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New Generation Drill-In Fluids and Cleanup Methodology Lead to Low-Skin Horizontal Completions

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Abstract

Though frequently prolific, a significant number of horizontal wells have ultimately proven to be engineering failures. Improvements were needed involving the drilling and completion process to increase producing efficiency and completion reliability. New, more capable brine-based drilling fluids have been developed for drilling-in to productive formations. Usually, this well type involves drilling through varying amounts of non-pay sections en route to accessing productive reservoirs. This requires that an optimal drill-in fluid possess the qualities of both a non-damaging completion fluid and a good quality drilling mud.

This, coupled with a new technique for the cleanup of productive intervals has been developed and field-proven. This paper will discuss the approach and methodology employed in a number of successful horizontal wells. Design information and production results on a representative case history are also discussed.

Introduction

Horizontal wells are normally selected for their ability to deliver very high production rates and large reserve volumes. Also, the need for horizontal and open hole completions may be dictated by the presence of water or gas contacts, or by well geometry constraints. In many cases, high deliverability wells of this type are a requirement for projects to be economically attractive.

Efficient cleanup of the productive interval has proven to be the key to optimal performance from this well type[1]. In poorly consolidated reservoirs requiring sand control, achieving this becomes imperative due to the wells' inability to cleanup naturally. Efficient cleanup of long intervals in this completion type has taken considerable study, and is now being regularly accomplished. A number of wells have been successfully drilled and completed using an optimized brine-based drilling fluid, coupled with a new, simultaneous cleanup and gravel pack methodology. These wells are producing unimpaired, at zero skin factors.

Modern brine-based drilling fluid systems are inherently flexible, and can be optimized for a large number of well parameters. Most importantly, they can exhibit inhibitive qualities that mimic those of more conventional drilling fluids designed to drill large amounts of shale. In most cases, a fairly rigorous testing program is required to fully optimize the drill-in fluid and cleanup sequence for a given well.

Background

The majority of horizontal wells have proven successful from an economic standpoint. However, a large number of wells have been disappointments with regard to completion efficiency or longevity. Operator surveys indicate that this well type has exhibited unacceptably high failure rates in the Gulf of Mexico[2,3]. In addition to the failed wells, a second group of wells has shown premature production decline.

To be considered overall successes, wells should do more than just meet initial production rate or economic payout criteria. A fully successful completion should maximize profitability, and thus be capable of producing all available reserves without the need for intervention. Through diligent pooling of experiences and ideas, industry has identified a number of mechanisms suspected of causing the failures and disappointing productivity results[2,3].

A large number of identified failures were considered to be a result of the well screens becoming plugged. This plugging phenomenon, considered the most problematic of all the failure modes, is exacerbated when target reservoirs are dirty or shaley, or when shale is encountered prior to drilling the pay zones. It is important to note that in nearly all cases, the causes are linked to inadequate cleanup of the productive interval. With this evidence, it became apparent that a better methodology was needed.

As horizontal and open hole completions gained popularity, larger and larger quantities of shale began to be encountered while drilling to access pay zones. In some cases, uncertain geology was the cause, in other cases, well trajectories required that shale sections be drilled first. Today, it is not uncommon for gross intervals to contain more shale than pay sand. This requires that shale inhibition be a mandatory design parameter for reservoir drill-in fluids.

Although early generation drill-in systems usually were not optimal from a shale inhibition standpoint, operators were normally able to maintain decent borehole stability with them. As they were principally designed for drilling into productive horizons, usually sandstone, the inhibitive qualities imparted by the base fluid were thought to be adequate for these pay sections. Until a fairly sudden rash of failures occurred in the mid nineties, just how poorly some systems were performing when shale was encountered went largely unchecked. This caused design and cleanup aspects of this completion type to begin receiving closer scrutiny. It became evident that more capable drill-in systems were needed.

Damage Minimization Focus

Unimpaired horizontal completions are attainable with correct fluid design, focus on damage minimization, adequate pre-job planning and good job execution. However, damage minimization in this well type must be viewed entirely differently than in normal cased and perforated applications. In the absence of a perforating step, the effects of drilling-induced damage are not so easily erased. Historically, with this well style the engineer's focus has been to drill the well successfully to TD, position the necessary hardware, then attempt to treat out the drilling-induced damage. This separated the well construction process into distinct drilling and completion phases. Now, after a number of experiences and somewhat of a shift in mindset, it is recognized that the drilling and completion processes cannot be viewed as separate. The two phases must be considered a singular operation where damage *minimization,* rather than damage *removal,* is the major thrust. Newer, more inhibitive drill-in fluids, coupled with the recent advances in cleanup methods are ensuring that any drilling-induced damage can be readily and efficiently reversed. Improvement in these areas is considered the primary reason for a recent string of major successes in the Gulf of Mexico.

The general engineering approach can be condensed to a few basic areas. First, engineers must recognize and pay close attention to certain factors that will have an overriding influence on completion success. Conversely, a number of secondary factors can be identified, but must be recognized as having only a minor impact. Optimization surrounding these major factors is what has separated a number of very successful producers from past disappointments and failures.

