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Accessing Deep Reservoirs by Drilling Severely Depleted Formations

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Abstract

In many maturing prospect around the world, operators are facing the challenge of having to drill through highly pressure-depleted formations in order to access lower-lying hydrocarbon-bearing zones. New technologies such as expandable casing are now becoming available to allow for extensions to conventional well designs in order to deal with depletion. However, before one can case off depleted formations, one first has to successfully drill them.

This paper highlights key aspects in the planning and execution of the Ursa A-11 well, which was drilled through a 5500 psi depleted sand to a deeper horizon. Drilling complications included risks of excessive mud loss, internal blowout and differential sticking on the depleted sand. Moreover, fracturing of the depleted sand carried the risk of jeopardizing production at a nearby horizontal well. Key factors in the successful drilling of the Ursa A-11 well included special drilling fluid design, rock mechanics study, pro-active use of borehole strengthening technology, integration of supplier and operator expertise, and excellent communication between all parties involved.

Introduction

Producing a prospect's reservoirs "from the bottom up" may not always be feasible. Development economics often dictate that higher-reserves or better-quality reservoirs must be produced first before deeper-lying horizons can be accessed. In many maturing prospects operators are challenged to drill through zones that are severely depleted from past or ongoing production in order to unlock these deeper reservoirs. This situation applies to the deepwater prospect Ursa in the Gulf of Mexico (GOM).

The main reservoir at Ursa is the Yellow sand, which is currently being depleted by three high-rate producing wells. Pore-pressures in the Yellow sand have typically dropped by 5000 – 6000 psi since production commenced in 1998. Production has not only reduced the pore-pressure but has also lowered the minimum horizontal stress in the Yellow sand (see **Fig. 1**). Such conditions greatly complicate accessing the Sub-Yellow reservoir, an untapped hydrocarbon-bearing zone at virgin pressure situated just below the Yellow sand.

Significant challenges surfaced while planning the Ursa A-11 Sub-Yellow producer, for which the casing program is given in **Fig. 2**:

1. The high GOM cost environment dictated the need for a high rate completion from a small Ursa template slot. Marginal economics on the Sub Yellow sand precluded any other development concepts (e.g. separate subsea well, use of a large Ursa slot etc.).
2. Drilling risks included the possibility of an underground blowout from virgin-pressured sands above and below the Yellow sand (i.e. pore-pressures of adjacent sands are higher than the reduced fracture gradient / minimum horizontal stress in the depleted Yellow sand, see **Fig. 1**). Also, there was a high risk of differential sticking and associated loss of hole while drilling the Yellow sand at high overbalance (5500 psi).
3. The optimum bottom-hole location for the Ursa A-11 well placed it in very close proximity (~ 400 ft) to the high-rate Yellow horizontal producer Ursa A-6 (see **Fig. 3** for a subsurface projection of the A-11 and A-6 wells). This introduced the significant risk of fracturing the A-11 well at the depth of the Yellow formation into the direction of the A-6 well. Propagation of drilling mud from A-11 to A-6 could result in impairment of the A-6 completion and thus compromise further production from A-6. To gain a proper perspective of the proximity of the A-11 and A-6 wells, it was estimated that hydrocarbons would be flowing by the A-11 well at an amazing rate of 2 ft/day due to ongoing production at the A-6 well.

URSA A-11 Well Planning

Significant effort went into the planning of the Ursa A-11 well to address the challenges associated with developing the Sub-Yellow sand. Planning was tackled by an integrated project team that included the Ursa prospect development team, drilling engineers and drilling fluids & cement team, R&D experts, and resources from various suppliers. Specific planning elements are discussed in detail below.

Drilling Fluid Selection

Although synthetic-based muds (SBMs) offer superior fluid loss control on depleted zones compared to water-based mud (WBMs), the fracturing risk associated with using SBM was deemed too high for the Ursa A-11 well. As explained in more detail below, SBMs inherently yield lower fracture propagation pressures than WBMs. A suitable 12.5- 12.8 ppg WBM system was therefore developed in accordance with the following requirements (see also **Table 1**):

- Excellent fluid loss control, to mitigate seepage losses and differential sticking risk in the depleted Yellow sand;
- Low rheology and gels, using a dispersed mud formulation to minimize ECD's and surge pressures that could lead to induced fracturing;
- Borehole stability in shales, tackled by the use of shale inhibition additives for chemical stability[1]. Mud weight for mechanical stability, however, was sub-optimum in an attempt to reduce over-balance on the Yellow sand;
- Bit-balling prevention / ROP enhancement, using an ROP enhancing additive[2,3];
- Elevated fracture propagating pressures, exploiting the fracture sealing & healing capabilities offered by WBM systems (see below).

WBM characteristics are given in **Table 2**. Note that WBM systems are usually abandoned when overbalance starts to exceed 2000 psi as risks for excessive fluid loss, filter cake build-up and differential sticking go up exponentially above this point. The bridging capability of the mud was optimized by analyzing the pore-size distribution of the Yellow sand, which was obtained from mercury capillary injection pressure curves (see **Fig. 4**). A 1/3 – 1/7 rule was then used to optimize the particle size distribution in the mud for optimum pore plugging. The result of this exercise can be observed in **Fig. 5**, showing the result of a high temperature / high pressure (HTHP) fluid loss test using a pore-plugging apparatus. Excellent fluid loss control was obtained using a 3μ aloxite disk as the filter medium that best represented porosity and permeability of the Yellow sand.

As a contingency, spotting fluids were evaluated using full-scale differential pressure sticking and lubricity (DPS/L) test equipment[4]. A typical test result of this evaluation is shown in **Fig. 6**. The results were used to select the spotting fluid that was best equipped to deliver pipe release in the WBM system used.

