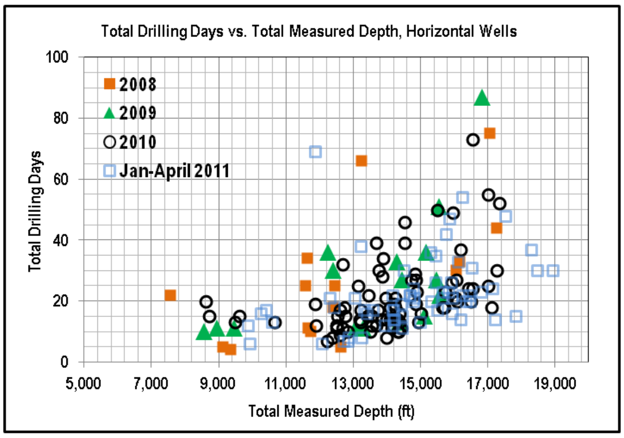

Fig. 10 – Drilling days of horizontal wells versus total well depth between 2008 and 2011 in Eagle Ford Shale.

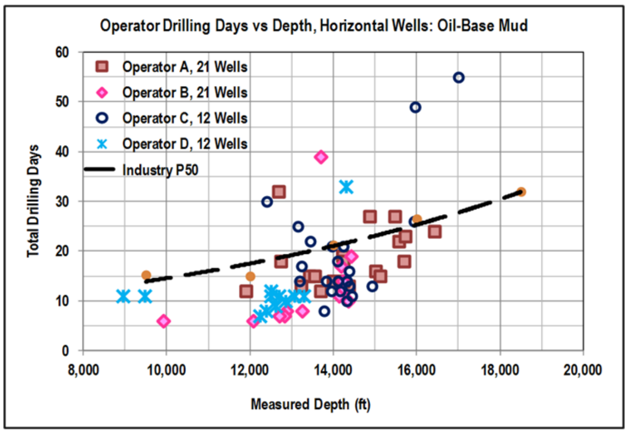

Fig. 11 – Drilling performance of different operators with OBM.

Haynesville Shale

Haynesville shale gas encompasses approximately 15 million acres. The development of Haynesville started earnestly in 2007. It currently produces approximately 6 BCFD and is the largest shale gas producer. Drilling and drilling fluids data from 240 Haynesville shale gas wells were collected and analyzed. Among these 240 wells, only 35 wells (14%) were drilled using WBM while the rest were drilled with OBM. Lower percentage of wells drilled with WBM is partly due to the high-temperature and high-pressure nature of Haynesville shale.

Fig. 12 shows the true vertical depth versus total measured depth. The reservoir depth varies from approximately 10,000 to 14,000 feet; and the lateral or horizontal section of the wells varies from 3000 to 7000 feet. Fig. 13 shows the average drilling days for different well lengths drilled with OBM or WBM. As shown in Fig. 13, most of the wells longer than 14,000 feet were drilled with OBM and the average drilling days range from approximately 30 to 60 days.

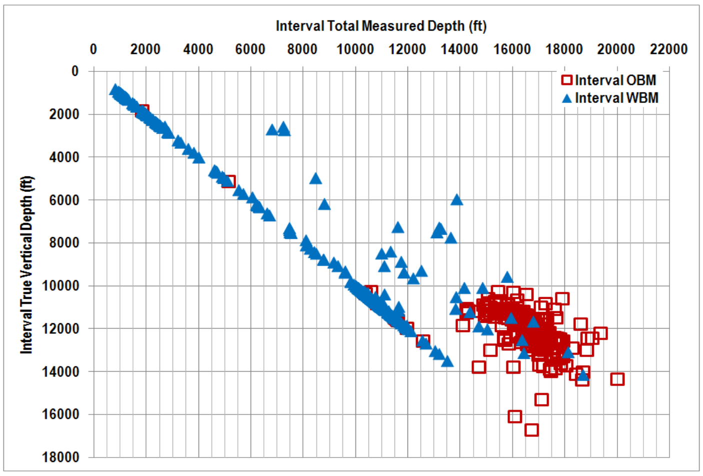

Fig. 12 – Depth range of over two hundred Haynesville shale gas wells drilled between 2007 and early 2011.

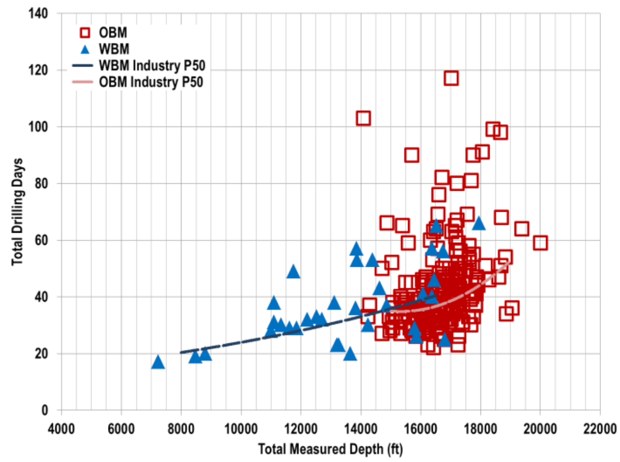

Fig. 13 – Drilling days versus total well depth with water-based and oil-based drilling fluids.

