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Journal of Technology



Field Deployment of a Rigless, Cable Deployed ESP Using a Vertical Wellhead
see page 2

Offshore Drilling Operation Time Optimization Using PDC Bit Shear Cap Technology
see page 36



Some of the many team members who made the field installation a success.

On the Cover

Alternate deployment methods for electric submersible pumps (ESPs) reduce well intervention cost and production deferral by decreasing the use of workover rigs. Saudi Aramco's high hydrogen sulfide (H₂S) cable deployed ESP system advances alternate deployment technology through robust design and simplification of the overall system. On the cover is the first installation of this new technology in an onshore well.

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Field Deployment of a Rigless, Cable Deployed ESP Using a Vertical Wellhead

Brian A. Roth, Dr. Jinjiang Xiao, Mohammad Abdelaziz, John Mack, Yahya Sarawaq, Richard Reid and Andrew Helvenston

ABSTRACT

Electric submersible pumps (ESPs) are a widely used artificial lift technology. Conventional ESP systems provide power through a cable banded to the outside of the tubing. These systems have drawbacks in terms of installation speed and efficiency. To overcome these obstacles, a novel cable deployed (CD) ESP system, developed for use in a high hydrogen sulfide (H_2S) production environment, was formulated as a future solution. This article focuses on the challenges, results and lessons learned from the first field deployment in the world of a rigless, high H_2S CDESP system.

A metal-jacketed power cable was a key enabler to developing the CDESP system. The metal-jacketed power cable delivers the best protection against a H_2S attack and provides a smooth outside diameter that can be gripped on and sealed. The cable has been tested to withstand H_2S levels up to 15% and chloride levels in excess of 150,000 ppm with an expected service life in excess of 10 years.

To overcome well control concerns, a cable hanger spool was developed enabling the ESP cable to be terminated below the master valve. In addition to the surface termination of the cable, the cable hanger spool provides hang-off and production flow through capabilities.

The field deployment of the CDESP system, using a specialized inverted ESP, required the close integration of several equipment and service providers during the development of the equipment and procedures to ensure success in the installation of the system. The system's initial deployment was in a benign onshore well that offered ample workspace for the various service providers to learn the unique aspects of this rigless deployment. Of particular importance, the interface for the service providers at the surface cable termination was critical to the successful installation. For this trial test, the well completion was changed from 4½" tubing to 7" tubing to accommodate the cable deployed 562 series ESP.

Lessons learned from this field trial will be incorporated into future trials of the CDESP technology. The goal of these future trials will be to deploy the technology in offshore H_2S wells where high rig costs can be significantly reduced through the use of a lower cost barge coupled with the increased speed, efficiency, and ease of CDESP deployment.

INTRODUCTION

A majority of electric submersible pumps (ESPs) installed today are installed with tubing. The ESP is installed as part of the tubing string, and the cable that provides power to the ESP is banded or clamped to the tubing. This method has been in use since the beginnings of ESP installations back in the 1930s.

Since the 1970s, several types of alternative deployment methods have been developed. These are represented by various technologies, including a cable suspended submersible pump system¹, cable internal coiled tubing (CT) deployed submersible pump system² and umbilical system³. A significant amount of learning was achieved in the use of these alternative deployment systems; however, each of these systems had drawbacks that prevented widespread adoption of the alternative deployment technology.

ALTERNATIVE DESIGN APPROACH

Saudi Aramco, with a large installed ESP base, sought alternatives to conventional rig deployed ESP installations. A key benefit of alternative deployed ESPs is that workover rigs are freed up for other well activities.

A number of alternative deployed ESP technologies have been field tested over the past few years with limited success. One major concern with the current alternative deployed ESP options is that those systems cannot survive long-term in high hydrogen sulfide (H_2S) environments.

A new alternative deployed ESP system able to function long-term in high H_2S wells was considered and developed as a collaborative project involving Saudi Aramco, Baker Hughes and GE. Some of the challenges in the development were the need for a high H_2S cable, for compatibility with Saudi Aramco well control requirements and for a cable hanger interface, as well as issues with the deployment of the new technology. Each of these challenges will be discussed further.

TECHNICAL CHALLENGES

High H_2S Cable

Saudi Aramco's wells can be particularly hostile, with up to

15% H₂S in vapor phase and up to 200,000 ppm chloride levels in some fields. Conventional tubing deployed ESPs as well as most alternative deployed solutions do not adequately address these aggressive environments with their power cable design. As a result, service life for ESPs in these well environments is relatively short, with electrical failures as the main cause of failure. This aggressive well environment therefore necessitated the design of a cable system that could survive in its long term.

Several different metallurgies were identified and tested. The materials were not fully NACE compliant: the metal-jacketed cable could not be annealed down to the maximum allowable hardness after welding because of the elastomer inside of the outer jacket. Only nickel alloy N825 was able to pass a modified TM-0175 immersion test⁴.

The unique cable design introduced other benefits in addition to long-term survival. It eliminated all standard electrical connections, thereby reducing the weak points that usually cause electrical failure, and the cable was also fully isolated from well fluids, which eliminated the cable elastomer expansion during changes in pressure cycles.

Well Control Requirements

Saudi Aramco requires that the wellhead master valve have the ability to be closed after cable deployed (CD) ESP installation so as to isolate the ESP hanger from the remainder of the wellhead. The wellheads on existing offshore platforms have limited spacing between them and so prevent the consideration of horizontal trees, which are currently not approved for use.

Well controls are stringent as most wells have pressure at the wellhead, including wells with an ESP installed. Saudi Aramco requires that a minimum of two barriers be in place during ESP change out. Saudi Aramco does not recognize a subsurface safety valve (SSV) as a barrier because of its allowable leakage rate and the inability to test the valve with positive pressure from the surface. A further consideration concerning well control requirements is that Saudi Aramco requires a waiver for removal of the wellhead without a rig.

Xiao et al. (2017)⁵ provides more detail on the well control strategy for rigless deployed ESP systems with a power cable.

Cable Hanger Interface

Another area of challenge was the cable hanger interface for the vertical cable hanger spool. The cable hanger spool required the coordinated engineering efforts of wellhead manufacturers, electrical penetrator manufacturers, artificial lift manufacturers and completion manufacturers to develop and provide a solution that integrated the requirements of the various vendors.

The resulting cable hanger spool met the technical requirements, which included the required hanging load, conduction of the required electrical current, limited restriction of production flow bypass and ease of installation and recovery⁶.

Deployment of New Technology

The effort devoted to solving these challenges culminated in the field deployment of the CDESP system. The deployment of this new technology is discussed next.

DESCRIPTION OF EQUIPMENT (SURFACE AND SUBSURFACE EQUIPMENT)

Rig Installed Completion

The initial field trial was planned for the Abu Hadriya field due to the significant number of premature ESP failures — caused by electrical cable failure — experienced by wells there. In the planning for the field trial, we determined that the required Xmas tree SSV did not have the large bore required to run the rigless equipment and would need to be ordered. The field trial was shifted to the Khurais field, the backup location for the CDESP system, since the field is electrified and instrumented for ESPs, making monitoring of the system after installation much easier.

The pump was planned to be set at 4,920 ft measured depth (MD), to operate above the gas bubble point, and in a low deviation section of the wellbore. At the planned setting location of the ESP, the well deviation is approximately 40°.

The flow rate requirement of 5,000 bbl of fluid per day necessitated the use of a Baker Hughes 562 series ESP. The Baker Hughes Flex 80 pump is capable of flow rates up to 8,000 bbl/day. It is an inverted design and has a Zenith sensor gauge to measure normal ESP characteristics (well pressure and temperature, motor temperature, current, voltage and vibration);

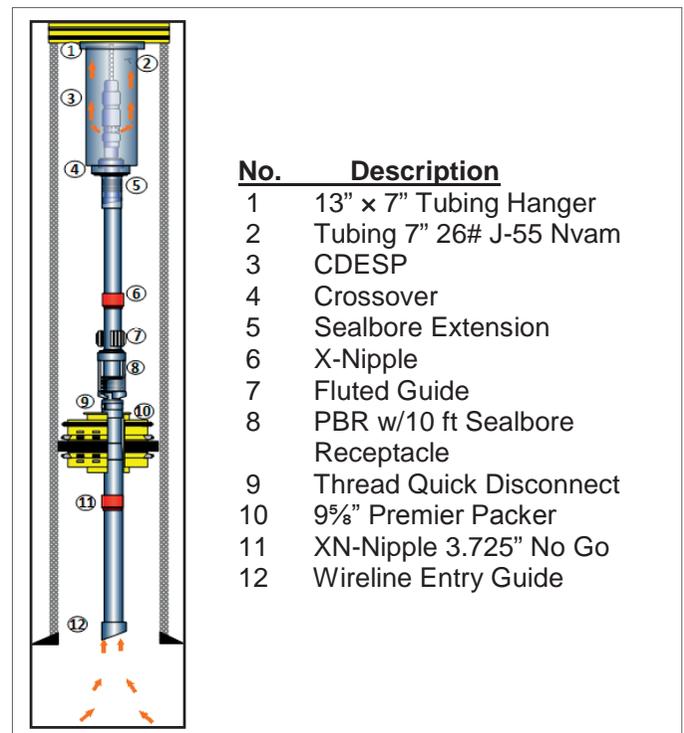


Fig. 1. CDESP and well's downhole permanent completion.

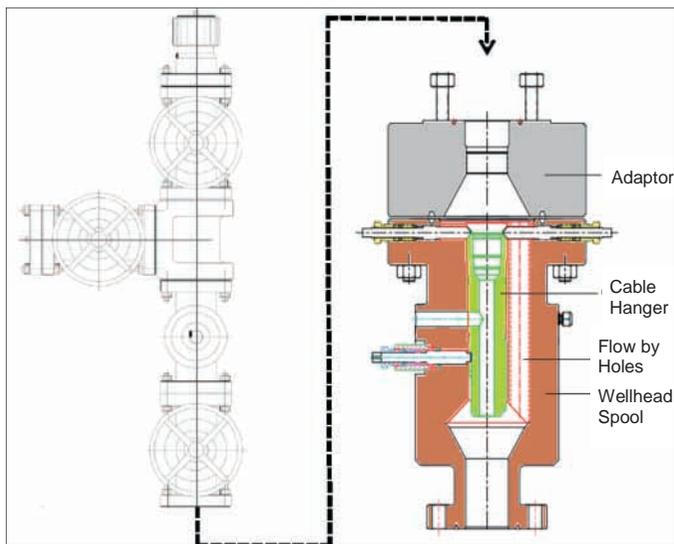


Fig. 2. Vertical Xmas tree with cable hanger.

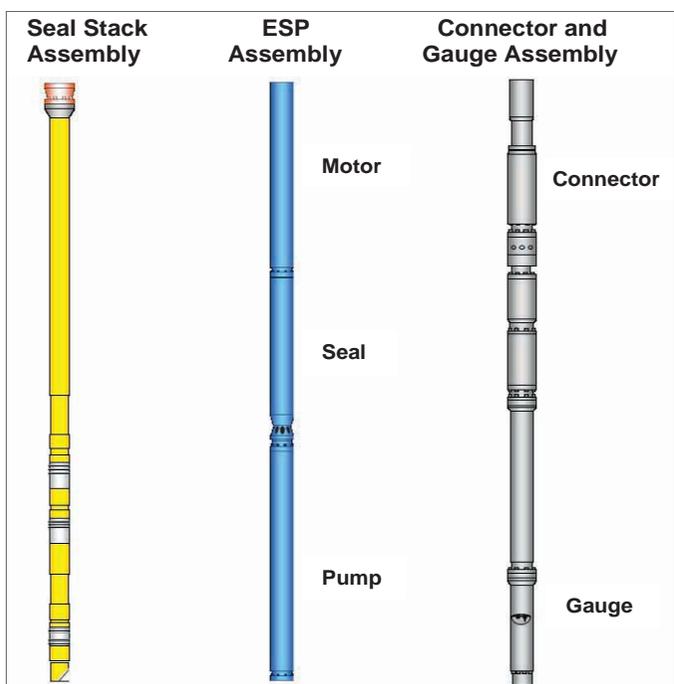


Fig. 3. ESP string sections.



Fig. 4. Metal-jacketed ESP cable on location.

however, the pressure intake line was not used in the initial field trial due to a restriction in the tubing hanger's internal diameter.

The completion was designed with a 7" 26 ppf tubing from the surface to 5,183 ft, Fig. 1. The completion was crossed over to a 5" 21.4 ppf sealbore extension at 4,931 ft, then to a 4½" tubing with a stringer and polished bore receptacle (PBR) with a sealbore receptacle placed above a hydrostatic-set, removable production packer. The production packer was set using a 3.725" plug placed in the XN nipple below the packer.

The 7" completion was landed with a 13⅝" x 7" tubing hanger. One of the newly developed technologies, the GE VetcoGray cable hanger spool, was landed on top of the tubing bonnet. The cable hanger spool provides a means for mechanical and electrical termination of the CDESP system. The cable hanger spool also allows passage of a 562 series ESP motor complete with an intake pressure line clamped to the outside of the motor. The cable hanger spool further provides a guide pin to enable auto orientation for the cable hanger as it lands inside the cable hanger spool. Flow ports allow the production fluid to bypass around the cable hanger when it is installed in the cable hanger spool, Fig. 2.

Above the cable hanger spool is a receptacle for a Type K-1 back pressure valve (BPV) in case remedial work is required on the Xmas tree. The tree requires a large 7⅞" API bore capable of drifting the cable hanger and ESP. The design of the wellhead allows for a fully closed master valve with the cable termination below the master valve.

Rigless Installed ESP System

The bottom-hole assembly (BHA), from the bottom to the top, consisted of an indexing muleshoe, 30 ft seal stack, secondary shear with retrieving recess, pump, seal, motor, sensor gauge, connection chamber, primary shear with retrieving recess, stabilization gland and CT adapter, Fig. 3. The CT adapter connected the BHA with the power cable.

The cable was manufactured in a continuous process. In this process, a standard ESP cable is fed into the production assembly line along with a flat strip that makes up the outer jacket. The flat strip is formed around the inserted cable and laser welded closed. As a final step, the laser welded outer jacket is tightened down onto the ESP cable to interlock the outer jacket with the inner ESP cable, Fig. 4. The cable is designed to carry the weight of the cable and BHA, and to protect the electrical cables from the production fluid.

The cable terminated at the surface with the cable hanger adapter. The adapter had to provide an interface for the cable hanger spool designed by GE VetcoGray, the mechanical slip system designed by Baker Hughes and the electrical connection designed by Quick Connectors Inc.

The cable hanger adapter incorporates a muleshoe feature to provide auto rotation to align the electrical penetrator in the adapter with the mating holes in the cable hanger spool. The

cable hanger adapter also incorporates a “GS” type profile in the top of the hanger to provide trouble-free deployment and retrieval, Fig. 5.

PILOT FIELD TRIAL WELL DETAILS

Rig Deployment

The well in the Khurais field was completed as a horizontal open hole producer to a MD of 10,372 ft. A 9 $\frac{5}{8}$ ” casing was run to 6,320 ft MD and an 8 $\frac{1}{2}$ ” horizontal open hole was completed at total depth. The well was de-completed in August 2016, removing a failed ESP along with its cable, ESP packer and production tubing.

The well was recompleted with a rig to facilitate the installation of the CDESP system. A 4 $\frac{1}{2}$ ” tubing was installed from the open hole to 4,963 ft. The completion was crossed over to 7” 26 ppf tubing to the surface from 4,932 ft. A 9 $\frac{5}{8}$ ” \times 4 $\frac{1}{2}$ ” premier production packer was installed to isolate the tubing casing annulus (TCA) at 5,134 ft. A 3.725” XN nipple was installed below the packer to provide a means to land a plug and set the packer.

