

Best Non-Aqueous Fluids Clean-up Practices for an Offshore Sandstone Reservoir Completed with an Inflow Control Device

Chad F. Christian, Oscar Becerra Moreno, Baker Hughes, J. Eric Lauritzen, Saudi Aramco

Copyright 2010, AADE

This paper was prepared for presentation at the 2010 AADE Fluids Conference and Exhibition held at the Hilton Houston North, Houston, Texas, April 6-7, 2010. This conference was sponsored by the Houston Chapter of the American Association of Drilling Engineers. The information presented in this paper does not reflect any position, claim or endorsement made or implied by the American Association of Drilling Engineers, their officers or members. Questions concerning the content of this paper should be directed to the individuals listed as authors of this work.

Abstract

Maximizing productivity and minimizing near wellbore damage and the associated production impairments are achieved with an effective clean-up while flowing back the well after drilling. Previous papers have documented formation damage and productivity impairments associated with drilling open-hole sections with non-aqueous fluids (NAF). The use of best practices for clean-up of long horizontal sections of an unconsolidated sandstone reservoir drilled with NAF and completed with an inflow control device (ICD) has resulted in improved productivity. The results discussed show that in relative high Darcy sands, the use of proper chemical treatments and initial flow back will maximize the productivity index and minimize near wellbore damage. The conclusions are based on the evaluation of different clean-up methods including coiled tubing deployed nitrogen kickoff, chemical treatments, artificial lift - electric submersible pump vs. natural flow, time spent on clean-up and flow rate.

Introduction

The objectives of drilling horizontal wells are to maximize reservoir contact to sustain production, enhance oil or gas recovery and improve well productivity. However, horizontal wells commonly produce reservoir fluids non-uniformly due to reservoir permeability and pressure variations along laterals, presence of fractured zones and frictional effects along the wellbore. This non-uniform inflow is what promotes early water or gas break-through.

The sandstone reservoir, one of the largest offshore oil fields in the world, is a thick sequence of sandstone, siltstone, and shale with intervals of limestone. Historically, the sands are unconsolidated and have the potential for fines migration that can result in plugging of the screens, perforations, tubulars and surface flow lines. These sands are divided into multiple layers based on facies heterogeneity.¹ Several new horizontal wells were drilled with an oil-based reservoir drill-in fluid (RDIF). The wells were completed with integrated sand screens and ICD completions, as seen in **Figure 1**. Because of rig limitations, the drawdown applied at reservoir depths during the initial flow back was minimal (~15 psi).

Removal of formation damage resulting from internal and external filter cake deposition while drilling is desirable to

maximize the well productivity index (PI) and ultimate hydrocarbon recovery. Simple modeling confirms that during radial flow, near wellbore damage has the greatest impact on pressure drop and productivity. Efficient filter cake clean-up is required for a number of open-hole completion operations.



Figure 1: Sand control screen with ICD

The optimization of inflow performance in long open-hole horizontal completions involves several challenges:

- Drilling fluids and the associated formation damage
- Sand control and optimum ICD completion design
- Initial clean-up, which depends on several factors such as filter cake quality, permeability heterogeneities and the heel-to-toe effect

This paper will focus on the results of different clean-up methods used during this multi-well development and will discuss the results associated with the best method for clean-up of formation damage and improved productivity.²

Results and Discussion

Drilling Fluids

Invert NAF drill-in fluids are commonly used to drill heterogeneous sandstone reservoirs. Non-aqueous fluids were chosen to drill the reservoir section of these wells because of the increased wellbore and shale stability, increased lubricity and reduced differential sticking compared to past wells drilled with water-based mud (WBM). The wells were drilled with sized calcium carbonate weighted NAF and completed with an ICD sand control screen. Historical and offset well diagnostics indicate a productivity impairment related to near wellbore damage and/or severe plugging of the screens, either occurring while running the screens to bottom in solids free NAF or induced by a mixture of formation sand and OBM filter cake adhering to the screen during drawdown. It was recognized that OBM could have a few drawbacks:

- NAF can contain more solids than WBM. In this drilling operation, total solids content ranged from 16

to 21%, increasing the risk of particle invasion.

