

Minimizing Formation Damage While Using API Grade Barite Laden Nonaqueous-Based Systems to Drill Reservoir Sections of Open-Hole Completed Producer Wells – Case Studies

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This paper was prepared for presentation at the 2018 AADE Fluids Technical Conference and Exhibition held at the Hilton Houston North Hotel, Houston, Texas, April 10-11, 2018. This conference is sponsored by the American Association of Drilling Engineers. The information presented in this paper does not reflect any position, claim or endorsement made or implied by the American Association of Drilling Engineers, their officers or members. Questions concerning the content of this paper should be directed to the individual(s) listed as author(s) of this work.

Abstract

It is recognized that barite laden fluids can cause permanent formation damage if used while drilling the reservoir section of open-hole completed wells. Some of the primary damage mechanisms are due to fine barite particles invasion, filtercake compaction and the difficulty of removing barite with traditional chemical treatments such as utilizing an acid or a chelant.

The preference of many operators is to avoid using barite while drilling through the reservoir section. The preferred alternative is to use specially-designed fluid systems containing selected acid-soluble solids of appropriate particle size ranges. To limit the weighting solids, a brine is used as the primary weighting agent to achieve the necessary overbalance pressure in the wellbore.

Nonaqueous-based reservoir drill-in fluid systems present additional challenges. Moderate density fluids are usually designed with high density brines, such as calcium chloride or calcium bromide as the internal phase and sized calcium carbonates to provide optimal filtercake quality (thin and ultra-low permeability). Nevertheless, for deep-water wells or wells requiring high overbalance pressures, barite may be necessary as the primary weighting agent where high-density brine and carbonates cannot provide the sufficient density to drill the reservoir sections.

To minimize formation damage, the added barite should be accounted for and included as part of the overall bridging particle design. With a properly designed bridging package, filtercake compaction, solids invasion, and excessive fluid loss can be minimized to help reduce formation damage¹.

This paper discusses lab designs and field applications of API grade barite and calcium carbonate laden synthetic-based systems (SBM) used to drill through reservoir sections of open-hole completed producer wells. Two case studies are presented

to illustrate some of the challenges experienced. Maintenance procedures to minimize formation damage is also discussed.

Introduction

Barite has primarily been used in the drilling fluids industry as a weighting material to provide the density required to maintain mechanical wellbore stability and to prevent formation fluids from entering the wellbore during conventional drilling operations². Since barite particles in the filtercake cannot be removed using conventional acid or chelant treatments, the use of barite for reservoir section drilling has been limited to cased and perforated completion techniques because any near wellbore damage caused by barite particles will be bypassed after perforating.

In this paper, we review and share laboratory designs, field applications and lessons learned from two case studies where API grade barite was used; specifically, the combination of API barite with sized calcium carbonates in nonaqueous reservoir drill-in fluids to drill reservoir sections of open-hole completed producer wells.

The first case study discusses a single system solution to drill both intermediate and reservoir sections to minimize fluid costs related to the use of a dedicated fluid system for each section.

The second case study presents the lab design and field application of API grade barite laden SBM systems used to drill reservoir sections of open-hole completed producer wells requiring high overbalance pressure.

Case Study #1- Single System Solution for Drilling both Intermediate and Reservoir Sections

In 2016, an operator in North America decided to reduce their fluid related drilling costs by using a single fluid system to drill both the intermediate and reservoir sections. The operator requested a single fluid solution that would minimize formation

damage while drilling reservoir sections of its open-hole completed producer wells.

The solution proposed was to optimize the barite laden SBM used in the intermediate section by removing fine solids using a chemically enhanced centrifugation technology and adjusting the density and particle size distribution (PSD) with sized calcium carbonates and API barite, while maintaining the necessary rheological properties.

Lab tests were performed to determine the optimization method and bridging package to be used to minimize formation damage. A particle size distribution software was used to select the size and concentration of calcium carbonate and API barite to adjust the PSD to the necessary values.

The optimized SBM was evaluated for filtercake quality and its ability to restore initial permeability by mechanically lifting off the filtercake without using acid or breaker treatment.

Lab Testing

The main objectives for the lab tests were to:

- Simulate the SBM optimization at the end of the intermediate section
- Determine additional bridging package to be used
- Assess the damaging effect of the optimized SBM (RDF) on the reservoir section
- Recommend properties assessment and maintenance strategies while drilling the reservoir section using the optimized fluid (RDF)

The following steps were followed in order to meet the above objectives:

- The maximum common pore size of the reservoir formation was determined using thin section analysis of the available reservoir core plugs. This value allowed the estimation of the target PSD using a proprietary software³.
- The PSD of the intermediate section SBM was measured and compared to the target PSD required to drill the reservoir section.
- A full mud check was performed on SBM used to drill the intermediate section to establish its properties, particularly its PSD and solids content.
- Based on the SBM particle size distribution and solids content, the decision was made to reduce the concentration of fines solids by using chemically enhanced centrifugation technology.
- Then the properties of SBM sample, including particle size distribution and solid content, were re-measured.
- The system was then weighted with a blend of sized calcium carbonates and API barites

- The PSD software was used to determine sizes and quantities of grade sized calcium carbonate to be used in function of the barite required.
- To meet drilling specifications of the reservoir formation and conditions, the system was treated with emulsifier, wetting agent and organophilic clay as required.
- The properties of the optimized SBM was then measured and its particle size distribution compared to the particle sizes distribution predicted by the software.
- HTHP fluid loss and flowback tests were performed on the selected aloxite disks select to mimic properties of the reservoir formation pore size distribution. These tests were run, to assess the filtercake quality and damaging effect of the optimized SBM.

1. Maximum Common Pore Size and Target Particle Size Distribution (PSD)

The selection of an optimal bridging package requires knowledges of the formation particle sizes and pore size distribution. In this case study, thin section images of the reservoir formation cores were available, and the PSD was acquired via a proprietary software.

