Winter 2015

Saudi Aramco

Journal of Technology

THE SAUDI ARAMCO JOURNAL OF TECHNOLOGY
A quarterly publication of the Saudi Arabian Oil Company

Saudi Arabia's Emerging Unconventional Carbonate Shale Resources: Moving to Horizontals with an Integrated Engineering and Geosciences Approach
see page 2

First High Rate Stimulation Treatment through Coiled Tubing with Real-Time Downhole Monitoring — A Story of Success
see page 39

Tuwaiq Mountain is a narrow escarpment that cuts through the plateau of Nejd in central Arabia. It is 600 m high and also has a Middle Jurassic stratigraphic section. The eastern side slopes gradually downwards, while the western side ends in an abrupt manner. The Tuwaiq Mountain formation is a carbonate source rock play, which is thought to have sourced the majority of the conventional reservoirs of the Arabian Plate. These organic-rich sediments are some of the richest hydrocarbon source rocks in the world. With an excellent reservoir quality, the Tuwaiq Mountain is a promising unconventional gas play for the success of the unconventional resources program.

On the Cover

The nature of unconventional operations has driven unconventional resources to build a lean operating model with a focus on safety, efficiency and cost management. Due to heavy reliance on equipment intensive operations, well site equipment spacing and layout is becoming a complex matter in unconventional wells, particularly when there are simultaneous operations (SIMOPs). In SIMOPs, several product service lines operate simultaneously to perform coiled tubing, e-line, pumping and testing operations on the same well.

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ISSN 1319-2388.

The *Saudi Aramco Journal of Technology* gratefully acknowledges the assistance, contribution and cooperation of numerous operating organizations throughout the company.

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Saudi Aramco

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Contents

Saudi Arabia's Emerging Unconventional Carbonate Shale Resources: Moving to Horizontals with an Integrated Engineering and Geosciences Approach

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ABSTRACT

Unconventional resources in Saudi Arabia offer an opportunity to extend needed gas plateaus in the long term, to substitute gas for liquid fuels and to provide potential feedstock for the growing chemical industry. This article outlines the integrated engineering and geosciences approach to well completion that was applied in the Jafurah shale gas play. The goal was to address complex unconventional reservoirs and their associated challenges, and to determine the optimum completion and fracture design.

Sweet spot identification within the Jurassic Tuwaiq Mountain formation in the Jafurah basin is a major challenge as it requires drilling a large number of wells over a wide geographical area with high associated costs. Reducing those costs requires innovative drilling, completion and stimulation practices. To identify and maximize potential frac stages and placements, a comprehensive study was completed using an advanced workflow that encompasses drilling, geophysics, geomechanics, reservoir characterization, completion and fracturing design, and microseismic monitoring.

The targeted Jurassic Tuwaiq Mountain rocks are calcareous, interpreted as having been deposited in a restricted marine environment within an intra-shelf basin. This shale carbonate play shows a high total organic content (TOC), low clay content, good matrix permeability, high gas saturation and high effective porosity. Scanning electron microscope (SEM) images reveal the dominant presence of an organic porosity associated with kerogen. Initial results from vertical wells drilled in the Jafurah basin proved that proppant fracturing can be successful and indicated the presence of a potential gas-rich play within the same source rock. Subsequent horizontal wells were the first liquid-rich gas carbonate horizontal wells drilled in areas with ultra-low shale permeability in Saudi Arabia. The first horizontal wells had excellent gas production with significant amounts of condensate.

By further building on the experience from the drilled and stimulated wells, we can lay a foundation for the completion of future unconventional gas wells in the Jafurah basin.

INTRODUCTION

Saudi Aramco's unconventional resources program is a part of the Kingdom's efforts to diversify local energy resources. Developing the Kingdom's unconventional resources will fuel the growing local demand for energy and enrich the larger energy industry landscape. Unconventional plays are currently considered to be a potentially significant future source of long-term, Kingdomwide hydrocarbon production. The development of unconventional resources requires procedures and logistics that differ from those of standard conventional development. Unique unconventional development models and plans are required to ensure efficiency and economic viability.

Unconventional plays in the Kingdom are being developed utilizing the latest technologies in hydraulic fracturing. Multistage hydraulic fracturing techniques used worldwide are being adjusted continuously to fit the parameters of the Kingdom's unconventional plays. Coupling new fracturing techniques with lessons learned is the approach taken by Saudi Aramco's unconventional team to overcome various challenges associated with the operation and engineering of newly explored unconventional plays.

The unconventional program also requires a new organization and decision making model. Therefore, Saudi Aramco adopted the asset team model to commence and sustain the unconventional development program. Professionals with related experience and backgrounds were assembled to explore and assess the unconventional plays and to establish the strategy to develop these plays. This organization will guide all activities related to the exploration, appraisal, pilot projects and development of the Kingdom's unconventional resources.

The regional focus areas for the unconventional program are North and South Arabia, Jafurah and the Rub' al-Khali (Empty Quarter). The primary objective of the unconventional resources strategy is to prove, produce and deliver significant volumes of hydrocarbon liquids and/or gas from mud rocks and tight gas reservoirs.

The "de-risk" element of the strategy includes three phases: exploration, appraisal and pilot. As illustrated in Fig. 1, the dark blue areas within the triangles reflect the shifting emphasis in each phase, moving from reservoir data collection, to increasing expected ultimate recovery (EUR), i.e., the total amount of

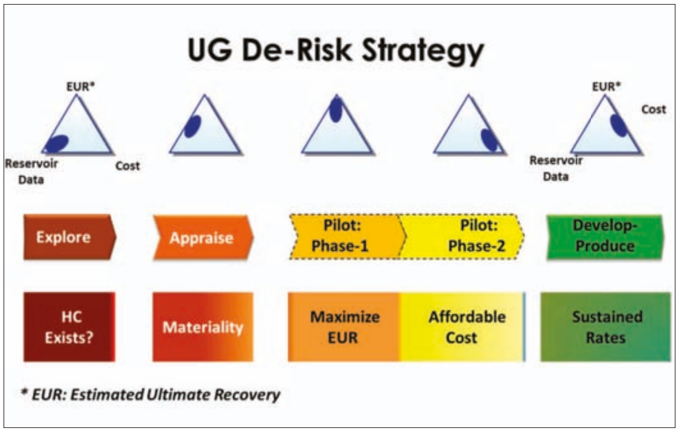

Fig. 1. De-risk strategy.

hydrocarbon resource a well will produce in its lifetime, to cost efficiency and management.

This strategy element involves critical decision points that consider the expected probability of success at the conclusion of each phase. For example, in shale gas plays, decisions are made to either proceed to the next phase or exit based on critical parameters, such as: (1) the total organic content (TOC), maturity, thickness and "brittleness" (silica vs. clay content) of the reservoir at the end of the exploration phase; (2) gas volumes and areal density at the end of the appraisal phase; and (3) EUR per well and the expected development cost at the end of the pilot phase. As shown in the boxes in Fig. 1, in each phase we are trying to meet or exceed certain conditions:

- In the exploration phase, we drill several regional wells to determine if hydrocarbons are present.
- In the appraisal phase, we drill a few wells around a successful exploration well to determine how big the play is and if there are enough hydrocarbon resources to justify development.
- In Phase 1 of the pilot phase, we may drill several wells to test technologies, establish best practices for development and identify ways to increase the EUR. We then determine if we can increase efficiency enough to reduce costs and make the well economically feasible in Phase 2.
- If so, the field goes into development.

GEOLOGICAL AND DEPOSITIONAL SETTING

Mesozoic basins formed as a result of the Late Permian and Early Triassic opening of the adjacent Neo-Tethys Ocean and the development of its margins — Tethys passive margins. The Jurassic succession of the Arabian Gulf region refers to the progressive flooding of a stable craton by a shallow sea during a major sedimentary cycle that ended with the stagnation of the seawater flood and the formation of an extensive evaporitic platform over much of the shelf during the Late Jurassic.

Variation in the sedimentary facies throughout the Jurassic rock is essentially due to eustatic changes as sea level rose or fell. Differential subsidence within the shelf, combined with a relative increase in sea level, led to the formation of relatively short-lived, intra-platform sub-basins that served as depocenters[1]. These intra-shelf sub-basins, Fig. 2, formed within the interior of a broad, extensive, shallow water carbonate platform that was separated from the open ocean to the east by a high energy platform margin. This shallow water carbonate platform has been referred to as the Central Arabian Intra-shelf Basin.

The targeted Jurassic source rocks are calcareous and interpreted as having been deposited in a restricted marine environment within an intra-shelf basin. During the Late Jurassic, the carbonate shelf environment became dominant, producing broad shelves and local intra-shelf basins containing interbedded, kerogen rich, marine lime mudstones and marls[2]. The basinal facies consist of cycles of the laminated, organic rich, lime mud wackestone that essentially comprises the Tuwaiq Mountain formation. It was in this setting that the late Callovian-Oxfordian and early Kimmeridgian Tuwaiq/Hanifa formation was deposited.

Storms that swept sediment down-dip into the outer ramp/basin appear to have waxed and waned in a cyclic manner. Three lithofacies resulted: (1) anoxic, black, laminated wackestone to mud-dominated packstone; (2) dysoxic, black, horizontally micro-bioturbated, laminated or very thin bedded wackestone to mud-dominated packstone; and (3) oxygenated, gray, bioturbated, thin bedded wackestone to mud-dominated packstone. It has been suggested that the pycnocline divided the water column, with (a) anoxic water beneath; (b) dysoxic water at the contact; and (c) oxygenated water above[3]. The pycnocline moved up and down in the water column, creating an apparent cyclicity within the strata; this movement may have been controlled by relative sea level change, variable restriction

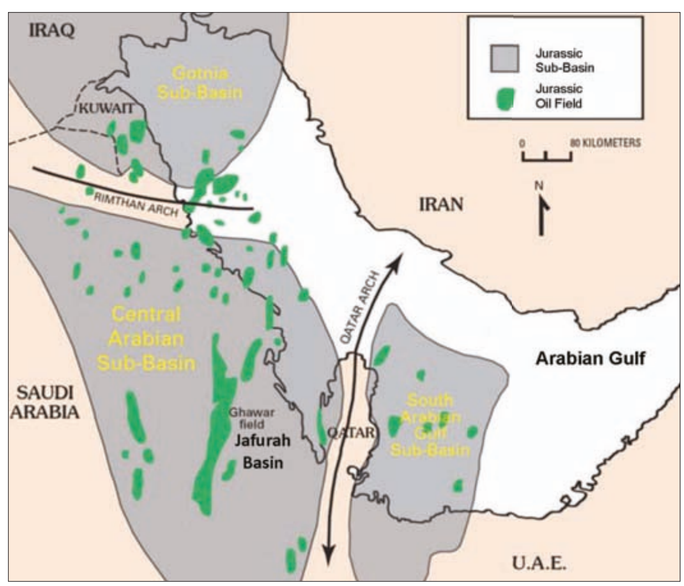

Fig. 2. Jurassic intra-shelf basins in the Arabian Gulf region[1].

of circulation or a combination of both processes, Fig. 3.

The targeted Jurassic sediments are one of the richest hydrocarbon source rocks in the world. The Jurassic carbonate source rocks in the Jafurah basin, Fig. 4, include the Tuwaiq Mountain, Hanifa and basal Jubailah formations that supplied vast amounts of oil to the Jurassic carbonate reservoirs. These source rocks, comprising the current unconventional reservoirs, contain up to 14% TOC as well as several hundreds of feet in growth thickness. The Tuwaiq Mountain play has exhibited different maturation windows — from volatile oil to gas rich condensate.

A vertical well was drilled, completed and tested to assess reservoir properties and examine flow characteristics. The well was cored, logged, hydraulic fracture stimulated and then flowed back. The results proved the success of the proppant fracturing placement and confirmed the presence of liquid rich hydrocarbons in the Tuwaiq Mountain play. Based on the encouraging results, horizontal wells were subsequently drilled, then multistage fractures were pumped along the horizontal lateral to evaluate the reservoir's maximum potential.

TUWAIQ MOUNTAIN SOURCE ROCKS CHARACTERISTICS

One of the main targets, the Tuwaiq Mountain formation, is a laminated lime mud wackestone with TOC values reaching up to 14%. Two different trends were identified based on the content of the organics: A thicker sequence exhibiting averages of 2% to 4%, and a thinner section with a predominance of high

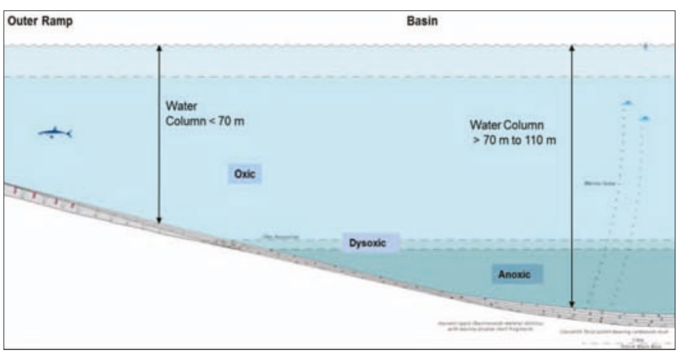

Fig. 3. Water column processes.

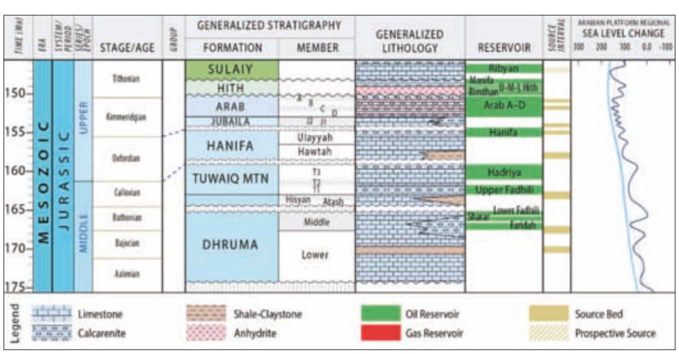

Fig. 4. Central Arabian Intra-shelf Basin geologic column.

TOC values up to 14%. Maturation was assessed with T_{MAX} — the peak temperature that corresponds to the temperature during pyrolysis that causes the maximum generation of hydrocarbons — and Vitrinite reflectance values — derived from a method for identifying the maximum temperature history of sediments in sedimentary basins. T_{MAX} values in the area of interest correspond to the maturity window of wet gas to early dry gas. The Vitrinite reflectance equivalent is estimated to be 1.34% using the Jacob conversion formula. The Tuwaiq Mountain formation is composed of thinly laminated mud wackestone and peloidal dark packstone. Based on X-ray diffraction (XRD) measurements from cores and cuttings, calcite is the dominant component. Quartz content is very low on average, and total clay content is extremely low, with the kaolinite, illite and chlorite as the predominant clays. The extremely low volume of clays makes the mineralogy unique compared with other organic rich carbonate mudstone plays.

This low volume of clays supports the low water saturation in the matrix of the rock as measured in the lab; the petrophysical properties of the rock were measured using the Gas Research Institute methodology. The total interconnected porosity in the Tuwaiq Mountain formation averages 9.67%. Samples exhibiting higher porosity are commonly associated with a high content of organics. Gas saturation in the rock is very high. Due to the low content of clays in the matrix, water saturation is low. Matrix permeability, determined from the limited number of samples, is up to 1,300 nanoDarcies (0.0013 mDarcies).

These results were calibrated with the petrophysical model, where the vertical variability of each property is identified, and the sweet spots for our lateral drilling and multistage stimulation were selected. Based on the measured reservoir properties so far, such as TOC, porosity and gas saturation, a reservoir quality matrix was used to assess the vertical and lateral variability of the rocks. Using data from the drilled horizontal wells, the reservoir quality matrix showed that the lateral variability of the reservoir is not very high. Throughout the horizontal wells, we have seen a predominance of excellent reservoir quality with minor moderate properties.

COMPLETION AND STIMULATION

Success in all unconventional projects is driven largely by completion and stimulation design. The optimum completion equipment, including wellhead, tubing, casing and liner, must be selected based on stimulation needs. The stimulation design is regulated by injection rates, treating pressures, treatment volume, fluid type, proppant, perforations and number of stages[4]. Hydraulic fracturing is an operation performed after drilling to stimulate well productivity by making fractures in the formation and thereby increasing the drainage area[5]. Early vertical completions were clearly uneconomic, which meant moving rapidly to horizontal completions, known — together with multistage fracturing — to crack the code of unconventional reservoirs. The transition from vertical single-stage completions to horizontal multistage completions was no easy task. Several technical challenges were encountered in the transitional phase; the items discussed next can benefit engineers working in unconventional fields by shortening the learning curve.

COMPLETIONS

To engineer successful fracture stimulation treatments in the Jafurah basin, fit-for-purpose completions had to be selected carefully. Completion challenges were linked to the high treating pressure, which required the proper selection of wellhead, tubing, casing and liner. Based on the first vertical well experience[6], formation closure pressure was expected to be high — in the range of 0.98 psi/ft to 1.05 psi/ft — necessitating high-pressure completions. The strategy developed for the first vertical exploration well in the Jafurah basin was further enhanced for the early horizontal wells.

The horizontal wells in the Jafurah basin are typically completed with 4½" Q-125, 15.1 lb/ft floating tubing and cemented liner with a 10,000 psi tree, along with a 30 ft polished-bore receptacle, normally strung at 8,000 ft to 9,000 ft to allow for 25 ft tubing movement during stimulation treatments. The true vertical depth for central Jafurah wells is ± 10,000 ft, with horizontal laterals exceeding 5,000 ft, Fig. 5. A wellhead isolation tool is required to allow for pumping frac jobs while isolating the 10,000 psi wellhead components. The surface equipment is rated for 15,000 psi, but the treating pressure is limited to 13,500 psi for safety reasons. The injection rate ranges from 50 barrels per minute (bpm) to 55 bpm.

The number of stages has been maintained at 16 per lateral, but is expected to increase in the near future. The current completion designs utilize three, 1½ ft clusters per stage with six shots per foot (SPF) and 60° phasing. The additional stages' spacing and number of clusters per stage will depend on microseismic data to be collected by offset wells, together with reservoir modeling simulators. The horizontal wells are drilled in the direction of the least principal horizontal stress. This allows for transverse fracs to the wellbore, which encourages maximized reservoir contact.

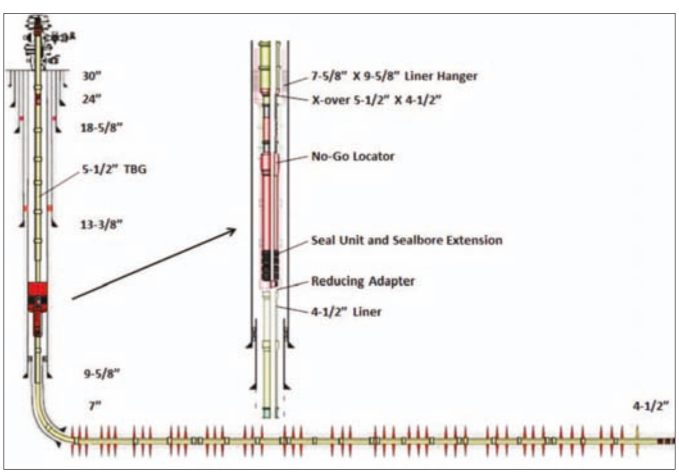

Fig. 5. Completion design for initial Jafurah basin wells.

WELLBORE STABILITY

The difference between maximum horizontal stress calibrated from a Diagnostic Fracture Injection Test (DFIT) and vertical stress obtained from the density logs is significant. This creates complexity both while drilling and during the completion stage. Having a tectonically stressed environment together with heterogeneous rock can lead to wellbore instability unless conditions are properly analyzed and managed. The horizontal laterals in the Jafurah wells were found to be substantially broken out, and the holes were over gauged. Breakouts are caused by hoop stresses greater than the uniaxial compressive strength (UCS). The TOC in the rock is expected to have an impact on the hole's stability; higher TOC reduces the rock UCS, leading to more breakouts.

Wellbore instability with tight spots were encountered in the first two wells, which were drilled with water-based mud (WBM). The 4½" liner could not be run in the 6⅛" hole to total depth (TD) as planned, leaving 700 ft to 1,000 ft of open hole drilled in the lateral section. To complete the wells, the liner had to be rotated and pushed down with significant torque applied. In one of the wells, this resulted in 42 over-torqued joints in the upper part, which had to be milled through with high-pressure coiled tubing (CT). This "soft" milling caused 20% metal loss in several sections of the liner, according to caliper logging. A WellCAT completion analysis limited the maximum bottom-hole pressure while pumping to 19,000 psi. To avoid compromising the completion integrity, the treatment options were limited, and it was opted to use a conservative approach.

Based on lab tests, oil-based mud (OBM) showed a greater ability to maintain a high-pressure differential across the core face. For water-wet rock with very small diameter pores or fractures, a very high capillary pressure is required to force oil through the core. This effect is what gives operators using OBM the ability to drill efficiently through shale, which presents problems when drilled with WBM. Although the rock in these tests is limestone rather than shale, the very low permeability means that the effect of capillary pressure is similar. Switching from WBM to OBM significantly improved wellbore stability and allowed the running of liners to TD in subsequent wells. Additionally, drilling with OBM reduced the number of days required to drill the horizontal laterals, which reduced the drilling costs.

TUBING SIZE

Completing the early horizontal wells with 4½" monobore completions presented two challenges, namely limited wellbore accessibility and high wellhead treating pressure (WHTP).

Caliper logging showed twisted off sections of the tubing/liner with abnormal deformations due to fatigue and excessive torque. The fatigue was attributed to the multiple exposures of the tubing to forces and pressure cycles while pumping the stimulation stages. On the other hand, the excessive torque occurred while running the liner, as previously addressed. In general, well stability is known to be problematic for well intervention operations. For two of the early wells, Plug-n-Perf pump down using a wireline was discontinued, and the remaining stages had to be completed with CT, which increased the capital cost and caused a substantial delay. Later, while milling the plugs with CT, significant drag was observed, reaching the CT limitations.

Bottom-hole treating pressure (BHTP) is another important parameter in hydraulic fracturing treatments. Analysis of BHTP is used to make on-the-fly decisions regarding design and job completion. The value of BHTP is composed of three components, namely surface treating pressure, hydrostatic pressure and friction pressure. Friction pressure is the total friction loss due to pipe and entry friction when frac fluid is being pumped from the surface. By using tubing and liner with a larger inside diameter (ID), friction is reduced, providing more room for increasing the surface pressure, and consequently, BHTP.

Pressure loss due to pipe friction is expressed in Eqn. 1:

$$\Delta P = \frac{2f\rho v^2}{D_i}\Delta z \quad (1)$$

Pressure sensitivities for different well configurations were simulated for:

- 4½" monobore, Fig. 6.
- 5½" monobore, Fig. 7.
- 4½" × 5½", crossover at 8,480 ft, Fig. 8.

The maximum WHTP was 13,135 psi, 11,462 psi and 12,269 psi, respectively. Adapting to the configuration in Fig. 8 allowed for less WHTP, and consequently, less horsepower.

In an attempt to lower pipe friction pressures, and therefore wellhead pressure, a 4½" × 5½" string was adapted to improve the completion efficiency and lower the pumping pressure to acceptable limits. Plans are for future wells to be completed with a 5½" monobore to further lower friction pressures and improve efficiency.

Pipe Erosion

In the Jafurah basin, pumping pressures during fracturing jobs can reach up to 14,000 psi. At the same time, fracturing trees used for the operation are rated for only 10,000 psi working pressure. For this reason, an isolation tool is being used to guard the trees from high pressures. An issue involving this tool has surfaced, though. On the fourth treated well, Well H-3, during Stage 13 communication between the tubing and the tubing casing annulus occurred. Results from the multi-finger imaging tool (MIT) log showed an ID increase in the 5½" tubing from 4.778" to more than 5½", Fig. 9.

It had been noticed during the job that the area just below the exit point of the isolation tool (bull nose) — where the pipe changes from a smaller isolation tool ID of 2.75" to a

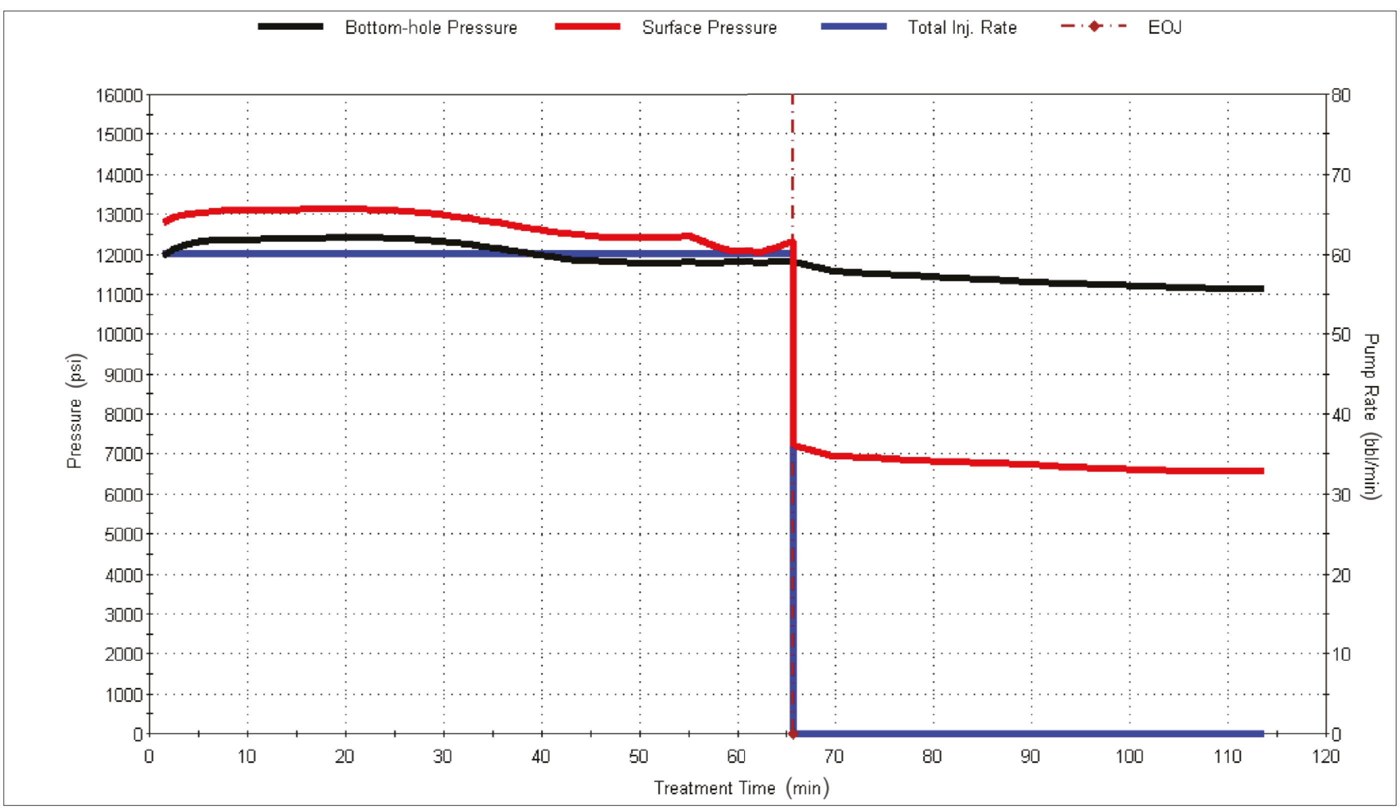

Fig. 6. A 4½" monobore maximum pressure simulation.

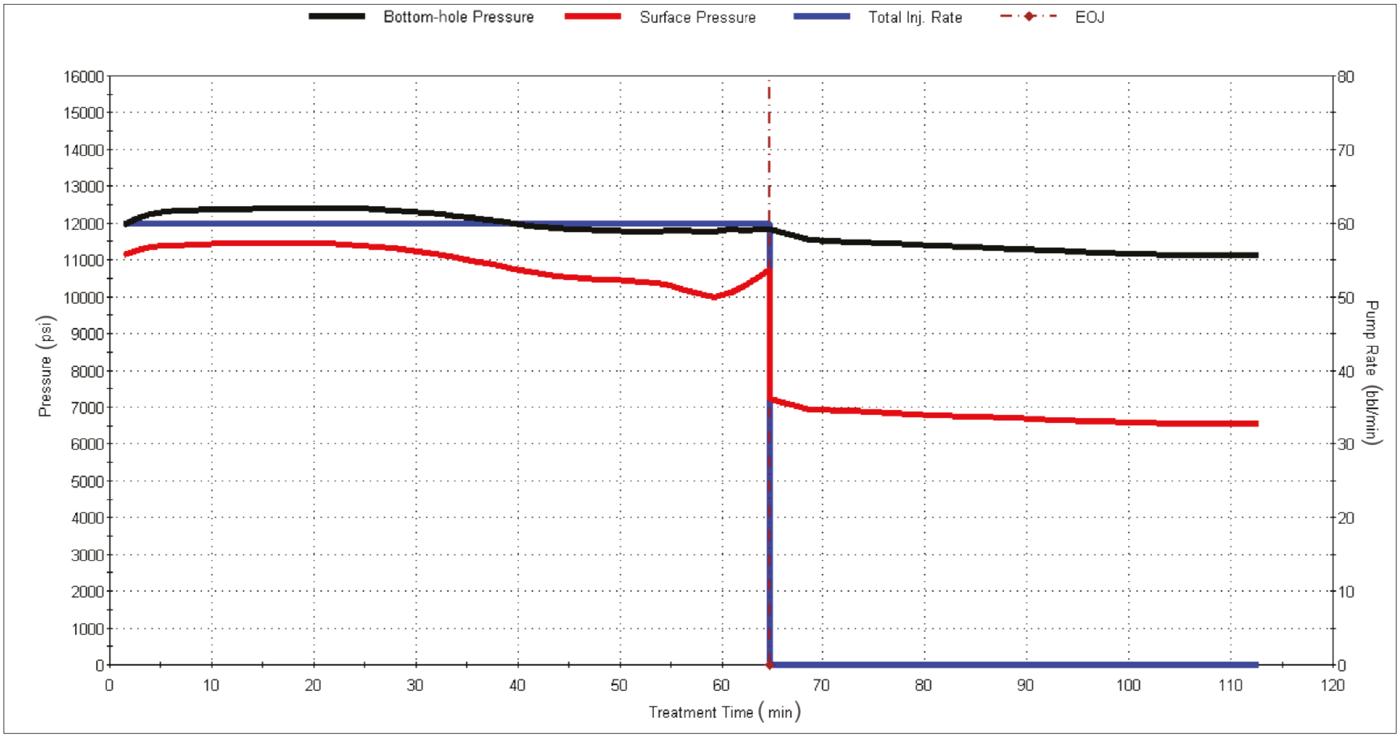

Fig. 7. A 5½" monobore maximum pressure simulation.

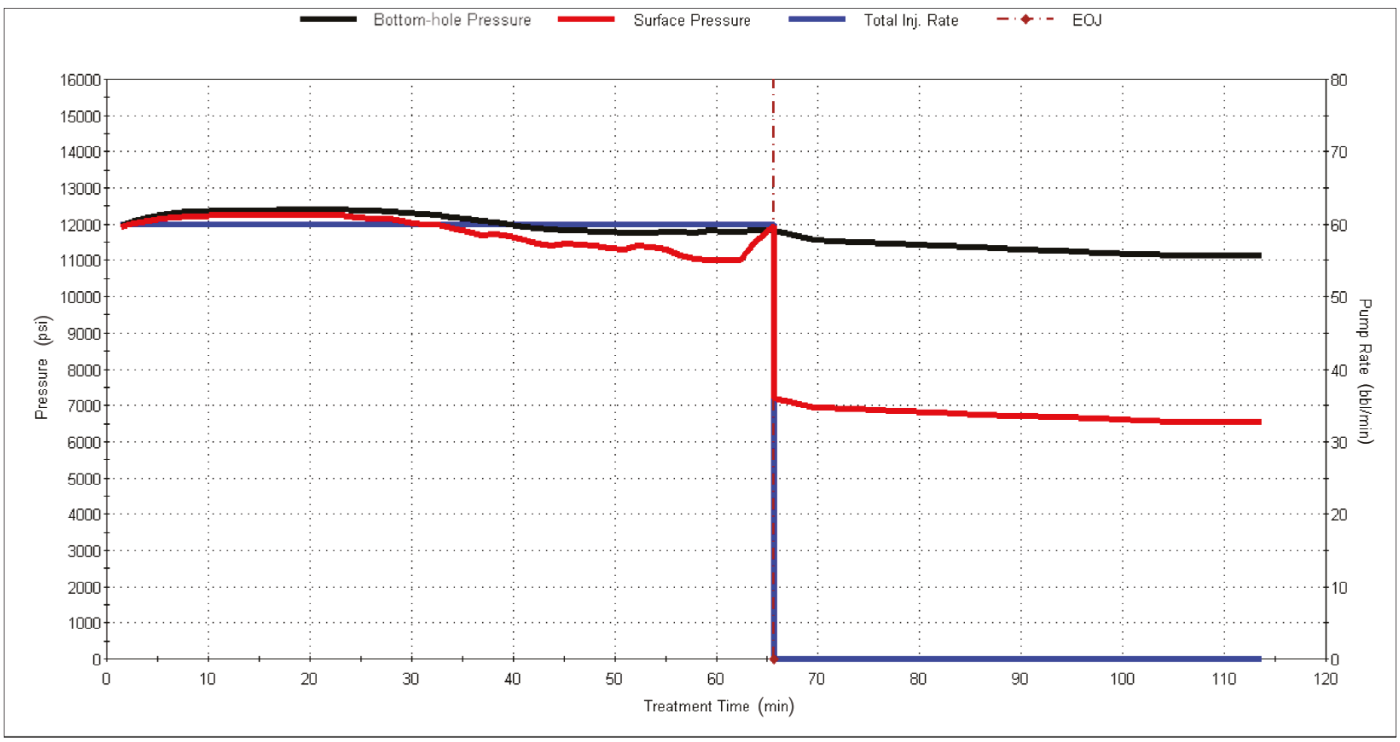

Fig. 8. A 4½" × 5½" maximum pressure simulation.

larger ID of 4.778" for 5½" tubing or 3.826" for 4½" tubing — was eroding due to the high velocities and turbulent flow of the proppant slurry. The erosion effect became more severe with an increase in the amount of proppant pumped, an increase in pumping rate, and a decrease in the tubing's ID. We could see that roughly 1 foot of the tubing was affected across the whole circumferential area of the pipe, with extreme ID increase at one area where the pipe had burst. The average pump rate for 13 stages was 60 bpm at 10,000 psi surface pressure, and a total of 3.73 million lb of 30/50 intermediate strength proppant (ISP) and 20/40 high strength proppant (HSP) was pumped. The 4½" tubing was affected more compared to the 5½" tubing at the same pumping rates and proppant amounts pumped. The well had to be worked over to change the upper completion.

On future wells we introduced several standard operating

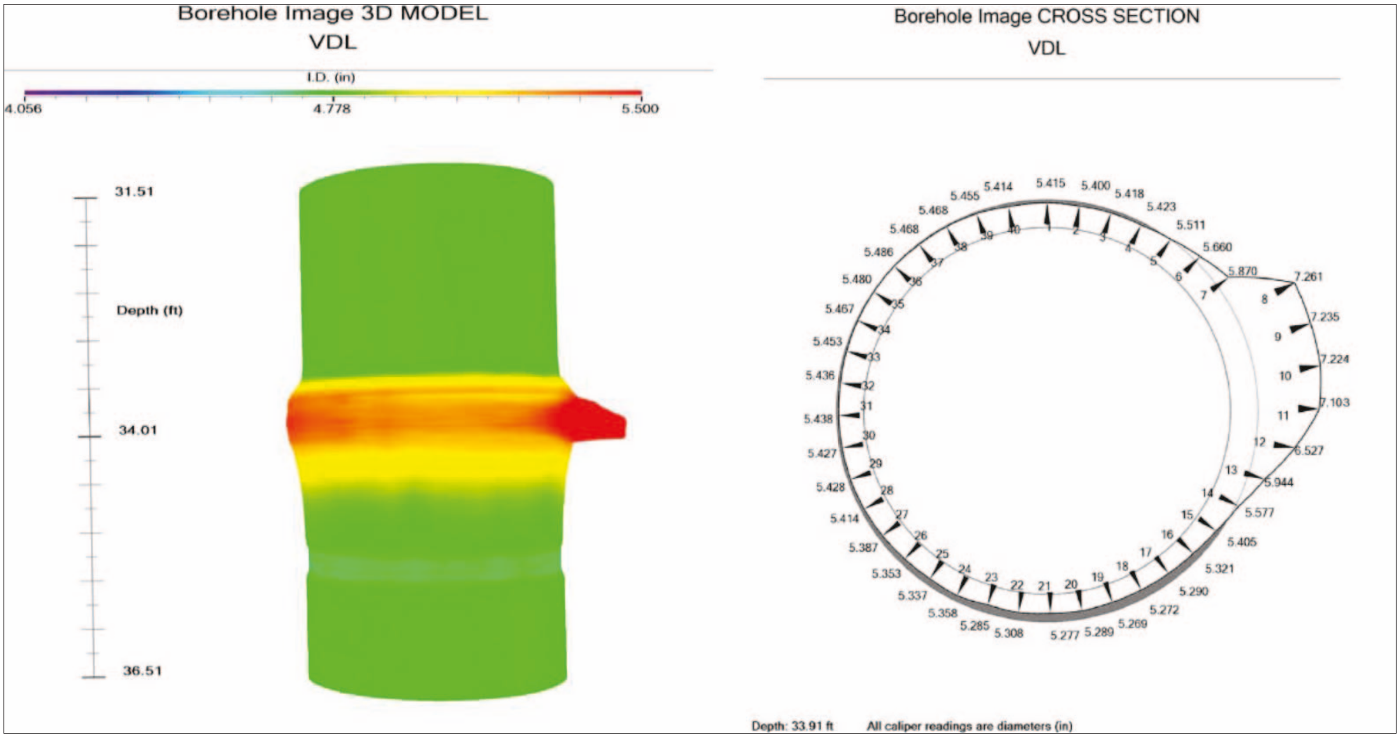

Fig. 9. Well H-3 MIT log of 5½" tubing below isolation tool bull nose.

procedures to minimize the erosion effect:

- The pumping rate was limited to 52 bpm. That was the minimum rate needed for efficient diversion of three clusters.
- The isolation tool bull nose was set at selectively different depths during the fracturing stages to alter the area being exposed to erosion, Fig. 10. This causes the erosion to be evenly distributed over several sections and so minimizes severe erosion impact on only one section, as in Well H-3.
- A regular bull nose was replaced with a high rate bull nose at the end of the isolation pipe. With its longer and smoother cone shaped transition area between the tool and tubing, the high rate bull nose resulted in smoother and less turbulent flow below the tool, and consequently reduced the erosion effect on the tubing.
- A MIT log was run every five to six stages to closely follow up the development of erosion areas.

