

Recent Application of a Non-Biopolymer Reservoir Drill-in Fluid to a Deepwater Openhole Gravel Pack and the Ability to Incorporate Unique Chemistries

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Abstract

A biopolymer-free reservoir drill-in fluid (RDF) was developed in very early 2000 for high-density applications ranging from approximately 10.6 lb_m/gal to greater than 16 lb_m/gal. This existing system was recently improved to promote functionality for densities less than the previous 10.6 lb_m/gal to as low as 9.6 lb_m/gal. This improvement allowed the incorporation of relatively inexpensive calcium chloride to formulate systems that expanded the lower density range to as low as 9.6 lb_m/gal. Conversely, the use of calcium chloride allowed maximum densities up to approximately 12.8 lb_m/gal. whereby calcium bromide and/or blends of these two brines can be used for even greater density. Global implementation of this system over the last three years has demonstrated not only flexibility with a wide range of reservoir and completion types (Luyster et al. 2016) but also the ability to incorporate refined chemistry to mitigate common damage mechanisms (Eyaa Allogo et al. 2014).

A case history of a deepwater openhole gravel-pack (OHGP) is presented to demonstrate this system's functionality with respect to the issues and objectives associated with the drilling and completion phases. Also included are two novel applications of refined chemistries; the first demonstrates the potential to mitigate scale and the second illustrates the ability to increase density whereby less solids are utilized to maintain hydraulics. The former demonstrates the use of an inhibitor and the latter the use of calcinated magnesium oxide whereby the incorporation of calcinated magnesium oxide creates viscosity, specifically low-shear-rate viscosity, at a lower density range that has not been achievable before.

The evaluations and assessments for the OHGP include analysis of the systems rheology and hydraulics, particle size of the bridging solids, amount and type of residual formation solids, and lessons learned. These results are contrasted with the initial design, targets established, and results collected in the field. The case history discusses the hydraulics, displacements used to prepare the open hole, running the sand-control screen, the OHGP, and finally, the application and results after post-spotting a novel breaker system.

Introduction

A reservoir drilling fluid or system which utilizes an acid-

or enzyme-soluble polymer that serves as both a viscosifier and fluid-loss additive was developed for high-density drilling and completion applications in the late 1990's with publication of concept in 2001 (Horton et al. 2001a). The concept for this non-biopolymer reservoir drill-in system (NBRDF) includes a magnesium complex (DFS) in a divalent cation-based brine whereby in lieu of a biopolymer (e.g., xanthan, diutan, welan gum, scleroglucan), only a starch is needed to generate viscosity and reduce fluid loss. Since the development of this system, numerous publications (Horton et al. 2001a and 2001b; Knox et al. 2002; Campbell et al. 2002; Eyaa Allogo et al. 2014 and 2015) detail this system's properties and attributes as well as contrasting these with common biopolymer/starch/calcium-carbonate systems (Horton et al. 2001a and 2001b). In addition, recent publications present unique applications of the chemistry addressing specific issues identified for a well/project (Eyaa Allogo et al. 2014 and 2015).

During development of the NBRDF system, the primary objective focused on the utilization and compatibility of high-density divalent brines as the base for a drilling and completion system whereby no biopolymer would be necessary and the concentration of bridging solids could be reduced. Therefore, upward density adjustments to the system could be accomplished using the working brine rather than additions of traditional weight solids such as calcium carbonate or barite. In this manner, while maintaining a relatively low concentration of bridging solids, a relatively thin filter cake would in theory be deposited on the target formation. It follows that if fewer solids are required in the system, a low-viscosity profile could be obtained with less hydraulics required with respect to drilling/pumping. However, it was also recognized that this system would require the ability to generate high low-shear-rate viscosities (LSRV).

During this same period of development (late 1990's), the most commercially available dense brines were calcium chloride, calcium bromide, and zinc bromide; thus, the focus remained only on using these commonly available divalent brines. The use of these divalent brines as a base for drilling fluids however was limited (Queiroz et al. 2000; Argillier et al. 1999; Luyster et al. 2000). Generally, water-soluble polymers used for viscosity and filtration control did not

perform (e.g., generate necessary high LSRV) in calcium bromide or zinc bromide brines (Horton et al. 2001; Dobson et al. 1996). Therefore, the basic components necessary for successfully compounding a high-density drilling system – approximately 11.5 to 17.5 lb_m/gal, exhibiting high LSRV, shear-thinning capabilities, and low filtrates – were not available at that time.

Furthermore, the initial development of this NBRDF system was predicated on two concepts – buoyancy and generating LSRV with fluid-loss control in high-density brines. Inherent buoyancy would provide suspension of typical solids and/or mitigate their compaction in higher density brines. In addition to the buoyancy, a component was desired which would provide fluid-loss control as well as high LSRV. These latter concepts included the development of components compatible with the aforementioned divalent brines and would generate viscosity and subsequently deposit a filter cake that would mitigate losses to the target formation.

In recent years, this NBRDF system was expanded to achieve the above objectives using even lower density divalent brine, specifically calcium chloride, to achieve a final density of approximately 9.5 lb_m/gal. The development of this system and the recent capability to achieve lower density without a biopolymer has enabled recent applications of a low density (LD-NBRDF) as well as a non-biopolymer, solids-free (NBSF) system to a wide range of drilling and completion applications. Some of these include drilling cement, running completion assemblies whereby premature plugging of the sand control screen is mitigated, workovers, milling windows and incorporating an inhibitor when drilling a scale-sensitive reservoir (Eyaa Allogo et al. 2015).

The next sections of this paper delineate two unique applications of this chemistry. The first is proven in a West Africa field as an application to prevent calcium-based scales and the other a concept for utilization of sized calcined magnesium to reduce total bridging solids thus improving the hydraulics of the RDF while maintaining solubility of the residual filtercake.

Incorporation of Unique Chemistries

The flexibility of the NBRDF and NBSF systems allow for incorporations of unique chemistries. In the first example, a concentrated phosphonate-based additive capable of inhibiting scale such as calcium carbonate, calcium sulfate and barium sulfate was introduced into the base brine, calcium chloride, of a NBRDF. This scale inhibitor is soluble in most water-based fluids including calcium chloride and calcium bromide completion brines. As such, it was subsequently dispersed as a component of the filtrate that ultimately leaked-off into the formation and contacted formation fluids such as the water phase thereby mitigating scale. The second example is a conceptual application of a calcined magnesium oxide, specific gravity of 3.56 and hardness of 5.5 on the Mohr's scale, as a bridging grade material for RDF and fluid loss pills that is readily dissolved with common chemistries.

Incorporation of a Scale Inhibitor

The ability to incorporate a scale inhibitor in the LD-NBRDF and the NBSF were documented in two previous SPE papers (Eyaa Allogo et al. 2014 and 2015). The drilling and completion systems were selected based on extensive laboratory analyses performed at several regional technical centers. These systems selected included a LD-NBRDF formulated to 10.2 lb_m/gal density. In addition to the requirements to drill and complete the reservoir, these systems were optimized to minimize formation damage, provide shale inhibition, control rheological properties to minimize the equivalent circulation density (ECD), as well as provide acceptable environmental characteristics. A scale inhibitor was incorporated to mitigate formation of calcium carbonate scale due to comingling with formation water. A calcium chloride brine was used as the base for the LD-NBRDF, NBSF, working brine, gravel packing and various other operations including the upper completion. These provided the source of calcium for the potential scaling.

In this project, the application of a scale inhibitor was applied for the first time. The inhibitor was incorporated into the LD-NBRDF, NBSF and breaker systems as well as the gravel pack system and the calcium chloride working brine. A breaker system was pumped post-gravel pack to mitigate residual skin (e.g., residual filtercake) and degrade and dissolve the filtercake however, this system included the scale inhibitor.

The utilization of this inhibitor was based on production impairment in previously completed wells in this field. The root cause was the continued use of incompatible divalent brines that contacted the formation waters via whole mud losses, secondary losses such as filtrate, and losses of the completion brine. As calcium chloride was readily available and cost effective, a solution was desired whereby a low-cost additive could mitigate the formation of the scale. Filtrate collected from the LD-NBRDF, which is primarily calcium chloride, was commingled with formation water collected from the field. An immediate turbidity increase was prevalent in all ratios tested and as the scale was suspended. An inhibitor was added to the LD-NBRDF at 0.25 vol%, subsequently aged, and then the filtrate was collected. This filtrate was then commingled with the formation water using the same ratios. **Figure 1** shows these results. Note that no turbidity increase is apparent as shown in all three bottles in Figure 1B. These tests were repeated using increased/decreased concentrations to optimize the loading for the field. This testing showed that only a defoamer was required for application in the field. The drilling properties were unaffected as documented in SPE 170310 (Eyaa Allogo et al. 2014).

Incorporation of Calcined Magnesium Oxide

Calcination is a thermal treatment process in the absence or limited supply of air or oxygen applied to ores and other solid materials to expedite thermal decomposition. Thus by altering the exposure of time, heat, and air one can alter the reactivity of a desired ore. For calcined magnesium oxide (CMO), the alteration of its reactivity allocates its use not only

as a secondary buffer but also as a bridging and weighting material. As CMO is readily ground, one can produce sized grades, ranging from approximately 3 to 150 μm , that subsequently allows flexibility for optimizing a blend of two or more grades to reduce fluid loss if used as a bridging material. The specific gravity of CMO, approximately 3.56, is greater than calcium carbonate thus can yield a reduction of total solids loading by 20-25 wt% and subsequently reduces the plastic viscosity (PV) of a drilling system. Its hardness, approximately 5.5 on the Mohr's Scale, also is advantageous as a bridging blend and wellbore stability material. CMO is readily degradable in organic and inorganic acids as well as chelates (*i.e.*, at pH of 9 to 12). **Table 1** shows laboratory results of the aforementioned degradation testing.