The reservoir formation was a sandstone with calcite as cement. Thin-section analysis estimated the maximum common pore size to be 50 μm and the common pore sizes ranging from 20 μm to 30 μm .

Figure 1 shows one of the thin-sections used to estimate the maximum pore size of the reservoir section formation.

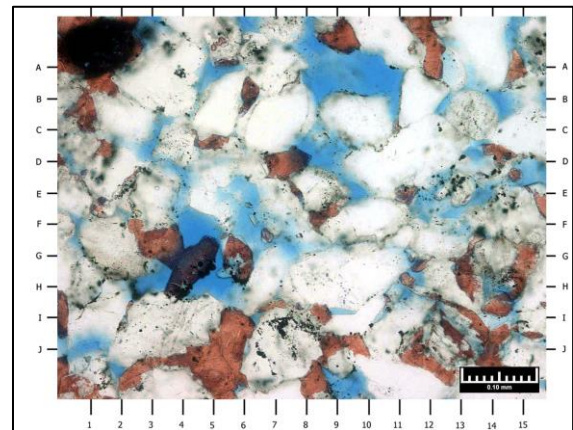


Figure 1- Reservoir Formation Core Thin-section Image.

The maximum pore size of 50 μm was input into the PSD software and the target particle size distribution below was determined:

Table 1- Target Particle Size Distribution based on a Maximum Pore Size of 50 μ m

	Targeted Diameter (μ m)
D₁₀	0.6
D₅₀	15.4
D₉₀	50.0

2. Intermediate Section SBM Particle Size Distribution and Properties

The PSD of a sample of 10.6 lb./gal (1270 Kg/m³) barite laden SBM collected at the lower intermediate section analyzed and results are shown in **Table 3** and other drilling fluid properties measurements in **Table 2**.

The solid analysis of the intermediate section SBM revealed 181lb./bbl. of solids (50% of solids have sizes less than 4.8 μ m) mostly from ground barite and drilled solids, **Table 2**.

Table 2- Intermediate Section SBM Properties

Properties	Units	Values
Density	lb./gal	10.6
Fann-35 Viscosity		
Rheology, Temp	°F	120
R600	lb./100ft ²	64
R300	lb./100ft ²	42
R200	lb./100ft ²	34
R100	lb./100ft ²	25
R6	lb./100ft ²	12
R3	lb./100ft ²	12
Gels 10 ² /10 ³	lb./100ft ²	15/20
Yield Point	lb./100ft ²	20
Plastic Viscosity	cP	22.0
HTHP Fluid Loss at 121°C & 500 psi	mL	5.0
Solid Analysis		
OWR		76/24
Corrected Solids	Vol. %	16.4
LGS	Vol. %	11.1
HGS	Vol. %	5.3
Total Solids	lb./bbl.	181.0
CaCl ₂ Weight Percent	Wt. %	18.4
Electrical Stability at 120°F	Volts	643.0
Excess Lime	lb./bbl.	1.5

Table 3- Particle Size Distribution after Drilling the Intermediate Section

	Targeted PSD (μ m)	SBM PSD (μ m)
D₁₀	0.6	1.0
D₅₀	15.4	4.8
D₉₀	50.0	27.1

To adjust the particle distribution of the intermediate section SBM, it was required to reduce the quantity of fines particles.

3. Reduction of Fine Solids Concentration by Using a Chemically Enhanced Centrifuge Technology

A chemically enhanced centrifugation technology was developed to help remove ultra-fine solids (< 2 μ m) from nonaqueous based systems which typically are difficult to remove using conventional high-speed centrifuge alone. **Figure 2** shows operating range of conventional mechanical solids removal system while **Figure 3** shows the range extension of chemically enhanced centrifugation.

This new technology combines chemical flocculant, using a surfactant/polymer blend, and high centrifugal force to help remove ultra-fine solids from a nonaqueous-based system. The chemical flocculant increases the relative size of fine particles to above 5 microns; these larger particles then allow the centrifuge process to be more efficient.

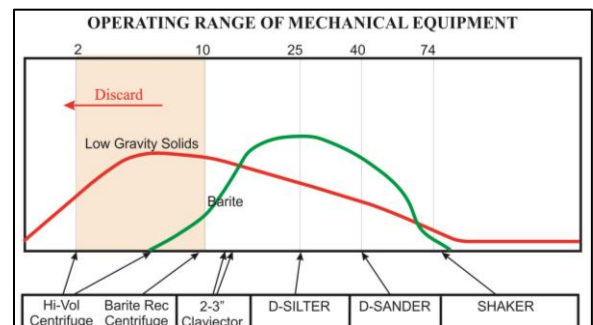


Figure 2- Conventional High-Speed Centrifuge

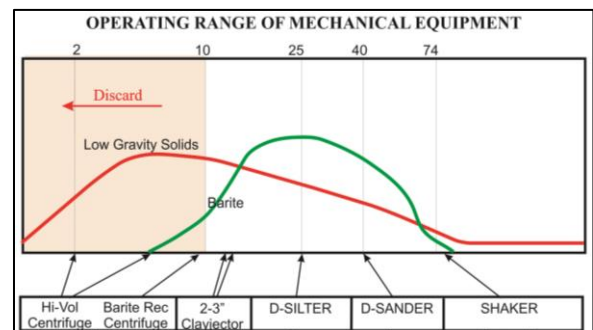


Figure 3- Chemically Enhanced Centrifugation

Due to the elevated concentration of solid particles under 5 μ m size in the SBM used for intermediate section, the chemically

enhanced centrifugation technology was utilized to reduce solids concentration before adjusting the fluid particle size distribution to approach targeted values required to drill the reservoir section.

Reducing the fine and ultra-fine solids concentration was crucial because these solids can easily invade the formation pores and cause permanent damage. In addition, a high concentration of fine particles can cause filtercake compaction and increased lift-off pressure.

