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## **Optimized Flat Rheology Oil Based Drilling Fluid with Nano Particles Eliminate Differential Sticking Challenge on High Overbalance Drilling**

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### **Abstract**

A significant portion of the increasing costs associated with drilling oil and gas wells can be attributed to rig spread rates, which are typically addressed during the well design phase. Rig spread rates, which involve the daily cost of operating the rig, are an essential factor in overall drilling expenses and can be managed through effective planning. However, an even larger contributor to rising drilling costs is nonproductive time (NPT), a major challenge in modern drilling operations. NPT refers to the time during a drilling project when no productive work is done, and it often results from unplanned events, delays, or complications. As the search for oil and gas reserves becomes increasingly complex and the design of wells becomes more sophisticated, these unplanned costs can have a profound and long-lasting impact on the feasibility and profitability of developing marginal fields. For rig operators, two of the most significant causes of NPT are differential sticking and downhole losses, both of which can lead to expensive delays and operational inefficiencies.

Differential sticking occurs when the drill pipe becomes stuck in the wellbore due to a significant pressure differential between the drilling fluid column and the formation pressure. This can be a particularly costly issue, as it may lead to the loss of an entire well section, requiring costly re-drilling. In addition, the cost of the tools and equipment that become stuck and are left behind in the well can add a substantial financial burden to the operation. Similarly, downhole losses—when drilling fluids are lost into the formation—pose a serious problem. These losses often occur in porous or fractured formations, and once the drilling fluid is lost, it can be difficult and expensive to regain control over the wellbore. Addressing downhole losses frequently involves costly operations like cementing and sidetracking, which are not only expensive but also carry the risk of causing irreversible formation damage. This damage can hinder future drilling operations, complicating the completion of the well and impacting the overall success of the project.

These issues are often most problematic when drilling in depleted reservoirs, where the goal is to access remaining hydrocarbons or to create a gas storage reservoir. In these situations, drilling is often carried out under high overbalance conditions, meaning the pressure exerted by the fluid column is higher than the formation pressure. This overbalance, while necessary to prevent fluid influx from the formation, creates additional risks. Drilling through depleted reservoirs or other difficult formations using traditional drilling fluids and methods increases the likelihood of encountering issues like differential sticking and fluid

loss. In some cases, operators turn to advanced techniques such as underbalanced drilling, which involves deliberately maintaining a lower pressure in the wellbore. While this approach can help manage formation pressure, it is technically challenging and considerably more expensive than conventional methods.

Additionally, when drilling through multiple reservoir targets that possess varying geological characteristics, the risk of encountering high-pressure differentials increases due to changes in lithology. As the lithology changes, so does the formation pressure, which can create challenging scenarios where differential sticking or downhole losses become more likely. These complex geological conditions further complicate well planning and design, requiring highly adaptable and cost-effective solutions to mitigate risks.

One of the most effective strategies for managing these challenges is the development of drilling fluids specifically designed to provide wellbore strengthening. Wellbore strengthening fluids are formulated to address the issues associated with high overbalance pressures and low formation strength. By enhancing the wellbore's ability to withstand these pressures, these fluids help prevent the occurrence of differential sticking and minimize the risks of downhole losses. In particular, wellbore strengthening fluids are engineered to improve the mechanical properties of the wellbore, ensuring greater structural integrity under challenging conditions. This paper focuses on how enhancing wellbore strengthening can lead to significant reductions in NPT, which in turn can help make marginal wells more economically viable.

The paper summarizes real-world field experiences that highlight the adaptability and effectiveness of wellbore strengthening techniques. These case studies demonstrate how the application of these techniques has resulted in tangible reductions in NPT, allowing previously problematic wells to be drilled more efficiently and safely. A key component of wellbore strengthening fluids is the incorporation of nanoparticles, which have shown exceptional promise in improving the performance of the filter cake. The filter cake is the layer of material that forms on the wellbore wall to seal off the formation and prevent fluid loss. Nanoparticles help to create a filter cake that is both thin and robust, ensuring that the pressure exerted by the fluid column is effectively minimized. This reduced pressure transmission prevents fluid loss to the formation, allowing the formation to seal more effectively and reducing the risk of formation damage.

By promoting the formation of a thinner filter cake, nanoparticles enhance the overall quality and integrity of the well. This improvement in the filter cake leads to greater wellbore stability, as the formation is better sealed and the pressure within the wellbore is more effectively managed. These advancements in filter-cake technology have proven to significantly reduce NPT, directly contributing to faster drilling times and lower overall drilling costs. As a result, wellbore strengthening techniques, particularly those involving nanoparticles, offer substantial potential for transforming marginal wells into economically viable projects.