Damage Mechanisms

Successful engineering of this well type requires that we first assess the types of damage associated with this style completion. In doing this, we find that it can be separated into two distinct categories. The first category is termed *formation damage*, the second is considered *completion damage*. Each damage type is located in distinctly different areas of the producing system. Their potential to impact production can also differ greatly. **Formation damage** is defined as permeability impairment induced to the reservoir rock itself. **Completion damage**, on the other hand, refers to materials, residue or contaminants contained *within the confines of the borehole* that can hinder well productivity or reliability (**see Fig. 1**). As completion damage is considered the overriding concern, especially in sand control environments, emphasis must be placed on this mechanism. This concept is easily grasped if it accepted that uniform, natural cleanup of drilling-induced damage is unlikely or impossible in these well configurations. Conversely, damage to the rock matrix proper (formation damage), unless extreme, can prove to have substantially less impact on well productivity[4,5].

Minimization of "Completion Damage"

Whereas base fluid and filtrate compatibility with productive zones has not been problematic in most cases, incompatibility with shale sections *has* been a major source of completion damage. Accepting this requires engineers to shift their focus away from conventional thinking, where *reservoir matrix* interaction is considered key, to the less obvious solution involving interaction between fluids and ***non-pay*** sections. This way of thinking becomes plausible when the overall production system is scrutinized.

Shale Inhibition. A major damage mechanism can result from poor inhibition and the corresponding inability to keep the fluid "clean" during the drill-in operation[5]. Without proper inhibition, standard drill-in systems can readily disperse reactive shales, causing the fluids to quickly become contaminated with shale and clayey drill solids. This event causes a dramatic reduction in the solubility and degradability of the deposited filter cake. Filter cakes containing high levels of insoluble drill solids are notoriously difficult to treat, and often cause engineers to resort to overly aggressive chemical cleanup treatments. Usually, this approach proves to be a futile exercise. Survey data shows that in a number of cases, such aggressive treatments did irreparable harm to well hardware, ultimately resulting in completion failure[2].

The residue left in the completion interval from the drill-in operation is all-important, and considered a primary cause of the completion plugging problem that has been prevalent in this well type. Dirty filter cakes, i.e. those that are contaminated with native drill solids, should be considered irreparable completion damage. Normally, this impairment must be endured for the well's entire producing life, as remedial attempts have largely been unsuccessful. It therefore becomes paramount that the engineer's focus be placed on minimizing this damage mechanism from the onset of the project.

Minimization of "Formation Damage"

Matrix Invasion. One means of preventing damage to productive formations is accomplished by minimizing whole fluid invasion. The majority of modern drill-in fluids do a reasonably good job of minimizing matrix invasion when pore geometry is known, as this is a fairly well-founded science. However, to maximize well performance, well planning must involve contingencies to allow a broad range of formation types and permeabilities to be drilled and completed without undue damage from invasion[6]. There have been cases where a ten-fold change in permeability was seen within a single completion interval. While the original fluid was designed to accommodate the lower perm section, adjustment of the bridging particle size distribution was required to efficiently bridge the high permeability interval. Without adequate planning and this onsite manipulation, deep whole fluid invasion likely would have caused productivity impairment.

Filtrate Compatibility. Base fluid or filtrate compatibility with productive formations has not proven to be a major problem. However, assuring that filtrates are not grossly incompatible with the reservoir rock matrix is an important design parameter. Field history can be a valuable tool in ensuring against any gross incompatibility, and in most cases standard commercial base brines will prove sufficiently benign. As mentioned previously, unless this incompatibility is severe, it will normally have a relatively minor influence on final well productivity. However, in cases where the reservoir makeup is not understood and field history is not known, this interaction should be checked. Compatibility with crude oil should also be checked, especially in areas where crudes are known to be problematic, or field history is lacking.

Whole Fluid Losses. Minimizing formation damage during the drilling operation also requires working below formation fracture pressure. Without accurate prediction of equivalent circulating density (ECD), substantial whole mud losses can result. Scrutiny here is especially important during the well planning stage, as this often requires the design of a new, well-specific drilling fluid. Extended reach wells can be especially problematic, as we are often required to work within fairly small pore pressure/frac pressure windows[3]. The impact of not adequately addressing this not only can hinder productivity, but can have a large influence on overall job cost and the ability to reach TD. Sound onsite engineering entails disciplined monitoring of ECD, as well as strategies to adjust fluid properties as lithology and well conditions change. In the subject well, there was good agreement between predicted ECD and that measured by pressure-while-drilling (PWD) equipment (**see Fig. 2**).

Non-Invasive Cleanup

The merits of drilling productive reservoirs with minimally-invasive fluids have already been established. Likewise, it is advantageous to perform the wellbore cleanup in the same manner. Unconventional cleanup methods are now available that allow engineers to concentrate on the most important damage mechanism, that is, damage contained essentially *within the wellbore.* This alternate technique allows engineers to get away from conventional cleanup methodologies where treatments are normally injected and deep-invading. With the conventional techniques, thorough cleanup of the borehole-contained damage was difficult, and presented a separate set of problems surrounding fluid-formation compatibilities.