The Fluid properties and particle size distribution after removing fine solids are shown in **Tables 4 & 5**.

Table 4- Intermediate Section SBM After Removing Fine Solids

Properties	Units	Values
Density	lb./gal	8.75
Fann-35 Viscosity		
Rheology, Temp	°F	120
R600	lb./100ft ²	42
R300	lb./100ft ²	27
R200	lb./100ft ²	22
R100	lb./100ft ²	16
R6	lb./100ft ²	8
R3	lb./100ft ²	7
Gels 10"/10'	lb./100ft ²	10/14
Yield Point	lb./100ft ²	12
Plastic Viscosity	cP	15
HTHP Fluid Loss at 121°C & 500 psi	mL	6.2 (0.2 mL of water)
Solid Analysis		
OWR		75/25
Corrected Solids	Vol. %	6.7
LGS	Vol. %	5.0
HGS	Vol. %	1.8
Total Solids	lb./bbl.	72.2
CaCl ₂ Weight Percent	Wt. %	17.9
Electrical Stability at 120°F	Volts	731.0
Excess Lime	lb./bbl.	1.5

Table 5-PSD before and after Removing Fine Solids

	Before Treatment (µm)	After Treatment (µm)
D ₁₀	1.0	1.0
D ₅₀	4.8	5.6
D ₉₀	27.1	14.3

After treatment, the density dropped from 10.6 lb./gal (1270 Kg/m³) to 8.75 lb./gal (1050 Kg/m³) and the total solids content was reduced by 60%. The D₁₀ and D₅₀ remained nearly constant. And the concentration of solids of less than 5 µm were

reduced by the same percentage. This treatment allowed the addition of a substantial amount of particles that could effectively bridge and reduce formation damage.

4. Adjustment of Particle Sizes Distribution using a PSD Software

A software was used to adjust the particle size distribution of the intermediate SBM after removing the fine solids. The goal was to select the size of calcium carbonate to supplement the amount of API barite to achieve the PSD targeted value.

PSD simulations using different calcium carbonates distributions showed that the combination of calcium carbonate with D₅₀ equals to 40µm with API barite produced a fluid PSD close to the targeted values, based on the 50µm maximum common pore size (Table 7). Typical API grade barite and calcium carbonate with D₅₀ equals 40µm are shown in Table 6.

Table 6- Typical Calcium Carbonate with D₅₀ equals to 40µm and API Barite Particle Sizes Distribution

	Calcium Carbonate with D ₅₀ equals to 40µm (µm)	API Grade Barite (µm)
D ₁₀	2.7	1.5
D ₅₀	48.1	14.8
D ₉₀	195.9	58.1

Table 7- Converted SBM Predicted Particle Sizes Distribution

	Targeted PSD (µm)	10.4 lb./gal Converted SBM PSD (µm)	11.3 lb./gal Converted SBM PSD (µm)
D ₁₀	0.6	1.7	1.6
D ₅₀	15.4	13.4	13.7
D ₉₀	50.0	84.2	78.5

Figures 4 and 5 illustrate PSD snapshots after particle size distribution adjustment respectively for 10.4 lb./gal (1250 Kg/m³) and 11.3 lb./gal (1350 Kg/m³) fluid densities.

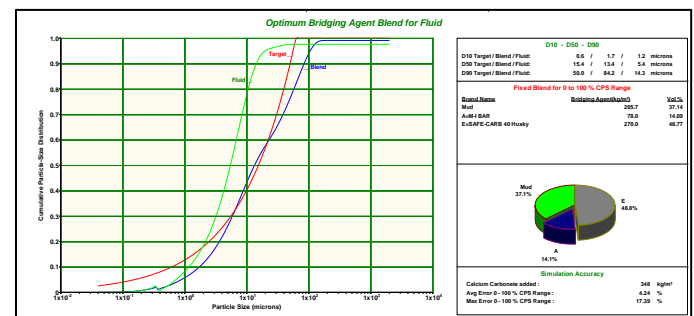


Figure 4-10.4 lb./gal (1250 kg/m³) Converted SBM PSD Snapshot

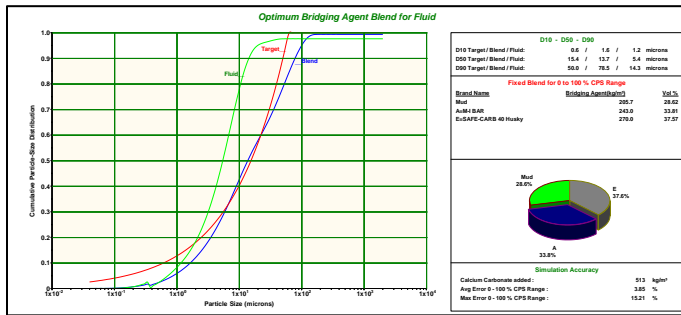


Figure 5-11.3 lb./gal (1350 Kg/m³) Converted SBM PSD Snapshot

5. Optimized SBM Properties and Flowback Assessment

In addition to optimizing the PSD and density of the fluid system, the SBM was treated with surfactants (emulsifier and wetting agent) and small concentration of organophilic clay to strengthen its emulsion, improve thermal stability, and improve both HPHT fluid loss and resistance to sagging at reservoir temperature.

Rheological properties and electrical stability of the optimized SBM are shown in **Table 8**.