Fig. 14 shows the mud weight range over the total well depth. For the surface casing the spud mud weight range varies from 85 to 10 ppg. The mud weight range for the intermediate casing is from 10 to 12.5 ppg. The reservoir or the horizontal sections were generally drilled with OBM with a mud weight from 15 to 17 ppg.

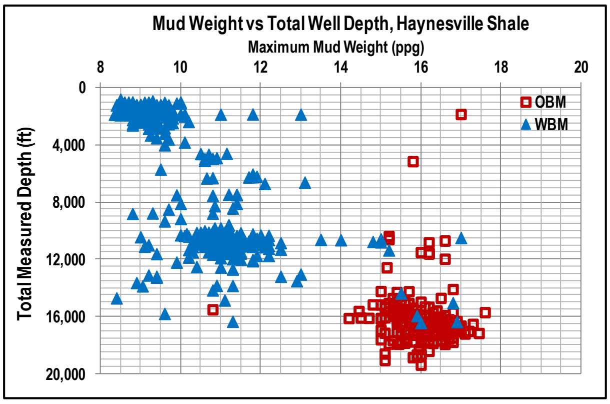

Fig. 14 – Mud Weight range in Haynesville shale.

Marcellus Shale

Marcellus shale play encompasses approximately 3.5 million acres. Earnest development of Marcellus shale started in 2007. Drilling and drilling fluids data from about 170 wells from Marcellus shale gas wells were collected and analyzed. These wells were drilled between 2007 and early 2011. About 40% of these wells were drilled with WBM while the rest with OBM. The higher percentage of wells drilled with WBM reflects the higher environmental requirement in the New York and Pennsylvania area.

Fig. 15 plots the true vertical depth versus the total measured depth from approximately 100 wells from Marcellus shale. As shown in Fig. 15, Marcellus shale varies from 5000 feet to 9000 feet deep, with total measure well depth varies from approximately 9000 feet to over 14,000 feet. The lateral or horizontal length varies from 3000 feet to 8000 feet. The average drilling days range from 16 to 23 days for OBM (see Table 3). Mud weight range for the horizontal section is from 12 to 14 ppg.

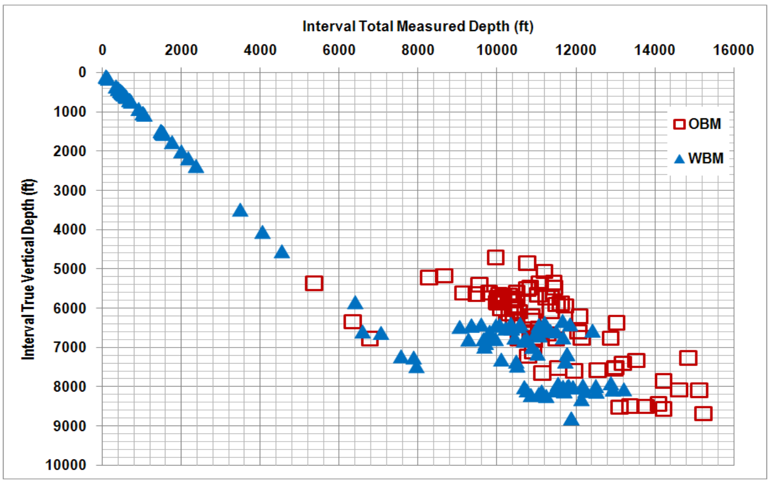

Fig. 15 – Depth range of about two hundred Marcellus shale gas wells drilled between 2007 and early 2011.

Table 3 – Drilling Days vs Total Depth (OBM)

TD (ft)	P_{10}	P_{50}	P_{90}
9500	6	16	22
10500	8	17	28
11500	9	20	36
12600	11	23	38
14225	12	23	40

Summary and Conclusions

Many thousands of shale gas or oil wells have been drilled in the US in the past few years. Drilling and drilling fluids data from about one thousand wells from key US shale plays were collected and analyzed. Based on these data and analyses, we obtained the following findings and conclusions:

- Gas or oil shale is very different from traditional shale. Gas or oil shale is strongly laminated and brittle, fails through fracture development along laminations.
- Because gas shale is different from traditional shale, many of the effective techniques developed for evaluating shale-fluids interactions and shale instability problems do not work for gas shale. New techniques are required and the drilling and drilling fluids industry is working on and has made initial progress on this.
- Drilling performance results from Eagle Ford, Haynesville and Marcellus showed that not all the shale plays are the same. Haynesville shale play is high temperature and high pressure while Marcellus is low temperature and low pressure. Drilling days for a Haynesville well are over three times of drilling days for a Marcellus well or about two times of drilling days for an Eagle Ford well.

- OBM does not always perform better than WBM. For longer wells, it usually takes fewer drilling days using OBM than the drilling days using WBM. However, for relatively shorter wells and even some long wells, certain WBM performs as well as OBM.
- Although our industry has made clear continuous improvements in drilling efficiency over the years, there is still a large scatter or variation in drilling days for wells of similar length and architecture, indicating there is still a large opportunity for further improvement.
- Certain operators perform much better than the industry average. In Eagle Ford, drilling days from better performance operators can be about 10 days fewer than the industry average for similar wells.
- The average drilling days for Eagle Ford, Marcellus and Haynesville wells are 15 to 32, 16 to 23 and 35 to 53 days, respectively, depending on the depth and complexity of the wells.
- All the data reported in this paper were collected and analyzed in early 2011. We are in the process of updating the data and analyses.

Acknowledgement

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