As an example, a 15.2-lb_m/gal NBRDF was formulated using a combination of CMO and calcium carbonate and compared to a NBRDF system of equal density whereby only calcium carbonate grades were used for bridging. The base brine for both systems was pure calcium bromide. The bridging solids blend for the former system was comprised of sized calcium carbonate and a 10- μm CMO while the latter system comprised 100% sized calcium carbonate. As the CMO can also function as a buffer, no other buffering agent was incorporated to maintain pH in the former system. Two thermal extenders were incorporated in both systems. Both systems were dynamically and statically aged for 16, 24 and 48 hours at 260°F. The rheology was measured after each aging period. No other additive was incorporated into these systems during or immediately after the aging periods. These results (**Table 2**) show that the NBRDF with CMO exhibited no degradation of the LSRV, maintained a stable pH and exhibited no excessive gel strength. While the PV increased marginally after the initial mixing this is most likely due to the full yield of the DFS; however as compared to the system that utilized only calcium carbonate plus a buffer, this systems' PV increased from 24 to 111.

The next sections detail the incorporation of this flexible NBRDF chemistry in the pre-planning, field execution, and the initial production results of the only horizontal drilled and completed well in the Who Dat Field to date. This OHGP required a reservoir drill-in fluid (RDF) with a final density of +12.9 lb_m/gal to drill an 8½-in. hole at 90 degrees through the target reservoir.

Deepwater OHGP Completion

The Who Dat field is located in the Gulf of Mexico in approximately 3,000 feet of water. The discovery well realized more than 380 feet (116 meters) of gas and oil pay zones in four separate reservoir packages. Who Dat is primarily an oil field consisting of stacked amplitude-supported reservoirs in a salt withdrawal mini-basin. In 2011 Who Dat was scheduled to produce from ten stacked Pliocene and Upper Miocene reservoirs from 10,000 – 17,000 ft. On test, the zones that were mainly oil tested 17-26° API gravity crude with gas/oil ratio (GOR) ranging from 400 to 1,300. Reservoir pressures ranged from 6,000 to 12,500 psi.

Beginning in 2012 to early 2013, the drilling and

completion teams for the Who Dat field initiated planning for a single horizontal completion as an OHGP in approximately 2645 ft of water. A 9⅞-in. tieback was required before drilling the 8½-in. lateral. The driver for this completion was two-fold; first the largest reservoir in the field still held considerable reserves and multiple vertical to low-angle wells would be required to produce the relatively high viscosity crude. Simulations showed that a single horizontal was capable of producing more crude than a cased-hole frac-pack. Thus a successful horizontal would minimize the drawdown and subsequently increase the productivity index (PI), and more importantly, decrease the abandonment pressure thereby increasing the total produced crude over an equal period of time.

A high-rate water pack was desired to pack the annulus of the horizontal followed with spotting a breaker system to dissolve/degrade any residual filtercake that would further enhance and accelerate the cleanup and reduce skin upon initial production. With the decision to complete as a horizontal, the drilling and completion teams established objectives for both phases as:

Drilling Phase

- No HSE issues
- No non-productive time (NPT)/Maintain critical path
- Mitigate problems associated with kick-off angle for lateral
- Maintain 8½-in. hole in the bright spot

Completion Phase

- No HSE issues
- No NPT/Maintain critical path
- Use established best practices for hole preparation to ensure landing the sand-control screen at target depth
- 100% water pack
- Successful clean-up of residual filtercake to mitigate skin
- Skin less than 5. Post remediation dependent upon cleanup decreasing over period well tested.

Target Reservoir

The target reservoir is a sandstone of upper Miocene age and considered a lower slope sheet deposit identified as relatively uniform with maximum porosity of 34% and permeability ranging from 800 to 1000 mD. The optimum reservoir has an approximate thickness of approximately 57 ft at 16,963 to 17,020 ft measured depth (MD). Particle size data (PSD) over this interval show that this sand is a fine-grained and unimodal that grades into silt and clay-sized grains (**Figure 2**). As fine-grained and considered a prograding unconfined turbidite, these reservoirs commonly do not outcrop which makes it difficult to determine architectural changes in downdip and lateral direction as well as reservoir continuity (Bouma 2001). Furthermore, a cross-plot over this same interval shows permeability and porosity ranging from 990 to 3440 mD and 32.6 to 35.0%, respectively. At approximately 17,010 ft MD, the permeability and porosity are drastically reduced (**Figure 3**).

Optical assessments of thin sections (**Figure 4**), created from sidewalls taken from the offset well show that grains are angular to sub-rounded in shape, poorly sorted and strongly unconsolidated. Visually, quartz comprises ~80%, clays ~5-10%, feldspar ~5%, and rock fragments ~5%. The percent clay mineral content is relatively low. These images show dissolution of quartz throughout as well as traces of insoluble organic matter. Visually, grain sizes range from 30 to 130 μm . The common pore sizes range between 15 and 40 μm while the maximum pore size approaches 75 μm .

However, X-ray diffraction data (XRD) in **Table 3** show that this sandstone is predominantly quartz, 85 wt%, with feldspars ranging from 11 to 12 wt%. As the rock fragments approximate 5%, this sandstone is most likely subarkosic, however point counting was not performed. The CEC values are consistent with the optical and XRD and range from 3 to 4. These values indicate relatively low reactivity.

This sand had a calculated water saturation (S_w) of 22% and the reservoir pressure of approximately 9537 psi in June of 2013. The desired drilling system density ranged from 12.8 to 13.0 lb_m/gal . and provide relatively high static safety margins of 414 psi and 570 psi. The reservoir temperature measured 210°F. At this pressure and temperature, the fluid properties measured 20° API gravity at a viscosity of 4 cP with a GOR of 900.

A laboratory assessment was performed to design and optimize compatible drilling and completion systems. These included a drilling, liner running and breaker system. These systems were assessed for rheology and hydraulics at the required density. These systems were also assessed for compatibility with the target reservoir as well as the desired completion method.

Laboratory Assessment of Fluids

The laboratory assessment below was specific for the Who Dat well, but is representative of assessments to qualify fluids and ensure compatibility with downhole situations. The assessments presented below include: analyses of the NBRDF, preliminary testing for the true crystallization temperature (TCT), optimizing rheology for hydraulics as well as fluid loss and the bridging solids. As the reservoir pressure was not confirmed when these assessments were performed, the maximum anticipated density was used for all systems, thus the NBRDF was formulated to a density of 13.3 lb_m/gal .

Optimization of the Base Brine

Drilling operations required a 20°F TCT for all brines. The TCT for a calcium bromide, as a single salt, ranges from 30°F at 8.4 lb_m/gal to less than -30°F at 12.3 lb_m/gal and remains less than -30°F until its eutectic point at approximately 13.5 to 13.6 lb_m/gal . As the desired NBRDF density is greater than 13.0 lb_m/gal , there is nil risk of crystallization when using calcium bromide as a single salt. However, the utilization of a two-salt blend, calcium chloride and calcium bromide, is more likely as this reduces brine cost. Using base brine densities ranging from 13.0 to 13.6 lb_m/gal , their TCT values range from approximately 6 to 14°F. These TCT values will yield pressure crystallization temperature

(PCT) values ranging from 17 to 27°F at 10,000 psi (Freeman 2000). **Figure 5** shows TCT data for each base brine discussed. The maximum anticipated density for the working brine approximated 13.1 lb_m/gal which provided a safety factor of 647 psi.

Optimization of the Bridging Solids

Next an optimum bridging solids blend was developed using the D $\frac{1}{2}$ Rule to finalize the required grades or blend of calcium carbonate (Dick 2000). This software program requires particle size data of locally sourced carbonate grades and user input for permeability or more desired pore size data from the target reservoir. The algorithm then generates a “target” based on these inputs. A closest fit is then generated using the local grades particle size distribution (PSD). By comparing the “target” to the “blend”, reiterations can be performed to optimize a best fit. Fluid loss simulations can then be performed using common API test methods. The pore size was estimated using the aforementioned optical analyses. The optical data shows that the common pores range from 15 to 40 μm with a maximum of 75 μm . This optical assessment agrees, in part with the estimated median pore size from the PSD. While the larger pores identified may be due to the unconsolidated nature as well as the storage and condition of these samples, the measured diameter is not exceedingly larger than the common pores and thus is considered valid.

Optimization/iterations using this method included the addition of finer calcium carbonate particles to mitigate fluid loss initially as when drilling-out from the shoe into the target sand. Thus, the addition of 2 lb_m/bbl of a 2- μm graded calcium carbonate is included to enhance/reduce fluid loss until the expected and predictable grinding and subsequent reduction of the larger grades occurs due to circulation thru the bit. The optimized bridging solids blend included concentrations of 2-, 30- and 5- lb_m/bbl of calcium carbonate grades with d_{50} of 2, 20 and 40 μm , respectively, or a total loading of approximately 37 lb_m/bbl . However, to assess the effectiveness of these blends, the next sections shows rheology and high-temperature, high-pressure (HTHP) fluid loss test results as confirmation of this recommendation.

Optimization of the NBRDF and NBSF Systems

Next the NBRDF systems were formulated using the 20°F TCT, 13.0- lb_m/gal two-salt brine as well as pure calcium bromide and calcium chloride brines for reference. A final density of 13.3 lb_m/gal was used for these formulations. The NBRDF system achieved the required rheology without the use of xanthan, instead a dual-function starch, DFS, and reactive magnesium compound, MC1, were assessed to ascertain the potential for elevated LSRVs and/or filtrate loss. All formulations were dynamically aged for 16 hours at 180°F (**Table 4**). The calcium bromide single salt (Salt #1) utilized 10.0/1.00 lb_m/bbl of DFS/MC1, respectively and exhibited similar rheology as a calcium chloride single salt, (Salt #2), with 6.0/0.25 lb_m/bbl of DFS/MC1, respectively. The dual-salt based systems – Salt #3 and Salt #4 (as a repeat) – were mixed using 8.0/0.25 lb_m/bbl of DFS/MC1, respectively and these results exhibit similar rheology. To assess the rheology with respect to field maintenance, approximately 1.0/0.25

lb_m/bbl of DFS/MC1 were added to the previous Salt #3 and Salt #4 formulations and are shown as Salt #5 and Salt #6 in Table 4.

