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Extending the Limits of Lab Testing to Deliver Wells in Challenging Environments

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Abstract

As current and future well design grow in complexity, so do the requirements of fluids design in an ever-changing environment. Some of these challenges include exploration in new fields, development of existing fields, extended reach, and high- pressure/high-temperature wells. Commercialization of the land, inland, and “shelf” wells have created a demand to explore the deepwater market. These challenges require a new method of design and development of wellbore fluids to meet them. As the complexities of fluid design have increased, so have the testing methods which conventional or “traditional” methods can no longer accurately predict a fluid’s properties under extreme environments. Operators and fluid service providers at times must modify the existing equipment and methodology to meet these new challenges.

Introduction

Laboratory testing of drilling fluids is fundamental to success of efficiency in our industry. Service companies often follow standard test methods to monitor trends in fluid properties. This approach allows results from various sources to provide a comparison against a standard in which validation of a potential solution has been tested by multiple sources. While these industry test methods have their place with conventional wells, they often don’t adequately evaluate the fluids for use in more extreme well environments.

As the complexity of well design continues to develop and reservoirs in more challenging downhole environments are targeted, it has been shown that standardized testing methodologies are no longer universally sufficient to ensure adequate drilling fluids design and evaluation. In this paper we show examples where standard testing methods do not satisfactorily evaluate fluids for extreme environments; subsequently compromising the well objectives and fluid design criteria when insufficient testing parameters and methodologies are applied.

An extended testing protocol can overcome obstacles encountered on a fluids’ first deployment and ensure success on the second application. Testing methods discussed include an increased accuracy mud balance, extended fluid loss testing, automated breakthrough time testing, fluid loss testing in high overbalance conditions (up to 10,000 psid) for extended periods of time (16+ hours) assisted by using specialized equipment and data acquisition (DAQ) software. Additionally, an alternate method of SAG testing at higher pressure is discussed. Real-well examples show how an extended testing plan provides confidence that a fluids system will be successful in the field. When standard lab testing protocols are not sufficient, extending the limits of current lab testing methodologies better meets the requirements to deliver wells in challenging environments.

Increased Accuracy Pressurized Mud Balance

Shell has drilled several Gulf of Mexico wells using CML (Controlled Mud Level (CML) (Fisher, et al 2021) as a managed pressure drilling technique. The pressure downhole is a function of the fluid density and the hydrostatic pressure (mud level) from the riser. Changes in downhole ECD could be caused by changes in the level of the mud in the riser or fluctuations in the mud density. Accurately measuring and therefore maintaining an accurate mud weight minimizes one of the variables, simplifying operations to maintain a desired and constant bottom hole pressure.

After struggling with minor density fluctuations which caused extended time adjusting the CML on two Gulf of Mexico wells, a new pressurized mud balance was developed which could more accurately determine the density of the fluid, Figure 1. The typical accuracy of a mud balance is 0.1 lb/gal. However, the graduations on this modified mud balance go down to 0.01 lb/gal, Figure 2. Furthermore, the scale is pressurized, therefore the effects of gas entrainment are also minimized. For Wells #3 and 4, the increased accuracy pressurized mud balance was used at the mud plant and at the rig to ensure accurate density measurements. The operational complexity of using CML on wells #3 and 4 was greatly reduced due to a more accurate measurement of the drilling fluid density. This valuable tool has now become standard on CML operations for Shell.

A typical pressurized mud balance has a measurement range of ~ 6.5 - 23.0 lb/gal. Due to the increased accuracy and number of graduations, a set of three mud balances is required to cover the entire mud density range of a traditional mud balance. The low-density range increased accuracy mud balance is 6.5 to 10.5 lb/gal. The mid-range balance is 9.5 to 13.5 lb/gal, and the high-density range is 12.5 to 16.5 lb/gal. Given the application of the mud balance is for narrow window drilling conditions, the range of expected mud densities on any application is usually small and only one of the three balances needs to be on location.