- Strong oil-wetting surfactants used to disperse solids in OBM alter the wettability of the formation converting it to an oil-wet state. This significantly reduces the relative permeability to oil.
- Cationic emulsifiers used to stabilize water-in-oil emulsions also stabilize *in-situ* emulsions that already tend to build up inside oil-wet porous media. Emulsions can be stabilized in sandstone reservoirs, especially those of high clay content, and emulsion blockage can occur.

To minimize formation damage, an effective means to remove the filter cake and aid in the removal and clean-up of the internal near wellbore damage created by a NAF is required. Collaborative research between the operator, service company and laboratories resulted in improved treatments for removing NAF filter cake and associated formation damage. A fluid was developed to fluidize and reverse the wettability of the NAF filter cake solids, acidize soluble particles and clean-up the near wellbore skin damage caused by the drilling fluid.³⁻⁷ Traditional laboratory methods, including return permeability, core flood and HPHT tests, and field results show that the use of this technology will remove skin damage, completely eliminate the risk of screen plugging by the NAF filter cake, improve well productivity, water-wet and disperse the solids and optionally acidize soluble particles. Traditional methods using inorganic acids, organic solvents and mutual solvents have not been effective at cleaning up NAF filter cake deposits when completing with ICD screens.

Sand Control and Optimum ICD Completion Design

Sand Control

Sand control and optimum screen size were investigated through grain size distribution tests and sand screen selection criteria that creates optimum sand control and minimal restriction to production based purely on the ability to retain the sands without plugging. Screen selection with regard to sand retention performance is typically based on certain parameters of the formation sands.

End trims and core plugs were collected from different wells and layers of the reservoir. A Dry Test Sieve Analysis (DTSA) was collected for each plug, (Figure 2) to get the average sand grain size for optimum screen aperture to formation sands. The D_{10} , D_{30} , D_{50} , and D_{95} have been identified for all core plugs. In this case, the aperture selection was based on a slot-opening equivalent to 1.4 x the average D_{50} , provided that the minimum D_{10} is not exceeded. The average D_{10} grain size versus the cumulative percentage retained sand is about 380 microns (Figure 3).

For this development, 350 microns were used to control the target sands. It should be noted that Saudi Aramco does not use standard wire wrapped screens (WWS) for horizontal producers but instead uses the more robust direct wrap type screens. Direct wrap screen sizing is based on the above WWS criteria. This practice results in a reduced concern for screen failure during deployment especially when deploying through sidetrack windows. This concern is also minimized

when deploying metal mesh screens as they are jacketed type screens.