These NBRDF systems show that the 6/3-rpm dial readings as well as the yield point (YP) increased using these relatively low additions of the DFS/MC1. Note that the 600-rpm dial reading increases from approximately 100 to 143 or approximately 45%. At a density of 13.3 lb_m/gal and with 35 to 40 lb_m/bbl of total solids, the NBRDF system remains pumpable and exhibits no excessive gels. Based on prior experience with the system, these properties are conducive to mitigate the equivalent circulating density (ECD).

In addition, a liner running system, non-biopolymer screen running fluid (NBSF) was formulated and assessed for pumping head-to-head with the now “used” NBRDF once the target depth was achieved. Typically a NBSF system is formulated to meet the following targets:

- Viscosity, 6- and 3-rpm dial readings 25% greater than the NBRDF
- Final density 0.3 to 0.5 lb_m/gal greater than the NBRDF depending on the ECD

These parameters/targets promote effective displacement of the used NBRDF above the casing shoe and help decrease the interface as well as mitigation of the NBSF “fingering” over the residual NBRDF in the openhole while pumping.

As the final required density of this system was not confirmed at the time of lab testing, a 13.6-lb_m/gal NBSF system was formulated to assess rheology. To elevate the viscosity, specifically the 6- and 3-rpm readings, in lieu of biopolymer a low-end modifier, MC3 was incorporated. This solid compound has a d₅₀ of 10 μm. As this system must not induce plugging of the sand-control screen while running in hole (RIH) and during its displacement, testing was also performed using a coupon cut from the primary weave of the premium screen. **Table 5** shows that the addition of the MC3 with decreasing DFS/MC1 maintained the 6/3 readings and more importantly did not result in plugging when a production screen test (PST) was performed (Sorgard 2001). One liter of lab-prepared NBSF system flowed through a cut-out of the primary weave using 20 psi and did not impede or plug this coupon. This test would subsequently be performed after blending the required volume at the plant and again at the wellsite immediately before displacing the well.

As the testing and qualifying of all systems progressed, the final desired NBRDF density was established as 13.0 lb_m/gal. To better assess this system's rheology at this density under field conditions a FANN 70 viscometer test was performed. As is known in deepwater environments, water temperatures easily attain 40°F and below. This low-temperature environment effectively cools the drilling system, subsequently increase viscosity, which in turn impacts ECD and surge pressures. The primary challenge in most deepwater drilling operations consists of effectively balancing the rheology of the system for hole cleaning, ECD and solids suspension simultaneously (van Oort, E. et al, 2004). However the data from this type of test not only allows one to

predict ECD, sag, and surge pressures but assess the potential for gelation and the capacity to break circulation.

Table 6 shows data generated from a FANN 70 using the 13.0 lb_m/gal formulation at temperatures and pressures ranging from 41°F to 275°F and from ambient to 1500 psi, respectively. Typically, one can assess a drilling system with respect to the aforementioned concerns using a FANN 35 and acquiring rheology at three temperatures (*e.g.*, 40°F, 80°F and 150°F). However, the entire dataset is shown in **Table 6** to illustrate and differentiate potential advantages of the NBRDF as used in this deepwater environment. This data shows that the 6 rpm and 3 rpm values remain reasonably constant over this range of pressure/temperature. The same comparison/conclusion is reasoned for the YP values. As no biopolymers are used in the NBRDF system, this suggests that the absence of these long-chain type molecules mitigates excessive viscosity especially at the lower temperatures/higher pressures. The lack of excessive gelation also supports this premise, as this system exhibits stable viscosity with time. While the PV, YP, 6/3 rpm and gels increase at the lowest temperature/highest pressure and decrease at the highest temperatures as expected, a comparison with other drilling systems illustrates a relatively narrow YP window for this NBRDF system. **Figure 6** shows a comparison for several drilling systems. The temperatures and pressures range from 40 to 320°F and atmosphere to 9000 psi, respectively. The drilling systems include the 13.0 lb_m/gal NBRDF, a 13.1 lb_m/gal SBM, a 12.9 lb_m/gal K-formate, a 14.8 lb_m/gal WBM with barite, and two xanthan-starch-carbonate systems; a 9.0 lb_m/gal and a 9.8 lb_m/gal. This data shows a relatively wider range of YP values for these systems.

Assessment of Fluid Loss Using HTHP

To confirm the fluid loss of the NBRDF system, tests were performed using HTHP and aloxite disks that best simulated or matched the target sand. Based on the previous optical analyses, a FAO-05 manufacturer grade aloxite disk was identified as best simulating the target sand. All HTHP fluid-loss tests were performed using 500 psia differential pressure at 180°F. It should be noted that these disks have measured porosity of approximately 50%, thus should be considered “worst-case” test results.

The fluid loss was measured before and after treatments with the finer calcium carbonate grades with d₅₀ of 2 and 10 μm. Thus an additional 5-lb_m/bbl calcium carbonate was added as 2-lb_m/bbl of a 2-μm and 3-lb_m/bbl of a 10-μm grade material. These adjustments were added to the same formulation and dynamically aged for another 16 hours at 180°F and is referred to as “after treatment” (AT) to distinguish it from the “before treatment” (BT) results. These results are shown in **Table 7** and illustrate that the incorporation of the two finer grades reduced the fluid loss, the spurt as well as the 30- and 36-minute values.

Assessment of a Breaker System

The laboratory assessment included the potential use of two post-breaker systems. This matrix assessed the potential to degrade a residual NBRDF filtercake while providing a delay. The delay period simulated pulling out of the hole

(POOH) with the washpipe. For this well, a target of 12 hours was established.

It was surmised that a chelate-based system would promote a delay as this mechanism is relatively slower than traditional acid. Furthermore, the incorporation of a chelate would promote a more uniform degradation as chelates at specific pH will preferentially complex calcium/magnesium, (e.g., residual calcium carbonate and MC1) versus other cations. A second optional chemistry that was included in the test matrix was an acid-coated gravel. This “solid” metastasizes with time to produce an organic acid which reacts with the residual filtercake, thus eliminating the need for a post spot.

To fully assess these breaker systems and determine relative breakthrough time/delay for this well, a relative return to flow test method was used to simulate initial production. A total of three HTHP cells were assembled. A 13.3-lb_m/gal NBRDF system was dynamically aged for 16 hours at 180°F and used to deposit/create filtercakes for 0.5 hours using the aforementioned FAO-05 aloxite disk. The fluid loss data for these cells was consistent with spurts ranging from 2.0 to 2.8 mL and total fluid loss ranging from 4.2 to 4.6 mL.

One HTHP cell was used as a control whereby no breaker system was applied. The proposed breaker systems are summarized below.

- Breaker #1: Control. Only brine was poured into the HTHP cell with the filtercake and 20/40 gravel. Fluid loss was measured during the seven-day static aging period.
- Breaker #2: Simulated a post-spot. Breaker included 30 vol% chelate plus 2.5% v/v buffer with the filtercake and the 20/40 gravel.
- Breaker #3: 20/40 gravel coated with an organic acid. The gravel was pre-soaked or wetted with 13.0-lb_m/gal CaCl₂/CaBr₂ brine.

For each breaker system, a two-phase test was performed. The first phase assessed the relative delay and used a 13.3-lb_m/gal breaker system and 500 psia differential to air applied to a HTHP cell heated to 180°F. The breakthrough time was measured beginning with the addition of the breaker and ending when a steady stream of effluent was evident through the stem located on the bottom of the cell. As a note, breakthrough occurs when the filtercake partially or completely degrades, in the cell, allowing the partially to completely spent breaker effluent to flow uncontrolled through the stem.

The results of the first phase are shown in **Table 8**. Breaker #2 exhibited approximately 45 hours of delay while Breaker #3 exhibited eight hours compared to the control where no breakthrough was recorded. As a target of 12 hours was desired, Breaker #2 achieved the target by a factor of nearly four. Breaker #3 realized eight hours of breakthrough however as a safety factor was included this was considered acceptable; the relatively slow reaction for Breaker #2 is consistent with the application of chelates.

For the second phase, a control or reference flow rate was

established using an HTHP cell with a saturated FAO-05 aloxite disk, low-toxicity mineral oil with a viscosity of approximately 2 cP (LTMO) and the 20/40 gravel (60 grams) saturated with 13.0-lb_m/gal CaCl₂/CaBr₂ brine. Note that the acid-coated gravel system was used to establish a reference, however, there was no difference in test results with and without the coating. The flow rate was measured from the reservoir side to the wellbore side of the disk (*i.e.*, gravel) using LTMO at arbitrary pressures of 1, 2, 3, 4 and 5 psi thus simulating production.

As previously discussed the delay for each breaker system has been captured, approximately 80 mL of breaker are in each HTHP cell and the breakthrough event (if it occurred) has been noted. After a breakthrough event, the bottom and top valves of the HTHP were closed and the differential pressure decreased to 50 psi and the breaker system cells were statically aged for six days. The six days were arbitrarily selected and represent the period from end of completion until the well test. After each test, the now spent breaker was recovered from the HTHP cell and the pH measured. Following the static age period, LTMO was used to refill the cell before simulating flow as production. This step was performed using the same arbitrary pressures.

The percent return to initial flow is calculated as a ratio of the flow rate of the aforementioned control (LTMO and no breaker) and the flow rates for Breaker #2 and Breaker #3 at all pressures. Subsequently, these percentages can be compared to Breaker #1 (brine only) to determine the relative effectiveness of the breaker system. **Table 9** summarizes the percent return to flow and the initial and final pH readings.