Figure 1. Increased-accuracy pressurized mud balance

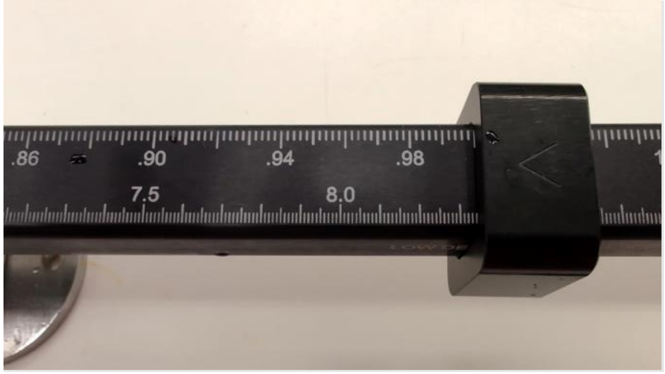

Figure 2. Close-up of density resolution on increased accuracy mud balances.

Extended Fluid Loss Testing

The traditional API Fluid Loss Test (low-pressure, low-temperature filtration test) and the High-Pressure, High-Temperature (HTHP) fluid loss test are used to evaluate the static filtration behavior of drilling fluids (API Recommended Practice 13B, 2023). While the API fluid loss is run at ambient temperature and 100 psi, the test pressure and temperature of the HTHP can be varied to represent downhole conditions more adequately. The length of the fluid loss test is not a variable; however, and 30 minutes is the normal duration. At very high temperatures, a modification can be made to run the test on a porous media instead of filter paper. Shell has run extended time fluid loss testing to determine the limits of a fluid in the laboratory. An extended fluid loss test of 16 hours is now standard, and for some applications, a longer duration is tested. The test is run on an aloxite disk which is more robust than filter paper. One of the benefits of the longer duration fluid loss test is that issues with the fluid health are detected much earlier and treatments can be made sooner.

Case history #1. A recent HTHP drilling project utilized a specialty Synthetic-Based Mud Drill-In Fluid (SBM DIF) for the reservoir section. DIFs are specially designed fluids that function as a drilling fluid but minimize formation damage to allow for the best possible production from the reservoir. Once a DIF is formulated and tested for its return permeability properties, any treatments to the fluid can alter the lift off pressure and return permeability characteristics of the fluid. This specific DIF was formulated and fully vetted numerous times in the lab. In the 16 hr fluid loss test at 350°F and 500 psid, no water was observed in the filtrate on the lab samples. However, in the field, on the first application, the fluid showed issues with stability. The API standard 30-minute test result was normal, but testing extended times showed the filtrate rate was not reducing and eventually water would show up in the filtrate after 8 hours, Table 1. The extended fluid loss testing showed the fluid was losing stability and needed treatment to avoid excessive filtrate invasion and overall stability issues with the fluid.

Table 1. Differences between the loadout sample and rig sample where water in the filtrate would appear after ~8 hrs.

	Loadout	Rig Sample
Spurt, ml	trace	0.1
30 min, ml	2.3	2.5
1-hr, ml	3.5	3.8
16 hr, ml	17.3	29.3
WIF	0.0	1.8

The standard API HTHP fluid loss test likely would've eventually showed the SBM DIF required treatment, but the extended fluid loss test was able to give an earlier indication of the fluid's stability making treatment easier.

Case history #2: A similar HTHP drilling project utilized a Water-Based Mud Drill-In Fluid (WBM DIF) on an injection well. The service provider followed their quality control process and evaluated the DIF using the HTHP fluid loss test for 1 hour on a ceramic disk under two conditions: 1) when it was built in the plant ("new" DIF) and 2) during drilling operations ("used" DIF). Photos of the 1-hr filtercakes of the DIFs are shown in Figure 3. Neither the filtercake thickness nor the fluid loss at 1 hour were very different between the "new" and "used" DIF tested before drilling. While drilling the section, the HTHP 1 hr fluid loss was in spec (<10 ml) and did not trend negatively throughout the section. After reaching total depth of the section, a wellbore cleanout run was conducted. While running in hole, the BHA became stuck.

Efforts to free the BHA were not successful and the original wellbore was lost. An extensive investigation looked at all aspects of the sticking event. Initially, the DIF wasn't thought to be a part of the root cause because the fluid always met the 1-hour specification (<10 ml) and had a thin 1-hour filtercake. Nevertheless, fluid samples were collected and sent into the lab for investigation, including extended fluid loss testing.

Figure 3. A comparison of the 1- hr filtercakes of new DIF (left) versus used DIF (right).