Table 8- Converted SBM Rheological Properties and Electrical Stability

Properties		Initial	After aging	Initial	After Aging
Dynamic Aging Time	hour		16		16
Aging Temperature	°F		230		230
Density	lb./gal.	10.4	10.4	11.3	11.3
Fann-35 Vis.					
Rheology, Temp	°F	120	120	120	120
R600	lb./100ft ²	75	74	84	85
R300	lb./100ft ²	49	46	54	53
R200	lb./100ft ²	39	35	42	41
R100	lb./100ft ²	28	24	31	28
R6	lb./100ft ²	13	9	14	11
R3	lb./100ft ²	12	8	13	10
Gels 10"/10'	lb./100ft ²	12/16	9/12	13/17	11/14
Yield Point	lb./100ft ²	23	18	24	21
Plastic Viscosity	cP	26	28	30	32
E.S. at 120°F	Volts	839	487	831	642

The HPHT fluid properties measured using FAO-05 aloxite disc at 230°F and 500 psi are shown in **Table 9**. Both the low values of spurt loss and cumulated filtrate after 30 minutes and 4 hours confirmed that the particle distribution of the converted

SBM would quickly form a thin and ultra-low permeable filtercake necessary to minimize formation damage while drilling.

After the 4-hours HPHT fluid loss (230°F / 500psi), a flowback test was performed to measure the filtercake lift-off pressure and a qualitative assessment of the damage to the aloxite disk.

Filtercake lift-off pressure was determined to be 1 psi and return to flow was close to 90% (at 10 psi) for both optimized fluid densities, **Table 10**.

The 11.3 lb./gal filtercake after flowback is shown in **Figure 6**. The filtercake was less compacted and easily dispersed during flowback.

Table 9- Optimized SBM HTHP Fluid Loss

HPHT Fluid Loss	10.4 lb./gal	11.3 lb./gal
Aloxite Disk	FAO-05	FAO-05
Temperature, °F	230	230
Differential Pressure, psi	500	500
Spurt Loss, mL	0.4	0.0
30 minutes Filtrate, mL	1.8	0.5
1 hour Filtrate, mL	2.3	0.6
4 hours Filtrate, mL	4	0.8

Table 10-- Converted SBM Flowback Data

Pressure (psi)	10.4 lb./gal Return (%)	11.3 lb./gal Return (%)
1	74.2	81.1
2	77.6	84.8
3	82.4	88.5
4	81.7	89.3
5	84.4	90.9
10	87.2	92.8

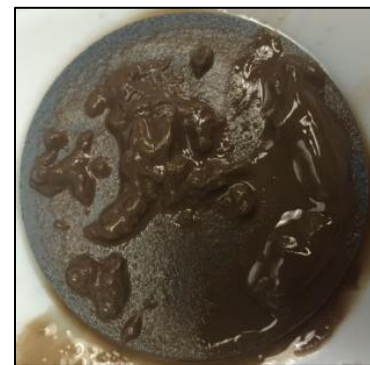


Figure 6- 11.3 lb./gal filtercake after flowback

Based on the laboratory results obtained above, the operator decided to use the recommended conversion method without further return permeability testing.

Field Application

1. Properties Maintenance while Drilling

The fluid properties maintenance plan was defined and tailored to mud pits, mixing system and solids control equipment available on the rig site. Particle sizes distribution was maintained by adding Calcium Carbonate with D_{50} equals to $40\mu\text{m}$ as needed to compensate for the reduction of particle sizes due to the grinding effect of the drill bit and hydraulic energy, **Figure 7**.

The shaker screens cut point was selected to discard drilled solids, maintain density within the range specified by the drilling program while minimizing dilution.

The centrifuge was not used in the active system to minimize further reduction in particle sizes. However, the density of the SBM was reduced offline while drilling.

HPHT fluid loss was controlled by the addition of surfactants and sized calcium carbonate. No other fluid additive was used.

Figures 7, 8 and 9 show particle sizes distribution and other fluid properties versus depth while drilling more than 6,550ft. (2,000m) of reservoir section using the optimized SBM.

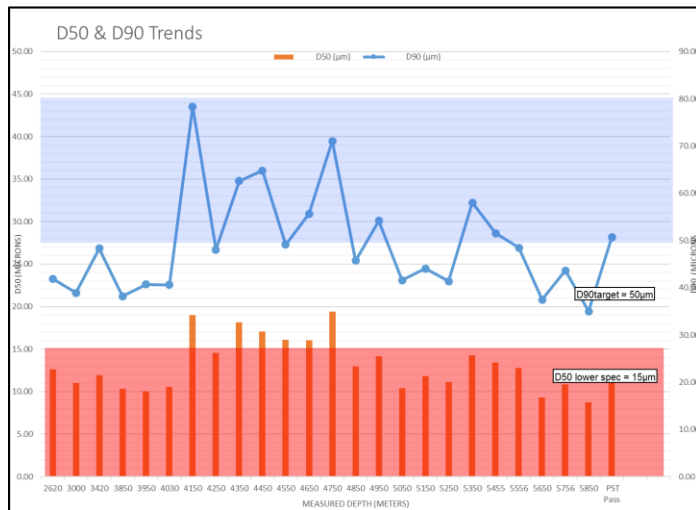


Figure 7-Particle Sizes Distribution (D50 & D90) of the Optimized SBM while Drilling the Reservoir Section