In conclusion, the ability to reduce NPT through wellbore strengthening is a critical factor in improving the feasibility of challenging drilling projects. By addressing the root causes of differential sticking and downhole losses, wellbore strengthening can make a substantial impact on overall drilling efficiency. The incorporation of nanoparticles into the fluid system plays a central role in enhancing the performance of drilling fluids, ensuring that the wellbore remains stable under high-pressure conditions and promoting successful completion of the well. Ultimately, these advancements in drilling fluid technology offer promising solutions for addressing the rising costs and technical challenges faced in the oil and gas industry, particularly in marginal fields.

## Introduction

Recent advancements in drilling fluid design have primarily focused on improving wellbore stability and mitigating lost circulation issues. One of the key strategies employed involves the use of low-fluid-loss fluids that are specifically designed to minimize fluid loss to the formation. These specialized fluids typically incorporate a blend of granular materials, such as sized calcium carbonates and graphite. Their primary function is to seal fractures in the formation, preventing the full hydrostatic pressure exerted by the fluid

column from being transmitted to natural fractures within the formation. While this approach is highly effective in preventing the loss of circulation, it does not necessarily improve wellbore stability on its own.

The combination of calcium carbonate and graphite, however, has been shown to significantly enhance wellbore stability. This is achieved by increasing the hoop stress, often referred to as the "Stress Cage," in the area surrounding the wellbore. The particles of calcium carbonate and graphite form a bridging structure within the fractures, either at the fracture's opening or close to it, creating a seal with low permeability. This sealing action allows the fluid and pressure that are confined between the seal and the fracture to dissipate into the surrounding formation, which aids in the closure of the fracture. When the particles forming the bridge possess sufficient strength, the bridge is compressed but still prevents the complete closure of the fracture, thereby generating a hoop stress around the wellbore. This hoop stress plays a critical role in reinforcing the near-wellbore integrity, preventing further fracture propagation, and enhancing overall wellbore stability.

However, while the combination of sized calcium carbonate and graphite provides valuable reinforcement, it is not always sufficient to seal smaller, microfractures that naturally occur in the rock or form between the sized particles. This issue becomes particularly pronounced when the overbalance (i.e., the differential pressure between the fluid column and the formation pressure) becomes significantly high. In such cases, the existing particles may not effectively bridge the microfractures, allowing them to remain open and potentially leading to fluid loss or wellbore instability.

In addition to the mechanical properties of the materials, temperature plays a critical role in the sustainability and functionality of the drilling fluid. The filter cake, which is an essential component of the wellbore sealing system, is composed of both the bridging materials (calcium carbonate and graphite) and synthesized polymers. These polymers serve to hold the sized particles in place, forming a cohesive network that stabilizes the filter cake and enhances its sealing capacity. The temperature within the wellbore can significantly affect the performance of these polymers, as high temperatures may degrade their effectiveness. Therefore, the functionality and long-term stability of the fluid system depend not only on the materials used but also on their ability to withstand the elevated temperatures typically encountered during drilling operations.

Overall, while sized calcium carbonate and graphite provide an essential function in sealing fractures and preventing lost circulation, their ability to reinforce wellbore stability and seal microfractures under high overbalance and temperature conditions requires careful consideration of the overall fluid design, including the incorporation of temperature-resistant polymers and the optimization of particle size and distribution.

## Enhanced Sealing Technology

Microfractures that develop in geological formations, particularly when different lithologies such as coal, shales, and sandstone are interbedded within the same section, present significant challenges during drilling operations. These challenges require the use of highly sophisticated and advanced technologies to effectively manage and mitigate their effects. One of the most promising and cutting-edge technologies for this purpose is nanotechnology. This technology employs nanoscale particles, which, when introduced into mud systems, are capable of dispersing into unique submicron-sized particles. These particles, at such a small scale, deliver exceptional performance in a wide array of drilling conditions, ensuring optimal outcomes during complex operations.

Nanotechnology is essentially a polymer-based solution that plays a critical role in enhancing wellbore stability, particularly when drilling through formations that contain shales. The synthetic polymer used in this process has an incredibly small particle size, with a d-50 value of approximately 200 nanometers, allowing the particles to penetrate deeply into microfractures within the formation. This penetration helps to significantly reduce fluid invasion, which in turn lowers the associated increase in pore pressure—an important factor for maintaining drilling efficiency and wellbore integrity. By ensuring the fluid is

effectively sealed within the fractures, nanotechnology prevents potential damage to the formation and reduces the risk of blowouts or other operational failures.

In addition to its beneficial effects on wellbore stability, nanotechnology works synergistically with other materials, such as sized calcium carbonate and graphite, to seal highly porous and permeable formations. This combined action further reduces the risk of differential sticking and downhole losses—two critical issues that can lead to costly delays and complications during drilling. The use of these materials not only stabilizes the formation but also prevents excessive fluid loss into the surrounding rocks, preserving the integrity of the wellbore.