The results show that pH increases (more alkaline) as expected as these breakers acidic components react with a residual filtercake’s alkaline components. The control for this test matrix, where the filtercake was not removed, exhibited approximately 21% return of initial flow at 5 psi. This relatively low value is consistent with the combination of Newtonian fluids (*i.e.*, brine) and relatively thin, resilient, and compacted residual filter cakes whereby fluid loss is relatively low. Note that the breakthrough event did not occur until differential pressure was increased to approximately 3 psi. The combination of relatively low percent return flow and elevated liftoff pressure suggests that the application of a breaker would enhance the removal of the residual filtercake. Breaker #2 and Breaker #3 exhibited 83.5% and 91.8% return flow, respectfully. As discussed previously, Breaker #3 required no other fluids. Both of these values are indicative of dissolution and degradation of the residual filtercake, either preferentially (a channel) or more uniform removal.

The aloxite disk/gravel were removed from the cells and a razor was used to dissect the residual filtercake. This was performed to visually assess the texture as well as the absence or presence of residual material in the gravel. It was surmised that these visual cross-sections would provide a more complete understanding of the aforementioned results. In addition, an iodine test was performed to determine the presence of residual starch. Iodine in the presence of starch turns from yellow-red to black.

Figures 7-8 show the residual filtercakes after removal from the HTHP cells. Note that these filtercakes represent approximately 0.5-hour filtercake formation, 8 to 45 hours of static aging with breaker at 500 psi differential pressure, 8 to 45 hours of dynamic/static aging with 50 psi differential pressure, and flowback as simulated production with LTMO.

Figure 7 shows Breaker #1 which is the control using only brine. Note that the filtercake is almost completely intact across the disk. This visual and the filtercakes texture agrees with the measured 21% return to flow. A very small area shows separation of the filtercake from the disk and is indicative of channeling. As expected, an iodine test is positive for the presence of starch (black color change).

Figure 8 shows the results of Breaker #2. The residual filtercake is the light tan/yellow layer. With respect to the half of the disk where the gravel was removed, a small portion of the filtercake is present whereby a larger area of the aloxite disk is clean. A portion of the filtercake can be seen in the gravel indicating that the flow of the LTMO was lifting the residual filtercake off the disk.

Figure 9 shows the results of Breaker #3. This shows nearly all the residual filtercake has been dissolved or mechanically removed from the surface of the aloxite disk. This result agrees with the approximate 91.8% return to flow.

As a note, previous field applications where a delayed type breaker system was applied as post completion, typically realized 5 to 7 times more delay than the laboratory reported results. This difference may be due in part to the dynamics, dimensional complexity and/or scale-up realized in the field.

Based on these results, Breaker #2 was selected based on logistics (*i.e.*, readily available) and previous utilization.

Execution of the Drilling and Completion Phases

Drilling

The NBRDF system was mixed at the plant and required six batches. To reduce the shear time required, the base brine was heated and batch temperatures ranged from 115 to 135°F. The final desired density, 13.0 lb_m/gal, included 35 lb_m/bbl of three grades of sized calcium carbonate as well as the DFS and MC1. The DFS was added at the rate of 4-5 min/sack to mitigate fish eyes. **Table 10** shows consistent rheology for all batches. The NBRDF was received at the rig and a total of 2900 bbl was pumped into clean pits. The wellbore and surface volumes measured 1000 bbl inside the casing and riser with approximately 800 bbl for the surface pits. The wellbore was displaced at 8.5 bbl/min from a 14.1-lb_m/gal synthetic-based drilling fluid (SBM) to the 12.95-lb_m/gal NBRDF using a spacer. The operator decided to weight-up from the average NBRDF density of 12.95 to 13.00 lb_m/gal. Approximately 80 sacks of dry CaBr₂ was used to increase the surface/pit density. However, to increase the density in the riser, circulation through the booster line was used to add calcium carbonate. The final density was approximated 13.0 lb_m/gal at 63°F temperature after 1.5 hours of circulation.

Subsequently the 8½-in. BHA and drillstring was RIH to TOC and after one circulation, drilling of the cement started.

During this period approximately 6 lb_m/bbl of calcium carbonate was added to the active system to increase the volume in the casing by 0.05 lb_m/gal. The TOC was tagged at approximately 16,375 ft and after drilling approximately 18 ft of cement, an increase of 30 bbl was realized in the active pits, the pump pressure decreased and the triplex pumps began cavitating. At this time microbubbles were observed in the returns, which are often interpreted as foaming issues. However as the calcium carbonate additions simultaneously finished, a possible source of this trapped air was thought to be from the addition of the calcium carbonate at the hopper. An investigation revealed that the return from the mixing line/pump was in communication with both active pits and one of the pits was the suction. Air was being suctioned directly from this mixing line into the charger and triplex pumps. As a consequence, this line/air aerated the NBRDF and was compressed by the triplex pump(s) and pumped into the well bore. As circulation continued down and up the annulus the trapped air was eventually exposed to less hydrostatic pressure promoting a relatively extreme increase of microbubbles. The root cause and exasperation of the air/bubbles were a combination of:

- Temperature of the circulating system in the flowline, approximately 65°F, increased the viscosity and retained more air/bubbles (*e.g.*, mitigating breakout)
- Hopper configuration was the source of the air into the system
- Bit nozzles added shearing, thus reducing the size of the bubbles
- Contamination of the system with surfactants from pit cleaning

The recommendations to resolve the problem included:

- Isolating the mixing line from hopper to the line from the suction pit
- Stopping the agitator on the return pit to allow the air to breakout faster
- Turning on the gas-removal equipment to help breakout the trapped air
- Treating the active system with 0.05 gal/bbl of defoamer as a contingency due to residual cleaning chemicals,

It should be noted that the shakers did remove some of the air from the returns.

Drilling of the cement continued and subsequently ten new feet of formation were drilled. Drilling stopped and a FIT was performed to 1,720 psi. Drilling of the target sandstone continued to a total depth of approximately 17135 ft MD/14995 ft true vertical depth (TVD). The wellbore was circulated one bottoms-up and then backreamed to the shoe. The drillstring/BHA was then tripped-back to total depth and no tight spots were apparent.

Additions of DFS and MC1 were used to maintain properties and to eliminate of pumping tandem pills for removal of any cuttings beds; however as backreaming was not indicative of excessive beds, no tandem pills were necessary. The average maintenance included 15 sacks of the DFS and 2 sacks of the MC1 every 3 to 4 hours. This addition

was based on target increments of 0.25 and 0.1 lb_m/bbl of DFS and MC1, respectively. This maintenance was performed every two bottoms up which is equivalent to three hours of circulation.

Several parameters of the NBRDF were assessed during the drilling of the lateral from approximately 16,758 to 17,135 ft MD. These included the rheology, ECD, total and acid insoluble and a MBT performed at the end of the lateral to assess the incorporation of reactive clay solids. A summary of the rheological properties is shown in **Table 11**. This data shows consistent PV/YP with the PV approximating 30 – an indication of relatively low accumulation of formation solids. The low-end rheology was assessed using the 6/3-rpm readings and also remained consistent, approximately 7/5. No gelation was apparent. The ECD was predicted using a proprietary software program (Thorsrud et al. 2000) and also measured using a Pressure While Drilling (PWD) technique. Several data points are compared in **Table 12**. Note that the standpipe pressure (SPP) was included and ranged from 3500 to 4000 psi over this interval. The predicted ECD was slightly less than measured by PWD thus the delta averaged 0.045 lb_m/gal.

The acid insoluble solids were assessed post analysis using a gravimetric and centrifuge technique and showed the maximum value at TD was approximately 0.98 vol%. The total solids ranged from 39 to 49 lb_m/bbl which is consistent with the bridging solids loading and the treatments of MC1 and incorporation of formation solids. No dilution was necessary while drilling due to the total volume of casing, riser and surface. As such, only the shale shakers were utilized for solids-control removal.

An MBT test showed approximately 0.2 lb_m/bbl of reactive clay solids and is consistent with the previous XRD data.

Fluid loss was assessed during the drilling of the lateral and utilized the same technique as the pre-assessment testing (e.g., FAO5 aloxite disk). **Table 13** shows that the total fluid loss ranged from 6.5 to 6.8 mL.

During drilling of the horizontal interval, three LCM shakers were fitted with 2x110/1x140 screens. No issues regarding screen blinding were observed, even initially when cold, unshered and viscous RDF systems typically blind-off.

Samples collected during drilling were also assessed for PSD. The plot shown in **Figure 10** shows that the initial sample collected at 16425 ft MD was optimized with the recommended PSD blend, which ranged from 30 to 60 μm. Samples collected from 16425 to 16493 ft MD represent one full circulation and the PSD from the range of 30 to 60 μm decreased due to mechanical degradation and scalping. Therefore, a graded calcium carbonate with a d₅₀ of 20 μm was added. As drilling continued, moderate degradation of the optimum range continued even with additions of calcium carbonate. At TD, the optimum PSD shifted to finer as expected and larger particles were apparent, however, these are most likely formation solids carried out of the well.

Completion

NBSF Displacement and PST Results

At TD, the NBRDF was circulated bottoms up and then the horizontal section was backreamed to the shoe. The drillstring was tripped back to TD to check for tight spots and none were apparent. The wellbore was circulated bottoms up again and approximately 115 bbl of NBSF were used to displace the NBRDF from 17135 ft MD to above the casing shoe. Prior to this displacement, a one-liter sample was used to perform a PST with a coupon representative of the sand-control screen. This test resulted in a PASS. Next, the drillstring was tripped to approximately 16105 ft MD and the 13.0-lb_m/gal NBRDF was displaced with a total of 1931 bbl of 13.0-lb_m/gal calcium bromide brine. Approximately 54 bbl of interface were noted.

Subsequently, the drillstring was laid down and the gravel pack assembly picked up and RIH. No tight spots were apparent and the sand-control assembly landed at TD. The NBSF was then displaced to above the packer by forward circulation using one-hole volume of 13.0-lb_m/gal calcium bromide brine. The ball was dropped, the packer was set, and the residual NBSF was then displaced to surface. Prior to the gravel pack, a pickle job was performed on the work string.

