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A New Approach to Increase the Initial Capacity and Improve the Decline Curve on Oil and Gas Wells

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Abstract

It is well understood that formation damage, once formed, is never completely removable. It was believed that formation damage could be minimized during the drilling and completion phase, but not during the production phase. That's because of the inability to predict the damage behavior of reservoir fluid and rock properties. Historically, our economic viability necessitated reducing formation damage during the drilling/completion cycles. That all changed in the 1990's with the introduction of frac packing. This tool enabled producing highly laminated, high angle completions by creating highly permeable pathways that trapped migrating fines away from the wellbore which was unachievable in conventional gravel packs.

This completion method has deemphasized the concern for preventing formation damage. The reduction in cost of drilling horizontal and high angle wells and the increased reliability of frac packing has led to adding isolation hardware (i.e. sliding sleeves) to the completion equipment to lower the cost of zonal abandonment. The evolution of these technologies has had many unintended consequences, especially in the mid- to late-life productivity of the well.

This paper identifies damage mechanisms that currently plague the drilling and completion process. The use of synthetic OBM and resultant filter cake damage, as well as, new removal techniques are examined. Completion fluid treatments that prevent calcium salt deposition, prevent NORM scales from seawater, restore wettability and optimize saturation. For the first time, a new approach for monitoring the change in reservoir conditions to predict damage during the production cycle on new wells is presented.

Introduction

The current paradigm of drilling and completions has allowed for the low-cost development of frac packed high angle and horizontal wells capable of extracting oil that was previously considered economically infeasible.[1,2] The results in this paper display that while technological developments have allowed for production from previously unreachable zones, they have also encouraged many harmful behaviours that drastically reduce the ultimate recovery from these wells. The data presented and used in this study in based on over 800 wells in the shallow waters of the Gulf of Mexico (GoM) that were treated between 2008 to 2018. The majority of these wells have frac packed completions, however the damage mechanisms evaluated are applicable to many other drilling and completion methods. In the GoM there is an increased reliance on horizontal drilling in order to access previously bypassed or stranded oil. The ability to drill through existing wellbores and utilize previously existing structures greatly reduces the cost associated with these mature brownfield assets. However, this necessitates drilling under challenging conditions using more environmentally safe, Oil Based Mud (OBM). The use of OBMs makes these high angle, extended reach targets much easier to drill, but more formation damaging than less efficient fluid systems.[3,4]

The beneficial properties of these OBMs have properties that encourage and accelerate formation damage during drilling and during the later production cycle. OBM usage leads to a filter cake consisting of oil and emulsion coated weighting material, drill cuttings, and organophilic clay.[5] This filter cake is highly impermeable and tenaciously cohesive. The filtrate resulting from OBM usage is very chemically active with leak-off resulting in the early onset of wettability reversal in reservoir rock while the mud also leaves an oil-wet film on the wellbore casing annulus surfaces.[6,7,8] The failure to remove this film leads to poor cement bonding between the casing and the wellbore.[9] This poor cement bonding results in poor zonal isolation and increases water encroachment into the producing zone. Wettability reversal being the alteration of the naturally water-wet formation to an oil-wet condition leads to the increased production of water which can now smoothly flow over the reservoir rock.[10,11] With this increased ease of water production coupled with the increased available water volume due to poor cement bonding, water laden production begins to easily move higher density materials into the fracture and near wellbore that would normally be non-migratory under the production of hydrocarbons.[12] Production pulls in the low permeability filter cake residue and emulsion layer where they independently cause plugging, and also encourage sticking and agglomeration of naturally occurring (now oil-wet) fines that would have otherwise passed through the pack if they were water-wet.[13]

There has also been a reduction in the concern for the composition of completion and workover brines. These brines can contain weighting salts that are incompatible downhole and cause an immediate reduction in permeability through the deposition of scale. The use of seawater as a completion and workover fluid has also increased as it is more economical and is believed to become inhibited by the use of KCl and KCl substitutes. However, it has been shown that this method of seawater conditioning can not only reduce the stability of clay contacted by the seawater, but also offer no protection from the severe scaling and biomass hazards present.[14,15,16]

It has been widely believed that frac packing is capable of removing the ill-effects of drilling and completion fluids in regard to formation damage.[17] It is well understood that the filter cake and drilling fluids can cause plugging and the early onset of wettability reversal, but the common belief is that the frac packing process creates such a dispersion of drilling products and such a high permeability pathway for production that drilling damage plays a very small role in production decline seen over time. Contrary to this popular belief, the efficiency and effects of frac packing and high rate water packing (HRWP) are not completely understood or predictable in unconsolidated sand. The belief that the damage can be fractured away is false and has encouraged the perpetuation of practices that cause irreparable damage to the well's later life.