After the plug was installed, the tubing pressure was increased to 3,000 psi to set the packer. Confirmation of the proper packer setting was performed with overpull and a TCA pressure test. A PBR installed above the packer was sheared out and the seal assembly was picked up to provide for circulation of inhibited brine in the TCA. A 13 $\frac{5}{8}$ ” \times 7” tubing hanger was made up and then landed after the TCA fluid was swapped out.

The GE cable hanger spool, along with the BPV adapter, was installed on top of the tubing hanger. A bowl protector was installed in the cable hanger spool prior to its makeup to the tubing hanger. The bowl protector is designed to protect the BPV and cable hanger sealbores from damage during CT and wireline operations. The well was completed with a 7 $\frac{1}{16}$ ” Xmas tree. The 7 $\frac{1}{16}$ ” tree was pressure tested to confirm the integrity of the wellhead.

During the completion, the well’s losses were managed through the topping up of the kill fluid. Kill fluid was weighted to 69 pcf and losses were found to be 30 bbl/hour.

Rigless Deployment

Rigless equipment was mobilized at the well site in mid-December 2016. The surface equipment included a CT unit with a separate spooling unit for the 1.62” power cable, pressure pumping equipment — including kill fluid storage tanks, mixing tanks and filtration equipment — and functional test equipment with zero-flare flow

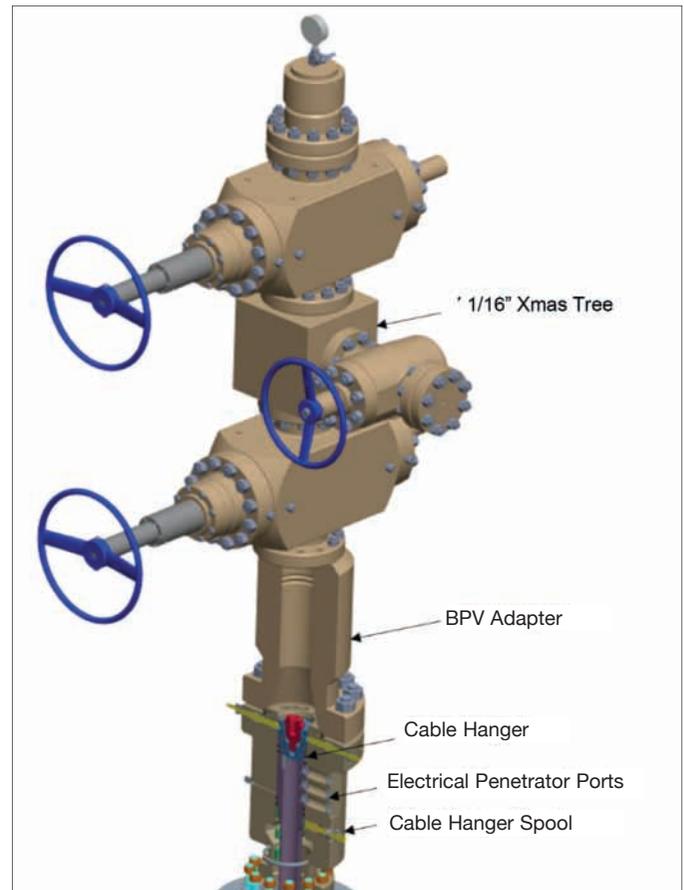


Fig. 5. Xmas tree with cable hanger adapter.

lines for control of the well fluids and flow back. Because of the increased height of the wellhead with the addition of the cable hanger spool and the use of a larger size Xmas tree, a 10 m CT tower was modified to provide work access. Two cranes were used to allow efficient operations during the deployment of the BHA. One crane was used to hold the injector and strippers, while the other crane was used to lift and place the BHA into the well, Fig. 6.

Well control during deployment operations was accom-



Fig. 6. Well site setup.

firmed the cable capable of supporting in excess of 70,000 lb of tensile load with the 40,000 lb preload.

The cable connector and the injector head were moved off the CT tower to allow the building of the ESP subassembly. The seal stack assembly was located on the CT tower. The complete ESP with pump, protector and motor was lifted and made up to the stringer assembly with the bolted flange. Before they were lifted, the ESP motor and protector were filled with dielectric. The bolted connection between the ESP pump intake and the seal provided a secondary shear location for the BHA should the seals become stuck in the PBR.

The 60 ft seal stack and ESP BHA subassembly was then lifted and installed in the well, landing on a C-plate located on top of the annular BOP. The annular BOP was closed to provide the two required barriers. The last section of the ESP BHA, containing the sensor gauge, connection chamber, primary shear sub and stabilization gland, was lifted and bolted to the motor flange. The sensor gauge and connection chamber were filled with dielectric fluid. Once these were filled, the annular BOP was opened, and the BHA was lowered to provide access to make up the cable connector, Fig. 10. Once the BHA was lowered, the annular BOP was reengaged.

After the cable connector was made up to the ESP BHA, the annular BOP was opened, and the BHA and power cable were injected several feet into the well. The 1.62" pipe/slip rams were engaged. The injector head and strippers were lowered onto the annular BOP and made up. The ring gasket between the annular BOP and strippers was tested to confirm pressure integrity. With the BOP stack testing positive, the CDESP system was run to location. Care was taken when the BHA passed through restrictions such as the BOP and Xmas tree. Run-in speed for this initial field trial was limited to 25 ft per minute.

As the BHA approached the target depth and the PBR, the run-in speed was decreased. When the seals entered the PBR, a noticeable drop in weight was observed. This could be attributed to a restriction in flow, causing the fluid to be redirected into the pump. Further weight was lost when the stringer shouldered out. The stringer was removed and reinstalled in the PBR to confirm the correct location.

Once the BHA was landed, equipment space out and well-head termination were the next steps. A total of 51 ft of cable was pulled back out of the well. This distance allowed for sealbore space out, wellhead loss for cable termination, and 12 ft to provide adequate distance to remove the installed bowl protector and provide space for making up the cable hanger. The 1.62" pipe/slip ram was set against the cable, the BOP stack was broken between the annular BOP and strippers, and the injector head was raised 12 ft. A mark was made on the cable just under the raised injector head and strippers. The mark would serve as a guide to the location to cut the cable, although, the bowl protector first would need to be retrieved from the cable hanger spool. A split retrieval tool, which latched into the bowl protector, was installed just below the marked location on the cable. The split retrieval tool for the

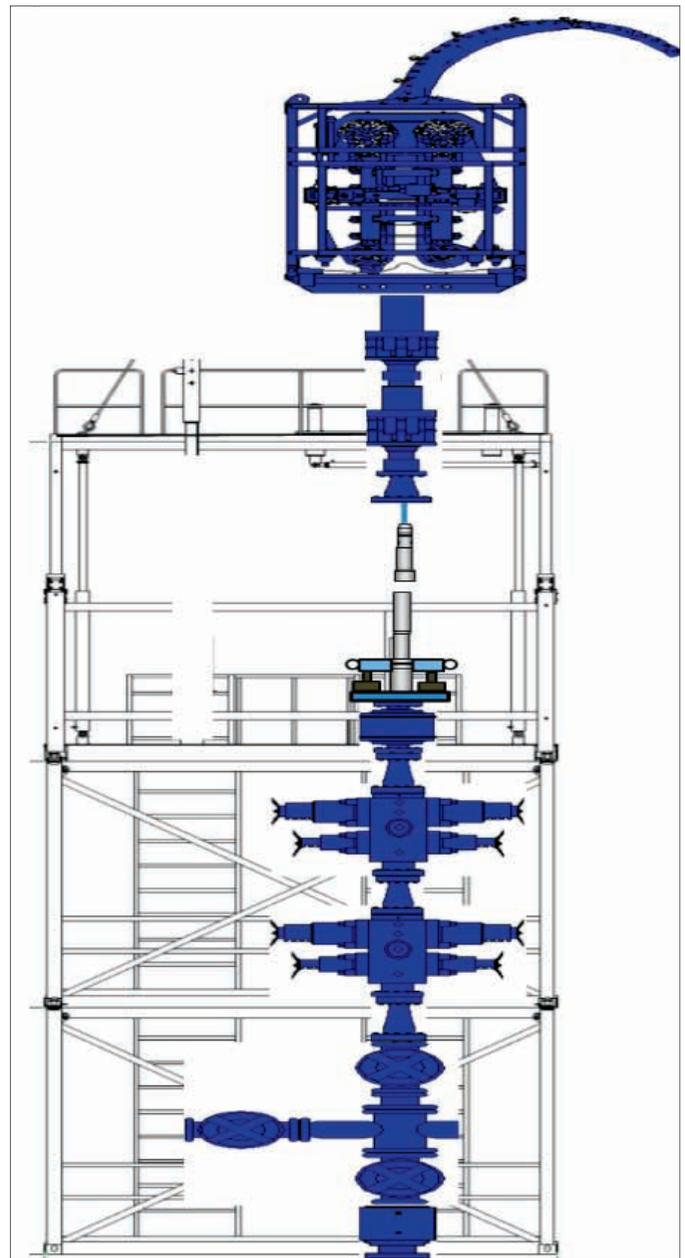


Fig. 10. Making up the cable connector to the BHA adapter in the ESP string.

bowl protector was run into the cable hanger spool, latched onto the bowl protector and then retrieved it. The power cable was cut at the marked level above the bowl protector and split retrieval tool, and the bowl protector was removed.

The cable hanger was then made up to the cable for cable termination, Fig. 11. The cable hanger is similar to the down-hole connector, which was installed at the bottom of the cable and made up to the ESP BHA. Differences between the cable hanger and the cable connector include the change from a vertical to horizontal electrical penetrator, the self-orienting hanger and the hanger landing and release profile. In addition to O-ring seals to keep fluids away from the electrical connections, graphite packing was used to seal the hanger to the cable. All the seals are capable of being pressure tested to ensure pressure tight connections.

Once the cable hanger was made up, the guide screw in the

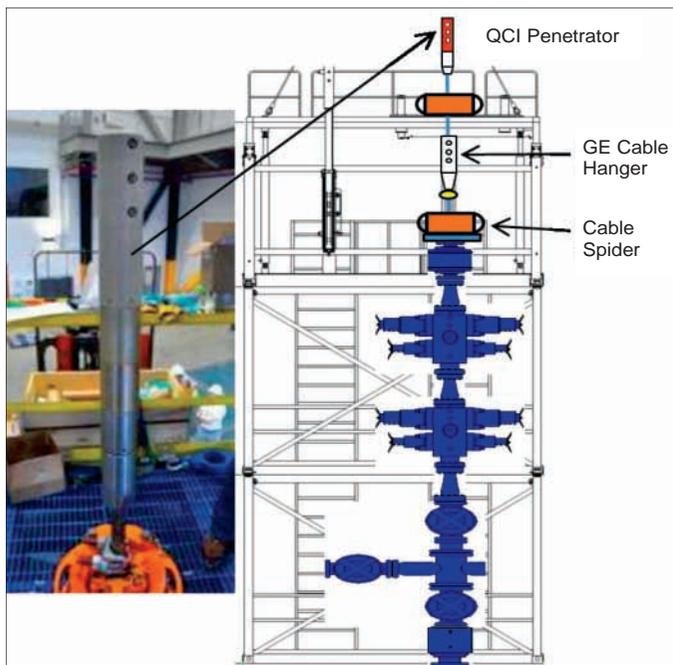


Fig. 11. Cable termination with cable hanger.



Fig. 12. Stabbing GS running tool.

cable hanger spool was tightened to provide auto rotation of the hanger while landing. The seals were pressure tested, the electrical connections were tested for resistance, and a hydraulic “GS” Model was installed into the internal fishing neck profile at the top of the cable hanger. The hydraulic GS was attached to one of the cranes by a pup joint. The hydraulic GS flow port was blocked, and a hydraulic hose and pump were installed to release the GS once the cable hanger was landed. When the hanger landed in place, the lockdown screws were tightened in the cable hanger spool, retaining the cable hanger, Fig. 12. The GS was released and the crown valve was closed to secure the

well. The shear/blind rams on the dual combination BOP were closed to provide an added mechanical barrier.

Pressure test ports between the seals on the cable hanger were tested to ensure a seal before blanking plugs were removed from the cable hanger spool to provide access for the horizontal electrical connectors to attach to the female vertical electrical connectors. The horizontal electrical connectors were made up and connected to a temporary variable speed drive and generator, Fig. 13. Power was applied to the ESP motor and the well was unloaded of the kill fluid.

First-time rigless operations proved efficient in reducing installation time, nearly 50% over the rig-based installation, with further deployment efficiency improvements expected in the future.

LESSONS LEARNED

The initial installation of the CDESP went extremely well with minimal delays. Much of the success can be attributed to detailed pre-job planning, including a review of safety aspects and operation contingency planning. The pre-planning meetings also included on a regular basis many of the individuals who participated in the field trial.

The field trial involved 13 different departments within Saudi Aramco. Frequent consultations with all departments that could have an impact on the project were held to ensure their concerns were addressed.

The use of specific company experts to deploy the technology contributed significantly to the field installation success. These were the individuals who designed the equipment and performed the system integration tests. The experts were very familiar with the new technology and did not have to learn the new equipment as it was put in use.

Team dynamics in any project can make or break the success of the project. With round-the-clock operations, communication was key. At each major step in the installation, everyone on-site stopped to attend a five- to 10-minute job discussion detailing the steps that were to occur, along with job safety considerations.

Safety was paramount on the job location. In addition to the safety talks before each major activity, the decision to use



Fig. 13. Makeup of electrical connections to the cable hanger.

an annular BOP was critical to the job success. The annular BOP was engaged multiple times due to the continued loss of kill fluid to the formation. Using the VBR, with its limited number of allowable cycles, for this safety purpose would have increased the operation risk. The annular BOP provided even further protection in that it was able to seal on all diameters.

While the initial field installation did not use any downhole barriers such as barrier valves or safety valves, well losses in excess of the 30 bbl/hour encountered during the rig operations caused additional time to be spent ensuring the well was controlled during the installation. The use of a downhole barrier would have minimized or eliminated the well fluid loss.

FURTHER WORK

Improvements recommended for future jobs include a revised CT tower design for improved work safety and to eliminate the need to remove the flow line. The ability to leave the flow line in place improves the turnaround time to get the well back into production.

A purpose-built injector stand is another improvement area. The injector stand needs to be able to accommodate the height of the strippers as well as provide a work space to install the cable connector.

Filling the sensor and connection chamber on the CT tower took longer than anticipated. Prefilling the chamber will reduce overall deployment time.

These areas, as well as others to be identified in an upcoming after-action review meeting, will be looked at for future improvements, particularly as we move to offshore platforms.

CONCLUSIONS

Rigless CDESP technology was developed with the goal to reduce well intervention cost and production deferral. The core of the technology is the slim, high-strength cable that is resistant to high levels of H₂S and chloride in the produced well fluids. The cable hanger spool was necessary to address well control concerns, but it also provided an efficient method to land the hanger and make up the electrical connections.

Deployment of the CDESP system went well because of in-depth pre-job planning, which worked to minimize risk and develop contingencies for higher risk operations — such as the addition of an annular BOP to the pressure control equipment stack.

Standard CT operational practices do not readily apply to the CDESP operation. Because of these differences, training of well site personnel will be critical to the continued success of this technology.

The success of this initial installation of the CDESP technology paves the way for reducing the workload of rigs for ESP change out, while providing a more efficient, lower cost, more readily available and more reliable alternative to the current alternate deployment ESP technologies.

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He received both his M.S. and Ph.D. degrees in Petroleum Engineering from the University of Tulsa, Tulsa, OK.