The gravel pack was performed as an alpha-beta wawe technique at a maximum rate of 7 bbl/min using 13.1-lb_m/gal calcium bromide and 30-50 ceramic proppant. This rate was selected as the optimum to achieve the aforementioned 100% pack of the annulus. Approximately 30,000 lb of gravel were placed while taking full returns. Post gravel pack analysis indicated 100% gravel packed. Approximately 45 bbl of Breaker #2 was prepared and pumped at 5 bbl/min through the work string and then slowed to 2 bbl/min when the system turned the corner into the openhole annulus. While POOH, losses were recorded at 4 bbl/hr and subsequently the FIV was closed.

Lessons Learned

Several lessons for the drilling and completion phases of the OHGP were documented. These are listed in no order below.

- One key for blending the NBRDF to the achieve the desired rheological properties is the use of extended shear with time and temperature. This effectively yields the DFS. For this OHGP approximately 1.5 to 2 hours mixing at 115 to 135°F was sufficient as 50% of YP was realized after this period.
- The root cause of pump pressure loss during drilling was trapped air attributed to a hopper/mixing line connected to both active and suction pits. The cause was initially considered foaming due to residual chemicals used to clean the pits however its persistence after treatment mandated an investigation.
- DFS and MC1 additions for the 710-ft lateral approximated 15 sacks of DFS per 3 to 4 hours and 2 sacks of MC1 per 3 to 4 hours. This maintenance elevated the low-end rheology due to lower temperatures, approximately 63°F, when circulating through the riser.
- The 2x110/1x140 mesh shaker screens used while drilling did not impact the density of the NBRDF.

- The combination of mechanical shear and screening/scalping after one full circulation resulted in a decrease of the optimum particle size (30 to 50 μm). As a result, a calcium carbonate grade ($d_{50} = 20 \mu\text{m}$) was added to the system while drilling.
- MBT approximated less than 0.2 lb_m/bbl for a sample collected at total depth. This result is consistent with CEC results, approximately 4 $\text{mg}/100\text{g}$.
- The AIS deposited in the residual filtercake by the NBRDF was approximated using post analysis. The maximum AIS, 0.98 wt%, was less than the target of 2 wt%. As the openhole volume (*i.e.*, gauge) to casing/riser/surface volume approximated 2.5 vol% even if no solids control were used, no dilution was necessary.
- Representative NBRDF samples recovered while drilling were used to perform HTHP fluid loss tests and the results varied insignificantly compared to the laboratory testing.
- Hydraulics/ECD were assessed prior to drilling and also measured while drilling using PWD. The maximum difference between these two methods over the entire lateral approximated 0.09 lb_m/gal .
- The average ECD approximated 0.7 lb_m/gal for the 13.0- lb_m/gal NBRDF.
- A 13.1- lb_m/gal NBRDF slug was effective for POOH.
- The 13.1- lb_m/gal NBSF system, approximately 115 bbls, exhibited a PASS when a PST was performed. This test was used to assess premature plugging of the sand control screen before RIH.
- No losses or tight spots were apparent when running the sand control screen through the open hole.
- A head-to-head pumping technique was used whereby a 13.1- lb_m/gal NBSF system displaced the 13.0- lb_m/gal NBRDF out of the openhole and into the casing.

Production Results

Two build-up tests were performed at the end of July 2013. The first test realized a maximum of 6269 $\text{bbl}_{\text{oi}}/\text{day}$ (BOPD) with a flowing tubing pressure of 4777 psia. The total pressure drop due to skin approximated 454 psia and yielded a skin factor of 15.5 as the total drawdown approximated 643 psia at gauge depth. However, it was suspected that the formation isolation valve (FIV) was not fully open during this 16-hour producing period. The valve was functioned again and the well was shut-in for only four hours as opposed to the previous 29 hours. After the second shut-in period, the well flowed 5943 BOPD at a flowing tubing pressure of 5066 psia. The total pressure drop due to skin approximated 35 psia and yielded a skin factor of 1.13 as the total drawdown approximated 217 psia at gauge depth. The Productivity Index (PI) increased from 9.7 to 28.1 $\text{bbl}_{\text{fluid}}/\text{day}/\text{psi}$ (Bfpd/psi). The daily production, averaged approximately 5500 BOPD, has remained constant and data through November 2015 is shown in **Figure 11**.

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Table 1 – Solubility of CMO at 150°F

Type Solution/Acid	Percent by Weight Soluble After 24 hours
10 wt% Acetic acid	90.0
10 wt% HCl	95.0
30 wt% Chelate	87.0

Table 2 – Comparison of Rheological Properties of 15.2-lb_m/gal NBRDF with and without CMO

Property ¹	NBRDF with CMO ²				NBRDF with no CMO	
	Initial	Dynamic Aged 260°F 16 hr	Static Aged 260°F 24 hr	Static Aged 260°F 48 hr	Initial	Dynamic Aged 260°F 16 hr
Final Density, lb _m /gal	15.2	15.2	15.2	15.2	15.5	15.5
6/3-rpm Dial Reading, lb _m /100 ft ²	9/10	15/13	15/13	13/11	14/10	23/19
LSRV @ 0.0636 sec ⁻¹ , cP	24,700	28,000	50,389	36,790	58,900	122,000
Gel Strength (10-sec/10-min), lb _f /100 ft ²	9/10	14/15	14/15	12/13	11/13	22/23
Plastic Viscosity, cP	24	20	55	62	98	111
Yield Point, lb _f /100 ft ²	21	23	40	35	65	68
pH, direct	8.0	8.04	8.03	8.13	7.64	8.1
Fluid Loss (Spurt), mL		0.5				
Fluid Loss (30-min), mL		4.5				

1. Rheology recorded at 120°F
2. Approximately 45% w/w CMO as a bridging component

Table 3 – X-Ray Diffraction and CEC*

	18,494 ft MD	18,518 ft MD	18,540 ft MD
Quartz	84	80	85
Feldspars	11	12	11
Illite	nd	3	nd
Smectitic	5	5	4
CEC (meq/100 g)	4	4	3

* Samples received from an offset well in the Who Dat field.

Table 4 – Rheology of 13.1-lb _m /gal NBRDF Laboratory Formulations*						
Formulations	#1	#2	#3	#4	#5	#6
Base Brine	CaBr ₂	CaCl ₂	Two-salt CaCl ₂ /CaBr ₂			
DFS/MC1 (lb _m /bbl)	10/1	6/0.25	8/0.25	8/0.25	9/0.50	9/0.50
600-rpm Dial Reading	92	86	98	97	142	144
300-rpm Dial Reading	63	54	61	60	97	97
200-rpm Dial Reading	50	42	47	46	78	78
100-rpm Dial Reading	35	29	31	30	55	54
6-rpm Dial Reading	10	10	9	8	15	14
3-rpm Dial Reading	8	9	7	6	12	11
10-sec Gel Strength (lb _f /100 ft ²)	8	8	6	5	11	11
10-min Gel Strength (lb _f /100 ft ²)	9	9	7	6	13	12
Plastic Viscosity (cP)	29	32	37	37	45	47
Yield Point (lb _f /100 ft ²)	34	22	24	23	52	50

* Rheology recorded at 120°F after dynamic aging for 16 hours at 180°F

Table 5 – 13.5-lb _m /gal NBSF Laboratory Formulations				
Formulations	#1	#2	#3	#4
Base Brine	Two-salt CaCl ₂ /CaBr ₂			
DFS/MC1/MC3 Conc. (lb _m /bbl)	10/1.5/-	9/1.5/-	9/1.0/-	9/1/0.5
600-rpm Dial Reading	10	8	7	9
300-rpm Dial Reading	9	7	6	8
10-sec Gel Strength (lb _f /100 ft ²)	9	7	6	7
10-min Gel Strength (lb _f /100 ft ²)	10	8	7	8
Plastic Viscosity (cP)	48	41	39	45
Yield Point (lb _f /100 ft ²)	43	34	31	40
PST	Fail	Fail	Fail	Pass

Table 6 – 13.0-lb _m /gal NBRDF HTHP Viscosity						
Temperature (°F)	Pressure (psi)	600/300-rpm Dial Reading	200/100-rpm Dial Reading	6/3-rpm Dial Reading	10-sec/10-min Gel Strength (lb _f /100 ft ²)	PV(cP)/YP(lb _f /100 ft ²)
40	0	155/93	66/37	8/5	5/5	62/31
40	500	182/107	80/49	10/7	7/7	75/32
40	1000	214/123	98/66	13/10	11/9	91/32
90	0	101/61	45/28	7/5	5/5	40/21
90	500	109/65	49/32	8/6	6/6	44/21
90	1000	117/69	53/36	8/7	7/7	48/21
120	0	82/50	37/24	6/5	4/5	32/18
120	500	87/52	40/26	7/5	5/6	35/17
120	1000	92/55	43/29	7/6	6/6	37/18
150	0	68/42	32/21	5/4	4/5	26/16
150	500	71/44	34/22	6/5	5/5	27/17
150	1000	75/45	35/24	6/5	5/6	30/15
200	0	52/33	25/17	5/4	4/4	19/14
200	500	54/34	26/18	5/4	4/4	20/14
200	1000	55/35	28/19	5/4	4/5	20/15
200	1200	56/35	28/19	5/4	4/5	21/14
200	1500	57/36	29/20	5/4	5/5	21/15
250	1000	43/28	22/15	4/3	3/3	15/13
250	1200	43/28	23/15	4/3	3/4	15/13
250	1500	44/29	23/15	4/4	4/4	15/14
275	1000	38/26	20/13	4/3	3/3	12/14
275	1200	39/26	21/13	4/3	3/3	13/13
275	1500	39/26	21/14	4/3	3/3	13/13