Shale inhibition was achieved by incorporation of low levels of potassium ions (K^+) in the mud. Although the concentration of potassium was limited for reasons of aquatic toxicity, lab testing showed that potassium can be an effective inhibitor even at levels as low as 7,500 – 10,000 ppm (see **Fig. 7**). These levels will still give yield low aquatic toxicity values (i.e. Mysid LC50 > 150,000 ppm). An ROP enhancer was used to minimize the inherent bit-balling tendencies of dispersed WBM systems. This additive works by oil-wetting of the bit and BHA components as well as cuttings (thus minimizing sticking tendencies), and by breaking the large, ribbon-like strands of PDC cuttings apart into smaller pieces that are more easily evacuated from the bit-face[2,3].

Rock Mechanical Analysis

Two types of rock mechanical analyses were carried out: (1) an experimental study into the fracturing characteristics of different mud systems; (2) a theoretical rock fracturing analysis to estimate the possible outcomes of fracture propagation from the A-11 well towards the A-6 well.

A specially designed fracturing apparatus (see **Fig. 8**) was used to test cylindrical cores (either sandstone or shale) confined in a Hassler-type cell. These cores were exposed to drilling fluid of which the pressure was progressively increased. Initial fracture opening and re-opening cycles were applied to characterize the fracture sealing and healing ability of the mud formulations. **Fig. 10** shows a typical result for a SBM. While ramping up mud pressure during a fracture re-opening cycle, pressure communication from the mud to the outside of the sample through the fracture was observed for mud pressures below the sample confining pressure. As soon as mud pressure and confining pressure became equal they increased in parallel, indicating full communication of the mud to the outside of the sample. By comparison, in WBM (**Fig. 11**) no communication across the fracture was seen for mud pressures below the sample's confining pressure. Moreover, it was observed that mud pressure may exceed the confining pressure by a considerable amount (i.e. several hundred psi) before pressure communication (indicating fracture re-opening) was observed.

The difference in fracture (re-)opening behavior between WBM and SBM/OBM was highlighted many years ago during the DEA13 investigation[5-7]. It is attributed to a difference in fluid loss (spurt loss) behavior between WBM and SBM/OBM (see **Fig. 9**). When fractures grow in WBM, spurt loss into the newly created opening will quickly leave a dehydrated mud cake which (pressure-)isolates the tip of the fracture from the full hydraulic force of the mud. Propagating the fracture first requires breaking through this filter cake. The additional force/pressure required to achieve this effectively yields a higher fracture re-opening and propagation pressure. By comparison, very little spurt loss occurs in most SBM/OBM systems upon fracture growth. Moreover, these muds primarily bridge formations with internal emulsion blocks rather than external filter cakes. As a result, the tip of a fracture created in SBM/OBM will be exposed to the full hydraulic force of the mud. This results in very smooth and low-resistance fracture re-opening and propagation.

The experimental study clearly showed the benefits of using a WBM system to minimize the fracturing risks associated with the Ursa A-11 well. Although there would be no benefit from an initial fracture opening standpoint (fracture opening pressures are similar for WBM and SBM/OBM), WBM would yield a higher propagation pressure, i.e. effectively a higher fracture gradient.

Proprietary fracturing software was used to quantify the fracture dimensions and volume of mud lost for different loss scenario's. The results are compiled in **Table 3**. Based on this information, the fracture dimensions and volume of mud lost was determined at which the loss in hydrostatic head (due to a falling fluid level in the annulus) would cause the fracture to arrest. This yielded guidance on the placement of the A-11 well relative to the A-6 well to permit acceptable volume loss prior to fracturing into the A6 well bore.

Wellbore Strengthening

Wellbore strengthening[8,9] is a chemical treatment (see **Fig. 12**) to alter the material properties of formations (including sandstones, carbonates, fractured shales and other formations, faults etc.). Compressive and tensile strength, Young's modulus, Poisson's ratio and fracture toughness of the treated area are generally improved over base formation properties. Moreover, formation permeability may be strongly reduced. Wellbore strengthening can be used to line wellbores, consolidate weak zones and seal off unwanted flow zones. Caution should be taken when using wellbore strengthening techniques on objective zones, as production may be highly impaired as a result of treatment.

A wellbore strengthening treatment, based on monomer / resin technology was designed for the depleted Yellow sand to:

1. destroy all permeability and therefore eliminate the risks of seepage loss and differential sticking;
2. strengthen the near-wellbore zone (i.e. increasing tensile strength) to increase fracture initiation pressure, thus minimizing the risk of fracturing and propagating a fracture in the direction of the A-6 well (note that the low-stress environment surrounding the A-6 well would preferentially direct a fracture towards A-6).

The monomer system used was designed to polymerize after placement in the formation (see **Fig. 13**) to yield a rock-plastic ("geo-synthetic") material. This was achieved by mixing the monomers in a batch of drilling fluid with no fluid loss control, weighting this batch back up to the density of the mud, and spotting this batch across the previously drilled formation. The lack of fluid loss control together with the high overbalance on the depleted formation ensured that the monomer material invaded through the deposited filter cake and penetrated into the formation by a considerable radial distance (estimated at 1-2 ft).

Polymerization of the monomers is activated by formation temperature and occurs over time. Pumping / set time and ultimate strength of the rock-plastic material are all factors that can be controlled by selecting the right type of monomer / resin material (and any other required materials, such as chemical activators / initiators) and by varying their concentration.

The cured monomer was designed to yield enough integrity for permeability plugging and near-wellbore strengthening, but with insufficient strength to cause sidetracking of the well (preferably, compressive strength of cured monomer / resin material is limited to several hundred psi). Drillability of the cured monomer material was confirmed in a large-scale drilling test conducted in full-scale drilling equipment.