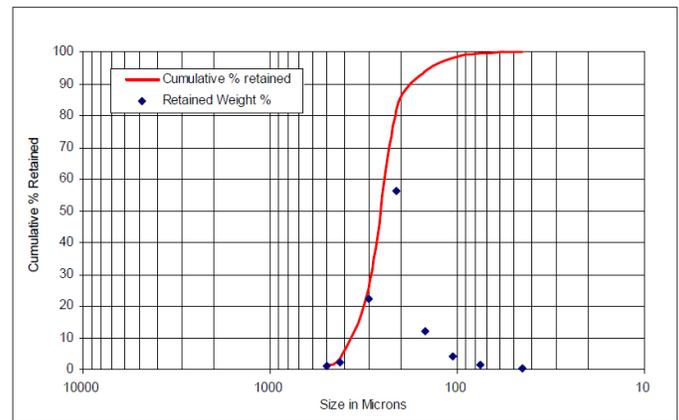


Figure 2: Dry Test Sieve Analysis

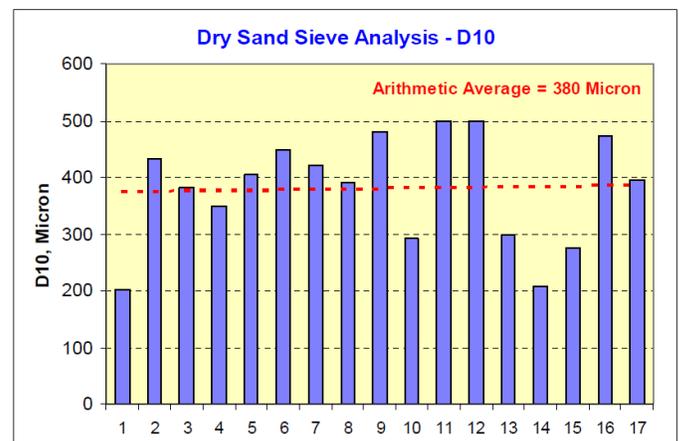


Figure 3: D_{10} values for core plugs

ICD Completion Design

ICDs provide a cost-effective method to equalize inflow from the entire horizontal section, increase and sustain well production, mitigate unwanted fluid (gas or water) and improve ultimate reservoir recovery. The ICDs are designed to normalize the inflow distribution by providing a controlled pressure drop, which is predominately a function of the flow rate; essentially a choke apparatus is connected to the sand screen.

The ICD net effect is to restrict high productivity zones while increasing flow in zones of lower productivity. Equalization is achieved by breaking the horizontal length into flow compartments using zonal isolation.⁸ The heel generally tends to dominate flow (assuming everything else is equal) to the total exclusion of the remainder of the lateral. The heel compartment will usually require choking back to give the remaining zones of the lateral a chance to flow. For non-equalized wells, the toe section usually shows little or no contribution to flow, especially if reservoir pressure is lower than at the heel. There are cases where it may be desirable to reduce contribution to flow from the heel to retard water breakthrough, especially when the heel is higher pressure than the toe or if it is highly fractured and underlain by water or overlain by gas.

ICD benefits in horizontal wells include the following:

- Improvement of the ultimate recovery by having uniform depletion from the targeted zones
- Maximization of production from heterogeneous sands (shaley sands)
- Extension of well life by controlling the pressure drawdown and delay the water break through
- Control of sand production
- Improved well clean-up reducing the effect of formation damage caused by the drilling of the well
- Equalization of the flux along the well path, thereby reducing coning
- Reduction of the annular flow, which reduces the risk of sand production behind the screen and subsequent plugging or erosion

Before running the ICD screens, the NAF should be conditioned and tested using a Production Screen Tester (PST) to confirm that the fluid will flow back through the screens without causing screen plugging.

Formation Damage with Non-aqueous Fluids

Non-aqueous reservoir drill-in fluids are designed to create a robust and low permeability filter cake during drilling to minimize filtrate and solids invasion. Filter cake properties and ease of removal of the external and internal filter cake are all important for maximizing the productivity of a well.

An extensive formation damage study was conducted to understand the damage mechanism and the ultimate design of a remedial treatment. A core flood test was conducted in the lab on high and low permeability core plugs using two densities of NAF to simulate drilling conditions. As seen in **Figure 4**, a reduction of 25 to 65% of the original permeability was observed after exposing the core to NAF. Some improvement in permeability was seen after removing the NAF filter cake, indicating that the filter cake created some flow restriction. Several formation damage mechanisms were identified:

- Poor hydraulic NAF filter cake clean-up during draw down
- NAF fluid retention
- Fines movement

High-density mud created further reduction in formation permeability.

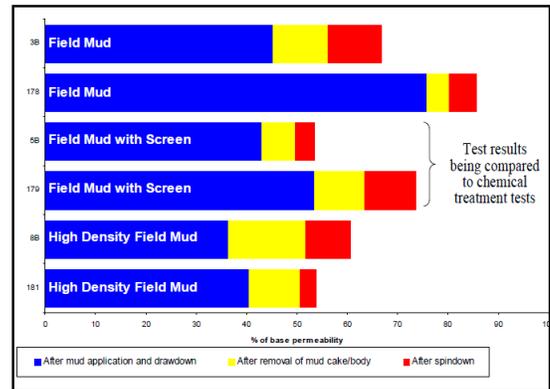


Figure 4: Summary of return permeability results

Figures 5 and 6 illustrate the CT scans of the core plugs after circulating the NAF drill-in fluid and after circulating a screened “solids free” NAF, respectively.

