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Optimal Selection of Mud Type for Solving Drilling Problems of Carbonate Reservoirs

By

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Abstract
Heterogeneous nature and complex rock properties of carbonate reservoirs plus variable fluid composition make optimal selection of drilling mud very difficult and challenging endeavor. Optimal selection and/or design of drilling fluid have been substantially proven to be effective in providing successful drilling, viable formation testing, and feasible economics. In this study, several important prevailing drilling problems such as; compatibility of mud with testing tools, loss of mud circulation, formation damage, temperature stability, gas hydrate suppression, and shale sloughing have been evaluated and proven eliminated by selecting a suitable mud type. Optimal selection of mud type to provide required properties can be effective in controlling and sometime eliminating these problems. The paper also analyzes different field cases in which these problems have been alleviated through applying effective treatments via better selection of drilling muds. The case histories from Indonesia, Iran, and Croatia are presented, analyzed, and evaluated to conclude successful applications of optimal mud selection for carbonate reservoirs. The results indicated that biopolymer muds are recommended for drilling shale sloughing reservoir while lignosulfonate muds are not.

Keywords: Mud selection, optimum mud system, and biopolymer mud.

1. Introduction

Matching reservoir rock characteristics with optimum drilling fluid formulation is important to provide higher penetration rate and enhance the economics of any field development. In recent years, this need has become even more important with the growing drilling rate in carbonate heterogeneous formations. Drilling carbonate rocks place several demands on the drilling fluids used in this type of formation in general and in pay-zone section. Therefore, Bourgogne et al[1] indicated that it is important to have good enough properties of the selected drilling fluid to:

1. enable good bottom-hole cleaning,
2. provide good lubricity to avoid frictional problems,
3. produce minimum permeability damage of the formation.
4. provide enough hydrostatic pressure against subsurface formation pressure,
5. secure good inhibition with respect to interstitial clays and interceded shales,
6. provide suitable environment for planned well testing and evaluation techniques,
7. keep the newly drilled borehole open until steel casing is cemented in the hole,
8. reduce/prevent corrosion problems of drilling equipment and subsurface tubular.

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[1] Bourgogne, M.E. Chenevert, K.K. Millheim and F.S. Young Jr. 1991. Applied Drilling Engineering, *SPE Textbook Series* **vol. 2**, Society of Petroleum Engineers, Richardson, TX

Several drilling problems are attributed in different ways to inadequate selection and/or inappropriate additives of the drilling fluid to function properly in drilling carbonate reservoirs. This may lead to severe economic infeasibility of drilling costs of a single and/or group of wells.

2. Specialty of Carbonate Reservoirs

Chilingarian *et al*[2] .has indicated that more than 50 % of the world oil reserves are contained in carbonate reservoirs. The complex nature of carbonate reservoirs provides special requirements in selected type of drilling fluid. The problem will be more difficult for fractured and/or micro-fractured carbonate reservoirs. The major constituent of carbonate rocks is calcium carbonate ($CaCO_3$) which is affected by using water-base muds and may be converted to calcium dolomite according to the following well-known chemical reaction;

$$\underset{\text{Calcium Carbonate (Limestone)}}{2\,CaCO_3} + \underset{\text{Magnesium Chloride}}{MgCl_2} \rightarrow \underset{\text{Dolomite}}{CaMg\,(CO_3)} + \underset{\text{Calcium Chloride}}{CaCl_2} \tag{1}$$

It has been observed that dolomite is more porous than limestone. This is the reverse of what someone may expect because dolomite is less soluble than calcite. The use of conventional water-based mud in drilling limestone reservoirs may cause serious problem of wellbore instability due to the dissolution process. Therefore, special mud types/design should be considered in similar cases to avoid this type of problem.