The plan for future wells is to run 5½" tubing on every well and use 15,000 psi operational pressure rated fracturing trees to avoid the need for the isolation tool.

Table 1 shows the MIT results for some of the wells.

We can conclude that an increase in pumping rate exponentially increases the effect of erosion. Well H-2, at an average rate of 50 bpm, doesn't have significant erosion in 5½" tubing. In Well H-3, the 5½" tubing, with only a 20% higher pumping rate and a 13% larger amount of proppant, burst. Furthermore, in Well H-5, the smaller 4½" tubing lost 29% of the wall thickness at an average pump rate of only 38 bpm and 1.50 million lb of proppant pumped after six stages. In Well Q-4 — with 5½" tubing — after seven stages and 1.80 million lb of proppant pumped pipe thickness reduction was only 15%.

Stimulation

A successful frac job is key to achieving good production rates from wells. Like with all unconventional reservoirs, the goal is to contact as much rock as possible with a fracture network of adequate conductivity[7, 8].

The governing parameters in proppant selection are frac placement and conductivity. Adequate frac conductivity, especially near the sand face, is a must to assure production. The DFIT results were used to select the proper proppant strength. The stresses obtained from the DFIT placed the proppant requirement at the upper limits of ISP, but the early stages were pumped with HSP.

Height Containment

Height containment, due to stress contrast, is key to keeping the fracture in the intended zone. Stress barriers are evaluated carefully to design a confined fracture height without compromising frac length and width. This is particularly critical in the Jafurah basin to avoid the Hanifa formation reservoir, which is known to be water wet. Plug-n-Perf completions use multiple perforation clusters per stage, which create several injection points. The pumped fluid chooses the path of least resistance, which makes controlling fracture height largely impossible. The post-frac simulations, Fig. 11, show that the frac breached into the Hanifa formation, was confirmed by production logging.

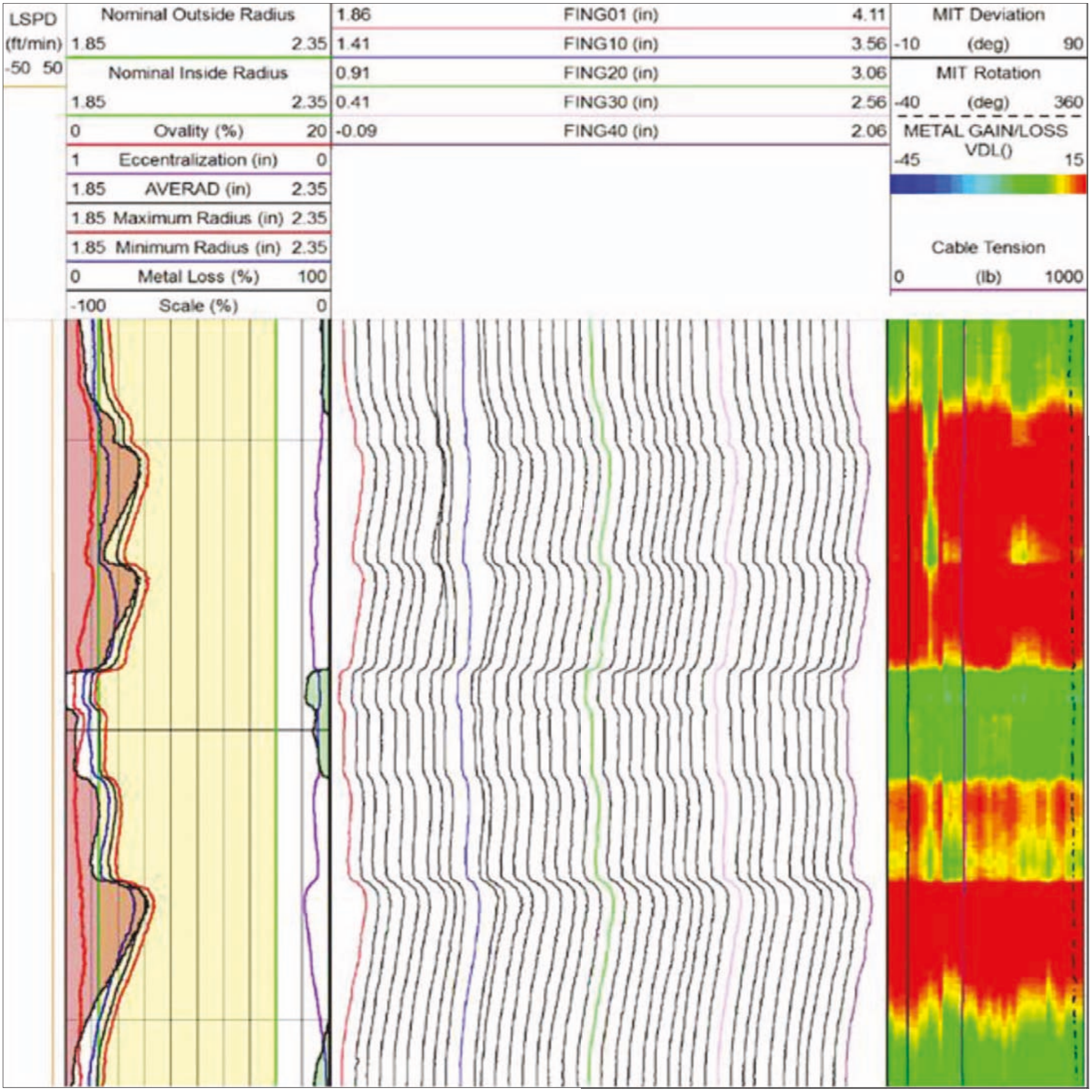

Fig. 10. Well H-5 MIT log of 4½" tubing showing several areas of erosion due to different setting depths of the isolation tool bull nose.

	Well H-2	Well H-3	Well H-5	Well Q-4
Tubing Size (in)	5½	5½	4½	5½
Proppant Pumped (million lb)	3.09	3.48	1.50	1.80
Pumping Rate	50	60	38	37
ID Loss from MIT (%)	No significant erosion (after 16 stages)	Burst pipe (after 13 stages)	29% (after 6 stages)	15% (after 7 stages)

Table 1. The MIT results for some Jafurah basin wells

Acid Effect

Near wellbore tortuosity and friction can lead to significant path restrictions between the wellbore and potential fractures. Therefore, it is necessary to remove this restriction to assure successful frac placement.

The XRD analysis for the tested core samples showed that the cores consist mainly of calcite with lower concentrations of dolomite, quartz, anhydrite, pyrite and clays — kaolinite, chlorite, palygorskite and illite. Core samples were tested for their solubility in hydrochloric (HCl) acid. The reaction was confirmed in 15 wt% and 28 wt% HCl acid at a rock/acid ratio of 1 g/10 ml (5 g solid in 50 ml of acid), and the reaction time was 3 hours at room temperature. The acid solubility test results were utilized while designing the stimulation treatment in the horizontal wells.

Early fracs were designed with < 1,000 gal of acid per cluster, but this was increased to 2,000 gal to enhance diversion and alleviate near wellbore friction. Acid proved to be effective for flow diversion among clusters and not only ensured successful treatment placement but also assured the contribution of all clusters to production. From the job plot, Fig. 12, we can clearly see the acid effect on near wellbore friction once it starts going through the perforations, where 6,000 gal of acid reduced the near wellbore friction pressure by almost 3,000 psi.

Correlation between Frac and Production Parameters

It is traditional industry practice to displace the end of the last proppant stage with a clean fluid by a volume greater than the pipe displacement volume from the surface to the top perforation, usually by an excess of 25 barrels to 75 barrels of overflush volume. The overflush is intended to leave a proppant-free wellbore and so eliminate well intervention difficulties during the Plug-n-Perf operations.

This practice has raised concerns about disturbing near wellbore proppant conductivity and potentially harming fracture continuity with the wellbore, and therefore, productivity[9]. These concerns have encouraged the production engineering team to minimize excess flush volumes in the Jafurah formation.

Figure 13 shows a clear relationship between overflush volume and production rate. As the overflush volume decreases,

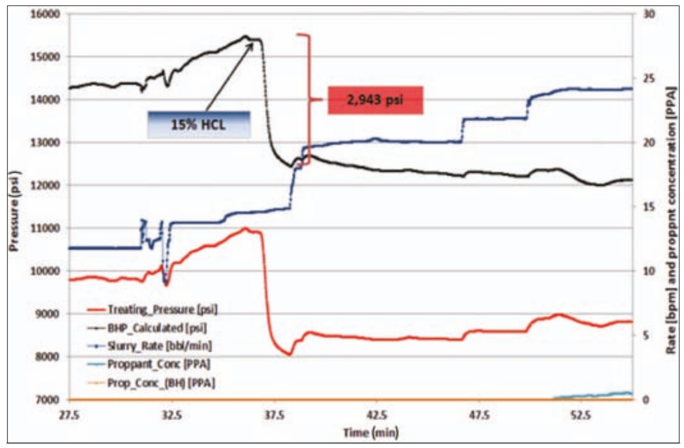

Fig. 12. Acid effect on near wellbore friction.

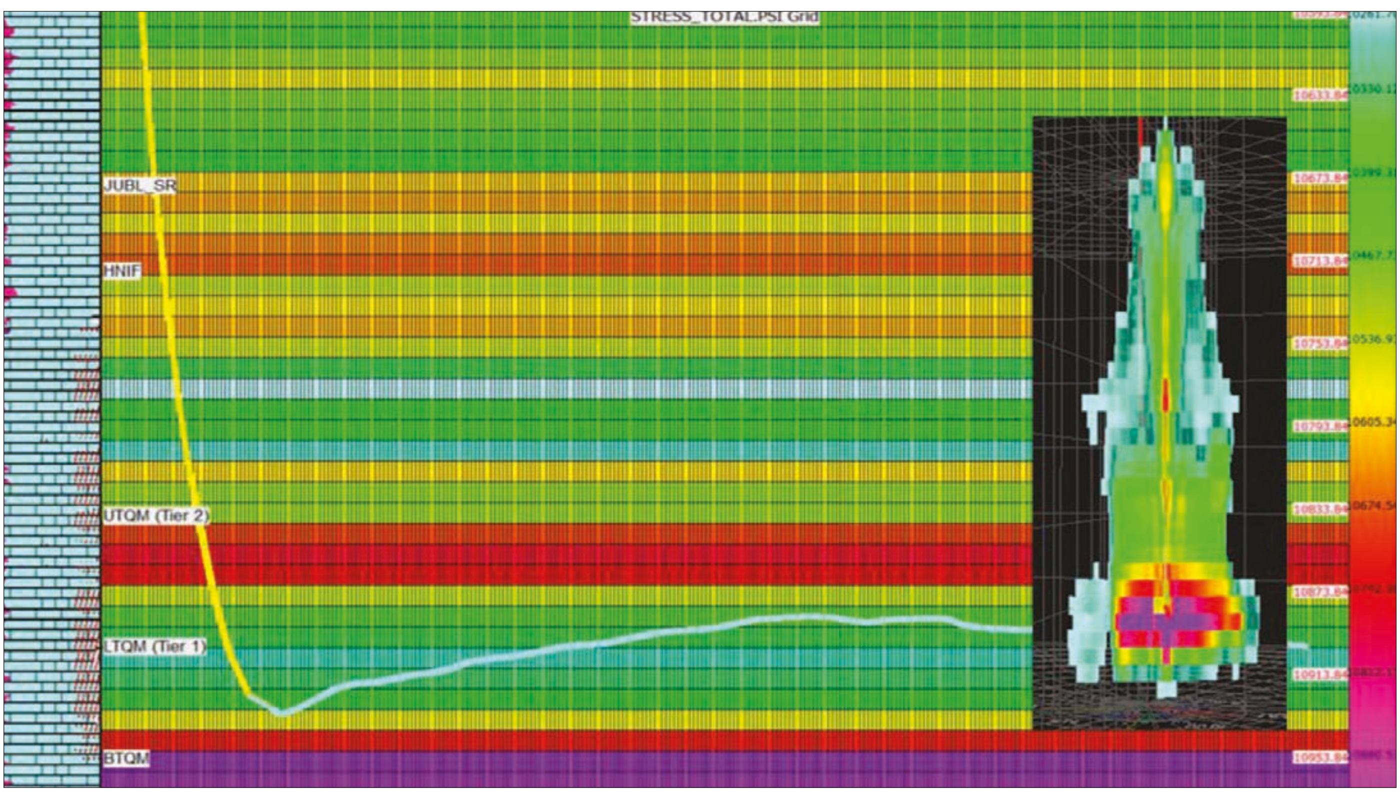

Fig. 11. Fracture growth to neighboring formations in a Plug-n-Perf completion.

gas production increases, and vice versa. This proved true for all seven wells except Well Q-4, where we saw a slight gas production decrease with a minor overflush reduction. Comparing overflush volume with condensate production doesn't result in the same clear trend, but for most of the wells the trend is still there. Minimization of overflush volume assures the presence of proppant near the wellbore, resulting in better connectivity between the fracture and the wellbore, and consequently, more of a conductive flow path for hydrocarbon production.

A higher value of instantaneous shut-in pressure (ISIP) or fracture net pressure at the end of the job corresponds to a larger fracture width, and consequently, greater production. No relationship was graphed between the ISIP and production. On the other hand, Fig. 14 shows a corresponding trend between maximum proppant concentration and gas production in five out of seven wells. The relationship between proppant concentration and condensate production also gives us the same trend for five wells. Evidently, higher production is more dependent on maximum proppant concentration than on ISIP. The same goes for the pumping rate, which in our case can be related to ISIP but not to maximum proppant concentration and production.

The total amount of proppant placed inside the fracture doesn't appear to have a direct relationship with production,

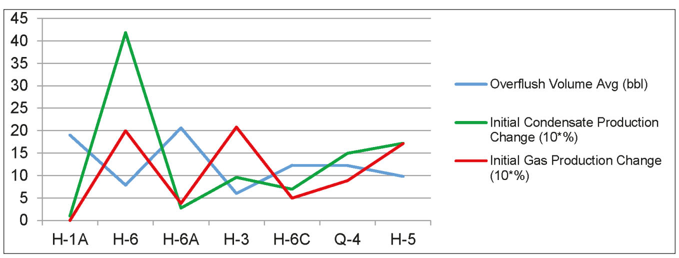

Fig. 13. Overflush volume vs. production.

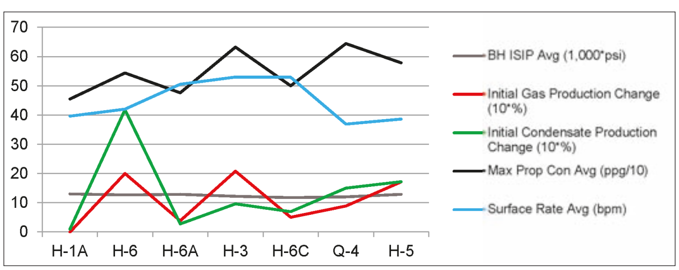

Fig. 14. Net pressure, ISIP, proppant volume and concentration vs. production.

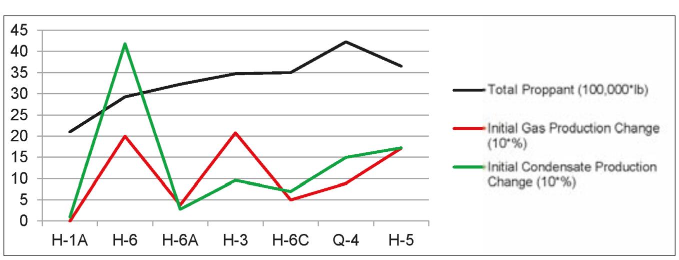

Fig. 15. Total proppant vs. production.

i.e., a lower amount of proppant can yield equivalent production results, Fig. 15. There is always a threshold above which an increase in the proppant amount, frac width or maximum proppant concentration has no further significant effect on production.

CONCLUSIONS

1. It will take time to fully exploit a resource of the size and complexity of the Jafurah shale gas play.
2. The horizontal laterals are currently drilled with OBM to improve wellbore stability.
3. A well completion design upgrade to 4½" liner and 5½" tubing has lowered friction and WHTPs.
4. Experimental tests were carried out to come up with the optimum acid volume and percentage of potassium chloride.
5. Overflush volume was directly linked to the production profile and was minimized in subsequent wells.
6. All laterals using three, 1½ ft clusters per stage, six SPF and 60° phasing were found to be contributing in production logs. The goal is to test four-cluster stages and compare productivity.
7. Standard operating procedures were introduced to control pipe erosion below the wellhead isolation tool.
8. Frac height containment was found to be vital to reduce water production from neighboring formations.
9. Further analyses are required to come up with the optimum proppant volume and maximum concentration.

ACKNOWLEDGMENTS

The authors would like to thank the management of Saudi Aramco for their support and permission to publish this article. Furthermore, the authors would like to thank Azmi Al Ruwaished, Well Completion Superintendent, for his contribution and support.

This article was presented at the SPE Asia Pacific Unconventional Resources Conference and Exhibition, Brisbane, Australia, November 9-11, 2015.

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BIOGRAPHIES

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World's First Tandem 2.125" Coiled Tubing Tractor for ESP Open Hole Completions

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ABSTRACT

Hydraulic coiled tubing (CT) tractors with a 4.7" outside diameter (OD) have been employed quite effectively, with superior CT accessibility, in the extended reach, open hole horizontal wells of a giant carbonate field in Saudi Arabia. The use of such tractors in these mega-reach wells has allowed more cost-effective chemical placements and well stimulation treatments. Relatively large monobore completions — with 7" OD tubing — of water injectors in this field have been necessary for the success of the CT tractor deployment. Conducting similar well interventions with hydraulic CT tractors in oil producers posed a challenge, mainly because of the smaller completion sizes and the chance of restrictions in the completion. Although a smaller 2.125" OD tractor existed, the pulling force of this tractor was insufficient to reliably pull the CT to total depth (TD) in many of these extended reach oil wells. Subsequently, the wells have not been stimulated to TD, which results in reduced production and reservoir optimization.

To overcome this challenge, following successful simulation runs, a special team assembled and trial tested a 2.125" hybrid tractor built to run in a tandem configuration. New components were designed and manufactured to allow two of the 2.125" tractors to run together and convey CT beyond the helical lockup point. The trial was the first successful application of a 2.125" tandem tractor to convey 2" CT through a completion with a 2.441" inside diameter (ID) minimum restriction.

The tandem tractor performance was close to the predictions of the simulation, reaching a TD of 21,591 ft with over 4,000 ft in an open hole environment. The new tractor system pulled the CT over 1,500 ft. At this depth, a ball was pumped down the reel to isolate the tractor from the acid, allowing matrix stimulation treatments across the pay intervals at relatively high rates without damaging the tool.

The successful deployment of the new tandem tractor in this field not only represents a significant opportunity for the development of the field, but also has potentially far reaching global applications. The broad implications include the possibility of interventions in existing mega-reach oil producer wells with relatively small bore completions.

INTRODUCTION

Tractor interventions in the well stimulation of extended reach power water injectors (PWIs) in this field have been reviewed quite extensively[1]. The field is the largest extended reach hydrocarbon producer project in the world. Successful open hole interventions in the PWIs have been possible employing 4.7" hydraulic coiled tubing (CT) tractors. The use of hydraulic tractors provided superior CT accessibility in the extended reach, open hole horizontal wells and enabled more cost-effective chemical placements and stimulation of the PWIs. The specific intervention objectives for the PWIs include acid stimulations and running water injection profiling tools to evaluate the reservoir injectivities after stimulation and to evaluate the injectivity index of the wells. Despite the success of well interventions with 4.7" hydraulic tractors in the water injectors, it was impossible to conduct well reentries with 4.7" sized tractors in oil producers because of the 2.441" minimum inside diameter (ID) of the Y tools in the electrical submersible pump (ESP) completions.

The challenge posed by these restrictions in the ESP completions necessitated the development of a tandem, electric-hydraulic hybrid 2.125" tractor. After tool development, the first well selected to trial test the new tandem tractor was one of many extended reach wells in this large Middle East heavy oil carbonate field. The purpose of the trial was to confirm whether the newly developed tractor could convey CT through the typical 2.441" minimum ID restriction of the Y tool in the ESP completions for the extended reach oil wells and so maximize open hole coverage for acid treatments. More than 44% of the oil producers have lengths greater than 16,000 ft, typically beyond the normal reach of CT in oil wells. The newly drilled wells required remedial acid treatments to remove mud particle and filtrate invasion from drilling and completion fluids across the open hole intervals.

The field development combines peripheral PWI wells to provide pressure support and ESP assisted oil producers to optimize production over the life of the field. The field is one of the largest ongoing increments in Saudi Arabia and represents a major company investment to meet global energy demand in the 21st century. The wells are located onshore, offshore and on 25 man-made island pads that run along the

Arabian Gulf coastline. To optimally exploit the resources in this carbonate reservoir, drilling and completion of extended reach wells for maximum reservoir contact was necessary. The extended reach wells were also needed to ensure a minimum environmental footprint in the development of wells on the artificial islands. Given the relatively long open hole reservoir intervals, acid treatment using CT for mechanical diversion was the most effective method to combat the wellbore damage arising from normal drilling operations and to stimulate the wells. An additional downhole pulling force was required to overcome helical buckling and enable the CT to reach the toes of the extended reach horizontal wells and to allow stimulation treatments.

The efficacy of applying CT tractors as conveyance solutions to overcome the challenges of weight stacking and helical buckling in extended reach wells has been previously demonstrated[2, 3]. The typical operation of CT tractors in extended reach, open hole horizontal wells is to move the CT lockup point further toward the toe of the well as much as possible. Weight stacking and helical buckling in extended reach wells can often prevent the CT from reaching the horizontal well's total depth (TD). During acid stimulation jobs, when CT lockup occurs before the CT reaches the toe of the well, it can usually leave potentially large portions of the reservoir unstimulated. Typically, when the treatment is then bullheaded from the lockup depth, uneven distribution can result. The possibility of washing out hole sections is also present with bullheading, possibly making the hole inaccessible by downhole tools for future interventions. Further, natural fractures and the natural heterogeneity of carbonate reservoirs with large porosity and permeability contrasts often result in fluids taking the path of least resistance to deliver ineffective zonal coverage in stimulation treatments[4].

The extended reach oil producers have open hole completions that require acid stimulation. The root cause of the intervention challenge in oil producing wells is their relatively smaller completion size compared with the completion size in the PWIs in the field. Whereas the PWIs have 7" monobore completions, which allow relatively larger hydraulic tractors to convey CT to TD in extended reach wells of over 30,000 ft, the oil producers have 4½" tubing with 2.441" ID restrictions in the upper completions because of the ESPs installed there. These restrictions limit the size of the CT bottom-hole assembly (BHA) being run for intervention.

The importance of zone coverage in acid treatment placements is evident in the increased reservoir production from shallower wells in the field. Kalfayan (2008)[5] showed that apart from improper well diagnosis, the main reason why stimulation treatments do not succeed is improper placement — when treatment fluids do not sufficiently contact the pay zone. Other justifications for ensuring zone coverage of acid treatments include the potential improvement in reservoir optimization[6], improved return on investment per well/per field[7] and increased optimization of rigs — with the preferential application of CT rigless stimulations instead. Initially, well interventions, including CT stimulation operations, were performed with a rig on location to validate the CT reach capabilities using conveyance solutions, such as tractors and agitators. Subsequent successful CT rigless stimulation trials helped to capitalize on rig cost savings and expedite project execution.

The extended reach, open hole oil well completions not only aggravated the CT reach problem but also affected the stimulation treatment placement, necessitating real-time temperature monitoring to ensure targeted acid placement in the reservoirs. Pre- and post-stimulation logging was conducted on selected oil producers to assess treatment effectiveness and to gain knowledge applicable to subsequent well treatments. To increase the CT reach, a combination of tapered CT strings, drag reducers and a variety of agitator solutions have been applied in the stimulation of the oil wells.

THE USE OF A RIG VS. CT RIGLESS STIMULATION

Cost Savings

The reach limitation during well intervention seems more of a concern — how far and how operators cost effectively can access the well post-drilling — than the extent to which wells can be drilled. For the extended reach wells in the field, the preferential use of CT over a rig to conduct the stimulation arose partly because of cost and availability. Therefore, extending the reach of the CT via the tandem tractor conveyance technique both allows much more effective stimulation of oil producers and opens a window of opportunity for other intervention in the wells. The solution lets operators use CT to complete stimulation activities in oil producers instead of using a drilling rig for the same purpose.

Health, Safety and Environmental (HSE) Considerations

The use of a seamless pipe (CT) compared with the use of a jointed pipe (rig pipe) for an acid stimulation provides a significant HSE advantage in terms of physical rig-up, storage and transfer of acid, pumping of acid and exposure to personnel. The CT unit typically leaves a smaller footprint than the rig, with fewer lifts, lower carbon dioxide (CO_2) emissions, etc. Also, the complete pumping and successful placement of stimulation treatments using CT, with full zone coverage vs. partial zone coverage, means less live acid transport and disposal after the job. Another major HSE consideration is the increased possibility of a well control problem on a rig while tripping out of hole with a jointed pipe after the acid stimulation treatment. Although enzymes and retarding systems have been applied to delay the hydrochloric (HCl) acid reaction times, these systems have offered mixed results, especially for extended reach wells where well control issues are ever present[3].

DESIGN CHALLENGES

A team was assembled with the responsibility to design a conveyance solution for extending the reach of the CT in extended reach oil wells and subsequently enabling more effective stimulation operation. Given a specific window of design requirements, the team set its engineering objective to develop a special 2.125" hybrid (electric-hydraulic) tractor that utilized the fluid flow from the CT for generating significant pull force on the end of the CT to overcome buckling and make progress toward the toe of the horizontal well. At the toe — or as deep as the CT could be pulled to — the tractor would then allow pumping of the acid treatment across the pay zone for optimal reservoir stimulation and greater oil production. As is the standard in engineering work in the oil field, the tandem tractor development had some challenging considerations or bases for design.

Safety for operations. The system should be built in compliance with global safety regulations and standards. Design considerations in meeting this criterion include weight, ease of handling and safety. The tractor should be relatively lightweight, easy to handle, safe to handle physically, and safe to operate both electrically and hydraulically.

Speed of development. The development of the hybrid 2.125" CT tractor had to happen in record time. The time allotted from the feasibility discussions up to field testing of the hybrid system in the Kingdom of Saudi Arabia was only four months and required, at that delivery schedule, the completion of three systems.

Tight specifications. The tractor solution should pass through well restrictions, such as pre-installed Y tools and ESPs, which required a maximum tractor outside diameter (OD) of 2.125", while still possessing the capability of exerting a pull force of 2,000 lb in an open hole environment drilled with a 6.125" bit.

Harsh environment. The tractor was required to survive and operate in the harsh environment — high pressure, high hydrogen sulfide (H_2S) and high CO_2 — created as part of normal stimulation operation, where low pH acid (HCl acid) is also pumped.

Modular. A modular system was necessary to allow the addition or removal of certain sections as required for pulling the CT as far as possible in a wide spectrum of wells, some of which have rig-up height limitations.

Reliable. A trained crew should be capable of operating the resulting design on a number of wells with minimum maintenance despite the difficult environment. The tractor should not merely be a one-well, one-trip solution, but a robust tool that would deliver results well after well — on a continuous basis — for maximum reservoir optimization.

TOOL DEVELOPMENT SOLUTION

The tool design team's approach to finding solutions to the tool's development challenges were "polytechnical," not only encompassing mechanical, electrical and materials engineering, but also incorporating several aspects of inorganic chemistry, hydraulics and engineering planning. The resulting solution was a 2.125" CT hybrid tractor conveyance system. In the hybrid system, hydraulic flow through the CT is converted to a stable and controllable power output that can be configured to drive a variable number of proven electric-hydraulic tractors coupled to the end of the CT unit. The hydraulic force activates the tractor and provides the pull force required to overcome the helical buckling of the CT and so extend its reach. By using electrical connections to transmit the converted power, the need for hydraulic flow through channels is minimized, and the risk of acid corrosion and damage to the tool can be mitigated.

The hybrid tractor conveyance system consists of five key components, carefully engineered together.

Ball drop sub. This is a reengineered and improved flow diversion sub, which has shown increased performance over standard ball drop subs for horizontal applications. The ball drop sub protects the inner parts of the tractor from acid corrosion by diverting the flow. This sub is integral to protecting the system during the acid stimulation operations.

Flow control sub. This is a new engineered sub for controlling the flow of fluids passing through the CT. It does not work through diversion, as conventional systems do, but through pressure buildup. The advantage of this mechanism is that a constant flow is kept up through the CT and the required parts of the 2.125" CT hybrid tractor conveyance system — even if the CT pumps are unable to keep the flow stable at downhole conditions.

Turbine sub. This improved downhole turbine converts the downhole hydraulic flow from the CT to mechanical momentum on a shaft, energy that in turn can be harnessed. Protected by the ball drop sub and the flow control sub, the turbine sub was optimized and improved to more accurately convert the mechanical power output required. The design also incorporates improved stall regulation to make the turbine less sensitive to flow. As a result, the stability of the turbine is significantly improved, and the total system represents a much more reliable hydraulic power conversion system during stimulation operations.

Generator subs. These newly developed, three-phase, synchronous generators are connected to the turbine sub and convert

Fig. 1. Design of new 2⅛" CT well tractor.

the mechanical power from the turbine shaft to electric power. Given the relatively small space available within the 2.125" tool body, the engineering challenges to overcome included to find a mechanism that could magnetize the rotor of the synchronous generator and also to ensure that sufficient cooling of the winding systems in the stator would take place.

Tractors wheels. The electric-hydraulic wheel sections of the 2.125" CT hybrid tractor conveyance system, powered by the previously mentioned components, open downhole and generate a pull force that is exerted on the CT. The modular nature of the well tractors allows their configuration with a variable number of wheel sections to provide different pull forces, as needed for the application and the available lubricator or rig-up height.

Figure 1 illustrates the new 2.125" CT hybrid tractor. The metallurgy of the component parts of the conveyance system are materials that can handle the required mechanical stresses and strains of a push/pull action through variable IDs — those of restrictions, completions, open holes, etc. — as well as exposure to live acid in a high-pressure stimulation.

SIMULATION RUNS

The simulation of CT lockup depth used 2" CT. The well information is shown in Table 1.

The tubing force analysis is expressed in Fig. 2 as a crossplot of the CT weight indicator load and the measured depth of the tool string using:

- 2" CT with friction reducer only, Fig. 2a.
- 2" CT with friction reducer plus a single 2.125" tractor (assuming 1,200 lb pulling force), Fig. 2b.
- 2" CT with friction reducer plus the 2.125" tandem tractor (assuming 1,700 lb pulling force), Fig. 2c.

The results are summarized in Table 2.

Well	TD Survey (ft)	Liner Shoe (ft)	Tubing		Minimum Restriction (in)
			OD	Shoe (ft)	
Well-XXX	23,826	17,430	5½ * 4½ * 2⅞	8,910	2.44

Table 1. Well information for simulation

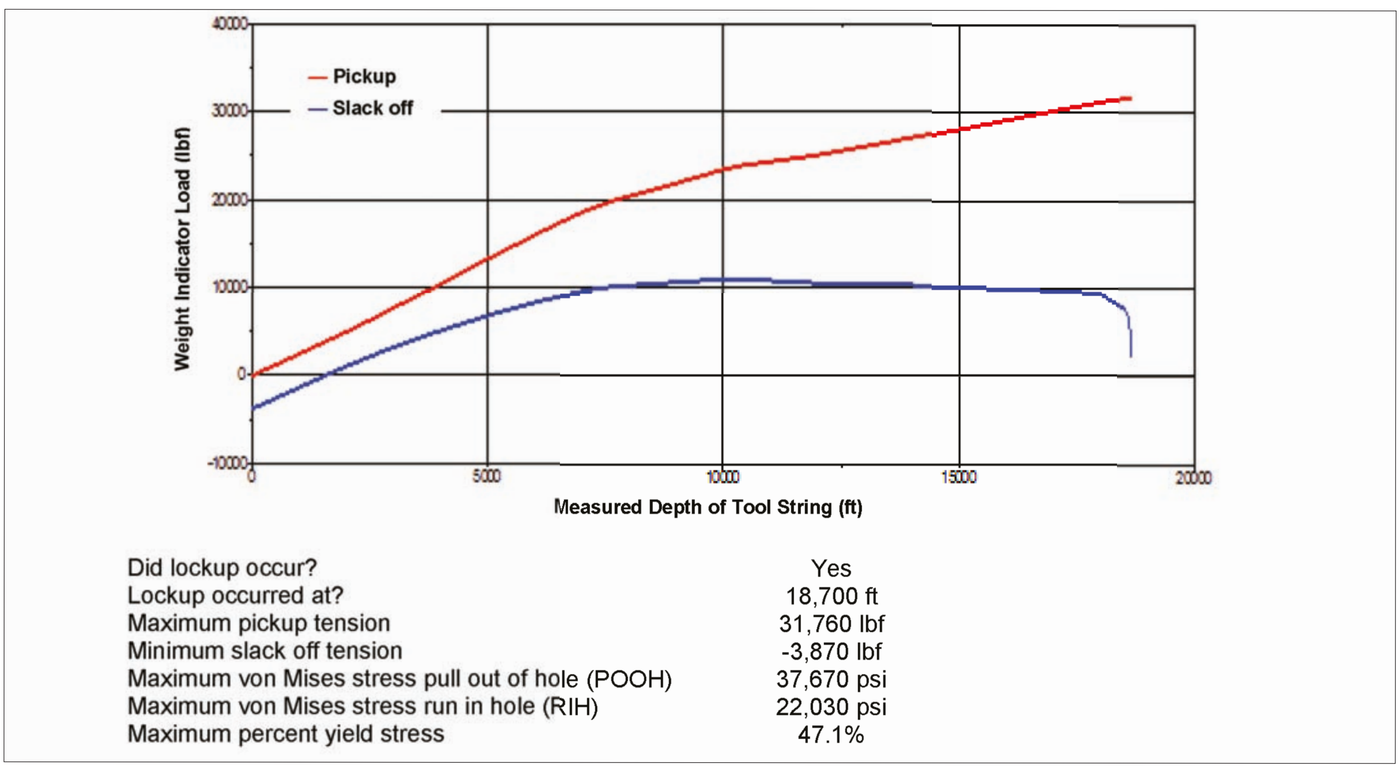


Fig. 2a. Simulation using 2" CT with friction reducer.

Well Information	Lockup Depth
Well-XXX	Using 2" CT
With Friction Reducer	18,700 ft
With Friction Reducer and Single 2.125" Tractor	20,445 ft
With Friction Reducer and Tandem 2.125" Tandem Tractor	21,762 ft

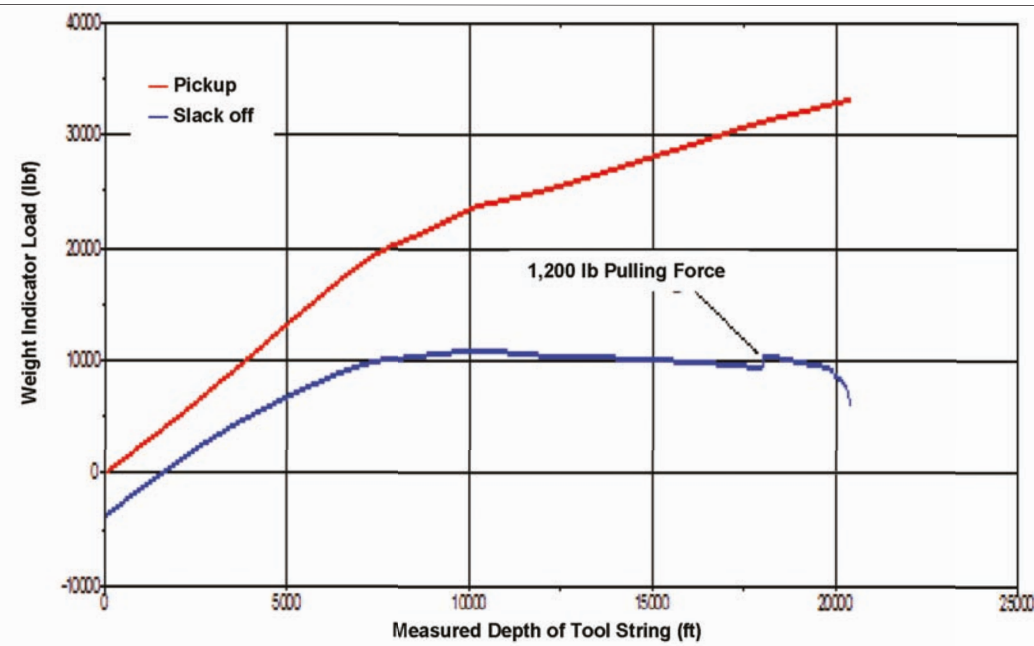
Table 2. Summary of simulation results

OPERATIONAL PERFORMANCE

After pressure testing the risers, CT and connector, the CT was run in hole with the tandem tractor. The 2.125" tandem tractor configuration for the job had 2 × 4 wheel sections and a length of 50 ft. The designed tool had a maximum pull of 2,000 lb. Friction reducer was pumped at 5 bbl/1,000 ft of open hole while performing pull tests every 1,000 ft. Post-flush was pumped while in the 6.125" open hole at 1.6 barrels per minute (bpm) to activate the tractor. As shown in Fig. 3, the tractor was activated after the first lockup at 20,061 ft. A tractor operating flow rate of 1.5 bpm to 1.9 bpm was maintained in the course of the CT conveyance.