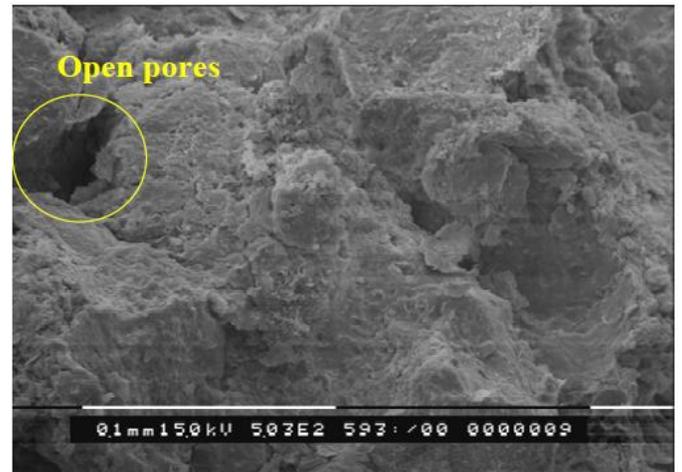


Figure 5: CT scan of core plug after circulating NAF DIF



Figure 6: CT scan of core plug after circulating NAF DIF and “solids free” NAF DIF

Analysis showed poor clean-up of the NAF filter cake,

blocked and flow restricted pores at the core face and movement of fines.

Screen plugging created by the NAF can be seen in **Figure 7** and the results from the return permeability evaluation of brine-based surface active additive package in **Table 1**. It should be noted that the NAF was conditioned and a surface screen tested was used to ensure that NAF solids would not plug the screen.



Figure 7: Filter cake screen plugging from lab testing (NAF only, no treatment)

Table 1: Return permeability results from screen testing with conditioned NAF and chemical displacement

| Test # Cleanup Treatment | Screen Permeability (D) | | Final % Retained Screen Perm |
|---|-------------------------|-------|------------------------------|
| | Initial | Final | |
| DS-A022908A "A-40" Circulating | 733 | 674 | 92 |
| DS-A022908B Conditioned Mud / Mineral Oil | 729 | 168 | 23 |
| DSA022908B2* Retreatment with "A-30" Single Pass | 729 | 555 | 76 |
| DS-A022908C "A-30 Circulating" | 768 | 625 | 81 |

Case History

Traditional NAF Hydraulic Clean-up Without Chemical Treatment

Filter cake on the sand face and particles infiltrating the surrounding pores represents a significant challenge. In most cases, it is thought that backflow from the reservoir will lift off the filter cake and remove invaded solids. The efficiency of such removal depends on the filter cake quality, the applied drawdown and inflow rate along the wellbore. A minimum drawdown of approximately 25 psi is required to locally remove most drill-in fluid (DIF) filter cakes. When the

wellbore pressure is reduced, the filter cake will only be lifted off certain higher pressure sections of the wellbore, initiating inflow. The reservoir fluid will find the path of least resistance, avoiding sections still covered by filter cake. The sand face will still have intact filter cake, even though the pressure drawdown between reservoir and wellbore far exceeds the pressure difference needed to lift off an unbroken cake. Since flow restriction along the wellbore reduces the drawdown in lower sections of the well, it is conceivable that intact filter cake exists over long sections and an efficient NAF filter cake clean-up is required.

Commonly, after ICD screens are run in the open-hole, coiled tubing (CT) is deployed to unload the well with N₂ for production. The well is expected to start flowing while the CT is displacing the well with N₂ in the vertical section. Once the well is kicked off, oil is flowed to surface. The well is killed by circulating brine in the upper completions allowing the drill stem test (DST) string to be recovered. The upper completion, including the electrical submersible pump (ESP) and a fluid loss isolation valve are installed. To function test the ESP, the well is produced for eight hours.