The damage done by these methods can drastically reduce production, can become difficult to remove, and after time, even with repeat treatments, a well may never completely recover from the damage. The best action is to intervene early on into the life cycle of the well, and to clean up damage at that time. Once formed, the longer the damage is present, the decreased likelihood of its successful removal. (see Figure 1) The current opinion carried towards remediation is that the risk of treating a producing well is far too high to typically consider, and as a result treatment is withheld until the well is nearly at uneconomical levels.[18] At that point the remedial treatments necessary may be too large, too expensive, and too unreliable to be considered so that zone or well is abandoned.

Traditionally, treatment methods involved harsh conventional acids that resulted in emulsion and asphaltene blockages, the formation of acid insoluble reaction products, the degradation of the cement job, the water seeking behavior of acid would result in increased water production, and the compressive strength of the reservoir could be degraded leading to compression and further reductions in permeability/porosity.[19,20,21,22] With such a large risk, it made sense to postpone treatment until there were no other options available. However, with improved diagnostic tools and improved chemistries we have eliminated all the major risks that prevented early remedial intervention.

The common drilling and completion practices of using OBM and frac packing have placed less concern on drill-in fluid, filter cake, filtrate, and completion fluid induced formation damage. They also placed less of a desire to optimize mud and filter cake removal prior to cementing, less of a desire to run remedial treatments prior to production, and less of a desire to diagnostically determine the initial health of a well. The evidence is clear that the damage mechanisms present during these activities are not evaded through frac packing and do negatively affect ultimate production. With such a paradigm, a shift should occur where well designed remedial packages are used to remove early onset formation damage to maximize initial capacity. The maximizing of initial capacity is a mandatory step in maximizing ultimate recovery.[23,24]

Damage Incurred During Drilling and Completions and The Myths of Frac Packing It Away

During drilling, the filter cake is engineered to seal off and stabilize the wellbore and facilitate rapid penetration rates. OBM is the most efficient of the drilling fluids leading to its preferred usage in unconsolidated and highly permeable sand formations. The result of these fluids is an internal and external filter cake that is left around the wellbore.[13,25] This filter cake is often seen as unimportant as the external filter cake is readily fracked past and the internal filter cake is typically unconsidered. With a frac pack extending the radius of production beyond the zone damaged by the external filter cake the significance to production of this damage mechanism is initially reduced. While damage may not be initially apparent, the poor practices involved in the handling of filter cake damage is resulting in newly completed wells that display a skin of 20 or higher.[26]

In addition to the reduction in initial permeability displayed by these very high skin factors, the mud filtrates lead to premature oil-wetting of the reservoir rock and naturally occurring fine material.[6,7,8] This increases the likelihood of water production and assists the migration of denser materials that would otherwise be stationary until much later in the well's lifecycle.[12] As the reservoir is produced the available internal pressure of the formation decreases, exacerbating the migration of once stable materials. As water production increases and formation pressure decreases, internal mud cake and unbroken gels that may have been used in completion can start to migrate, delivering oil-wet solids into the pack and near wellbore.[13] The lower pressure results in an increase in the deposition of asphaltenes, paraffin wax, and inorganic water-formed scale.[27,28,29] The oil-wetting agents in the drilling fluids and the resulting internal filter cake alter the naturally water-wet fines and scale allowing them to stick, agglomerate, and pose a higher risk of plugging. In soft, unconsolidated sands which were frac packed with a low polymer crosslinked fluid, sub parallel fractures can form during fracturing, trapping leak off. With the reduced pressure, this leak off can now start infiltrating the pack worsening the wettability conditions of the formation.[30] This pressure decline doesn't just induce damage mechanisms but with time will start to pull whole formation rock into the near wellbore completely shutting down production.[31,32]

There is also damage that is incurred during the completions phase. There are risks associated with the use of calcium salt-based brines and the use of seawater as completion and workover fluids. Calcium salts are often used to achieve a higher density fluid, but the compatibility of the fluid with downhole conditions are typically overlooked. These brines are comprised of calcium chloride and calcium bromide salts. Below saturation levels these salts easily dissociate in water and provide a brine. However, this may be an unnecessary addition of calcium ions to the reservoir. If the formation water is high in carbonate concentration, calcium carbonate scales can deposit if the pH of solution is not sufficiently acidic.[29,33] In the event that the formation water is high in carbonate and is alkaline, there is almost a guarantee of calcium carbonate deposition. This deposition can severely reduce the permeability of a sand formation, and when oil coated, can become troublesome to remove.