CaCO ₃ Load (lb _m /bbl)	Formulation #3		Formulation #6	
	35 (BT)	40 (AT)	35 (BT)	40 (AT)
Time (min)				
Spurt (0)	2.5	1.8	1.6	1.2
1	2.8	2.0	2.0	1.3
2	3.0	2.2	2.2	1.4
4	3.3	2.5	2.4	1.8
9	3.8	2.9	3.0	2.2
16	4.2	3.3	3.5	2.6
25	4.6	3.6	3.8	3.0
30	4.8	3.8	4.2	3.2
36	4.9	4.0	4.4	3.4

BT = Before treatment
 AT = After treatment with an additional 5-lb_m/bbl calcium carbonate was added as 2-lb_m/bbl of a 2- μ m and 3-lb_m/bbl of a 10- μ m grade

Time (hr)	Breaker #1	Breaker #2	Breaker #3
1	0.2	0.2	0.2
2	0.6	0.4	0.4
3	0.8	0.9	0.9
4	1.2	1.9	1.5
5	1.6	2.1	1.8
6	1.7	2.4	2.1
12	2.1	3.0	8.0 (breakthrough)
24	3.7	5.9	
28	4.1	7.6	
29	4.2	7.8	
30	4.3	7.9	
45	4.6	14.0 (breakthrough)	
48	5.1 (no breakthrough)		

Pressure (psia)	Breaker #1 (Control) (%)	Breaker #2 (%)	Breaker #3 (%)
1	0.00	53.15	54.31
2	0.45	72.25	74.85
3	6.97	78.02	83.69
4	14.94	80.07	89.90
5	21.36	83.51	91.81
Average Pressure	8.74	73.40	78.91
pH (cell)	7.3	3.25	5.25
pH (Filtrate)	6.9	3.74	5.65

¹ Estimate value based on linear equation adjustment from Table 1.

Table 10 – NBRDF Batch Results Measured at Plant¹

Property	Program	Batch 1	Batch 2	Batch 3	Batch 4	Batch 5	Batch 6	All Batches
Density (lb _m /gal)	12.90	12.95	13.00	13.00	13.00	12.90	13.05	12.95
Plastic Viscosity (cP)	25-35	36	32	33	32	32	33	37
Yield Point (lb _f /100 ft ²)	ALAP	12	14	17	15	16	21	26
6/3-rpm dial readings	8-12	8/6	8/6	8/6	8/6	7/5	8/6	8/6
Gel Strengths (10-sec/10-min/30-min) (lb _f /100 ft ²)	non-progressive	6/8/8	6/7/8	6/6/7	6/6/7	6/7/7	6/7/7	6/7/7
pH(direct)	7.0-8.0	8.1	7.8	7.5	7.3	7.2	7.8	

1. All rheology recorded at 120°F.

Table 11 - Rheology Summary of NBRDF While Drilling Lateral Section¹

Measured Depth (ft)	16425	16490	16728	16800	16955	17135
600-rpm Dial Reading	80	71	79	74	81	76
300-rpm Dial Reading	50	43	49	45	52	46
200-rpm Dial Reading	39	33	39	34	40	35
100-rpm Dial Reading	26	21	26	22	27	22
6-rpm Dial Reading	7	7	7	7	9	7
3-rpm Dial Reading	5	5	5	5	7	5
10-sec Gel Strength (lb _f /100 ft ²)	5	6	5	6	7	6
10-min Gel Strength (lb _f /100 ft ²)	6	6	5	6	7	6
Plastic Viscosity (cP)	30	28	30	29	29	30
Yield Point (lb _f /100 ft ²)	20	15	19	16	23	16

1. All rheology recorded at 120°F.

Table 12 - Summary of the ECD for the 13.0-lb_m/gal NBRDF While Drilling Lateral Section

Measured Depth (ft) ¹	16,480	16,720	16,800	16,960	17,135
SPP (psi)	3600	3550	3650	3675	3880
Measured Density (lb _m /gal)	12.9	13.0	13.0	13.0	13.0
Software ECD – predicted (lb _m /gal)	13.60	13.65	13.63	13.74	13.76
PWD ECD – measured (lb _m /gal)	13.59	13.68	13.69	13.71	13.79
Difference (lb _m /gal)	+0.01	-0.03	-0.06	+0.03	-0.03
Approximate ECD Range (lb _m /gal)	0.07	0.07	0.07	0.07	0.07
Approximate Maximum Difference ²	0.725	0.715	0.725	0.745	0.825

1. Depths for ECD data are approximate

2. Maximum Density Increase in lb_m/gal using PWD

Table 13 – Fluid Loss Using a FAO-05 Disk at 150°F and 500 psi

Depth (ft)	16,425	16,490	16,728	16,995	17,135
HTHP Fluid Loss including spurt (mL)	6.8	6.8	NA	6.5	6.6

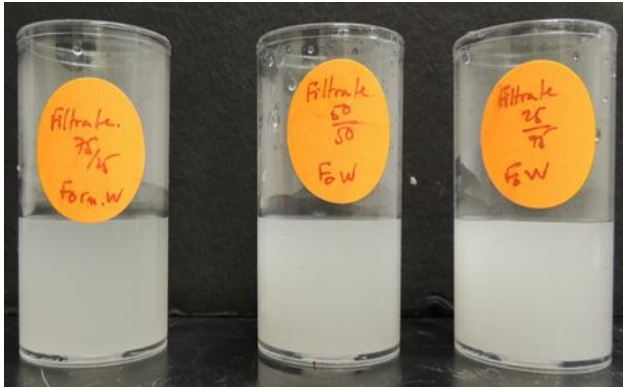


Figure 1A – Digital image showing commingled formation water and filtrate, collected from a LD-NBRDF system, ratio from 50/50, 75/25 and 25/75, left to right. Note that the scale forms almost immediately and is suspended in the comingled brine as no substrate is present.

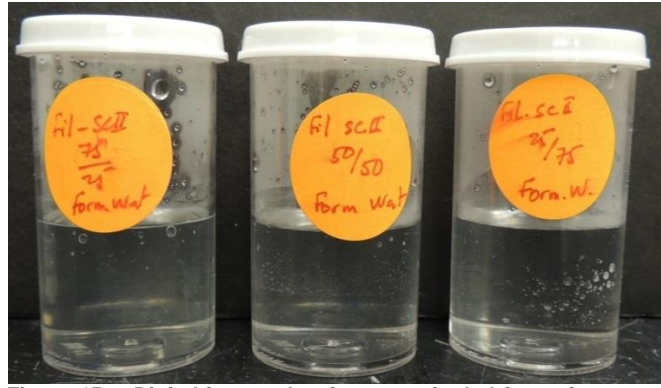


Figure 1B – Digital image showing commingled formation water and filtrate, collected from a LD-NBRDF system, ratios of 50/50, 75/25 and 25/75, left to right. The LD-NBRDF was treated with 0.25 vol% inhibitor.

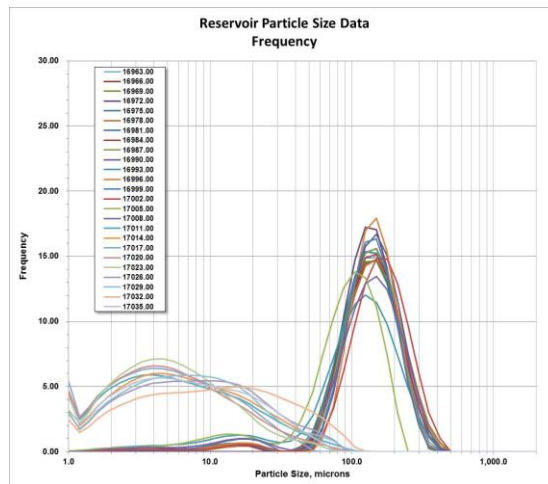


Figure 2 – Laser particle size data showing that the shallower portion of this sand is predominantly fine-grained, approximately 125 to 175 μm , and then with depth, approximately 17,014 ft, grades into silt and clay-sized particles.