One of the most remarkable features of nanotechnology is the ability of its nanoparticles to deform under the pressures and temperatures encountered deep within the earth. This unique capability enables the nanoparticles to adapt to the specific shape and structure of the fractures they encounter, ensuring a perfect seal regardless of the fracture's size or complexity. This adaptive sealing mechanism provides a significant advantage in maintaining wellbore stability in even the most challenging drilling environments. The image below, captured using a Scanning Electron Microscope (SEM), offers a detailed view of the nanoparticles' size in relation to the fracture width and shape, illustrating the technology's effectiveness in improving drilling performance. The SEM image serves as a visual representation of the precision and efficiency with which nanotechnology can optimize drilling operations and enhance overall wellbore integrity.

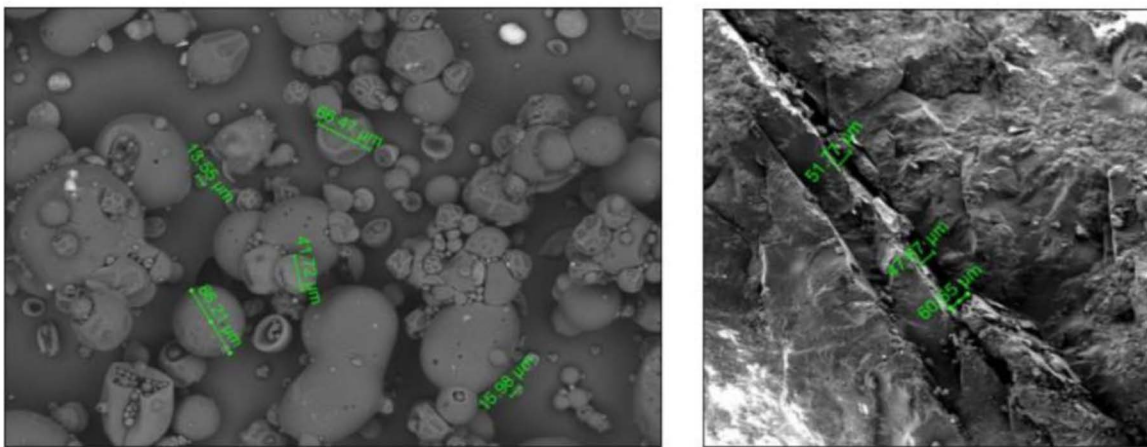


Figure 1—Photo by SEM showing nanoparticles sealing polymer (left) and fracture width measurement of coal sample from the well.

## High Temperature High Pressure Validation

While wellbore-strengthening muds can be specifically engineered to demonstrate low filtration properties, conventional API tests may not fully capture the extreme conditions encountered during actual drilling operations. These tests, although useful in certain contexts, do not always reflect the unique challenges presented by high temperature and high-pressure (HTHP) environments. It is crucial to understand how drilling fluids behave under such conditions, particularly when the goal is to form an effective seal, such as when constructing a bridge within a fracture. In less extreme conditions, such as those with moderate temperatures and differential pressures, it may be possible to achieve a low fluid-loss mud. However, when operating in HTHP environments, the behavior of the drilling fluids becomes more complex. The fluid systems used will begin to degrade due to the intense heat, causing a shift in their performance characteristics. This degradation can lead to compromised fluid properties, which could significantly impact the overall success of the drilling operation.

Moreover, in conditions involving high differential pressure, the challenges become even more pronounced. Under such high-pressure conditions, sealing the formation and preventing the transmission of

pressure through the formation layers becomes significantly more difficult. The effective sealing of fractures and preventing fluid loss are key objectives, but the increased pressure further complicates this task. As a result, it becomes clear that the effectiveness of wellbore-strengthening treatments, including the use of specialized mud systems, must be thoroughly evaluated under a range of permeable media and various environmental conditions to ensure their reliability and performance under extreme circumstances.

To address these challenges, a flat rheology oil-based system was subjected to a series of tests conducted at varying temperatures and pressures. In each of these laboratory experiments, a combination of sized calcium carbonate and graphite was used, providing a consistent baseline for evaluating the performance of the drilling fluid system. The introduction of nanoparticles into this fluid system proved to be a critical enhancement, as it demonstrated the ability of the fluid to maintain stability even under the extreme conditions of HTHP environments. This stability is vital in preventing issues such as fluid loss, maintaining the structural integrity of the wellbore, and ensuring the overall effectiveness of the drilling operation.

The test conditions, including temperature and pressure ranges, along with the results obtained, are detailed in [Table-1](#), which provides an overview of the experimental setup and the outcomes achieved. These results highlight the importance of maintaining a stable and effective fluid system when drilling under harsh conditions. Furthermore, [Tables 1-3](#) provide a more granular look at the fluid filtrate behavior across different ceramic disks and mud weights, demonstrating how the system's performance changes with variations in these parameters. [Figures 2-4](#) visually represent the filtrate behavior over time for all three mud samples, each tested with different ceramic disk sizes. These figures provide valuable insights into how the fluid responded to varying conditions and offer a clear comparison of the three samples. The ability to track filtrate behavior over time is crucial for understanding the long-term stability of the mud system and its ability to function effectively under extended high-pressure, high-temperature conditions.