Since brines made from fresh water are seen as cost prohibitive, it is a common method to use inhibited seawater. The largest risk seen with seawater usage is clay swelling in the formation. However, most sandstone formations are marine depositions that are compatible with seawater salinity levels. Still, this misconception leads operators to treat seawater with KCl or KCl substitute in order to reduce the perceived swelling risk. As seen in Figure 6 the seawater doesn't pose a severe clay swelling risk initially, while the use of KCl substitute can cause more clay swelling than seawater alone. The risk with seawater usage is the sulfate ion content of the water. When this sulfate rich water encounters naturally occurring barium, even at very low concentrations (see Figure 5), acid insoluble barium sulfate is formed. Barium sulfate is very problematic because of its chemically stable nature and acid insolubility. Complete removal typically requires high temperature and high pH conditions. Induced alkaline conditions can cause voluminous amounts of mineral scale to form, plugging up a well completely.[29]

The damage that was intended to be dispersed or destroyed through the use of frac packing quickly manifests as production continues. Frac packing may make the damage seem insignificant during initial production but the latent damage is severe and difficult to remove if not done so immediately upon its formation. As damage is left over time multiple damage mechanisms may take effect and make an economical treatment very complex if not impossible. Frac packing allows for the production of zones that were once too challenging or uneconomical, but they should not be utilized as a one size fits all completion and should still be thoroughly designed. They do not prevent the damage mechanisms seen in gravel packed completions, they simply allow for the creation of a high permeability pathway through what would otherwise be a nonproducing interval.

While not the only causes of early production declines, drilling and frac packs represent very good examples of how beneficial, sometimes necessary, procedures used initially can have a negative effect in later stages of production. Using this information allows for a low risk treatment program of maintenance, thus keeping production (productivity) at its maximum. Other production problems become easier to identify and so does an effective treatment. More importantly, perhaps, an understanding of the relationship of initial drilling and completions to mid- and later-lifetime production declines can eliminate using an ineffective treatment. Avoiding such "valueless" costs keeps cash flow and other economic parameters positive.

Diagnostics Allowing for Early Detection and Intervention of Damage

Due to the inability to initially predict the risk factors of reservoir rock and fluids, we normally wait until a significant loss of flow efficiency has occurred before acting. Previous investigators have shown that good wells are better stimulation candidates.[34] The industry mantra of "don't risk messing up a good well" still persists. This study shows that early intervention is critical. Fortunately, new diagnostic tools provide early, precise formation damage detection and identification. Improved analytical methods and production simulators allow for the detection of discreet, subtle changes in production with time. By performing early life analytics, a baseline reservoir condition can be modelled. Progressive testing is then done throughout the life of the well that can determine if any changes in the reservoir have occurred. Advanced crude compositional analysis allows for the early determination of microfilm induced wettability alteration and paraffin and asphaltenic depositional behavior. Analysis of the changes in the water ion composition can determine if downhole conditions are inducing scale depositions through the well and the best removal fluid for that deposition. Advances in crystallography and polarized microscopy enables solids analysis from a single crystal extracted from a wellhead sample. Born out of necessity because of the lack of available core sample materials, advanced microscopy helps determine formation damage mechanism, confirm pack integrity and enhance targeted chemistry design.

Examining these very subtle changes allows for the early detection of formation damage factors that can be treated early on when the damage can be more efficiently removed without risking the deterioration of reservoir rock or the completion. This paradigm of early intervention and a data driven treatment strategy is essential for maximizing ultimate recovery by increasing capacity and extending decline curves.