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Completions and Interventions on projects like the Manara intelligent completions and the well lateral intervention tool. Mohannad also initiated the downhole robotic platform project.

In 2015, he successfully finished a one-year business assignment as a Production Engineer at the Safaniyah field. Following that, in 2016, he joined the Artificial Lift Team and is currently working on high impact technologies like cable deployed electrical submersible pumps (CDESPs) and a shallow-set subsurface safety valve for CDESPs. Mohannad is also leading EXPEC ARC's efforts for ESP intelligent data analytics.

He received his B.S. degree in Mechatronics Engineering from the University of Jordan, Amman, Jordan, and his M.S. degree in Mechanical Engineering from King Abdullah University of Science and Technology (KAUST), Thuwal, Saudi Arabia. Mohannad will graduate with an M.S. degree in Petroleum Engineering from Heriot-Watt

University, Edinburgh, U.K., in June.

He is an active Young Researcher committee member and one of the founding officers for the first KAUST alumni chapter in Saudi Arabia. Mohannad has twice received the EXPEC ARC SPARX (Special Achievement Recognition of Excellence) award, has filed three patents and has five international publications. In 2016, he won the Abu Dhabi International Petroleum Exhibition and Conference Young Engineer Award.



John Mack is a Principal Technical Specialist with Baker Hughes Artificial Lift Systems. After receiving a degree in Mechanical Engineering, he spent six years as an Engineer in the recreational vehicle and recreational sports industries before joining

artificial lift provider Oil Dynamics. John joined Baker Hughes as part of the 1997 acquisition of Oil Dynamics.

During his 34-year career in the artificial lift industry, John has amassed 19 patents, many of which are related to gas avoidance systems and coiled tubing (CT) deployed electrical submersible pumps (ESPs). He is the subject matter expert for CT deployed ESP technology at Baker Hughes. John was instrumental in the design and deployment of a first-generation ESP system that is still running in one field after 9 years and he was a leader of the project team for the next-generation TransCoil™ rigless deployed ESP system that was successfully installed in the Middle East in December 2016.



Yahya Sarawaq is a Project Manager at Baker Hughes Artificial Lift Systems. He joined Baker Hughes in 2010 and occupied different roles in Operations, Engineering, Sales and Account Management. Yahya has 14 years of experience in the oil and gas sector working with the leading companies in the market.

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Richard Reid is a Coiled Tubing (CT) Service Line Coordinator with Baker Hughes Saudi Arabia. He has over 21 years of experience in CT operations and applications. Richard began his career in 1996, out of Aberdeen, U.K.

He was brought in for the TransCoil project in July 2016, leading the CT operation. The deployment of the project has been a success in part because of Richard's actions and abilities. He was instrumental in modifying a CT tower to the job requirement and overseeing its approval for use with the operator as well as assisting/advising the Project Manager at the well site.



Andrew Helvenston is an Engineering Technical Leader with GE Oil & Gas Pressure Control. In his 9 years of experience, he has worked in applications engineering, requisition engineering, R&D, product testing and as a Team Leader, all relating to

wellhead and flow control technologies. Andrew has 11 combined pending and granted patents.

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In Situ Steam Generation: A New Technology Application for Heavy Oil Production

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ABSTRACT

The recovery of unconventional oil, such as heavy oil, is receiving great interest as the world oil demand increases. Producing such high viscosity oil is complex and challenging, and it usually requires thermal techniques. Thermal recovery methods are widely used to recover heavy oil and bitumen, basically by thermally reducing oil viscosity, improving the mobility ratio and enhancing the heavy oil displacement.

One of the promising new technologies in thermal recovery uses in situ steam generation via chemical reaction to mobilize the low API crude oil or tar reserves. In this article, a new steam flooding methodology is introduced and compared with existing technologies.

Using in situ steam generation as a thermal technique for heavy oil displacement is of increasing interest. The most critical limitation when generating steam on the surface, transporting it to the wellhead and injecting it downhole, apart from the application challenges in relatively deeper resources, is heat loss. Overcoming or avoiding heat loss has been an industry challenge for maturing in situ steam generation techniques, which involves both maximizing the heat delivery efficiency of steam into the reservoir and minimizing heat losses into underburden, overburden and producing areas.

The first field trial of an in-house technology using exothermic reactants (EXO-Clean) achieved a significant improvement in a water disposal well's injectivity. The well's injectivity was poor because of downhole obstructions and formation damage, attributed mainly to an accumulation of organic and inorganic damaging material. To identify the type of damaging precipitates present in the well and determine an effective treatment recipe, a sample comprising a heterogeneous, thick sludge of mixed dark oil and other materials was collected from the injection line of the disposal well. Laboratory analyses using extraction and scanning electron microscopy and energy dispersive X-ray spectroscopy indicated that corrosion products — iron oxide and sulfides — and hydrocarbon material, such as asphaltene, made up the main sludge composition. To restore the well's injectivity, a chemical train was required to remove the hydrocarbons and to dissolve the iron compounds so as to eliminate the sludge plugging the wellbore and the perforated zone.

The well treatment was designed in two main stages: (1) wellbore tubular cleaning treatment, and (2) near wellbore formation damage removal. EXO-Clean employs two reacting chemicals with a predesigned exothermic chemistry that is triggered by either an increase in temperature — as in downhole conditions — or a low pH achieved using weak acid. The reaction was designed to trigger at a specific heat level (420 °F) with nitrogen gas at 4,425 psig. After breaking down and lifting most of the damaging elements in the near wellbore region, the treatment was displaced with brine and flowed back to release the generated pressure and remove the damage and the injected acid. When the disposal well was put back on injection and tested, its injectivity had increased from 1 barrel per minute (bpm) to 5.8 bpm (almost sixfold) at 1,500 psi, with a wellhead pressure decrease of almost 85% from 1,500 psi to 253 psi. The post-treatment injectivity improvement reveals EXO-Clean as a cost-effective application in the stimulation of sandstone and carbonate formations, especially when using thermal techniques for heavy oil displacement.

INTRODUCTION

In response to the recent effort at leveraging heavy oil and tar plays in Saudi Arabia, Saudi Aramco has launched a new thermochemical research program to tackle challenges associated with lowering oil viscosity enough to improve well productivity and the overall reservoir depletion efficiency.

Of all the recovery methods available, steam flooding is the most commercially applicable technology. In a steam drive process, steam is continuously introduced into injection wells to lower the viscosity of the heavy oil and provide a driving force to mobilize the oil and direct it toward production wells. The injected steam is approximately 80% steam and 20% water.

When steam is injected into the reservoir, heat is transferred to the oil-bearing formation and the reservoir fluids, with some heat transferred to the adjacent base and cap rocks. As a result, some of the steam condenses to produce a mixture of steam and hot water flowing through the reservoir.

The steam drive functions by driving the water and oil to form an oil bank ahead of the steam zone. Ideally, this oil bank remains in front and keeps increasing in size until it is recovered by production wells. In many cases, the steam over-

rides the heavy, viscous oil, due to differences in gravity and mobility, and transfers heat to the oil by conduction. This reduces the viscosity of the oil present at the interface between the oil and steam, and the oil is dragged along with the steam to the producing wells, leading to an increase in recoverability.

In steam flooding, the steam injection rate is high at the start so as to reduce heat losses to the base and cap rocks. Reservoir heterogeneities and gravity segregation of condensed water from oil can cause the formation of a highly permeable, oil-free channel between injector and producer wells. If this channel is close to the cap rock, it causes undesirable heat losses to the cap rock. To make the situation worse, neither the steam drive nor the convective heat transfer works as efficiently as required. As a result, steam sometimes breaks through into the production wells without sweeping the entire heated interval.

HEAVY OIL RECOVERY METHODS

There are two main categories of heavy oil recovery: cold production and thermal production. These methods are described next.

Cold Production

In cold production, heavy oil is recovered with flooding. Processes falling in this category are:

- Primary production
- Gas flooding with nitrogen, carbon dioxide (CO₂), hydrocarbon gas, pressuring pulsing, liquefied petroleum gas, etc.
- Improved waterflooding with low interfacial tension, alkaline-surfactant-polymer, polymer, solvent, etc.
- Cold heavy oil production with sand
- Water injection alternating with sand

Thermal Production

The application of thermal recovery methods is more popular and economically viable for recovering heavy oil. The main processes in this category are:

- Steam flooding
- Cyclic steam stimulation
- Huff-n-puff
- Steam assisted gravity drainage (SAGD)
- Fire flooding (in situ combustion)

Thermal Stimulation

Most thermal production relies on thermal stimulation processes that decrease resistance to flow in the vicinity of the

wellbore and therefore allow the reservoir driving forces to increase crude production. In heavy oil reservoirs, thermal stimulation methods near the wellbore are the most commonly used recovery tactics in the oil industry. It is believed that one or more of the following mechanisms improve production:

- Drastic reduction in oil viscosity and some reduction in water viscosity — this mechanism is always in force in all thermal processes.
- Wellbore cleaning may occur.
- Organic solids near a wellbore may be melted or dissolved.
- Clay may be stabilized.
- Absolute permeability may be increased by high temperatures.
- Fines that could be inhibiting flow in gravel packs may be flushed away.

Because of their high viscosity values, most heavy oil reservoirs have poor lateral continuity, and therefore the thermal effects are confined to the nearby regions of the wellbore. This is the main reason that thermal stimulation processes in most cases improve oil production rather quickly. In displacement processes, on the other hand, no significant sustained increase in production rates can be expected until an oil bank or heat (or both) reaches a producing well¹.

Limitations of Steam Flooding

Currently, there are several limitations to existing commercial steam flooding technologies. The new in situ steam flooding technology described here has the potential to overcome these limitations. Table 1 describes the pros and cons of thermal recovery technologies. The limitations are:

- The cost of the steam process can be more than 50% of the revenue².
- The reservoir pay zone thickness must be more than 20 ft, and the oil saturation must be high enough to keep the heat losses to an adjacent formation at a minimum.
- Steam flooding is primarily applicable to high viscosity oils found in high permeability sandstones or unconsolidated sandstones. It is not normally used in carbonate reservoirs. Recently, however, using the SAGD technique, the process has proven its technical and economic viability in some Canadian carbonate reservoirs.
- Steam flooded reservoirs should be as shallow as possible because of excessive heat losses in the wellbore and the difficulty of pressure maintenance for sufficient injection rates.
- The cost per incremental barrel of oil is usually high.
- Steam channeling could be problematic in some

| Type of EOR | Pros | Cons |
|--|--|--|
| Steam flooding | High recovery factors (50-60% oil in place (OIP)) | <ul style="list-style-type: none"> • High surface facility cost • Requires special safety measures • Depth limited to <4,500 ft • Applicable to onshore fields only |
| SAGD | <ul style="list-style-type: none"> • High recovery factor (up to 60% OIP) • Widely tested and used | <ul style="list-style-type: none"> • Mainly oil sand • Requires high vertical permeability (Kv) • High energy and water intensive • Applicable to onshore fields only |
| In Situ Combustion | <ul style="list-style-type: none"> • Proven track record • Used for wide range of crudes | <ul style="list-style-type: none"> • Safety issues • Low success rate • Gas override • Viscous fingering • Operational issues (plugging, sand and wax production, corrosion, emulsion, acidic water) • No proven for carbonate reservoirs • Applicable to onshore fields only |
| In Situ Steam Generation (Exothermic Reaction) | <ul style="list-style-type: none"> • High recovery factor (twice as high as steam flooding) • Reduced footprint • Cost-effective/Uses less manpower • Safety (downhole, so no surface exposure) • Combines thermal and gas flooding • Maximizes heat delivery efficiency and minimizes heat losses • Improves matrix permeability, • Independent of reservoir depth (deep/shallow); works in onshore and offshore fields | <ul style="list-style-type: none"> • Requires special handling |

Table 1. Pros and cons of thermal recovery technologies

heterogeneous reservoirs.

- An unfavorable mobility ratio may cause poor sweep efficiency.

In Situ Steam Generation Using Combustion

The most critical limitation to generating steam at the surface, transporting it to the wellhead and then injecting it downhole is the heat loss; this can seriously hamper exploitation of heavy oil resources in an economically viable manner. The other major issue is that the current conventional steam injection technology cannot be applied to relatively deep resources. Therefore, it makes perfect sense to concentrate on developing tools and techniques to generate steam downhole, thereby overcoming or avoiding these limitations.

Hart (1982)³ presented a comparative evaluation of the following surface and downhole steam generation techniques:

- Low-pressure combustion steam generators.
- High-pressure combustion steam generators using air as the oxygen source.
- High-pressure combustion steam generation techniques using pure oxygen in the combustion process.

From an efficiency viewpoint, the study concluded that downhole steam generation technologies appear to be superior to surface steam generation technologies when used with uninsulated injection strings in deep, low injectivity reservoirs, whereas the surface uninsulated system is preferred over the downhole techniques for high injectivity reservoirs of less than 1,100 m in depth.

Many types of downhole steam generation techniques are available commercially; however, the choice of technique must be based on reservoir depth, formation injectivity and targeted heavy oil properties. One needs to be careful because not all available downhole steam generation techniques qualify for all applications. Castrogiovanni et al. (2011)⁴ presented an overview of the benefits and technical challenges of downhole steam generation techniques for thermal enhanced oil recovery/improved oil recovery (EOR/IOR). They highlighted the importance of developing downhole steam generation techniques to target the many reservoirs around the world that can benefit from the technology. They also described a new downhole steam generation technique that operates with natural gas and several oxidizer/diluent combinations and stoichiometries. A typical implementation scenario used inert gas or CO₂ along with the steam front to drive the reduced viscosity oil toward a producer well.

In Situ Steam Generation Using Chemical Reaction

The current method of generating in situ steam using chemical reaction — EXO-Clean — is believed to improve the effectiveness of steam injection by minimizing steam losses and cost. Moreover, the method can be applied to produce deep heavy oil reservoirs that cannot be produced with traditional steam injection methods, Fig. 1. Also, because no oxidation reaction takes place during the treatment, the treatment should be safer compared to existing technologies.

It is well-known that steam injection cannot be applied to deep heavy oil reservoirs. The new technique relies on in situ steam generation for the thermal recovery of deep heavy oil. Among other benefits, the new technology minimizes the injected heat lost to the overburden, substratum and hot water zone that usually occurs with traditional steam flooding. The generated nitrogen also increases the heated area and reduces the steam-to-oil ratio, thereby improving oil production.

In the newly developed method, exothermic reactants are incorporated with injected water to generate heat and pressure in situ. Both thermal and mechanical forces are used to mobilize the heavy oil, thereby improving production. Exothermic reaction results, in terms of heat and pressure generated using

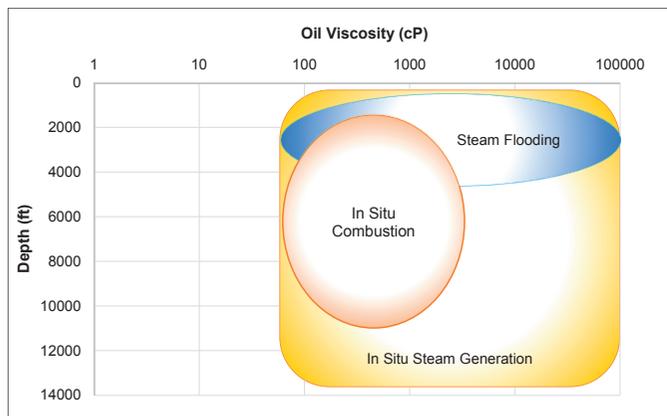


Fig. 1. Application profile of in situ steam generation compared with other thermal recovery methods.