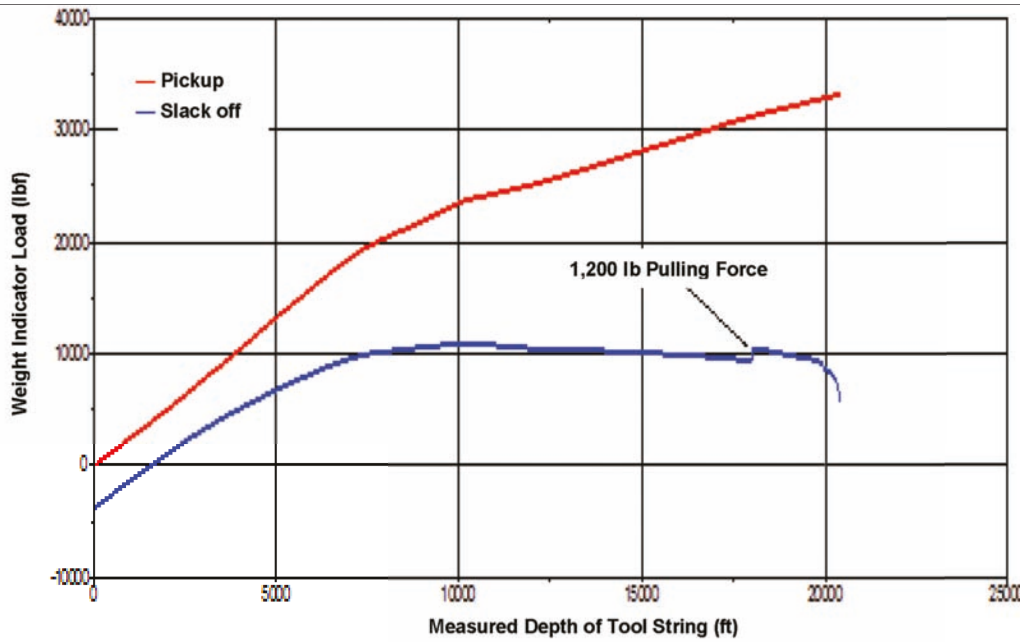
Figure 4 shows trip events up to the point of helical buckling on the first run, when weight on the CT dropped off sharply and could not transfer to the end of the CT. The average weight during trips in and out of the hole matched with the average weight from the simulation. Friction coefficients were adjusted on the job accordingly. As shown in Table 3, the actual friction coefficient during the job was less than the simulated value, resulting in a deeper reach before lockup. Assuming the same friction coefficient from 20,000 ft to 21,590 ft, a weight plot match indicated the pulling force of the tandem tractor was around 600 lb. The tractor worked until CT had a second lockup at 21,591 ft.

Prior to commencing acid treatment, a 0.25" ball was successfully dropped and pumped to set on the seat of a flow diversion sub, called the ball drop sub. The subsequent isolation of the tractor was confirmed, based on pressure readings that rapidly increased to +4,200 psi. A 15% HCl acid and viscoelastic diverter acid (VDA) stimulation recipe was pumped to remove the drilling damage from the formation and maximize the production of the well. The first five acid stages in the original program were cancelled to adjust for the unreached hole interval, while the remaining treatment was pumped according to the schedule in Table 4. Thereafter, a post-flush was pumped while pulling out of hole. Figure 5 is a cross-plot of wellhead pressure, circulating pressure, CT weight and depth with time during the stimulation. The drop in wellhead pressure from 1,442 psi to 250 psi is evident, which occured



Did lockup occur?	Yes
Lockup occurred at?	20,445 ft
Maximum pickup tension	31,760 lbf
Minimum slack off tension	-3,870 lbf
Maximum von Mises stress POOH	39,379 psi
Maximum von Mises stress RIH	21,584 psi
Maximum percent yield stress	49.2%

Fig. 2b. Simulation using 2" CT with friction reducer and a single 2.125" tractor (1,200 lb pulling force).



Did lockup occur?	Yes
Lockup occurred at?	21,200 ft
Maximum pickup tension	33,799 lbf
Minimum slack off tension	-3,870 lbf
Maximum von Mises stress POOH	40,083 psi
Maximum von Mises stress RIH	19,494 psi
Maximum percent yield stress	50.1%

Fig. 2c. Simulation using 2" CT with friction reducer and the 2.125" tandem tractor (1,700 lb pulling force).

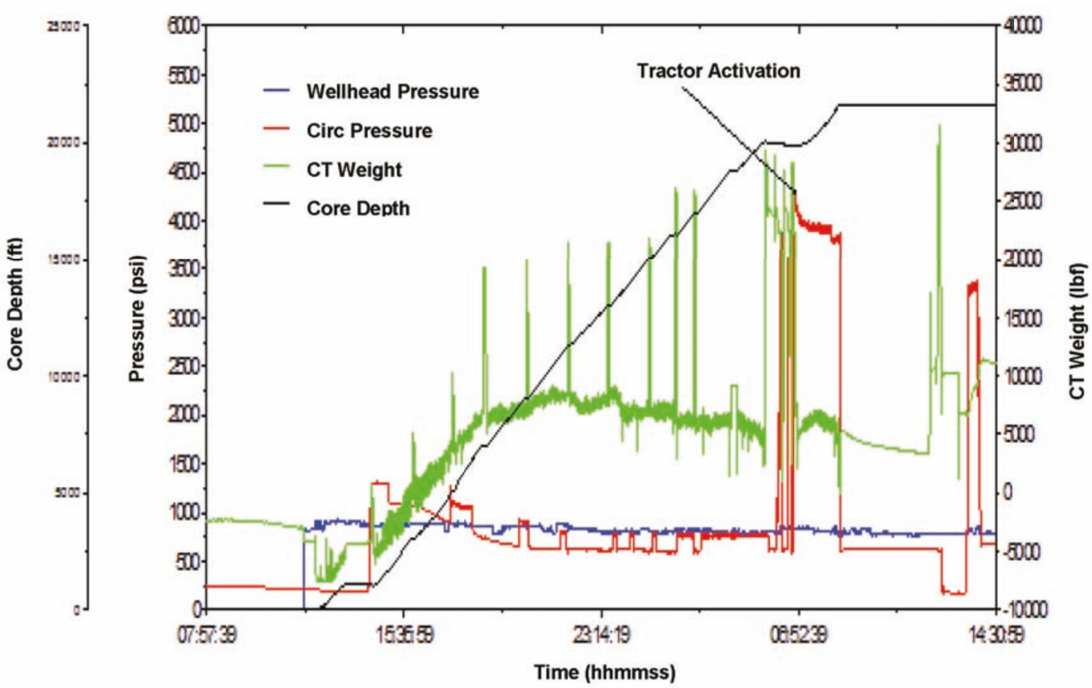


Fig. 3. Acquisition panel plot post-job plot showing onset of tractor activation.

when acid hit the formation face during the acid stimulation. A description of events for the second CT run (Run 2) is shown in Fig. 6. Figure 7 shows a summary of events after tractor activation and stimulation. (The drop in weight shown is a result of a temporary malfunction of the weight recording device.) After acid treatment, the CT was pulled out of hole to the surface while pumping at a minimum rate. The well was flowed back to produce the spent acid. After flowing the well

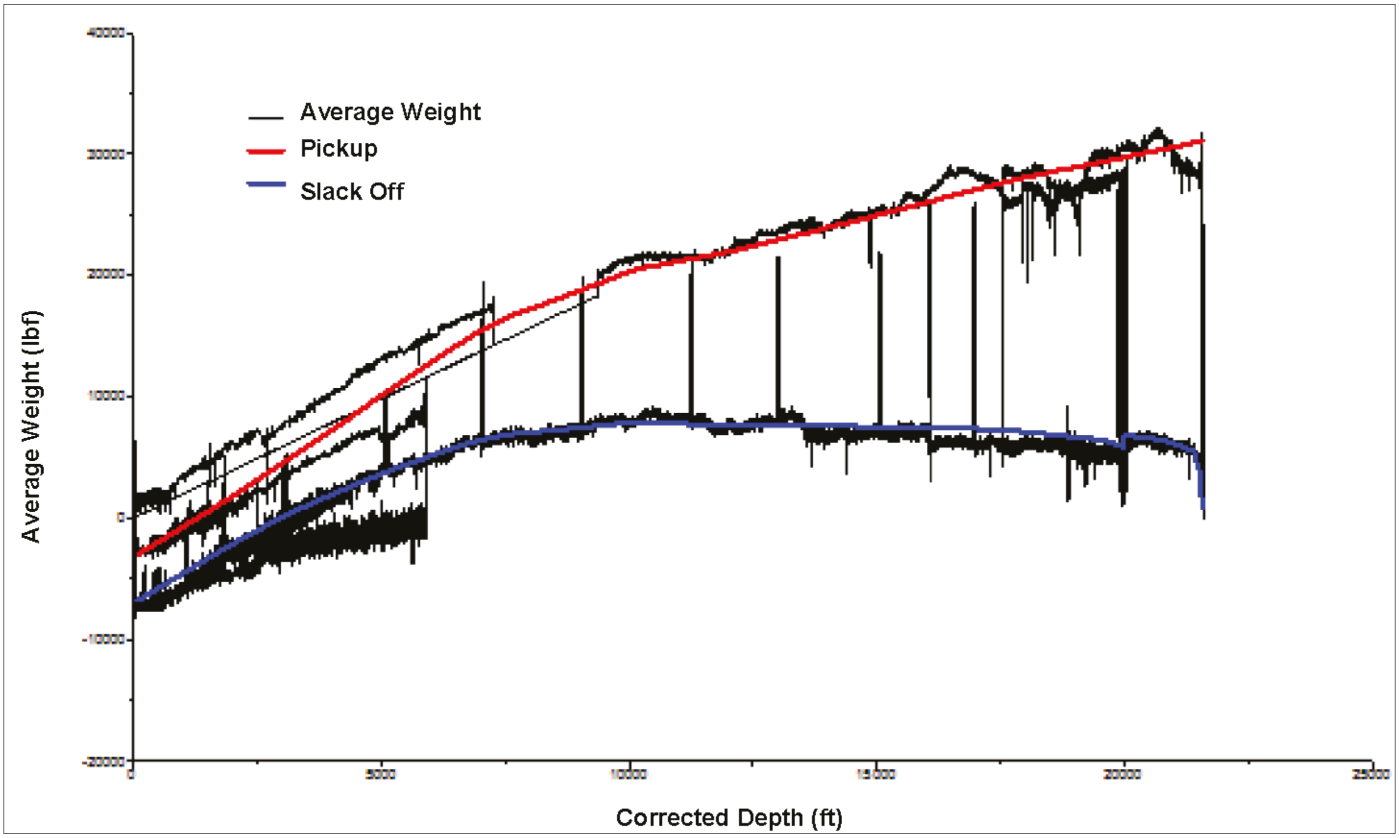


Fig. 4. Trip events with helical buckling when weight dropped sharply.

	FC Simulated Cased Hole	FC Simulated Open Hole	FC Post-Job Cased Hole	FC Post-Job Open Hole
RIH	0.19	0.27	0.15	0.20
POOH	0.18	0.18	0.18	0.18
Lockup	18,700		20,061 ft	
Max depth with tractor	21,762		21,591 ft	

Table 3. CT Simulation and post-job values for friction co-efficient (FC) and CT reach

clean, the tubing was displaced by pumping 150 bbl of inhibited diesel to protect the ESP from H_2S attack prior to commissioning the well. Figure 8 is an illustration of the well cross section plot.

RESULTS

As previously shown in Table 3, the tandem tractor's performance exceeded the predictions of simulation runs for a single tractor to a depth of 20,445 ft — 1,146 ft more than predicted — but it achieved 171 ft less than predicted for the twin or tandem tractor configuration. The actual tractored distance was 1,530 ft. Pumping a ball down the CT reel isolated the tractor from the acid, allowing matrix stimulation treatments across the pay intervals at relatively high rates without damaging the tool. Although the maximum time at downhole conditions in inhibited 15% HCl acid as designed is 12 hours, the entire operation lasted for 139 hours with the tractor in hole for a total of 120 hours. After rig down, however, the tools were in good condition with no visible damage or corrosion anywhere along the tractor. Upon the tools' return to base, they were redressed and inspected thoroughly. Again, no sign of any damage within the tractor was evident.

FINDINGS AND LESSONS LEARNED

A tension compression sub in the CT BHA allowed an estimation of the pulling force during the operation. The range of tractor pulling force in the horizontal section after lockup was 600 lb, less than the 2,000 lb pulling force of the specification design. Although a tractor pulling force of 2,000 lb was confirmed in the tractor pull test in the liner section, this pulling force was not reproduced in the open hole section. No function test was conducted while running in hole because of insufficient preflush on location. As a result, validation of the tractor pulling force was impossible. After pulling out of hole, the upper

		Depth (ft)				Volume	N_2 Rate	Cumulative
Stage	Step	From	To	Direction	Fluid	(bbl)	(scf/bbl)	(bbl)
6	9	21,726	21,201	POOH	VDA	63	800	1,272
	10				HCL	125	0	1,397
7	11	21,201	20,676	POOH	VDA	63	800	1,460
	12				HCL	125	0	1,585
8	13	20,676	20,151	POOH	VDA	63	800	1,648
	14				HCL	125	0	1,773
9	15	20,151	19,626	POOH	VDA	63	800	1,836
	16				HCL	125	0	1,961
10	17	19,626	19,101	POOH	VDA	63	800	2,024
	18				HCL	125	0	2,149
11	19	19,101	18,576	POOH	VDA	63	800	2,212
	20				HCL	125	0	2,337
12	21	18,576	18,051	POOH	VDA	63	800	2,400
	22				HCL	125	0	2,525
13	23	18,051	17,530	POOH	VDA	63	800	2,588
	24				HCL	125	0	2,713
14	21	17,530	15,861	RIH	Post-flush	450	0	3,163

Table 4. Pumping schedule of the simulation treatment

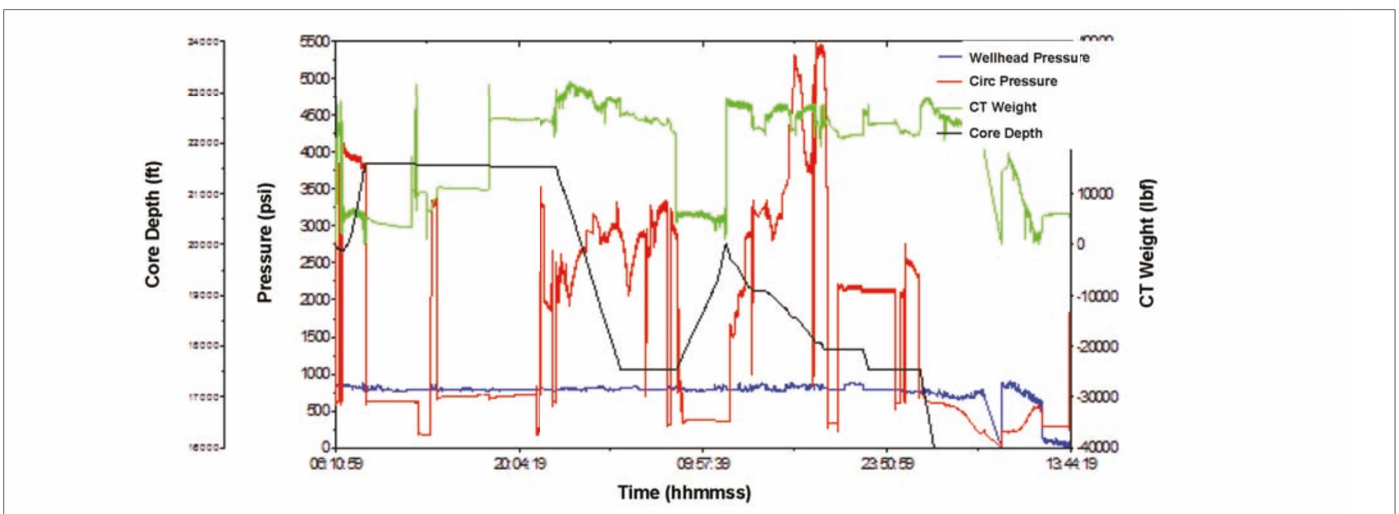


Fig. 5. Cross-plot of operating parameters with time during stimulation.

generator sub was shorted out, which probably resulted in the relatively less effective tractor performance in the upper well.

SUGGESTIONS FOR SUBSEQUENT OPERATIONS

A significant number of field trials seem necessary to establish

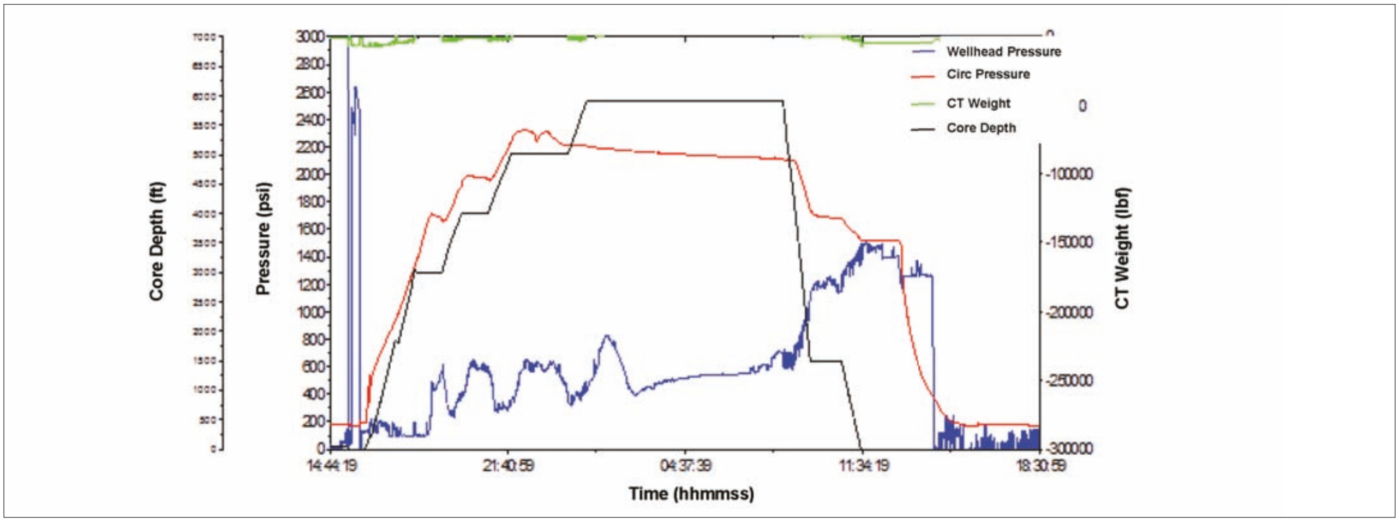


Fig. 6. Cross-plot showing a description of events for CT Run 2.

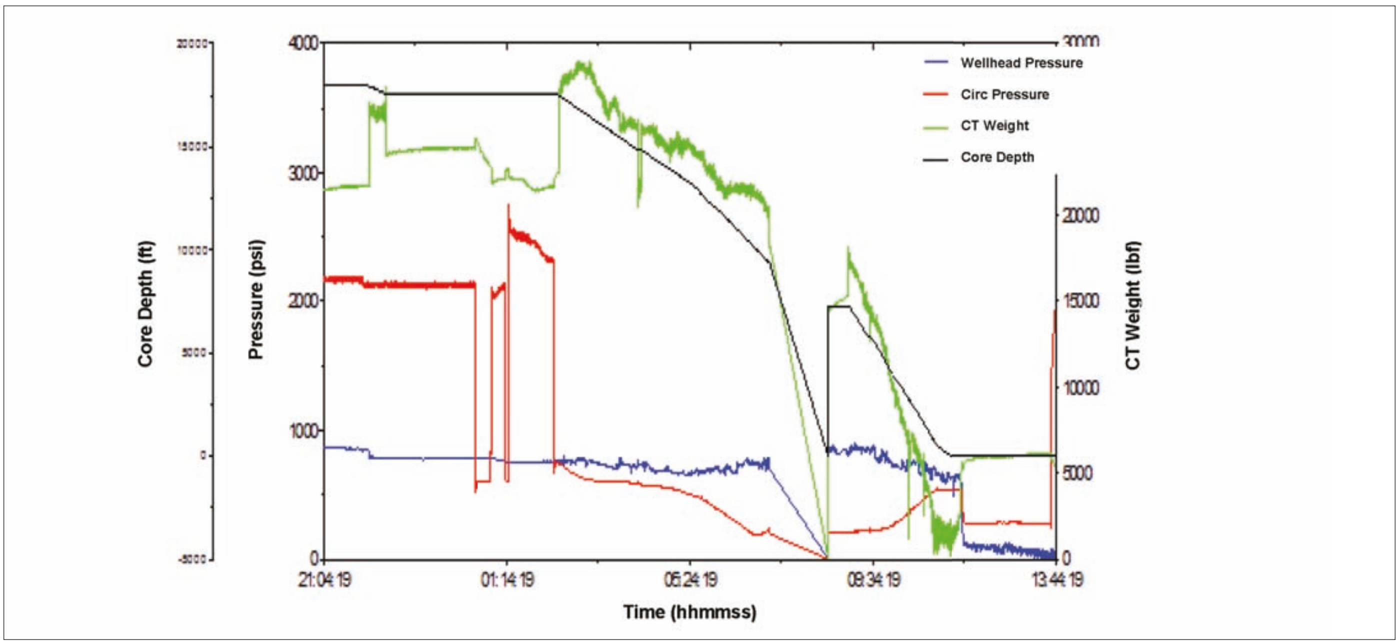


Fig. 7. Cross-plot providing a complete summary of events after tractor activation and stimulation.

the ideal operating parameters for the smooth performance of the tandem tractors. Proper calibration of the tension and compression sub is required because that sub provides an indication of the pull force the tractor provides. An optimization of the running in hole speed is necessary. A recommendation is to reduce the CT speed and increase the pumping rate when approaching lockup depth. A guideline regarding the suggested operating parameters — speed of feeding CT, pumping rate, etc. — is required for optimum performance of the tractor. The well profile or hole geometry should be reviewed for proper candidate selection prior to job mobilization. It is recommended to ensure sufficient drillstring lubrication is present, especially during trips in hole. Sufficient prior hole cleaning to remove debris and cuttings bed seems vital to the efficient operation and progress of the tractors, especially in open hole sections. Although removing mud solids and drill cuttings in low spots of the well may be challenging, it is recommended to ensure good hole cleaning prior to deployment of the tandem tractor. Preferably, future tractor runs could be executed in wells already commissioned and flowing, with reduced risks of cuttings accumulation. Alternatively, a fill or cuttings cleanout is recommended ahead of the tandem tractor runs.

CONCLUSIONS

The tandem tractor enabled the well stimulation team to extend the reach of CT in this oil candidate well. The deployment of the innovative 2.125” tandem tractor in this field not only marks significant progress in the development of the field but also has potentially far reaching global applications. The

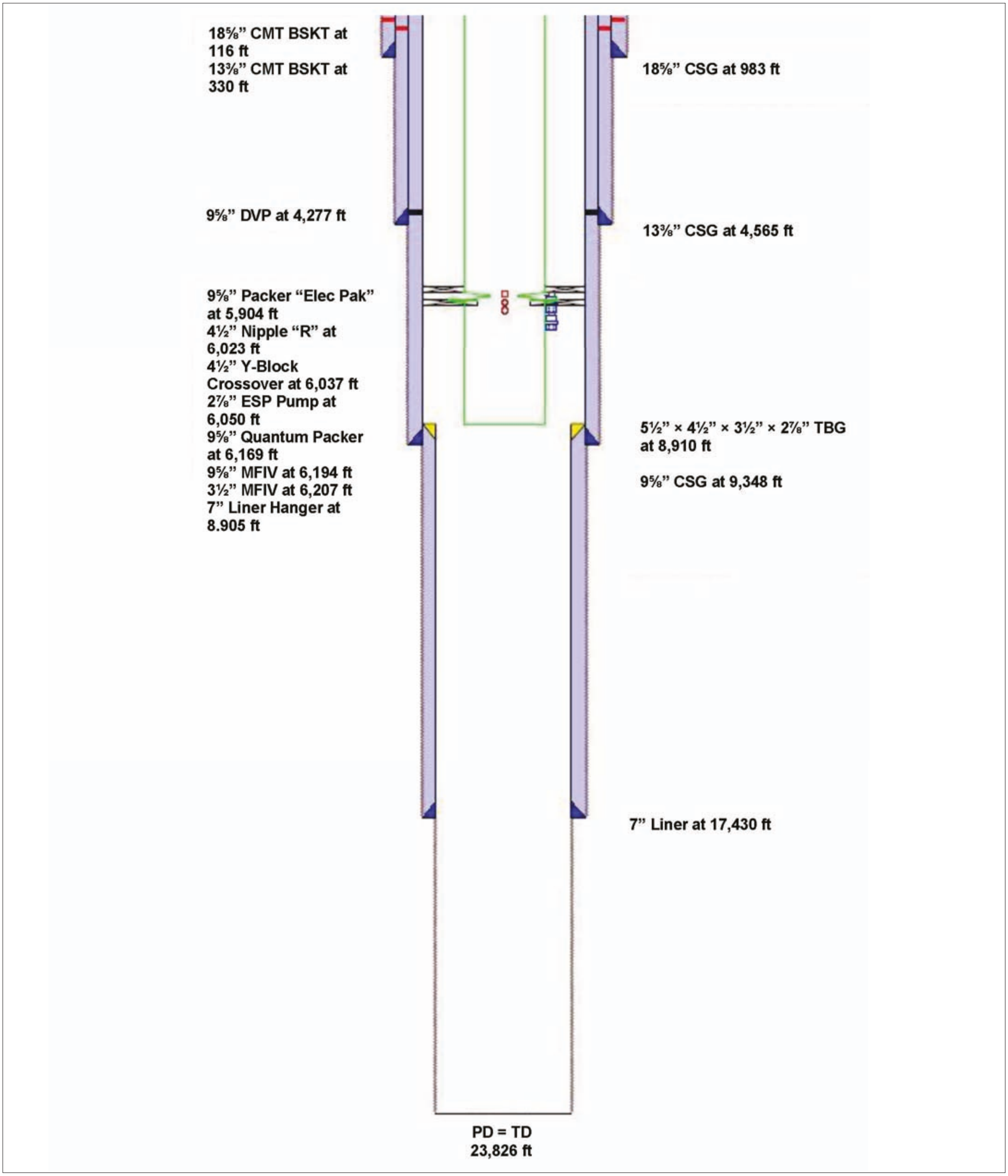


Fig. 8. Well cross section plot.

broad implications of further successful field qualification tests include the possibility of interventions in existing mega-reach oil producers with relatively small bore completions.

ACKNOWLEDGMENTS

The authors would like to thank the management of Saudi Aramco for their support and permission to publish this article. Our special thanks also go to the service company for providing

unwavering support in all phases of the job execution.

This article was presented at the International Petroleum Technology Conference, Doha, Qatar, January 20-22, 2014.

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The First Worldwide Deployment of a Pulsed Neutron Tool with Coiled Tubing Fiber Optic Real-Time Telemetry

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ABSTRACT

Production logging in horizontal wells presents particular challenges, especially when the wells are completed uncemented using prepacked screens or slotted liners. These challenges are attributed to well geometry, i.e., the existence of severe doglegs and undulations where trapped fluids that could directly affect and influence data readings from the tools, such as stagnant water, may lie either inside or outside the liner in low areas at the bottom of the well or stagnant gas accumulating on the high side of drain hole undulations.

Considering these challenges, an integrated horizontal multiphase production logging tool (IHMPLT) is usually required. In many cases, this tool needs to be complemented with a pulsed neutron logging tool (PNLT) to deliver a more accurate reading of fluid entries.

Over the last 20 years, coiled tubing (CT) equipped with an electric cable has been widely used to conduct production logging in horizontal wells. More recently, CT equipped with an optical fiber has both eliminated the restrictions associated with CT equipped with an electric cable and afforded several advantages, such as distributed temperature sensing (DTS) to complement production profiles from the IHMPLT. The previous CT system was unable to run a PNLT.

With a more robust portfolio of production logging tools available, a new solution for acquiring real-time downhole measurements has been introduced. The use of CT equipped with fiber optics has enabled real-time data acquisition of DTS, IHMPLT and PNLT logs.

This article discusses the case history of this first worldwide application of the adapted technology. It also provides lessons learned and perspectives for this technology.

INTRODUCTION

Gas wells drilled into tight sandstone reservoirs and produced at below dew point pressure can lead to condensate production. As a result, accurate estimation of well deliverability in such cases requires an accurate evaluation of both gas and condensate effective permeability[1]. This is particularly important within the near wellbore region of producing wells, where the effective permeability to gas and the value of the flowing bottom-hole pressure (BHP) are affected by the condensate saturation distribution. Loss of well productivity in low permeability reservoirs is significant when they experience large BHP drops, and consequently, fall below the dew point pressure faster[2]. As a result, three radial zones with different liquid saturations can appear around a gas condensate well producing below the dew point pressure.

The zones include an outer region away from the well, which has the initial liquid saturation. Closer to the well, where there is a rapid increase in liquid saturation and a decrease in gas mobility, a region has liquid that is immobile. In an inner region next to the well, liquid saturation is higher than critical, and both the oil and gas phases are mobile. Finally, in the immediate vicinity of the well, a fourth region shows lower liquid saturation due to the capillary number effect, which represents the ratio of viscous to capillary forces[3]. The existence of this fourth region is important because it counters the reduction in productivity caused by liquid dropout[4].

This scenario of different liquid saturations becomes more critical in cases where horizontal gas wells drilled into tight reservoirs and producing below the dew point pressure are completed with slotted liners.

The problem with slotted liner completions is that many of the conventional production logging sensors are restricted to measuring inside the liner itself; of course, the liner can be situated anywhere in the borehole, but most likely it is lying along the bottom. Consequently, situations can occur where flow segregates and stratifies inside the wellbore, and it is possible that the lighter component, gas, will flow outside the top of the slotted liner and not be picked up by the spinner logs or holdup sensors, which are limited to measuring inside the liner. This was recognized by Bamforth (1996)[5], Fig. 1.

In cemented or open hole completions, production logging sensors have been developed to recognize the effects of fluid stratification, and these sensors work well to calculate the components of the fluids present and their flow rates. In slotted liner completions, it is possible that one of the components, usually the light one (gas), will flow for part or all of the reservoir section outside the slotted liner and so will not be identified by the conventional production logging sensors. Consequently, where fluids are expected to stratify in slotted

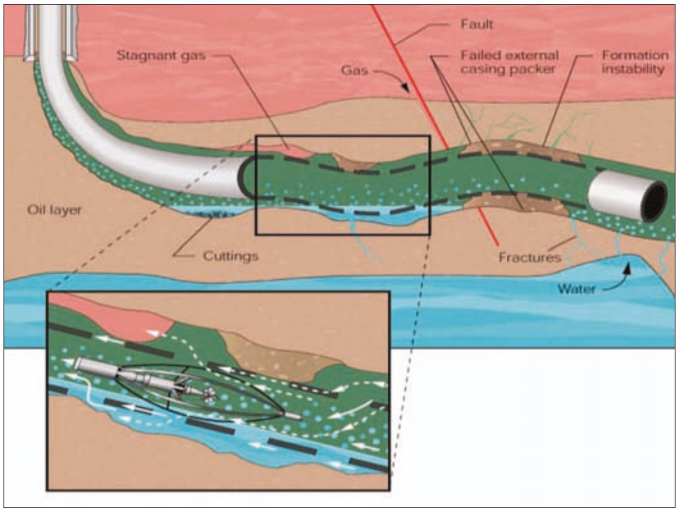

Fig. 1. Challenges faced by production logging in horizontal wells having slotted liners[5].

liner completions, additional measurements are required to complement the conventional production logging sensors so engineers can determine the magnitude of the flow that is undetected by these sensors.

In horizontal wells, coiled tubing (CT) is the most cost-effective, robust and easy-to-use method for deploying production logging sensors along the horizontal section of the reservoir. In the past, it was not possible to run all the sensors required to properly interpret three-phase problems in slotted liner situations — where flow can occur outside the liner.

This article discusses the first deployment of horizontal production logging tools together with pulsed neutron tools, enabling the measurement of water velocity and oil holdup inside and outside the slotted liner along with distributed temperature measurements, which reflect the mass flow rate, again independently of the flow location inside the wellbore or the position of the slotted liner.

ADDITIONAL DATA REQUIRED FOR SLOTTED LINER FLOW EVALUATION

The additional measurements required for flow characterization outside the liner are as follows:

1. Holdup is determined from the yield-based carbon-oxygen (C/O) ratios, taken from the near and far detectors of a C/O log, which are primarily sensitive to oil and water. A net inelastic (capture background removed) C/O log count rate ratio between the detectors provides information about borehole gas.

2. Water velocity is determined from the oxygen activation of water. The basic principle involves the activation of the oxygen atoms of the moveable water in the vicinity of the pulsed neutron logging tool (PNLT) and measuring the subsequent released gamma rays on the PNLT detectors mounted downstream of the neutron source[6]. Measuring the time from the neutron source to the peak of the detector signal and using the distance from the pulsed neutron generator to the detector allows a velocity to be computed[7].

3. The distributed temperature sensing (DTS) data is determined in response to mass flow rate measurements under stable flowing conditions.

ANALYSIS RESULTS COMPARED TO CONVENTIONAL "INSIDE LINER" MEASUREMENTS

The well in question is a horizontal, low permeability condensate well completed with a slotted liner. Well test production rates are 4.8 million standard cubic feet per day (MMscfd) of gas, 300 barrels per day (bpd) of oil and 850 bpd water.

Figure 2 shows the spinner logs recorded inside the slotted liner during a pass down and up with the multispinner production logging tool. Note that below 14,510 ft the spinners are not showing much character and have values that are often around zero — the red and blue traces are the down passes, and the green and orange traces are the up passes. From the casing shoe down to 14,510 ft, the higher spinners, Spinners 2, 3 and 4, increase in speed dramatically, indicating that the gas is passing into the liner at 14,510 ft and continues flowing inside the liner above this depth.

Although it is possible to create a flow profile from the data using the few points on the spinner traces, which appear reasonable below 4,510 ft, the flow rate is computed using the liner inside diameter, and so must be extrapolated to the real hole inside diameter to get a representative rate along the reservoir interval. As the spinners do not "see" any gas flow outside the liner, this extrapolation can be erroneous and requires confirmation from some other independent source.

The C/O holdup analysis, which is full bore, is shown in the lower graph of Fig. 3 and compared to the conventional analysis

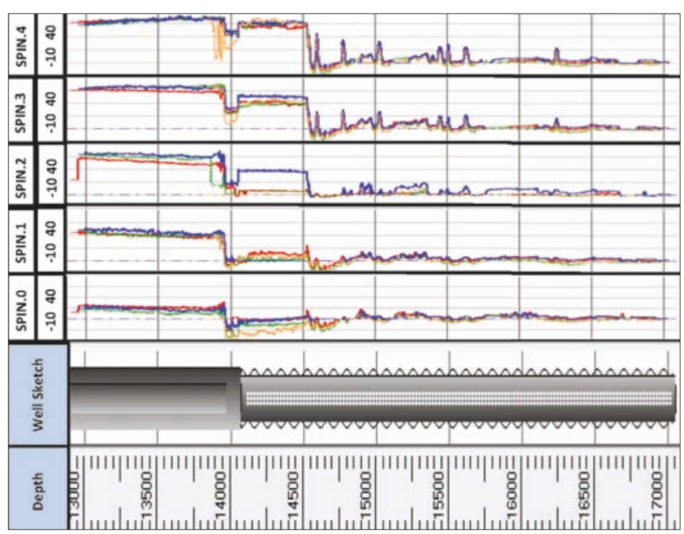

Fig. 2. Spinner logs inside the slotted liner.

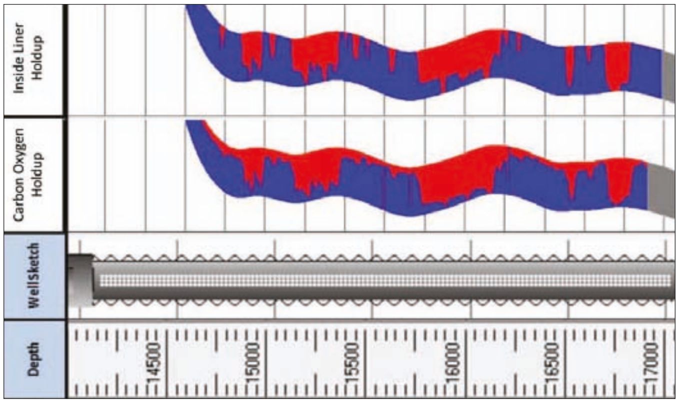

Fig. 3. Conventional (inside liner) vs. C/O holdup analysis.

(upper graph) obtained from the production logging sensors inside the slotted liner.

The C/O holdup analysis shows that there is gas (red) flowing from the bottom of the well (leftward in the figure) all along the reservoir, while the conventional analysis only shows the gas in the downward parts of the well trajectory. In the upward trajectory sections, the gas is in many places flowing completely outside the slotted liner and so is not registered by the conventional production logging sensors.