The Older the Damage the Reduced Likelihood of Successful Removal

The reluctance to use conventional acid except as a last resort is founded in a history of poor outcomes, many of which were catastrophic.[18] Everyone has heard stories of preferentially stimulating water production or locking up a well with gelatinous or even insoluble acid reaction products. This method of "only as a last resort" acid stimulation carries several severe flaws. As time and production proceed, the sources of damage overlap and often can no longer be restored to an acceptable economic level.[35] The volumes of chemical needed for conventional acid treatment and the associated equipment spread are so expensive that the well will never cover the cost of treatment. The greatest challenge created by conventional acid treatments is that once applied, a differential permeability between the accessible lower quality portion of the reservoir (i.e. high-water saturation), and the damaged high hydrocarbon saturation portion is increased. The resultant unwanted preferential permeability zone often leaves trapped or stranded oil contained in the more extensively damaged areas of the reservoir.

Selecting a measurement, that would provide clarity in over 800 stimulation treatments was very difficult. Finding Pressure Transient Analysis, skin reduction, flow efficiency and changes in ΔP data was largely unavailable. The only data consistently available was treatment life based on sustaining resultant production improvement. Figure 1 shows that the most effective treatments are done on new wells, followed by early life wells, followed by late life wells, and finally 2nd treatment mature wells. The longer the damage is left the more damage mechanisms can simultaneously occur which reduces the efficiency of treatments. We see this manifest in the decrease in treatment life as the well matures. Even a thoroughly designed treatment can only remediate a portion of the damage that an older well has sustained if frequent remedial treatments haven't taken place throughout the well's life. Treatments are specific to damage mechanisms and as mechanisms occur simultaneously then they may require conflicting treatments and create a situation where the damage to a well can never be removed.

The most common method for damage removal is conventional acid treatments. The most common acids used for conventional sandstone acid treatments are Hydrochloric (HCl) and Hydrochloric: Hydrofluoric (HCl:HF) acid blends. HCl can induce the precipitation of asphaltene rigid film emulsions and asphaltenic sludges that result in insoluble formation damage and catastrophic facility upsets with entire field shut ins. HF acid has many associated risks such as the compromising of cement isolation, the degradation of the formation rock, and the precipitation of irremovable reaction byproducts.[21,22,36] McLeod showed that the more complex, low permeable reservoirs require lower acid concentrations and slower reacting organic acid components to avoid inducing more damage from reaction products than could be removed by the treatment.[37] However, field analysis by advanced crystallography shows that frac packed soft formations are eventually plugged by more whole rock than typical silica fines. Conventional treatments cannot provide the necessary rock dissolving power without inducing even greater damage. The best option is to use diagnostics to first determine the damage present and then designing a data driven hybrid treatment comprised of several very specialized chemistries, working in conjunction to target the damage. Figure 2, Figure 3, and Figure 4 show that not only are hybrid treatments more effective initially, but that they have a longer period of production improvement allowing for the treatments to quickly pay for themselves.

New Damage Prevention Methods During Completion and Workover

When using high-density calcium brines, the reservoir conditions should first be analyzed to see if there is a threat of scale formation as a result of their use. If a likely scaling tendency exists, then alternatives should be sought after. There are also a series of buffering solutions that can be added to the brine to maintain a lower pH as a mechanism of preventing the formation of calcium scales.[38,39]

It is best to avoid the use of seawater but if it is economically mandatory then the proper conditioning steps should be taken. For the conditioning of seawater completion fluids, it is known that KCl and KCl substitutes provide no scale protection or additional clay swelling protection. There have been advancements in the development of highly efficient chelating chemistries that are seawater compatible.[40] These chemistries have been used in conjunction with anti-foulant chemistries to allow for the complete inhibition of the damage mechanisms posed by seawater usage. (see Figure 5)

Novel Formation Damage Removal Treatments

Conventional treatments have been shown to be higher risk and largely ineffective on current GoM shallow water wells. But recent developments in treatment chemistries have allowed for low risk alternatives that more successfully remove the targeted damage, increasing the initial capacity and maximizing economic production.

The risks associated with conventional acid systems have been circumvented by the use of kinetically controlled, azeotropic acids. This system allows for the application of HF acid to dissolve silica-based material without the aggressive reaction rate that results in the damage most often associated with HF acid.[18,41,42] Since HCl and HF are both water seeking acids they have a large likelihood of opening pathways that already yield water heavy production while providing no benefit for the areas that are more damaged. The ability for an azeotropic system to infiltrate hydrocarbon rich areas makes it more effective in removing damage from zones that can yield hydrocarbon production. These advanced acid systems in conjunction with new developments in diversion systems allows for targeted placement of effective systems without the risk of increased water production and with the added benefit of specifically treating highly damaged areas.