On the very first extended fluid loss test of 16 hrs, it was obvious the DIF filtration rate was not reducing as time continued, and thus very thick filter-cakes resulted. A comparison of the "new" DIF 16 hr filtercake which was expected versus the used DIF 16 hr filtercake is below in Figure 4.

Figure 4. A comparison of the 16- hr filtercakes of new DIF (left) versus used DIF (right).

It is likely that if the operations team had the 16 hr fluid loss data in real time, the stuck pipe incident could have been prevented. A few different mitigations could have been employed such as spotting a new drilling fluid in the open hole with better properties, optimizing the BHA design, or changing the run-in hole practices on the WBCO. For future wells, extended fluid loss testing was performed on the rig to ensure the fluid stability during drilling. Performing the extended testing at the rig-site can be difficult, as the apparatus needs constant monitoring. A 3rd mud engineer was sent to the rig to assist and monitor the modified testing plan. The extended time fluid loss testing proved beneficial on future wells. It is now used as an earlier indicator of fluid health and treatments can be made quicker.

Extended fluid loss testing does not have to be limited to a traditional HTHP cell. In a deepwater GOM well, a logging program was needed on a depleted reservoir section. The expected depletion was greater than 4,000 psid with a bottom hole temperature of 340 °F. The logging program was expected to be multiple runs and take longer than 4 days. Shell's fluids expertise team was asked to provide guidance on the ability of the DIF to maintain an acceptable fluid loss for the duration of logging. If the fluid was not able to provide stability for the entire 4 days, a plan to make a cleanout run and spot fluid would be needed. Extended fluid loss testing on a PPA was used to evaluate 4 different fluid combinations to log the interval. The first option was to weight up the drilling DIF at TD. This did not prove a viable option because the fluid loss rate continued and therefore the filtercake thickness would increase over time (Figure 5). The second option was to test the drilling DIF but to replace it with fresh DIF after reaching total depth of the section. This was tested on the PPA by conducting a 16 hr fluid loss test to establish a filtercake, then replacing the fluid with new DIF. While the rate of filtrate loss decreased over time, the total amount of fluid loss was higher than what was preferred. In a normal operations sequence, after finishing the section, a solids free screen running fluid (SF-SRF) would be spotted in the open hole. To test to see if it would be viable to use a screen running fluid to conduct logging, a DIF cake was built and then replaced with a SF-SRF (blue line on the graph). This option was satisfactory from a filtrate loss over time point of view, but the operations team deemed it too great of a risk if the logging program was prolonged, and a cleanup trip was required. It was preferred to have a dedicated logging pill. A fluid with a bridging material and increased fluid loss properties was formulated and tested. As shown in Figure 5, the fluid loss approached static after 3 days in the well. Based on the extended fluid loss data on the PPA, a logging pill was chosen as the base case for high differential logging.

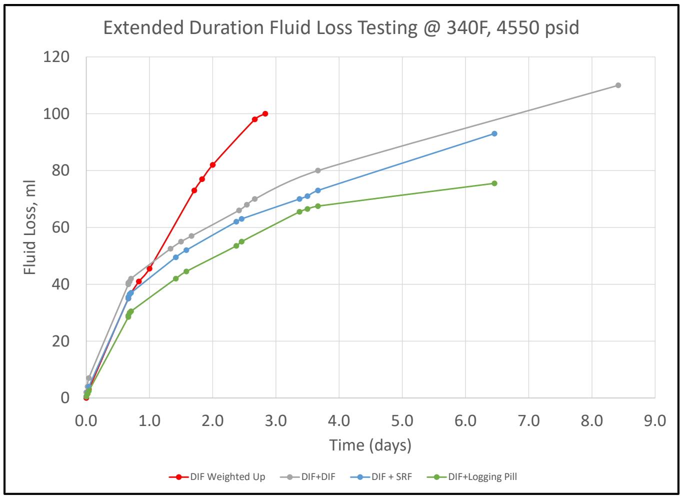

Figure 5. Extended-duration fluid loss testing of fluid options for logging.