Accurate definition of carbonate rocks is required to be understood by petroleum engineers. Geologists generally define carbonate rocks as those containing more than 50 % of carbonate minerals as presented by Bissell and Chilingar[3]. Similarly, dolomite is also defined as the sedimentary rock containing greater than 50 % of the mineral dolomite. Friedman and Sanders[4] recognized limestone and dolomite as the two-compositional end member types.

2. Drilling Problems and Solutions of Carbonate Reservoirs

Many drilling problems related to carbonate reservoirs are covered below and proposed solution(s) using selected mud type is presented;

2. 1. Compatibility of Drilling Fluid with Testing Tools;

Formation testing and evaluation are mainly affected by used drilling fluids. Therefore, it is imperatively important to select a suitable drilling fluid for drilling carbonate reservoirs and for successful testing of these formations.

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[2] Chilingarian, G. V., Mazzullo, S. J., and Rieke, H. H. 1992. Carbonate Reservoir Characterization: a geologic-engineering analysis, part 1," Elsevier, New York.

[3] Bissell, H. J. and Chilingar, G. V. 1967. Occurrence and Classification of Carbonate Rocks, Developments in Sedimentology, 9A. Elsevier, Amsterdam, pp. 87-168.

[4] Friedman, G. M. and Sanders, J. E. 1967. Origin and Occurrence of Dolostones," Elsevier, Amsterdam, 1967, 9-A, pp. 267-348.

Today, it is important to apply teamwork concept between Service Company and operating professionals to define the challenge of accurate formation testing and provide effective solution by selecting suitable mud type. Okuyig et al[5] indicated that formation evaluation of low permeability carbonate reservoirs has been challenging with frequent tool plugging, extended pumping time, and multiple trips out of hole. Tseng et al[6] indicated that the determination of fluid type and contacts (FT & C) in carbonate reservoirs is challenging because of complexity and heterogeneity of reservoir rock and lithology.

2.2. Lost of Circulation and Formation Damage

The total loss of the amount of fluid varies from one well to another. Usually, majority of fluid loss occurs in the lower part of the formation. The fluid losses are classified into four categories including seepages, moderate, severe, and total losses. While drilling in carbonate reservoirs, the mud is overbalanced at the top part of the reservoir and is kept in pressure average of 150 psi. The over balance increase quickly toward the lower part of the reservoir. Since hydrocarbon reservoirs have some large void spaces exist between the particles. The fluid hits these void spaces, the annular overbalance is lost, causing a mud loss and the annular level will decrease to a level at which the mud hydrostatic will equal the formation pressure at the loss zone. If the under balance wasn't handled properly, it will allow gas to enter the well bore which in turn will cause a gas kick with a mud loss.

Three different methods were found to solve the mud loss problem. The first method provides operational procedures to handle the total mud loss. In this method, a sufficient amount of mud and conventional medium is used and a float valves were attached to the drill string which act as a mechanical barrier to avoid influx entering the drill string. The second method is the use of optimized annulus fill-up rate to reduce mud lost into the formation while safely curing mud losses. Using an average mud mixing capacity around 100 BPH, the surface mud volume will decrease and will be lost in the formation before losses can happen. The volume of mud lost is dramatically reduced, while in the same time it gives the same volume of mud at the surface. The third method is curing losses with bridging agents like tuff fiber cement pills. Bridging agents are added to the drilling fluid to prevent loss circulation and solid invasion into the formation by building a filter cake through bridging across the pore throats or fractures of an exposed rock.

The size of the carbon structure is large and extensive comparing to the cement particles. The use of cement in curing losses on the base that the cement particles will fillup the void caused from the carbon. The use of fiber cement allows the fibers to generate complex bridges for the cement particles so it will attach, harden and cure losses.

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5 Okuyig, M, Berrim, A., and Haddad, S. 2007, Integrating Drilling-Fluid Optimization, and New Technology Improves Carbonate-Reservoir Evaluation, SPE 105298, the 15th Middle East Oil & Gas Show (MEOS) and Conference, Manama, Bahrain, 11-14 March.