There are a multitude of acid alternatives that yield the benefits from acid removal without the risks. These systems can be tailored and designed based on data derived from the new proposed paradigm of testing and analysis. The benefits of these systems are compounded in their ability not only to remove damage but also condition the reservoir to maintain its improved production for an extended time period by reduci the likelihood of damage formation. Table 1 shows a non-acid system applied to a low BHT well where a large volume of cold completion fluid was lost to the formation. Wax deposition modeling indicated that wax blockage, wettability reversal and high-water saturation were likely causal factors to the well's poor performance. A wax deposit was synthesized in the laboratory and solvent solubility tests were performed. The resultant custom solvent-based treatment was applied and increased daily oil production by 497% and reduced daily water production by 45%.

This study shows that the only way to maximize production is to intervene early and often. Poor procedures in the drilling and completions phase of a well can plague the well for its entire life. By minimizing this initial damage with a new paradigm of analysis and remediation then the capacity can be maximized allowing for an increase in ultimate recovery.

Tables

Table 1. The initial state of production of a low temperature well and the state of production following a hybrid non-acid treatment.

	Before Treatment	**After Treatment**
BOPD	68	338
BWPD	262	144

Figures

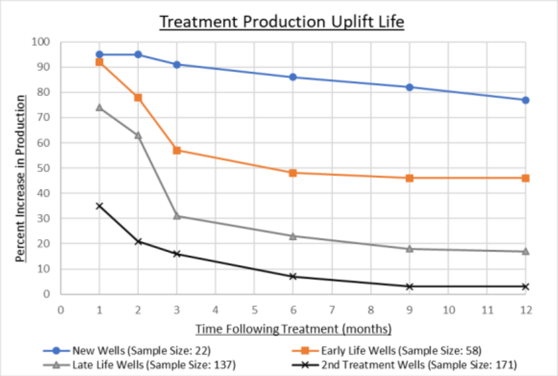

Figure 1. The average production uplift resulting from a stimulation treatment performed on new wells, early life wells, late life wells and wells that are being treated for the 2nd time. The trends show that the earlier the intervention in the life cycle of the well the higher the resulting production improvement and the longer the duration of improved production.

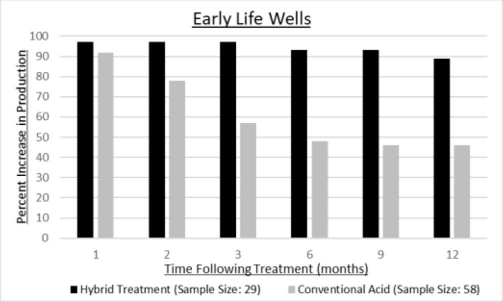

Figure 2. The average production uplift due to hybrid and conventional treatments in early life wells. The trend shows that hybrid treatments as compared to conventional treatments provide more additional uplift and a longer treatment life.

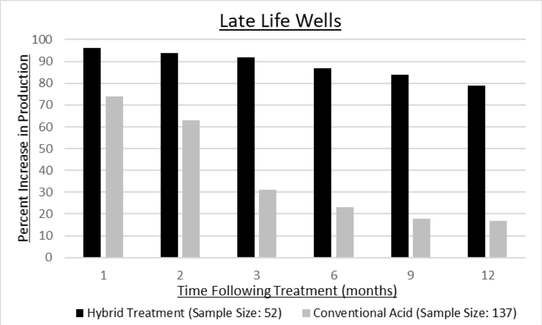

Figure 3. The average production uplift due to hybrid and conventional treatments in late life wells. The trend shows that hybrid treatments as compared to conventional treatments provide more additional uplift and a longer treatment life.