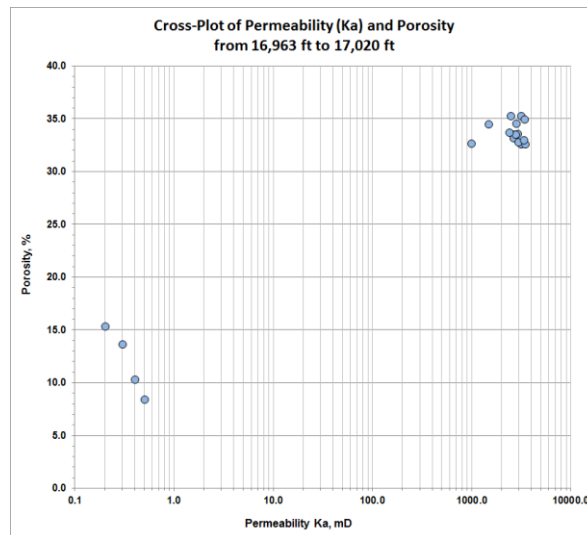
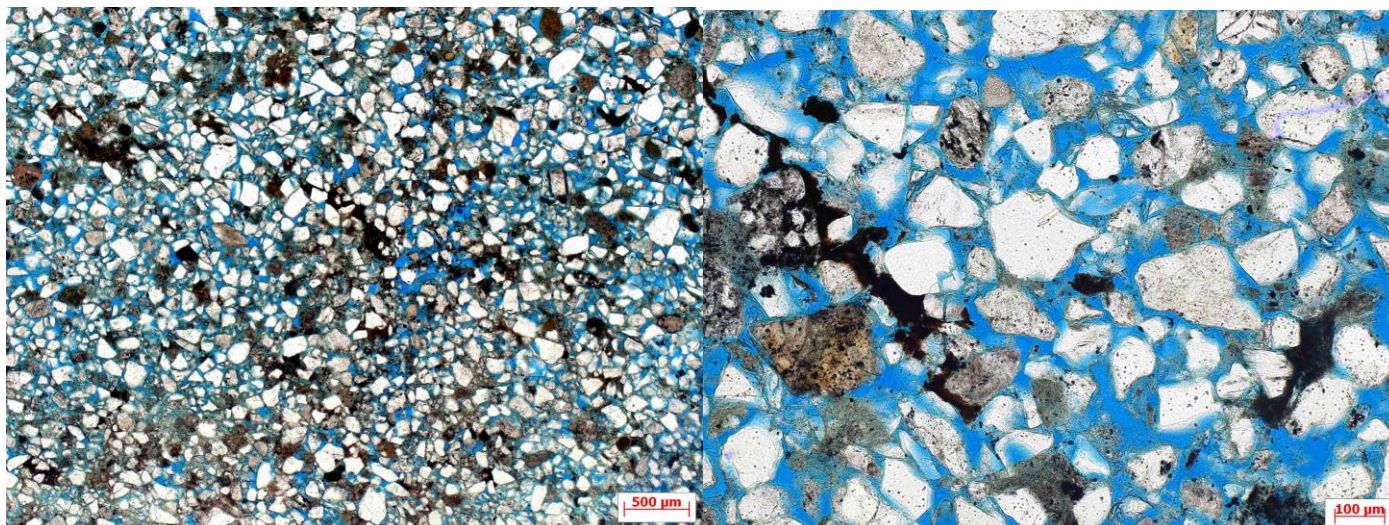
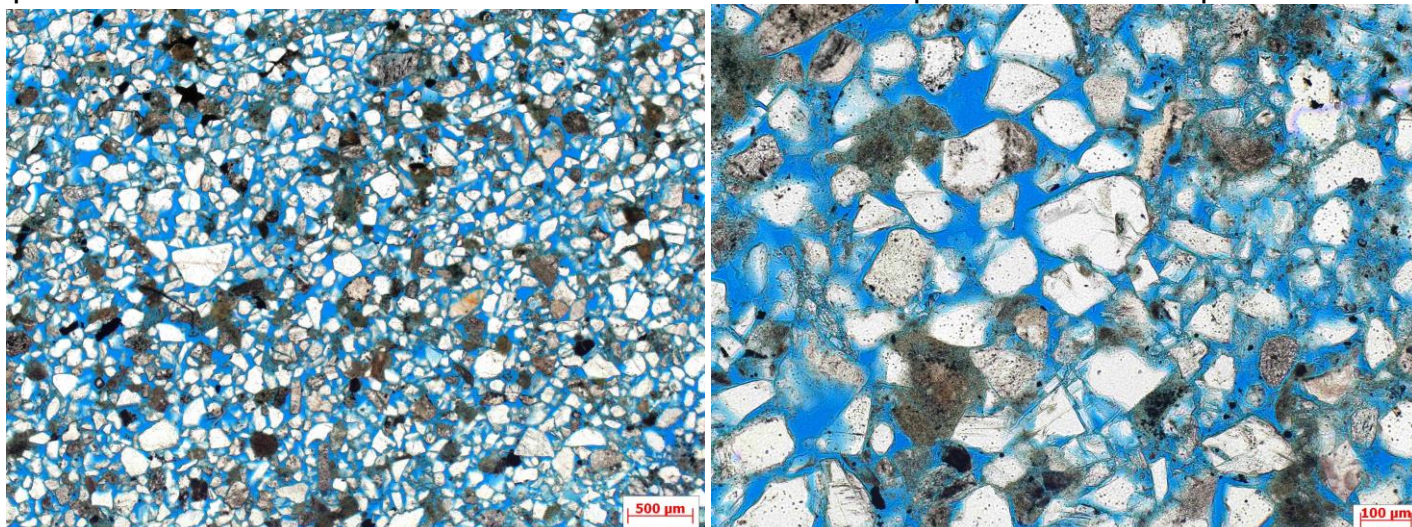


Figure 3 – Cross-plot of permeability (K_{air}) and porosity (%) data which were derived using chips from the conventional core. The permeability and porosity are drastically reduced at approximately 17,010 ft as per the four data points less than 1.0



18,482 ft. – Sample from Offset Well. Left image is textural view and right image higher magnification. White grains are quartz, gray grains are feldspar/rock fragments, brown grains are predominantly clay and black is insoluble organic matter. This sample/depth is predominantly quartz. The lack of cementation is indicative of the unconsolidated nature. The common pore size is estimated as 40 μm.



18,530 ft – Sample from Offset Well. Left image is textural view and right image higher magnification. White grains are quartz, gray grains are feldspar/rock fragments, brown is clay and black is insoluble organic matter. This sample/depth is estimated 85% quartz. Rock fragments are estimated as 5%. The maximum pore size is estimated as 75 μm.

Figure 4 – Optical assessments of fragments recovered from sidewall cores from an offset well in the Who Dat field.

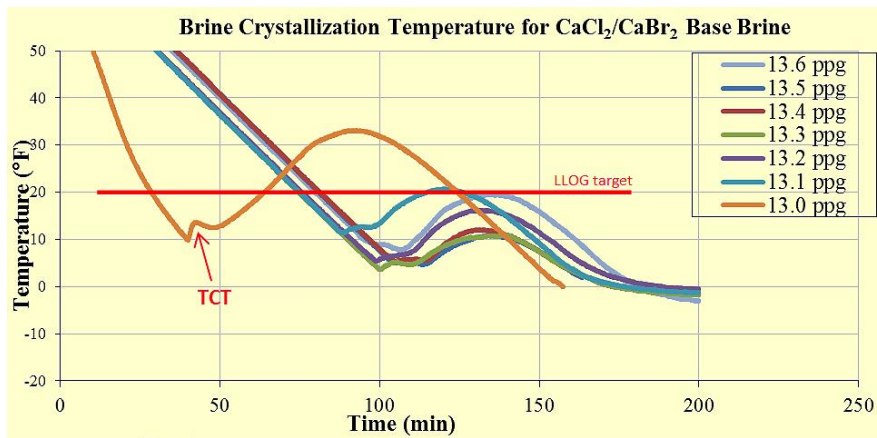


Figure 5 – Selected TCT data for two-salt calcium chloride-calcium bromide brines.

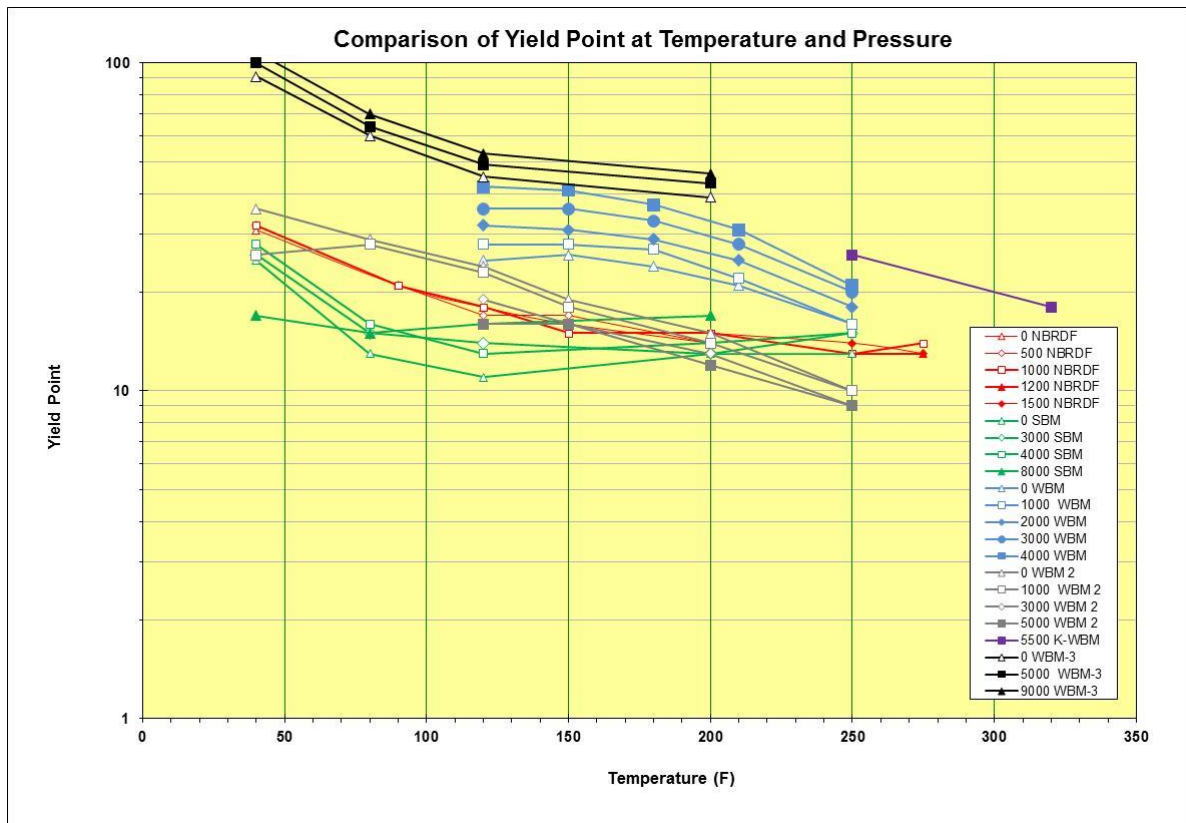


Figure 6 – Comparison of YP values calculated using a FANN 70 viscometer. The temperatures and pressures range from 40 to 320°F and atmosphere to 9000 psi, respectively. The drilling systems include the 13.0 lb_m/gal NBRDF (red lines), a 13.1 lb_m/gal SBM (green lines), a 12.9 lb_m/gal K-formate (purple line), a 14.8 lb_m/gal WBM with barite (black line), and two xanthan-starch-carbonate systems; a 9.0 lb_m/gal (gray lines) and a 9.8 lb_m/gal (blue lines). This data shows a relatively narrow range of YP values for the 13.0 lb_m/gal NBRDF as compared to the other systems.