New, non-invasive techniques involve the use of chemicals that react in a slow, controlled fashion. This feature allows the cleanup treatment to be efficiently placed across the entire completion interval without premature "breakthrough", and a corresponding loss of circulation. In maintaining the ability to circulate, one is able to guarantee that the completion damage throughout the completion interval is treated. As indicated in work done by Browne and Smith[4], this is crucial to maximizing productivity from horizontal wells. Case studies also support this conclusion.

Earlier cleanup techniques usually involved spotting fairly aggressive mineral acid (usu. HCl) in the completion interval. These chemicals normally will not allow prolonged circulation. Usually, such treatments break through the filter cake at a point in the wellbore, and the ability to continue circulation is lost[7]. Incomplete coverage of the zone results, leaving portions of the damage in the wellbore untreated and intact. This premature breakthrough phenomenon presents a secondary problem beyond the two obvious issues surrounding incomplete cleanup and fluid loss control, however. Because of the penetration of the cleanup treatment and the corresponding loss of circulation, these aggressive chemicals can be left standing on downhole hardware for extended periods. Given that the ability to circulate has been lost, there is usually no means for effectively flushing the corrosive materials off of downhole hardware. Not surprisingly, this mechanism is suspected of being a cause of well failure[2]. Simple bull-heading of a benign fluid to flush the chemicals will usually prove futile, as this will only serve to flush the portion of the well accepting fluid. Many times, the chemicals cannot be flushed until production is initiated, and even then, efficient removal may not be achieved.

VK 825 Horizontal Well - Design Issues

Viosca Knoll Block 825 is located in the eastern Gulf of Mexico in approximately 1700' of water. Kerr-McGee Oil and Gas Corporation operates the block and is partnered with Consolidated Natural Gas. Taking advantage of the existing infrastructure required the use of a semi-submersible drilling rig and a subsea well configuration. It was decided that the most economical path for development of the Cib Carst reservoir was with a horizontal well at approximately 8700' TVD. The Cib Carst is a poorly consolidated sandstone of Lower Miocene age, with approximately 120 feet true thickness. The subject well was designed to complement an existing vertical well in the reservoir.

Planning. The objective of the Viosca Knoll 825 #5 well was to transverse the Cib Carst reservoir through two fault blocks, utilizing a single horizontal rather than with two vertical wells. Well #5 was originally planned for a 2350' open hole interval, anticipating as much as a few hundred feet of shale in the vicinity of the fault. A complicating factor in the well was that the possibility existed for two different pressure regimes on either side of the fault. A pore pressure of 11.3 ppg EMW (original reservoir pressure) was expected in one fault block, while the other was potentially connected to the existing producing well, with a partially depleted reservoir pressure of an estimated 8.0 ppg EMW. The horizontal interval would begin in the partially depleted fault block, intersect the fault, then proceed through the virgin pressure reservoir. The well would be kicked off in the 12 1/4 inch hole section, angle built to 86°, and penetrate the top of the Cib Carst. A sodium chloride/polymer mud would be used in this hole section. The 9 5/8" production casing shoe would be set approximately 20' MD (~2' TVD) into the target reservoir. Prior to drilling out the 9 5/8" casing shoe, the polymer mud system would be displaced to the 12.6 ppg drill-in fluid. A horizontal 8 1/2" wellbore would then be used to traverse the target reservoir.

A drilling fluid density of 12.6 ppg was chosen for the horizontal section in order to provide borehole stability in any encountered shale sections. The relatively high mud weight warranted conducting a leakoff test below the casing shoe prior to commencement of drilling. Leakoff tests indicated a breakdown pressure of 13.9 ppg EMW. Expected permeability range was 30-300 md based on data from the offset producing well, and the drilling fluid was designed accordingly. With little probability of future intervention, an open hole gravel pack was selected as the completion style. This completion type has demonstrated the ability to provide maximum production efficiency, while at the same time proving to be very robust.

Drilling Fluid Selection and Design. The brine-based drilling fluid selected for use in the subject well was chosen for a number of critical reasons. First, a highly soluble, low-solids fluid was desired to permit thorough cleanup of the productive interval. Second, the selected fluid had to demonstrate the ability to drill shaley environments exceptionally well, while maintaining good filter cake cleanliness. And lastly, the system had to provide a means for achieving thorough cleanup of the entire producing interval. Also important was the system's ability to successfully accommodate the open hole gravel pack that was the preferred completion style. A number of other parameters influenced the fluid selection process, most of which are discussed in the following.