The change in material properties accomplished by chemical borehole strengthening treatment is illustrated in **Fig. 14.** An unconsolidated sand sample is strengthened to create a sheath of improved material properties in the near-wellbore region. After treatment, compressive strength of the sample was increased 5-6 fold. Permeability of the formation was decreased from approximately 500 mD to being virtually impermeable (i.e. no flow of N_2 gas at 1500 psi differential pressure). The treatment was performed through a mud filter cake which had a permeability of 2 mD.

Ursa A-11 Drilling & Casing Strategy

The drilling & casing strategy was tailored to meet the extra-ordinary challenges posed by the A-11 well. Key elements of this strategy were:

1. Designing the well to be dropped back to vertical through the Yellow Sand to reduce wall contact loads;
2. To drill an oversize borehole to reduce the drill string / casing contact area;
3. Limiting the maximum mud weight to below estimated fracture propagation pressure;
4. Controlling ECD and surge pressure with the help of pressure-while-drilling (PWD) technology to below the estimated fracture gradient (fracture initiation pressure);
5. Simulating connections across the Yellow sand (i.e. typically leaving the string static for 1 minute to test for sticking tendency before any real connections are made) and limiting the time and instances that the drill string is motionless across the Yellow sand;
6. An aggressive casing centralization program to reduce the potential of the liner body to contact the borehole wall;
7. A comprehensive communication plan that tied together all parties involved. Workshops were held prior to - and during - well execution with rig crews to communicate the results of the well planning study and the specifics of the drilling strategy. Feedback from these workshops was used to further develop the tactical drilling plan to meet the various operational challenges;
8. Special attention was given to the HSE aspects of the unique systems and measures employed during drilling of the A-11 well. For instance, special job safety assessments (JSA's) were written and communicated for the monomer system, which contained hazardous materials. All rig crew members were informed of the contingency plans that were developed in case severe lost circulation or stuck pipe was to occur in the Yellow sand. A critical safety measure employed was shutting in the A-6 well, with concomitant loss of production, prior to entering the Yellow sand while drilling and running casing.

Ursa A-11 Well Execution

High- and lowlights of the A-11 well execution were:

1. The first pass at drilling the 9 5/8" hole with WBM failed primarily due to slow ROP in the 5000 ft shale section overlying the Yellow sand. Extended open hole time (lengthened by hardware failures of two underreamer systems, two rotary steerable assemblies and two MWD combo tools) in combination with the low mud weight required to drill the Yellow sand led to insurmountable borehole instability problems prior to penetrating the Yellow sand. The hole section was plugged back and quickly re-drilled with SBM to within 100 ft of the Yellow sand, where a 7 5/8" protective / production liner was run. SBM was thereafter displaced for WBM to drill the Yellow and Sub-Yellow sands.

2. The A-6 horizontal producer was shut in prior to drilling the Yellow sand, and again while running and cementing the 5.5" production liner as a safety precaution and as an attempt to minimize the risk of damage to A-6 in case fracturing occurred in the A-11 well. The A-6 well was brought back on production without problems.

3. The Yellow sand was drilled without problems with the specially designed WBM. No differential sticking tendency was noted. A small seepage loss of 4 bbl upon initial penetration of the Yellow sand was noted but quickly ceased and no further mud losses were observed from then on.

4. Monomer, mixed in a batch of WBM without any fluid loss control (for maximum penetration through the deposited filter cake and into the Yellow sand) was spotted across the Yellow sand and left to cure for a period of 8 hours. Presence of cured monomer material was noted in the mud returns upon clean-out.

5. Drilling the Sub-Yellow zone was uneventful. Slight upward drag was noted in the Sub-Yellow prior to pullout of the drillstring, but no drag or sticking tendency was noted in the Yellow sand. This is considered indirect evidence that the monomer treatment was successful in plugging up and strengthening the Yellow sand.

6. The 5.5" production liner was run to bottom without problems and cemented with full returns.

7. The A-11 well was brought successfully on-stream and is currently producing from the Sub-Yellow reservoir.

Main Conclusions

- ✓ An integrated approach, employing engineering & field staff, supplier resources and R&D expert support, was successfully employed to deliver the highly challenging Ursa A-11 well.
- ✓ The drilling of highly depleted zones can be successfully accomplished by properly understanding the drilling risk and challenges, and addressing each challenge with integrated, multi-tiered solutions.
- ✓ Increasing drilling crew awareness and soliciting their participation in preparing the tactical operational plan is crucial to safe operation and ultimate success.
- ✓ The combination of lost circulation control measures and new monomer / resin technology for plugging and strengthening of near-wellbore zones is seen as enabling technology for drilling through depletion in mature prospects with deeper hydrocarbon-bearing horizons.