Figure 4 shows the results of the spinner flow analysis — extrapolated to the open hole inside diameter — together with the predicted water production and oxygen activation water velocity. Note that the computed water velocity can vary because the water velocity is changing with the holdup, which is well trajectory dependent. Two clearly anomalous measurements at 15,510 ft and 14,900 ft, which are too high, are at intervals where the well trajectory is upward and where the water velocity will usually slow down as the holdup increases. That clearly the opposite is happening shows that the water flow is not stable and instead is slugging along the well. This effect can be exacerbated by the piston effect of the CT moving up and down the well before it is stopped to make the water flow velocity measurements.

Figure 5 shows the conventional "inside liner" holdup analysis when the well was shut-in with the liner full of water.

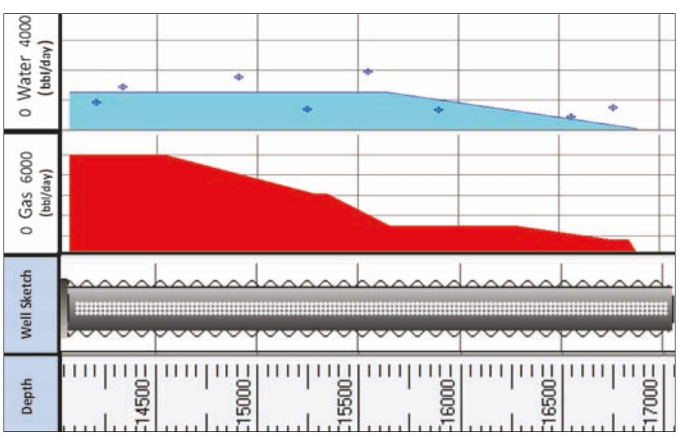

Fig. 4. Spinner flow analysis including predicted production and the oxygen-activation water velocity (shown with dark blue indicators).

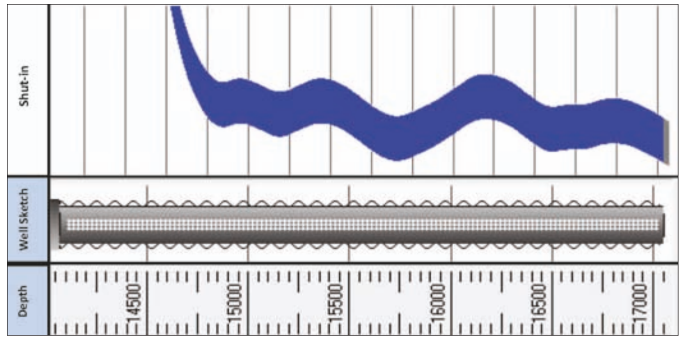

Fig. 5. Shut-in well conventional production logging flow analysis.

The spinner analysis also shows that inside the liner there is no cross flow. Given that the majority of the gas flow is outside the liner, this is not sufficient to say that under shut-in conditions the gas is not cross flowing outside the liner from one zone to another.

Normally, the flowing and shut-in DTS traces are recorded sequentially, with a flowing period followed by a shut-in period of a few hours. In this way it is possible to see any time-based transient effects of the shut-in. Also, because the DTS data is acquired when the CT is stationary at the bottom of the well, the results are not influenced by any piston/plunger effect of moving the CT up and down the well to record production logging temperatures. In this well, the shut-in DTS data was acquired 34 hours after the flowing data and only for 2 hours. Nevertheless, the data shows that the well is stable without any cross flow at that time. Even after a significant period of shut-in, the main gas inflow zones can be identified because they remain cold longer than the other reservoir intervals. These are shown by the dark red zones on the 3D plot in Fig. 6.

Typical flowing and shut-in DTS traces, recorded when the CT was stationary at the bottom of the well, are shown in Fig. 7. Note that when the well is shut-in, the green trace is 3 °F higher over most of the reservoir interval except below 16,650 ft, where there is little change. Also there are decreases in the flowing temperature from 16,350 ft to 16,550 ft and from 15,500 ft to 15,300 ft (red zones) on both the flowing and shut-in traces. These decreases in temperature indicate zones

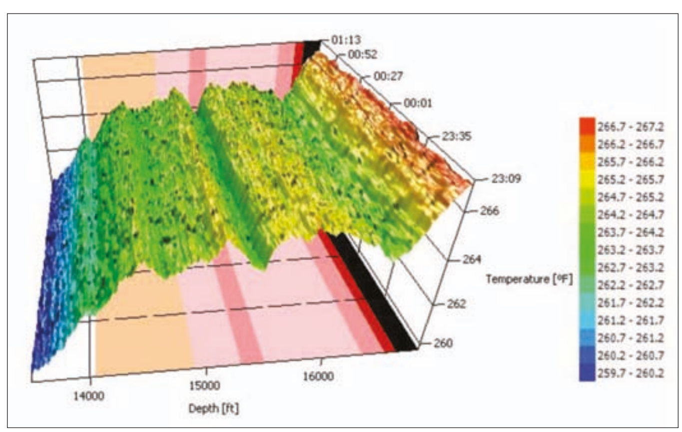

Fig. 6. 3D plot of the shut-in DTS data.

where gas is flowing from the formation in preference to the other intervals.

Figure 8 shows the results of the flow analysis using the DTS data where the thermal model flowing temperature (red line) is matched to the DTS measured flowing temperature. Because of the uncertainty in the water production distribution, we have assumed uniform water production along the whole reservoir interval. Note that the DTS temperature can only be used to solve for one unknown at a time — in this case, gas flow. Also, if the formation permeability had been high and the fluid only oil, the large Joule-Thomson cooling effect observed in this well would not be present. Nevertheless, because temperature data is not restricted to the inside of the liner, it responds to the mass flow rate from the whole well diameter along the reservoir section, and therefore, is influenced by the flow of gas outside the liner.

Again note the two significant inflow zones identified in the analysis from 16,350 ft to 16,550 ft and from 15,500 ft to 15,300 ft, although there is also gas production from the other intervals along the reservoir. The DTS data therefore shows that there is no flow from beyond 16,650 ft and that the higher permeability producing zones at 15,500 ft and 16,500 ft are thinner than determined from the multispinner data.

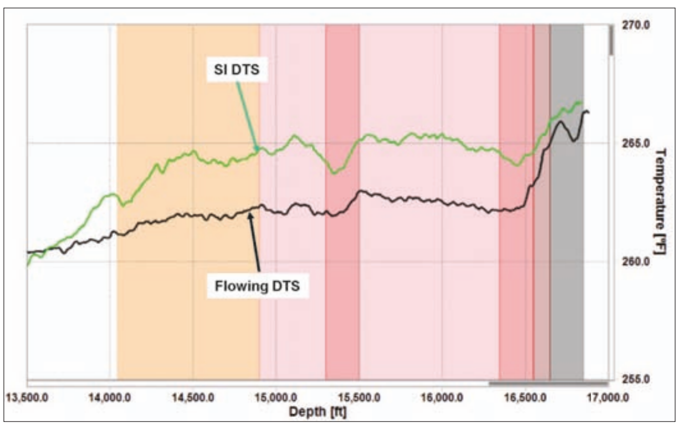

Fig. 7. Graph of the flowing and shut-in DTS traces.

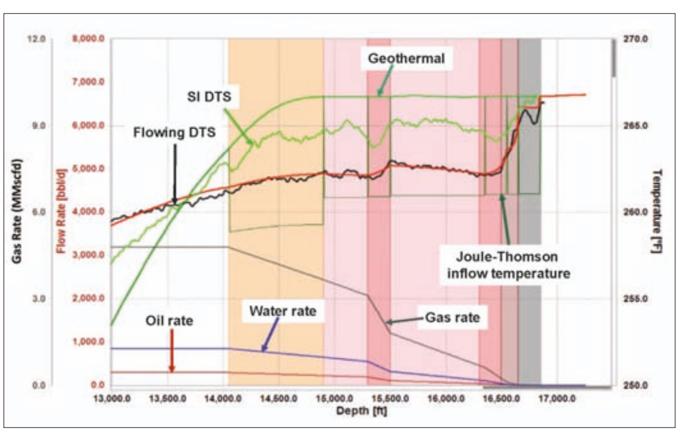

Fig. 8. DTS thermal model flow analysis.

CONCLUSIONS

Production logging in horizontal wells with slotted liners can cause conventional spinner and holdup sensor problems because the wellbore fluid can flow outside the liner and not be "seen" by these sensors. This problem requires additional sensors that measure full bore and are not influenced by the effects of the slotted liner.

This is the first successful deployment of a suite of production logging sensors that can effectively be used to interpret the flow both inside and outside a horizontal slotted liner and so highlight anomalies missed by the "inside only" production logging sensors.

In this well, it is clear that the conventional multispinners/sensors, which are reading only inside the liner, miss the gas flowing outside the top of the liner. The sensors could not be used to determine gas cross flow on shut-in because the liner completely fills with water upon shut-in.

Although the oxygen activation water velocity measurement appears to be suffering from unstable flow, it does show that there is water production from along the reservoir interval and that it is not localized to just one single zone.

The DTS data shows that there are two higher permeability zones, which are thinner than was determined from the multispinner log analysis, where readings were extrapolated to the whole well diameter based on the assumption that the flow inside the liner is representative of the whole well cross section flow profile. The DTS data indicates there is unlikely to be flow from below 16,550 ft.

The results show the importance of acquiring sufficient representative data to fully evaluate downhole multiphase flow in slotted liner completions.

ACKNOWLEDGMENTS

The authors would like to thank the management of Saudi Aramco and Schlumberger for supporting publication of this article.

This article was presented at the SPE Oil and Gas India Conference and Exhibition, Mumbai, India, November 24-26, 2015.

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BIOGRAPHIES

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Hashem is an active member of the Society of Petroleum Engineers (SPE).

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Then he spent 15 years with BP Exploration, where he was Head of the Petrophysics Group at the Sunbury Research Center and later a Senior Formation Evaluation Consultant working with BP's "Intelligent Wells" team.

George joined Sensa in March 1999 as Manager of Interpretation Development; Sensa was bought by Schlumberger in 2001.

He has published over 40 technical papers, been awarded several patents and was a Society of Petroleum Engineers Distinguished Lecturer during 2004/2005.

George received his B.S. degree (with first class honors) in Mechanical Engineering from Coventry University, Coventry, U.K.

Danish Ahmed is a Senior Intervention Production Engineer currently working with Schlumberger Well Intervention – Coiled Tubing Services, supporting the ACTive Services Platform. His experience began with working as a Field Engineer with Well Production Services, based in 'Udhailiyah, Saudi Arabia, supporting proppant/acid fracturing and matrix acidizing jobs, followed by working as a Production Technologist with Petro Technical Services (formerly Data and Consulting Services) in Dhahran, Saudi Arabia. Danish began working for Saudi Schlumberger in 2007.

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Shauket M. Malik is a Senior Geoscientist with Schlumberger (SLB) Saudi Arabia. He has over 25 years of experience in the oil and gas industry, and was involved in several SLB disciplines in the Middle East and Africa. Shauket started his career with SLB Iraq as an Open Hole Log Analyst and then as an Open and Cased Hole Log Analyst with SLB Angola.

Afterwards, he led the Data Management Group of SLB Saudi Arabia and then worked as a Log Analyst (open and cased hole) until 1999.

Shauket joined the Reservoir Domain Group in 2000 and then moved into the Lead Production Domain Group where, to date, he is involved in vertical and horizontal production analysis, along with new production technology implementation and support. During his time with SLB Saudi Arabia, Shauket was also involved in software testing and training of new hires. Over the last few years, he has conducted several Production Logging workshops for Saudi Aramco.

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From March 2013 until September 2014, Nestor was Technical Manager for Schlumberger Well Intervention in Saudi Arabia, leading the Schlumberger CT Technical Team and supporting Saudi Aramco on the technical aspects of CT interventions in oil, gas and power water injector wells conducted for matrix stimulation, descaling, perforating, clean outs, milling, fishing, zonal isolation, etc. Prior to this assignment, he held technical and sales positions in Egypt and Mexico, where he was responsible for the introduction of new technologies for CT and matrix stimulation. Nestor started his career in Venezuela in 1999 as a Field Engineer for Schlumberger Well Services, completing his field assignment in Colombia and Ecuador.

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Afsal AM is currently working as a Senior Design Engineer for CoilTOOLS at the Schlumberger (SLB) Houston Conveyance and Surface Equipment product center in Sugar Land, Texas. He has extensive experience in developing and sustaining downhole tools in SLB's ACTive and CoilTOOLS portfolios. Afsal is also currently an InTouch subject matter expert on SLB trademark tools, including CoilFLATE, AbrasiJET, multilateral tools and the ACTive platform.

He started his career in 2008 as a Mechanical Design Engineer for Schlumberger India where he was involved in coiled tubing equipment design. From 2012 to 2015, Afsal worked as a Field Engineer and ACTive specialist based in 'Udhailiyah, Saudi Arabia, where he was involved in a variety of coiled tubing applications, including high rate matrix stimulations, zonal isolation using CoilFLATE inflatable packers, production logging, unconventional Plug-n-Perf campaigns, etc.

In 2008, Afsal received his B.Tech degree in Mechanical Engineering from the National Institute of Technology, Calicut, India.

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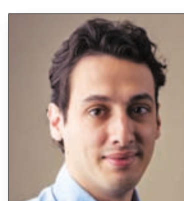

Jordi Segura is the Project Leader for the iFC Power project at the Well Services and Coil Center, Sugar Land, TX. He joined Schlumberger in 2008 in Japan, and worked in several optical telemetry projects for the Coiled Tubing, Wireline and Slick Line operations, including the development of the ACTive PS 1.0 and 2.0 systems.

Jordi's main areas of experience include optical transceiver, power supply and firmware design. In his current assignment, Jordi is responsible of defining the architecture and leading the development efforts to send electrical power from the surface to power the ACTive tools.

He received his M.S. degree in Telecommunications Engineering from Universidad de Málaga, Málaga, Spain.

Innovative Techniques in Utilizing Real-Time Downhole Pressure and Distributed Temperature Surveying for Skin Quantification during Matrix Stimulation in a Complex Multilateral Well in Saudi Arabia

Authors: Nooreddeen M. Al-Bokhari, Talal A. Ghamdi, Ramy Ahmed and Abdulrahman A. Al-Dosary

ABSTRACT

This article describes an innovative workflow for well intervention in a complex multilateral well, not only to access each lateral with certainty, but also to quantitatively evaluate matrix treatment independently for each lateral in real time. The quantitative evaluation is based on two simultaneous criteria. The first criterion is the downhole pressure diagnostic plot, or pressure transient analysis (PTA), derived using the data acquired by the downhole real time gauge. The second is an estimate of the zonal coverage from the temperature profile plot before, during and after pumping a treatment. PTA gives formation damage (skin) as a direct output, and the cooling down/warming up distributed temperature sensing (DTS) profiles identify where the treatment fluids went into the formation.

This approach of combining well testing and analysis techniques, applied throughout the treatment, with zone coverage evaluation is strongly recommended for horizontal and complex wells in either clastic or non-clastic rocks. Basically, deriving the skin value from the injectivity test (pre-treatment) and the skin value from the post-flush (post-treatment DTS analysis) will give an accurate as well as confident result when evaluating matrix treatments.

In a field case, a comparison of the formation damage (skin) before and after the treatment was performed on the spot. The treatment showed an improvement of eight times in injectivity rate and was achieved with nearly uniform distribution of treatment fluids across the five well laterals.

By following the state-of-the-art procedures proposed and executed in this well, we were able to combine different technologies and techniques, with a measurable cost reduction. The application of the techniques will improve treatment results by eliminating confusion in accessing well laterals, quantifying the formation damage improvement in real time, eliminating the nonuniform distribution of treatment, optimizing diversion design/placement and offering the ability to make treatment changes on the spot.

INTRODUCTION

Formation damage treatments have been used in the industry for almost 80 years. With increasing well complexity, stimulations are now more complicated, especially in carbonate formations[1]. Carbonates are well-known for their heterogeneity, complexity in both permeability and porosity, and the presence of irregular flow paths. The objective here is to create newly conductive paths, known as wormholes, to reduce and bypass the formation damage and thereby enhance the production and/or injection rate. Several factors must be considered when treating any carbonate formation[2]. Reservoir temperature, pumping rate and the use of chemical diverting agents are critical parameters in such an operation. Engineers struggle with accurately predicting the stimulation influence on the production and/or injection profile of any given well. In addition, the challenge that consistently arises after conceptually designing the treatment is how to determine the zonal coverage and thereby evaluate the stimulation, especially in extended reach wells in carbonate reservoirs. Significant effort has been spent on using modern technologies to qualitatively evaluate the zonal coverage and to estimate the skin factor after the treatment. Little work has been done, however, on the sensitive issues underlying the following questions: How does matrix acidizing alter the near wellbore permeability and affect the reservoir sections defined in a long horizontal section? Can the treatment really modify the critical matrix permeability?

It is believed that when treating multilateral wells in carbonate formations, wormhole creation significantly changes the flow characteristics in the near wellbore area, especially when effective chemical diversion is deployed[2]. Currently, there are no methods to estimate the change in permeability. Usually the change is accounted for in simulators by assigning a very low skin value. Other work conducted in carbonate reservoirs using pressure transient analysis (PTA) techniques has shown that applying a change in permeability is necessary to obtain a type curve match, though this still assumes a lump sum skin value and does not approach the skin per foot (S/ft) concept. The following sections of this article present an innovative workflow and algorithm to estimate the changes in formation damage, i.e., skin. A way forward on how to incorporate these estimated changes into further reservoir simulations is also presented. A case study then shows how we could derive a flow profile for the pre-stimulation stage; optimize matrix stimulation treatments in real time according to the formation response and diversion efficiency; define reservoir sections/

zones that are contributing to production and/or injection before and after the treatment; and finally, estimate the new values of permeability and skin to be used in post-treatment reservoir simulations[1].

WELL OVERVIEW

The well is a five-lateral power water injector located in Saudi Arabia. Well-A was initially drilled in Field-A as a single-lateral horizontal well. Its injection rate then experienced a gradual drop: initially, the rate was 7 × 103 barrels of water per day (BWPD), then it decreased to 1.4×10^3 BWPD at a fully open choke setting. Therefore, the decision was made to sidetrack this well with a new motherbore and three fishbone horizontal laterals across the reservoir, Fig. 1. Afterward, a maximum injection rate of 8 × 103 BWPD was realized. Nonetheless, the injection rate of this well also suffered a rapid decrease, again down to 1.4 × 103 BWPD at 100% choke size. A falloff test was performed and indicated that the permeability of the well's offset area was approximately 3 millidarcy (md). Consequently, the decision was made to acid stimulate the well using 2⅜" fiber optic enabled coiled tubing (CT) and the multilateral reentry tool, as well as implementing PTA and distributed temperature sensing (DTS) techniques for skin quantification purposes.

Well-A had been drilled in an area of low permeability and porosity. Table 1 shows the important reservoir/well characteristics, plus the total depth of the well (Lat 0) and the laterals (Lats 1, 2, 3 and 4).

CHALLENGES

The main challenge here is how to access and stimulate carbonate formation in a sour environment where there is a high risk of having the CT stuck in the well's open hole portion. One answer is to use a hydrogen sulfide (H_2S) scavenger to protect the CT prior to running in hole, as well as pre-flush and post-flush solutions that also include an H_2S corrosion inhibition component. The risk of stuck CT is further reduced by conducting the intervention at the optimum speed, slowing down when passing restrictions, performing frequent pull tests and monitoring the weight indicator for any abrupt changes.

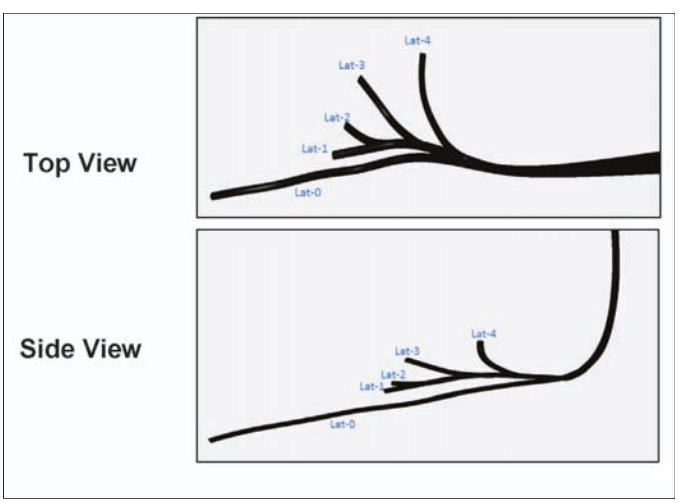

Fig. 1. Well-A trajectory.

The second challenge here is how to identify the intervened lateral. For this, the multilateral tool (MLT) is the best option on the market[3]. A lateral identification tool functions using only the pressure profile. A significant pressure drop indicates the presence of a window, so by correlating the available gamma ray data with the depth and pressure profile, the MLT determines the correct lateral entry. Nonetheless, should there be a need to pull out of hole (POOH) above the window of the intervened lateral, the angle at which the MLT intervened the denoted lateral will be lost due to the presence of helical/sinusoidal buckling in the CT. Therefore, pressure mapping is required to re-identify the lateral window around its depth. In addition, the fact that all the laterals are in the same plane — with no remarkable pressure variation — adds ambiguity in terms of specifying the current intervened lateral; because of the premature CT tagging presence, there is no adequate interval to utilize for the gamma ray logs as an identification tool.

The third challenge here is how to achieve the relatively high rate required to activate the MLT; a minimum rate of 1.3 barrels per minute (bpm) and an optimum rate of around 2 bpm. This problem is encountered during the acid stimulation job, where the MLT must deal with both a tight formation (permeability of 3 md) and a pressure limitation of 3 K psi at the tree. The solution here was to use the mutual solvent — rather than water — as the fluid to activate the MLT due to the solvent's ability to soften the formation.

The fourth challenge here is how to remove the unexpected downhole obstructions found in Lat 0, prior to both the Lat 1 and Lat 2 windows, which resulted in premature tagging. When bullheading acid from the tagged depth failed to overcome the encountered obstacle and extend the reach, a non-calcite deposit was assumed. Ordering and using chemicals to remove the suspected drilling mud blockage, however, was not feasible from both a logistic and operational point of view.

The fifth and final challenge here is the limited battery life of the pressure and temperature tool. In the event battery power runs out, it is necessary to POOH to change out the battery so live readings of both pressures and temperatures are consistently obtained. This action will result in a delay in operations and in a possible re-mapping around the window of the targeted lateral.

SOLUTION

The proposed solution to these challenges was to utilize fiber optic enabled CT downhole tools to evaluate and stimulate the well, as described in each step below.

- Evaluate the overall performance of the well before and after the treatment with an injectivity test and a PTA

Reservoir Rock			Limestone		
Well Type			Power Water Injector		
Reservoir Pressure			4,300 psi at 9,720 ft measured depth, ~4,600 psi at 10,250 ft TVD		
Bottom-hole Static Temperature			220 °F		
True Vertical Depth of the Top of Reservoir			9,440 ft		
Permeability			3 md		
Fluid Density			7.5 ppg		
Fluid Viscosity			0.75 cP		
H_2S			1.82% to 4.84%		
Lateral	**0**	**1**	**2**	**3**	**4**
Window Depth	11,082 ft to 11,147 ft		13,640 ft to 13,683 ft	12,865 ft to 12,910 ft	11,780 ft to 11,964 ft
Total Depth Lateral	18,982 ft	15,172 ft	15,007 ft	14,890 ft	14,039 ft
Comments	Lat 0 of 4 sep. from rest		Lat 2 of 4 sep. from WB 1 of 4	Lat 3 of 4 sep. from rest	Lat 4 of 4 sep. from rest

Table 1. The important reservoir/well characteristics (above) and the total depth of the well, Lat 0, and of the laterals, Lat 1, 2, 3 and 4 (below)

conducted at the junction point, using a fiber optic enabled downhole pressure gauge.

The pressure, temperature, casing collar locator (CCL) and gamma ray downhole system is a real-time bottom-hole measurement and communication system for CT applications. A fiber optic control line is placed inside the CT to transmit data to and from a bottom-hole assembly, Fig. 2. The standard measurements, taken at the end of the CT, include pressure inside the CT, pressure outside the CT, temperature, and CCL and gamma ray readings for depth correlation.

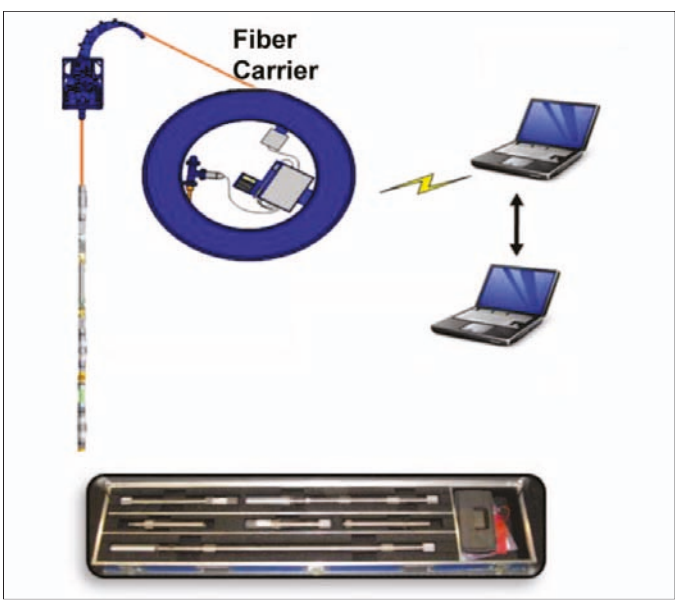

Fig. 2. Fiber optic data transmission from a bottom-hole assembly for downhole pressure and temperature measurement downhole.

- Access each lateral by deploying a multilateral reentry system[3].

The selected multilateral reentry system, shown in Fig. 3, provides controlled, selective entry of the CT to all levels of a multilateral well. The system sends a pressure signal to the surface to confirm that the correct lateral has been accessed. The ability to adjust the sub-orientation, or bend, from the surface and to get real-time feedback of window identification saves a substantial amount of time by significantly increasing the

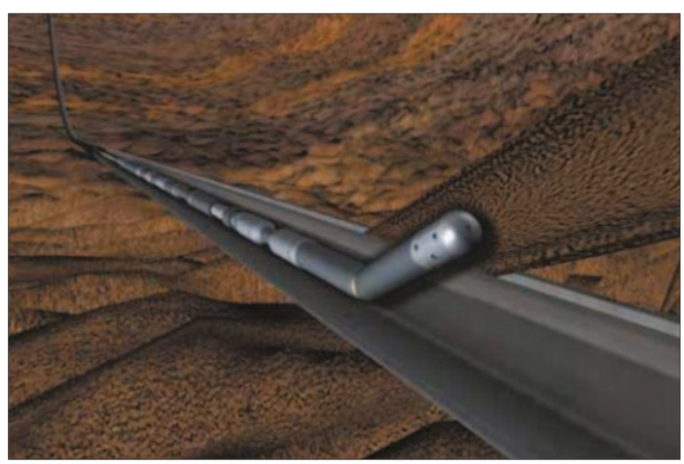

Fig. 3. Selected multilateral reentry system.

chance of successful reentry on the first attempt. Only one run to the bottom of the lateral is required for confirmation. The system is also acid resistant, enabling accurate execution of all types of fluid treatments. The system therefore offers a cost-effective and operationally simple solution for maximizing acid treatment at all levels of a multilateral well.

- Correlate and verify the treated lateral with the downhole live CT gamma ray logging tool.
- Determine high and low intake zones using DTS to optimize the pumping schedule in real time.

For the distributed temperature measurement, an industrial laser launches 10 nanosecond bursts of light down the fiber optic. During the passage of each packet of light, a small amount is backscattered due to molecules in the fiber. This backscattered light can be analyzed to measure the temperature along the fiber. Because the speed of light is constant, a spectrum of backscattered light can be generated for each meter of the fiber using time sampling, thereby producing a continuous log of spectra along the fiber, Fig. 4.

A physical property of each spectrum of backscattered light is that the ratio of the Stokes Raman band to the Anti-Stokes Raman band is directly proportional to the temperature of the length of fiber from which it is generated. Consequently, a temperature log can be calculated at every meter along the whole length of the fiber using only the laser source, the analyzer and a reference temperature in the surface system. There is no need for any calibration points along the fiber or for calibration of the fiber before installation.

Spectrum acquisition times can be varied from as little as 2 seconds to hours; the length of time determines the accuracy and resolution of the measured temperature log. Typically, a resolution of 0.05 °C is required for reservoir surveillance.

- Evaluate each lateral in real time to determine a skin factor value, and adjust one or more stimulation parameter values, also in real time.

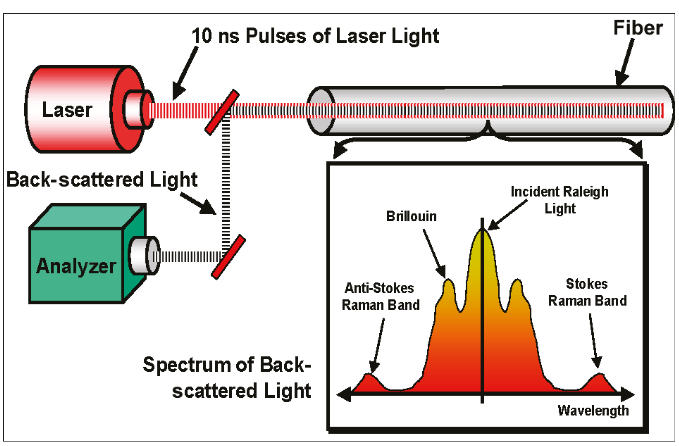

Fig. 4. The distributed temperature measurement.

Stimulation Design

In our case, the formation is carbonate, so our goal was to increase the number of wormholes and so bypass the damage. Since the well is a power water injector, the objective of the matrix stimulation process was to convert the matrix to oil-wet to maximize water injection. To achieve that goal, an oil-based acid treatment was used. An emulsified acid was selected as the best option to create deep wormholes and achieve the oil-wet conversion; the emulsified acid was basically a mixture of acid and diesel, with a percentage of 70% acid and 30% diesel.

In any stimulation process, diverters are also needed. Effective diversion here required both the oil-based acid and a diverting agent.

Based on previous engineering experiences, the following treatment using hydrochloric (HCl) acid was selected:

1. Spearhead (15% HCl acid).
2. Viscoelastic diverting acid (VDA) (20% HCl acid).
3. Spacer (15% HCl acid).
4. Emulsified acid (20% HCl acid, 30% diesel and 70% acid mix).

When pumping an acid treatment, it is very important to separate the VDA from the emulsified acid with a spacer to ensure the VDA is directed to the high permeability zones and the emulsified acid is sent to the low permeability zones. Therefore, the typical sequence is: spearhead (HCl acid), VDA, spacer (HCl acid), and emulsified acid.

This technique was optimal for achieving deep wormholes. The variable that changes from one treatment to another is the volume of acid and diversion. Due to the size of the open hole section and the borehole size, zonal coverage is a common challenge.

Innovative Workflow

A large amount of effort was directed toward developing and refining the workflow for optimal results. The workflow was designed in a way to allow a systematic reproduction of consistent results for any multilateral well in this field. Efforts are still ongoing to implement the same methodology on similar wells to verify its success. The idea here is to extend the standard matrix stimulation engineering process (design, execution and evaluation) to include advanced reservoir analysis as well. The process objective is to provide reservoir simulation engineers with more detailed information about flow characteristics in the critical matrix. The focus of this methodology is on permeability and skin per section of the horizontal section before and after the matrix treatment. The application of the proposed methodology involves using fiber optic enabled CT to pump and monitor the treatment simultaneously. It is recommended to have logging while drilling mobility data and basic lithological interpretation on hand prior to starting.

Skin evaluation is a new technique for evaluating formation damage on the spot, in real time, to optimize the volumes of acid and diverter.

This technique was used here to quantify formation damage using the pressure response from the critical matrix, which corresponds to the injection rate change. The steps described next were followed to achieve this.

The first step was to conduct a well test (injection/falloff); from this, values for reservoir parameters, such as formation capacity (KH), and the average reservoir pressure (P_{avg}) were obtained.

Later, these parameters were used to evaluate formation damage (skin).

The next step was to position the CT pressure gauge at maximum depth to start injection through the CT; once pressure readings stabilized (P_{inj}), formation damage (skin) corresponding to a particular point in the lateral section (X) was calculated from Eqn. 1:

$$S = \frac{KH}{141.2 q \beta \mu} \Delta Ps \tag{1}$$

where S = skin, K = permeability, H = thickness, q = rate, B = formation volume factor, $\Delta\mu$ = viscosity and P_s = pressure drop due to damage.

The same process was repeated while the CT was POOH to obtain a value for skin at every change in X. Finally, a skin profile was created across the whole horizontal section.

The process was done before and after the treatment to evaluate the change in formation damage (skin) in response to the stimulation treatment.

Figure 5 shows a schematic of the process where a particular change in X (ΔX) delineates the intervals of interest.

Stimulation Evaluation

The well was tested after treatment and showed a significantly large increase in injection rate, eight times the pretreatment rate at the same wellhead pressure.

Figures 6 to 8 shows the results of the treatment, i.e., the real-time skin evaluation, pre- and post-treatment, skin profile vs. depth and PTA post-treatment injection, respectively.

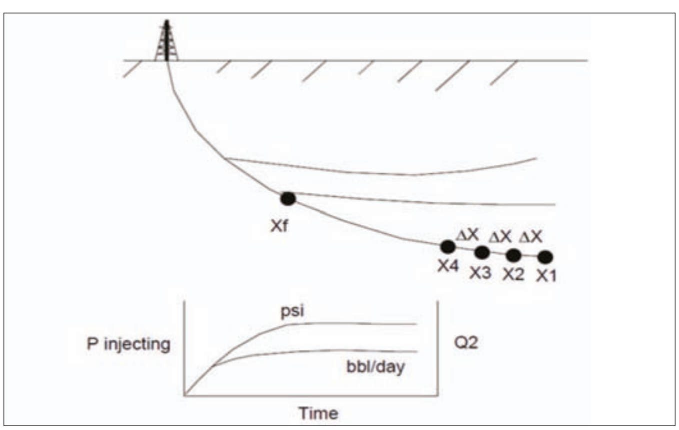

Fig. 5. Real-time skin evaluation schematic.

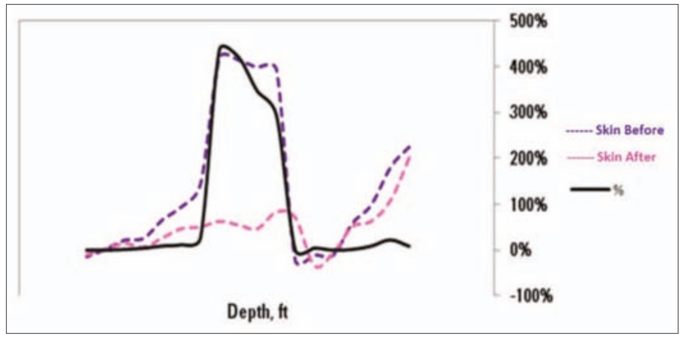

Fig. 6. Real-time skin evaluation (before and after treatment).

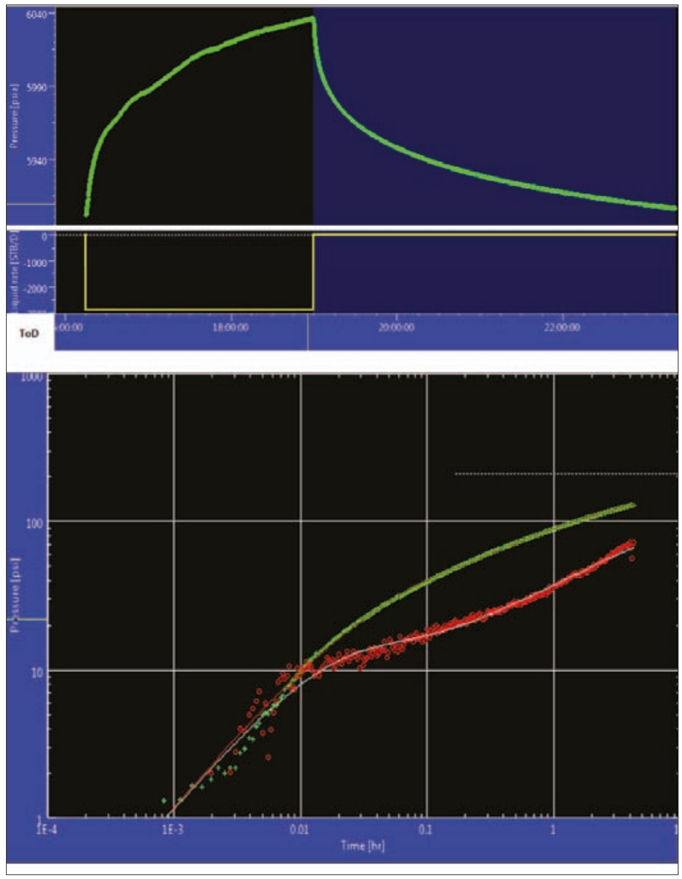

Fig. 7. PTA post-treatment injection.

CONCLUSIONS

Using fiber optic enabled CT downhole tools, the operations and engineering teams managed to tackle the challenges and provide an improved stimulation design that tremendously increased the well's injectivity.

DTS, along with real-time PTA, successfully identified low and high intake zones, and therefore saved operation time and resources.

Applying DTS and PTA together also improved efficiency and eliminated uncertainty related to the performance of each of the well's laterals.