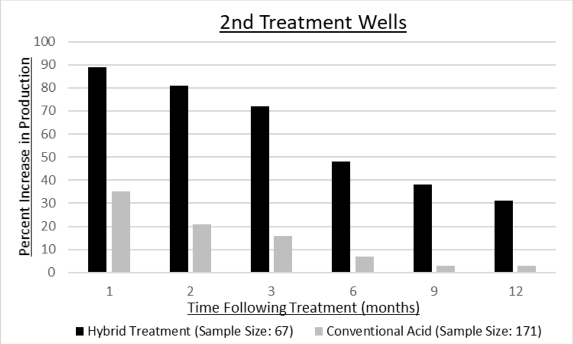

Figure 4. The average production uplift due to hybrid and conventional treatments in wells undergoing a 2nd treatment during their lifecycle. The trend shows that hybrid treatments as compared to conventional treatments provide more additional uplift and a longer treatment life.

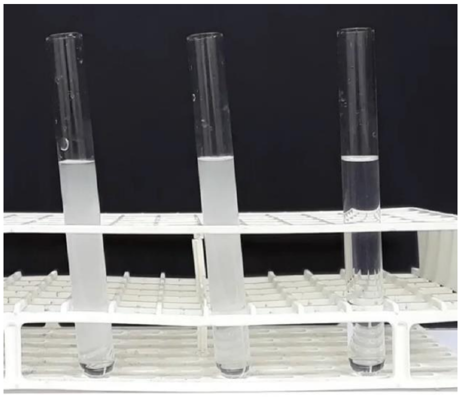

Figure 5. The test tubes show the reaction of seawater with a barium chloride brine. The sulfate content of the seawater is typical, and the barium ion concentration introduced to the solution is 220 ppm. The test tubes, from left to right, contain untreated seawater, seawater treated to a 2% KCl solution, and seawater treated at 0.5% with a chelating and antifoulant solution. When barium is introduced the solution precipitates barium sulfate identically in untreated seawater and seawater treated with KCl. The reaction is not present in the seawater treated with the chelating and antifoulant solution.

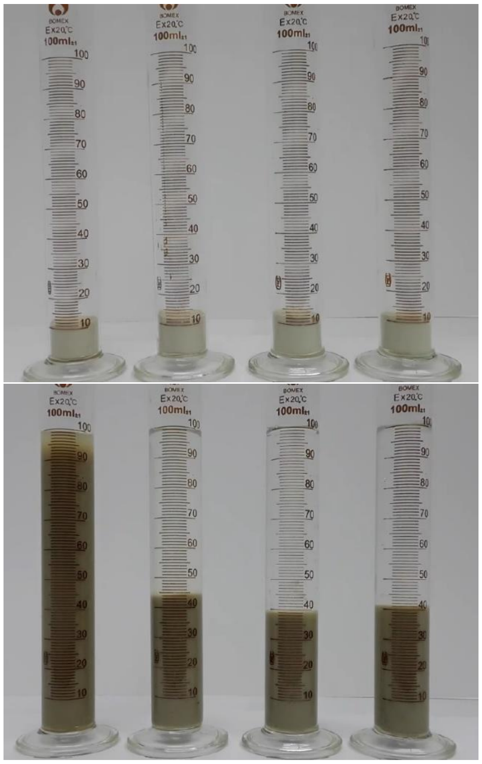

Figure 6. The images show the before and after effects of introducing fluids to a sodium montmorillonite clay. From left to right the introduced fluids are fresh water, seawater treated at 2% with a KCl substitute, untreated seawater, and seawater treated at 0.5% with a chelating and antifoulant solution. The results show that untreated seawater resulted in the least amount of swelling, followed by the chelating and antifoulant solution, followed by the KCl substitute, and lastly the fresh water. The clay swelling properties of the seawater were not aided by the addition of a KCl substitute.

Conclusions

- New analytic diagnostic tools and advanced chemistry can allow early damage detection and identification. These tools can improve well capacity during the drilling, completion and workover process.
- Increasing ultimate recovery requires maximizing initial capacity by formation damage prevention combined with early diagnosis and treatment.
- Frac packing is essential to enhance productivity, but formation damage will eventually occur, and conventional remediation methods are less effective than data driven hybrid treatments.
- The paradigm of only treating badly damaged wells as a “last ditch” effort will produce the worst technical and economic outcomes.
- Maintaining a near damage free zone is only achievable by early detection and treatment.
- Novel chemistries are abundant that are very safe, economical, low risk, and provide higher returns.

Nomenclature

OBM =Oil-based mud
NORM =Naturally occurring radioactive material
GoM =Gulf of Mexico
KCl =Potassium chloride
HRWP =High rate water pack
HCl =Hydrochloric acid
HF =Hydrofluoric acid

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