Acknowledgements

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Table 1 — Mud System Characteristics

Required Characteristic	Reason for Requirement	Fluid Solution
Excellent fluid loss characteristics	To mitigate the risk of differential sticking across the depleted Yellow sand, with overbalance as high as 5500 psi	Use of a dispersed mud system with special fluid loss additives and optimized particle-size distribution
Elevated fracture propagation pressure	To mitigate the risk of fracturing in – or near – the depleted Yellow sand, possibly intersecting the Ursa A-6 horizontal producer	Use of dispersed mud system with fracture healing/sealing capability as verified by fracturing tests
Good shale stabilization, ability to keep bit free from balling	To manage borehole stability in the 6000 ft interval to be drilled consisting primarily of shale, and to prevent low ROP from bit-balling	Use of elevated levels of Potassium ions (K^+ ~7,500 – 10,000 ppm), use of an ROP enhancer
Good rheology at 12-13 ppg density	To minimize ECD's and the risk of induced fracturing & mud losses	Use of dispersed mud system with low YP, low & non-progressive gels

Table 2 — Mud System Base Formulation & Properties

Mud Formulation		**Mud Properties, AHR 16 hr @ 180°F**		
Additive	***Concentration***		***120°F***	***150°F***
Water	0.76 bbl	600 rpm	74	60
Bentonite	6 ppb	300 rpm	46	37
KOH	1.5 ppb	200 rpm	34	28
NaCl	6 ppb	100 rpm	22	18
KCl	2.5 ppb	6 / 3 rpm	4 / 3	3 / 2
Lignite	5 ppb	PV (cP)	28	23
Potassium Lignite, Lignosulphonate	5 ppb	YP (lbs/100 ft^2)	18	14
Ultra-low PAC	1.75 ppb	10", 10' Gels (lbs/100 ft^2)	13 / 16	13 / 15
Sulphonated asphalt	7.5 ppb	API (ml/30 min, RT)	3.3	
XC-polymer	0.35 ppb	HPHT (ml/24hr, 3μ aloxite, 500 psi, 180°F)	52.8	
ROP enhancer	1.25 gal (3%)	HPHT Cake Thickness	7/32"	
Barite	215 ppb	HPHT (ml/6 hr, 3 μ aloxite, 2800 psi, 180°F)	4.0 (see **Fig. 5**)	

Table 3 — Fracture Modeling Results

Lost Circulation Case	**Loss Rate (bbl/min)**	**Over Pressure (psi)**	**Leakoff Coef. (ft/ √min)**	**Volume Lost (bbl) For Created Fracture Length:**		
				100 ft	**500 ft**	**1000 ft**
Massive losses, no returns	24	500	0.001	156	1257	3161
No returns with higher overpressure	24	1000	0.001	284	2084	4827
No returns with low leak-off	24	500	0.0001	125	836	1819
No returns with 80 ft fracture height	24	500	0.001	77	602	1550
Partial losses (50% losses)	12	500	0.001	171	1498	4000
Seepage losses (~5% losses)	1	500	0.0001	135	948	2122
Low Seepage losses (~0.5% losses)	0.1	500	0.0001	175	1541	4130

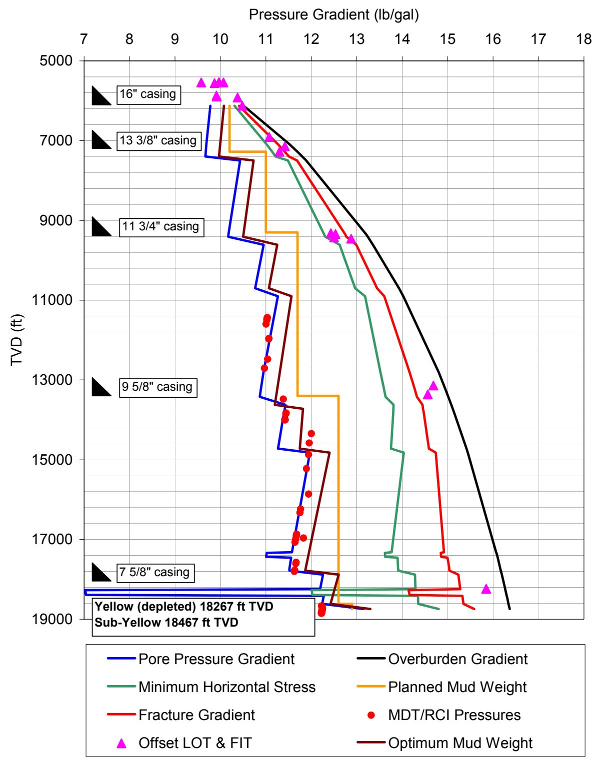

Figure 1 — Ursa A-11 Pore pressure / fracture gradient plot. Note the depletion in the Yellow sand (12.3 ppg / 12,000 psi original pressure depleted to ~7 ppg / 6700 psi at the time Ursa A-11 was drilled) and the concomitant reduction in minimum horizontal stress and fracture gradient.

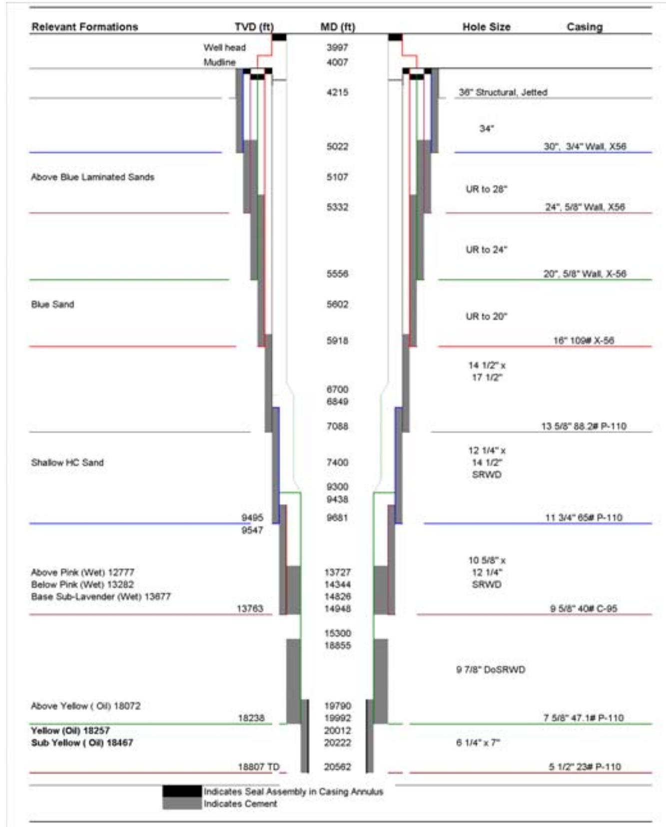

Figure 2 — Ursa A-11 casing program. Note that the 7 5/8" liner set on top of the depleted Yellow sand was not part of the original casing design. It was run as a contingency liner after hole problems in drilling the overlying shale section with WBM required a re-drill of this section with SBM.