Generally, reservoir drill-in fluids should be designed and selected based on a fairly comprehensive set of criteria. Depending on the application, these selection criteria may include:

- Density and the ability to adjust as needed
- Thermal limits
- Shale control
- Rheology (hole cleaning and ECD)
- Environmental Compliance
- Crystallization behavior of base fluid
- Formation compatibility (including fluid-fluid interaction)
- Contamination tolerance
- Ability to execute the completion as designed
- Fluid displacement method
- Wellbore cleanup technique and efficiency

The subject Viosca Knoll well presented a complex set of design parameters. However, through a rigorous design process, a final fluid was formulated that met all required properties. Table 1 provides a brief summary of the properties of the fluid selected for this application. While some of the more routine fluid properties are included in this paper, only the design issues considered most crucial to this application are discussed in detail.

Density and Density Adjustment. The fluid density for this project was selected at 12.6 ppg. Fluid density was determined from wellbore stability modeling, as the highest anticipated pore pressure was 11.3 ppg EMW. Additionally, a critical provision for the fluid was that the density could be increased by at least one half pound per gallon as needed, without sacrificing other crucial properties. Of particular focus was the 100,000 ppm LC-50 requirement of the fluid. It is noteworthy that the final fluid formulation was quite different than a similar fluid without this capability.

Rheology. The fluid's rheological profile is critical for several reasons, and can have a large impact on the ability to drill to TD successfully. First, the rheological properties of the drill-in fluid will determine the equivalent circulating density (ECD) of the fluid. Exceeding the limit that the well can withstand will lead to breakdown of the formation, which can lead to wholesale loss of drilling fluid. During the initial design phase, the upper limit of ECD was planned at 14.2 ppg. However, upon conducting the shoe test, a limit of 13.9 ppg was established. Fluid properties had to be set where the ECD limit would not be reached at the circulation rates required by the drilling program. As is customary, this required achieving a delicate balance, where this requirement was met while still accomplishing good hole cleaning.

Crystallization Behavior. The base brine of a drill-in fluid will have a characteristic crystallization temperature (the temperature where salt crystals begin to form). A special consideration for brine based drilling fluids for use in deep water applications is the effect of pressure on the crystallization temperature of the base brine. Work has been done to define the effect of pressure on the crystallization temperature of brines[8], and this property is referred to as the pressure crystallization temperature (PCT). In general, as the pressure increases on a given brine the crystallization temperature increases. In some brines the effect is quite pronounced and if not accounted for, can cause a number of serious operational problems. Thorough design of a brine based drilling fluid for deep water use requires the formulation of the base brine to account for the highest pressure in combination with the lowest temperature the fluid will encounter.

In the current case the brine was designed to have a maximum 30^{o} F crystallization temperature at a pressure of 8000 psi. Pressure effects on the crystallization temperature of the subject fluid's base brine were studied using a low temperature, high pressure crystallator. This apparatus was specifically designed and constructed to determine the pressure crystallization temperature (PCT) of a brine. The crystallator monitors the temperature and pressure on a brine sample as the brine is taken through a cooling cycle. The data from the cooling cycle is computer analyzed and the PCT determined. This property is generally reported, for example, as a PCT of 8/30, which implies a pressure of 8000 psi with a crystallization temperature of 30^{o} F or less. Additionally, an important design feature was that the subject fluid had to maintain the desired PCT rating throughout the weight up schedule.

Environmental Compliance. Toxicity of drilling fluids to marine organisms is an environmental concern to offshore Gulf of Mexico operators. Drill-in fluids are required to pass a definitive bioassay test in order to be used offshore in other than a zero discharge operation. The toxicity test for drilling fluids in the Gulf of Mexico follows the protocol specified in 58CFR63964 and in the NPDES permit for oil and gas activities in the Gulf of Mexico OCS. The results of this testing yields a statistically significant 96 hour static LC_{50} for the test organism, Mysidopsis bahia.

NPDES permits require a minimum passing LC_{50} of 30,000 ppm for overboard discharge of fluid or drill cuttings. However, for the subject well, it was decided that the fluid should have an LC_{50} of 100,000 ppm or higher, while still meeting all other requirements. This, it was felt, would provide the confidence necessary to begin discharge of cuttings from the onset of drilling, thereby saving the cost and trouble associated with a zero discharge operation. Many low-solids brine-based drilling fluids in this density range have either failed this requirement, or passed marginally. However, with proper additives, a specially formulated drill-in fluid such as this can be made to pass handily. Definitive testing of the final formulation resulted in an LC_{50} in excess of 120,000 ppm at the maximum anticipated density.

Shale Control. Except in rare cases, control of reactive shale sections in or around the target formation is a critical feature of a drill-in fluid. Encountered shales must be controlled in two ways. First, the drill-in fluid must stabilize the shale section and provide a stable borehole. Second, the drill-in fluid must be formulated to prevent the breakup or dispersion of the shale cuttings. The first requirement is considered primarily a drilling-related solution, whereas the second ties most closely with filter cake degradability and completion damage, as discussed previously. These two aspects of shale control are paramount requirements in order to successfully drill horizontal sections, then provide suitable wellbores for installation of efficient open hole completions.