A comparison of the PI was made for wells treated with a mesophase brine-based SAAP and those not chemically treated, by recording the ESP gauge pressure data (intake, discharge pressure). The data is historically matched with the actual pump curve data obtained from the manufacturer. Flow rate is calculated and the static and dynamic intake pressures are extrapolated to the horizontal section of the reservoir (Tulsa and Beggs & Brill). This intake pressure has been used to calculate the actual PI, then compared with the PI obtained from a static near wellbore inflow modeling program (SNWM) at the same rate and static pressure. The SNWM uses Joshi's PI model in a steady-state environment to calculate the PI. Below is the PI establishment methodology.

Actual PI

- Use ESP intake and discharge pressure to estimate flow rate.
- Use the pump static and dynamic intake pressure and the estimated flow rate to calculate static and flowing bottomhole pressure (FBHP) at the heel.
- Calculate actual PI from the FBHP.

Theoretical PI

- Use simulation model with actual ICDs configuration and flow rates as generated from ESP data.
- Calculate theoretical PI from FBHP at heel.
- Compare both PIs to identify presence of damage.

Figure 8 shows the production trends normalized to the net pay for the expected and the actual production rates from wells completed with ICD screens that were not displaced to a brine-based mesophase SAAP treatment during completion.

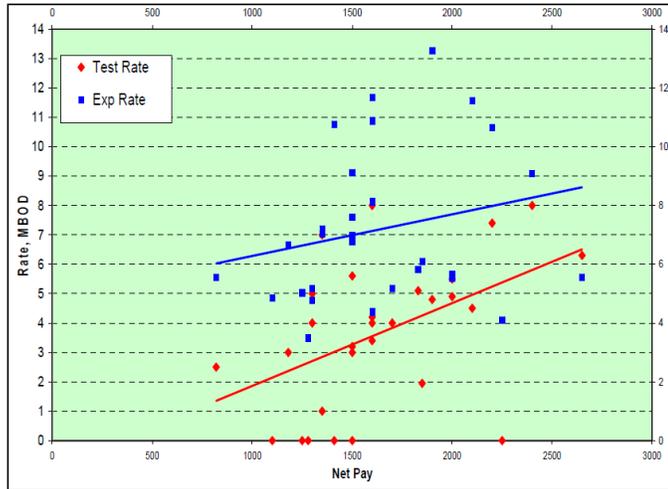


Figure 8: Production trends for expected versus actual rate after completing with ICD screen without any treatment

Wellbore Clean-up With Chemical Treatment

To optimize wellbore clean-up, the associated NAF filter cake removal and PI, it was essential to displace the NAF to a properly designed clean-up fluid and to increase the inflow along the wellbore. A spotting fluid was developed to increase the permeability of a NAF filter cake by altering the wettability from oil-wet to water-wet. By altering the wettability of the NAF:

- The permeability of the filter cake will be greatly enhanced going from an NAF filter cake to a WBM filter cake.
- Converting the filter cake and water-wetting the formation will reduce the required drawdown and promote uniform inflow along the wellbore.
- The SAAP is designed to disperse filter cake solids allowing for more effective flow mobility and reducing the risk of solids plugging the sand control screens.

The technology has proven quite successful in removing NAF formation damage, cleaning up NAF filter cakes and enhancing productivity.

The completion practice and sequence involved the following:

- NAF conditioning and the use of a surface screen tester to ensure no screen plugging
- Deployment of the ICD screen to total depth (TD) with an internal wash pipe
- Open-hole mechanical packers to provide zonal isolation as required for the ICD design
- The use of a 2 3/8-in. wash pipe to displace the NAF and spot the brine-based chemical treatment around and inside the screens before setting the openhole

packers and landing the liner hanger

- Recovering the inner string setting and setting the open-hole packers
- Allowing the chemical treatment to soak in the open hole while running the test string or upper completion
- Flowing back and testing the well observing flowing pressure, rate, water-cut and both filter cake and chemical treatment residue

In longer horizontal wells (length greater than 2,000 feet), the rate per relative unit length (inflow density) is usually low, even though the total production may appear high. Additionally, in a well without inflow control, the inflow density will be inherently low at the toe. It has been verified that in some cases, flow friction alone may reduce the inflow at the toe to a negligible contribution.