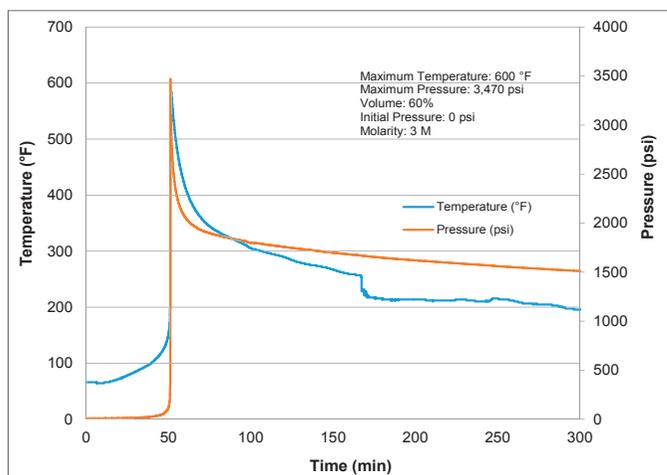


Fig. 2. Heat and pressure profiles generated by in situ chemical reaction (EXO-Clean).

the EXO-Clean, are depicted in Fig. 2. This test was conducted using an autoclave system. As the reaction took place, in situ temperature and pressure increased from room conditions to 600 °F and 3,470 psi, respectively. The generated downhole reaction temperature can be designed, set from 100 °F to 600 °F, depending upon well conditions. The generated downhole pressure can also be designed, set from 500 psi to 5,000 psi. Higher pressures can also be generated if downhole fracturing is required.

The overall potential benefits of this technology include:

- Provides a new thermal recovery method to improve heavy oil production.
- Maximizes heat delivery efficiency and minimizes heat losses.
- Can be used to induce fractures for an improved drainage radius.
- Can be applied to deep heavy oil and tight oil reservoirs.
- Can be applied to both onshore and offshore fields.
- Offers a low cost, less labor intensive delivery of thermal energy in the reservoir (no steam plant and facility are needed).
- Reaction byproducts do not contain any damaging materials or residual leftovers.
- Presents minimum safety issues — it occurs downhole, so there is no surface exposure.
- Has a reduced footprint, is environmental friendly, requires no generators, and produces no toxic emission.

COMPARISON BETWEEN STEAM FLOODING AND EXO-CLEAN

The evaluation of downhole steam generation is based on the thermal heat generated by the chemical reaction of EXO-Clean, which is 144,000 KJ/BL. To evaluate the efficiency and feasibility of this technology, a case study that modeled and compared data from actual energy injected by steam flooding and data from calculations — based on the same volume injected by chemical reaction — was conducted. Table 2 shows the data

| | |
|---------------------------------|-----------------|
| Barrel of Steam Injected | 3,600 (B/D) |
| Oil API | 13° |
| Porosity | 43% |
| Permeability | 2D |
| Space | 145 acres |
| Patterns | 7 spot inverted |
| Oil-to-Steam Ratio (assumption) | 0.2 |
| Steam Quality (assumption) | 75% |

Table 2. The actual steam flood field data used in the model

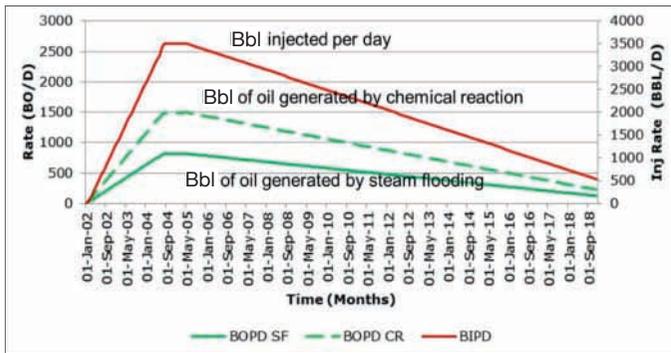


Fig. 3. Comparison of oil production from steam flooding and in situ chemical reaction.

and assumptions for the oil field, where the steam quality is 75%, the oil API is 13°, and the oil-to-steam ratio is 0.2.

Based on the BTU delivered from the reaction, it was determined that 1 bbl of the reaction is equivalent to 1.82 bbl of steam injected per day at the given oil field conditions. Figure 3 presents comparisons of the same volumes of steam and chemical reaction with corresponding oil production. The oil production when chemical reaction is used for in situ steam generation is about double the oil production of super quality steam flooding.

In steam flood operations, generators are put in place to provide steam to the field. These generators are bulky and costly, and they require filtered water for feed-in to convert to steam. The water has to be treated before entering the generators to avoid blocking, scaling and rusting. This adds to the facility cost. The generators also require fuel to operate, which further increases the cost and has an adverse environmental impact due to its CO₂ emissions.

To ensure maximum thermal delivery to the reservoir, the steam quality must be high, over 65%. Steam loss occurs at four stages:

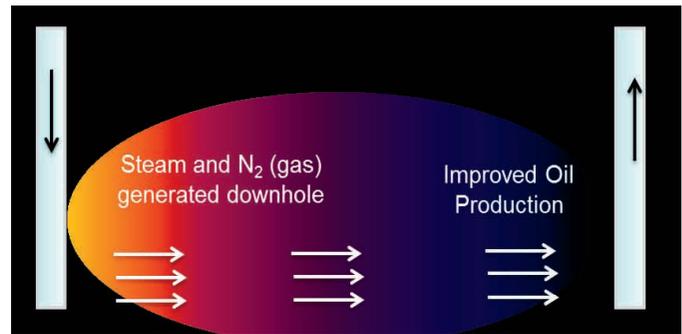


Fig. 4. Illustration of heavy oil flooding using in situ steam generation.

1. In the steam generators
2. In the steam pipes and during distribution
3. In the wellhead
4. In the wellbore and reservoir

In situ steam generation using chemical reaction eliminates the first three stages where steam is lost, which means it has the highest impact in terms of delivering heat to the reservoir. Therefore, using chemical reaction to generate steam will almost double production at a lower cost. Figure 4 is an illustration of in situ steam generation.

INDUCED FRACTURE TESTING

A shale block sample from Mancos was used for this test. A drilled vertical open hole, 2" long and 1½" in diameter, simulated a vertical well. In this test, the reactive chemicals were injected first. Then the block was placed in an oven at 200 °F for a set time to simulate downhole temperature recovery of the wellbore. After three hours, a chemical reaction took place and multiple fractures were created, Fig. 5. The breakdown pressure for this test was 6,600 psi. The physical and mechanical properties of the rock samples were as follows: porosity = 3.8%, bulk density = 2.50 gm/cc, Young's modulus = 2.66 × 10⁶ psi, Poisson's ratio = 0.20, uniaxial compressive strength = 4,965 psi, cohesive strength = 1,268 psi, and internal friction angle = 36°.

as follows: porosity = 3.8%, bulk density = 2.50 gm/cc, Young's modulus = 2.66 × 10⁶ psi, Poisson's ratio = 0.20, uniaxial compressive strength = 4,965 psi, cohesive strength = 1,268 psi, and internal friction angle = 36°.

FIELD CASE: IMPROVING INJECTIVITY

A decrease in injectivity had been observed in one disposal well in a Saudi Arabian oil field. The disposal well is used for getting rid of produced water that has been separated from oil. The water disposal system is also part of the hydrocarbon recovery system. Failure to successfully inject produced water into a

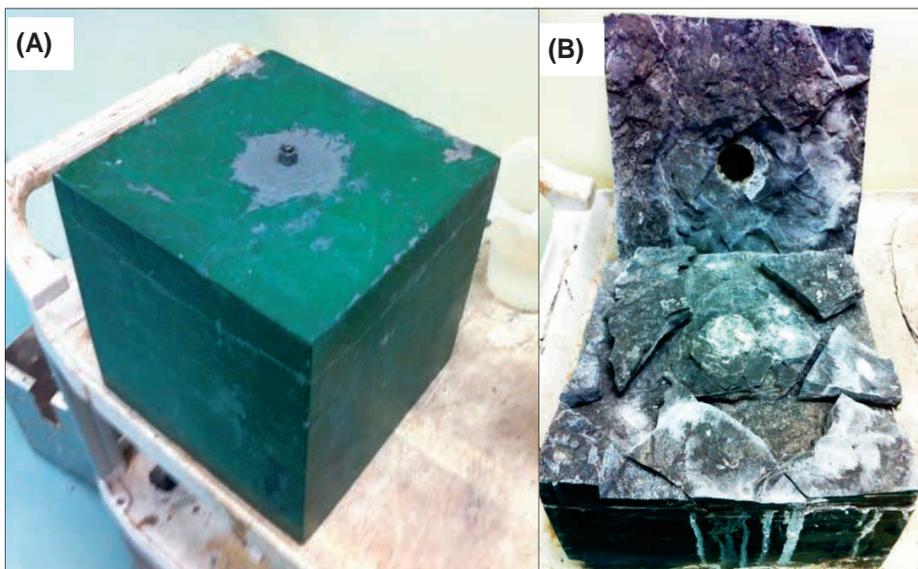


Fig. 5. (A) Pre-treatment and (B) post-treatment shale block sample, used to test chemical reaction for pulsed fracturing.



Fig. 6. Collected sludge sample from the injection line of the damaged disposal well.

disposal well will restrict oil flow in production wells and impact crude oil production⁵. To identify the type of damaging precipitates in the disposal well and determine an effective treatment recipe, a sample was collected from the well injection line, Fig. 6. The sample was a thick sludge, a mixture of many materials, with a dark oil color. The objective of this study

was to design a proper treatment to remove the sludge material from the disposal well and restore its injectivity.

Damaging deposits in disposal wells are usually a mixture of organic and inorganic materials. An accumulation of corrosion products and scales along with organic deposition in the wellbore tubing or in the near wellbore area may restrict water injection and result in partial or total loss of injectivity.

In the selected well, the sludge material was found to be filling the wellbore area, both restricting the perforated zone and damaging the near wellbore area. A treatment procedure was designed to treat the well with two stages of in situ steam generation. The first stage was designed to remove the sludge material from the wellbore tubing and to remove formation damage occurring in the perforated zone. The second stage was designed to remove damaging material from the matrix and restore injectivity.

The objectives of this study were twofold: (1) Determine the nature of the sludge material obtained from the disposal well injection line, and (2) conduct an in situ steam generation treatment to remove the sludge deposition from the wellbore and from the near wellbore injection formation, thereby restoring well injectivity.

Lab Testing

The laboratory analyses of the heterogeneous sludge sample, using extraction and scanning electron microscopy and energy dispersive X-ray spectroscopy, indicated that the sludge composition was mainly corrosion products (iron oxide and sulfides) and hydrocarbon material (asphaltene), as well as sodium chloride, calcium carbonate and silica, Table 3.

Based on the analyses results, the well's low injectivity was attributed to the deposition of primarily asphaltene and corrosion products solids. To restore well injectivity and remove

| Component | Wt% |
|-------------------|------|
| Asphaltene | 11.3 |
| Iron Oxide | 32.4 |
| Iron Sulfide | 21.6 |
| Sodium Chloride | 16.5 |
| Calcium Carbonate | 9.9 |
| Silica | 8.3 |

Table 3. Compositional analysis of sludge material

this damaging material, an in situ steam generating system was used to dissolve the solids and provide in situ pressure to flow back the dissolved product. Based on the lab results, the well treatment to restore well injectivity was designed in two main stages:

- Wellbore tubular cleaning treatment to remove restricting material within the tubing.
- Near wellbore formation stimulation to remove the near wellbore damage.

The process consisted of injecting chemicals in the wellbore that would produce an exothermic reaction, thereby generating in situ pressure and heat pulses. The generated heat was expected to be sufficient to reduce tar or heavy oil viscosity, while the reaction generated nitrogen gas would provide lifting energy to flow back the well.

Viscosity Measurements

Prior to measurement of the viscosity and API of the sludge material, it was mixed thoroughly in a high speed blender to ensure homogeneity, Fig. 7. A low API of 13 and a high viscosity of 2,000 cP (non-Newtonian behavior) confirmed that the sludge sample was semi-solid in nature. The viscosity of the



Fig. 7. Sludge sample after mixing.

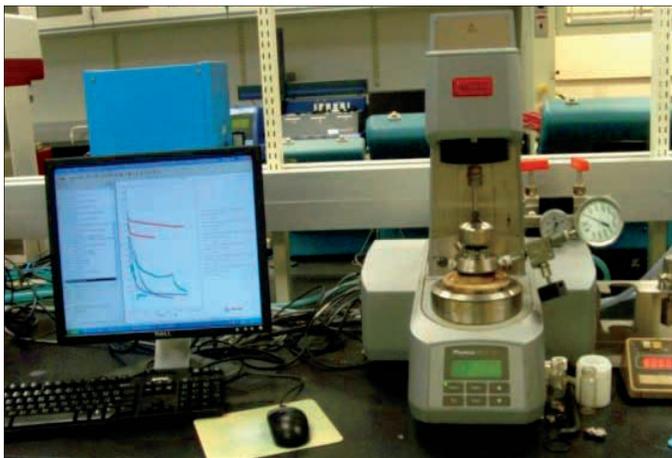


Fig. 8. Anton Paar rheometer.

collected sample was generally very high compared to the virgin crude viscosity of Arab Heavy crude oil.

An Anton Paar rheometer, Fig. 8, was used to determine the effect of an exothermic reaction on the sludge material viscosity. The viscosities during the chemical reaction were measured using a temperature-controlled pressure cell to avoid evaporation of light-end hydrocarbons while heating the crude. The sample was first allowed to equilibrate at a set temperature for 10 to 15 minutes. The viscosity of the sample was then measured as a function of shear rate. The sludge sample was next mixed with an in situ steam generation system and placed inside the pressure cell. Viscosity was measured as heat was generated by the chemical reaction. As shown in Fig. 9, the sludge viscosity was reduced from 5,800 cP down to 700 cP as the cell temperature increased from room temperature to 220 °F.

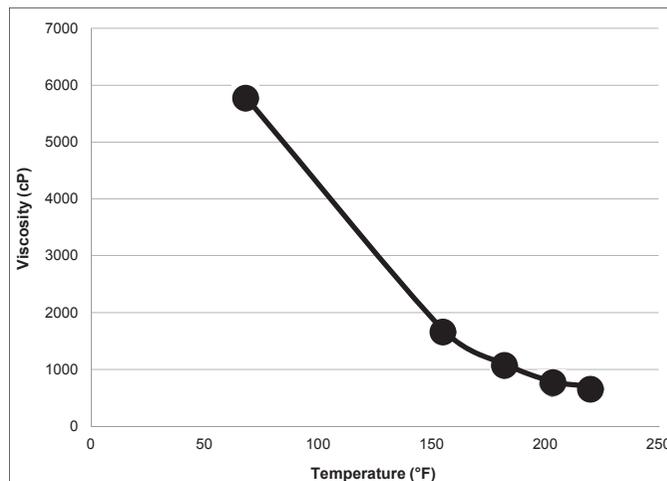


Fig. 9. Viscosity of sludge sample mixed with EXO-Clean.