The innovative technique to estimate formation damage (skin) in real-time provided a unique solution that resolved

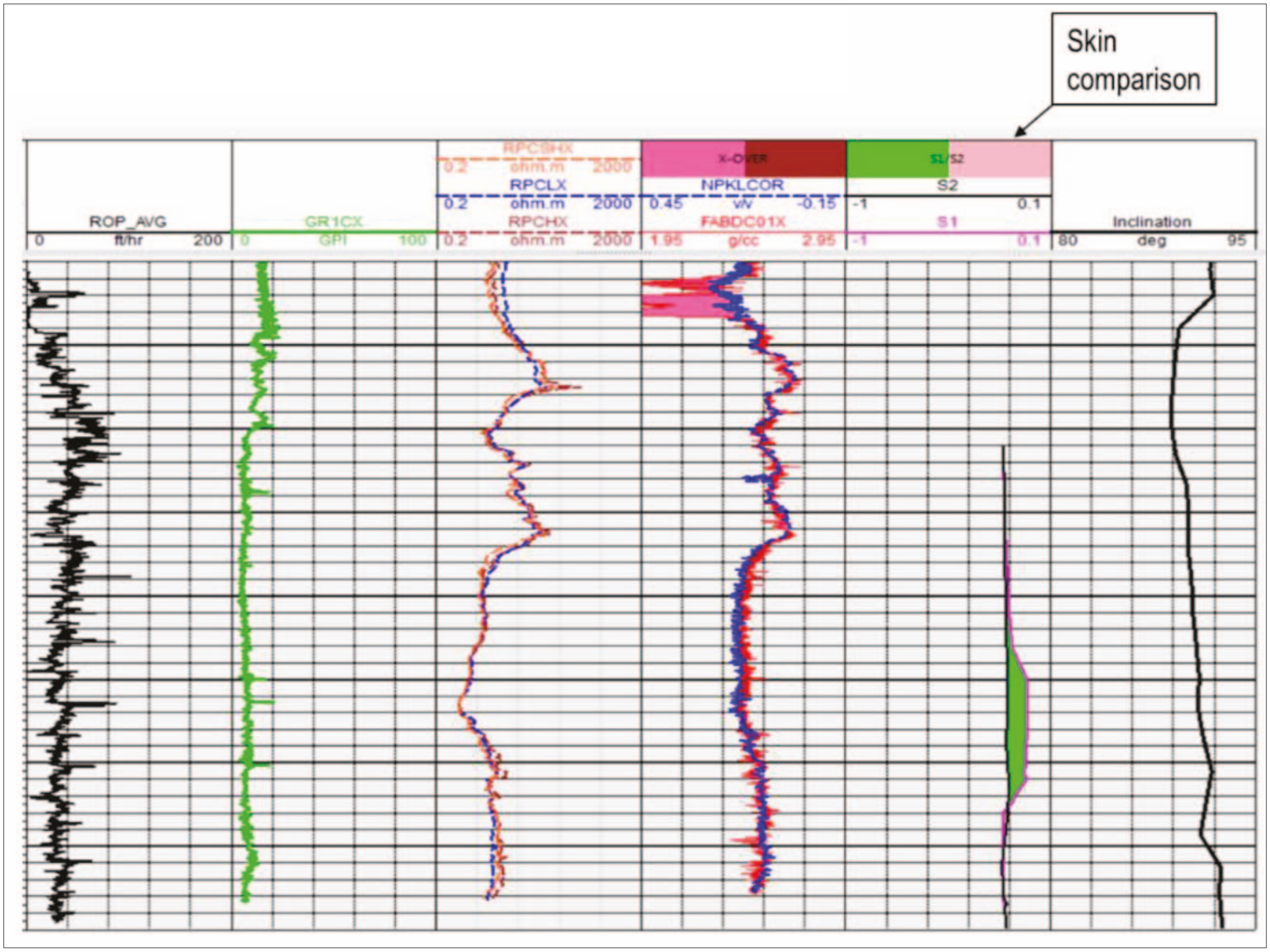

Fig. 8. Skin profile vs. depth.

uncertainty and evaluated the enhancement in formation injectivity in real-time in a complex, challenging environment.

ACKNOWLEDGMENTS

The authors would like to thank the management of Saudi Aramco and Schlumberger for their support and permission to publish this article. Furthermore, the authors would like to thank Abdulrahman Ahmari, Saleh Ghamdi, Mohammed Ajmi, Murad Abubakr and Saud Maymouni (Saudi Aramco), and Mahdi Altarooti and Tamer Elsherif (Schlumberger).

This article was presented at the SPE/ICoTA Coiled Tubing and Well Intervention Conference and Exhibition, The Woodlands, Texas, March 24-25, 2015.

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BIOGRAPHIES

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Nooreddeen received his B.S. degree in Petroleum Engineering from Pennsylvania State University, State College, PA, and was awarded the Merit Medal from the Dean of the College of Earth and Mineral Sciences. Currently, he is pursuing his M.S. degree at Stanford University, Stanford, CA.

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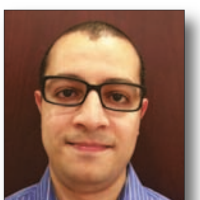
In 2004, he received his B.S. degree in Petroleum Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia.



Ramy Ahmed is a Senior Reservoir Engineer and Schlumberger Reservoir Engineering Team Lead for the Saudi Arabia and Bahrain region. He works on matrix stimulation design and diagnostics, pressure transient analysis, formation testers and sampling interpretation, numerical modeling of fluid flow, production optimization, and reservoir monitoring. Ramy's work experience includes working for several different operating and service companies.

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Ramy has published several publications and patents on matrix stimulation design and diagnostics, production optimization, interpretation of wireline formation testers, and reservoir monitoring.

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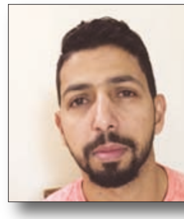

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Abdulrahman works on matrix stimulation design and diagnostics, pressure transient analysis, and high profile technology wells, such as the wells located at the giant Manifa field.

His work experience includes working in different segments within Schlumberger, including PTS, CTS, CoilTOOLS and CTD.

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In 2010, Abdulrahman received his B.S. degree in Petroleum Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia.

First High Rate Stimulation Treatment through Coiled Tubing with Real-Time Downhole Monitoring — A Story of Success

Authors: Adel S. Al-Thiyabi, AbdulAziz A. Al-Ruwaily, Sajid Mehmood, Mohammed Aiman Kneina, Nestor Molero, Danish Ahmed, Afsal AM and Ruben Ortega Alfonzo

ABSTRACT

Over the last 10 years, matrix stimulation of multilateral wells has been one of the most fascinating and technology driven interventions in the oil and gas industry due to the several challenges involved in this kind of operation. The prospect of overcoming these challenges, which include lateral identification and accessibility, reservoir assessment and accurate placement of stimulation fluids, has encouraged operators and manufacturing and service companies to develop innovative techniques and novel technologies.

In Saudi Arabia, coiled tubing (CT) equipped with real-time downhole measurement tools and a multilateral identification tool has been one of the most valuable technologies developed to enhance interventions in multilateral wells. The ability to monitor real-time data enabled a more efficient operation of the multilateral identification tool. It also optimized the proper placement of the stimulation treatment fluids by identifying high intake zones to be avoided across each lateral.

Most recently, the incorporation of a gamma ray tool into the real-time downhole measurement tool package has allowed a faster identification of each lateral and the accurate depth correlation needed for pinpoint acid stimulation. Nevertheless, when this technology was deployed, pumping rates had to be kept to a maximum of only 2.0 bbl/min due to limitations on the downhole tools and optical fiber installed inside the 2⅜" CT. In some cases, this low pumping rate proved to be a drawback for optimum fluid penetration and efficient diversion across the zone of interest during the stimulation treatment.

This article documents the first worldwide applications of an enhanced version of the real-time downhole measurement tool package deployed on 2⅜" CT for the matrix stimulation of a multilateral power injector well in Saudi Arabia, where the pumping rate of 2.0 bbl/min was far exceeded while maintaining intact all downhole readings. The enhanced package represented a significant increase in operational efficiency and set a new record for this technology. A total of 4,585 bbl of stimulation fluids were injected across the open hole laterals — 7,685 ft combined on both wells — at a maximum rate of 4.6 bbl/min. The laterals were successfully accessed with the use of the multilateral identification tool in a single run without the need to pull the CT back to the surface.

The use of this enhanced real-time downhole measurement tool package reduced the operational time by almost 50%, enabled more effective formation damage removal by injecting stimulation fluids at a higher rate, provided real-time depth correlation, verified access to each lateral via gamma ray without the need to tag total depth (TD) and resulted in a tangible cost reduction.

INTRODUCTION

Most hydrocarbon reservoirs in Saudi Arabia are carbonate formations where oil, water and gas wells have been drilled. Typically, peripheral water injection is employed for waterflooding and maintenance of the reservoir pressure. When injectivity in a newly drilled or a reentry water injection well declines, it is mostly due to mud filter cake buildup or drilling fluid impurities carried over in the formation. When the injection declines over a period of time, it is often due to impurities present in the injection water, which impair the formation permeability.

Most of the water injection wells with these declines are treated by matrix acid stimulation using coiled tubing (CT), which serves to restore or increase well injection rates. Field-A in Saudi Arabia is produced using water injection as a means of pressure maintenance. Water injection enables better sweep efficiency and helps to restrict the pressure decline. Water injection takes place at the reservoir peripheries. Sometimes the water injectors are in same layer as the oil producers, but others may be in a water layer below the oil layer, particularly when aquifer mobility is very low and cannot act as an effective water drive[1].

JOB OBJECTIVES AND CHALLENGES

The well in this study is a 6⅛" open hole dual-lateral water injector, Fig. 1.

The completed well began injecting at approximately 14,000 barrels per day (bpd), and increasing the injection rate was the main objective. To achieve this, the following job objectives were identified:

1. Use CT to access and identify the laterals correctly.
2. Pump stimulation treatment at a high rate and bypass the

damaged zone to achieve deeper injection of the treatment fluids, therefore creating wormholes of a greater depth.
3. Determine bottom-hole pressures (BHPs) during stimulation to ensure that stimulation treatment is carried out below the fracturing pressure[2].
4. Identify tight or damaged zones for proper placement of the stimulation fluids[2].
5. Determine the bottom-hole temperatures (BHTs) after treatment to verify the working temperatures of the stimulation fluids[2].

PROPOSED SOLUTION

To access a particular lateral for a CT intervention, it is possible to set a whipstock using CT, but little discussion of the process is available in literature. Furthermore, setting a whipstock via CT in an operation other than CT drilling requires a lengthy process: first killing the well, then making a run to set the whipstock, and finally making other separate trips to perform the treatment, retrieve the whipstock and lift the well. The additional trips often lead to more time-consuming and costly treatment.

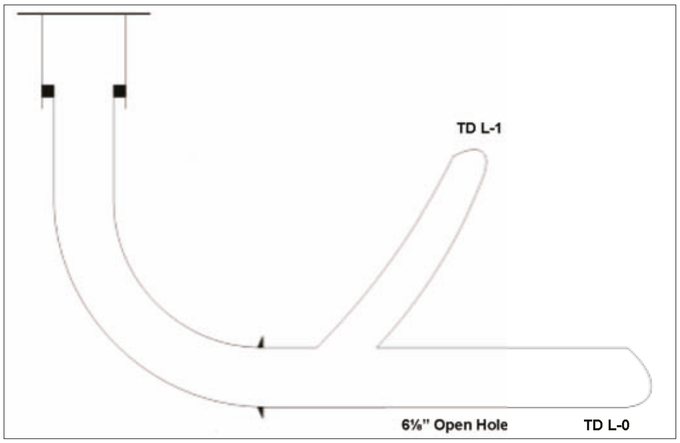

Fig. 1. Open hole horizontal dual-lateral water injector.

The Technical Advancement of Multilaterals group has defined a code of classifications for junctions associated with multilateral wells, as presented in Fig. 2. Previously, it was not possible to access Level 1 and Level 2 completions. In fact, accessing multilateral wells with conventional CT was not possible without some sort of mechanical isolation at the junction, and even then, CT was only able to access the natural path. Some further drawbacks of using conventional CT for multilateral wells include the following:

1. If CT was run in hole (RIH) past the junction depth, the exact travel path of the CT was not clear.
2. If the CT locked up before reaching lateral total depth (TD), it was not possible to identify in which lateral the CT was present; therefore, it was imperative that the CT reach to lateral TD.
3. If laterals were of the same TD, reaching lateral TD was still not enough to confidently define in which lateral the CT was present.

Therefore, a multilateral identification tool was devised that allows the CT to successfully enter each lateral. Early use of this multilateral identification tool provided success in accessing

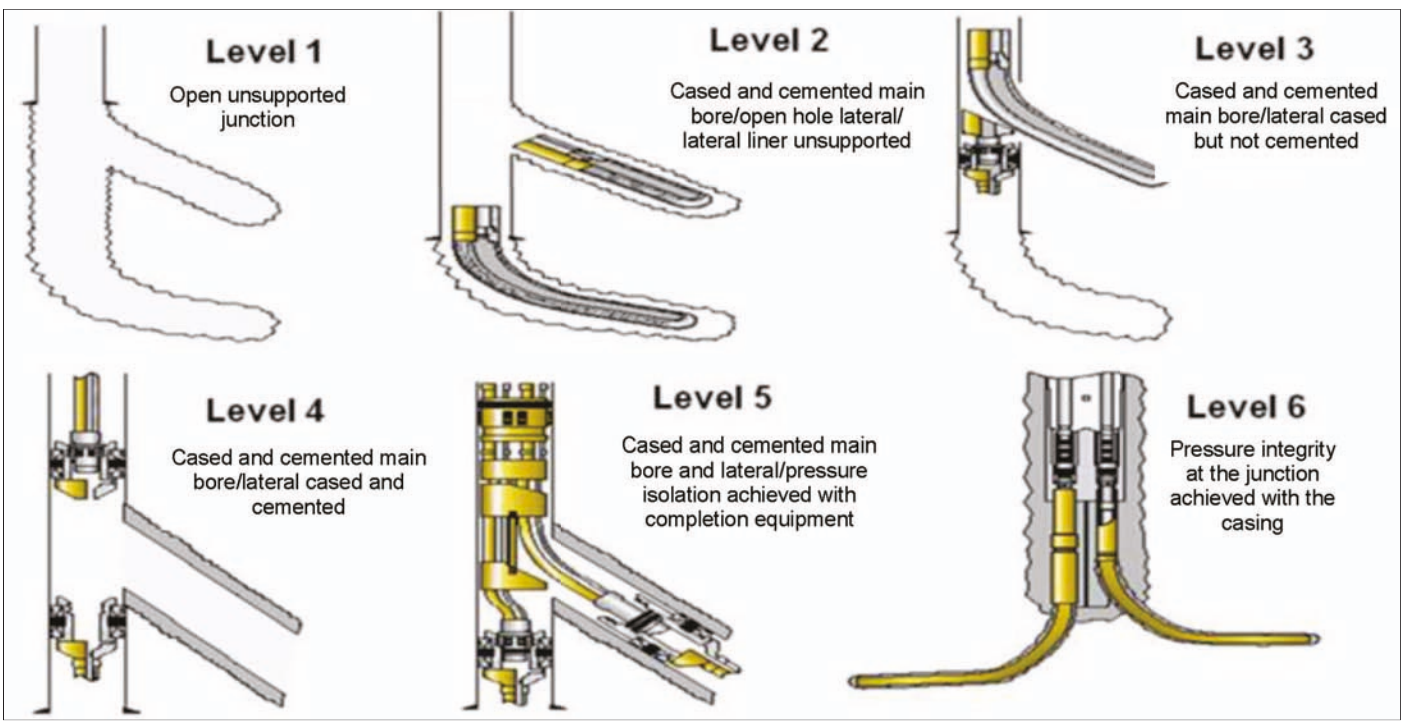

Fig. 2. TAML classification system for multilateral wells junctions' classification (source: http://www.drillingcontractor.org/merged-multilaterals-system-cuts-time-risk-9935 and http://www.drillingcontractor.org/wp-content/uploads/2011/07/ml04.jpg).

laterals, but the functionality of the multilateral identification tool relied on readouts of surface parameters. To meet the challenge of ending this reliance on surface parameters, a multilateral identification tool was run with CT along with a real-time bottom-hole monitoring system. Figure 3 shows the multilateral identification tool bottom-hole assembly (BHA) schematic. The multilateral identification tool system consists of an orienting tool and a controllable bent sub. The multilateral identification tool is operated by pumping fluid from the surface. The fluid sends a pressure signal to the surface, and a pressure gauge at the bottom of the hole confirms that the correct lateral has been accessed. The ability to adjust the orienting tool and the controllable bent sub from the surface and also to obtain real-time bottom-hole measurements saves considerable time during the mapping process[3].

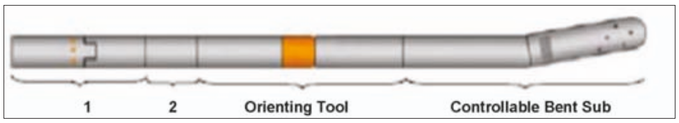

Fig. 3. Multilateral identification tool BHA schematic[3].

The multilateral identification tool works with the assistance of software that enables the surface display of several essential parameters, such as tool orientation relative to the lateral window. The software not only shows the current index, or multilateral identification tool profile, mapped for a window, but also shows previous indices and guides the operator through the indexing cycles, thereby providing accurate real-time information on the downhole situation. After profiling the window, the software memorizes the window orientation and monitors the BHA orientation throughout the entire operation[3], Fig. 4.

Considering the challenges of the operation, the use of CT equipped with real-time downhole measurements was deemed essential. Optical fibers inside the CT are connected to the BHA, where the fiber acts as a source of telemetry, transmit-

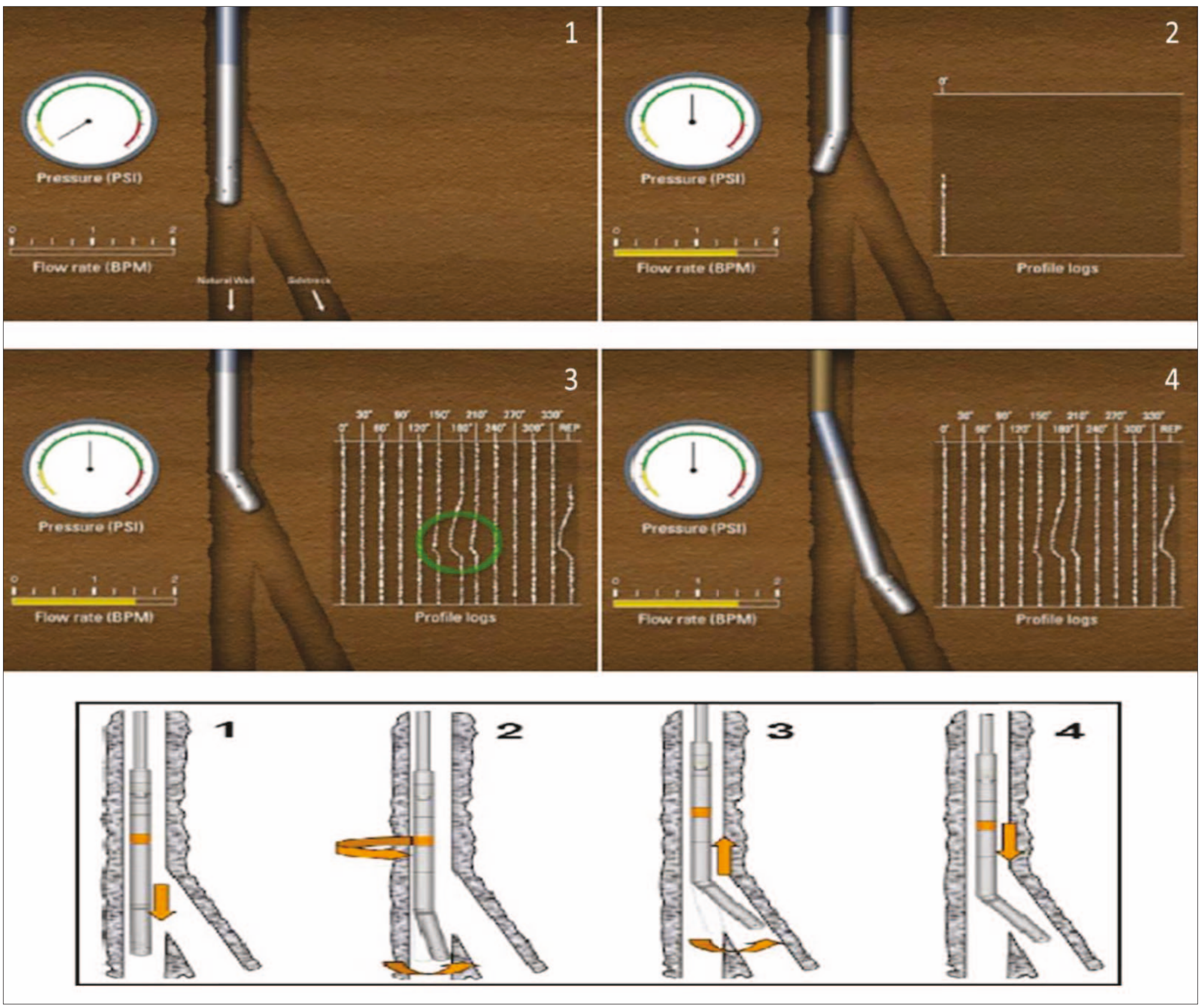

Fig. 4. Lateral identification tool operation sequence[3]: (1) Running the tool across the junction, (2) Indexing, (3) Finding the lateral, and (4) Accessing the lateral.

ting data from the downhole tools to the surface in real-time. The fiber can also be used to make distributed temperature sensor (DTS) measurements all the way down the well when the CT is stationary[2].

Because the conventional downhole tools that are used to conduct a DTS survey and to obtain real-time bottom-hole measurements have to be sized to 2⅛" — the size of the CT — they are limited to a pumping rate of only 2.0 bbl/min. This low rate and some limitations with respect to fiber parameters have resulted in the following:

- Long pumping time, leading to a long job time.
- An inability to obtain deeper penetration of stimulation fluids, which restricts the depth of wormholes.
- A low tensile strength for the fiber carrier that has fibers inside it for DTS and for telemetry purposes, which means it has a tendency to break at high pump rates.
- The likelihood the fiber carrier will be affected by the pumping of certain fluids, especially sticky or highly viscous fluids.

Because these limitations led to low execution efficiency, a new tool and an enhanced fiber carrier were developed especially for CT interventions with real-time bottom-hole measurement tools. It features the following upgrades[4]:

1. A 3¼" real-time downhole sensor package is included that consists of the following:
   - BHT sensor.
   - BHP gauge — measuring the inside and outside pressure of the CT.
   - Gamma ray tool for accurate depth correlation and for lateral identification.
2. A pump rate up to 8.0 bbl/min can be achieved through this tool, which enables deeper penetration of fluids, leading to deeper wormhole creation.
3. The tensile strength of the fiber carrier installed is double that of the 2⅛" standard tool. This enables not only higher pumping rates, but also the pumping of very viscous or abrasive fluids that could not be pumped through the standard system.
4. The new tool can help make descaling and cleanout jobs more efficient and faster.
5. The tool enables monitoring of the CT tool performance based on real-time downhole measurements, ensuring that the pump rates delivered provide a suitable differential pressure for optimal tool performance.

Table 1 compares the new system and the previous conventional system. The following operational steps were defined to meet the job objectives:

1. Open the well, RIH to the natural path lateral, and verify the lateral accessed via gamma ray correlation.
2. After confirmation that the CT is accessing the natural path lateral, activate the multilateral identification tool and access the nonnatural path lateral.
3. Verify access to the nonnatural path lateral; when this is confirmed, reach its TD and start stimulation treatment while the CT is pulled out of hole (POOH).
4. After finishing the nonnatural path lateral stimulation treat ment, access the natural path lateral.
5. Reach its TD and start stimulation treatment while the CT is POOH.
6. When the stimulation treatment of the natural path lateral is finished, the CT is POOH.

JOB EXECUTION (CASE STUDY)

This section gives details of some of the job steps previously discussed as performed on the case study well.

Access the Natural Path Lateral (L-0)

The 2⅜" CT was run up to 7,000 ft, approximately ~600 ft

	Standard System Sensor Package	Enhanced System Sensor Package
Maximum Flow Rate	2 bpm	8 bpm
Outside Diameter	2⅛"	3¼"
Ball Drop	⅝"	1"
Pressure Rating	12,500 psi	12,500 psi
Operating Temperature	300 °F	325 °F
Measurements	BHP, BHT, gamma ray, DTS, casing collar locator and TC	BHP, BHT, gamma ray and DTS
	Fiber Optic	**Fiber Optic**
Outside Diameter	0.071"	0.094"
Maximum Flow Rate	2 bpm	8 bpm

Table 1. Comparison between standard and new enhanced fiber optic telemetry and downhole measurements package[4]

past the liner shoe, to get a good gamma ray signature and to confirm L-0 as the motherbore. One more pass was made to confirm the repeated entry into L-0 as the motherbore.

Figure 5 compares the gamma ray log acquired during the job (maroon line) against the reference logs (black line) from the client for the L-0 lateral (left track) and L-0-1 lateral (right track). As shown clearly, the logs were matched with L-0 — verified with two passes — confirming L-0 as the motherbore.

Multilateral Identification Tool Profiling

Figure 6 shows the multilateral identification tool profiling pressure while mapping across the window — 6,350 ft to 6,220 ft.

In the figure, 0° is the reference orientation of the bent sub when the first profiling pass was made. Positive indication of the window was noticed at 180°, during the seventh profiling pass, by way of a drop in the downhole differential pressure across the tool measured by the real-time CT BHP gauge.

After the indication, L-0-1 was successfully accessed by running in hole without stopping the pumping — keeping the tool bent at 180° orientation.

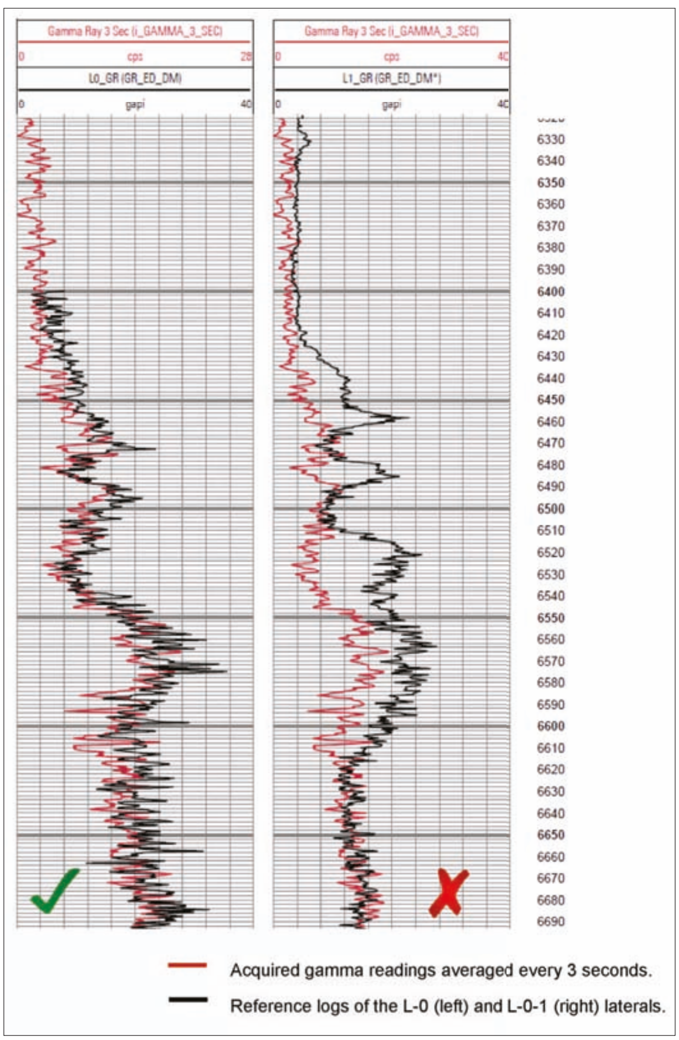

Fig. 5. Gamma ray log confirming L-0 as motherbore.

Gamma Ray Log Confirming L-0-1 Access after Multilateral Identification Tool Profiling

Figure 7 shows the comparison of the gamma ray log acquired after multilateral identification tool mapping (maroon line) against the reference log (black line) from the client for the L-0 lateral (left track) and L-0-1 lateral (right track). As shown

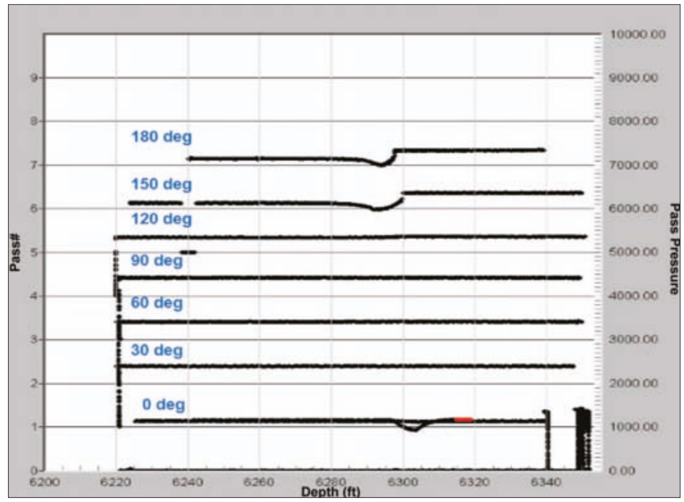

Fig. 6. Multilateral identification tool profiling.

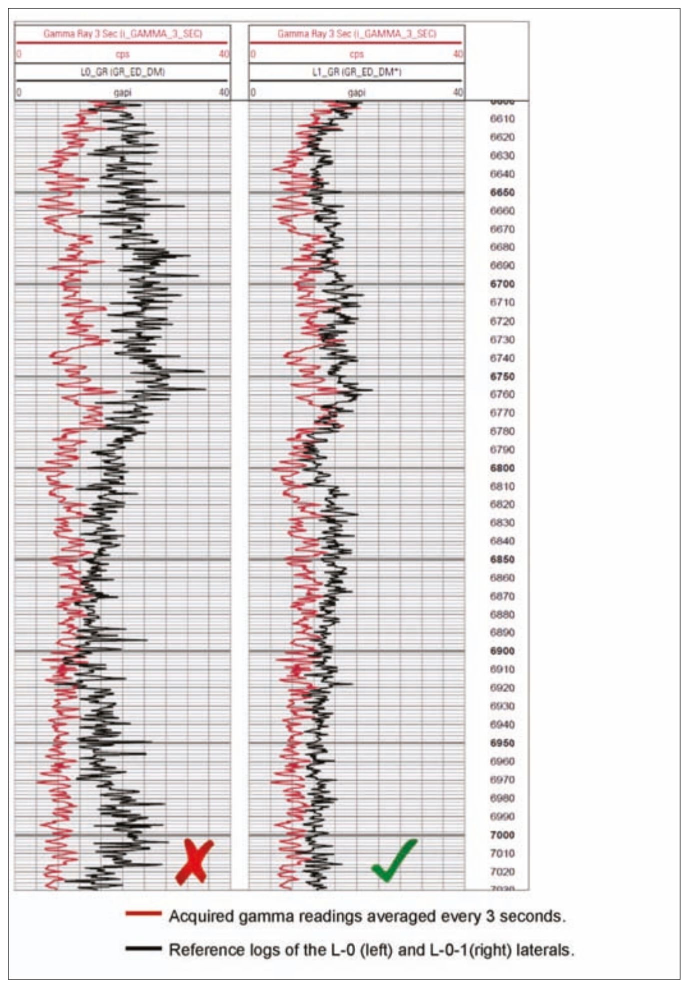

Fig. 7. Gamma ray log confirming access to L-0-1 upper lateral.

clearly, the logs matched with L-0-1 — verified in two passes — confirming access to the L-0-1 lateral with multilateral identification tool mapping.

Figure 8 depicts the downhole differential pressure trend across the circulating sub piston when a ⅞" ball was dropped to shear/activate the circulating sub and isolate the multilateral identification tool for the main high rate stimulation treatment.

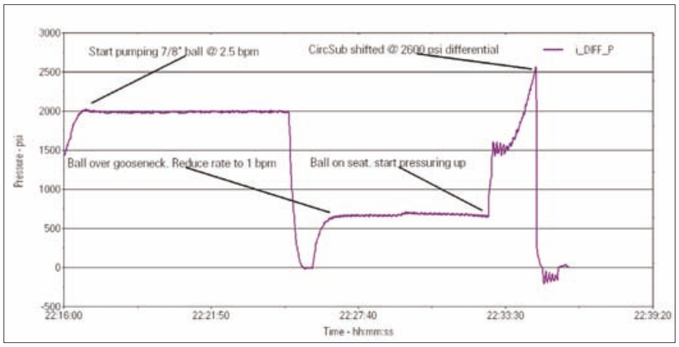

Fig. 8. Activation of circulation sub.

Stimulating L-0-1

Figure 9 shows the surface and downhole parameters obtained during stimulation of lateral L-0-1. The events are described in Table 2.

Stimulating L-0

Figure 10 shows the surface and downhole parameters obtained during stimulation of lateral L-0 (motherbore). The events are described in Table 3.

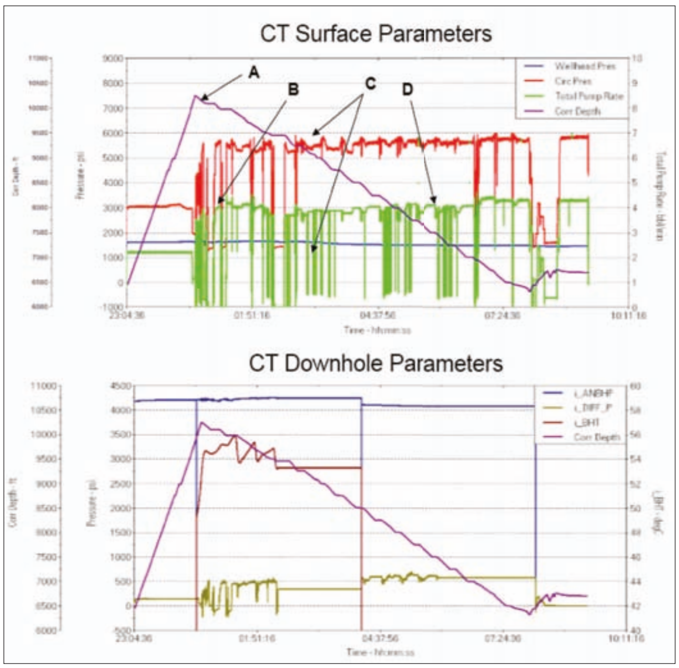

Fig. 9. Surface and downhole parameters during L-0-1 stimulation.

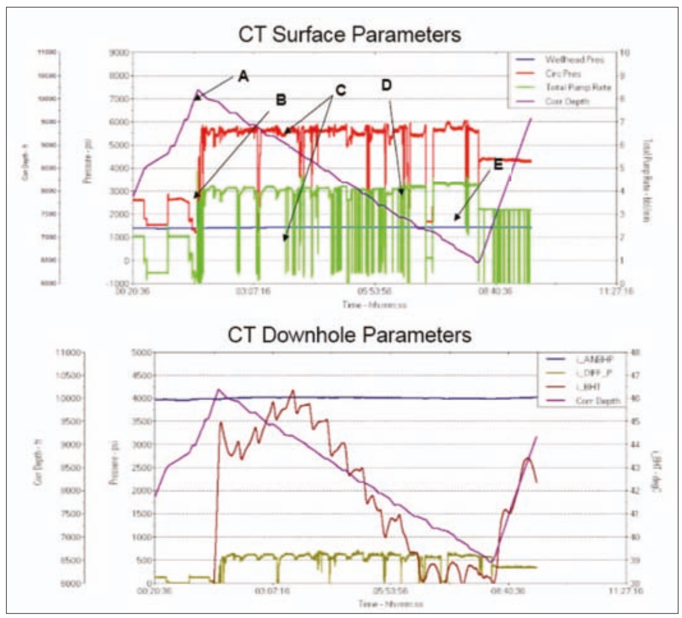

Fig. 10. Surface and downhole parameters during L-0 stimulation.

Parameter	Event
A	Stimulation while POOH from 10,253 ft to 6,350 ft for L-0-1. A volume of 89 bbl of acid was pumped in 250 ft intervals while pulling at 11 ft/min (equivalent to 15 gal/ft treatment at 4 bbl/min). A volume of 12 bbl of diverter was pumped with CT stationary after every 250 ft of acid treatment (equivalent to 2 gal/ft of stimulated interval). BHP in the annulus was constant at approximately 4,200 psi even while pumping at a higher rate, indicating signs of formation taking the stimulation fluids.
B	Average pump rate was 4 bbl/min (fluctuation in the rate plot is because of pump pressure fluctuation). Downhole differential pressure of approximately 500 psi (as predicted) while pumping at 4 bbl/min through the circulation sub ports indicated that the piston had shifted all the way and that the ports were fully open.
C	Circulation pressure was maintained below 6,000 psi, and wellhead pressure (WHP) was slowly dropping from 1,600 psi to 1,500 psi during the stimulation.
D	A 4.4 bbl/min pump rate was achieved during the latter part of the L-0-1 stimulation interval. The pump rate was limited by the circulation pressure maximum of 6,000 psi.

Table 2. Description of L-0-1 stimulation events

Parameter	Event
A	Stimulation while POOH from 10,191 ft to 6,465 ft for L-0. A volume of 89 bbl of acid was pumped in 250 ft intervals while pulling at 11 ft/min (equivalent to 15 gal/ft treatment at 4 bbl/min). A volume of 12 bbl of diverter was pumped with CT stationary after every 250 ft of acid treatment (equivalent to 2 gal/ft of stimulated interval). BHP in the annulus was constant at approximately 4,000 psi even while pumping at a higher rate indicating signs of formation taking the stimulation fluids.
B	Average pump rate was 4 bbl/min (fluctuation in the rate plot is because of pump pressure fluctuation). Downhole differential pressure of approximately 600 psi (as predicted) while pumping at 4.2 bbl/min through the circulation sub ports indicated that the piston had shifted all the way and that the ports were fully open.
C	Circulation pressure was maintained below 6,000 psi and WHP was constant at 1,450 psi.
D	A 4.4 bpm pump rate was achieved during the latter part of the L-0 stimulation interval.
E	Post-flush was pumped at an average 3.3 bpm while running in hole to TD at 45 ft/min.