**Table 1—Laboratory Testing Condition**

Project Information	Unit	Value
Mud System	-	Oil-Based
Temperature	°F	300
Differential Pressure	psi	5,800
Ceramic Disk Size	Micron	20/50/120
Ceramic Disk	Mercury	New
Fresh Mixed Fluid	-	Yes
Hot Rolled	-	Yes
Hot Rolling Temperature	°F	300
Hot Rolling Time	Hours	16

**Table 2—Results obtained for 80 pcf OBM**

80 pcf Mud PPT Results			
Time (min) \ Size (μ)	20 μ	50 μ	120 μ
1	0.4	0.5	2.7
5	0.8	0.9	3.2
7.5	0.9	1.1	3.4
10	0.9	1.2	3.8
15	1.1	1.3	3.9
20	1.2	1.3	4.0

<b>80 pcf Mud PPT Results</b>			
<b>Time (min) \ Size (<math>\mu</math>)</b>	<b>20 <math>\mu</math></b>	<b>50 <math>\mu</math></b>	<b>120 <math>\mu</math></b>
<b>25</b>	1.4	1.4	4.1
<b>30</b>	1.5	1.6	4.2
<b>Spurt (ml)</b>	0.4	0.5	2.7
<b>Total (ml)</b>	2.6	2.7	5.7

**Table 3—Results obtained for 100 pcf OBM**

<b>100 pcf Mud PPT Results</b>			
<b>Time (min) \ Size (<math>\mu</math>)</b>	<b>20 <math>\mu</math></b>	<b>50 <math>\mu</math></b>	<b>120 <math>\mu</math></b>
<b>1</b>	0.0	0.1	2.0
<b>5</b>	0.5	0.5	2.5
<b>7.5</b>	0.8	1.0	2.7
<b>10</b>	1.0	1.2	2.9
<b>15</b>	1.2	1.3	3.0
<b>20</b>	1.3	1.5	3.1
<b>25</b>	1.5	1.7	3.1
<b>30</b>	1.6	1.9	3.2
<b>Spurt (ml)</b>	0.0	0.1	2.0
<b>Total (ml)</b>	3.2	3.7	4.4

**Table 4—Results obtained for 120 pcf OBM**

<b>120 pcf Mud PPT Results</b>			
<b>Time (min) \ Size (<math>\mu</math>)</b>	<b>20 <math>\mu</math></b>	<b>50 <math>\mu</math></b>	<b>120 <math>\mu</math></b>
<b>1</b>	0.2	0.0	2.0
<b>5</b>	1.0	0.4	2.6
<b>7.5</b>	1.2	0.7	2.7
<b>10</b>	1.4	0.9	2.8
<b>15</b>	1.7	1.1	3.0
<b>20</b>	1.9	1.3	3.1
<b>25</b>	2.0	1.3	3.3
<b>30</b>	2.1	1.5	3.4
<b>Spurt (ml)</b>	0.2	0.0	2.0
<b>Total (ml)</b>	4.0	3.0	4.8