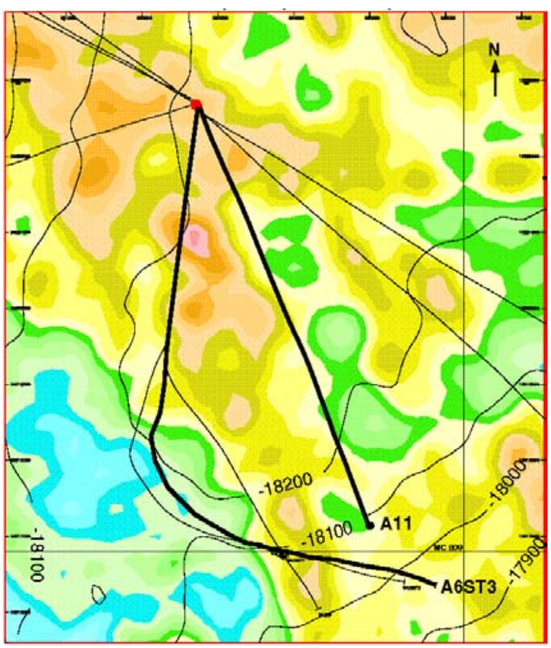

Figure 3 — Geological surface plot of the Yellow sand with projections of the paths of the Ursa A-11 well and the Ursa A-6 horizontal producer. At closest proximity, the distance between the two wells is only 400 ft.

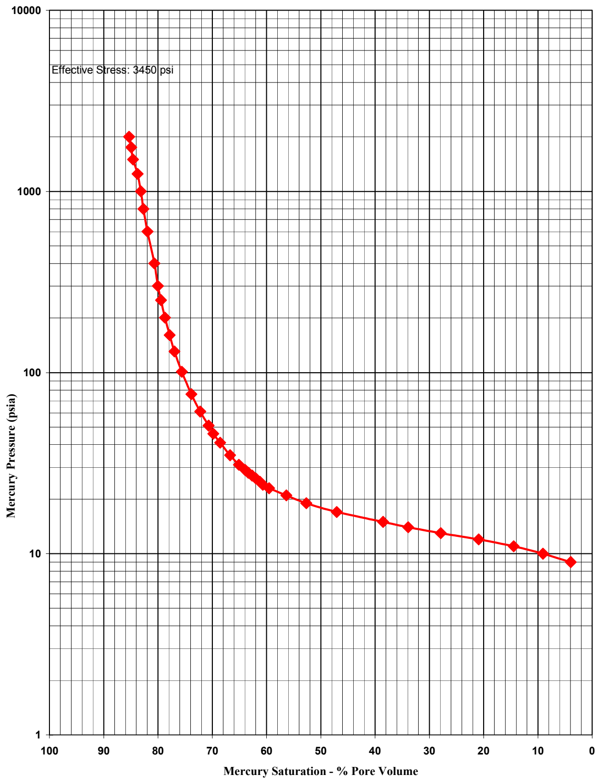

Figure 4 — Example of a mercury injection curve used to characterize porosity and pore size distribution of the Yellow sand, and to optimize the particle size distribution of the drilling fluid for optimum pore plugging.

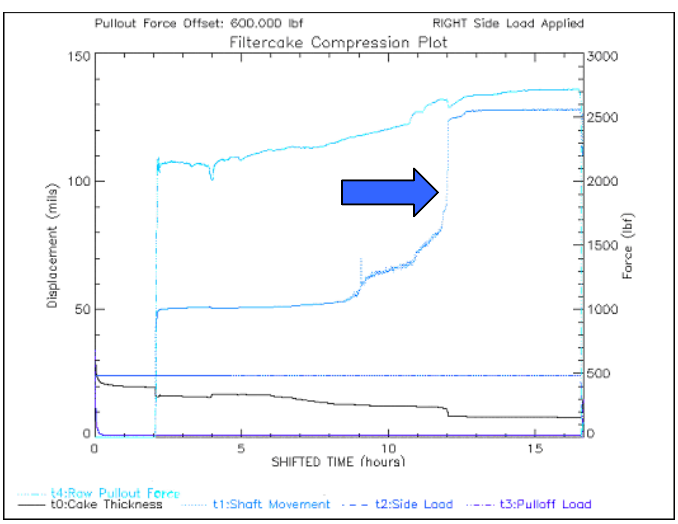

Figure 6 — Example of spotting fluid evaluation in full-scale DPS/L test equipment (see ref. 4). Release of differentially stuck pipe is indicated by movement of the pipe shaft (see arrow) after 10 hours of filter cake exposure to the spotting fluid.