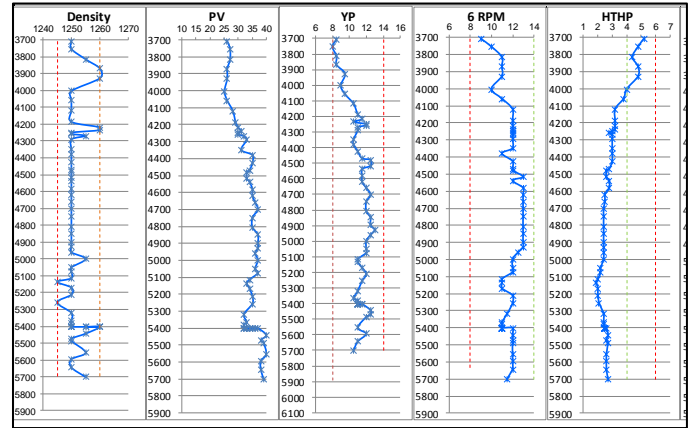


Figure 8- Converted SBM Properties versus Depth

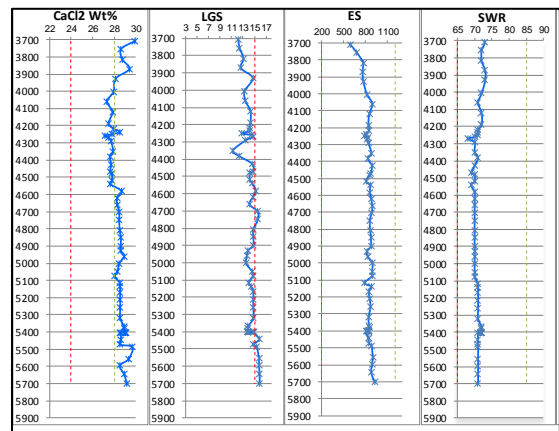


Figure 9- Converted SBM additional Properties versus Depth

2. Field Application Results

The single system solution was successfully applied in the field for drilling both the intermediate and reservoir sections and completed using stand-alone screens. The solution allowed a substantial reduction in drilling fluid related cost (up to 50% of saving) while minimizing formation damage, **Figure 10**. To date, a total of 4 producer wells were drilled using the single SBM system. The initial mechanical skin factor for all four wells were near-zero and production rates are excellent.

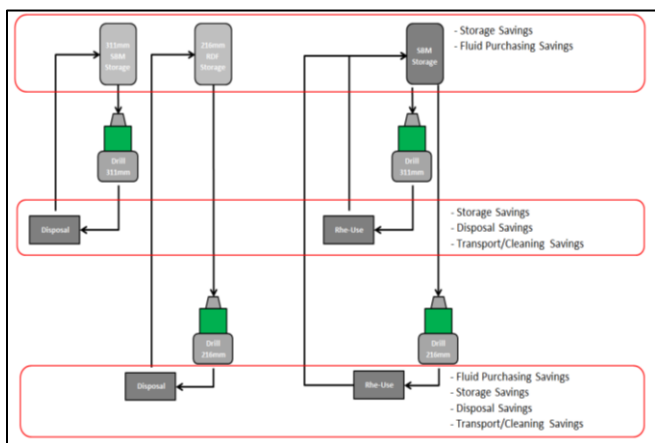


Figure 10- Savings Achieved using the Single System Solution for drilling the 12 ¼ “(311mm) intermediate section and 8 ½ ” (216mm) reservoir section.

Case Study 2- Reservoir Drilling at High Overbalance Conditions

The second case discusses the design and use of a API barite laden SBM for drilling the reservoir sections of open-hole gravel-pack producer wells with an expected overbalance pressure of up to 1,300 psi.

Since the anticipated pore pressures were high and the fracture gradient windows were very narrow, it was crucial to manage rheological properties of the reservoir drill-in fluids. Also, a high quality filtercake was required to minimize potential issue such as differential sticking while drilling and losses for successful gravel-pack operations.

Barite laden SBM with CaCl₂ brine as internal phase was selected to meet both the rheological properties and cost requirements. The fluids were designed with particle size distributions that would minimize formation damage by depositing a thin and ultra-low permeable filtercake.

Fit-for-purpose fluids were designed in the lab and successfully applied in the field.

Lab Testing

1. SBM #1 Fluid Design

The fluid design was initiated by the selection of the sized calcium carbonate which when combined with API barite would provide the particle size distribution needed to effectively bridge the reservoir formation and produce a thin and ultra-low permeable filtercake.

The size calcium carbonates and their respective concentrations were selected based on the anticipated average permeability of 500md (Sandstone formation permeability ranging from 150md to 1000md) for SBM 1 using a PSD selection software. The

PSD snapshot is shown in **Figure 11**.

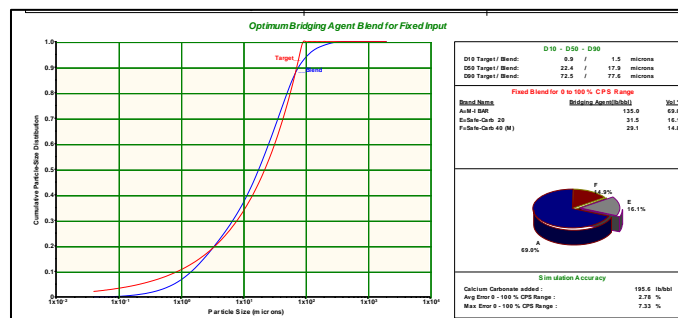


Figure 11- Particle Sizes Distribution Target based on 500md

After rheological properties optimization, the candidate formulation prepared for return permeability testing is shown in **Table 11**. Rheological and HTHP fluid loss properties after 16 hours dynamic aging at reservoir temperature are shown in **Table 12**.

Table 11- 11.2 lb./gal SBM #1 Final Formulation

Products	Function	Concentration (lb./bbl.)
Synthetic Base oil	External Phase	175
Organophilic Clay	Viscosifier	6.0
Surfactant A	Emulsifier	12.0
Surfactant B	Wetting agent	4.0
RM	Rheology Modifier	2.0
10.3 lb./bbl. CaCl ₂	Internal Phase	47.7
Water		24.1
API grade Barite	Weighting and Bridging	135.0
Calcium carbonate 40	Bridging	29.5
Calcium Carbonate 20	Bridging	31.5

Before performing HTHP fluid loss, the initial flow properties of the aloxite disk was measured by flowing a mineral oil through the aloxite, simulating hydrocarbon production. Initial flow-rates versus pressure differentials ranging from 1 psi to 5 psi were recorded. Then, HTHP Fluid loss was performed at reservoir temperature, and 850 psi differential pressure. Filtrate was collected for 4-hours. Next, a flowback test was performed to determine the lift-off pressure and qualitatively assess the damage effect of the selected fluid on the aloxite disk.