In another application, the fluids laboratory evaluated a fluid loss pill for a cased and perforated completion concept. The fluid was intended to remain at 4500 psi of overbalance for 160 hours (about 6-½ days) to satisfy operational requirements. These requirements necessitated the use of extended duration testing on a PPA. During the test, the fluid (Formulation A) performed as expected during the normal 1-hour and 16-hour intervals, eventually establishing a static filtration rate. As can be seen in Figure 6, at about 84 hours (about 3-½ days) of elapsed time, Formulation A began to break down, with a gradually increasing rate of filtration over the next 10 hours until the test was stopped due to reaching the maximum filtrate volume. Using the resolution of the data provided by the PPA data acquisition software combined with inspection of the remaining fluid, filtrate, and filter disc, the cause was determined to be related to the fluid rather than a seal failure, fractured filter disc, or other equipment malfunction. Any of these other test artifacts would have manifested as a near-instant pressure drop. The failure mechanism of the fluid was independently verified using static age testing. The fluid loss pill was re-formulated (Formulation B) and the more robust fluid was successfully evaluated for the full interval of the 160-hour test. The lab extended fluid loss pill testing at high differential helped to qualify the pill for use in the field.

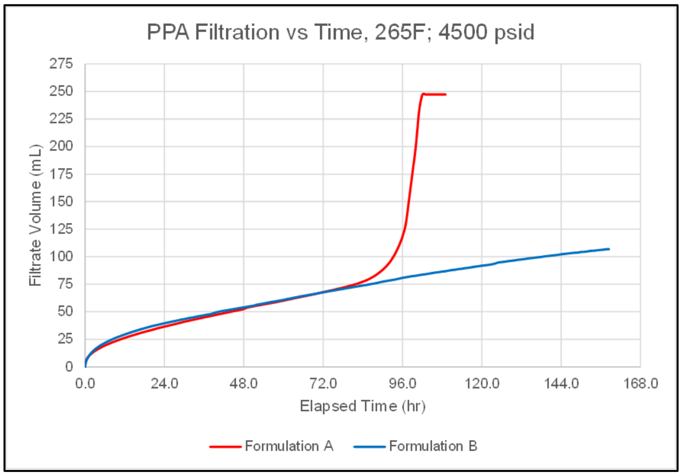

Figure 6. Fluid break-down after long static period at high pressure and temperature.

Automated Breakthrough Time

One of the most important steps in Shell's execution of an open-hole completion is pumping a breaker to remove the WB-DIF filter-cake prior to closing the isolation valve. Pumping live acid to clean up filter-cake in an open-hole completion can cause the well to have a high loss-rate, increase the chance of having difficulty closing an isolation valve, or lead to a well control incident. Furthermore, live acids may not allow full coverage of the entire wellbore causing incomplete filter-cake removal. A minor increase in delaying the breaker activity affords a greater chance of complete coverage and removal of the filter-cake. If a filter-cake breaker delay is too long, the breaker won't have enough acid to remove the filtercake. In most applications, losing all of the breaker to the formation is desired. If it's not lost, it will either be left above the isolation valve, or else it needs to be circulated out of the well. Leaving excess breaker in the casing, which is corrosive could impact the well integrity or the life of the well. Circulating excess breaker out increases costly rig-time and creates a HSE risk with having to handle it on surface. Therefore, it is ideal to have a fit for purpose breaker that has an engineered breakthrough time to optimize filter-cake cleanup. There is a balance between complete filter-cake cleanup and reaction time (breakthrough time). The breakthrough time is the time it takes for an acid breaker to react with the filtercake to the extent that leakoff occurs at a high rate.

A standard modified HTHP cell with an aloxite disk can be used to build a filtercake and then apply a breaker to it. There are health, safety, and environmental risks associated with leaving test equipment unattended where it is expected that you'll have a reaction which results in breakthrough and a high rate of breaker flow through the disk. Once breakthrough occurs, the gas used to pressure the cell will continue to leak through. The cell could be constantly monitored by a lab technician but is not very efficient and doesn't eliminate the HSE risk. To limit the potential for a large leak of gas post breakthrough, a smaller cylinder can be used, such as a CO_2 cartridge. However, one downside of this method is the pressure can decline over time due to the limitations of pressure supply in the cartridges. It is therefore ideal to have a setup supplied with a constant pressure and large volume of gas to pressure the modified HTHP cell while the acid is soaking but then would shut in when breakthrough is detected.