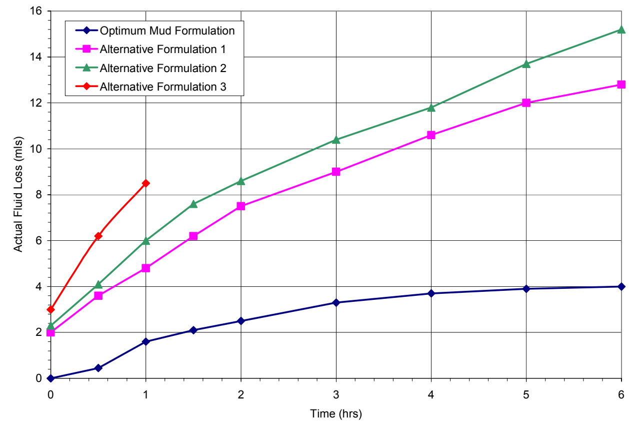

Figure 5 — Results of HTHP fluid loss tests conducted at 180°F with 2800 psi overbalance (maximum achievable under lab conditions) over a 3µ permeable disk in a pore-plugging test apparatus. The porosity and permeability characteristics of the permeable disk were similar to those of the Yellow sand. Note the excellent fluid loss control that was achieved using a mud formulation that was optimized for its pore-plugging ability.

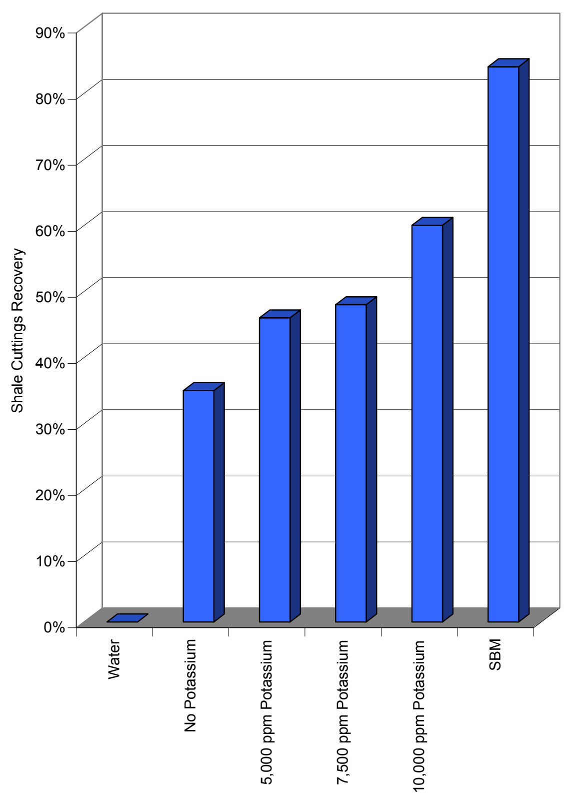

Figure 7 — Results of cuttings disintegration tests, measuring Ursa shale cuttings recovery after 16 hours of hot-rolling at 150°F. Results are shown for mud formulations with varying potassium ion content. Results for water and SBM are included for reference. Note that considerable inhibition can already be achieved at low potassium ion content.

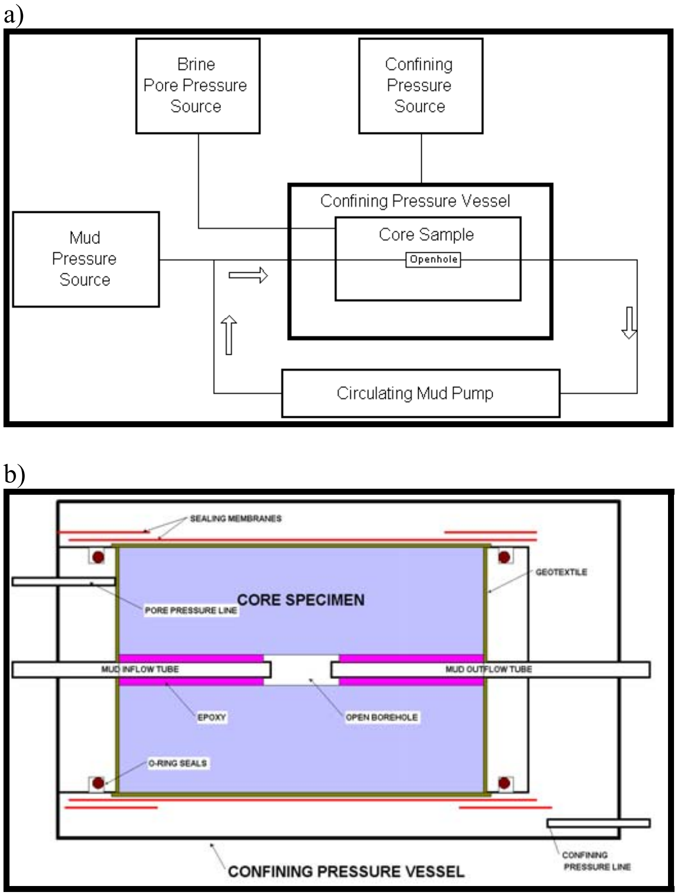

Figure 8 — Schematics of (a) fracturing set-up and (b) core holder used for fracture testing of cylindrical core samples. A packer assembly was glued into the core, exposing a pre-notched section to mud. Mud pressure was ramped up in successive cycles to achieve initial fracture initiation and subsequent fracture re-opening in various mud formulations.