A low spurt loss was achieved with only 3.3 mL filtrate collected after 30 minutes at 145°F and 850 psi. The flowback results are shown in **Table 13**. The lift-off pressure was 1 psi and a return to flow of 79 % was achieved at

5 psi. The filtercake after flowback is shown in **Figure 12**.

Table 12- SBM #1 Final Formulation properties

Properties		After aging
Dynamic Aging Time	hour	16
Aging Temperature	°F	145
Density	lb./gal.	11.2
Fann-35 Vis.		
Rheology, Temp	°F	120
R600	lb./100ft ²	80
R300	lb./100ft ²	51
R200	lb./100ft ²	41
R100	lb./100ft ²	29
R6	lb./100ft ²	13
R3	lb./100ft ²	12
Gels 10"/10'	lb./100ft ²	16/21
Yield Point	lb./100ft ²	22
Plastic Viscosity	cP	29
E.S. at 120°F	Volts	670
OWR		80/20
HPHT Fluid Loss		
Aloxite Disk		FAO-00
Temperature	°F	145
Differential Pressure	psi	850
Spurt Loss	mL	1.0
30 minutes Filtrate	mL	3.2
1 hour Filtrate	mL	
4 hours Filtrate	mL	

Table 13- SBM #1 Flowback Results

Pressure (psi)	Return (%)
1	83
2	78
3	74
4	78
5	79



Figure 12-Filtercake after Flowback

2. SBM #1 Return Testing

Part of the fluid evaluation process involved assessing the formation damage potential via return permeability testing on formation cores. Return permeability tests are typically run at near wellbore conditions and simulate the effect of fluid exposure to the formation. The general return permeability procedure is presented below:

- Prepare core and restore irreducible water saturation (S_{wi})
- Mount core in core holder
- Raise temperature and pressure to test conditions
- Measure initial (baseline) permeability with oil
- Expose core dynamically to the test fluid at overbalance pressure for 4 hours.
- For stack-up testing, lower test conditions and place gravel/carrier fluid slurry on wellbore side of core on top of filtercake.
- Re-establish test conditions and circulate sweep fluids at overbalance pressure.
- Measure the return permeability as in step d.

Given that the main permeability of the reservoir formation ranged between 150md to 1000+md (to nitrogen), the candidate fluid was tested on both the lower and higher permeability cores. Both return permeability tests were performed at bottom hole temperature (BHT) with 500psi pore pressure and 1,200psi overbalance. Duration of the fluid exposure was 4 hours and circulated under dynamic conditions. Results of both tests are shown in **Table 14**. Results suggest that the SBM candidate fluid had minimal damage to the formation for either the lower and higher permeability cores. Regained permeability for both tests were high, fluid loss control was excellent and the flow initiation/drawdown pressure was very low.

Table 14- SBM #1 Return Permeability Results

Test	Core	Fluid	Initial Perm.	Fluid Loss (4hr)	Return Perm.	Flow Initiation Pressure
1	SP97	SBM #1	834.9 mD	2.0mL / 12.4%PV	750.6mD / 89.9%	0.1 psi
2	SP164	SBM #1	154.0 mD	3.4mL / 18.9%PV	130.4mD / 84.7%	0.1 psi

Further testing incorporating the simulation of an open-hole sweep and gravel packing was conducted. The results of the full stack-up test are shown in **Table 15**.

Results from the full stack-up return permeability test suggest that the gravel and screen had minimal impact to the formation. However, return permeability of the full stack-up is lower than the one obtained without gravel-pack simulation most probably due to longer exposure at high overbalance pressure using brine-based transition spacer and gravel pack fluid.

Table 15- Full Stack-up SBM #1 Return Permeability Results

Test	Core Number	Initial Perm.	RDF Fluid Loss (4hr)	NaBr Fluid Loss (30min)	Carrier Fluid Loss (2hr)
3	SP106	682.5mD	7.2mL / 43.5% PV	0.9mL / 5.3% PV	4.7mL / 28.5% PV

Return Perm (Full Stack Up)	Return Perm (Without Gravel & Screen)	Return Perm (Without filtercake & Trimmed)	Flow Initiation Pressure
387.5mD / 56.8%	384.6mD / 56.3%	623.0mD / 91.3%	0.7psi

3. SBM#2 Initial Fluid Design

The focus for the design of SBM #2 was placed on the optimization of the rheological properties for equivalent circulating density (ECD) management and particle size distribution for high quality filtercake necessary for formation damage control and gravel-pack operations.

The target particle size distribution was initially determined based on a maximum pore size of 60µm from thin-section analysis (Figure 13). A PSD snapshot is shown in Figure 14 and target PSD in Table 16.

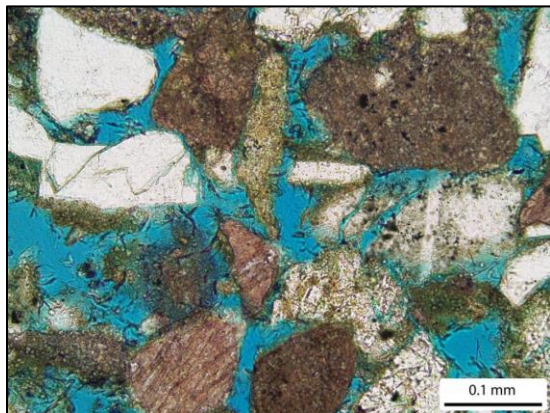


Figure 13-Thin-section of reservoir formation core (Sandstone) with estimated maximum pore size of 60µm (common pore size between 15 & 30 µm)

Table 16- Target PSD based on 60µm Maximum pore size

	Targeted PSD (µm)	Initial Blend PSD
D10	0.7	1.5
D50	18.5	17.4
D90	60	75.8

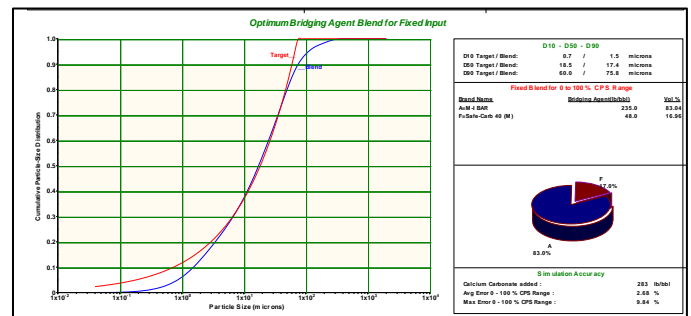


Figure 14- Particle Sizes Distribution Target based on Maximum Pore size of 60µm.