Adding an automatic shut off valve to a HTHP cell setup affords the benefit of using an existing piece of lab equipment, Figure 7. Valve control software for the pneumatically controlled isolation valve is paired with a fit-for-purpose DAQ program that takes input from a digital balance as well as temperature controllers and pressure transducers. A filtrate breakthrough event is detected by either a high filtrate flow rate, or a total volume of filtrate flow. After one of these conditions is met, the pneumatically operated valve will close (Figure 8), isolating the cell. Additionally, the DAQ software allows for cycling of the filtrate isolation valve on a set schedule if functionality beyond the standard breakthrough test is required. The automated breakthrough test differs from an extended fluid-loss test in that it is expected that once breakthrough occurs, a high flow of filtrate will expend through the valve.

For a deepwater well with a bottom hole temperature of 265 deg. F and a density of 15.4 lb/gal, balancing the breaker delay with filter-cake cleanup is extremely challenging. Furthermore, the high-density breaker is corrosive to carbon steel. Testing and predicting how long of an exposure the breaker may have downhole is key to efficient operations. During the breaker design, two main additives responsible for acid generation and reaction rate were identified. If too much acid generating chemical was used, the breaker would react too quickly and essentially act as a live acid. If the generation rate was too slow, the rig would have to wait until all the breaker reacted and was lost to the formation. The concentration of each additive and the ratio of the two products were varied in four different blends (Breaker #1, Breaker #2, Breaker #3, and Breaker #4) to determine their effect on the breakthrough time and filter-cake cleanup, Figure 9.

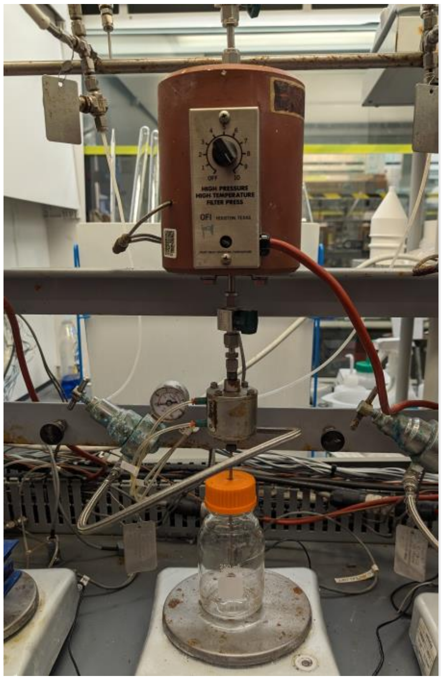

Figure 7. Automated Break-through test setup

Figure 8. Air-operated constant flow valve

Using the automated breakthrough time setup, the breaker design was optimized for preferred soak time while providing a satisfactory filtercake cleanup. In a recent example, it was estimated to take 3 hours to pull the wash pipe and close the isolation valve after the acid breaker was in place. Therefore, the preference was to have a delay greater than 3 hours. Breaker #1 reacted too quickly, and Breaker #4 had too much delay. Breakers # 2,3 had satisfactory breakthrough times and were further evaluated for corrosion, stability, etc. Breaker #2 was used on the first well and due to the delay mechanism, full coverage of the open hole was achieved. While it had 5 hours of delay in the lab, the reaction time was quicker in the field. This is not unexpected; however, as there are several variables that affect the breakthrough time such as filtercake thickness, displacement efficiency, contamination of the breaker, and formation permeability that can't be completely represented in lab testing. The use of the automated breakthrough time device has proved beneficial in comparing the relative breakthrough times of various breaker formulas to increase the chance of success on the first application in the field.

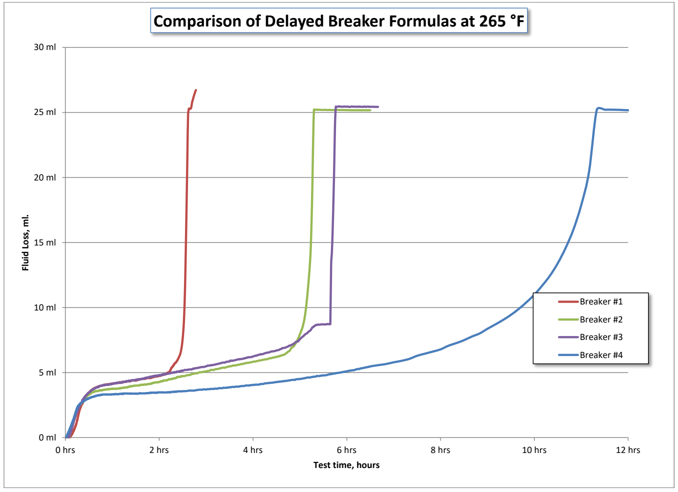

Figure 9. Comparison of delayed breaker breakthrough times.