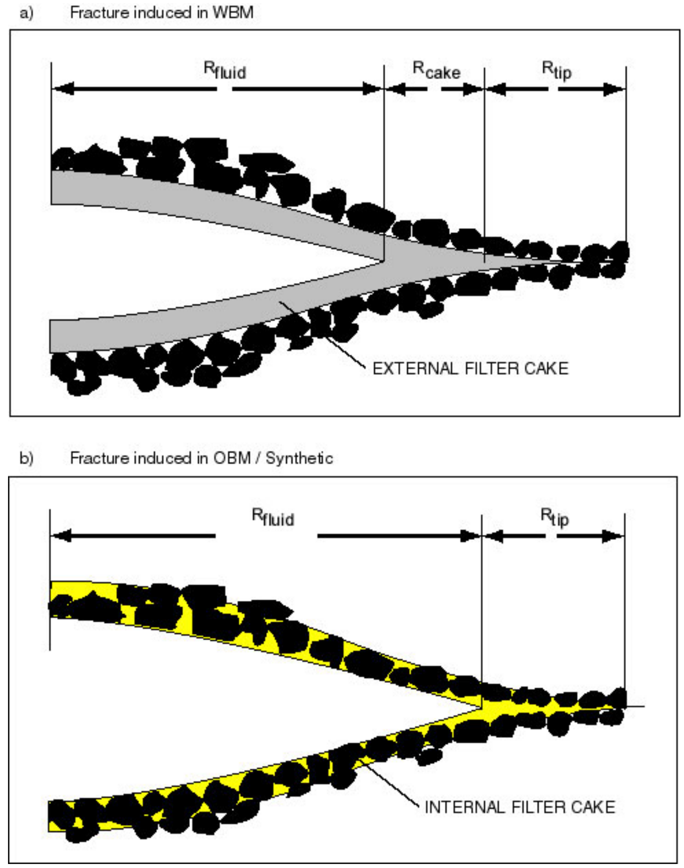

Figure 9 — Difference in fluid loss behavior in growing fractures between (a) WBM and (b) SBM. WBMs deposit external filter cakes during spurt loss in a growing fracture, thus isolating the fracture tip from the mud. SBMs create internal cakes that give rise to fluid-filled fractures, whereby the full hydraulic force of the mud is directly communicated to the fracture tip. This results in fracture re-opening and propagation at a lower pressure than in WBMs.

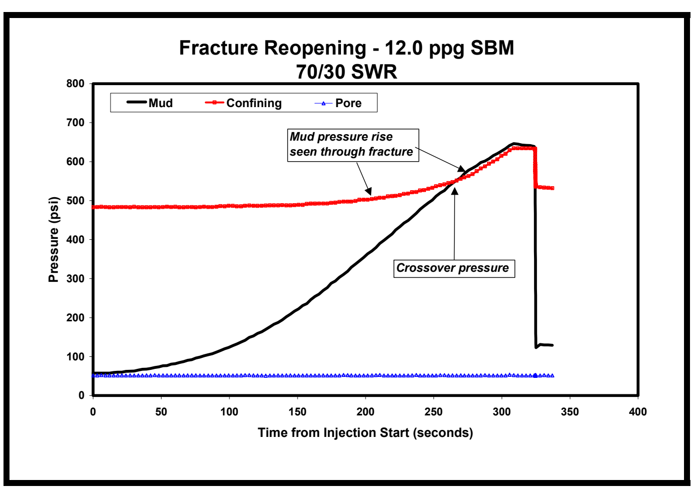

Figure 10 — Result of a fracture re-opening experiment using SBM. When mud pressure is increased on a pre-fractured sand sample, leakage through the fracture is observed as an increase in the confining pressure applied to the sleeve surrounding the sample. Mud pressure and confining pressure increase in parallel after they become equal.

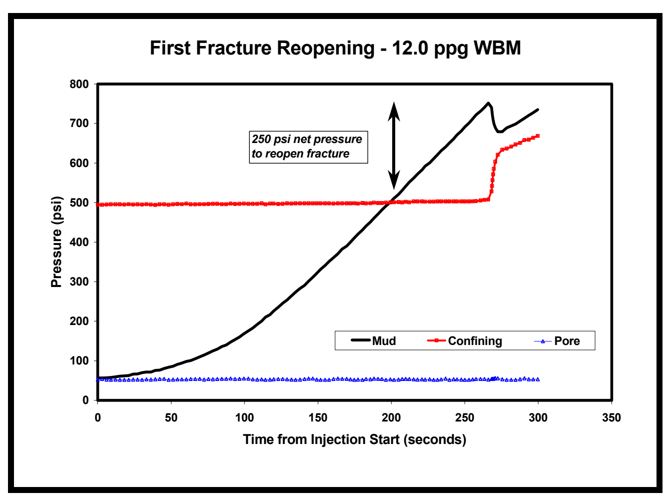

Figure 11 — Result of a fracture re-opening experiment using WBM. When mud pressure is increased on a pre-fractured sand sample, no leakage through the fracture is observed as mud pressure is increased. It appears possible to elevate mud pressure by a considerable amount above confining pressure before fracture re-opening is observed.

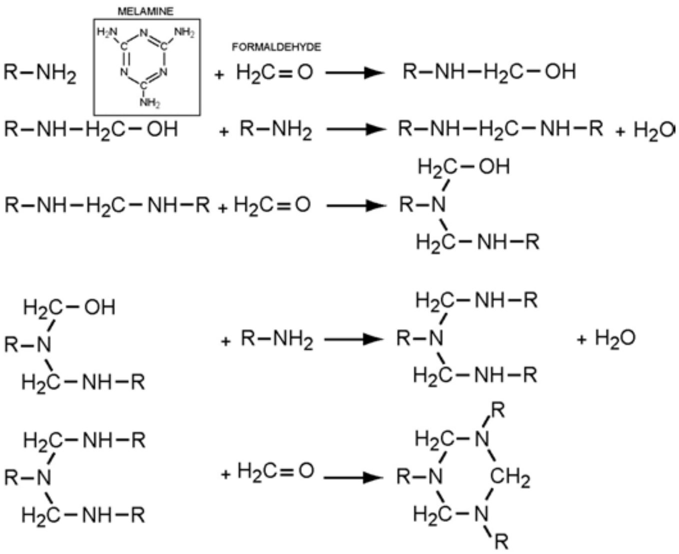

Figure 12 — Example of resin polymerization, in this case the complexation of melamine with formaldehyde. A strong 3-dimentional polymer network is formed. Note that the resin can bond directly with the rock itself through formation hydroxyl (-OH) groups (after ref.10).