Table 17- 13.5 lb./gal SBM #2 Initial Formulation (70/30 OWR)

Products	Function	Concentration (lb./bbl.)
Synthetic Base oil	External Phase	136.4
Organophilic Clay	Viscosifier	5.0
Surfactant A	Emulsifier	12.0
Surfactant B	Wetting agent	4.0
11.6 lb./bbl. CaCl ₂	Internal Phase	112.5
Water		4.1
API grade Barite	Weighting and Bridging	235
Calcium Carbonate 40	Bridging	48

Properties of the initial SBM #2 formulation after 16 hours aging at 150°F are displayed in Table 18. Figure 15 shows the filtercake after flowback (return to flow of 86% at 5psi).



Figure 15- Filtercake after flowback

Table 18- 13.5 lb./gal SBM#2 Initial Formulation Properties

Properties		After aging
Dynamic Aging Time	hour	16
Aging Temperature	°F	150
Density	lb./gal.	13.5
Fann-35 Vis.		
Rheology, Temp	°F	120
R600	lb./100ft ²	94
R300	lb./100ft ²	55
R200	lb./100ft ²	41
R100	lb./100ft ²	26
R6	lb./100ft ²	8
R3	lb./100ft ²	7
Gels 10 ⁷ /10 ⁷	lb./100ft ²	7/7
Yield Point	lb./100ft ²	16
Plastic Viscosity	cP	39
E.S. at 120°F	Volts	380
OWR		70/30
HPHT Fluid Loss		
Aloxite Disk		FAO-00
Temperature	°F	150
Differential Pressure	psi	850
Spurt Loss	mL	0.7
30 minutes Filtrate	mL	2.1
4 hours Filtrate	mL	3.3

4. SBM #2 Initial Formulation Return Permeability Test Results

The evaluation of the RDF via return permeability testing began with the original SBM system containing 48 lb./bbl. of calcium carbonate with D₅₀ equals to 40µm and 235 lb./bbl. of API grade barite. The original OBM system yielded a regained permeability of 56%. Fluid loss recoded was 22% PV. The flow initiation pressure was 28 psi.

Table 19- 13.5 lb./gal SBM#2 Initial Formulation Return Permeability Tests Results

Test	Core Number	RDF	Initial Perm	Fluid Loss	Return Perm	Flow Initiation Pressure
1	1-21C	SBM #1	43.8 md	1.1ml / 22% PV	24.5mD / 56%	28.1 psi

While the fluid loss was low, the high overbalance utilized in the test may have caused the filtercake to compact limiting the regain permeability. Figure 17 depicts the post-test core and filtercake. The filtercake is ~9mm thick and compaction appears more evident in the lower portion (closest to the core). From this test, it was suggested that additional bigger size

carbonate may be needed to reduce the effect of compaction from the high overbalance pressure.

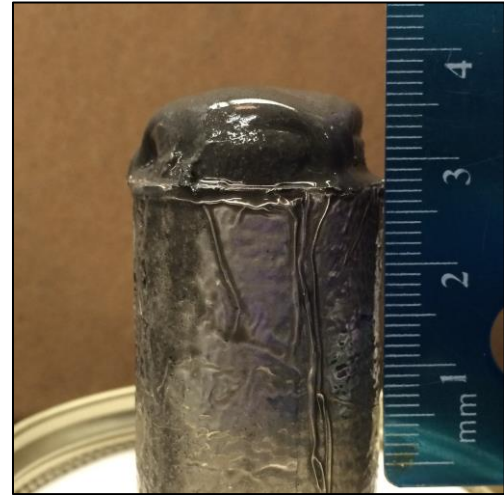


Figure 16- Side View of Core

To understand the filtercake compaction conjecture, a post-test thin-section of the core was performed. The thin-section analysis revealed that API grade barite and calcium carbonate particles had separated within the filtercake structure (Figure 17). Carbonate particles were found deposited mostly adjacent to the core face while the more compacted barite particles were observed primarily near the top (wellbore side) of the filtercake. This suggests that these two products may have separated in the mud accumulator prior to being circulated across the core face during the mud-off process.

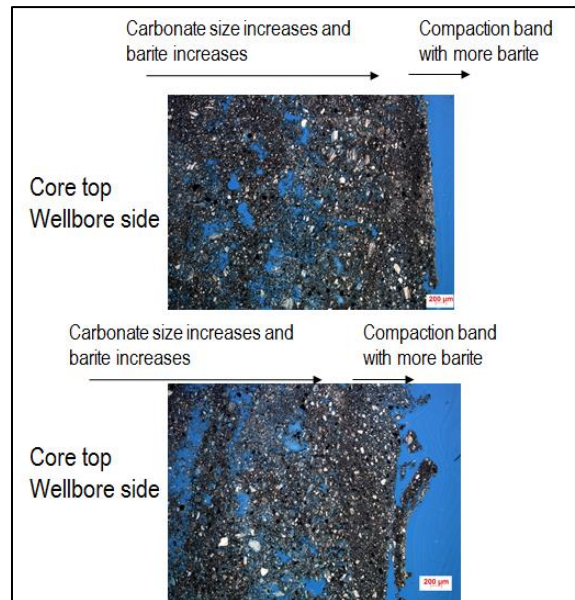


Figure 17- Post-test Thin-section Analysis

5. SMB #2 Optimized Formulation

The SMB#2 formulation was optimized primarily by increasing calcium carbonate and reducing API grade barite concentration to reduce the quantity of fine solids to minimize filtercake compaction at high overbalance pressure. Also, a rheology modifier was added in the formulation to address the barite settling observed in test #1.