As discussed previously, a similar analysis has been used for all the wells and the actual and theoretical PI results have been tabulated. The difference in PIs (actual vs. theoretical) for each well has been plotted against clean-up time (**Figure 9**). Although there is no clear relationship between cleaning time and the result of the mesophase treatment, the ESP data collected during the function test shows that the combination of time and rate is important to accomplish well clean-up (**Figure 10**).

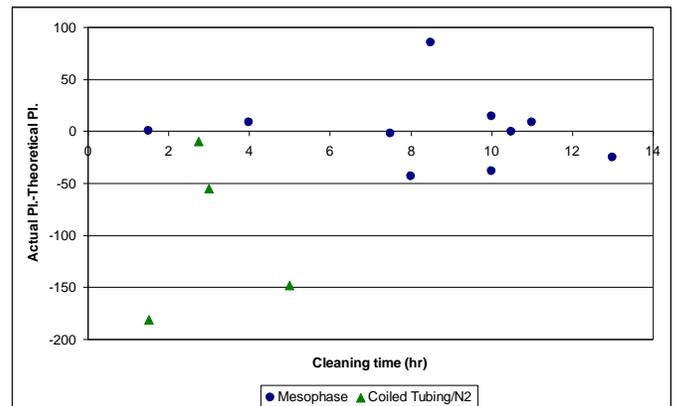


Figure 9: Actual PI minus theoretical PI vs cleaning time per treatment method

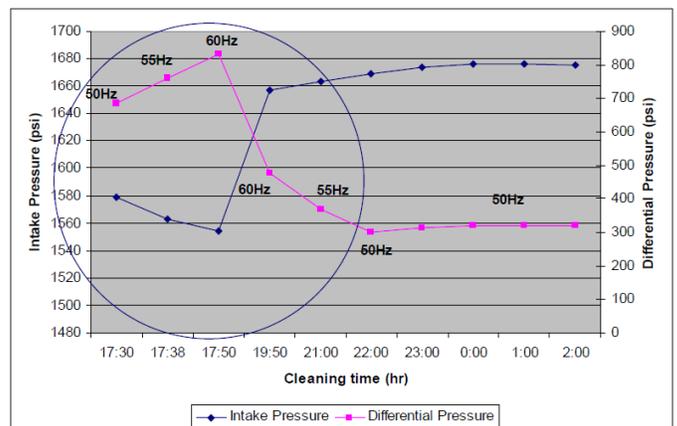


Figure 10: Example of ESP intake and differential pressure

during clean-up with mesophase clean-up

There is however a clear relationship between the PI of the treated and untreated wells, where the average actual and theoretical PI have been plotted (**Figure 11**). It is clear that the chemical spotting treatment used to displace the NAF from the open hole after running ICD screens improves the productivity of the wells. As a result of this treatment the actual productivity is closer to the theoretical PI.