Autoclave Reactor Testing

Two autoclave reactors, Fig. 10, were used to study the reaction kinetics of the selected chemicals. One system is rated up to 10,000 psi and 500 °C with a total volume of 3 liters, and the other is rated up to 20,000 psi with an 80 milliliter volume. Experiments were carried out in a dedicated, specialized, high pressure, high temperature laboratory equipped with the required safety features. The experimental parameters were controlled and monitored remotely. Real-time pressure and temperature data were recorded every two seconds to measure the resulting pressure and temperature behavior during the chemical reaction. This testing phase was performed to simulate the pressure and temperature changes that were an-

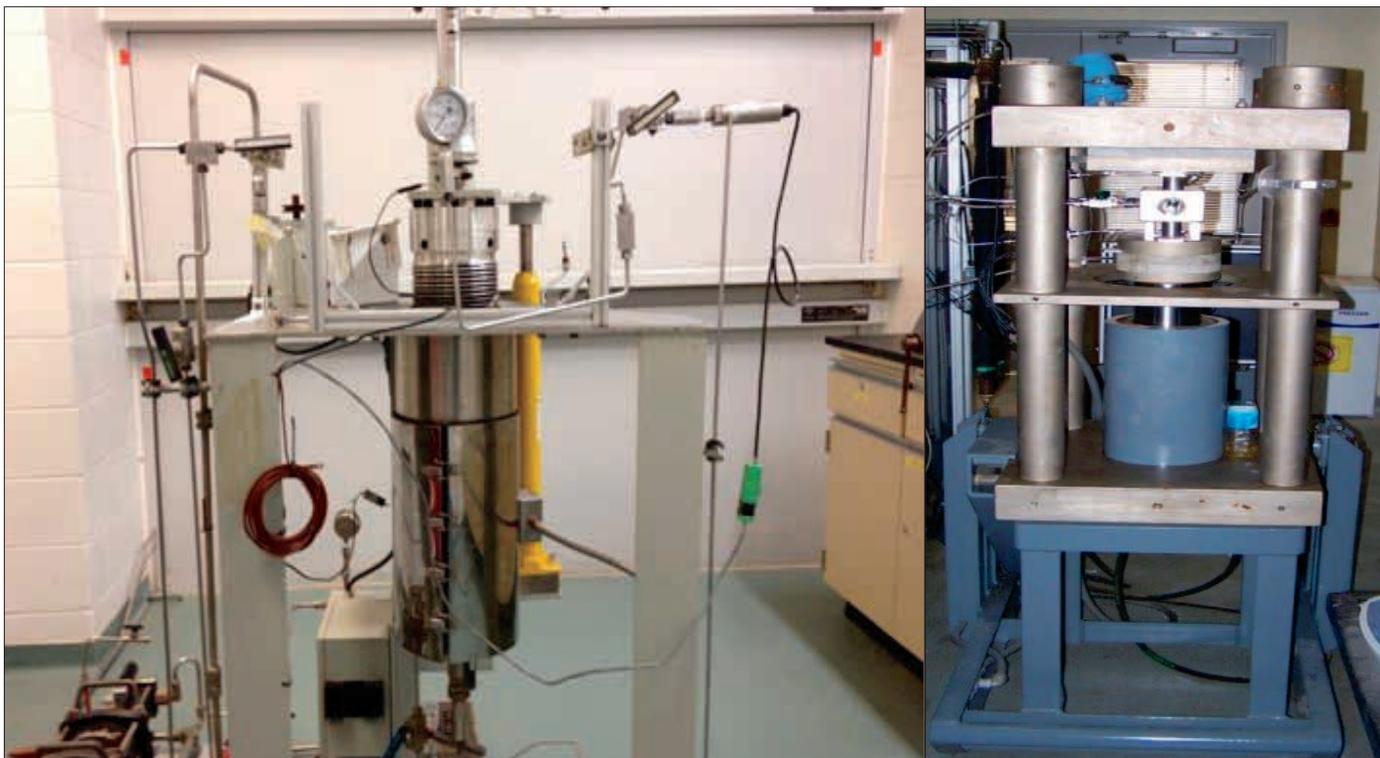


Fig. 10. Two autoclave systems rated up to 10,000 psi (left), and 20,000 psi (right).

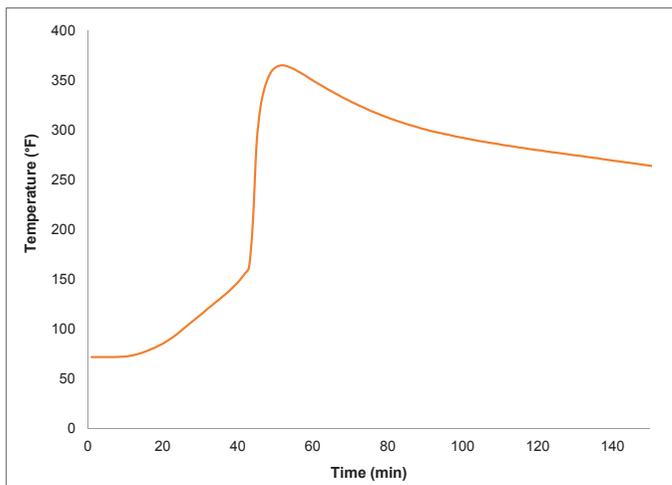


Fig. 11. Temperature profile of EXO-Clean reaction.

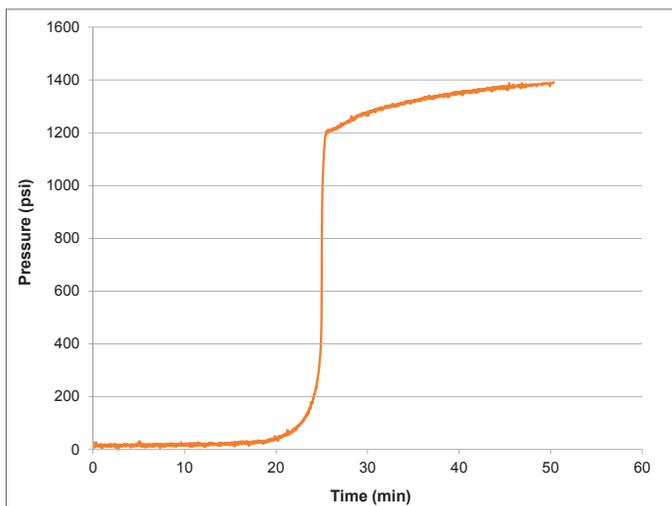


Fig. 12. Pressure profile of EXO-Clean reaction.

anticipated to occur in a given wellbore as a result of injecting the chemicals and triggering the reaction. Figures 11 and 12 show the temperature and pressure profiles, respectively, of the EXO-Clean reaction tested in the lab. The same chemical formula was used for the disposal well treatment. Figure 13 is an actual photo of the bench scale test of the exothermic reaction (EXO-Clean).

Well Information

The disposal well was drilled and completed as a vertical 7" cased hole well in 1981. The perforated interval was from 5,550 ft to 6,060 ft, and the total depth was at 6,112 ft. Production logging showed an injection rate of 6,500 barrels of water per day at 1,000 psig injection wellhead pressure (WHP). The well performance was monitored by conducting production logs and injectivity tests annually. All injectivity tests indicated that a positive skin factor existed in this well. Many workovers were performed to remove the damage and improve injectivity, but with no success.

Treatment Procedure to Restore Injectivity

Based on the results of the previous analyses and solubility tests, the well's low injectivity was attributed to the accumulation of asphaltene and corrosion products solids. To restore well injectivity, a chemical was required to remove the hydrocarbons, and an acid was needed to dissolve the iron compounds. Because the sludge material was plugging the wellbore and the perforated zone, the tubular had to be cleaned up first, followed by the near wellbore formation damage removal. The treatment procedure was designed as follows:

1. Conduct injectivity test using brine and identify initial well injectivity.
2. Inject 80 bbl of treatment fluid (exothermic reactants) to treat the wellbore tubular.
3. Once the reaction starts to take place, indicated by temperature and pressure increases, set the soaking time for three hours.
4. Displace the chemicals with brine.
5. Flow back to release the generated pressure and remove the sludge material.
6. Inject 300 bbl of treatment fluid (exothermic reactants) to treat the near wellbore area. Squeeze the chemicals inside the formation and watch the WHP. Give the reaction three hours of soaking time.
7. Flow back the well to remove the damaging material.
8. Inject acid treatment to dissolve inorganic scale, displace the acid with brine, and then flow back the well to remove all injected acid.
9. Put the well back on injection and test for injectivity.



Fig. 13. Bench scale test of exothermic reaction (EXO-Clean).

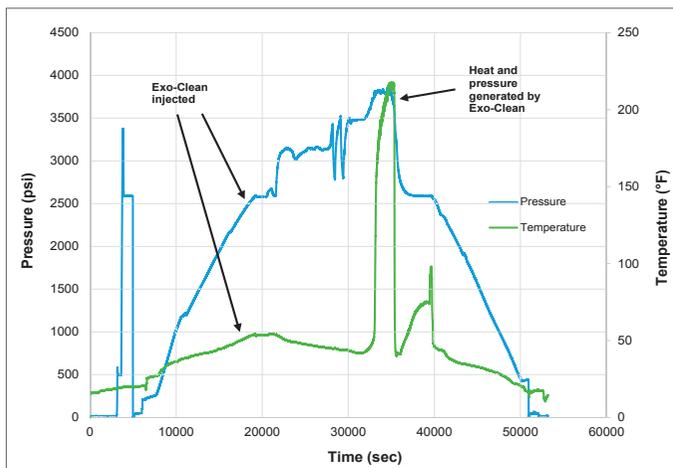


Fig. 14. First stage injection of exothermic reaction chemicals.

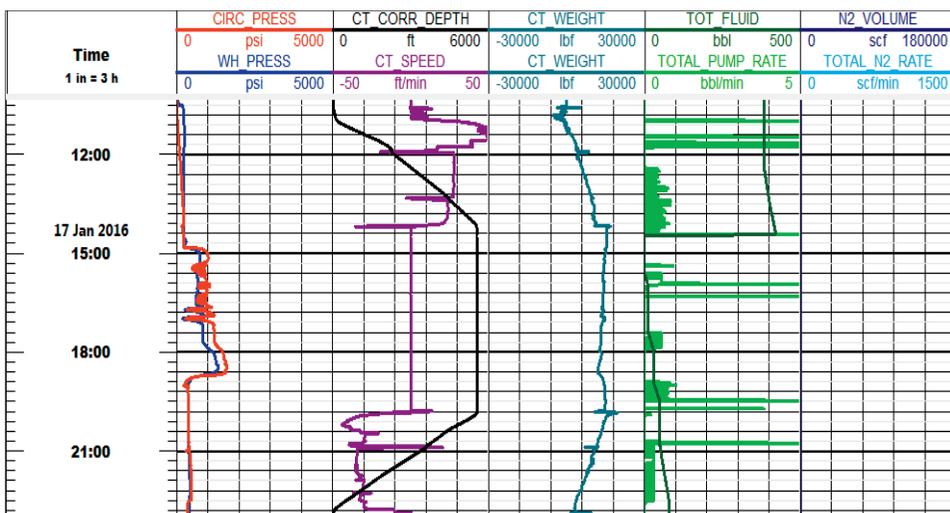


Fig. 15. First stage CT run with memory gauge.

First Stage: Wellbore Cleanup

The first stage treatment was designed to clean up and remove sludge material from the wellbore tubular as well as from the perforations. Prior to the treatment, an injectivity test was conducted to measure initial injectivity for subsequent comparison with the final one. Coiled tubing (CT) was used to

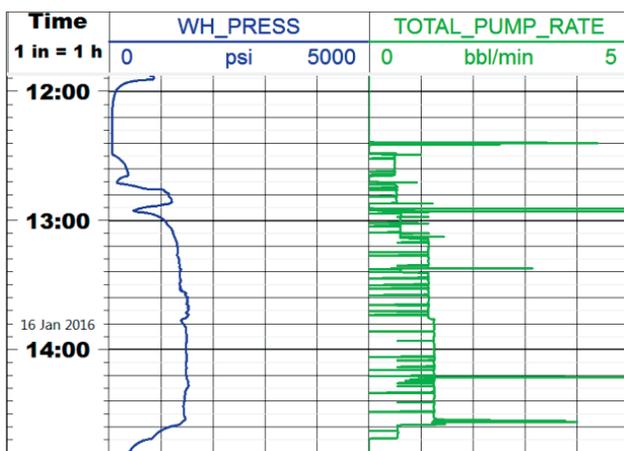


Fig. 16. Injectivity test of disposal well after the first stage treatment.

place the chemicals for reaction generating steam. While running in hole (RIH), however, the CT couldn't reach the perforated interval due to the plugging material and stopped at 5,546 ft. So, the chemicals were circulated above the damaged perforated zone. As shown in Fig. 14, the downhole pressure and temperature before injection were 2,600 psi and 130 °F, respectively. As 80 bbl of the chemicals were injected, the wellbore temperature fell to 110 °F. Then, as the reaction started to take place, the temperature increased to 420 °F and the WHP increased to 3,800 psi. The chemicals were given three hours soaking time. The generated in situ heat was enough to solubilize the sludge materials. Then the well was flowed back using the in situ generated pressure. During the flow back, sludge material was observed and disposed of in the dumping yard.

First Stage CT Run with Memory Gauge

Figure 15 shows the log of the first stage CT run with a memory gauge. After the CT was RIH to 5,546 ft, an injectivity test was conducted, Fig. 16. The maximum rate achieved was 1.4 barrels per minute (bpm) at 1,467 psi. The CT was tagged at 5,546 ft, and 80 bbl of exothermic reactants were injected.

Second Stage: Near Wellbore Damage Removal

Prior to the second stage chemical treatment, the downhole pressure and temperature were measured at 2,600 psi and 130 °F, respectively. Using CT, 300 bbl of the treatment chemicals were then injected at the perforated zone and squeezed inside the formation. As the reaction took place, pressure and

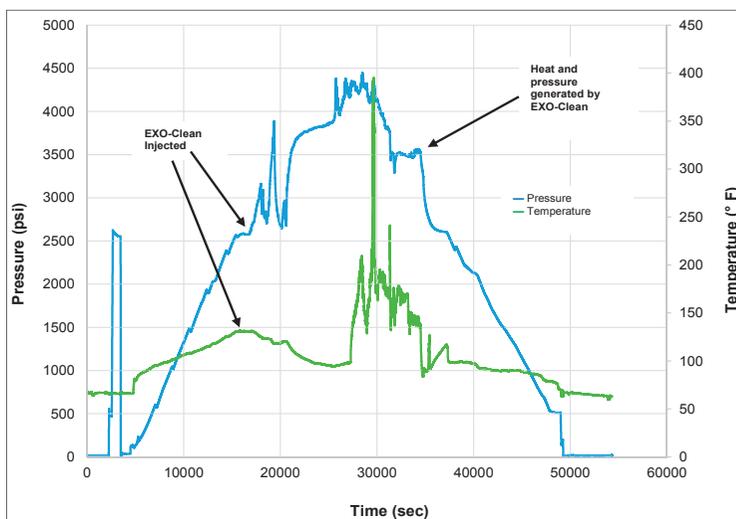


Fig. 17. Second stage injection of exothermic reaction chemicals.

temperature increased up to 4,400 psi and 400 °F, respectively, Fig. 17. During this stage, most of the reaction was pushed to take place inside the formation. The reaction was set for three hours soaking time. Then the well was flowed back. Sludge materials were observed, Fig. 18, during the flow back and disposed of in the dumping yard, Fig. 19. Acid was then used to remove the inorganic scale and corrosion products. Afterward, an injectivity test was conducted to assess treatment effectiveness.



Fig. 18. Collected flow back sample showing viscous hydrocarbons.



Fig. 19. Dumping yard for disposal of heavy hydrocarbons.

Second Stage CT Run with Memory Gauge

Figure 20 shows the the log of the second stage CT run with a memory gauge, which was again tagged at 5,546 ft. An injectivity test conducted before pumping the exothermic reaction chemicals showed that the maximum rate achieved was 2.1 bpm at 386 psi WHP, Fig. 21. A total of 300 bbl of exothermic chemicals were pumped followed by a three-hour soaking time.