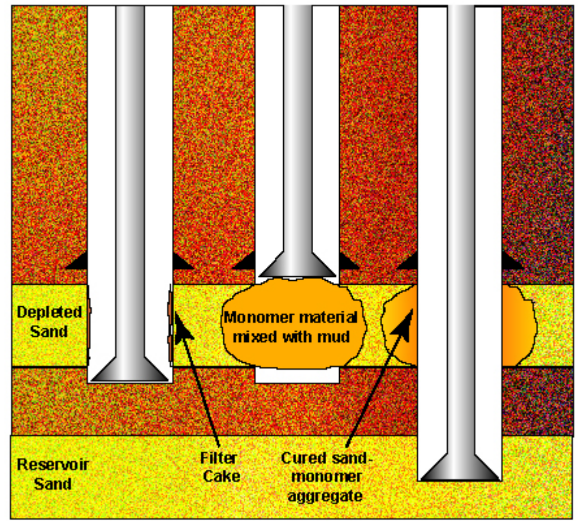

Figure 13 — Schematic representation of wellbore strengthening by monomer application: (left) drilling of depleted sand and optimum sealing by filter cake; (middle) spotting of monomer / mud mixture with penetration into formation; (right) drill-out of cured sand-monomer aggregate and deepening of the well towards the objective(s).

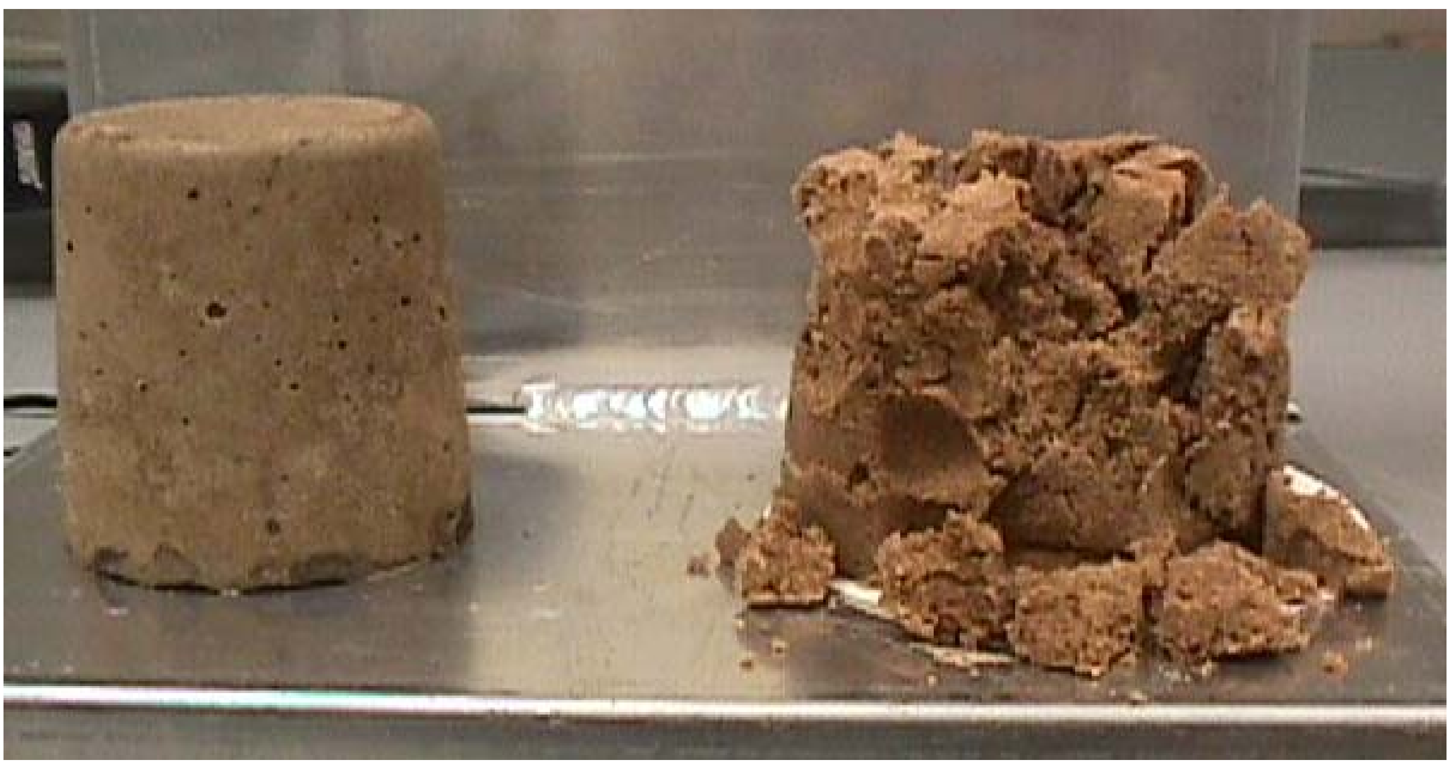

Figure 14 — Example of a loose sandstone core "solidified" using monomer material. The picture on the right shows a 6" sample of 500-600 mD sand before monomer treatment. Its compressive strength was only 20-30 psi and it allowed flow below a differential pressure of 100 psi. The figure on the left shows the same material after treatment, now with an elevated compressive strength of 140- 175 psi and a permeability of 0 mD with no flow through it at a differential pressure of 1500 psi N_2 gas.