6 Tseng, H. Y., Pottorf, R. J., and Mardon, D. 2007. Identifying Fluid Type and Contacts in Carbonate Reservoirs, IPTC 11201, International petroleum Technology Conference (IPTC), Abu Dhabi City, U. A. E., 4-6 December.

The four main components of most water-based reservoir fluid systems are the base brine, viscosifier, fluid-loss additive, and bridging particles. The first three components are normally kept unchanged, with exception of some weight adjustments that are always made. The two main types of bridging agents are calcium carbonate and sodium chloride salt according to Bissell and Chilingar[3]. Variety of bridging particles grades and sizes are used, depending on possible degree of fluid invasion that must be averted. Traditionally, Abrams' rule1 has been the principle guideline in selecting the proper particle size and concentration. Per this rule, "the median particle size of the bridging material should be equal to or slightly greater than 1/3 the median pore size of the formation." That means the concentration of the bridging solids must be at least 5% by volume of the solids in the fluid. By this rule, particles with size of 50 micron (μ) should be effective at sealing pores with diameter of 150 micron. The shortcoming of this rule is that it only addresses the size of particle required to initiate a bridge and does not give the best effective size. Also, it does not address an ideal packing sequence for reducing fluid invasion and enhancing sealing.

Ideal packing is distribution of particles with wide range of size, for effectively sealing all pores, even those formed by bridging particles, resulting in a tighter and less invading filter cake. Dick, et al[7] have introduced the new Ideal Packing Theory (IPT) that takes a graphical approach in determining the optimum particle-size distribution of bridging material for known formation characteristics to reduce formation damage and enhance the performance. IPT has been proved to be successful in different wells including a well offshore UK, for which the biopolymer system was designed at 9.5 lb/gal with 28 lb/bbl of properly sized ground marble and particle size was identified based on formation permeability that was expected to range from 50 to 80 md.

The underbalanced drilling has shown the following advantages over other drilling systems

1. Minimizing lost circulation
2. Increasing penetration rate
3. Minimizing differential sticking
4. Earlier production and increasing bit life
5. Reducing stimulation requirements
6. Improving formation evaluation

Formation damage is a strong function of particle size distribution in the mud and permeability of a rock. To reduce formation damage caused by drilling and completion fluids, particles used in these fluids must be sized to hold them off from entering formation and must be able to form an effective bridging to that filtrate, solids, or polymer invasion. Many researchers believe that particle invasion is the primary cause of formation damage during drilling.

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[7] Dick, M. A., Heinz, T. .J. and Svoboda, C. F. 2000, Optimizing the Selection of Bridging Particles for Reservoir Drilling Fluids. Paper SPE 58793 presented at the 2000 SPE International Symposium, Louisiana, 23–24 February.

Siddiqi, et al[8] introduced an optimized drilling fluid for a well in Haradh field, Arab-D carbonate reservoir in Saudi Arabia. The drilling fluids used for drilling wells in previous increments had caused great formation damage and extensive losses were experienced due to bad selection of drilling fluids. The main concerns in the study of the new drilling fluid formulation were optimization of particle size distribution, compatible with the porosity and permeability factors of Haradh field, to minimize formation damage, fluid loss control and damage removal, and maintenance of drilling fluid characteristics during drilling process. It was concluded that an optimum ratio of fine to medium calcium carbonate is 36:65 (8:15 ppb fine: medium) in 23 ppb (part per billion) bridging material loading. The results of this research are summarized in Table 1 and 2.

Furthermore, Bell and Davis[9] successfully alleviated lost circulation in a thick limestone reservoir characterized by vuggy and fractured porosity, in Natuna Sea in Indonesia. They added a concentration of 20 ppb Lost Circulation Material (LCM) was added to the system. They stabilized the system using a low molecular weight polymer deflocculant and reduced the high gel strength by addition of lignite-based thinning agent. Also, lime, a soluble form of calcium, and a 600-800 ppm was added to treat out the carbonate contamination, CO_2, pH was maintained at 10.5 to 11, to prevent the mud system to become highly lime-dominated. Also, to avoid stuck pipe problem, diesel oil is added, for which a salt water emulsifier is added to control the lost circulation and improve filter cake quality.