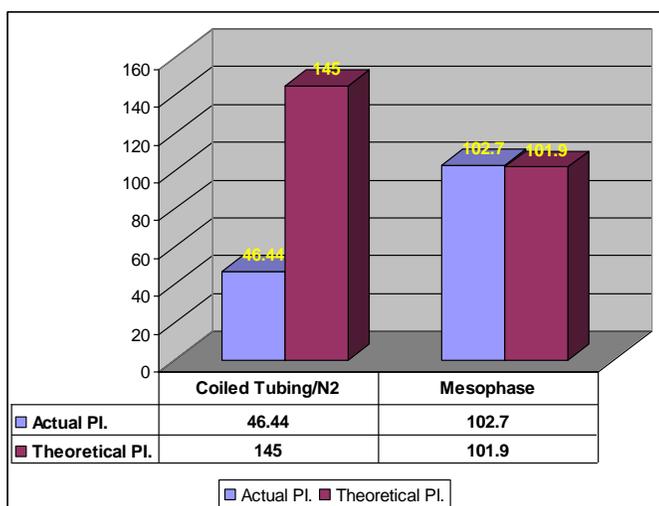


Figure 11: Average, actual, and theoretical PI

Conclusions

It is clear that the chemical treatment used as a means to displace the NAF after running the ICD screens to TD improves the productivity of the wells and, as a result of this treatment, the actual productivity is closer to the theoretical PI.

- Displacing the NAF to brine and chemical treatment improved well productivity and wellbore clean-up including a significant reduction in screen plugging as seen from both PI and PLT data.
- Combining optimal screen sizing with a tested brine-based SAAP displacement program resulted in significant PI improvements.

Acknowledgments

The authors would like to thank Saudi Aramco and Baker Hughes for their permission to publish this paper and the information within. Special thanks to Khalid Kilany for his support and guidance.

References

1. Al-Sabti, H.M., Al-Bassam, K.A. "3D Electrofacies Model, Safaniya Reservoir, Safaniya Field, Saudi Arabia," SPE 25611, SPE Middle East Oil Technical Conference & Exhibition, Manama, Bahrain, April 3-6, 1993.
2. Shahri, A.M., Kilany, K., Hembling, D., Lauritzen, J.E., Gottumukkala, V., Ogunyemi, O., Bacerra Moreno, O. "Best Cleanup Practices for an Offshore Sandstone Reservoir with ICD Completions in Horizontal Wells," SPE 120651, SPE Saudi

Arabia Section Technical Symposium and Exhibition, Al-Khobar, Kingdom of Saudi Arabia, May 9-11, 2009.

3. Quintero, L., Jones, T. A., and Clark, D. E., "One-Step Acid Removal of an Invert Emulsion", SPE 86556, SPE 6th European Formation Damage Conference, Scheveningen, The Netherlands, May 25-27, 2005.
4. Laviox, F., Leschi, P., Aubry, E., Quintero, L., Le Prat, X., Jones, T., "First Application of Novel Microemulsion Technology for Sand Control Remediation Operations – A Successful Case History from the Rosa Field, a Deepwater Development Project in Angola", SPE 107341, SPE European Formation Damage Conference, Scheveningen, The Netherlands, May 30 –June 1, 2007.
5. Quintero, L., Jones, T., Clark, D.E., Torres, C., and Christian, C. "Single-phase Microemulsion Technology for Cleaning Oil or Synthetic-Based Mud", AADE-07-NTCE-18, AADE National Technical Conference and Exhibition, Houston, Texas, April 10-12, 2007.
6. Bustin, B., Phillips, J., Al-Otaibi, M., Bin Moqbil, K., Christian, C.F., Torres, C., White, C. "Improved Wellbore Clean-up – Successful Case Histories in Saudi Arabia from Development to Field Implementation," SPE 08088, SPE Saudi Arabia Section Technical Symposium, Al-Khobar, Kingdom of Saudi Arabia, May 10-12, 2008.
7. Jones, et al. U.S. Pat. No. 7,134,496
8. Al-Otaibi, M.A., BinMoqbil, K.H., Al-Rabba, A.S., Abitradi, A.N. "Single-Stage Chemical Treatment for Oil-Based Mud Cleanup: Lab Studies and Field Case," SPE 127795, SPE International Symposium and Exhibition on Formation Damage Control, Lafayette, Louisiana, February 10-12, 2010.
9. Hembling, D., Sunbul, A.H., Salerno, G. "Advanced Well Completions Result in Enhanced Well Productivity and Recovery in Saudi Aramco's Offshore Fields," SPE 108877, SPE Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, Indonesia, October 30 – November 1, 2007.