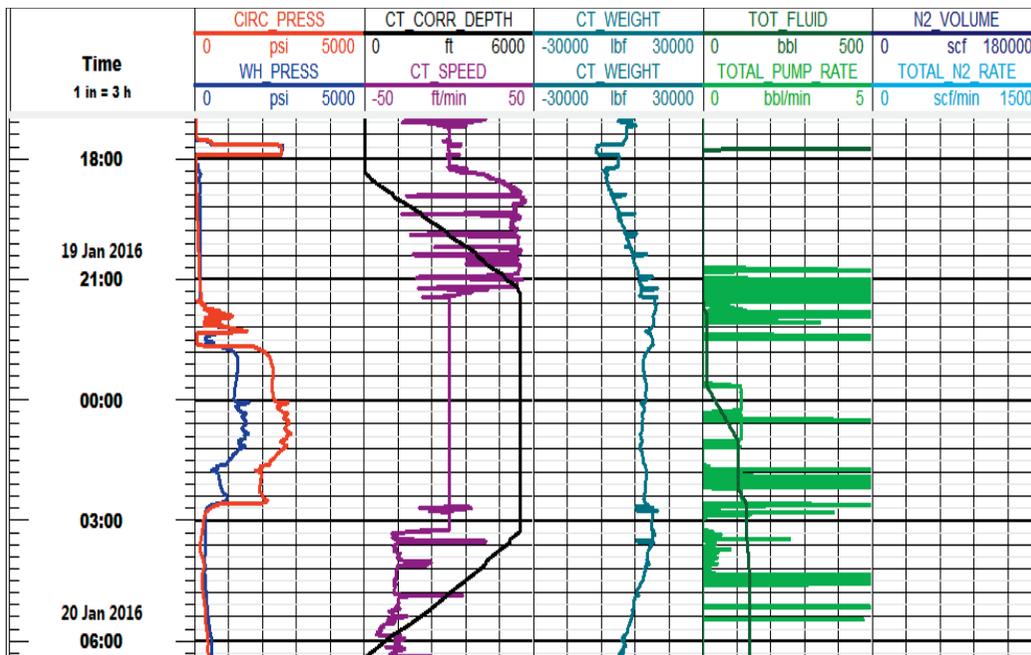


Fig. 20. Second stage CT run with memory gauge.

Nitrogen Lift

After all treatment stages were completed, nitrogen lift was applied to remove any remaining treatment fluid or viscous material from the well. Nitrogen was pumped at 500 scf/min. The nitrogen lift was followed by the final injectivity test, where the maximum rate achieved was 3.56 bpm at 1,391 psi.

CONCLUSIONS

Saudi Aramco successfully conducted the first field trial of an in-house technology using exothermic reaction chemicals to improve injectivity of a water disposal well from 1.0 Mbpd to 5.8 Mbpd at 1,500 psig flowing WHP. The well had been suffering from poor injectivity due to downhole obstruction and formation damage. The EXO-Clean employs two reacting chemicals with predesigned exothermic chemistry triggered by either an increase in temperature — as in downhole conditions

— or a low pH achieved using weak acid. The reaction was carefully designed for this well to trigger a specific heat level (420 °F) and nitrogen gas pressure (4,425 psig), thereby breaking down and lifting most of the damaging elements in the near wellbore region.

The well injectivity was significantly increased. When comparing the WHP before the treatment to the post-treatment WHP, it was found that injectivity had improved sixfold.

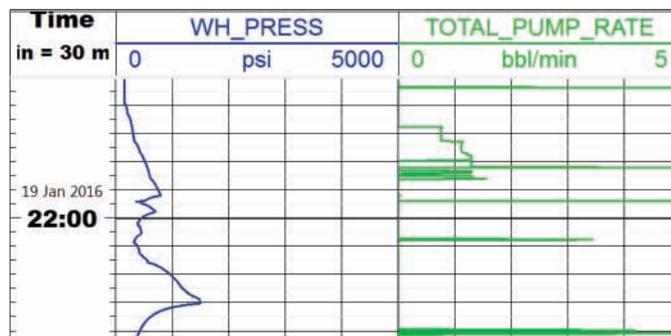


Fig. 21. Injectivity test of disposal well post-second stage treatment.

Disposal Wells in Saudi Arabia: Case Studies,” IPTC paper 16595, presented at the International Petroleum Technology Conference, Beijing, China, March 26-28, 2013.

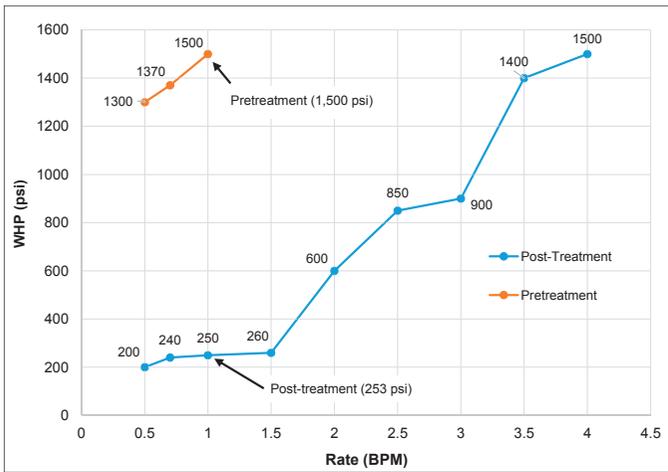


Fig. 22. Injectivity tests pre- and post-EXO-Clean treatment.

The WHP decreased from 1,500 psi to 253 psi, Fig. 22. This demonstrates how tremendous the exothermic reaction treatment improved well injectivity.

ACKNOWLEDGMENTS

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BIOGRAPHIES



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In 2015, he successfully finished a one-year business assignment as a Production Engineer at the Safaniyah field. Following that, in 2016, he joined the Artificial Lift Team and is currently working on high impact technologies like cable-deployed electrical submersible pumps (CDESPs) and a shallow-set subsurface safety valve for CDESPs. Mohannad is also leading EXPEC ARC's efforts for ESP intelligent data analytics.

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Mohammad has coauthored several training modules for coiled tubing (CT) operations, a number of Society of Petroleum Engineers (SPE) papers, and the documentation of InTouch Best Practices.

He is currently involved in several joint projects between Schlumberger and Saudi Aramco where he uses his expertise in CT and stimulation.

In 2000, Mohammad received his B.S. degree in Chemical Engineering from Gadjah Mada University, Yogyakarta, Indonesia.

First Worldwide CT Stimulation of a Quad-Lateral, Extended Reach Power Water Injector Using a Multilateral Tool with Gamma Ray and Distributed Temperature Survey

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ABSTRACT

The studied well was first drilled as a single lateral power water injector, then sidetracked as a multilateral injector with a total reservoir contact of 23,094 ft. The well was completed with three new laterals, all placed up-dip in the water leg. This geometry was specifically intended to increase the well's injection potential and provide more pressure support in the lower transmissibility areas of the well's complex carbonate field.

This article discusses the coiled tubing (CT) accessibility challenges faced, technology deployment and lessons learned during the stimulation of the first quad-lateral, extended reach power water injector ever drilled in the selected study area in Saudi Arabia. A power water injector is used to increase a well's injection capacity and provide extra support to reservoir pressure.

Due to the challenges posed by the extended reach well trajectory, technology unavailability and the need to effectively access all four laterals and properly identify each to stimulate them later, CT with real-time downhole monitoring was used in conjunction with a multilateral tool (MLT). The MLT was used to provide controlled, oriented mapping that enabled the CT to access each lateral independently. The indication that the correct lateral had been accessed was confirmed by downhole pressure drops across the MLT. As all the laterals are extended reach, getting to total depth (TD) was challenging for some of the laterals, even after implementing all the reach techniques. To more efficiently identify which lateral was accessed, an innovative method was developed using a gamma ray (GR) tool and casing collar locator (CCL) to properly identify each lateral without having to reach TD.

Once the proper lateral was accessed and confirmed, the acid treatment placement was pinpointed and optimized by a distributed temperature survey (DTS), which helped determine in real time the locations of high permeability thief zones and tight or damaged zones. The treatment schedule was designed to divert treatment acid from high intake zones using a visco-elastic surfactant diverting acid system, followed by hydrochloric

(HCl) acid for stimulation. The intervention was completed successfully without any safety incidents. The use of GR, CCL and downhole pressure and temperature measurements, made in conjunction with the MLT, proved to be the ideal method for lateral access and lateral confirmation, especially when reaching TD was not feasible due to CT lockup. In addition, the use of a DTS for optimum stimulation placement was key to improving operation efficiency.

The methods described in this article, which shows how downhole measurements such as pressure inside and outside the CT and its differential, as well as CCL, GR, MLT and DTS data, can be used in multilateral wells, have proven to be a major success. This intervention, the first of its kind, has opened up new innovative ways and techniques to confidently stimulate all the multilateral extended reach wells in Saudi Arabia.

INTRODUCTION

Water injection is part of the secondary hydrocarbon recovery used to balance the reservoir fluid's volume as it is withdrawn so as to restrict the rate of production decline. To achieve a good sweep of oil across the pay zone, proper water injection across the interval of interest is required. This can only be achieved by stimulating the injector wells to gain a more uniform injection profile.

Water injector wells are usually drilled peripherally, at the edge of the reservoir, with injection done to an aquifer that shows limited mobility. This injection can take place either in the same layers that are horizontally continuous with oil producers or below the oil-bearing zone. The water injected is either seawater or previously produced formation water.

Carbonate reservoirs are complex due to their highly conductive fractures (fissures and faults), and wells drilled there require complex completions — such as horizontal, open hole or cased hole completions — with perforation and inflow control devices. Due to these wells' complexity, acid placement during stimulation is a challenge and pinpointing the treatment at the

right place becomes very important.

In Saudi Arabia, several wells have been horizontally drilled, and then sidetracked and completed as multilateral wells. Interventions in these wells using conventional coil tubing (CT) can only be conducted in the motherbore lateral (L-0). Wellbore laterals can be accessed with conventional CT by using a downhole multilateral tool (MLT); however, it is often ambiguous which lateral has been accessed. These multilateral wells become even more complex when they have half of their laterals in the cased hole and half in the open hole, when the CT locks up before reaching total depth (TD) or when TD between laterals is the same, which limits the capability to confirm a lateral has been accessed by tagging the well end. Under these circumstances, the use of conventional CT that is not equipped with downhole measurements could result in directing stimulation at the wrong lateral¹.

To overcome the challenges that constrain conventional CT in this type of well, the conveyance advantage of CT can be leveraged by adding instruments to make real-time downhole measurements. This is possible by using downhole sensors within the intervention tool string that connects to the surface via a fiber optic line, which acts as a telemetry conduit²⁻⁴. The fiber optic itself brings an additional advantage as it can also be used for distributed temperature survey (DTS) purposes during the intervention⁵.

The sensors available for real-time monitoring can measure pressure inside and outside the tool string, which enables MLT performance monitoring, and temperature at the tool string, which allows DTS measurements. A casing collar locator (CCL) provides depth correlation in the cased section of the wellbore, and a gamma ray (GR) tool enables lateral identification and depth correlation in the open hole.

The GR tool plays an important role because it is required to identify the accessed lateral prior to the intervention. By using GR to acquire a profile in each lateral, it is possible to match those profiles with the initial reference logs of the laterals to determine the tool string location.

Once access is confirmed, the acid stimulation can be conducted while monitoring the DTS profile to decide on the most appropriate acid placement technique.

The case study presented in this article describes the acid stimulation intervention performed with a real-time CT downhole measurement system in the first quad-lateral, extended reach power water injector well drilled in Saudi Arabia. The case presents the novel methodology utilized for lateral access identification and the process followed to pinpoint the acid stimulation.

FIELD DESCRIPTION

The well in this case study is part of the secondary hydrocarbon recovery system for three fields in the Central Region. The three fields have the same drive mechanism: the aquifer is weak and the primary reservoir depletion mechanism is solution

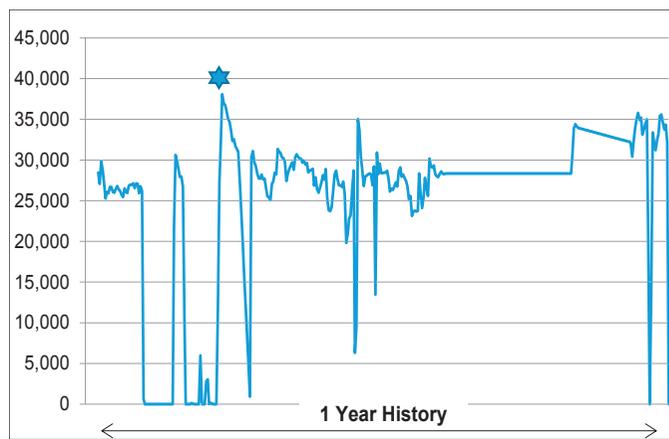


Fig. 1. Injection history for Well-A.

gas. So, water injection is indispensable for reservoir pressure maintenance.

The injection rate history for this quad-lateral well, Well-A, is presented in Fig. 1, which highlights the increase in injectivity achieved as a result of the stimulation discussed in this case study.

WELL DETAILS

Well-A is a quad-lateral, open hole water injector that was initially drilled and completed as a single lateral (motherbore or L-0) well with an open hole section of 5,069 ft. Its history showed that it was acidized using CT with 4,550 bbl of an acid system — including 20% hydrochloric (HCl) acid and additional diverting fluid systems — within the same year after drilling. Injection remained stable over a period of two and a half years with an average injectivity index of 66 bbl per day/psi. A new injection profile registered for the well showed that only 75% of the interval was contributing to injection, so a year later a decision was made to sidetrack the injector with multiple laterals placed up-dip in the water leg. The well was completed with three additional laterals (L-1, L-2 and L-3), Fig. 2. The true vertical depth of all the laterals was relatively the same, limiting the capability to utilize pressure readings from the downhole tool string as a means to identify which

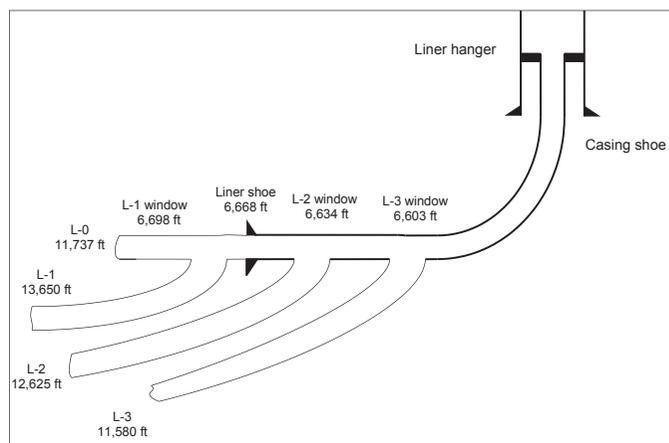


Fig. 2. Wellbore schematic showing three added laterals.

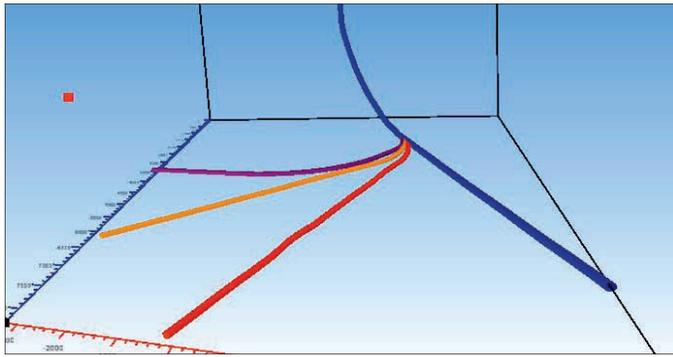


Fig. 3. 3D well diagram (blue: L-0, red: L-1, orange: L-2, purple: L-3).

lateral is being accessed; the 3D well diagram is shown in Fig. 3 as a reference illustrating the similar depth.