Table 20- 13.5 lb./gal SBM#2 Optimized Formulation (75/25 OWR)

Products	Function	Concentration (lb./bbl.)
Synthetic Base oil	External Phase	136.7
Organophilic Clay	Viscosifier	6.0
Surfactant A	Emulsifier	12.0
Surfactant B	Wetting agent	4.0
RM	Rheology Modifier	0.2
11.6 lb./bbl. CaCl ₂	Internal Phase	49.9
Water		25.2
API grade Barite	Weighting and Bridging	163.0
Calcium carbonate 40	Bridging	162.3

6. SBM#2 Optimized Formulation Return Permeability Test Results

After further optimization, the repeat test yielded 91% of regained permeability. Fluid loss recorded was 30.8% PV. The flow initiation pressure was 7.1 psi. Results from this test shows a significant improvement in the return permeability while maintaining similarly low fluid loss and a much-improved drawdown pressure. Visually, the filtercake appears uniform, **Figure 18**.

Table 21- SBM#2 Optimized Formulation Return Permeability Tests Results (Formation Core)

Test	Core	RDF	Initial Perm	Fluid Loss	Return Perm	Flow Initiation Pressure
2	2-151B	Optimized SBM #2	50.9 mD	2.09ml / 30.8% PV	46.5mD / 91.4%	7.1 psi



Figure 18- Side View of Core (Repeated test)

A third test was performed to confirm the results obtained in test#2. Due to the limited availability of formation core, test #3 was conducted on Berea. Results show a regained permeability of 87%. Fluid loss recorded was 11.1% PV. The flow initiation pressure was 0.3psi. Results from this test shows a significantly more controlled fluid loss while maintaining a high return permeability value. The filtercake in test #3 appears very uniform and no visible compaction was observed (**Figure 19**).

Table 22- SBM #2 Optimized Formulation Return Permeability Tests Results (Berea Core)

Test	Core	RDF	Initial Perm	Fluid Loss	Return Perm	Flow Initiation Pressure
3	Upper Gray Berea	Optimized SMB #2	148.9 mD	1.3ml / 11.1% PV	130.8mD / 87.9%	0.3 psi

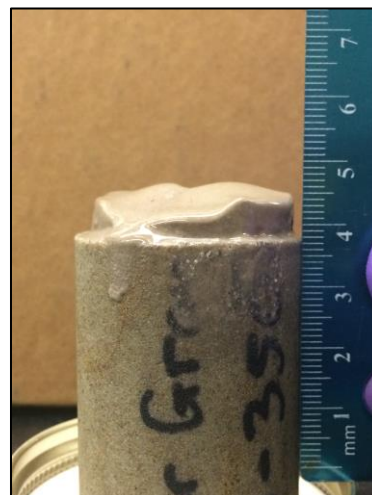


Figure 19- Side View of Core for Test #3

In addition, a breaker treatment was designed, to be spotted post-gravel pack operations, to reduce trapped gravel-pack fluid rheology and then diffuse to disperse the filtercake to further reduce the lift-off pressure, **Figure 20**.



Figure 20- Partially Dissolved and Disperse Filtercake after breaker Treatment

Field Application

The 11.2 lb./gal SMB #1 formulation was used to drill 2,300ft of reservoir lateral in a 10,685 ft. well in shallow water with no drilling related issue. Importantly, the gravel pack operation was successfully completed. The well was brought on to production with a production rate exceeding expectation, with a skin factor of zero; confirming the results obtained in the lab.

The SBM #2 optimized formulation was also successfully used to drill the reservoir section of a deepwater well without any issue. Gravel-pack operations were successfully completed with no formation losses and the designed filtercake breaker was spotted inside the production screens post-gravel pack operations. The results obtained during well testing suggest that the well will be able to produce at high production rate with initial mechanical skin factor of near-zero.

Conclusions

Drilling fluid related cost can be substantially reduced by using a single system solution to drill both the intermediate and reservoir sections of an open-hole completed producer well. The fluid can be formulated to maintain drilling performance while still minimizing formation damage and maximizing production rate. Proper particle size distribution optimization must be performed before drilling the reservoir section to ensure that a high quality filtercake will be laid down on face of the formation while drilling with an API grade barite laden nonaqueous-based system⁴.

A nonaqueous-based fluid with a high concentration of API barite can result in filtercake compaction at high overbalance conditions leading to high lift-off pressure and low return permeability (formation damage). Nevertheless, filtercake compaction can be minimize and lift-off pressure substantially reduced by substituting some of the API barite with larger

particle sizes selected from sized calcium carbonates. A filtercake breaker system can then be used to dissolve (calcium carbonate) and disperse the filtercake to further reduce the lift-off pressure.

For high fluid density and high overbalance applications, it will be useful to have barite in different particle size distributions to be able to design blends that will bridge different formation pore throats without using sized calcium carbonates.

This paper is aimed at advising operators on how to minimize formation damage when they decide to use API barite laden nonaqueous-based systems to drill reservoir sections of open-hole completed producer wells.

Acknowledgments

The author would like to thank Schlumberger for approving the publication of this paper. A special thanks to Loyola Carey, Mourad Kheder, Chelsea Squires and Matt Offenbacher for their contributions.

Nomenclature

BHA	=	Bottom hole assembly
PSD	=	Particle size distribution
FIP	=	Flow initiation pressure
SBM	=	Synthetic-based mud
PV	=	Pore volume
OWR	=	Oil-water ratio
PV	=	Plastic viscosity
YP	=	Yield point
HTHP	=	High temperature, high pressure

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