However, Luo, et al[10] developed a new drilling fluid to minimize formation damage in under-balanced drilling even further (by 20% to 40%). This new formula contains an elastic fiber-shaped additive, calcium carbonate particles, polymer and salt, clay, and water. This drilling fluid would plug on the wall instantaneously when over-balance condition appears and reduce fluid invasion into the formation.

2.3. Temperature Stability

As drilling continues to reach greater depths, higher demands are placed on drilling fluids to be stable at higher temperatures. At depths approaching 17,000 ft, the reservoir temperatures go as high as 400 ^{o}F. A water based mud (WBM) would evaporate at these temperatures. This would increase its viscosity, in turn decreasing the rate of penetration and other functions of the drilling fluids. Therefore, for drilling into carbonate reservoirs at depths greater than 15,000 ft, the use of an oil based mud (OBM) or non-aqueous fluid (NAF) is recommended. NAFs have been formulated to withstand temperatures up to 450 ^{o}F in practice and have the advantage of being the most tolerant fluids under these

[8] Siddiqui, M.A., et al. 2006. Drill-in Fluids for Multi-Lateral MRC Wells in Carbonate Reservoir-PSD Optimization and Best Practices Lead to High Productivity: A Case Study. Paper SPE 101169 presented at the 2006 SPE Asia Pacific Oil & Gas Conference and Exhibition, Australia, 11–13 September.

[9] Bell, R.J., and Davis, J.M. 1987. Lost Circulation Challenges: Drilling Thick Carbonate Gas Reservoir, Natuna D-Alpha Block. Paper SPE 16157 presented at the 1987 SPE/IADC Drilling Conference, New Orleans, 15–18 March.

[10] Luo, S., Li, Y., Meng, Y., and Zhang, L. 2000. A New Drilling Fluid for Formation Damage Control Used in Unbalanced Drilling. Paper SPE 59261 presented at the 2000 SPE/IADC Drilling Conference, Louisiana, 23–25 February.

conditions. High performance water based muds (HPWBM) used today do not have this temperature tolerance.

2.4. Gas Hydrate Suppression

Drilling in deep water poses another potential problem relating to preventing the formation of gas hydrate. Synthetic based muds (SBM) are well suited for preventing the formation of gas hydrates. Once the gas goes into solution, there is effectively no gas migration in synthetic muds. If a water based mud is used, free gas is found to collect at the BOP stack causing problems. This is not the case in synthetic muds as the free gas will go into solution. Hydrate suppression in SBMs are easily achieved by adding calcium chloride at a concentration of 20 % by weight. Additional hydrate suppression can also be achieved by adding a glycol specifically designed for gas hydrate suppression.

2.5. Shale Sloughing

Shales make up over 75% of drilled formations and cause over 90 % of wellbore stability problems. Shale instability in a borehole may be caused due to one or more of the following problems:

1. overburden pressure
2. compaction degree at the formation
3. pore pressure in shale exceeding the hydrostatic pressure
4. rate at which clays absorb water
5. tectonic forces and
6. presence of microfractures along cleavage planes on the clay platelets

The pressure of the overlying sediments has dehydrated subsurface shales. During the drilling of a well, the lateral pressure is relieved and the formation imbibes water from the drilling fluid. This change can result in very high swelling pressures which destabilize the borehole. Thus, the stability of the borehole depends a lot on the interaction between the drilling fluid and exposed shales. Improper selection of drilling fluid can restrict the productivity, on contact with the shale in the reservoir. Shales with high quantities of bentonite can absorb water, soften, and integrate with the drilling fluid increasing its viscosity. This can severely affect the drilling operations. Carbonate reservoirs in the Middle East have thin laminated shale beds intermittent with the reservoir beds.