The fluid in the subject well was formulated to give maximum shale stability. As impairment mechanisms inside the borehole are of primary concern, focus was placed on inhibiting dispersion of the shale into the drilling fluid. In order to do this, native shale plugs cut from a whole core were utilized for testing. **Figure 3** shows dispersion test results with the native shale for a number of the candidate fluids evaluated. A mixed divalent/monovalent fluid blend was ultimately selected, as it gave the highest degree of inhibition (98.7%). This fluid was also required to meet all of the other properties demanded by the project. The specific calcium bromide / sodium bromide blend was arrived at by subjecting candidate fluids to a fairly complex test matrix, and ensuring that all additives were optimized. Substantial work has been done to ensure that all system components gave the desired effect on fluid properties without any offsetting negatives.

Simultaneous Well Cleanup. Efficient cleanup of the productive interval has proven crucial to maximizing productivity. As the filter cake left behind by the drill-in operation will in large measure determine the ultimate efficiency of the completion, one of the most critical design criteria is the method of wellbore cleanup. One of the main innovative points of this paper is the uniform cleanup of the filter cake upon completion of the well.

A well-engineered cleanup method should provide controlled, uniform disruption of the filter cake along the entire well path. This can be done during the placement of the gravel pack, or after running screens in the case of open hole screen-only completions. In gravel pack completions like the subject well, performing the cleanup operation *simultaneous* with the gravel placement is considered optimal for a multitude of reasons. Some of these are:

- Method takes advantage of the last available circulating path, thus allowing *circulation* of treating fluids into place.
- Circulation around the outside of the completion assembly ensures that the entire wellbore is treated from heel-to-toe.
- Permits easy access to formation face, allowing thorough, intimate contact between damage mechanisms and treating fluid.
- Provides improvement over the lack of placement control inherent to injection-style treatments.
- Use of a non-invasive style treatment allows focus to be placed on the damage contained *within* the wellbore, and minimizes matrix interaction.
- Normally has a large economic advantage, as it requires no incremental rig time to execute.

In order to successfully accomplish a simultaneous cleanup and gravel pack treatment, a disciplined job design process must be undertaken. Treatments must closely coordinate breaker performance with pump schedules and other rig operations. Additionally, breaker performance must be well understood, and must have good predictability.

Laboratory testing for the Viosca Knoll 825 #5 well resulted in a breaker schedule designed to ensure completion of the gravel pack before complete breakdown of the filter cake. A conservative break time of 10 hours was targeted for an estimated pump time of 6 hours. The breaker schedule was coordinated with the gravel pack pumping schedule, and breaker was added to a preflush pad as well as to the gravel slurry in the form of a density-matched liquid concentrate. **Figure 4** shows the breaker performance curves developed during laboratory testing. A breaker loading of 5% v/v was selected to ensure gravel placement prior to complete breakdown of the filter cake.

Job Execution

Drilling. The well was ultimately TD'd at a measured depth of 10,952' after cutting 1577' of 8 1/2" horizontal open hole section. TD was called when no more pay was expected to be encountered. Of the gross interval drilled, approximately 730' had good quality sand, while a surprising 847' was shale and poor quality sand. Most of the interval involved drilling relatively thin sand-shale sequences. Also, a much wider range of permeabilities was encountered than originally anticipated.

The complex lithology and high overbalance conditions resulted in some fluid losses during the drilling operation. This was especially apparent when cutting across the numerous bedding planes encountered. This occurred even though the ECD did not reach the limit established in the shoe test, as verified with PWD measurement (**see Fig. 2**). Normally, a high instantaneous loss rate would be observed, then the losses would subside due to apparent hole healing. In most instances, the formation exhibited ballooning type behavior, where a portion of the fluid was given back upon shutting down circulation. Contingency plans involving reducing pump rate, fluid density or rheological profile were ruled out as not practical. It was thus decided that fluid losses of this type would be manageable.

When encountered, the high permeability sections initially created some difficulty with fluid loss. As the fluid had been designed for a significantly lower permeability regime, adjustments were required on location to handle the higher perm sections. Contingency plans were in place, and these losses were reduced via adjustment to the fluid's particle size distribution.

Overall drilling operations went very smoothly. Actual torque and drag readings were well below those anticipated, an indication of the fluid's extremely good lubricity. Sliding the steerable BHA for directional corrections was performed throughout the horizontal section without difficulty (e.g. stick-slip, wall sticking). No problems were experienced with hole cleaning, and good borehole stability was maintained throughout the drilling and completion operation. The filter cake and borehole maintained its integrity after the open hole was displaced to a solids-free pill and the completion assembly was installed. Screens were run to bottom cleanly with no problems.

The drilling fluid exhibited extremely good inhibitive qualities, as the extensive shale sections posed no problems after prolonged exposure, and dispersion of drill cuttings into the fluid was minimal. **Figure 5** shows the volume of entrained acid-insoluble material measured in the fluid as the well was drilled. At no time during the operation did the level exceed 1.2%. PWD equipment yielded ECDs very close to those predicted (**Fig. 2**), and gave no indication of cuttings bed buildup or hole restriction at any time. Calculation based on gravel volume placed revealed that the wellbore was within 0.1 inch of anticipated hole size. This provided yet another indicator of the fluid's inhibitive qualities, and was consistent with previous experience using synthetic oil based muds. These, coupled with other performance indicators, gave good evidence that the fluid was well suited to the shaley, highly variable formations encountered.