10,000 psi PPA Testing

Due to rapid depletion of reservoirs, it was required for Shell to develop a PPA cell which could reach up to 10,000 psi differential pressure. The components of the cell are shown below in Figure 10. This cell utilizes the same conventional aloxite disk as used on the 5,000 psi rated cells. Isco pumps and data acquisition software have been implemented to automate the testing.

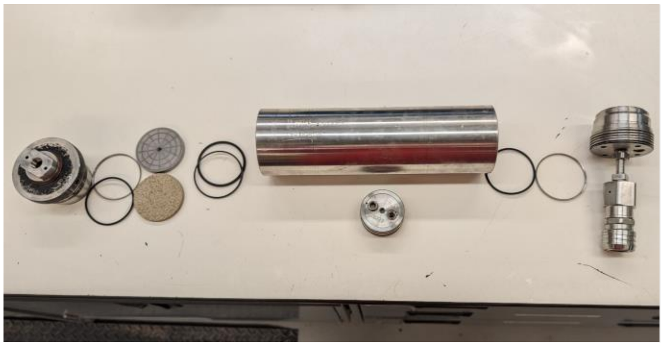

Figure 10. 10,000 psig PPA Cell components.

With the combination of the improved pressure and volume data resolution from the DAQ software along with the automated pump scheduling provided by the pump controller, the utility of the PPA instrument is improved not only for the standard permeability test, but for other variants of the permeability plugging test. An image of the PPA setup in operation is shown in Figure 11. Since the control software for the syringe pump allows for modifying the applied pressure and/or flow rate at any time or when a specific condition is met, it is possible for the operator to program a sequence of pressures and times to allow for a dynamic application of overbalance. This functionality is particularly useful when performing slot tests of LCM packages. The pressure is increased stepwise, holding a pressure for a set period until the maximum desired pressure is reached and maintained. If pressure does not build in the slot test, indicating that the LCM package could not bridge the slot, the pump will stop automatically after delivering a set amount of volume. Improved data resolution allows for the technician to observe pressure transients that may be missed when recording the values manually.

Figure 11. 10,000 psid PPA Assemblies in operation

The 10,000 psi PPA has extended the limits of lab testing to deliver wells in challenging environments. Traditionally, water-based muds have been limited to low depletion applications as synthetic based fluids are usually preferred for high overbalance applications. A HTHP GOM injection well with a 360 °F BHT and expected depletion of ~6,000 psi required a 12.8 lb/gal fluid. The well would go directly to injection, therefore it was desired to have a 100% acid soluble DIF which precluded a barite weighted synthetic based mud. A WB-DIF with breaker was previously used successfully in this field for virgin pressure producers. The fluid was evaluated to see if it had acceptable fluid loss and a thin filtercake up to 6,000 psi to mitigate the risk of differential sticking. The WB-DIF was tested on a modified HTHP at 800 psid and met the target specification of <10 ml at 1 hour and <25 ml at 16 hours with a filtercake thickness < 12/32". The same fluid was retested at 6,000 and 8,000 psi, Table 2 below. The WB-DIF had acceptable 1 hour fluid loss at both 6,000 and 8,000 psi.

Table 2. Fluid loss properties of a WB-DIF with increasing differential pressure

Device (pressure)	HTHP 800 psi	PPA 6,000 psi	PPA 8,000 psi	Target 5,000 psi
Filter media type	10-µm aloxite	10-µm aloxite	10-µm aloxite	
Spurt	1	0.5	0.5	
1 hr	7.2	8	8.5	<10
16 hr	20	31	38	<25
Filtercake thickness	3/32"	4/32"	4/32"	<12/32"

The 16-hour fluid losses were above the desired target of <25 ml at 5,000 psid; however, the filtercake thickness remained thin and below specification. Figure 12 has a photo of the 8,000 psi, 16-hour filtercake. When looking at the fluid loss data versus pressure, the filtrate volume increased over time but at a low rate.More importantly, even at high differential pressure, the fluid maintained a thin filtercake therefore the fluid was approved for use. By extending the limits of the lab testing capabilities, the operations team gained confidence a highly depleted well could be drilled with this fluid. The WB-DIF successfully drilled the injection well, and logging showed the depletion was greater than 6,500 psi.