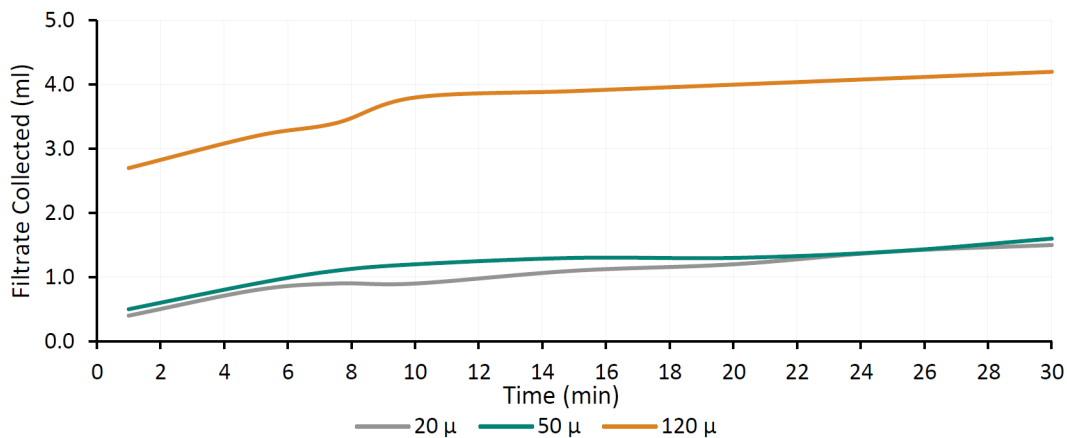


Figure 2—80 pcf OBM

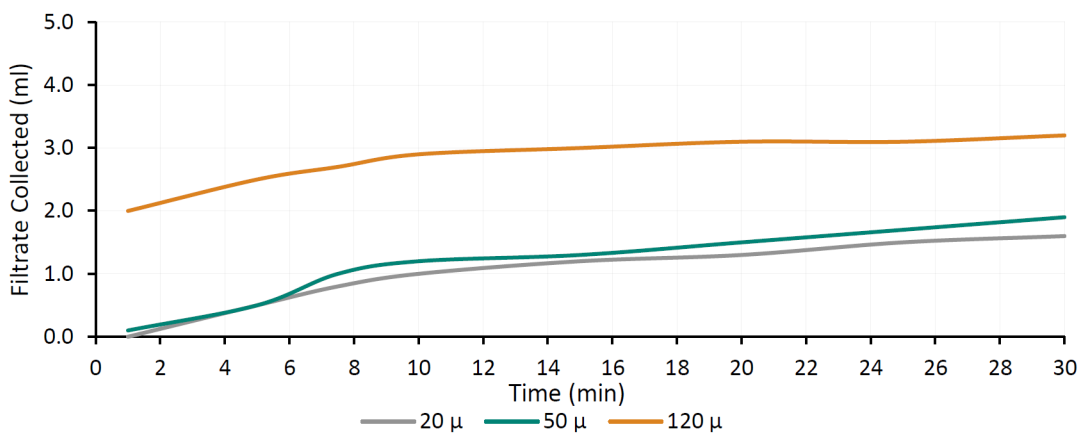


Figure 3—100 pcf OBM

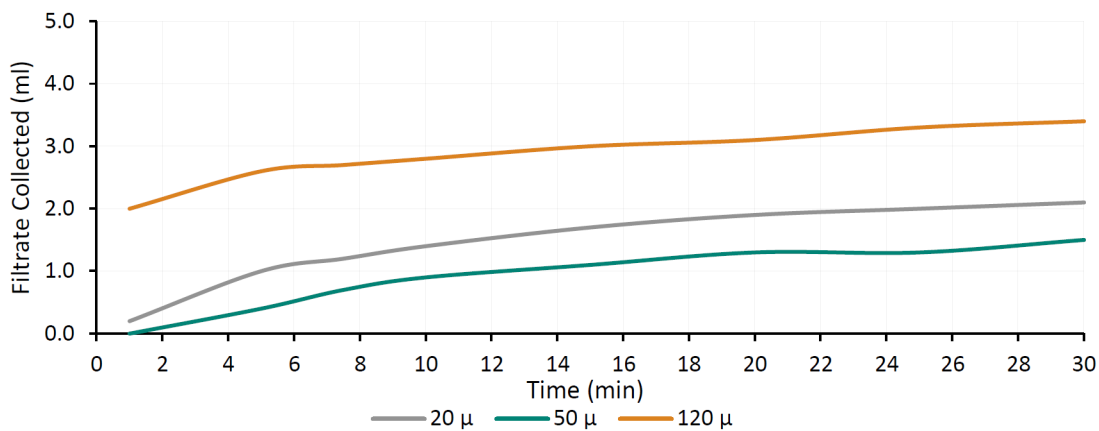


Figure 4—120 pcf OBM

In summary, these comprehensive test results underscore the importance of evaluating drilling fluid systems under simulated wellbore conditions that closely mimic the extreme environments encountered during actual drilling. The incorporation of nanoparticles into the fluid system significantly enhances the performance, particularly in the face of HTHP challenges, ensuring that wellbore integrity is maintained, fluid loss is minimized, and the overall drilling operation can be carried out efficiently and without costly delays. This thorough evaluation is essential for developing drilling fluid systems that can meet the demands

of the most challenging wells, ultimately leading to improved operational success and enhanced safety in the field.

Data obtained from various tests involving different ceramic disks and mud weights have demonstrated exceptional fluid loss control when evaluated using the Permeability Plugging Tester (PPT) under conditions of  $T = 300^{\circ}\text{F}$  and  $\Delta P = 5,800$  psi. These results are particularly valuable in challenging drilling environments, such as when drilling through depleted reservoirs. In such conditions, differential pressure acts as a significant barrier to continued drilling progress, posing a major obstacle that must be overcome to advance the operation. To ensure the successful completion of the drilled interval, preventing fluid losses and eliminating the risk of differential sticking become top priorities. Managing these issues effectively can prevent costly delays and enhance the overall efficiency of the drilling process.

In addition to these challenging conditions, even harsher environments may be encountered when drilling in specific fields where the bottom hole temperature (BHT) exceeds  $300^{\circ}\text{F}$ . To better understand how drilling fluids perform under these extreme conditions, a laboratory experiment was conducted to simulate environments where the BHT exceeds  $340^{\circ}\text{F}$ . The same methodology used to evaluate the effectiveness of nanoparticles in High-Temperature, High-Pressure (HTHP) conditions was applied to this experiment. The Permeability Plugging Tester (PPT) was used to assess the fluid's performance with the same mud type under the conditions of  $T = 350^{\circ}\text{F}$  and  $\Delta P = 5,800$  psi.