Completion Operations. The well was completed by running 5 1/2" 110 micron screens in the hole and gravel packing with 30/40 mesh gravel. Non-viscous completion brine containing cleanup chemicals was used as the gravel carrier fluid. Prior to pumping the job, circulating rates were established and returns measured. The returns ranged from 100% at 1 BPM, to 65% at a 4 BPM pump rate. The gravel pack was designed and pumped at 4 BPM with a lead pad of neat breaker fluid, followed by the sand-laden brine with breaker. The slurry was mixed at 0.9 ppa. The open hole section was fully and successfully packed, primarily during the alpha wave with a dune height-to-hole ratio of 0.87. The breaker schedule included in the carrier fluid was designed for a break time of 10 hours. After completion of the gravel pack, fluid loss rate was measured at 39 barrels per hour. An isolation valve was then activated, and the next phase of the completion operation begun. Some 8 days later when the isolation valve was ruptured, the fluid loss rate was checked and had increased to 180 barrels per hour.

Production Results. The well was flow tested through portable test equipment on the rig at maximum rates of 7100 BOPD and 6200 MCFD with a total drawdown of 890 psi. Measurement was via permanent down hole pressure gauges. Drawdown and buildup analyses were conducted on the well and yielded similar results. From this, the average reservoir permeability was calculated at 55–115 md. Pressure transient analysis revealed that an extremely efficient well completion had been accomplished. Four separate analyses yielded very favorable skin factors ranging from –2.7 to +0.4. This was considered a major engineering success in what was considered the poorest of geologic conditions. The well was connected into the subsea production system and has been producing at a stabilized production rate of 4500 BOPD since September, 1999.

Conclusions

1. More capable drill-in fluids are resulting in improved, more efficient horizontal producers.
2. Recent advances have rendered these systems extremely inhibitive, and thus very suitable for shaley environments.
3. A simultaneous cleanup technique, coupled with an optimal drill-in fluid result in very low skin completions.
4. Optimization efforts must place heavy emphasis on shale and non-pay sections that may be encountered.
5. Open hole gravel pack completions can be very successful in shaley reservoirs using non-damaging aqueous fluid systems.
6. Drill-in fluids optimized for completion purposes also possess the qualities of a very good drilling mud, and usually require little maintenance.
7. The Viosca Knoll 825 #5 well was a major engineering success under what are considered complex, worst-case geologic conditions.
8. Like results have been attained in other applications utilizing the strategies outlined in this paper.

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TABLE 1
Viosca Knoll Horizontal Well Drill-in Fluid Properties

Density, ppg	12.6 - 13.0
PV, cps	22 - 26
YP, lb/100 ft^2	28 - 33
10 sec gel, lb/100 ft^2	4 - 6
10 min gel, lb/100 ft^2	8 - 11
HTHP spurt loss,ml*	< 2
HTHP fluid loss,ml/30 min*	< 8
$LC_{50,}$ ppm	121,000 - 137,000
PCT, kpsi/°F	8/30 minimum