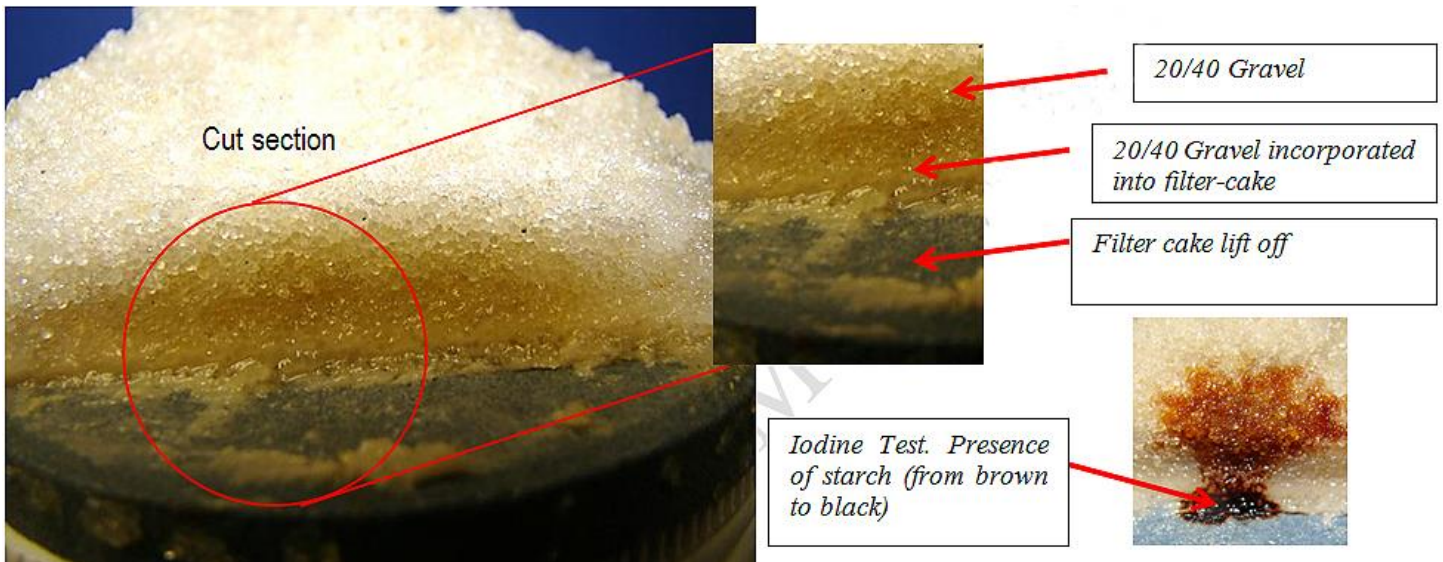


Figure 7 – Texture and high-magnification views of filtercake and gravel from the Breaker #1 (Control) test.



Figure 8 – Texture and high-magnification views of filtercake and gravel from the Breaker #2 test.



Figure 9 – Texture and high-magnification views of filtercake and gravel from Breaker #3 test. Note the absence of residual filtercake.

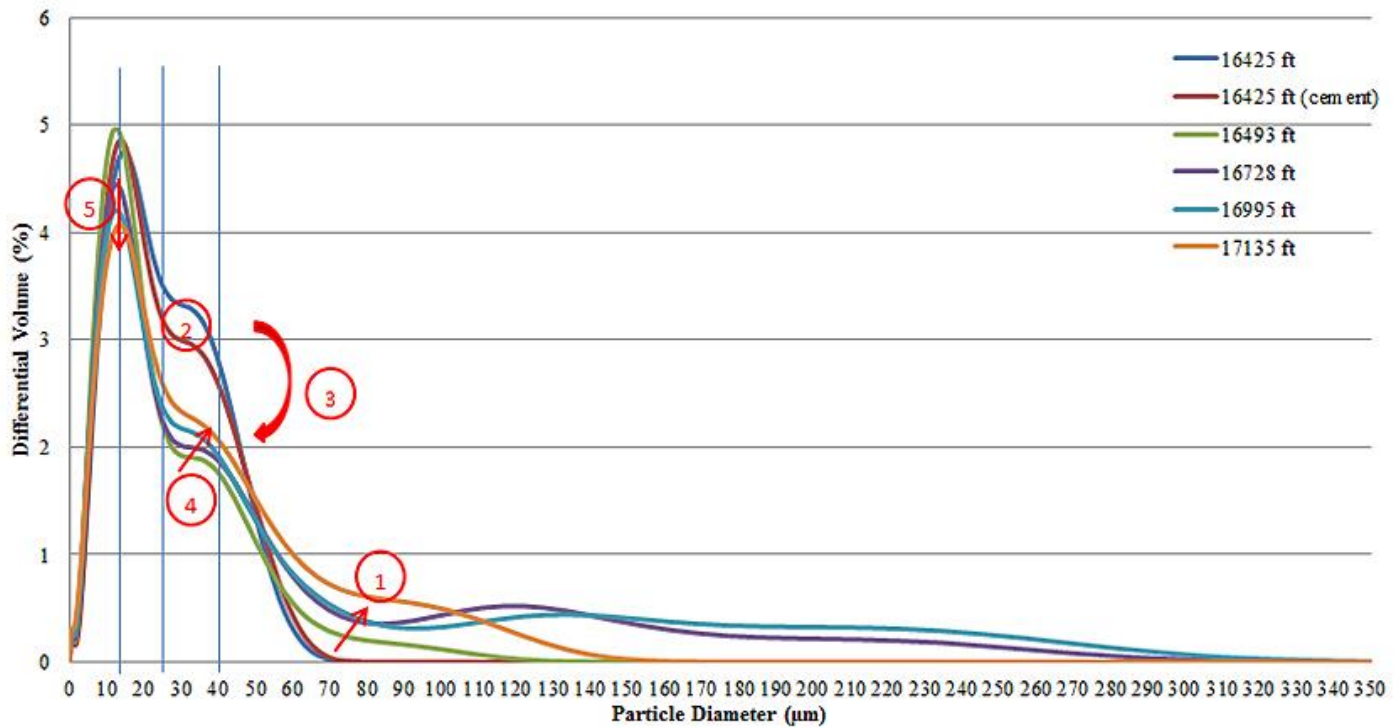


Figure 10 – PSD showing of samples collected during drilling of the horizontal. #1 – sample at the heel of the lateral (when drilling the lateral started). #3 – shift of PSD at 16493 after one circulation. #4 – shows the sample at TD.

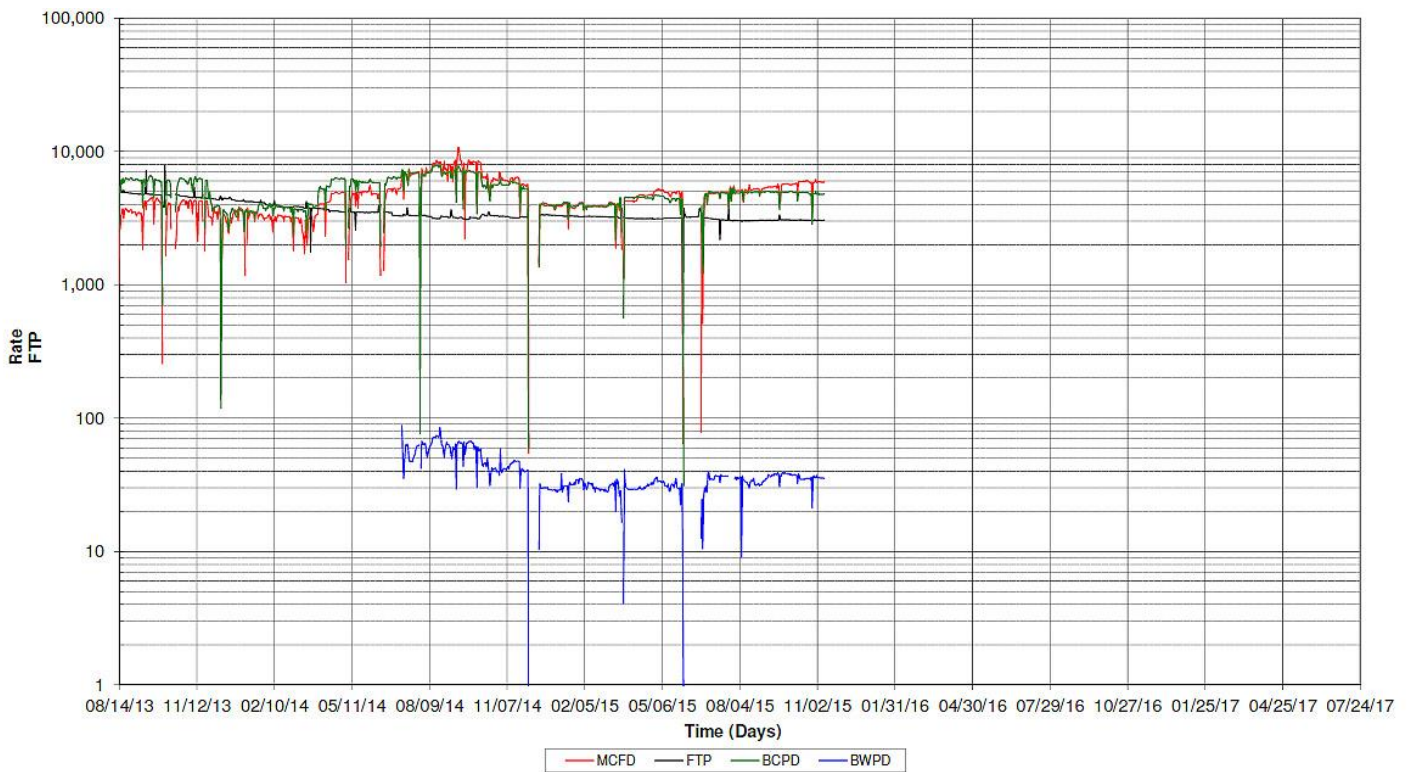


Figure 11 – Cumulative production from August 2013 through November 2015.