The test conditions for this experiment are detailed in [Table-5](#), providing an overview of the parameters and setup used during the analysis. Additionally, [Tables 6-8](#) and [Figures 6-8](#) present the results of the tests conducted at  $T = 350^{\circ}\text{F}$  and  $\Delta P = 5,800$  psi, showing how the fluid system behaved under these extreme temperature and pressure conditions. These results demonstrate the ability of the drilling fluid to maintain its integrity and functionality even in harsh environments, providing valuable insights into how nanoparticles can enhance drilling fluid performance and wellbore stability in wells with high temperatures and pressures. By evaluating the behavior of the drilling fluid under such conditions, it becomes possible to optimize the fluid system for even the most demanding drilling scenarios, ensuring continued success and safety in the field.

**T 5—Laboratory Testing Condition**

Project Information	Unit	Value
Mud System	-	Oil-Based
Temperature	$^{\circ}\text{F}$	350
Differential Pressure	psi	5,800
Ceramic Disk Size	Micron	20/50/120
Ceramic Disk	Mercury	New
Fresh Mixed Fluid	-	Yes
Hot Rolled	-	Yes
Hot Rolling Temperature	$^{\circ}\text{F}$	300
Hot Rolling Time	Hours	16

**Table 6—Results obtained for 80 pcf OBM**

80 pcf Mud PPT Results			
Time (min) \ Size ( $\mu$ )	20 $\mu$	50 $\mu$	120 $\mu$
1	0.5	0.4	3.0
5	0.9	0.8	3.8
7.5	1.1	1.2	4.3

<b>80 pcf Mud PPT Results</b>			
<b>Time (min) \ Size (<math>\mu</math>)</b>	<b>20 <math>\mu</math></b>	<b>50 <math>\mu</math></b>	<b>120 <math>\mu</math></b>
<b>10</b>	1.3	1.4	4.7
<b>15</b>	1.7	1.9	5.2
<b>20</b>	2.0	2.2	5.4
<b>25</b>	2.1	2.4	5.7
<b>30</b>	2.3	2.5	5.8
<b>Spurt (ml)</b>	0.5	0.4	3.0
<b>Total (ml)</b>	4.1	4.6	8.6

**Table 7—Results obtained for 100 pcf OBM**

<b>100 pcf Mud PPT Results</b>			
<b>Time (min) \ Size (<math>\mu</math>)</b>	<b>20 <math>\mu</math></b>	<b>50 <math>\mu</math></b>	<b>120 <math>\mu</math></b>
<b>1</b>	0.4	0.2	2.5
<b>5</b>	0.7	0.6	3.0
<b>7.5</b>	1.0	1.1	3.3
<b>10</b>	1.2	1.4	3.6
<b>15</b>	1.7	1.7	4.0
<b>20</b>	2.1	1.9	4.3
<b>25</b>	2.3	2.1	4.7
<b>30</b>	2.4	2.1	5.0
<b>Spurt (ml)</b>	0.4	0.2	2.5
<b>Total (ml)</b>	4.4	4.0	7.5

**Table 8—Results obtained for 120 pcf OBM**

<b>120 pcf Mud PPT Results</b>			
<b>Time (min) \ Size (<math>\mu</math>)</b>	<b>20 <math>\mu</math></b>	<b>50 <math>\mu</math></b>	<b>120 <math>\mu</math></b>
<b>1</b>	0.4	0.1	2.8
<b>5</b>	0.9	0.5	3.2
<b>7.5</b>	1.1	0.8	3.6
<b>10</b>	1.4	1.1	3.9
<b>15</b>	1.8	1.4	4.1
<b>20</b>	2.2	1.7	4.6
<b>25</b>	2.5	1.9	5.0
<b>30</b>	2.6	2.0	5.3
<b>Spurt (ml)</b>	0.4	0.1	2.8
<b>Total (ml)</b>	4.8	3.9	7.8