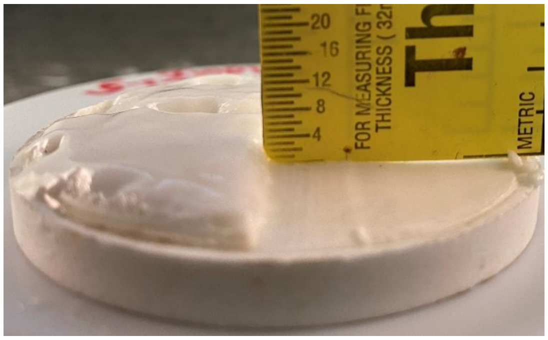

Figure 12. The 16 hr filtercake of the WB-DIF at 8,000 psi, 360 °F.

HTHP SAG Testing

A common concern in GOM drilling operations, especially those utilizing low equivalent circulating density (ECD) fluids is the settlement of weight material over time, also known as barite sag. Experiencing barite sag during operations can have several adverse impacts to the drilling operation as well as the wellbore, leading to non-productive time, formation damage, stuck pipe, and in severe cases, the loss of the primary barrier to the well. Qualification of a fluid includes an evaluation of whether a fluid will experience barite sag under static conditions, such as what would be experienced when performing a casing run, detaching from the well due to adverse weather conditions, wireline logging, or other conditions where the well would contain a fluid under static conditions for an extended period.

The most common laboratory test to evaluate static barite sag involves a standard HTHP aging cell, pressurized pneumatically with nitrogen gas at 200-500 psid (1,450-3,550 kPa). After the fluid has remained static for the desired amount of time, the cell is de-pressurized, put under vacuum to release entrained gas, and then a measurement of the syneresis (top oil) and the density at the bottom of the cell is taken by using a syringe to sample from the bottom of the aging cell. The density at the bottom of the cell is then compared to the initial density of the fluid, for which the change in density is compared to known acceptable fluids. This method has proven itself as a serviceable screening method for drilling and completion fluid qualification but is subject to certain limitations.

One limitation of the aging cell method of barite sag measurement is the lack of pressure that would be encountered at the same temperature in the wellbore. The hydrostatic pressure that the fluid encounters during the standard barite sag test often correlates to a fluid column depth that would terminate inside the marine riser, rather than at the total depth of the well or drilling interval. This lack of hydrostatic pressure may impact barite sag potential due to compressibility of the fluid, especially in synthetic-base drilling fluids. (Saasen, et al 1995). Another limitation of the aging cell method is the potential gas entrainment of the test fluid, potentially giving erroneous results even after mitigation measures such as holding the fluid under vacuum.

A potential solution to these limitations has been identified by using a Consistometer to perform static barite sag testing at wellbore conditions using hydraulic pressure rather than pneumatic. The consistometer ratings are a MAWP of 30,000 psig (206 MPa) and a maximum rated temperature of 600°F (315°C). A standard consistometer cell (Figure 13) was used to contain the test fluid with the consistometer paddle removed to prevent fluid agitation during the measurement. Further refinement of the cell assembly involved removing the temperature probe shaft entirely and sealing the top diaphragm to prevent the intrusion of hydraulic fluid into the test sample. Complete isolation of the hydraulic fluid from the test sample allows the technician to measure the syneresis of the fluid with relative ease. Additionally, a more robust elastomer (Viton 90) was used to construct the diaphragm, as the standard Buna-N diaphragm was distending during the test. This change in diaphragm elastomer reduced the likelihood of hydraulic fluid contamination of the test sample from a diaphragm rupture. The evaluation of the sample is like that of the aging cell test method, with syneresis being measured after removal of the pressure diaphragm, and then a 30 ml. sample from the bottom of the consistometer cell is taken with a wide gauge pipetting needle and sufficiently large syringe. Due to the construction of the cell, it is also easier for the technician to observe any hard packing of weight material at the bottom of the cell by removing the center section and observing what has collected on the bottom plate.