* 210°F, 300 psi, 750 md aloxite disk

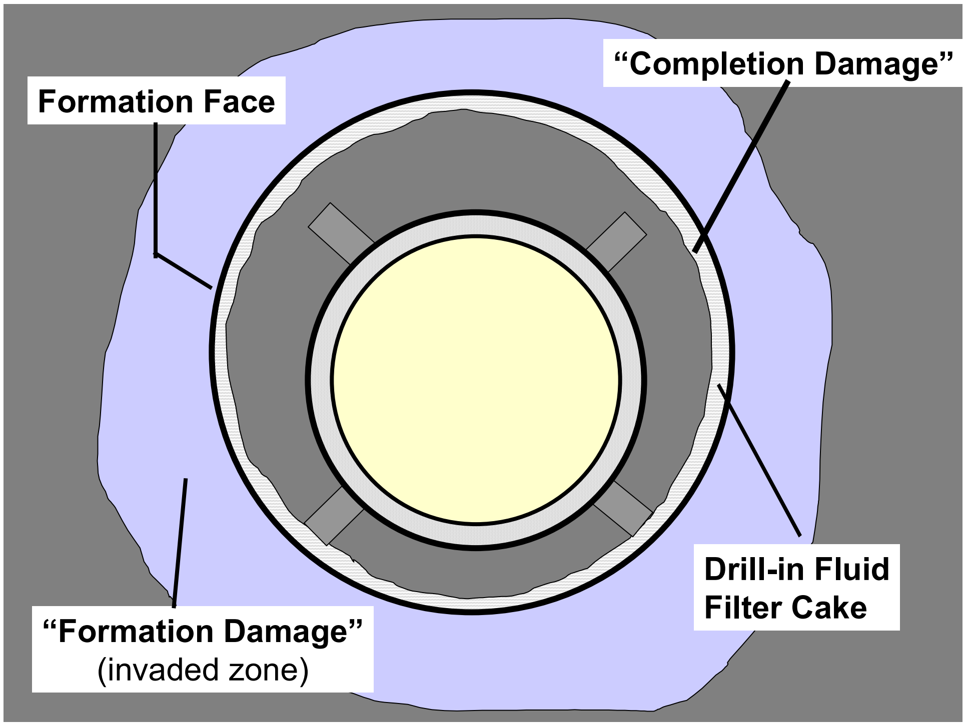

Figure 1: Well Damage Mechanisms

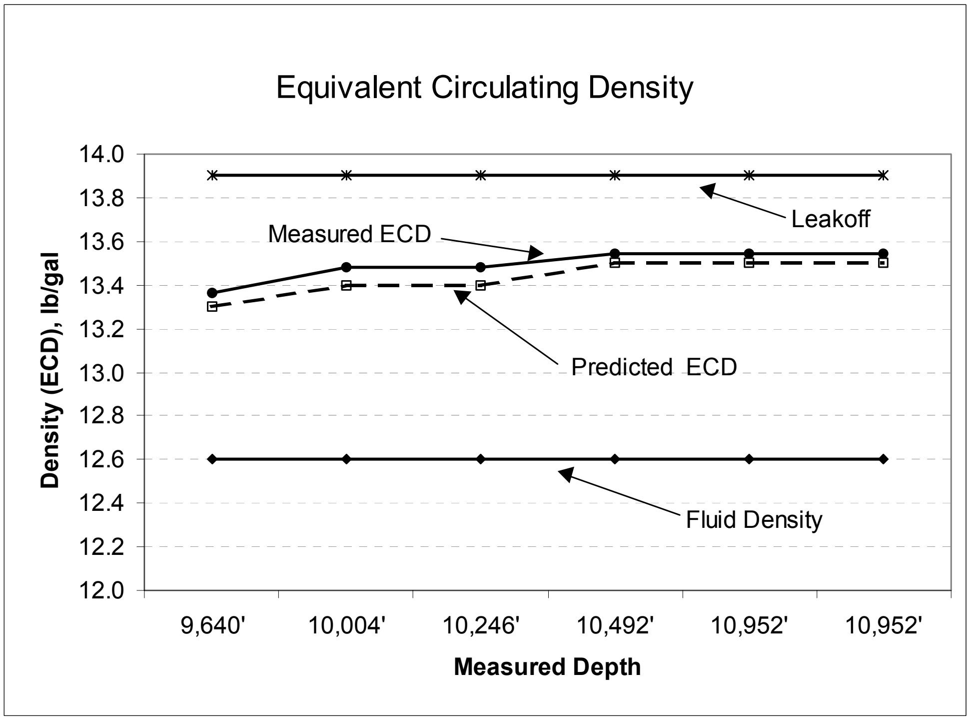

Figure 2: Predicted vs. Actual ECDs

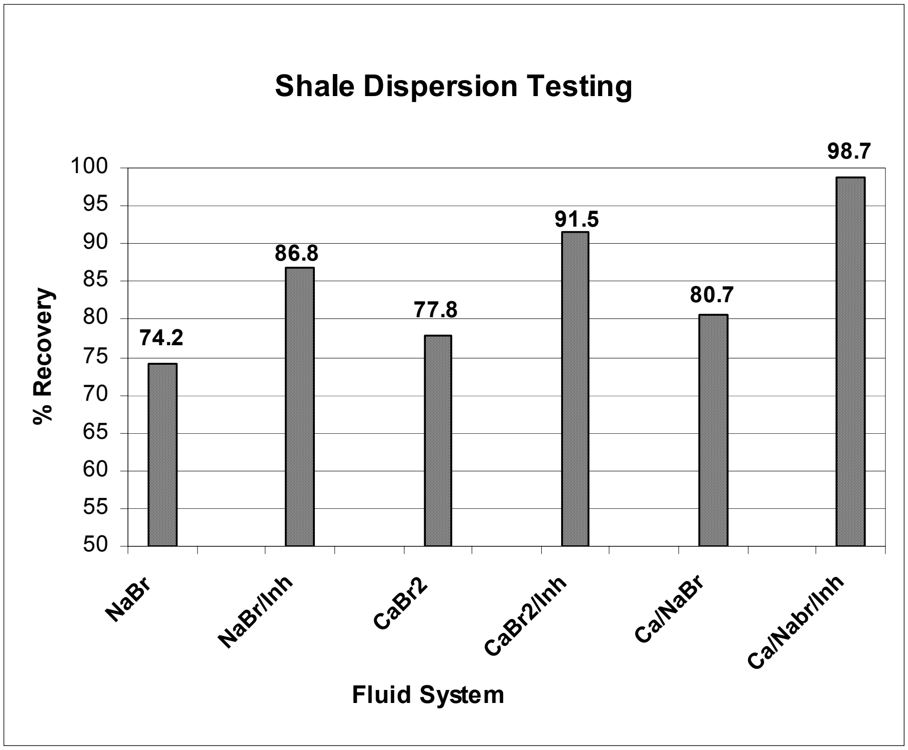