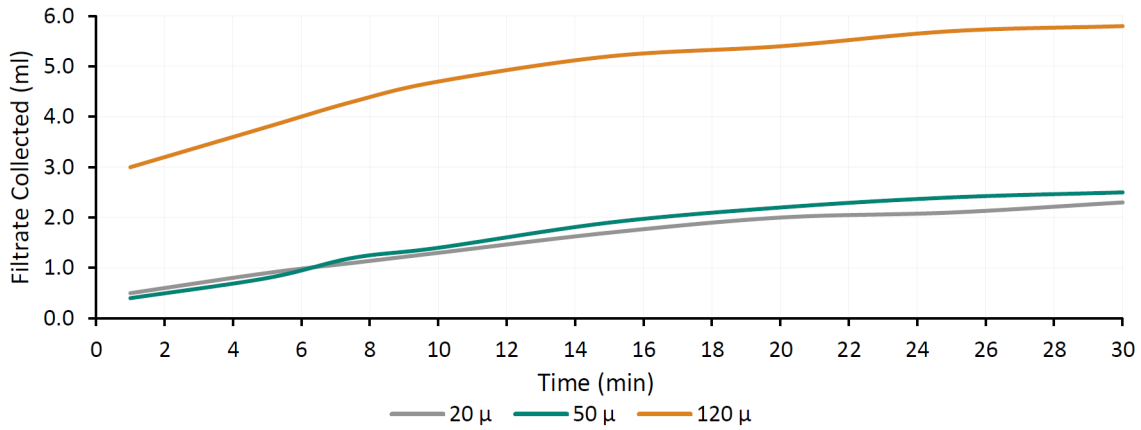


Figure 6—80 pcf OBM

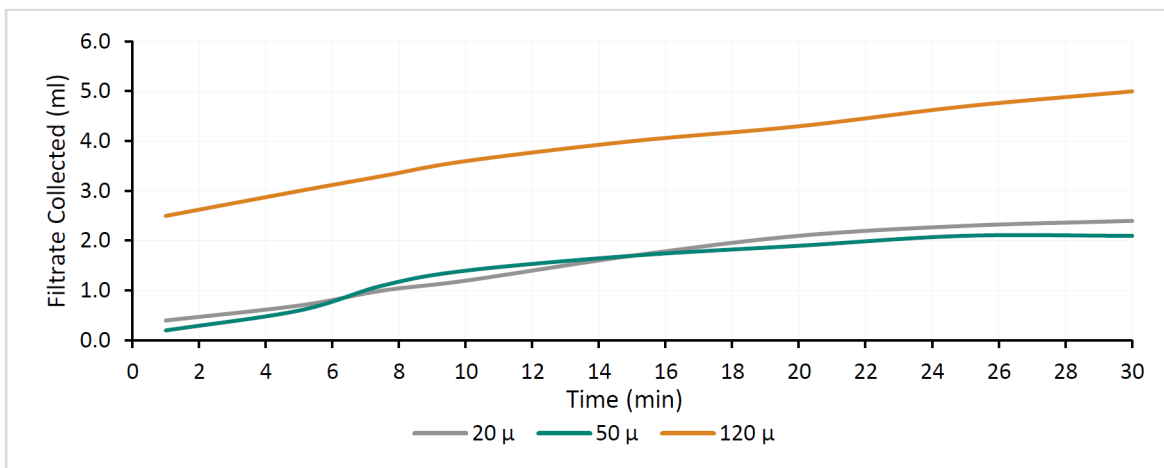


Figure 7—80 pcf OBM

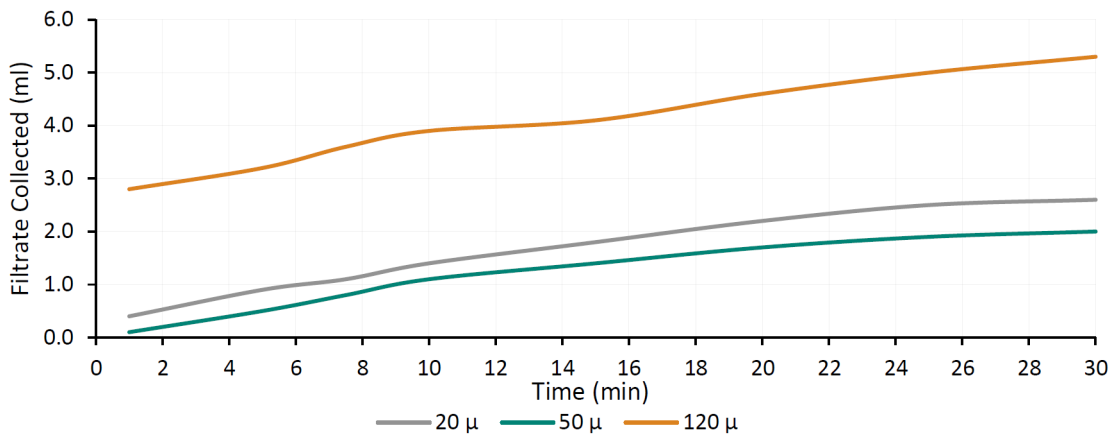


Figure 8—120 pcf OBM

Rheological profile is essential as well to be evaluated since fluid viscosity is one of the parameters that affects PPT results. As shown in below table T-9, T-10, T-11, are the fluid rheological behaviors showing consistency with different mud weight where all samples have been subjected to high temperature (i.e., Hot rolled at T = 350° F)

**Table 9—Rheological profile for 80 pcf hot rolled at 350 °F**

<b>80 pcf Rheological Parameters @ 150° F</b>	
Dail	Value
$\Theta_{600}$	60
$\Theta_{300}$	37
$\Theta_{200}$	27
$\Theta_{100}$	19
$\Theta_6$	8
$\Theta_3$	7
PV (cP)	23
YP (lb/100ft <sup>2</sup> )	14
LSYP (lb/100ft <sup>2</sup> )	6
10 sec gel (lb/100ft <sup>2</sup> )	10
10 min gel (lb/100ft <sup>2</sup> )	14
30 min gel (lb/100ft <sup>2</sup> )	16