Figure 13. Consistometer cell without paddle or shaft, used for HTHP sag measurement

As can be seen in Table 3, observations using this method have validated the screening method used within the laboratory but have provided critically vital information on samples that could not be reliably measured using the standard method. Most samples tested thus far have shown a reduction in the bottom density with the HTHP consistometer method, indicating a lower likelihood of barite sag. Additionally, in observations 4 and 6, a significant reduction in syneresis is noted. Measurement of syneresis in the first three observations was not attempted due to suspected hydraulic fluid on top of the test sample.

In observation 5, the fluid was particularly difficult to evaluate using pneumatic pressure due to gas entrainment, and several hours were spent with the fluid under vacuum to release all entrained nitrogen from the sample before measurement. In the consistometer method, the bottom density was determined within minutes rather than hours. In observation 7, a water-based reservoir drill-in fluid (WBDIF) was evaluated. Using the standard method, the gas entrainment was sufficiently severe that a valid bottom density could not be determined. This phenomenon of severe gas or air entrainment during laboratory testing has been commonly seen in WBDIF and high-performance water-base muds (HPWBM), particularly those using a heavy loading of polymers. Using the consistometer method, a valid bottom density measurement and syneresis measurement were obtained with relative ease.

Table 3. Comparison of results from standard and HTHP SAG testing

Fluid ID		**1**	**2**	**3**	**4**	**5**	**6**	**7**
Type		**SBDIF**	**SBDIF**	**SBDIF**	**SBDIF**	**SBDIF**	**SBDIF**	**WBDIF**
Sample Source		**Lab**	**Lab**	**Field**	**Lab**	**Lab**	**Field**	**Field**
Aging Temperature	**°F**	280	280	225	190	260	260	340
Aging Time	**hours**	168	168	168	168	168	168	168
Initial Density	**lbm/gal**	16.15	16.55	13.75	11.60	15.45	15.25	13.80
Standard Method Syneresis	**%/vol**	2.6%	3.1%	12.9%	16.0%	4.6%	21.4%	1.4%
Standard Method Bottom Density	**lbm/gal**	16.79	17.1	15.36	13.31	16.34	19.21	13.47**
HTHP Method Pressure	**PSIG**	20000	20000	20000	12000	500	20000	5000
HTHP Method Syneresis	**%/vol**	*	*	*	10.3%	16.2%	3.4%	8.4%
HTHP Method Bottom Density	**lbm/gal**	16.31	17.06	14.45	13.18	16.44	16.43	14.16
Differential between Methods	**lbm/gal**	**0.48**	**0.04**	**0.91**	**0.13**	**-0.1**	**2.78**	**-0.69**
*** - No Measurement**								
**** - Final density lower than initial due to gas entrainment unable to be broken with vacuum**								

Conclusions

An extended testing protocol can overcome obstacles encountered on a fluids' first deployment and ensure success on subsequent applications. Testing methodologies presented along with field examples include:

- increased accuracy pressurized mud balance
- extended fluid loss testing
- automated breakthrough time
- 10,000 psi PPA testing capability
- HTHP SAG

The above testing methods were developed because standard lab testing protocols were not adequate to qualify fluids for challenging wells. In some cases, simply extending the limits of current lab testing methodologies (ex: 16 hour fluids loss) were sufficient. The automated breakthrough time and HTHP SAG modified existing equipment to achieve their objectives. Lastly, the other two tests presented needed new equipment developed (increased accuracy mud balance, 10k psi PPA).
It was shown that while the tests can be simple in nature or vary slightly from the standard test, they more adequately represent downhole conditions and enable the delivery of wells in challenging environments.

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Nomenclature

BHA	*Bottomhole assembly*
DAQ	*Data Acquisition*
ECD	*Equivalent Circulating Density*
GOM	*Gulf of Mexico*
HPWBM	*High Performance Water Based Mud*
HTHP	*High Temperature, High Pressure*
HSE	*Health, Safety, and Environment*
LCM	*Lost Circulation Material*
MAWP	*Maximum Allowable Working Pressure*
POOH	*Pull out of Hole*
PPA	*Permeability Plugging Apparatus*
psid	*pounds per square inch differential*
psig	*pounds per square inch gauge*
RIH	*Run in Hole*
SB-DIF	*Synthetic Based Drill-In Fluid*
TD	*Total Depth*
WB-DIF	*Water Based Drill-In Fluid*
WIF	*Water in Filtrate*
WTE	*Wells Technical Excellence Group*
WBCO	*Wellbore clean out*

References

API 13I, API 13B2

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