Table 3. Description of L-0 stimulation events

RESULTS

The stimulation results showed significant improvement in the well's injection rate. A gain of 11,000 BPD was realized following the acid stimulation job at this well. The post-stimulation injection rate showed 25,000 BPD compared to 14,000 BPD at 2,500 psi prior to the stimulation job. A total of 7,698 ft of reservoir contact were acidized.

LESSONS LEARNED

The first worldwide high rate matrix stimulation treatment via CT with real-time downhole monitoring in a dual-lateral power water injector combined an enhanced sensor package with a multilateral identification tool. The stimulation was very successful, enabling pumping rates above 4.4 bbl/min without affecting telemetry readings.

During the stimulation treatment, a maximum pump rate of 4.6 bbl/min was achieved through the new enhanced sensor package, exceeding by far the previous limit of the conventional real-time downhole sensor package — 2.0 bbl/min. A total volume of approximately 4,500 bbl of stimulation fluids was injected across the laterals, which were successfully accessed with the use of the multilateral identification tool in a single run without the need to pull the CT out to the surface.

The use of an enhanced sensor package, combined with the multilateral identification tool, reduced the operational time by more than 50%, enabled more effective formation damage removal by injecting stimulation fluids at a higher rate, provided real-time depth correlation and verified access to each lateral via gamma ray signature without the need to tag TD.

ACKNOWLEDGMENTS

The authors would like to thank the management of Saudi Aramco and Schlumberger for permission to present and publish this work.

This article was presented at the SPE North Africa Technical Conference and Exhibition, Cairo, Egypt, September 14-16, 2015.

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BIOGRAPHIES

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Mohammed Aiman Kneina is the Account Manager for Oil South. He began working with Well Intervention – Coiled Tubing Services in Schlumberger Algeria in 1999. His experience includes working in 'Udhailiyah, Saudi Arabia, supporting coiled tubing and matrix stimulation jobs.

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Nestor Molero is a Sales & Technology Manager for Schlumberger Well Intervention in Mexico and Central America. He is a Technical Engineer with more than 15 years of experience in the design, execution and evaluation of coiled tubing (CT) workover interventions in onshore and offshore environments.

From March 2013 until September 2014, Nestor was Technical Manager for Schlumberger Well Intervention in Saudi Arabia, leading the Schlumberger CT Technical Team and supporting Saudi Aramco on the technical aspects of CT interventions in oil, gas and power water injector wells conducted for matrix stimulation, descaling, perforating, clean outs, milling, fishing, zonal isolation, etc. Prior to this assignment, he held technical and sales positions in Egypt and Mexico, where he was responsible for the introduction of new technologies for CT and matrix stimulation. Nestor started his career in Venezuela in 1999 as a Field Engineer for Schlumberger Well Services, completing his field assignment in Colombia and Ecuador.

He has authored several Society of Petroleum Engineers papers and articles that have appeared in various industry magazines.

Nestor received his B.S. degree in Mechanical Engineering from Universidad del Zulia, Maracaibo, Venezuela.

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In 2007, he received his M.S. degree in Petroleum Engineering from Heriot-Watt University, Institute of Petroleum Engineering, Edinburgh, Scotland.

Afsal AM is currently working as a Senior Design Engineer for CoilTOOLS at the Schlumberger (SLB) Houston Conveyance and Surface Equipment product center in Sugar Land, Texas. He has extensive experience in developing and sustaining downhole tools in SLB's ACTive and CoilTOOLS portfolios. Afsal is also currently an InTouch subject matter expert on SLB trademark tools, including CoilFLATE, AbrasiJET, multilateral tools and the ACTive platform.

He started his career in 2008 as a Mechanical Design Engineer for Schlumberger India where he was involved in coiled tubing equipment design. From 2012 to 2015, Afsal worked as a Field Engineer and ACTive specialist based in 'Udhailiyah, Saudi Arabia, where he was involved in a variety of coiled tubing applications, including high rate matrix stimulations, zonal isolation using CoilFLATE inflatable packers, production logging, unconventional Plug-n-Perf campaigns, etc.

In 2008, Afsal received his B.Tech degree in Mechanical Engineering from the National Institute of Technology, Calicut, India.

Ruben Ortega Alfonzo is currently Schlumberger's Well Intervention Operations Manager for Algeria, Tunisia and Libya. He has extensive experience in the oil and gas industry in well services and well interventions, both onshore and offshore, including deepwater. Ruben's various positions include 2 years as a Coiled Tubing Location Manager in 'Udhailiyah, Saudi Arabia; 4 years in Mexico as a Field Service Manager for Coiled Tubing and earlier as Engineer in Charge of three offshore Coiled Tubing Units; and positions in Venezuela for 5 years that included Coiled Tubing Services Sales Support Engineer, Engineer in Charge of a Coiled Tubing Drilling Barge and a Coiled Tubing Field Engineer. Prior to beginning to work for Schlumberger in 2004, he worked as a Process Engineer with Siderurgica del Orinoco, C.A. (SIDOR).

In 2004, he received his B.S. degree in Materials Science and Engineering from Universidad Simón Bolivar, Caracas, Venezuela.

Ruben has authored several Society of Petroleum Engineers (SPE) papers for different conferences around the world.

Mitigation of Stuck Pipe Challenges in HPHT Conditions Using an Acid-Soluble Blend of Barite and Manganese Tetroxide as Weighting Materials for Drilling Fluids

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ABSTRACT

Horizontal wells drilled in the Marrat (lower Jurassic), Minjur (upper Triassic) and Jilh (middle Triassic) formations in Saudi Arabia are known to present severe stuck pipe challenges. Stuck pipe in a horizontal well is a problem that can result in loss of tools, nonproductive time, the necessity for sidetracks and the loss of the well, thereby increasing wellbore construction cost.

To mitigate the problems arising due to stuck pipe issues, a new drilling fluid was formulated using a combination of barite and manganese tetroxide (Mn_3O_4) as weighting agents. The use of this combination as a weighting material provides both operational and monetary benefits.

Weighting material is added to drilling fluid to reduce solids loading and settling. Mn_3O_4 has a smaller particle size (D50 = 1 µm) and a higher specific gravity (SG = 4.95 g/cm^3) compared to barite (D50 = 20 µm and SG = 4.20). The fact that Mn_3O_4 is also acid soluble provides more operational benefits. In the event of a stuck pipe incident during drilling using a fluid with a combination of barite and Mn_3O_4 as a weighting agent, the use of acids or acid precursors would result in the dissolution of the Mn_3O_4, thereby resulting in a partial breakage of the Mn_3O_4 and barite filter cake formed in the well during drilling, which is likely to free the pipe. The monetary benefits come with the use of a barite along with Mn_3O_4 because barite is less expensive and so would result in reduced fluid cost compared to a fluid formulated with Mn_3O_4 alone as the weighting agent.

This article showcases the benefits of using a combination of barite and Mn_3O_4 as weighting materials in experiments with 100 pcf, 120 pcf and 150 pcf drilling fluids that have been hot rolled at 300 °F, 250 °F and 300 °F, respectively. The experimental work described in this article involved measuring the rheological properties, thermal stability, high-pressure/high temperature (HPHT) filtration and static sagging resistance of the fluid at 250 °F/300 °F. This article also reports the results of using different acid-based filter cake breaker fluids for the partial dissolution of a Mn_3O_4-based filter cake.

It is concluded that a blend of Mn_3O_4 and barite provides increased sag resistance compared to a drilling fluid formulated with barite alone as the weighting agent.

INTRODUCTION

Issues arising due to stuck pipe incidents, especially due to differential pressure sticking, are some of the major challenges faced by the oil and gas industry. Stuck pipe incidents result in a significant amount of lost time and other associated costs[1, 2]. Stuck pipe incidents on average account for about 25% of a well's nonproductive time, which translates to the cost of about two rig years every year[3]. To mitigate stuck pipe incidents, especially differential sticking incidents, operator companies often decrease the mud weight to minimize the overbalance, minimize stationary time, and increase drill collar and drillstring stabilization[4]. Despite the best efforts of the operators, however, stuck pipe incidents may still occur. To avoid increasing the drilling costs, it has become imperative to design drilling fluids that can help in further mitigating stuck pipe incidents.

This article describes the formulation of a drilling fluid containing a combination of manganese tetroxide (Mn_3O_4) and barite as weighting agents. The use of a combination of Mn_3O_4 and barite as weighting agents in a drilling fluid has many advantages.

Lower Equivalent Circulating Density (ECD) Due to Lower Solids Loading

An increasing number of solids in a fluid eventually led to a higher plastic viscosity (PV) value. A high PV then results in increased ECD due to increased pump pressures needed to pump the fluid[5]. A fluid with a high PV also decreases the rate of penetration[6]. On the other hand, a low PV maintains a high yield point (YP) to PV ratio (YP/PV), which improves cutting transport through the annulus in the laminar flow region at high YP values[7]. Mn_3O_4 has a higher specific gravity (SG = 4.95) than barite (SG = 4.2). The use of a weighting agent with a higher density, like Mn_3O_4 in combination with barite, helps to decrease the solids loading as compared to the conventional fluid formulated with 100% barite. This decreased solids loading results in a lower PV, which subsequently results in a lower ECD and better rate of penetration.

Sag Resistance

It is estimated that API barite settles 200 times faster than Mn_3O_4[8]. The lower settling velocity of Mn_3O_4 would result in a greater sag resistance for drilling fluid formulated with a combination of Mn_3O_4 and barite as compared to the conventional fluid formulated with 100% barite.

Fluid Cost

Mn_3O_4 is more expensive than barite. The use of Mn_3O_4 as the only weighting agent for the fluid would result in increased costs. The use of a combination of barite and Mn_3O_4 would reduce the fluid cost without sacrificing the greater sag resistance and lower ECD resulting from that combination as compared to a fluid formulated with 100% barite.

Acid Solubility of Mn_3O_4

Mn_3O_4 is acid soluble, while barite shows no acid solubility. This acid solubility of Mn_3O_4 can be used to design a fluid that enables the easy removal of filter cake from the wellbore by applying any acid treatment. In the event of a stuck pipe, this breaking of the filter cake will reduce the sticking force, thereby releasing the stuck pipe in the wellbore[4].

The next section describes the formulation of 100 pcf, 120 pcf and 150 pcf drilling fluids with a 60/40 v/v% barite/Mn_3O_4 combination as weighting materials. These new fluids, after hot rolling (AHR) at 250 °F/300 °F, show good rheological properties, good thermal stability, good high-pressure/high temperature (HPHT) filtration and increased static sag resistance. The section also describes the results of using different filter cake breaker fluids for the partial dissolution of a Mn_3O_4-based filter cake.

METHODS AND MATERIALS

The 100 pcf, 120 pcf and 150 pcf water-based fluids with a 60/40 v/v% barite/Mn_3O_4 combination were formulated with commercially available viscosifiers, filtration control agents, dispersants, weighting agents, bridging agents and shale inhibitors, etc.

The experimental procedure for this study was as follows.

Formulation of 100 pcf, 120 pcf and 150 pcf Drilling Fluids

1. The fluids were mixed in stainless steel mixing cups using the multimixer.
2. The fluids were next aged in HPHT stainless steel cells in a hot rolling oven at the desired temperature for 16 hours.
3. The fluids were then mixed, using a multimixer for 5 minutes, and their rheology was measured. After the rheology measurement at 120 °F, the fluids were placed in HPHT stainless steel cells. Static aging of the fluids was performed by placing the cells at an upright (90°) angle and at a 45° angle; an inclined setup was used to simulate the performance of the fluid if used in a 45° angled well, Fig. 1.
4. After static aging, the cells were inspected for top free fluid separation, which was determined in units of volume by drawing out the separated fluid with a syringe.
5. The sag performance of the fluid was assessed by determining the sag factor, which involved first establishing the density of the top and bottom portion of the fluid column of the drilling fluid in the aging cell. This was done by drawing out 10 ml aliquots from each segment and measuring their weights on an analytical balance.

The sag factor for the static aged fluids was then calculated using the formula in Eqn. 1:

$$SagFactor = \frac{SG_{bottom}}{SG_{bottom} + SG_{top}} \tag{1}$$

where SG_{bottom} is the density of the drilling fluid at the bottom of the aging cell and SG_{top} is the density of the drilling fluid at the top of the aging cell.

A sag factor greater than 0.53 implies that the fluid has the potential to sag[9].

6. After the sag factor determination, the fluids were mixed, using the multimixer for 5 minutes. Then the fluid loss was determined using a 175 ml capacity HPHT filter press cell. The rheological and HPHT fluid loss testing was performed as per API 13B-1 recommendations.

Fig. 1. Inclined setup to simulate a 45° angled well.

The rheology of the fluid was characterized in terms of PV, YP and low shear yield point (LSYP). The YP and PV are parameters from the Bingham plastic (BP) rheology model. The YP is determined by extrapolating the BP model to a shear rate of zero; it represents the stress required to move the fluid. The YP is expressed in the units of lb/100 ft^2. The YP indicates the cuttings carrying capacity of the fluid through the annulus, or in simple terms, the fluid's hole cleaning ability. A YP of 10 to 25 is considered good for drilling. The PV represents the viscosity of a fluid when extrapolated to an infinite shear rate, expressed in units of centipoise (cP). The PV indicates the type and concentration of the solids in the fluid; a low PV is preferred. Both PV and YP are calculated using 300 revolutions per minute (rpm) and 600 rpm shear rate readings on a standard oil field viscometer, as given in Eqns. 2 and 3.

$$PV = (600 \text{ rpm reading}) - (300 \text{ rpm reading}) \quad (2)$$

$$YP = (300 \text{ rpm reading}) - PV \quad (3)$$

The yield stress (Tau0) is a parameter from the Herschel Buckley (HB) rheology model. The Tau0 is determined by fitting the HB model to the shear stress vs. shear rate curve, which is derived from the dial readings plotted against the corresponding rpm determined on the standard oil field viscometer. The Tau0 is expressed in units similar to those for the YP. The Tau0 indicates the susceptibility of the fluid to barite sag; a high Tau0 is expected to deliver a sag-resistant drilling fluid. The Tau0 can be estimated reasonably by calculating the LSYP value from Eqn. 4.

$$LSYP = [2 \times (3 \text{ rpm reading})] - (6 \text{ rpm reading}) \quad (4)$$

The gels formed in the fluid were characterized by the 10 sec/10 min gel strength, which represents the highest dial reading at 3 rpm on the viscometer, after keeping the fluid static for an interval of 10 sec/10 min. The gel strengths indicate the suspension ability of the fluid for cut drill solids and barite particles when drilling stops.

Filter Cake Breaking Experiments of Mn_3O_4-based Drilling Fluids

The effectiveness of various acids and acid precursors to remove the filter cake formed by the Mn_3O_4-based drilling fluids was examined using an HPHT filter press. A 120 pcf fluid formulated with 60/40 v/v% barite/Mn_3O_4 was used for the study. A filter cake was first prepared on a 50 µ ceramic disk at 250 °F using a 500 ml HPHT cell, according to API 13B-1, Fig. 2. Filter cake breaking experiments were performed by contacting this filter cake with different filter cake breaker fluids using a soaking time of 4½ hours at 250 °F. The efficiency of the filter cake breaker fluids in the removal or breaking of the filter cake is calculated by the following formula, Eqn. 5:

Fig. 2. Filter cake of 120 pcf fluid before any acid/acid percursor treatment.

$$\% \, Removal \, Efficiency = \frac{(w_f - w_a)}{w_f} \times 100 \quad (5)$$

W_f = Weight of the filter cake before treatment with breaker fluid

W_a = Weight of the filter cake after treatment with breaker fluid

RESULTS AND DISCUSSION

Formulation of 100 pcf, 120 pcf and 150 pcf Fluids with 60/40 v/v% Barite/Mn_3O_4

Water-based drilling fluids with three different densities, i.e., 100 pcf, 120 pcf and 150 pcf, were formulated with a 60/40 v/v% barite/Mn_3O_4 combination as weighting agents.

Formulation of 100 pcf Fluid

Table 1 lists the additives and their mixing order for the 100 pcf fluid formulated with a ratio of 60/40 v/v% barite/Mn_3O_4 as weighting agents. Potassium chloride (KCl) is added in a concentration of 7% (w/v%) to inhibit some shale formations, mainly smectite clays. Potassium cations (K^+) can be easily exchanged with the sodium cations (Na^+) that are found in the shale clay surface, making KCl a very good shale inhibitor. Table 2 shows the rheology and filtration properties of the 100 pcf fluid AHR at 300 °F for 16 hours.

The combination of barite and Mn_3O_4 in the 100 pcf fluid showed a PV of 26 cP and a good YP and LSYP of 25 lb/100 ft^2 and 5 lb/100 ft^2, respectively. (A good LSYP is ≥ 5 lb/100 ft^2.) Good YP and LSYP values ensure that the fluid has the desired sag resistance and good cuttings carrying capacity. The HPHT fluid loss measured at 300 °F was only 10 ml. These results showed that the 100 pcf fluid formulated with a combination of barite and Mn_3O_4 was stable, with good rheology and filtration properties.

Additive	Concentration
Water (bbl)	0.74
Bentonite (ppb)	3
Viscosifier (ppb)	1
Synthetic filtration control agent (ppb)	5
HPHT fluid loss additive (ppb)	3
Polymeric filtration control agent (ppb)	4
KCl (ppb)	25
NaCl (ppb)	2
NaOH (ppb)	0.25
Bridging agent (ppb)	10
Barite (ppb)	133.3
Mn_3O_4 (ppb)	104.7
H_2S scavenger (ppb)	0.3
Shale stabilizer (ppb)	3
Shale inhibitor (ppb)	7

Table 1. Formulation of the new 100 pcf drilling fluid with 60/40 v/v% barite/Mn_3O_4

RPM	AHR Dial Reading (lb/100 ft^2)
600	77
300	51
200	40
100	27
6	7
3	6
PV (cP)	26
YP (lb/100 ft^2)	25
LSYP (lb/100 ft^2)	5
Gel 10 sec	7
Gel 10 min	28
HPHT fluid loss (ml/30 min)	10
pH	9

Table 2. Rheology properties of 100 pcf fluid with 60/40 v/v% barite/Mn_3O_4 hot rolled at 300 °F

Additives	Concentration
Water (bbl)	0.71
Bentonite (ppb)	2
Sodium carbonate (ppb)	0.3
Potassium hydroxide (ppb)	0.5
KCl (ppb)	10
Viscosifier (ppb)	0.35
Filtration control agent (ppb)	2
Polymeric filtration control agent (ppb)	0.75
HPHT fluid loss additive (ppb)	4
Barite (ppb)	224.7
Mn_3O_4 (ppb)	176.5
Oxygen scavenger (ppb)	0.3
Chrome-free lignosulfonate (ppb)	2.5

Table 3. Formulation of the new 120 pcf drilling fluid with 60/40 v/v% barite/Mn_3O_4

RPM	AHR Dial Reading (lb/100 ft^2)
600	84
300	54
200	43
100	28
6	6
3	6
PV (cP)	30
YP (lb/100 ft^2)	24
LSYP (lb/100 ft^2)	6
Gel 10 sec	6
Gel 10 min	13
HPHT fluid loss (ml/30 min)	10
pH	9.4

Table 4. Rheology properties of 120 pcf fluid with 60/40 v/v% barite/Mn_3O_4 hot rolled at 250 °F

Formulation of 120 pcf Fluid

Table 3 lists the additives and their mixing order for the 120 pcf fluid formulated with a ratio of 60/40 v/v% barite/Mn_3O_4 as weighting agents. Table 4 shows the rheology of the fluid AHR at 250 °F for 16 hours. An HPHT fluid loss additive with a concentration of 4 pounds per barrel (ppb) was added to the fluid for better fluid loss control. As the solids loading is high in a high density mud like the 120 pcf fluid, a chrome-free lignosulfonate with a concentration of 2.5 ppb was also added to the fluid as a deflocculant to avoid higher PV and gel strength values.

The 120 pcf fluid formulated with a combination of barite and Mn_3O_4 showed a PV of 30 cP and a good YP and LSYP of 25 lb/100 ft^2 and 6 lb/100 ft^2, respectively. Like the 100 pcf fluid, the 120 pcf fluid would have the desired sag resistance and good cuttings carrying capacity. The HPHT fluid loss measured at 250 °F was only 10 ml. These results, similar to those for the 100 pcf fluid, showed that the 120 pcf fluid formulated with a combination of barite and Mn_3O_4 was stable, with good rheology and filtration properties.

Formulation of 150 pcf Fluid

Table 5 lists the additives and their mixing order for the 150 pcf fluid formulated with a ratio of 60/40 v/v% barite/Mn_3O_4 as weighting agents. The performance of this new 150 pcf fluid was compared with that of a conventional 150 pcf fluid formulated with 100% barite. The additives, their concentrations and their times of mixing were kept the same for both fluids to ensure a fair comparison of their rheology and filtration properties AHR. Both fluids were hot rolled at 300 °F for a period of 16 hours.

Table 6 shows the rheology of the fluids AHR at 300 °F for 16 hours. The new 150 pcf fluid formulated with a combination of barite and Mn_3O_4 showed a PV of 38 cP and a YP and LSYP of 38 lb/100 ft^2 and 9 lb/100 ft^2, respectively. The conventional 150 pcf fluid formulated with 100% barite showed a PV of 52 cP and a YP and LSYP of 22 lb/100 ft^2 and 4 lb/100 ft^2, respectively.

The new 150 pcf fluid, which has a LSYP of 9 lb/100 ft^2, would have better sag resistance and cuttings carrying capacity than the conventional fluid, which has a LSYP of only 4 lb/100 ft^2. Also, a 150 pcf fluid — which is a high density fluid — requires a large concentration of weighting agent to achieve the desired density. The subsequent increased number of solids leads to a high PV value as well as excessive heat and dehydration. As the volume of solids in the drilling fluid goes up, the

Additives	150 pcf Fluid with 60/40 v/v% Barite/Mn_3O_4	150 pcf Fluid with 100% Barite
Water (bbl)	0.53	0.49
Bentonite (ppb)	4	4
Sodium carbonate (ppb)	0.30	0.30
Sodium hydroxide (ppb)	0.40	0.40
Potassium chloride (ppb)	15	15
Polymer (ppb)	0.35	0.35
HPHT fluid loss additive (ppb)	6	6
Barite (ppb)	345	625
Mn_3O_4 (ppb)	270	–
Oxygen scavenger (ppb)	0.30	0.30
Chrome-free lignosulfonates (ppb)	4	4
Lubricant (ppb)	7	7

Table 5. Formulation of the new 150 pcf drilling fluid with 60/40 v/v% barite/Mn_3O_4

RPM	150 pcf Fluid with 60/40 v/v% Barite/Mn_3O_4	150 pcf Fluid with 100% Barite
600	114	126
300	76	74
200	61	56
100	43	35
6	15	8
3	12	6
PV (cP)	38	52
YP (lb/100 ft^2)	38	22
LSYP (lb/100 ft^2)	9	4
Gel 10 sec	15	20
Gel 10 min	41	46.1
API fluid loss (ml/30 min)	4	4
HPHT fluid loss (ml/30 min)	18	20
pH	9.8	9.7

Table 6. Rheology of new and conventional 150 pcf fluids hot rolled at 300 °F

particles become more closely packed together, and it becomes more difficult for them to move freely, which results in particle-particle interactions.

It is well-known that the ECD has to be minimized by minimizing the PV value, especially with high density fluids that require high solids loadings. Comparison of the new 150 pcf fluid with the conventional 150 pcf fluid formulated with 100% barite shows that the new fluid has a PV of 38 cP while the conventional fluid has a PV of 51 cP. It follows that the use of Mn_3O_4, which has a higher SG than barite, would help to decrease the solids loading in the new 150 pcf fluid as compared to the conventional 150 pcf fluid formulated with 100% barite. The decreased solids loading in the new 150 pcf fluid reduces particle-particle interactions, thereby resulting in the reported lower PV value of 38 cP.

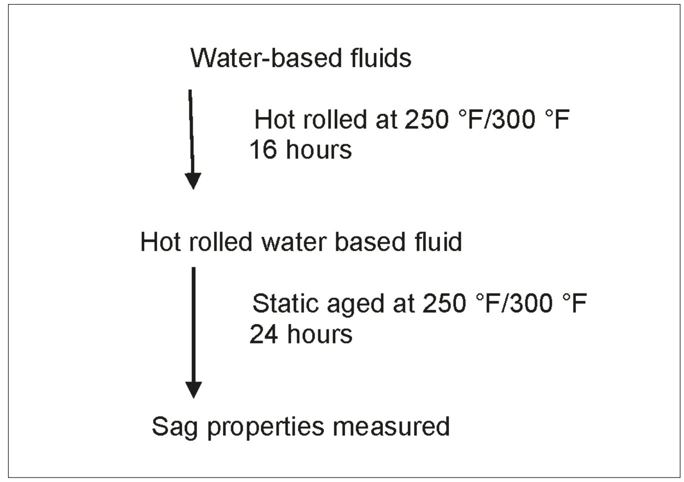

Fig. 3. Static aging study protocol.

Static Aging of 60/40 v/v% Barite/Mn_3O_4-based Fluids

Barite sag occurs due to the inadequate suspension of solids in the system when the drilling fluid is kept static for a certain duration of time in the wellbore. Barite sag can cause problems, such as stuck pipe, lost circulation, mud weight fluctuations, wellbore instability, etc. To understand the suspension behavior of barite in drilling fluids under static conditions, the following procedure was followed in the laboratory.

The 120 pcf and 150 pcf fluids were formulated and hot rolled for 16 hours at 250 °F/300 °F, respectively. These fluids were then static aged at 250 °F/300 °F for 24 hours in aging cells, kept in both vertical positions (90°) and inclined positions (45°). After exposure of the fluids to static conditions, the top free water separation was measured. The sag factor was calculated, as previously described, by measuring the top and bottom densities of the fluid after static aging and using the formula in Eqn. 1. A sag factor greater than 0.53 implies that the fluid has the potential to sag[9]. Figure 3 provides a flowchart of the testing protocol for the static aging studies.

Sag Performance Test at 90°

Static sag performance tests were conducted for 120 pcf and 150 pcf fluids at 250 °F and 300 °F, respectively. Table 7 shows the sag factor and the volume of top free fluid separated from the drilling fluid after 24 hours of static aging in vertical positions (90°). The 120 pcf fluid formulated with 60/40 v/v% barite/Mn_3O_4 when static aged at 250 °F showed a sag factor of 0.51 and top free fluid separation of 1 ml. The 150 pcf fluid formulated with a combination of barite and Mn_3O_4 when static aged at 300 °F showed a sag factor of 0.51 and a top free fluid separation of 15 ml. The sag performance of the 150 pcf fluid formulated with 60/40 v/v% barite/Mn_3O_4 was also compared to that of conventional 150 pcf fluid formulated with only barite as the weighting agent. The conventional fluid showed a sag factor of 0.53 and a top free water separation of 23 ml. These results demonstrate that the fluids formulated with a combination of barite and Mn_3O_4 show better sag performance as compared with conventional fluids formulated with 100% barite.

Sag Performance Test in an Inclined Position of 45°

To test the sag performance of barite/Mn_3O_4-based fluids while drilling deviated wells, 150 pcf fluid formulated with 60/40 v/v% barite/Mn_3O_4 was static aged at 300 °F for 24 hours in aging cells held at an angle of 45°, which simulates conditions of drilling in deviated wells. The sag performance of this 150 pcf fluid was then compared to that of conventional 150 pcf fluid, formulated with only barite as the weighting agent, after the same static aging. Table 5 previously listed the mixing order, concentration, and mixing time of the products used to formulate the new and conventional 150 pcf fluids used here.

Table 8 shows the sag factor and the top free fluid of the static aged fluids. The 150 pcf fluid formulated with a combination of barite and Mn_3O_4 again showed a sag factor of 0.51 and a top free fluid separation of 15 ml. The conventional 150 pcf

	120 pcf Fluid with 60/40 v/v% Barite/Mn_3O_4	150 pcf Fluid with 60/40 v/v% Barite/Mn_3O_4	150 pcf Fluid with 100% Barite
Static aging temperature	250 °F	300 °F	300 °F
Top free fluid (ml)	1 ml	15	23
Sag factor	0.51	0.51	0.53

Table 7. Sag factor for 120 pcf, new 150 pcf and conventional 170 pcf drilling fluids static aged in a vertical position (90°)

	150 pcf Fluid with 60/40 v/v% Barite/Mn_3O_4	150 pcf Fluid with 100% Barite
Static aging temperature	300 °F	300 °F
Top free water (ml)	15	24
Sag factor	0.51	0.53

Table 8. Sag factor for new 150 pcf and conventional 170 pcf drilling fluids static aged in an inclined setup (45°)

fluid with 100% barite showed a sag factor of 0.53 and a top free water separation of 24 ml. These results therefore demonstrate that the 150 pcf fluid formulated with a combination of barite and Mn_3O_4 shows better sag performance in an inclined static condition as compared with the conventional drilling fluid formulated with 100% barite.

Filter Cake Breaking of 60/40 v/v% Barite/Mn_3O_4-based Drilling Fluids

Filter cake breaking experiments were performed with filter cake created by 120 pcf fluids formulated with 60/40 v/v% barite/Mn_3O_4 at 250 °F. The formulation of the 120 pcf fluid was previously given in Table 3, and the filter cake pretreatment sample was previously shown in Fig. 2. Filter cake breaking experiments were performed using four different filter cake breaker fluids: 4% w/w hydrochloric acid (HCl) solution, 10% w/w organic acid solution, 15% w/w acid precursor, and a combination of 15% w/w acid precursor with 1% w/w HCl acid. Table 9 shows the results of the filter cake breaking tests.

Al Moajil et al. (2010, 2011, 2013)[10-12] and Elkatatny et al. (2013)[13] have done extensive work on the filter cake breaking of Mn_3O_4-based drilling fluids. They have demonstrated the use of HCl acid, various organic acids and their combination with HCl acid as filter cake breakers for Mn_3O_4-based drilling fluids.

Vernon (1891)[14], De Beni (1975)[15], and Depourdeaux (1975)[16] have published the following reactions, shown in Eqns. 6 and 7, respectively.

$$Mn_3O_4 + 8\ HCl \rightleftharpoons 2MnCl_2 + MnCl_4 + 4H_2O \quad (6)$$
$$Mn_3O_4 + 12\ HCl \rightleftharpoons 6MnCl_2 + 3MnCl_4 + 6H_2O \quad (7)$$

Manganese chlorides, which are soluble in water, will decompose and give $MnCl_2$ and chlorine gas. Therefore, Eqn. 6 becomes:

$$Mn_3O_4 + 8\ HCl \rightleftharpoons 3MnCl_2 + Cl_2 + 4H_2O \quad (8)$$

Also, Moajil et al. (2013)[12] identified the release of chlorine gas during the reaction of 5% w/w HCl acid with Mn_3O_4 particles. To avoid that, they recommended using HCl acid with a concentration below 5% w/w to break the Mn_3O_4-based filter cake. For our filter cake breaking experiments with the 120 pcf fluid, the use of HCl acid with a concentration greater than 5% w/w was avoided to prevent any release of chlorine gas. The use of 4% w/w HCl acid as a breaker fluid, however, resulted in only 7.4% breakage of the filter cake, Fig. 4. This showed

Fig. 4. Filter cake of 120 pcf fluid after treatment with 4% w/w HCl acid.

Breaker Solutions	% Removal Efficiency
4% w/w HCl acid solution	7.4
10% w/w organic acid solution	30.4
15% w/w acid precursor	2.3
15% w/w acid precursor + 1% w/w HCl acid	43.5

Table 9. Filter cake breaking test results

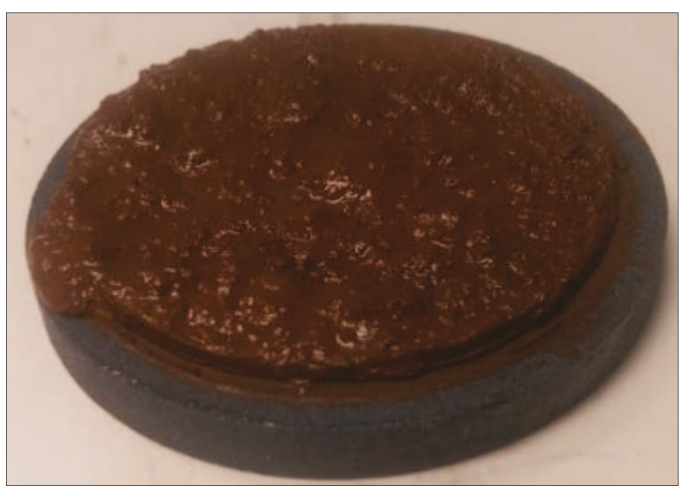

Fig. 5. Filter cake of 120 pcf fluid after treatment with 10% w/w organic acid.

Fig. 6. Filter cake of 120 pcf fluid after treatment with 15% w/w organic acid precursor.

Fig. 7. Filter cake of 120 pcf fluid after treatment with a combination of 15% w/w organic acid precursor and 1% w/w HCl acid.

that the filter cake removal efficiency by HCl acid having a concentration below 5% w/w was low.

The use of a 10% w/w organic acid filter cake breaker solution resulted in 30.4% breakage of the filter cake after 4½ hours, Fig. 5. To release the stuck pipe, a partial breakage of the filter cake would be necessary. With a removal efficiency of 30.4%, the treatment of the filter cake with organic acid having a concentration of 10% w/w should decrease the sticking force and release the stuck pipe in the wellbore.

The use of a 15% w/w acid precursor filter cake breaker solution resulted in 2.3% breakage of the filter cake after 4½ hours, Fig. 6. At 250 °F, the hydrolysis of the acid precursor was expected to be slow. The test showed that the slow hydrolysis of the acid prescursor led to very low filter cake removal efficiency.

Therefore, to overcome this problem of slow hydrolysis, a combination of 15% w/w acid precursor and 1% w/w HCl acid was used to break the filter cake, Fig. 7. The added HCl acid was expected to catalyze the hydrolysis of the acid precursor, thereby resulting in a faster release of the acid required to break the filter cake. This combination of HCl acid and acid precursor resulted in 43.5% breakage of the filter cake after 4½ hours. The test showed that a low concentration of HCl acid can be used along with the acid precursor solution to increase the filter cake removal efficiency.

CONCLUSIONS

1. The 100 pcf, 120 pcf and 150 pcf drilling fluids formulated with a combination of barite and Mn_3O_4 as weighting agents and hot rolled at 300 °F, 250 °F and 300 °F, respectively, were stable with good rheology and filtration properties.
2. The 120 pcf and 150 pcf drilling fluid formulated with a combination of barite and Mn_3O_4 as weighting agents showed better sag resistance than the conventional fluids formulated with 100% barite.
3. The 150 pcf drilling fluid formulated with a combination of barite and Mn_3O_4 as weighting agents showed good sag resistance when static aged in an inclined position.
4. The 4% w/w HCl acid and 15% w/w acid precursor solution gave very low filter cake removal efficiency.
5. Treatment with a 10% w/w organic acid solution resulted in a 30.4% filter cake removal efficiency.
6. Treatment with a combination of a 15% w/w organic acid precursor solution and a 1% w/w HCl acid solution resulted in 43.5% filter cake removal efficiency.
7. Treatment with an optimal concentration of organic acid and a combination of HCl acid and acid precursor can be used to release stuck pipes in the wellbore.

ACKNOWLEDGMENTS

The authors would like to thank the management of Saudi Aramco for their support and permission to publish this article.

This article was presented at the SPE North Africa Technical Conference and Exhibition, Cairo, Egypt, September 14-16, 2015.

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BIOGRAPHIES

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Dynamic Water Injection Profiling in Intelligent Wells Using Distributed Acoustic Sensor with Multimode Optical Fibers

Authors: Dr. Jinjiang Xiao, Mahmoud Farhadiroushan, Andy Clarke, Suresh Jacob, Abdulaziz H. Al-Mulhem, H. Craig Milne, Dr. Janti Shawash and Dr. Tom R. Parker

ABSTRACT

Distributed temperature sensing (DTS), which uses a multimode fiber, has previously been used for flow profiling in intelligent wells. In horizontal oil production wells, it is difficult to determine the flow profile due to the lack of a geothermal gradient, which necessitates using DTS to get temperature information along the wellbore. In water injector wells, the DTS can be used to monitor the warm-back temperature changes after the well is shut-in; however, if the water injector has been continuously operating over a long period of time, the warm-back may take several days or months, which is not practical for flow profiling.

The Intelligent Distributed Acoustic Sensor (iDAS) system, which commonly uses single mode fiber, is a very promising technology for inflow monitoring. In intelligent well completions, the acoustic energy generated across the inflow control valves (ICVs) and inflow control devices (ICDs) can propagate up through the production tubing. When recorded, that acoustic noise energy can be used for profiling. Using array processing, the speed of sound (SoS) can be measured to monitor the fluid composition. In addition, the flow velocity can be measured by evaluating the Doppler shift between the upgoing and downgoing acoustic waves.

The iDAS system was retrofitted to existing optical fibers that were already installed along several wells in Saudi Arabia. The acoustic noise energy generated across the inflow devices and propagating along the wellbore tubing was then recorded. The acoustic noise spectrum that resulted made it possible to monitor the fluid flow through the inflow devices, and after using array processing and determining the SoS over several sections of the tubing, to identify both the fluid composition and the velocity.

In this article, we report on a horizontal open hole water injector equipped with ICDs. This well was previously instrumented with a multimode fiber for DTS measurement. We retrofitted the iDAS system to the existing multimode fiber and recorded both the amplitude and the phase of the sound waves in real-time. The dynamic flow profiles across the ICD zone were observed as the injection rate was varied from 100% to 31% by changing the surface choke settings. The downhole injection rates were then quantified by determining the Doppler shift between upgoing and downgoing SoS, propagating well above the ICDs. A good correlation was observed with a surface flow meter.