**Table 10—Rheological profile for 100 pcf hot rolled at 350 °F**

<b>100 pcf Rheological Parameters @ 150° F</b>	
Dail	Value
$\Theta_{600}$	67
$\Theta_{300}$	41
$\Theta_{200}$	33
$\Theta_{100}$	23
$\Theta_6$	11
$\Theta_3$	9
PV (cP)	26
YP (lb/100ft <sup>2</sup> )	15
LSYP (lb/100ft <sup>2</sup> )	7
10 sec gel (lb/100ft <sup>2</sup> )	12
10 min gel (lb/100ft <sup>2</sup> )	16
30 min gel (lb/100ft <sup>2</sup> )	17

**Table 11—Rheological profile for 120 pcf hot rolled at 350 °F**

<b>120 pcf Rheological Parameters @ 150° F</b>	
Dail	Value
$\Theta_{600}$	84
$\Theta_{300}$	51
$\Theta_{200}$	40
$\Theta_{100}$	27
$\Theta_6$	12
$\Theta_3$	10

120 pcf Rheological Parameters @ 150° F	
PV (cP)	33
YP (lb/100ft <sup>2</sup> )	18
LSYP (lb/100ft <sup>2</sup> )	8
10 sec gel (lb/100ft <sup>2</sup> )	14
10 min gel (lb/100ft <sup>2</sup> )	19
30 min gel (lb/100ft <sup>2</sup> )	21

## Fields Experience

Several wells in the Kingdom of Saudi Arabia (KSA) have been successfully drilled with an Overburden Pressure (OB) exceeding 5,800 psi and a Bottom Hole Temperature (BHT) surpassing 340°F, all while utilizing nanoparticles. Remarkably, these operations have been carried out without any significant challenges or Non-Productive Time (NPT), showcasing the effectiveness of this technology in demanding environments. Additionally, hole stability during these operations has demonstrated exceptional integrity, further emphasizing the reliability of nanoparticles in maintaining wellbore conditions under extreme pressures and temperatures.

Deep gas drilling, one of the most complex and high-risk drilling operations, presents particular challenges. This process often involves directional drilling, where it is crucial to follow a specific azimuth to properly enter the reservoir and reach the "sweet spot" for optimal gas production. Traditionally, azimuths of 0° or 180° have been used as they represent the minimum stress direction, making them less prone to failure. However, these azimuths also present a challenge for wellbore stability due to the specific geological conditions.

In such challenging environments, the role of a premium filter-cake becomes critical. The filter-cake is vital in providing adequate support to the formation, preventing it from collapsing under high pressures and temperature conditions. Nanoparticles have added significant value by enhancing the structure of the filter-cake, resulting in a thinner yet more robust cake. This improvement helps prevent differential sticking, which can otherwise cause costly delays, and provides better support for the formation. By reinforcing the filter-cake's integrity, nanoparticles have proven essential in ensuring both wellbore stability and the success of deep gas drilling operations, even in the most difficult conditions.

## Conclusion

Nanoparticles, with their unique ability to deform under both pressure and temperature, have significantly improved the performance of drilling fluids by reducing the risk of differential sticking. This characteristic is particularly valuable in complex drilling operations, where maintaining smooth and efficient wellbore conditions is crucial. In particular, challenging well designs and harsh conditions—such as those encountered in High-Temperature, High-Pressure (HTHP) wells—demand highly effective and well-tested technologies to overcome obstacles and maintain wellbore integrity.

Nanotechnology has emerged as a proven solution for these demanding environments, demonstrating its ability to thrive under extreme conditions. By utilizing nanoparticles that adapt to the fluctuating pressures and temperatures of deep wells, this technology has consistently ensured successful drilling operations. Wells drilled using nanotechnology have been completed without significant issues, effectively eliminating the risk of delays or lost time typically associated with difficult drilling conditions. The remarkable efficiency and reliability of nanotechnology in these extreme environments have made it a game-changer for the oil and gas industry, providing a solid foundation for continued success in complex well construction.

## Acknowledgment

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## Nomenclature and Abbreviation Expansion

API:	American Petroleum Institute
BHT:	Bottom Hole Temperature
NPT:	Non-Productive Time
pcf:	Pound per Cubic Feet
PPT:	Particle Plugging Tester
ppb:	Pounds Per Barrel
OBM:	Oil-Based Mud
HTHP:	High-Temperature High Pressure
$\Delta P$ :	Change in Pressure
PV:	Plastic Viscosity
YP:	Yield Point
cP:	Centi-Poise
lb/100ft <sup>2</sup> :	Pounds per 100-foot square
psi:	Pound per Square Inch
LSYP:	Low Shear Yield Point
ppg:	Pound Per Gallon
gpb:	Gallons Per barrel
bbbl:	Barrel
ml:	Milliliter
$\mu$ :	Micron
d-50:	Diameter 50
sec:	Seconds
min:	Minutes
$^{\circ}$ F:	Degree Fahrenheit
OB:	Over Balance Pressure

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