Figure 3: Shale dispersion with various fluids

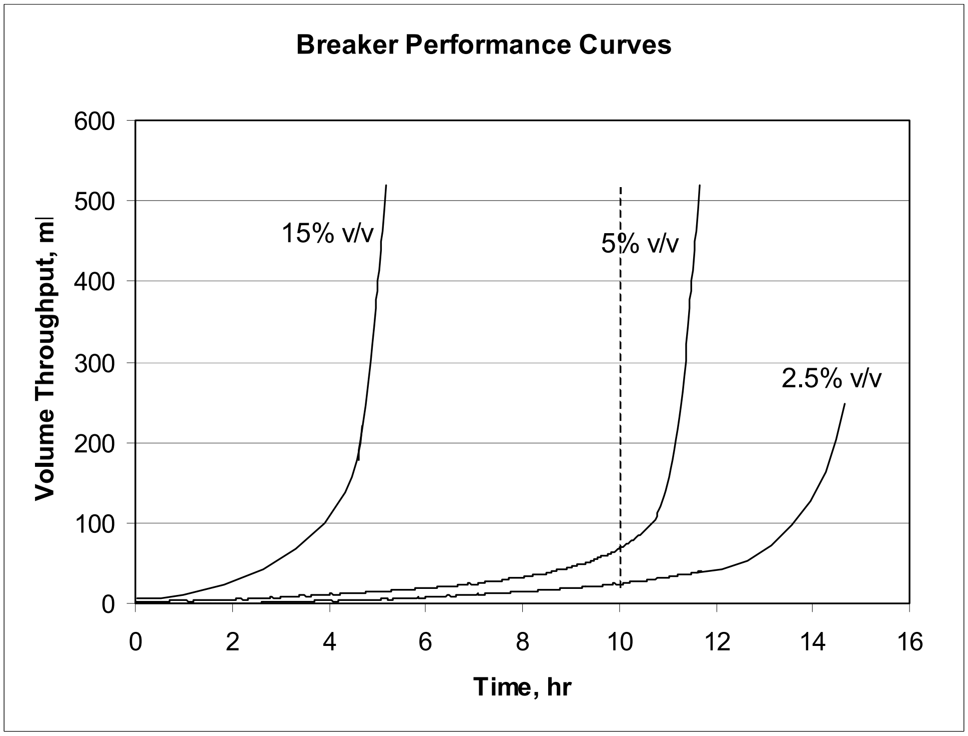

Figure 4: Breaker performance as a function of concentration

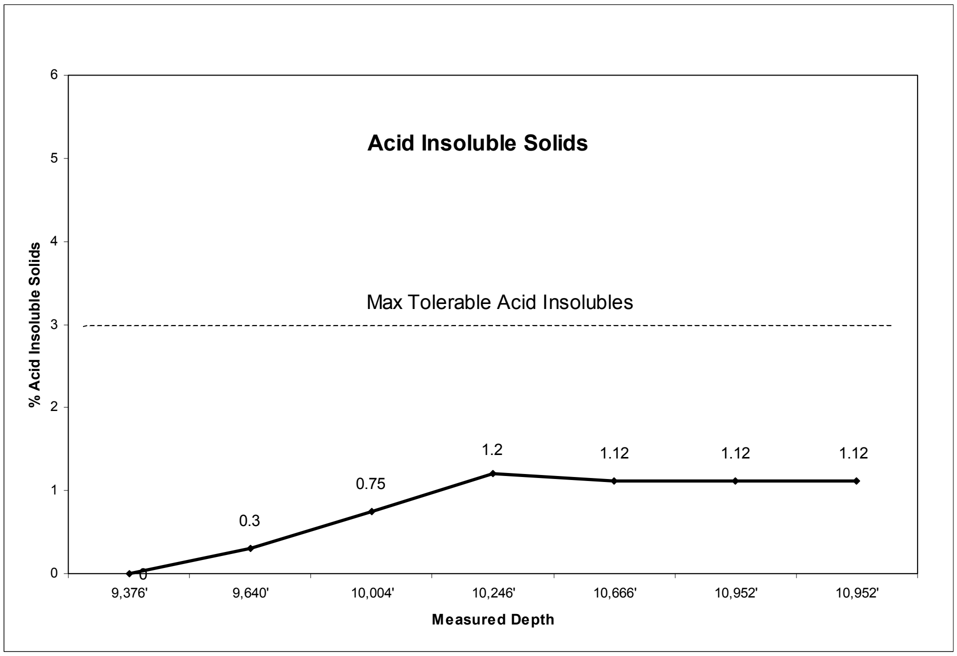

Figure 5: Entrained acid-insolubles vs. depth