The iDAS system's advantages over DTS are that it can be used with both single mode and multimode fibers, and it can be used for dynamic water injection profiling and optimization.

INTRODUCTION

Inflow control devices (ICDs) for water injector wells enable the water flow injection profile to be balanced across the completion interval in open hole completions, and therefore, minimizes the risk of bypassing reserves and maximizes hydrocarbon recovery. Although the operation of these devices is well understood, the optimization of these devices is complex. The real-time monitoring of fluid flow across the ICDs and along the completion can provide valuable information for further optimizations and greater well integrity.

The distributed temperature sensor (DTS) can provide useful information during the early stages of water injection, when shutting the well in for a period of 24 hours while measuring the slow warm-back temperature changes is long enough to determine the flow profile. After several months while the water injector is continuously operating, however, the warm-back temperature after shut-in may increase in increments too small to determine the flow profile[1, 2].

The Intelligent Distributed Acoustic Sensor (iDAS) system is a very promising technology for inflow monitoring. In intelligent well completions, the acoustic energy generated across the inflow control valves (ICVs) and ICDs can propagate up through the production tubing. The iDAS system can record the acoustic energy distribution along a length of optical fiber cable with a frequency range from a few millihertz to hundreds of kilohertz. By using an array, the speed of sound (SoS) can be measured to monitor the fluid composition. In addition, the flow velocity can be measured by evaluating the Doppler shift between the upgoing and downgoing acoustic waves.

In this article, we report on a horizontal open hole water injector equipped with ICDs. This well was previously instrumented with a multimode fiber for DTS measurement. The iDAS system was retrofitted to the existing multimode fiber and used to dynamically record both the amplitude and the phase of the sound waves in real time. The acoustic data was then used for dynamic water injection profiling as well as measuring the injection velocity downhole.

BACKGROUND

The water injector well in this study is in a heterogeneous fractured carbonate formation, drilled at a high angle with almost 1,500 ft of reservoir contact in one reservoir. The well was completed with ICDs to balance the injection profile along the open hole and prevent preferential injection in any one section[1]. Based on logs, the open hole was segmented with packers into six zones — five of them equipped with ICDs and one blank section, Fig. 1. The encapsulated multimode fiber optic cable was installed on the outside of the 4½" tubing string above the production packer, which was then crossed to a 3½" stringer tail pipe to convey the ICDs, swellable packers and fiber optic cable inside the 6⅛" open hole section of the wellbore. Swellable open hole packers with control line feed-through capability were used to isolate the different compartments.

The well was put on injection in August 2009. After 2½ months of injection, an acid stimulation was performed in November to increase the injectivity index using the initial DTS data and warm-back flow information. A subsequent warm-back indicated that 84% of the injection was entering the upper compartment, Fig. 2a.

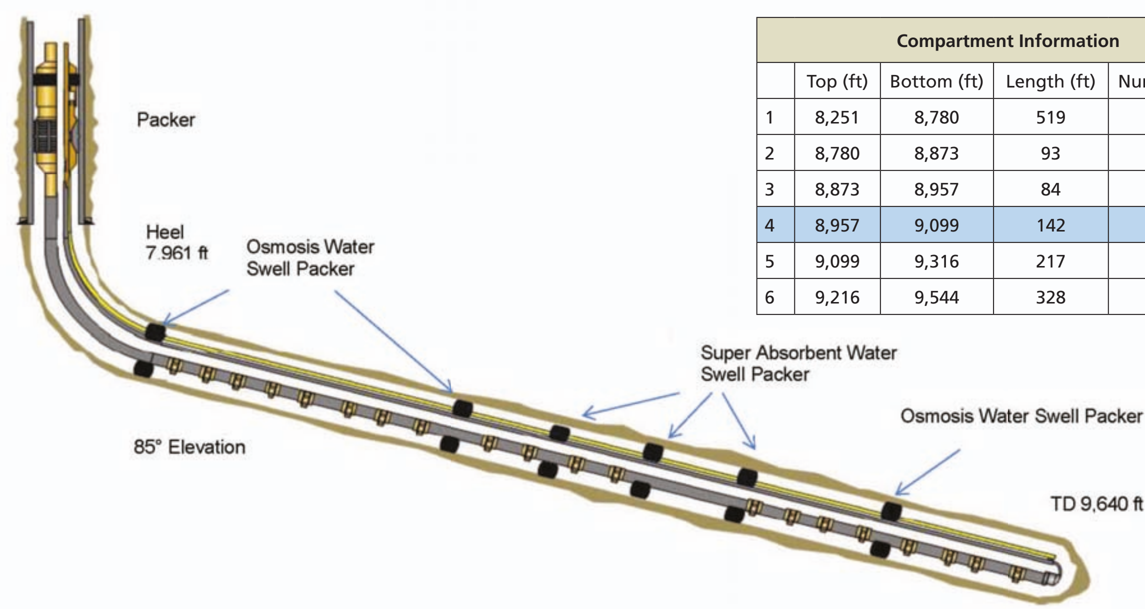
The well was then put back on continuous water injection for seven months before being shut-in at the start of a multi-vendor DTS acquisition and analysis in June 2010. The warm-back data collected at the end of the 30-day shut-in showed a temperature increase of nearly 65 °F in the upper sections of the well, but did not show any measurable increase in temperature along the horizontal reservoir section. In the absence of temperature changes from the warm-back technique in the horizontal section, a hot slug test was designed to create a temperature variation. The results of test data analyses provided by different DTS vendors were compared to a conventional log generated by a production logging tool (PLT). As seen in Fig. 2b, there was a large variation between the rates measured by the PLT and injection rates derived from different DTS interpretation techniques. The conclusion was that thermal models and interpretation techniques had to be improved to be comparable to the actual production log.

IDAS

The principle behind the operation of the iDAS is similar to that of the DTS. As shown in Fig. 3, when a pulse of light travels down an optical fiber, a small amount of the light is naturally backscattered — through Rayleigh, Brillouin and Raman scattering — and returns to the sensor unit[3]. The nature of this scattered light is affected by the tiny strain induced by the exertion of acoustic and/or vibration energy on the sensing optical fiber cable. By recording the returning backscatter signal against time, a measurement of the acoustic field all along the fiber can be determined. The iDAS has a frequency range from a millihertz to hundreds of kilohertz[4].

In addition, the iDAS system offers the flexibility to operate on single mode or multimode fiber without the introduction of external or additional apparatus. This unique feature made it possible to record the acoustic energy on the existing optical fiber cable that was installed for DTS monitoring.

We have developed a number of fast signal processing techniques to analyze the acoustic spectrum along the fiber optic cable. This enables us to characterize the acoustic energy generated along the wellbore[4]. In addition, using array processing to analyze the propagation of the acoustic waves in frequency and space domains — f-k analysis — we can monitor the fluid



Compartment Information				
	Top (ft)	Bottom (ft)	Length (ft)	Number of ICDs
1	8,251	8,780	519	8
2	8,780	8,873	93	2
3	8,873	8,957	84	2
4	8,957	9,099	142	None
5	9,099	9,316	217	4
6	9,216	9,544	328	4

Fig. 1. Open hole completion with fiber optics, swellable packers and ICDs.

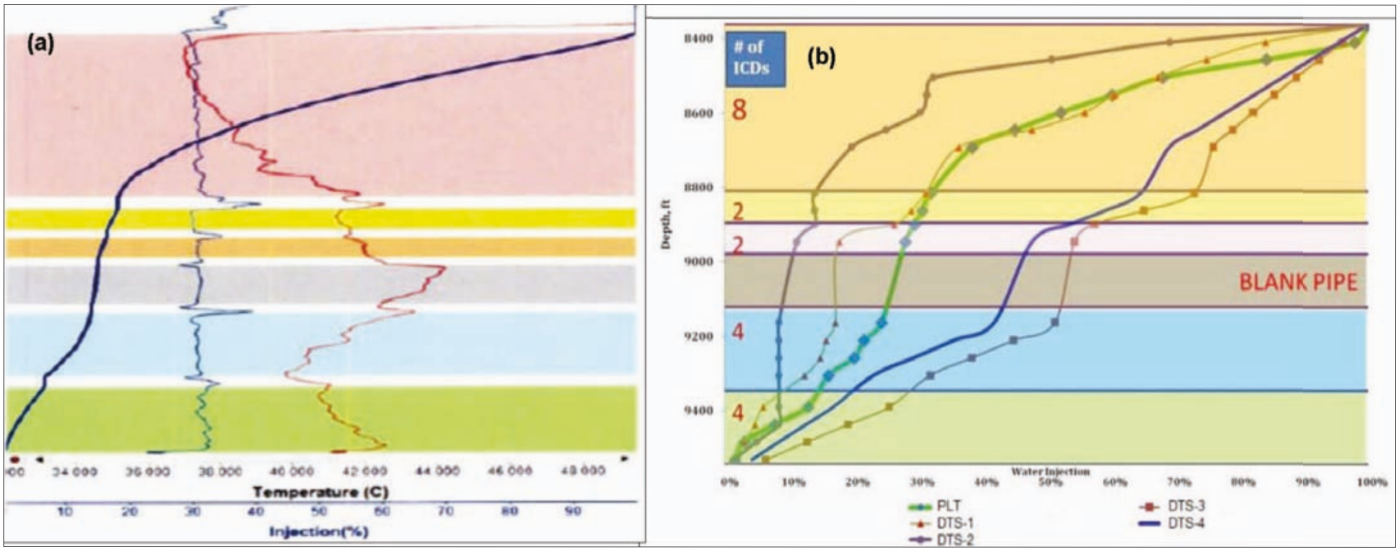


Fig. 2a. DTS warm-back measurement in November 2009, after the acid treatment showing the injection temperature (thin blue line), the warm-back temperature (red line) and the calculated accumulative flow profile (thick blue line)[1]. Fig. 2b. Comparison of multi-vendor DTS derived injection profiles with the PLT profile[2].

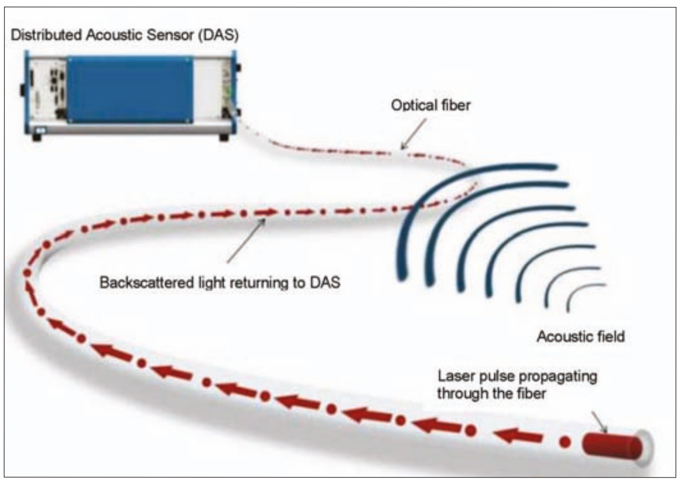


Fig. 3. Operation principle of the iDAS system.

Condition	Surface Choke
Base	0
1	100
2	80
3	64
4	42
5	37
6	31

Table 1. Well test matrix

composition and the fluid velocity by determining the SoS and Doppler shift, respectively.

DATA ACQUISITION

The acoustic data was collected using the iDAS system in three stages to ensure that each phase of the transition between all the different test points was recorded. First, data was collected for a period of approximately 1 to 2 hours, during which the surface choke valve setting was changed, Table 1. The data collected during this period can be used for transient diagnostics while monitoring the noise level within the wellbore. Once the well had stabilized, data was collected for a further period of approximately 1 hour. This data can be used in the flow profiling analysis using only the sound generated within the wellbore by ICDs or by the flow itself.

DATA ANALYSIS

The data was processed using two main approaches that treated the iDAS system: (1) as a set of many point sensors, and (2) as a distributed array of sensors. Considering each individual iDAS system on its own, as in the first approach, allows a physical quantity, such as the acoustic energy or the frequency spectrum, to be mapped along the wellbore at high resolution. In contrast, considering the iDAS system as a distributed array of sensors, as in the second approach, allows for the use of advanced signal processing techniques to determine the SoS for the propagating acoustic signals within the wellbore.

The first stage of processing was to correctly reference the iDAS receiver depth along the well. This can be done equally well in either the optical domain or the acoustic domain. The iDAS receiver channel corresponding to the wellhead was found by creating a controlled acoustic signal at the wellhead. Monitoring the iDAS response in real time also enabled us to map the position of the recording along the fiber optic cable with respect to the location along the wellbore.

Root-Mean-Square (RMS) vs. Depth

An estimate of the amplitude of the acoustic signal over a defined period of time and at a specific position on the fiber optic cable can be made by calculating the root-mean-square (RMS) value of a single iDAS receiver channel. This analysis treats each iDAS receiver channel as an individual receiver. The RMS value is calculated using Eqn. 1:

$$RMS = \sqrt{\frac{\sum_l x^2}{l}} \tag{1}$$

where l is the length of the time series in the acoustic samples and x is the iDAS time series data. The RMS levels were calculated to identify those noisy regions within the well that act as sound sources, which help to acoustically illuminate the production fluid. The presence of a sound source within the well can greatly increase the signal-to-noise ratio of the measurements by increasing the acoustic energy traveling within the production fluid. Figure 4 shows the water injection profile calculated from the acoustic amplitude for different surface choke setting conditions.

Frequency Spectrum vs. Depth

In addition to knowing the total acoustic energy measured at a specific depth in the well, it is also important to know the frequency content of that energy. The detection of propagating acoustic energy and the attenuation with distance of this energy is highly dependent on the frequency of the signal. Also, the frequency content of the noise at a specific location can be used to characterize the flow. For example, high frequency energy can be generated by high-pressure fluid passing through a small hole, such as through a perforation or a leak path.

Figure 5 shows a schematic of the lower completion with ICDs. The RMS amplitudes of the acoustic energy at different frequency bands are indicated alongside the well trajectory. As can be seen, the acoustic amplitude can be used for dynamic monitoring of the injection profile.

SoS and Flow

This data analysis focused on using powerful array processing techniques made possible by the iDAS ability to measure both the amplitude and the phase of the acoustic signal. These processing techniques produce a large number of receiver channels at a fine spatial resolution. By generating an f-k plot, it is possible to identify the speeds at which acoustic energy is traveling — SoS — as it is guided within the wellbore completion[5, 6]. The Doppler shift induced by the moving fluid, between the upgoing SoS and the downgoing SoS, can be used to estimate the fluid velocity along the wellbore.

Figure 6a is an example of an f-k plot, and Fig. 6b is the result of the line-fitting algorithm. As shown in Fig. 6a, there is a "V" shape where the lines correspond to the detection of sound traveling at a single speed. The result of a line-fitting

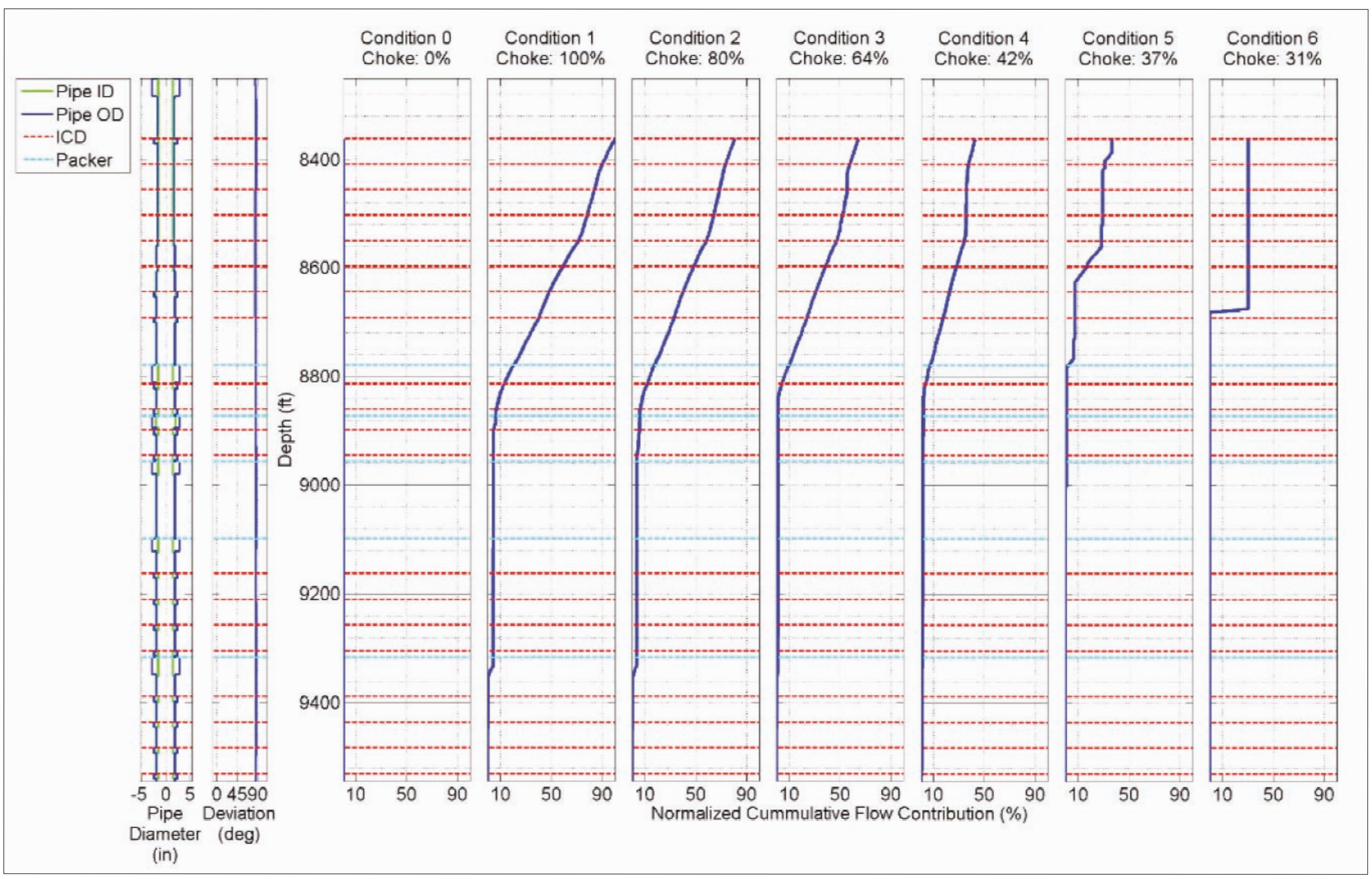


Fig. 4. The water injection profile across the ICD zones for different choke settings. The majority of the water injection is taken by the upper compartment.

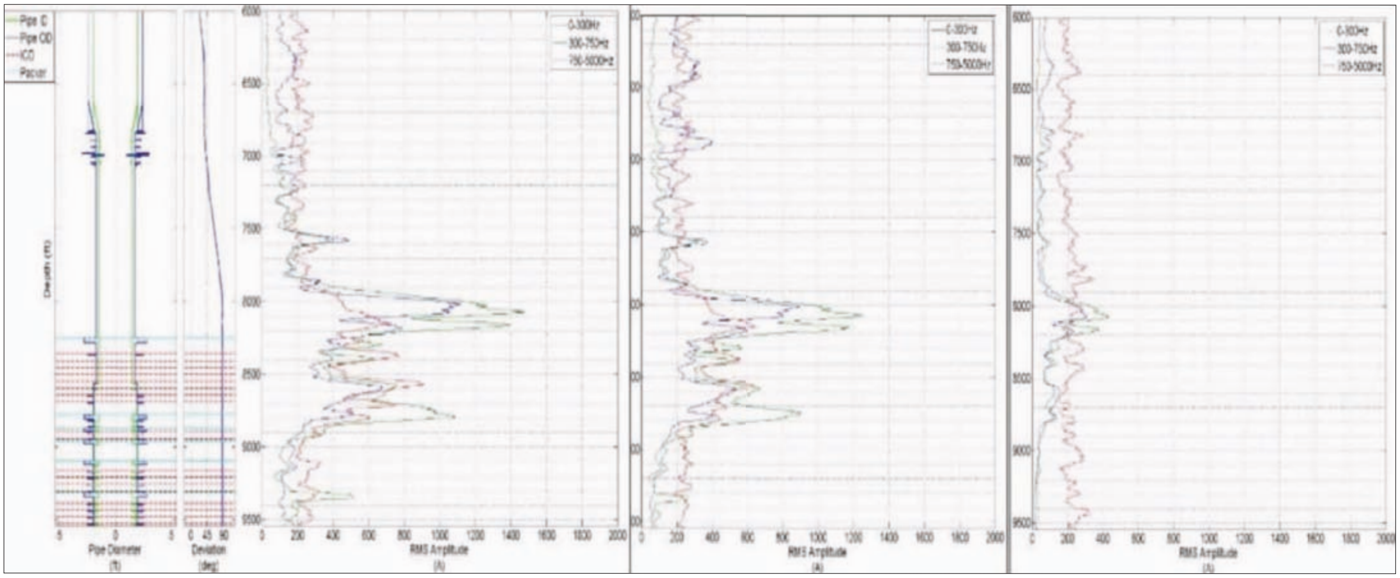


Fig. 5. Schematic diagrams of Well-1, together with the RMS amplitude of the acoustic energy at different frequency bands for 100%, 64% and 31% choke settings, respectively.

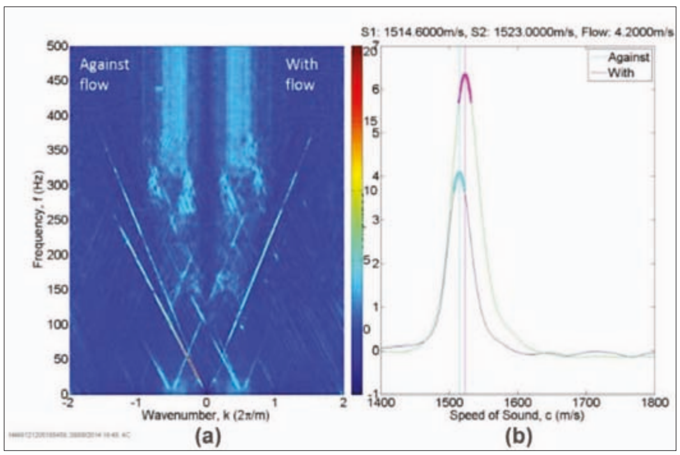


Fig. 6. SoS measurement showing upgoing and downgoing Doppler shift in the direction of the flow; (a) the f-k plot, and (b) the peak fit.

algorithm applied to this plot is shown in the plot seen in Fig. 6b. The exact SoS is found at the location of the peak in Fig. 6b. This SoS is dependent on two factors: (1) The SoS of the fluid in an infinite medium, and (2) The effect of the particular completion details on this SoS. The speed of propagation within the fluidic production volume will be dependent on the flow speed. This phenomenon is known as the Doppler Effect, and by measuring the SoS in both directions within the well, the speed of the flow can be calculated using Eqn. 2:

$$v = \frac{c_u - c_d}{2} \qquad (2)$$

where v = flow speed, c_u and c_d are SoS up and down the well, respectively. The actual SoS propagation is affected by both the fluid composition and the completion materials and structure. The interaction between the sound propagation and these factors is very complex and depends on a number of variables, such as the compliance of the pipe with the formation. Changes in the cross section dimensions, for example, will lead to changes in the SoS.

As indicated in Fig. 6b, the average SoS measured above the ICD sections was around 1,518 m/s, which is as expected in water. The injection velocity was determined from the Doppler shift and was compared with the surface flow meter readings for different choke settings, Fig. 7.

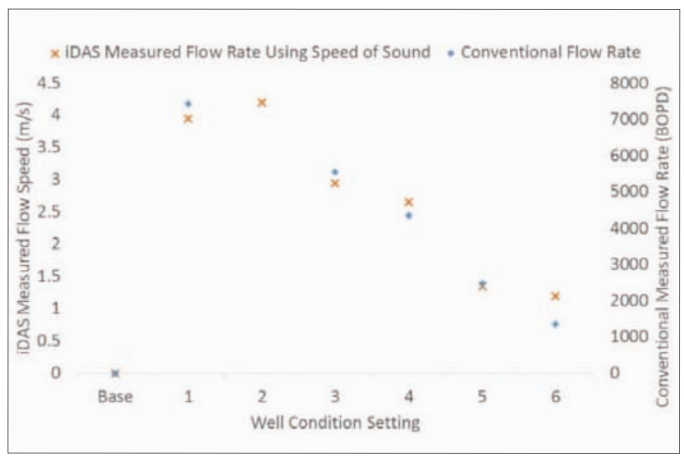


Fig. 7. Well test comparison of the iDAS calculated flow velocity (m/s) and the measured flow rate (BOPD) at the surface.

DISCUSSION

The real-time iDAS data allowed the injection profile to be monitored dynamically. The injection profiles were estimated directly by evaluating the acoustic amplitude over the ICD's compartments, typically after 2 hours of changing the surface choke settings. The injection profile for the surface choke setting of 100% is in good agreement with the initial DTS warm-back results and the PLT data. In this case, 70% to 80% of water is injected in the upper compartment, with about 10% reaching the toe of the well. Further comparison was not feasible since the estimation of the injection profiles for different surface choke settings is impractical for the DTS warm-back technique.

The frequency analysis of the acoustic data can provide further information about the fluid flow through the ICDs and into the formation. The noise generated across the ICDs depends on the pressure drop — flow rate — and the aperture size. It would be useful to characterize the noise spectrum of the ICDs for different flow rates.

Using f-k array processing, we can determine the SoS at different intervals along the wellbore. This can be used for quantitative flow measurement by estimating the Doppler shift between the upgoing and downgoing acoustic energy. This measurement can be used to calibrate and constrain the flow profile estimates derived from the acoustic amplitude plots.

Figure 7 shows there is a good correlation between the fluid velocity calculated from the iDAS data and the surface flow meter readings; however, the fluid velocity that the iDAS measured above the ICD compartment was higher than expected. For example, for a 100% surface choke setting, we measured 4.2 m/s for the injection velocity; however, for 8,000 barrels of water per day to flow through a 3½" outer diameter pipe with 2.992" inner diameter, we expect the injection velocity to be 3.15 m/s. The higher velocity measurement may be due to a change in the internal pipe diameter of the pipe, such as due to scaling, or it may be due to the change in the pipe trajectory.

CONCLUSIONS

The iDAS system can be used for dynamic monitoring of the injection profile in horizontal wells by recording the acoustic signals over a wide range of frequency bands. In addition, using array processing of the acoustic signals, the iDAS system has been shown to be capable of measuring the SoS and the fluid velocity when sufficient propagating acoustic energy is present along the wellbore. The iDAS system can be retrofitted using existing multimode fibers that are installed for DTS measurement.

ACKNOWLEDGMENTS

The authors would like to thank the management of Saudi Aramco for their support and permission to publish this article. We would also like to thank Daniel Finfer for his fruitful discussions.

This article was presented at the SPE Annual Technical Conference and Exhibition, Houston, Texas, September 28-30, 2015.

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In 1984, he received his B.S. degree (with honors) in Electrical and Electronic Engineering from Queen Mary University of London, London, U.K. In 1985, Mahmoud received his M.S. degree (with honors) in "Microwaves and Modern Optics" in Electrical and Electronic Engineering from University College London, London, U.K.

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Dr. Janti Shawash has been working on distributed acoustics and temperature sensors and a multitude of their applications at Silixa for the past 5 years. His research interests include digital signal processing, image processing, pattern recognition and the design of heterogeneous real-time computing systems.

Janti received his M.S. degree in Telecoms and a Ph.D. degree in Electronics Engineering, focusing on real-time machine learning, both from University College London, London, U.K.

Dr. Tom R. Parker co-founded Silixa in 2007 and is Silixa's Chief Technology Officer (CTO). As CTO, he takes the lead in the development of Silixa's IDAS and ULTIMA DTS portfolio of instruments, and he oversees Silixa's application specific development projects.

Tom's awards include the Metrology for World-Class Manufacturing Award and the British Telecom Technological Innovation Award.

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What Is an Intellectual Property Strategy?

Author: Dr. M. Rashid Khan

ABSTRACT

In recent years, the use of intellectual property (IP) has become increasingly strategic. The increasing importance of IP raises questions about how to best protect and use IP assets to achieve certain organizational objectives. IP strategy consists of a set of policy and procedures, and when implemented, creates a culture that encourages and facilitates effective creation, capture, protection, and deployment of IP to support the organization's objectives in coordination with other activities/organizations.

It has become "imperative" that companies have well-defined strategies that capitalize on maximizing the value of the IP assets. Strategy is a high level plan to achieve one or more long-term goals under conditions of uncertainty. Because the conditions change, so does the strategy as a function time. Military Generals set strategies in the Greek military era. In the modern times, corporate leaders and their assigned representatives set strategies.

IP STRATEGY VS. CORPORATE STRATEGY

Over a decade ago, Bill Gates stated that IP "is no longer simply the legal department's problem. CEOs must now be able to formulate strategies that capitalize on and maximize the value of their company's intellectual property assets to drive growth, innovation and cooperative relationships with other companies." IP strategy is the development of various imperatives around the use of IP to enable a company to be sustainable in the domain in which it operates and to achieve its broader objectives[1, 2].

There is no single strategy that applies for all organizations or even within the same organization, which often can have diverse interests, e.g., upstream, downstream, chemicals, pipelines and aviation — just to name a few. Furthermore, the strategic objectives of an international oil company (IOC) can be different from those of a national oil company (NOC). Depending on a company's role within the value chain, different considerations may apply. The incentive to invent is sector specific. For example, for the energy related sector, inventions are generally limited, because, unlike a digital product where there is a very rapid adoption leading to an incredible return within an exclusive patent period of 20 years, most energy breakthroughs are over a period of time — 20 years. Therefore, the strategy related to IP protection is also very sector specific.

This short brief is limited to oil and gas companies, discussing producers and service providers, modes of protection (patents vs. trade secrets), related collaborations and startups and any threat from non-practicing entities.

IP strategy often also includes many other vital topics, such as strategies related to the best modes of protection, geographical jurisdictions, value creation vs. legal costs of protection, landscaping and licensing, etc., as discussed elsewhere[3].

IP Strategy for Oil and Gas Producing vs. Service Companies

IP strategies for oil and gas producers are different from those of service companies; they vary based on the distinctions on the type of the technology solutions they develop, the domain they operate in and wish to expand to and the potential associated risks/rewards with deployment. All these factors often direct IP protection strategy. As the number of competitors increase, it becomes more difficult to maintain "first-mover" (technology leader) advantages. Under these circumstances, it is likely there will be an increase in filing for patents and enforcing patents in the industry moving forward.

Most large producers have relatively strong Research and Development (R&D) departments, which are focused on new technology development. Many producers generally do not develop technologies related to core service areas, e.g., drilling or well completion services or maintenance. Subsequently, the interests of many big producers may overlap with those of the service companies, i.e., both ExxonMobil and Saudi Aramco have been active in drilling and well completion areas.

In general, the service companies generally develop technologies to address the problems of producers. Solutions to these problems sometimes take many years of "know-how" developed through many practical field applications. Typically, these solutions yield significant commercial rewards, thereby rendering it easier to justify the initial investment in R&D, which reflects in their patenting strategies. By patent protecting a developed technology, a service company secures a tool it can use to block competitors from replicating the technology, which helps to preserve the competitive edge in the marketplace. Consequently, it is equally important for producers, especially for NOCs, to gain benefits from the service providers' know-how when that experience came with producing company R&D involvement. Therefore, trade secrets have a place in a producer's IP strategy as a means to retain significant know-how.

Strategy Related to Patents vs. Trade Secrets or Defensive Publication

When deciding between patent protection and trade secret protection, the latter is a relatively more realistic option for big producers. Because producers are better able to control outside access to their own information, they are better at preserving trade secrets. It is easier to control access to information on one's own territory or field; however, with increasing collaboration, employee moves, and the need to disclose information to regulatory authorities, trade secrets now may be difficult to maintain, even for producers.

There is a saying that "trade secrets go home every night." Therefore, in the extreme, the trade secret protecting organization can find itself vulnerable to a patent infringement claim by a later developer that independently patents the same technology. The risk of losing a trade secret and possibly facing an infringement claim discounts the trade secret protection as an IP strategy option for most producers. From a defensive perspective, it is preferable to protect a key technology that creates value via a patent, as opposed to protecting it as a trade secret. Subsequently, selective defensive publication is an excellent avenue to disclose a technology, rendering it potentially unpatentable by the competition. The IP vehicle of choice for service companies is also more likely to be patent protection, rather than trade secret protection, because it is more difficult to control information flow and trade secrets, when the provider's technology is used by multiple customers in many places.

Collaborations

The long-term success of a collaboration depends on defining IP rights from the outset. For potentially disruptive technologies, where their development carries significant risk and the rewards are not necessarily immediate, a partnership appears to be the appropriate avenue. Such a partnership not only offers more substantial resources to fund development, but also results in the sharing of risk. A necessary prerequisite for creating such a relationship, however, is clearly defining how the parties own and use IP, based on the strategic objectives. Otherwise, the parties' expectations may be at odds, and the objectives of collaboration may not be fully achieved.

Startups

It is difficult for an inexperienced startup to jump into the oil and gas service marketplace for many reasons, such as lack of insight into a customer's problems, insufficient track record, customer relationships, and associated commercial risks. Startups may develop technologies, including potentially disruptive ones, e.g., in the areas of upgrading wells or extraction, that the industry may find commercial use for. Startups, however, can benefit from the big producers to validate the technology, e.g., by field testing. From a defensive perspective, it is worthwhile for startups to grow a useful and strategic patent portfolio for a large producer, which facilitates cross-licensing arrangements. In addition, the part of the impactful patents can be assigned to regional startup companies for further development and marketing, which enables the big companies to enjoy the benefit of the technology by internal deployment while mitigating the risk of failure by the startups.

Another reason smaller companies may prefer a patent is its hope to be acquired by one of the larger companies. The value of a startup's technology and its ability to attract investment from a venture capital firm is dependent on whether the startup company has successfully protected the trade secret or acquired a patent, as previously discussed[1]. Unlike most IOCs, the NOCs have an added agenda of national development and local job creation this is often reflected their IP activities.

Non-practicing Entities (NPEs)

NPEs are business organizations that own patents for technologies they have no intention of using for commercial purposes. Because NPEs do not make, use or sell the technologies, they cannot be easily sued for patent infringement. As a result, when an NPE files a claim for patent infringement against an oil and gas company, the NPE is often untouchable to counterclaims by the supposedly infringing producer. This further magnifies the power imbalance beyond what is typically present in a patent dispute between marketplace competitors. Producing companies should be alert to business failures and IP that may become available for purchase and acquisition as a result of such business failures, if only to render these unavailable to NPEs.

CONCLUDING REMARKS

A company's IP strategy ideally should reflect the corporate strategy, i.e., to enable the company to create maximum value and be sustainable in the domain in which it operates while achieving its broader objectives, e.g., national development. There is no single strategy that can apply for all organizations. The strategic objectives of an IOC can be different from a NOC.

This short article is limited to oil and gas companies — producers and service providers, modes of protection, related collaboration and startups, and any threat from NPEs. In general, however, from a defensive perspective, it is preferable to protect via a patent, as opposed to trade secrets, although preserving a trade secret has a place in retaining significant know-how. The

IP vehicle of choice for service companies is often patent protection rather than trade secret protection; however, proactive disclosure by defensive publication is an excellent avenue to disclose a technology, making it potentially unpatentable for the competition. The fundamental point to always consider is the cost of patent protection vs. the value of the underlying technology being protected, and the benefits derived from a patent-protected technology.

As part of an IP strategy, organizations must be continuously vigilant on the matter, and monitor its IP assets to develop a culture for maximizing value, rather than simply counting numbers. From the value creation point of view, both strategy and organizational "culture" are important. As stated by Ducker[4] "Culture eats strategy for breakfast." Organizational culture can be more effective in creating value regardless what the strategy states, because organizational culture provides a greater discipline in implementation than disciplinary action by strategy statements alone.

REFERENCES

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4. Ducker, P.F.: "Innovation and Entrepreneurship: Practices and Principles," Harper & Row, 1985, 277 p.

BIOGRAPHY

Dr. M. Rashid Khan currently with Saudi Aramco's Exploration and Petroleum Engineering Center – Advanced Research Center (EXPEC ARC), previously led the Corporate Intellectual Assets Management Group for Saudi Aramco, and was the head of the Intellectual Property and Innovation Group of the Aramco Entrepreneurship Department. He served as the Deputy Director of the Technology Management Program of Engineering Services and has been a member of the Intellectual Assets and Innovation Management Group from the onset of these programs. Rashid also shaped the first Intellectual Property policy for King Abdullah University of Science and Technology (KAUST), and he has executed several technology transfer agreements.

He has work experience in upstream, downstream and other diverse areas of the oil and gas industry. Rashid has served as a Distinguished Lecturer for the Society of Petroleum Engineers (SPE) and presented many invited lectures throughout the world, including at Harvard and MIT. He served as a mentor for the MIT Energy Competition and Licensing Executive Business Competition, and taught a course on patent monetization at MIT.

Rashid received Texaco's highest technical award for creativity. He also received the American Chemical Society Texaco Research Award. Additionally, Rashid served as a Technical Advisor to the U.S. White House; was an Adjunct Professor for Vassar College, Poughkeepsie, NY; and served in the United Nations Development Program (UNDP). He has around 30 patent awards and has published over 200 journal papers. Rashid has edited or authored six books in the areas of energy, the environment or intellectual property related to business development.

Rashid received his M.S. degree in Environmental Engineering from Oregon State University, Corvallis, OR, in 1979 and his Ph.D. degree in Energy and Fuels Engineering from Pennsylvania State University, University Park, PA, in 1984.

He is the Chair Elect for the Chemical, Energy, Environment and Materials Committee of the Licensing Executive Society, and a Certified Patent Licensing Professional.