Davidson et al[11] indicated that the laboratory experiments showed that the use of calcium ions improved on the shale stability. Field experience on most wells showed that the use of potassium ions gave good indications of shale stabilization for approximately 48-72 hours. After this time, the shales started to swell and especially the ones in which caustic potash were used instead of caustic soda A 50/50 mixture of both salts produced better results. Both the mud and filtrate were maintained as low and close as possible.

[11] L. Davidson, Davidson. E, Richardson. L and Zoller. S. 2000., Control of Lost Circulation in Fractured Limestone Reservoirs. Paper SPE 62734, the 2000 IADC/SPE Asian Pacific Drilling Technology, Kuala Lumpur, Malaysia, 11–13 September.

The use of biopolymer alone is recommended for drilling through sloughing shale formations. This is due to the loss of fluid to the formation in form of polymer solution. This causes an increase in the osmotic pressure, thus weakening the shale bonds which may lead to shale swelling and heaving. It is recommended to prepare a drilling fluid composed of 70-80 % of biopolymer, and with the same salinity as the formation, or using $CaCl_2$ or KCI and then adding 20 to 30 % of (partially hydrolyzed high molecular polymers) when the pH is approximately equal to 8.0. This will result to a stable hole condition while drilling through sloughing formation. The presence of $CaCl_2$ or KCI helps to eliminate the differential osmotic pressure.

When drilling through shales that contain formation water, it is safer and more trouble free to maintain the same level of salinity and total dissolved solids in both formation water and mud system. Drilling mud with similar ions as those in shale formation should be used when drilling through troublesome shale formation. If step dip exists, the pore pressure must be exceeded, and plug back cementing job under pressure is preferable when drilling through step dip gumbo-plastic shales.

2.5.1. Surface Mud

It is usually straightforward that surface mud composes of fresh water, bentonite, and slaked lime. The slaked lime is added on the hydrated bentonite to increase the true yield value. Thus, the cuttings currying capacity will increase at low share rates. Additives like starch, non-ionic filter loss, are used when there is a need for filtration control.

2.5.2. Lignosulfonate Mud

It is one of the most important types of drilling fluids in which are used in most purposes. It mainly composed of fresh water or seawater, bentonite, chrome or ferrochrome lingosulfonates, caustic soda, carboxymethyl cellulose (CMC) or stabilized starch, and sometimes preservative. It is very important to consider that noticeable characteristics can be used when high density is required, greater than 14 lbm/gal. In addition, this drilling fluid can be used when there is a chance to face high temperature, high solid tolerance is desired, low filter loss is desired, and resistance to cement contamination is wanted. Moreover, lingosulfonate mud causes a reduction of the permeability since it contributes greatly to the formation damage as reported by Kelly[12].

Effect of Cost: The traditional primary focus for selecting drilling mud additives has been the cost. The person ultimately responsible for selecting products is the operator's purchasing agent. To aid purchasing personnel in selecting drilling mud additives, an in-house product comparison list, listing additives by primary function in addition to a description of the product was developed. Unlike World Oil's list provided by Lyons[13], the proposed list should contain purchasing recommendations. List of products should follow steps below;

[12] Kelly, J.; 1983. Drilling Fluids Selection, Performance, and Quality Control, Journal of. Petroleum Technology, May, pp. 889-898.

[13] Lyons, W. 2009. Working Guide to Drilling Equipment and Operations, Gulf Professional Publishing, USA.

1. Apply field experience for pre-approved list
2. Test and approve selected list
3. Test the feasibility of the list before purchase or
4. Recommended or reject the list.

This list provides the purchasing agent with quick comparisons of various products and a course of action required prior to purchasing products.