The strategy for increasing the well's injectivity was to use acid to stimulate the three laterals (L-1, L-2 and L-3) to remove the suspected damage from the drilling. The intervention would use a combination of a real-time CT downhole measurement system and a MLT. The stimulation was carried out one year after the multilateral completion was done.

The laterals L-2 (12,625 ft) and L-3 (11,580 ft) were sidetracked from windows inside the casing, while L-1 (13,650 ft) was sidetracked from the open hole section deeper in L-0. Based on the initial design of the CT reach for each of the laterals, it was anticipated that the CT would be unable to confirm lateral access by tagging TD, so the GR tool was added as part of the tool string to profile the well and compare those profiles to the reference logs prior to the stimulation treatment.

CT JOB DESIGN

The job was divided into multiple stages to evaluate first the lateral accessibility, then the CT reach for each lateral and finally the matrix stimulation to be executed. In addition, the monitoring of the lateral access and the stimulation was also identified as two separate steps.

Lateral Access

The first challenge in a multilateral well is to determine the access in each leg, so a mechanical tool that can enable successful conveyance in the correct leg is required. The means that is compatible with CT operations is a multilateral access tool or MLT.

The MLT consists of an orienting tool and a controllable bent sub, Fig. 4. The controllable bent sub has a linear signal sleeve with a profiling rate of 1.7 barrels per minute (bpm) to 2.2 bpm and with a 500 psi to 800 psi pressure signal drop.

The MLT is set up to turn 15° once the pump is activated to a flow

rate above 1 bpm and the pressure becomes constant. When the pump is stopped, all the pressure bleeds through the orienting tool, turning the MLT another 15° with a delay of 45 seconds to 1 minute. Therefore, at each pump cycle, the tool will turn 30°; 12 pump cycles would achieve a 360° turn.

Pumping through the tool creates a predetermined pressure drop. The mapping process is based on the identification of each pressure drop that occurs across the tool when it is moved uphole and a lateral is found. The tool is moved out of the hole 12 times while the unique pressure profile is recorded through a full 360°.

The MLT is operated with the assistance of software that enables the display of several essential parameters, such as pressure depending on the tool's orientation relative to a lateral window. It not only shows the current index of a MLT profile mapped for the window, but also shows previous indices, and so guides the operator through indexing cycles. This provides accurate real-time information on the downhole situation. After the window is profiled, the software memorizes the window orientation and monitors the orientation of the bottom-hole assembly (BHA) conveying the MLT, along with the downhole measurement system, throughout the entire operation, Fig. 5¹.



Fig. 4. MLT consisting of a controllable bent sub, movements depicted with arrows, and an orienting tool just visible behind it.

Lateral Access Monitoring

Performance of the MLT is based on pressure changes — pressure drops — that occur during the profiling process. In a conventional CT intervention, these pressure changes are mon-

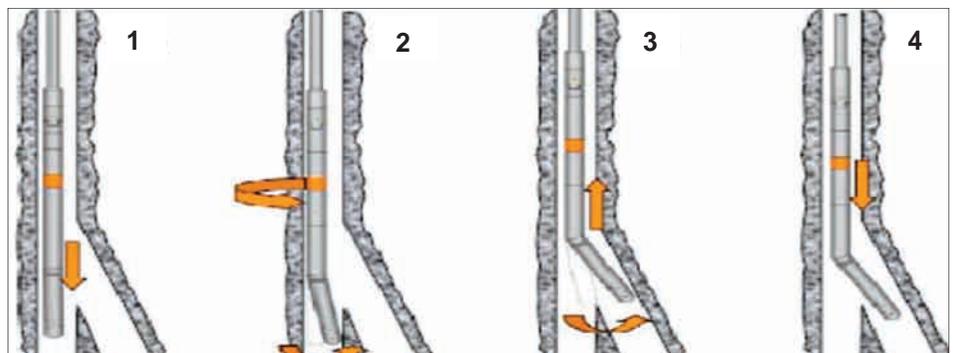


Fig. 5. MLT operation (1. Running across the junction, 2. Indexing, 3. Finding the lateral, 4. Accessing the lateral).

itored at the surface using pump pressure fluctuations while keeping a constant flow rate.

A real-time downhole measurement system with CT, as was selected for the intervention, relies on the downhole pressure signal inside and outside of the tool to better evaluate the performance of the MLT⁶.

The real-time downhole measurement system here consisted of CT with a fiber optic line inside that allows two-way communication between downhole tools and surface electronics. The downhole tool was comprised of a main sonde containing gauges to measure internal pressure and external pressure, as well as a device for point measurement of temperature. The tool was combined with a CCL and a GR tool that allow for a real-time depth correlation during the intervention. The system was fully compatible with the MLT and can be utilized in any CT intervention. A detailed diagram of the complete BHA utilized in the operation is displayed in Fig. 6.

CT Reach

Due to the complex wellbore diagram and results of the deviation survey, the CT was run individually for each lateral to determine the CT reach. Ideally, CT accesses the L-0 as a natural path, but this can change due to the CT's residual bending and tool-end orientation. All four laterals in the study well (L-0, L-1, L-2 and L-3) are highly deviated — 90° — which made the CT's ability to reach to the well's TD a major concern. To reach TD, several reach options can be considered, such as using a friction reducer (FR), nitrogen (N₂), fluid injection and a combination of the first two (FR+N₂).

A CT simulator was used to evaluate the forces acting in the CT pipe and to determine the maximum reach for each lateral. The results showed that L-0 and L-3 could be reached to TD only if FR+N₂ was used while run in hole (RIH), but the reach into L-1 and L-2 could be at most only 80% of the total open hole length.

Table 1 shows the results of the CT reach simulations. The final outcome was that it would not be possible to get 100% reach coverage, even using the different available techniques, so relying on the CT's capability to tag TD to identify the ac-

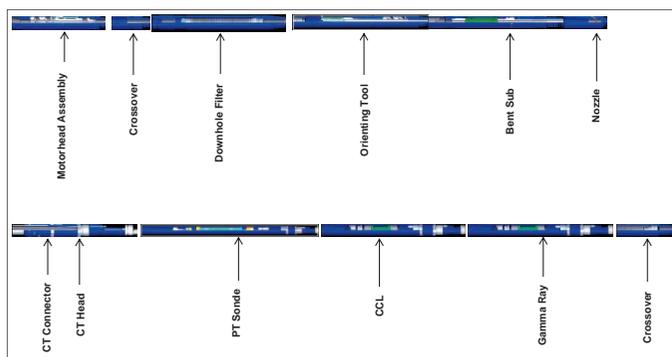


Fig. 6. BHA schematic showing MLT and downhole measurement system (the motorhead assembly includes check valves, circulation sub and hydraulic disconnect mechanism).

| CT OD 2.375" | Lockup | Reach (ft) | Interval Coverage |
|---------------------|--------|------------|-------------------|
| L-0 | | | |
| NO FR | Y | 10,508 | 76% |
| N ₂ | Y | 11,373 | 93% |
| Injection | Y | 10,989 | 85% |
| FR | Y | 11,469 | 95% |
| FR + N ₂ | N | 11,737 | 100% |
| L-1 | | | |
| NO FR | Y | 10,156 | 50% |
| N ₂ | Y | 10,901 | 61% |
| Injection | Y | 10,529 | 55% |
| FR | Y | 11,086 | 63% |
| FR + N ₂ | Y | 12,184 | 79% |
| L-2 | | | |
| NO FR | Y | 10,052 | 57% |
| N ₂ | Y | 10,706 | 68% |
| Injection | Y | 10,428 | 63% |
| FR | Y | 10,894 | 71% |
| FR + N ₂ | Y | 11,823 | 87% |
| L-3 | | | |
| NO FR | Y | 9,958 | 67% |
| N ₂ | Y | 10,616 | 81% |
| Injection | Y | 9,582 | 60% |
| FR | Y | 10,802 | 84% |
| FR + N ₂ | N | 11,580 | 100% |

Table 1. CT simulation reach results for all four laterals

cessed lateral was not a viable option.

Lateral Access Identification

As tagging TD was not possible for lateral identification, a different technique was decided on to identify the position of the CT after every attempt at lateral access. As part of the real-time downhole measurement system, the combination of CCL and GR tools provided a profile that could be compared to the well's reference logs, enabling identification of the accessed lateral without confirming TD.

With the use of the CCL while inside the liner shoe, it was possible to validate the following three conditions (see Fig. 2 for the liner shoe and each window's relative position):

- Loss of the CCL signal at the liner shoe, 6,688 ft (CT access in either L-0 or L-1).
- Loss of the CCL signal at the L-3 window, 6,616 ft to 6,603 ft (L-3 access).
- Loss of the CCL signal at the L-2 window, 6,647 ft to 6,634 ft (L-2 access).

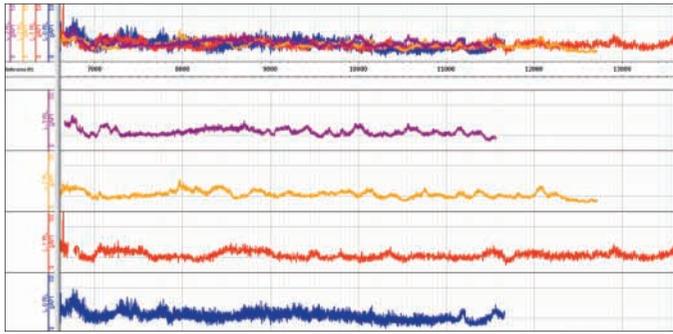


Fig. 7. Reference log for each lateral and the overlap of all four (top track).

With the use of the GR tool, the profile acquired with CT while running into the lateral was compared to each lateral's reference log to confirm the accessed lateral. Figure 7 shows the reference log for each lateral, as well as the overlap of the four laterals in the top track, highlighting that they are unique. These logs were used to identify CT access of a specific lateral.

Stimulation Monitoring

The major challenge of any matrix stimulation job is to understand where fluid injection is taking place. Due to heterogeneities in the reservoir rock across the different laterals, including changes in porosity, permeability and mineralogy as well as the presence of natural fractures, the placement of fluid requires the usage of diverting agents to allow acid to be directed toward the damaged zone.

The use of the real-time downhole measurement system previously discussed provided a real-time assessment that was used for determining the best fluid placement approach. The fiber optic line enabling telemetry between the downhole sensors and the surface electronics was used as a sensor to measure temperatures for the DTS across each lateral. When the CT was inside the lateral of interest, the DTS was used to measure the temperature at every meter along the interval, and the changes in temperature profile from a shut-in condition to an injection condition were used to assist in determining stimulation placement.

PROCEDURE

The job procedures were established based on the real-time data acquired during the intervention.

To enable lateral identification, the following steps were taken:

1. The CCL was logged every time the CT was RIH across a cased wellbore section.
2. The CCL signal was compared to the position of the liner shoe, L-3 window and L-2 window as a first approach to identifying the position of the CT in the wellbore.
3. The GR was logged every time the CT was RIH across an open hole section of the wellbore.

4. The GR profile acquired was compared to the GR reference log of each lateral to find the profile overlap that identified the accessed lateral. It was anticipated that each lateral could be identified within the first 1,500 ft of the section after the L-0 junction.

To properly map and profile each lateral, the following steps were completed:

1. The MLT was placed 50 ft below the window depth.
2. Water was pumped at the tool bending rate (1 bpm), followed by 2 minutes of wait time.
3. The MLT was pulled out of the hole (POOH) to 50 ft above the window depth.
4. The pump was stopped and the CT was RIH to place the tool again 50 ft below the window depth.
5. Steps 2-4 were repeated until a total of 12 cycles were completed to properly map the window by recording the pressure changes occurring inside of the tool string.
6. The pressure response of the sensor inside the downhole tool was recorded for each cycle. Once a pressure drop of 300 psi or more was noticed in one of the 12 profiles, then this indexing position was flagged, as it identified the lateral access angle.
7. To access the identified lateral, the CT was first POOH 50 ft above the window depth.
8. The required pumping cycles (on-off) were then performed to align the bending sub to the indexed position.
9. Pumping was continued as the CT was RIH.
10. The CT was run at least 1,500 ft while acquiring a GR profile to validate the identity of the accessed lateral.

To evaluate fluid placement prior to the stimulation, the following steps were taken:

1. When the CT was across the two windows and the open hole junction (either L-1 or L-0), a DTS was performed with the CT kept stationary.
2. When possible, DTS data was acquired while bullheading water to record the transition in the temperature profile of the wellbore due to fluid injection.
3. After fluid injection, pumps were shut-in to monitor the warmback of the wellbore toward the initial temperature condition.
4. With the above information, an evaluation was completed to decide on the steps for the matrix stimulation placement.

JOB EXECUTION

The execution of the job followed the designed steps to overcome the different challenges presented; in addition, the procedures were varied during the job based on the real-time feed-

back of both downhole sensors, which gauged the performance of the MLT and DTS, while making the fluid placement decision. These on-the-fly modifications were only possible with the use of the real-time downhole monitoring CT system.

Natural Path Access for the Motherbore

The first step in the intervention was for the CT to RIH to access the motherbore, or L-0, which corresponds to the natural path in the wellbore. Without operating the MLT, due to the residual bending nature of the CT pipe and the eccentricity of the tool string while it is RIH, it is possible to get into a different lateral.

Before the CT got into the open hole section, a CCL log was utilized to depth correlate the CT end. For this action, the CT was RIH 60 ft below the liner shoe, and an uphole CCL log pass was made to identify the location of the liner shoe — 6,668 ft — and a casing joint located at 6,628 ft. This first uphole log pass showed a depth offset of 2 ft, Fig. 8. The first track on the left of the figure shows the CCL signal (red for raw signal, blue for filtered) with the liner shoe and casing joint locations indicated by the black dots. As part of the correlation procedure, the CCL logging pass was repeated to verify a match between the acquired signal and wellbore reference logs; this second track is presented on the right side of Fig. 8.

After the depth correlation, the CT continued the trip in the hole while acquiring a GR log to be used to validate the accessed lateral by comparing it to the wellbore reference logs. The standard method in a conventional CT intervention to verify the accessed lateral consists in tagging TD, which in this case was clearly distinctive: L-0 is 11,737 ft, while L-1 is

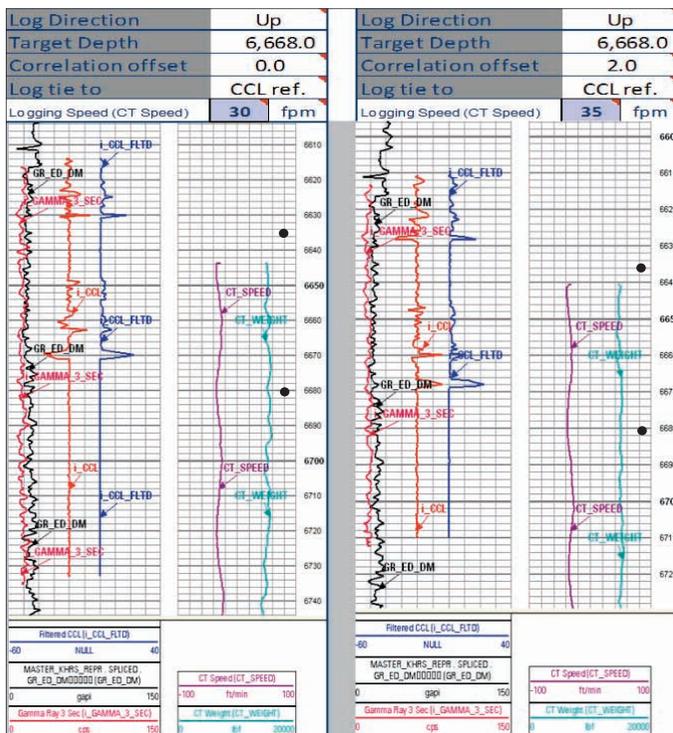


Fig. 8. CCL signal (left) and casing shoe depth correlation (right).