2015 SAUDI ARAMCO PATENTS GRANTED LIST

CLAY ADDITIVE FOR REDUCTION OF SULFUR IN CATALYTICALLY CRACKED GASOLINE

Granted Patent: U.S. 8,927,451, Grant Date: January 6, 2015
Abdennour Bourane, Omer R. Koseoglu, Musaed Al-Ghrami, Christopher Dean, Mohammed A. Siddiqui and Shakeel Ahmed

Summary

The patent relates to the reduction of sulfur in gasoline produced in a fluid catalytic cracking process, and more particularly to a method and composition for using a sulfur reduction additive composition in the fluid catalytic cracking process.

METHOD FOR PREVENTING CALCIUM CITRATE PRECIPITATION DURING CITRIC ACID ACIDIZING TREATMENTS

Granted Patent: U.S. 8,927,467, Grant Date: January 6, 2015
Mohammed H. Al-Khaldi

Summary

The patent relates to acidic treatment fluids used in subterranean operations, and more specifically to acidic treatment fluids, including citric acid and salts of ethylene di-amine tetra-acetic (EDTA), and the methods of their use in subterranean operations.

RELATIVE VALUATION METHOD FOR NAPHTHA STREAMS

Granted Patent: U.S. 8,930,149, Grant Date: January 6, 2015
Omer R. Koseoglu

Summary

The patent relates to a method and process for the evaluation of naphtha derived from crude oil, based on its composition and processability.

SUPER RESOLUTION FORMATION FLUID IMAGING WITH CONTRAST FLUIDS

Granted Patent: U.S. 8,937,279, Grant Date: January 20, 2015
Howard K. Schmidt

Summary

The patent relates to imaging subsurface structures, particularly hydrocarbon reservoirs and the fluids therein, and more particularly to cross-well and borehole-to-surface electromagnetic (EM) surveying.

EBULLATED-BED PROCESS FOR FEEDSTOCK CONTAINING DISSOLVED HYDROGEN

Granted Patent: U.S. 8,940,155, Grant Date: January 27, 2015
Omer Koseoglu

Summary

The patent relates to hydrocracking or hydroprocessing systems and processes that employ ebullated-bed reactors.

ADAPTIVE HYBRID WIRELESS AND WIRED PROCESS CONTROL SYSTEM WITH HIERARCHICAL PROCESS AUTOMATION FIELD NETWORK SETS

Granted Patent: U.S. 8,942,098, Grant Date: January 27, 2015
Abdelghani Daraiseh and Mohamed Landolsi

Summary

The patent relates to process control systems and methods, and more particularly to such systems and methods that include hierarchical adaptability and optimization capabilities to operate a hybrid wired and wireless process control and/or automation network while utilizing minimum system resources.

UTILIZATION OF HEAVY OIL ASH TO PRODUCE HIGH QUALITY CONCRETE

Granted Patent: U.S. 8,945,300, Grant Date: February 3, 2015
Mohammed Al-Mehthel, AbdulAziz Al-Utaibi, Mohammed Maslehuddin and Mohammed Ali

Summary

The patent relates to using heavy oil ash instead of, or in addition to, cement to produce high quality heavy oil ash Portland cement concrete, thereby decreasing the cost of the resulting concrete, while also reducing the carbon footprint. This invention will eliminate the need for using fly ash and silica fume to produce high quality concrete.

CONTROLLED RELEASE OF SURFACTANTS FOR ENHANCED OIL RECOVERY

Granted Patent: U.S. 8,946,132, Grant Date: February 3, 2015
Yun Chang and Mazen Kanj

Summary

The patent relates to a new composition and delivery system for the enhanced oil recovery process. More particularly, the invention provides a way to slow-release surfactant molecules by converting surfactants into salts that have limited solubility in water, thereby maintaining a constant flux of surfactant particles.

CONTROLLED RELEASE OF SURFACTANTS FOR ENHANCED OIL RECOVERY

Granted Patent: U.S. 8,951,406, Grant Date: February 10, 2015
Omer Koseoglu

Summary

The patent relates to a process and system for fluidized catalytic cracking of hydrocarbon feedstocks, and more particularly to presenting hydrogen in the liquid phase to enhance the desulfurization and denitrification reactions.

PROCESS FOR DEMETALLIZATION OF WHOLE CRUDE OIL

Granted Patent: U.S. 8,951,410, Grant Date: February 10, 2015
Omer R. Koseoglu, Adnan Al-Hajji and Hendrik Muller

Summary

The patent relates to the treatment of a whole crude oil feedstream to remove undesired metal compounds and so upgrade the crude oil, and thereby enhance and render more efficient the downstream processing of the treated crude oil.

PROCESS FOR DEMETALLIZATION OF WHOLE CRUDE OIL

Granted Patent: U.S. 8,956,528, Grant Date: February 17, 2015
Omer Koseoglu

Summary

The patent relates to hydrocracking or hydroprocessing systems and processes that employ ebullated-bed reactors.

METHODS FOR RECOVERING ORGANIC HETEROATOM COMPOUNDS FROM HYDROCARBON FEEDSTOCKS

Granted Patent: U.S. 8,961,780, Grant Date: February 24, 2015
Zaki Yusuf, Ahmad Hammad, Stamatios Souentie, Bandar Fadhel and Nayif Al-Rasheedi

Summary

The patent relates to methods for separating heteroatom compounds from hydrocarbons using a tunable/switchable/reversible solvent.

TUBE PLUG FOR A HEAT EXCHANGER TUBE

Granted Patent: U.S. 8,967,234, Grant Date: March 3, 2015
Dhawi Al-Otaibi

Summary

The patent relates to network integrity, particularly to fluid flow heat exchangers in which potentially corrosive fluid flows through heat exchange tubes whose ends extend through and are secured to tube sheets, and more particularly to tube plugs for plugging the open ends of damaged heat exchange tubes.

HYDROTREATING AND AROMATIC SATURATION PROCESS WITH INTEGRAL INTERMEDIATE HYDROGEN SEPARATION AND PURIFICATION

Granted Patent: U.S. 8,968,552, Grant Date: March 3, 2015
Vinod Ramaseshan, Ali Al-Abdulal and Yuv Mehra

Summary

The patent relates to oil and gas treatment, and particularly to hydrotreating and aromatic saturation systems and a method for efficient production of high quality distillates from high sulfur, high aromatic hydrocarbons at existing or new hydrocracking facilities.

METHOD OF FRACTURING WHILE DRILLING

Granted Patent: U.S. 8,973,661, Grant Date: March 10, 2015
Shaohua Zhou

Summary

The patent relates to drilling, and more particularly to a method of fracturing a formation that at the same time drills a wellbore through the formation, selectively deploys a seal from a drillstring and pressurizes the wellbore beneath the seal.

CLEANING APPARATUS FOR HEAT EXCHANGE TUBES OF AIR COOLED HEAT EXCHANGERS

Granted Patent: U.S. 8,974,701, Grant Date: March 10, 2015
Omer Koseoglu and Jean-Pierre Ballaguet

Summary

The patent relates to processes for the partial oxidation of a whole crude oil feedstock in a membrane wall gasification reactor to produce a synthesis gas and electricity.

INTEGRATED PROCESS FOR THE GASIFICATION OF WHOLE CRUDE OIL IN A MEMBRANE WALL GASIFIER AND POWER GENERATION

Granted Patent: U.S. 8,974,701, Grant Date: March 10, 2015
Omer Koseoglu and Jean-Pierre Ballaguet

Summary

The patent relates to processes for the partial oxidation of a whole crude oil feedstock in a membrane wall gasification reactor to produce a synthesis gas and electricity.

SYSTEM AND PROCESS FOR INTEGRATED OXIDATIVE DESULFURIZATION, DESALTING AND DEASPHALTING OF HYDROCARBON FEEDSTOCKS

Granted Patent: U.S. 8,980,080, Grant Date: March 17, 2015
Omer Koseoglu and Abdennour Bourane

Summary

The patent relates to oil and gas treatment, and more particularly to a combined desulfurization, desalting and deasphalting process that requires minimal modification of existing facilities.

ZERO LEAKOFF GEL

Granted Patent: U.S. 8,980,801, Grant Date: March 17, 2015
Saleh Al-Mutairi, Khalid Al-Dossary, Ali Al-Aamri and Mubarak Al-Dhufairi

Summary

The patent relates to production, and more particularly to a silicate gel composition, formed in situ, and a method of diverting a treatment fluid in a wellbore.

METHOD FOR REMOVING OXYGEN FROM A REACTION MEDIUM

Granted Patent: U.S. 8,986,534, Grant Date: March 24, 2015
Ahmad Hammad and Zaki Yusuf

Summary

The patent relates to oil and gas treatment, and more particularly to methods for removing or scavenging oxygen molecules, in situ, during electrochemical processes.

APPARATUS FOR UPGRADING WHOLE CRUDE OIL TO REMOVE NITROGEN AND SULFUR COMPOUNDS

Granted Patent: U.S. 8,986,622, Grant Date: March 24, 2015
Omer Koseoglu, Adnan Al-Hajji and Hendrik Muller

Summary

The patent relates to oil upgrading, and more particularly to the treatment of a whole crude oil feedstream to remove undesired compounds and so upgrade the treated crude oil, and thereby enhance and render more efficient the downstream processing of the treated stream.

IONIC LIQUID DESULFURIZATION PROCESS INCORPORATED IN A CONTACT VESSEL

Granted Patent: U.S. 8,992,767, Grant Date: March 31, 2015
Omer Koseoglu and Adnan Al-Hajji

Summary

The patent relates to oil and gas treatment, and more particularly to a system and process for desulfurizing hydrocarbon fractions that integrates ionic liquid extractive desulfurization with a hydroprocessing reactor.

METHOD FOR CONTEMPORANEOUSLY DIMERIZING AND HYDRATING A FEED HAVING BUTENE

Granted Patent: U.S. 8,999,013, Grant Date: April 7, 2015
Wei Xu, Thamer A. Mohammad, Kareemuddin M. Shaik and Aadesh Harale

Summary

The patent relates to chemicals, and more particularly to a method for simultaneously producing butene oligomers and butanol from a feedstream having butene.

COMBINED HEAVY REFORMATE DEALKYLATION-TRANSALKYLATION PROCESS FOR MAXIMIZING XYLENES PRODUCTION

Granted Patent: U.S. 9,000,247, Grant Date: April 7, 2015
Raed Abudawoud

Summary

The patent relates to chemicals, and more particularly to the production of mixed xylenes using heavy reformate.

APPARATUS TO CONTAIN PIPELINE LEAKS FROM A LONGITUDINAL PORTION OF A PIPELINE

Granted Patent: U.S. 9,004,813, Grant Date: April 14, 2015
Khaled Al-Buraik

Summary

The patent relates to network integrity, and more particularly to an apparatus to stop pipeline fluid from leaking into the surrounding environment until the pipeline can be shut down, depressurized and permanently repaired.

REMOVAL OF SULFUR COMPOUNDS FROM PETROLEUM STREAM

Granted Patent: U.S. 9,005,432, Grant Date: April 14, 2015
Ki-Hyouk Choi, Mohammad Al-Jishi, Ashok Punetha, Mohammed Al-Dossary, Joo-Hyeong Lee and Bader Al-Otaibi

Summary

The patent relates to oil upgrading, and more particularly to a process for upgrading oil by contacting a hydrocarbon stream with supercritical water fluid.

INTEGRATED PROCESS FOR IN SITU ORGANIC PEROXIDE PRODUCTION AND OXIDATIVE HETEROATOM CONVERSION

Granted Patent: U.S. 9,005,433, Grant Date: April 14, 2015
Farhan Al-Shahrani, Omer Koseoglu and Abdennour Bourane

Summary

The patent relates to oil and gas treatment, and more particularly to an integrated oxidation process to efficiently reduce the sulfur and nitrogen content of hydrocarbons.

WATER-BASED DRILLING FLUID COMPOSITION HAVING A MULTIFUNCTIONAL MUD ADDITIVE FOR REDUCING FLUID LOSS DURING DRILLING

Granted Patent: U.S. 9,006,151, Grant Date: April 14, 2015
Md. Amanullah and Mohammed K. Al-Arfaj

Summary

The patent relates to drilling, and more particularly to a multifunctional mud additive as part of a water-based drilling fluid containing particles, including nanoparticles, microparticles or a combination thereof, with the additive providing effective shielding around the particles.

GEOGRID SAND FENCE

Granted Patent: U.S. 9,009,977, Grant Date: April 21, 2015
Nasser Kahtani and Jonathan Grosch

Summary

The patent relates to a fence for precipitating, depositing and accumulating matter moved by wind currents to protect roads and facilities from sand encroachment.

SULFUR EXTENDED POLYMER FOR USE IN ASPHALT BINDER AND ROAD MAINTENANCE

Granted Patent: U.S. 9,012,542, Grant Date: April 21, 2015
Mohammed Al-Mehthel, Saleh Al-Idi, Ibnelwaleed Hussein, Hamad Al-Abdulwahhed and Junaid Akhtar

Summary

The patent relates to a method of preparing the homogeneous sulfur-modified polymer composition and an asphaltic concrete mixture.

METHOD, SYSTEM AND MACHINE TO TRACK AND ANTICIPATE THE MOVEMENT OF FLUID SPILLS WHEN MOVING WITH WATER FLOW

Granted Patent: U.S. 9,013,352, Grant Date: April 21, 2015
Ali Al-Mohsen and Peter O'Regan

Summary

The patent relates to a real-time tracking system for processing location data from tracking devices deployed in a marine environment.

HYDROGEN PURIFICATION FOR MAKE-UP GAS IN HYDROPROCESSING PROCESSES

Granted Patent: U.S. 9,017,547, Grant Date: April 28, 2015
Yuv Mehra and Ali Al-Abdulal

Summary

The patent relates to oil and gas treatment, and more particularly to a process for increasing the hydrogen partial pressure of recycled gas in hydroprocessing units.

DELAYED COKING PROCESS UTILIZING ADSORBENT MATERIALS

Granted Patent: U.S. 9,023,192, Grant Date: May 5, 2015
Omer Koseoglu

Summary

The patent relates to oil and gas treatment, and more particularly to a delayed coking process for treating heavy hydrocarbon oils containing undesired sulfur and nitrogen compounds.

PROCESS FOR DELAYED COKING OF WHOLE CRUDE OIL

Granted Patent: U.S. 9,023,193, Grant Date: May 5, 2015
Omer Koseoglu

Summary

The patent relates to oil upgrading, and more particularly to a delayed coking process of whole crude oil directly and without the preliminary atmospheric and/or vacuum distillation steps.

MULTI-CUVETTE AUTOSAMPLER FOR PHOTO OPTICAL MEASUREMENTS

Granted Patent: U.S. 9,028,753, Grant Date: May 12, 2015
Ezzat Hegazi, Christoph Stamm, Peter Engle, Benjamin Fellman and Hanspeter Sautter

Summary

The patent relates to network integrity, and more particularly to precise positioning of cuvettes in a multi-cuvette system undergoing depth-resolved, laser-induced fluorescence testing.

PULSATING FLOW METER HAVING A BLUFF BODY AND AN ORIFICE PLATE TO PRODUCE A PULSATING FLOW

Granted Patent: U.S. 9,032,815, Grant Date: May 19, 2015
Mohamed Noui-Mehidi

Summary

The patent relates to network integrity, and more particularly to a flow meter that is operable for imparting a pulsating flow on process fluids.

APPARATUS FOR STAGE CEMENTING AN OIL WELL

Granted Patent: U.S. 9,038,720, Grant Date: May 26, 2015
Omar J. Esmail

Summary

The patent relates to the step in the completion of oil wells in which the annular space between an outer casing and a smaller diameter inner casing that extends from the earth's surface is filled with cement.

UPGRADING OF HYDROCARBONS BY HYDROTHERMAL PROCESS

Granted Patent: U.S. 9,039,889, Grant Date: May 26, 2015
Ki-Hyouk Choi, Ashok Punetha, Mohammed Al-Dossary and Mohammed Al-Jishi

Summary

The patent relates to oil upgrading, and more particularly to a method and apparatus for upgrading a hydrocarbon feedstock with supercritical water.

COMBINED COOLING OF LUBE/SEAL OIL AND SAMPLE COOLERS

Granted Patent: U.S. 9,052,146, Grant Date: June 9, 2015
Abdullah M. Al-Otaibi and Montaser A. Al-Mubayidh

Summary

The patent relates to network integrity, and more particularly to heat exchangers useful for analyzing samples, such as condensate samples.

FACILITATED TRANSPORT MEMBRANE FOR THE SEPARATION OF AROMATICS FROM NON-AROMATICS

Granted Patent: U.S. 9,056,283, Grant Date: June 16, 2015
Garba O. Yahaya

Summary

The patent relates to chemicals, and more particularly to an apparatus for separating aromatic hydrocarbons from an aromatic hydrocarbon feedstream.

DUAL PHASE CATALYSTS SYSTEM FOR MIXED OLEFIN HYDRATIONS

Granted Patent: U.S. 9,056,315, Grant Date: June 16, 2015
Wei Xu

Summary

The patent relates to chemicals, and more particularly to compositions and processes for making alcohols from olefins using a dual-phase catalyst system.

GASIFICATION OF HEAVY RESIDUE WITH SOLID CATALYST FROM SLURRY HYDROCRACKING PROCESS

Granted Patent: U.S. 9,056,771, Grant Date: June 16, 2015
Omer R. Koseoglu and Jean-Pierre Ballaguet

Summary

The patent relates to oil upgrading, and more particularly to processes for the partial oxidation in a membrane wall gasification reactor of heavy residue bottoms recovered from a slurry hydrocracking process to produce a synthesis gas.

OXIDATIVE DESULFURIZATION IN FLUID CATALYTIC CRACKING PROCESS

Granted Patent: U.S. 9,062,259, Grant Date: June 23, 2015
Omer R. Koseoglu and Abdennour Bourane

Summary

The patent relates to oil upgrading, and more particularly to a process and system for integrated oxidative desulfurization and fluid catalytic cracking of liquid hydrocarbon feedstocks.

HYBRID TRANSPONDER SYSTEM FOR LONG-RANGE SENSING AND 3D LOCALIZATION

Granted Patent: U.S. 9,062,539, Grant Date: June 23, 2015
Howard K. Schmidt and Abdullah A. Al-Shehri

Summary

The patent relates to production, and more particularly to methods related to mapping the size and shape of hydraulic fractures in hydrocarbon reservoirs.

SYSTEM, METHOD AND NANOROBOT TO EXPLORE SUBTERRANEAN GEOPHYSICAL FORMATIONS

Granted Patent: U.S. 9,063,252, Grant Date: June 23, 2015
Rami A. Kamal, Modiu L. Sanni and Mazen Y. Kanj

Summary

The patent relates to geophysics, and more particularly to a method and apparatus for using nanorobots to move through a subsurface formation to identify various geophysical characteristics.

WIRELESS DRILLSTRING DISCONNECT

Granted Patent: U.S. 9,068,415, Grant Date: June 30, 2015
David Fraser

Summary

The patent relates to drilling, and more particularly to disconnecting and reconnecting a drillstring and its method of use.

SCALABLE SIMULATION OF MULTIPHASE FLOW IN A FRACTURED SUBTERRANEAN RESERVOIR WITH MULTIPLE INTERACTING CONTINUA BY MATRIX SOLUTION

Granted Patent: U.S. 9,069,102, Grant Date: June 30, 2015
Larry S.K. Fung

Summary

The patent relates to computational modeling, and more particularly to the simulation of fluid flow in a complex heterogeneous subterranean reservoir where multiple interacting formation phenomena may be present, such as multimodal porosity or multi-scale fracture networks with spatially variable fluid transmissibilities.

METHOD AND APPARATUS FOR UNPLUGGING DRAINS OR VENTS

Granted Patent: U.S. 9,073,101, Grant Date: July 7, 2015
Saleh H. Al-Shammari

Summary

The patent relates to network integrity, and more particularly to an apparatus used for unplugging a component of a hydrocarbon transportation or storage unit.

LOW CONCENTRATION WASTEWATER TREATMENT SYSTEM AND PROCESS

Granted Patent: U.S. 9,073,764, Grant Date: July 7, 2015
William G. Conner and Thomas E. Schultz

Summary

The patent relates to a system and method for wastewater treatment.

METHODS FOR EVALUATING ROCK PROPERTIES WHILE DRILLING USING DRILLING RIG MOUNTED ACOUSTIC SENSORS

Granted Patent: U.S. 9,074,467, Grant Date: July 7, 2015
Yunlai Yang and Yi Luo

Summary

The patent relates to production, and more particularly to identifying rock types and rock properties to improve or enhance drilling operations.

METHOD FOR TRANSIENT TESTING OF OIL WELLS COMPLETED WITH INFLOW CONTROL DEVICES

Granted Patent: U.S. 9,085,966, Grant Date: July 21, 2015
Noor M. Anisur Rahman, Faisal M. Al-Thawad and Saud A. Binakresh

Summary

The patent relates to a method for transient testing of an oil well completed with an inflow control device (ICD).

THROUGH TUBING PUMPING SYSTEM WITH AUTOMATICALLY DEPLOYABLE AND RETRACTABLE SEAL

Granted Patent: U.S. 9,085,970, Grant Date: July 21, 2015
Jinjiang Xiao and Abubaker Saeed

Summary

The patent relates to a device for use in producing fluid from a wellbore.

SOUND VELOCITY DEWATERING SYSTEM

Granted Patent: U.S. 9,086,354, Grant Date: July 21, 2015
Fawaz A. Al-Sahan and Omar Z. Al-Zayed

Summary

The patent relates to a method and apparatus for controlling a water stream exiting a dewatering tank, including automatic or remote drainage of water in hydrocarbon tanks.

RECOVERY METHOD AND SYSTEM FOR DELIVERING EXTRACTED BTX FROM GAS STREAMS

Granted Patent: U.S. 9,090,521 Grant Date: July 28, 2015
Mohammad N. Al-Haji

Summary

The patent relates to a recovery method for delivering an extracted BTX component from a BTX-rich hydrocarbon gas stream.

INFLATABLE PACKER ELEMENTS FOR USE WITH A DRILL BIT SUB

Granted Patent: U.S. 9,091,121, Grant Date: July 28, 2015
Shaohua Zhou

Summary

The patent relates to an inflatable packer designed for use as an earth boring bit assembly.

SYSTEM AND METHOD FOR EFFECTIVE PLANT PERFORMANCE MONITORING IN GAS-OIL SEPARATION PLANT (GOSP)

Granted Patent: U.S. 9,092,124, Grant Date: July 28, 2015
Kamarul A. Amminudin

Summary

The patent relates to a plant performance monitoring tool.

INTEGRATED HYDROPROCESSING AND FLUID CATALYTIC CRACKING FOR PROCESSING OF A CRUDE OIL

Granted Patent: U.S. 9,096,806, Grant Date: August 4, 2015
Ibrahim A. Abba, Raheel Shafi, Abdennour Bourane and Essam Sayed

Summary

The patent relates to an integrated hydroprocessing and fluid catalytic cracking process for production of petrochemicals, such as olefins and aromatics, from feeds including crude oil.

WELL TRACTOR WITH ACTIVE TRACTION CONTROL

Granted Patent: U.S. 9,097,086, Grant Date: August 4, 2015
Khalid A. Al-Dossary

Summary

The patent relates to a device for adjusting the viscosity of a working fluid in a wellbore tractor to control vibration in the wellbore tractor.

INTEGRATED HYDROCRACKING AND FLUIDIZED CATALYTIC CRACKING SYSTEM AND PROCESS

Granted Patent: U.S. 9,101,853, Grant Date: August 11, 2015
Musaed M. Al-Thubaiti, Ali M. Al-Somali and Omer R. Koseoglu

Summary

The patent relates to oil upgrading, and more particularly to integrated cracking systems and processes that combine hydrocracking and fluidized catalytic cracking operations for enhanced flexibility in the production of light olefinic and middle distillate products.

CRACKING SYSTEM AND PROCESS INTEGRATING HYDROCRACKING AND FLUIDIZATION CATALYTIC CRACKING

Granted Patent: U.S. 9,101,854, Grant Date: August 11, 2015
Musaed M. Al-Thubaiti, Ali M. Al-Somali and Omer R. Koseoglu

Summary

The patent relates to oil upgrading, and more particularly to integrated cracking systems and processes that combine hydrocracking and fluidized catalytic cracking operations for enhanced flexibility in the production of light olefinic and middle distillate products.

APPARATUS FOR DISTILLATION OF WATER AND METHODS FOR USING SAME

Granted Patent: U.S. 9,102,546, Grant Date: August 11, 2015
Tawfeek A. Molah

Summary

The patent relates to an inverted Y-shaped structure for distilling fresh water from seawater or other non-fresh water samples.

METHODS FOR GEOSTEERING A DRILL BIT IN REAL TIME USING DRILLING ACOUSTIC SIGNALS

Granted Patent: U.S. 9,103,192, Grant Date: August 11, 2015
Yunlai Yang

Summary

The patent relates to drilling, and more particularly to drilling operations using well logging and measurement techniques for steering a drill bit within a pay zone in a lateral well by employing acoustic signals generated by the drill bit drilling into rock.

COUPLED PIPE NETWORK — RESERVOIR MODELING FOR MULTIBRANCH OIL WELLS

Granted Patent: U.S. 9,104,585, Grant Date: August 11, 2015
Ali H. Dogru

Summary

The patent relates to computational modeling, and more particularly to the modeling of pipe networks in subsurface reservoirs.

MAXIMIZING AROMATICS PRODUCTION FROM HYDROCRACKED NAPHTHA

Granted Patent: U.S. 9,109,169, Grant Date: August 18, 2015
Fahad Altherwi, Noaman Alfudhail and Mansoor Aleidi

Summary

The patent relates to chemicals, and more particularly to maximizing aromatic product production while satisfying gasoline production demand using straight run and hydrocracked naphtha.

SELF-TESTING COMBUSTIBLE GAS AND HYDROGEN SULFIDE DETECTION APPARATUS

Granted Patent: U.S. 9,110,041, Grant Date: August 18, 2015
Patrick Flanders

Summary

The patent relates to network integrity, and more particularly to a method and apparatus for safely ensuring the functionality of combustible gas and hydrogen sulfide detectors.

MEASUREMENT OF SURFACE ENERGY COMPONENTS AND WETTABILITY OF RESERVOIR ROCK UTILIZING ATOMIC FORCE MICROSCOPY

Granted Patent: U.S. 9,110,094, Grant Date: August 18, 2015
Johannes J.M. Buiting, Ahmed Gmira, Wael Abdallah and Mikhail Stukan

Summary

The patent relates to an instrument to measure properties of reservoir rock.

HYDROCRACKING PROCESS WITH INTEGRAL INTERMEDIATE HYDROGEN SEPARATION AND PURIFICATION

Granted Patent: U.S. 9,115,318, Grant Date: August 25, 2015
Ali H. Al-Abdulal, Yuv R. Mehra and Vinod Ramaseshan

Summary

The patent relates to oil upgrading, and more particularly to the efficient reduction of the sulfur and nitrogen content of hydrocarbons.

INFLATABLE COLLAR AND DOWNHOLE METHOD FOR MOVING A COILED TUBING STRING

Granted Patent: U.S. 9,115,559, Grant Date: August 25, 2015
Hamoud A. Al-Anazi

Summary

The patent relates to production, and more particularly to methods and apparatus employed downhole to move a coiled tubing string that has become immobilized due to buckling, lockup and/or high frictional forces at the downhole end of the tubing.

LOW FREQUENCY PASSIVE SEISMIC DATA ACQUISITION AND PROCESSING

Granted Patent: U.S. 9,121,965, Grant Date: September 1, 2015
Mohammad A. Al-Jadani

Summary

The patent relates to a new and improved method of acquiring low frequency seismic data about the travel of naturally occurring seismic waves through the earth.

SYSTEM APPARATUS AND METHOD FOR UTILIZATION OF BRACELET GALVANIC ANODES TO PROTECT SUBTERRANEAN WELL CASING SECTIONS SHIELDED BY CEMENT AT A CELLAR AREA

Granted Patent: U.S. 9,127,369, Grant Date: September 8, 2015
Mohammed H. Al-Mubasher

Summary

The patent relates to network integrity, and more particularly to the protection of the metallic well casing from the corrosive effects of moist soil in the well's cellar area.

RESERVOIR PROPERTIES PREDICTION WITH LEAST SQUARE SUPPORT VECTOR MACHINE

Granted Patent: U.S. 9,128,203, Grant Date: September 8, 2015
Saleh A. Al-Dossary, Jinsong Wang, Nasher Al-Binhassan and Husam Mustafa

Summary

The patent relates to computational modeling, and more particularly to the determination of reservoir attributes or properties as reservoir models when there is a limited amount of well log data available.

HIGH PERFORMANCE AND GRID COMPUTING WITH RELIABILITY QUALITY OF SERVICE CONTROL

Granted Patent: U.S. 9,128,211, Grant Date: September 8, 2015
Raed A. Al-Shaikh and Sadiq Sait

Summary

The patent relates to computational modeling, and more particularly to computerized simulation of hydrocarbon reservoirs in the earth, geological modeling, and processing of seismic survey data, and to quality of service control of such computing.

HIGH PERFORMANCE AND GRID COMPUTING WITH HISTORY QUALITY OF SERVICE CONTROL

Granted Patent: U.S. 9,134,455, Grant Date: September 15, 2015
Raed A. Al-Shaikh

Summary

The patent relates to high performance and grid computing of data for exploration and production of hydrocarbons, such as the computerized simulation of hydrocarbon reservoirs in the earth, geological modeling, and processing of seismic survey data, and more particularly to quality of service control of such computing.

FLARE NETWORK MONITORING SYSTEM AND METHOD

Granted Patent: U.S. 9,142,111, Grant Date: September 22, 2015
Patrick Flanders

Summary

The patent relates to a flare monitoring system that receives real-time data associated with the release of a processing facility's combustible fluids to a flare stack.

SYSTEMS AND METHODS FOR EXPERT SYSTEMS FOR WELL COMPLETION USING BAYESIAN DECISION MODELS, DRILLING FLUID TYPES, AND WELL TYPES

Granted Patent: U.S. 9,140,112, Grant Date: September 22, 2015
Abdullah Al-Yami and Jerome Schubert

Summary

The patent generally relates to the drilling and extraction of oil, natural gas, and other resources, and more particularly to the evaluation and selection of well completion operations.

SYSTEM FOR REAL-TIME MONITORING AND TRANSMITTING HYDRAULIC FRACTURE SEISMIC EVENTS TO SURFACE USING THE PILOT HOLE OF THE TREATMENT WELL AS THE MONITORING WELL

Granted Patent: U.S. 9,140,102, Grant Date: September 22, 2015
Kirk Bartko and Brett Bouldin

Summary

The patent relates to the field of hydraulic fracturing, monitoring, and data transmission of microseismic information from a zone of interest within a reservoir.

DRILL BIT FOR USE IN BORING A WELLBORE AND SUBTERRANEAN FRACTURING

Granted Patent: U.S. 9,140,073, Grant Date: September 22, 2015
Shaohua Zhou

Summary

The patent relates to an earth boring bit for use in forming a wellbore.

UPGRADING OF HYDROCARBONS BY HYDROTHERMAL PROCESS

Granted Patent: U.S. 9,145,885, Grant Date: September 29, 2015
Brett Bouldin and Jinjiang Xiao

Summary

The patent relates to a method and apparatus for upgrading a hydrocarbon feedstock.

ELECTRICAL SUBMERSIBLE PUMP WITH RECIPROCATING LINEAR MOTOR

Granted Patent: U.S. 9,145,885, Grant Date: September 29, 2015
Brett Bouldin and Jinjiang Xiao

Summary

The patent relates to the field of electrical submersible pumps, and more particularly to an electrical submersible pump having a reciprocating linear motor.

UPGRADING OF HYDROCARBONS BY HYDROTHERMAL PROCESS

Granted Patent: U.S. 9,145,521, Grant Date: September 29, 2015
Omer R. Koseoglu

Summary

The patent relates to hydroprocessing systems and methods, and more particularly for an efficient reduction of catalyst fouling aromatic nitrogen components in a hydrocarbon mixture.

DUAL-PHASE ACID-BASED FRACTURING COMPOSITION WITH CORROSION INHIBITORS AND METHOD OF USE THEREOF

Granted Patent: U.S. 9,145,512, Grant Date: September 29, 2015
Saleh H. Al-Mutairi, Yaser K. Al-Duailej, Ibrahim S. Al-Yami and Abdullah M. Al-Hajri

Summary

The patent relates to a fluid composition and method of using the fluid composition to coat the metal tubing and downhole equipment of the well during both the injection and the flow back phases.

SELECTIVE TWO-STAGE HYDROPROCESSING SYSTEM AND METHOD

Granted Patent: U.S. 9,144,752, Grant Date: September 29, 2015
Omer R. Koseoglu

Summary

The patent relates to hydroprocessing systems and methods, and more particularly to an efficient reduction of catalyst fouling aromatic nitrogen components in a hydrocarbon mixture.

SELECTIVE SERIES FLOW HYDROPROCESSING SYSTEM AND METHOD

Granted Patent: U.S. 9,144,753, Grant Date: September 29, 2015
Omer R. Koseoglu

Summary

The patent relates to hydroprocessing systems and methods, and more particularly to an efficient reduction of catalyst fouling aromatic nitrogen components in a hydrocarbon mixture.

UTILIZATION OF HEAVY OIL ASH TO PRODUCE SELF-CONSOLIDATED CONCRETE

Granted Patent: U.S. 9,150,455, Grant Date: October 6, 2015
Mohammed Al-Mehthel, Fahad R. Al-Dossari, Mohammed Maslehuddin, Rizwan Ali and Mohammed Barry

Summary

The patent relates to using heavy oil ash as a component of self-consolidated concrete.

METHOD FOR PREDICTION OF INHIBITION DURABILITY INDEX OF SHALE INHIBITORS AND INHIBITIVE DRILLING MUD SYSTEMS

Granted Patent: U.S. 9,164,018, Grant Date: October 20, 2015
Md. Amanullah, Mohammed K Al-Arfaj and Adel Al-Ansari

Summary

The patThe patent relates to drilling, and more particularly to evaluating well drilling fluids and testing the effectiveness of the durability of inhibition of inhibitive mud systems on reactive wellbore material.

SEQUENTIAL FULLY IMPLICIT WELL MODEL FOR RESERVOIR SIMULATION

Granted Patent: U.S. 9,164,191, Grant Date: October 20, 2015
Ali H. Dogru

Summary

The patent relates to computational modeling, and more particularly to the simulation of flow profiles along wells in a reservoir.

DEMULSIFICATION OF EMULSIFIED PETROLEUM USING CARBON DIOXIDE AND RESIN SUPPLEMENT WITHOUT PRECIPITATION OF ASPHALTENES

Granted Patent: U.S. 9,169,446, Grant Date: October 27, 2015
Zaki Yusuf and Bandar Fadhel

Summary

The patent relates to oil and gas treatment.

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Submission deadlines

Issue	Paper submission deadline	Release date
Summer 2016	February 29, 2016	June 30, 2016
Fall 2016	May 31, 2016	September 30, 2016
Winter 2016	August 31, 2016	December 31, 2016
Spring 2017	November 30, 2016	March 31, 2017

Nitrate Treatment — Effect on Corrosion and Implementation Guidelines

Dr. Tony Y. Rizk

ABSTRACT

Sulfate-reducing bacteria (SRB) colonization of oil field systems and the associated generation of hydrogen sulfide (H2S) is a major corrosion concern. Conventional treatment is centered on the use of a blend of biocides to kill all microorganisms. By comparison, nitrate bio-modification technology is a non-biocidal approach for the control of SRB. The effect of the nitrate technology on corrosion, however, remains a concern in the oil industry.

Proving the Concept of Unconventional Gas Reservoirs in Saudi Arabia through Multistage Fractured Horizontal Wells

Ali M. Al-Momin, Mohammed S. Kurdi, Sohrat Baki, Karim Mechkak and Ali H. Al-Saihati

ABSTRACT

Saudi Arabia has embarked on an exploration journey of its unconventional gas resources by recently targeting three different areas across the Kingdom. The targeted formations include tight sandstone, shale and tight carbonate, with a permeability range of 200 nano-darcy to 0.1 millidarcy. Extensive exploratory work in each of the areas has involved drilling vertical wells to identify and characterize potential targets through coring and open hole logging, along with flow potential testing of those targets after placing vertical fractures, all of which is beyond the scope of this article. This article highlights the progress the unconventional program has made in drilling horizontal monobore wells and stimulating them with multistage fracturing using the Plug-n-Perf technique.

Robust Quantification of Uncertainty in Heterogeneity for Chemical EOR Processes: Applying the Multilevel Monte Carlo Method

Dr. Ali M. AlKhatib

ABSTRACT

Reservoir heterogeneity can be detrimental to the success of chemical enhanced oil recovery (CEOR) processes. Therefore, it is important to evaluate the effect of uncertainty in reservoir heterogeneity on the performance of CEOR. Usually, a Monte Carlo (MC) sampling approach is used, where a number of stochastic reservoir model realizations are generated and then numerical simulation is performed to obtain a certain objective function, such as the recovery factor. Monte Carlo simulation (MCS), however, has a slow convergence rate and requires a large number of samples to produce accurate results. This can be computationally expensive when using large reservoir models. This study used a multiscale approach to improve the efficiency of uncertainty quantification regarding reservoir heterogeneity. This multiscale approach is known as the multilevel Monte Carlo (MLMC) method.

Diagnosis and Characterization of Cross Flow behind the Casing from Transient Pressure Tests

Dr. N.M. Anisur Rahman, Saud A. Bin Akresh and Faisal M. Al-Thawad

ABSTRACT

In a reservoir system with two neighboring layers, the tested and the adjacent layers, which are separated by impermeable strata fluid, may still migrate from the adjacent layer to the tested layer if the zonal isolation behind casing is compromised or if flow channels exist in the vicinity. A method is presented to diagnose the fluid contribution to the tested layer from the adjacent layer, and to quantify the transient rate of cross flow by utilizing the transient pressure data.