3. Case Histories

Application of appropriate screening criteria for mud selection results in many successful applications of drilling fluids. Three case histories of this application are presented below

3.1. Natuna D-Alpha Block, offshore Indonesia

Bell and Davis[14] indicated that the L-Structure in the Natuna D-Alpha Block of the East Natuna Basin is in the Natuna Sea in Indonesian waters, northwest of Kalimantan. It is mainly a large structural stratigraphic hydrocarbon trap. This reservoir has a unique aerial extent and reservoir thickness. The porous reef complex of Terumbu formation has a homogenous gas column of 5200 ft thick with CO_2 content averaging 72 %.

The thick Terumbu reservoir is a fractured limestone. Also, the long gas column in the reservoir presents a pore pressure profile which ranges from abnormally high in the top, down to a fresh water gradient in the bottom. The above factors caused severe loss circulation problems in the reservoir. Loss circulation was seen in all four sections of the Natuna-Terumbu formation. Loss rates as high as 600 barrels per hour were observed. There were several causes for the loss of circulation. Bottomhole temperatures of up to 376 ^oF, coupled with CO_2 contamination caused drilling mud problems. The adverse affects on mud properties were due to the coagulation of mud, which caused increases in the yield point, gel strength and fluid loss. The deterioration of these properties in turn caused an increase in the equivalent circulating density (ECD) and made it more difficult break circulation after trips. Thermal gradation of organic mud additives caused high temperature gellation and CO_2 from the drill gas flocculated the drilling mud. Lost returns resulted in gas influx, causing CO_2 contamination, mud clabbering and finally, stuck pipe.

The problem of high temperature gellation of the mud was controlled by stabilizing the system with a low molecular weight polymer deflocculant. The high gel strengths were reduced by addition of some lignite based thinners and reducing the bentonite in the mud from 20 ppb to 10 ppb.

The effects of carbonate contamination could not be treated with lignosulfonates or other flocculants; removal of the carbonates was necessary. Lime was added to precipitate the carbonate ion as calcium carbonate. Some excess calcium was left to treat out the CO_2. The pH was carefully maintained at 10.5-11.0 to avoid the mud from becoming very alkaline, which is not desirable at high temperatures.

[14] Bell, R. J., and Davis, J. M. 1987. Lost Circulation Challenges: Drilling Thick Carbonate Gas Reservoir, Natuna D-Alpha Block," paper SPE 16157 presented at the 1987 IADC/SPE Drilling Conference, New Orleans, LA, 15-18 March

In the last well, diesel oil (6 to 8 %) was added to the mud to reduce drag and the possibility of stuck pipe. A salt water emulsifier for the diesel was used to control fluid loss and improve the filter cake quality. Batch treatments of the mud with Loss Circulation Material also greatly improved the drilling conditions.

3.2. Paris Field, Iran

Parsi field is located approximately 100 Km South East of Ahwaz and Shanoul field in the south of the Fars province. Parsi field is the one of the largest Iranian oil and gas fields. The initial reservoir pressure was approximately 3800 psi. By the end of 2001, about 1.48 Billion STB had been produced, with a pressure decline of about 800 psi.

Fried at al[15] indicated that stable and stiff foam drilling in this carbonate field gave good results for the following reasons:

1. Drilling with foam mud gives a higher rate of penetration
2. Stable foam possesses solids carrying capability much higher than that of liquids
3. foam velocity and pressure consideration help to control washing effects and formation water influx

The different parameters of foam drilling depend on field conditions like drill string components, bottom-hole pressure (BHP), hole size and foam properties. Foam drilling in this field was proven to be superior in terms of longer bit life and less wellbore instability.

3.3. 1-H Well, Croatia

Horizontal well (1-H) was drilled in a mature field in Croatia with an extended open hole interval and a high differential pressure. As a result, differential sticking has occurred when drilling the horizontal section. Soric et al[16] showed that this was the first horizontal well to be drilled in that area with application of a drill-in fluid that included specially sized calcium carbonate bridging agent with a blend of viscosifying and filtration control polymers.

To identify the best drill-in fluid composition for the horizontal section, three compositions were evaluated based on fluid-loss control and plugging properties, low-shear rheology (LSR) and formation damage potential.

Stranding and sticking of drilling string during round trips represented an “expected” technological problem during the drilling process. It is quite impossible to drill a horizontal well trajectory without departure from the previously set dip angle, azimuth and vertical depth and correction of them. One of basic reasons for sticking and stranding the string is the higher density of the drilling fluid than designed. The designed density of drill-in fluid (DIF) was 1050 to 1100 kg/m^3, and the horizontal part of the well was finished with a fluid having a density of 1190 g/m3 (the differential pressure was 20.8 bar). After finishing the drilling, a 4 ½ -in. production liner was set in the interval from 1780 to 2305.5 meters.

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[15] Frid, S., Geir, H, Teichrob, R. R, and Behbahani, H. S. 2008. Optimized Foam Drilling Improves Drilling Performance in Iranian Carbonate Fields , SPE paper 114057-MS, SPE Western Regional and Pacific Section AAPG Joint Meeting, 29 March-4 April, Bakersfield, California, USA.

[16] Soric, T, Huelke, R., and Marinescu, P. 2003. Uniquely Engineered Water-Base High Temperature Drill-In-Fluid Increases Production, cuts Costs, in Carbonate Croatia campaign, SPE paper 79839-MS,

4. Conclusions

This study presents frequently occurring drilling problems and used optimal selection of drilling fluid for solving these problems in carbonate reservoirs. The following conclusions are attained;

1. Severe heterogeneity and variation of deposition environment of carbonate reservoirs have special drilling fluid requirements.
2. Application of biopolymer alone is recommended for drilling through sloughing shale formations.
3. For drilling into carbonate reservoirs at depths greater than 15,000 ft, the use of oil based mud (OBM) or non-aqueous fluid (NAF) is recommended.
4. Lingosulfonate muds are not suitable to stabilize shales and cause a reduction in permeability.
5. The problem of high temperature gellation of the mud can be controlled by stabilizing the system with a low molecular weight polymer deflocculant
6. Stable and stiff foam drilling in carbonate fields was evaluated to provide good results.
7. Drill-In Fluid (DIF) must be well-designed for successful horizontal well drilling.

Nomenclatures

BHP	Bottom-Hole Pressure
CMC	Carboxy-Methyl Cellulose
DIF	Drill In Fluid
ECD	Equivalent Circulating Density (ECD)
FT & C	Fluid Type and Contacts
LCM	Lost Circulation Material
IPT	Ideal Packing Theory
LSR	Low-Shear Rheology
NAF	Non-Aqueous Fluid
OBM	Oil-Based Mud
SBM	Synthetic-Based Mud
WBM	Water-Base Mud

Table 1—Recommended formulation of optimized DIF

Ingredients	Quantity (per bbl)	
Fresh Water	0.96 bbl	0.94 bbl
Defoamer	0.01 gal	
XC-Polymer	0.5-1.0 lb	
Drispac	0.25-0.5 lb	
Starch	4.0-6.0 lb	
Lime	0.15-0.25 lb	
NaCl	15 lb	42 lb
$CaCO_3$ (fine)	8.0 lb	8.0 lb
$CaCO_3$ (medium)	15.0 lb	15.0 lb

Table 2—Properties of optimized DIF

Properties	Value	
Density (lb/ft^3)	66	70
Plastic Viscosity (cp)	14	18
Yield Point ($lb/100\ ft^2$)	20	25
100 sec. gel (lb/ft^2)	4	6
10 min. gel (lb/ft^2)	8	12
Filtrate (API)	5-6 ml/30 min	5-6 ml/30 min
pH	9-10	9-10
Cl^-	12,000-75,000 mg/I	