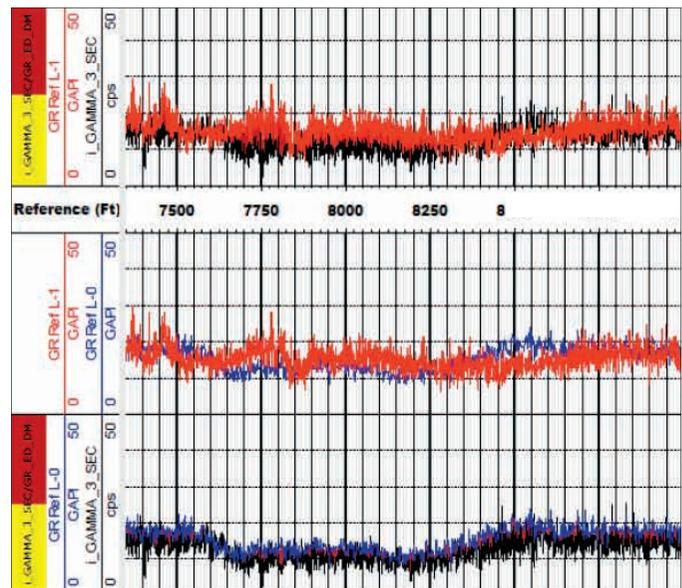


Fig. 9. Real-time GR log acquired with the CT downhole monitoring system. The middle shows the two reference logs (L-1 in red and L-0 in blue), which are overlapped with the GR log at the top and bottom, respectively.

13,650 ft. During the trip in the hole, however, the CT locked up at 10,537 ft, and even though some attempts to gain extended reach were made using N₂ and FR, the CT only reached to 11,663 ft.

The GR log acquired (in black) is presented in Fig. 9, which shows its overlap with reference log L-1 (in red on the top) and with reference log L-0 (in blue at the bottom). When looking at the overlap of the L-1 and L-0 reference logs (in the middle track), it is clear that unique and distinctive profiles occur at 7,750 ft and 8,500 ft. As this was the first run, the log was acquired until lockup occurred. From the overlap of reference log and acquired log, a perfect match to L-0 is evident in the bottom track. This result provided confidence in defining the CT location based on real-time GR acquisition during the intervention.

DTS Baseline Reference in L-0

Once the CT was confirmed to access L-0, a DTS was performed while keeping the CT stationary and having the well shut-in to determine the initial baseline of the temperature profile. The acquired trace is presented in Fig. 10. The baseline temperature shows a downhole temperature for the horizontal

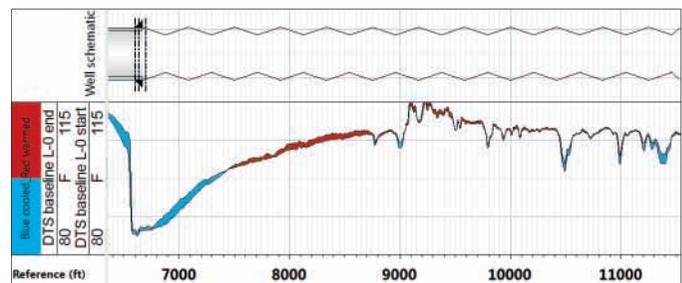


Fig. 10. Temperature profile baseline reference in L-0.

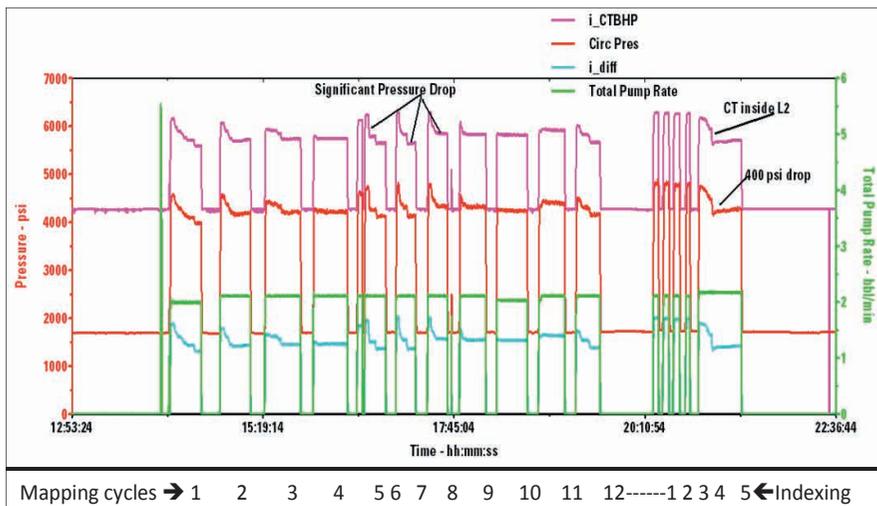


Fig. 11. Mapping sequence for L-2 access.

section of 115 °F, but then it drops. Due to the extended water injection that has taken place in this well over its life, the temperature across the open hole section remained very cool even though the well was under static conditions — no water injection occurring during DTS data acquisition. So, the temperature drop of around 30 °F near the window is evidence of a section where water injection had taken place. Other intervals in the mid-section toward the toe showed similar cooled spots, but with milder variation. The original reservoir rock was documented to be originally 123 °F.

L-2 Access

Due to operational conditions at the well site, the decision was made to leave L-1 access for a later step in the intervention, so the CT was POOH to map the window for L-2 and access this lateral for stimulation.

For this mapping process, the CT was positioned 200 ft below the window, and pumping was initiated at 2.2 bpm (the MLT operation design rate). The downhole pumping pressure was monitored until it was stabilized, then the CT was POOH at 10 ft/min. The pressure was observed now for changes that could identify the position of the window. During this mapping, the CT had to be POOH and RIH 12 times to complete the required indexing profile.

Figure 11 shows the variations in the downhole pumping pressure during these cycles (1-12). A major pressure drop occurred in the fifth cycle — a drop of approximately 600 psi — so once mapping was completed, the CT was first POOH above the window, then the pump was cycled (on-off) five times to position the orienting tool toward the lateral indicated by that pressure drop. At this point, the pump-

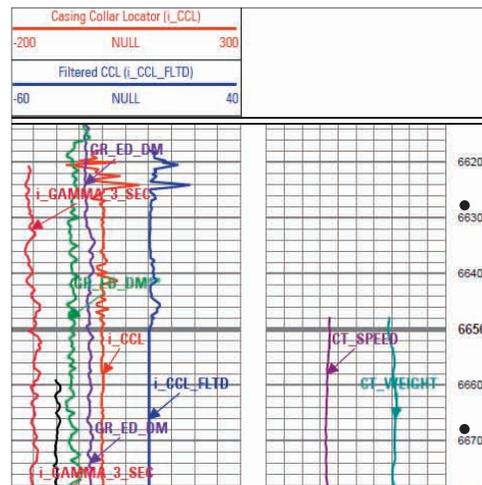


Fig. 12. Validation of L-2 access using a CCL profile while RIH.

ing rate was kept constant at 2.2 bpm to bend the controllable bent sub, and the CT was RIH while monitoring both the CCL and the GR profiles.

The first approach to identifying the accessed lateral was to use the CCL. Due to the well completion configuration, if the CT continued to run inside the casing toward the motherbore, the CCL should show a peak signal at the liner shoe location. As presented in Fig. 12, this was not observed while RIH. The CCL was flat at a position of 6,668 ft (lower black dot in the image) where the liner shoe would be in the motherbore.

The L-2 access was confirmed once the acquired GR profile was compared to the four lateral reference logs, finding a unique match between the acquired GR profile (black curve) and the L-2 reference log (yellow curve), Fig. 13. In the same image, the acquired GR was overlapped with the L-3 reference log to show that there was only one possible match.

L-2 Stimulation Monitoring

Once the access to L-2 was confirmed, a DTS was performed to acquire a baseline, and the stimulation of the lateral was carried out by pumping the treatment fluids down the CT and

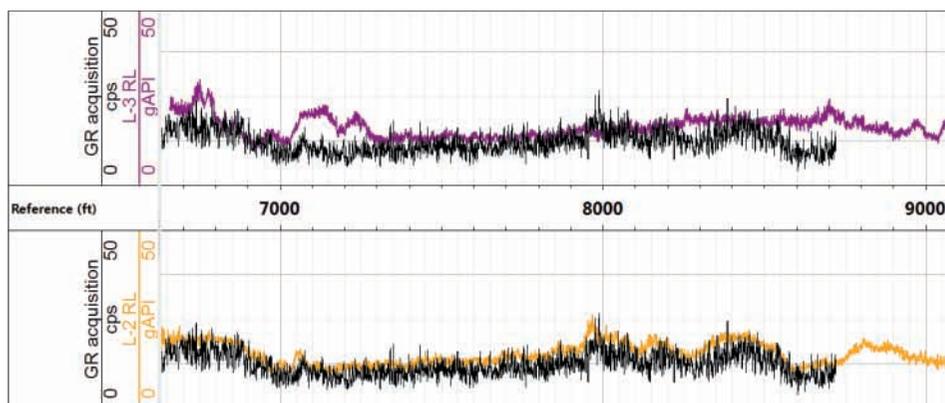


Fig. 13. Real-time GR log (black curve) acquired with the CT downhole monitoring system. The bottom shows the GR log overlapped with the L-2 reference log (yellow curve, identifying the accessed lateral as L-2). The top illustrates the acquired GR overlapped with the L-3 reference log (purple curve).

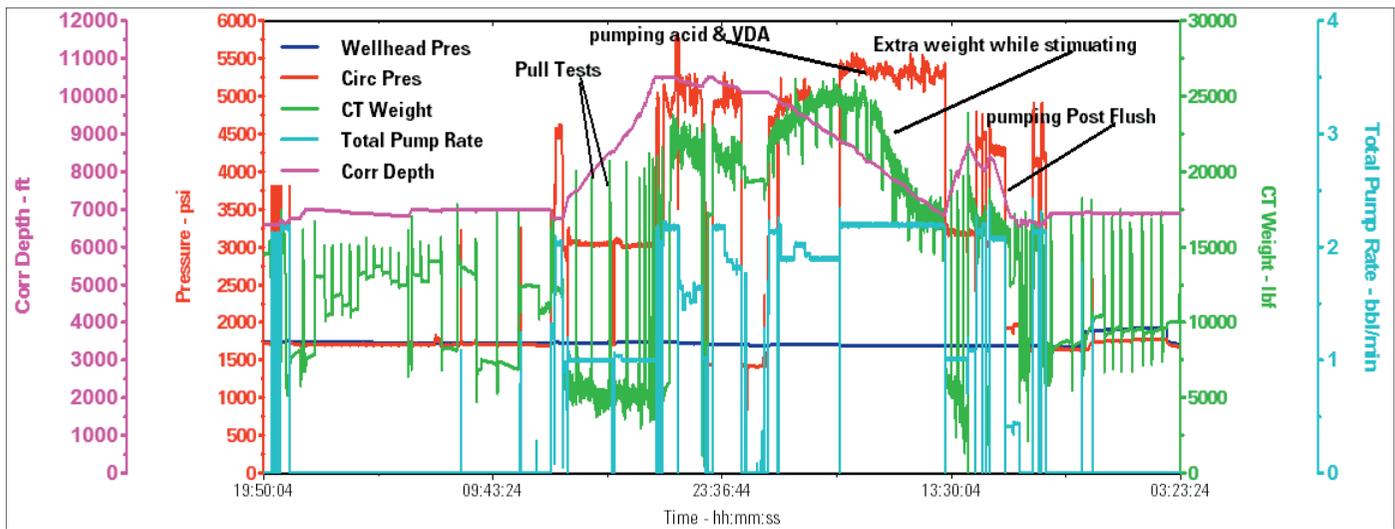


Fig. 14. Real-time CT downhole and surface parameters monitored during stimulation of L-2.

moving the CT across the open hole section of L-2. The stimulation of this lateral included 300 bbl of pre-flush, 1,300 bbl of HCl acid, 180 bbl of a diverting agent and 240 bbl of post-flush. The fluids were pumped by stages and the downhole pressure in the annulus of the tool string was monitored. The stimulation analysis is outside the scope of this article, but the real-time parameters acquired during the fluid placement and injection are displayed for information, Fig. 14.

L-3 Access

The next step in the intervention was the stimulation of L-3. For this, the CT was POOH just below the L-3 window, and the mapping process with the MLT was started while monitoring the downhole pressure inside the tool string. In this case, the pressure drop in the MLT was found in the second cycle, Fig. 15, so instead of completing the 12 indexing cycles, the decision was made to RIH and validate the accessed lateral with the use of the GR real-time profile. The GR validation process was followed as in the previous evaluation of L-2.

The stimulation of the L-3 lateral was conducted the same way as for L-2 using the same fluids, a similar sequence of events and similar volumes. After stimulation, the CT was returned to the surface to prepare for the final treatment of L-1.

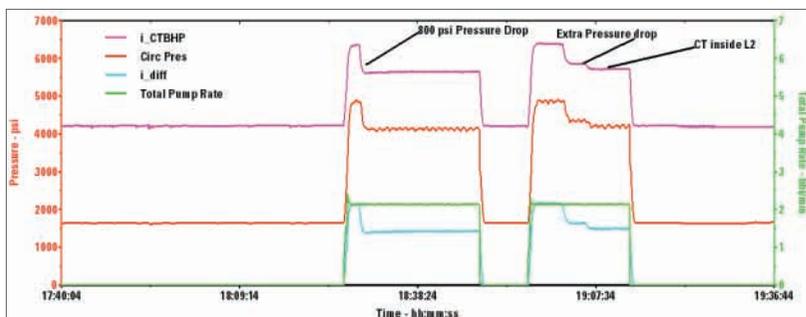


Fig. 15. Mapping of L-3 access in which only two indexing cycles were required.

Access of L-0 Resulted in L-1

At this point in the intervention, as part of the pipe management process, a section of the CT's end was trimmed when it was at the surface. The CT then was RIH again and was expected to be able to reach the natural path, or L-0, without requiring the operation of the MLT, as had happened in the first run; however, this was not the case.

The CCL log was used to monitor and validate the pass across the casing joint between L-3 and L-2, and the pass across the liner shoe. GR logging was also monitored. While overlapping the acquired GR with the reference logs of L-1 and L-0, it was observed that the CT was no longer in the natural path, but instead was in L-1. The GR log and the overlap are presented in Fig. 16. This type of situation is a common occurrence since the nature of the CT pipe and its residual buckling can cause it to access a different lateral. What is notable is that the use of real-time GR during the intervention removed this uncertainty, allowing the operator to make the right decisions in a timely fashion.

Based on this result, the decision was made to continue with the stimulation of L-1 following a similar practice as in L-2 and L-3 previously described.

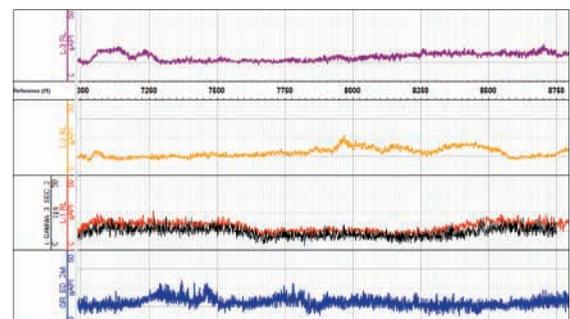


Fig. 16. Real-time GR log acquired with the CT downhole monitoring system and overlapped with the L-1 reference log (red) shows the tool string accessing L-1 instead of the expected natural path of L-0.

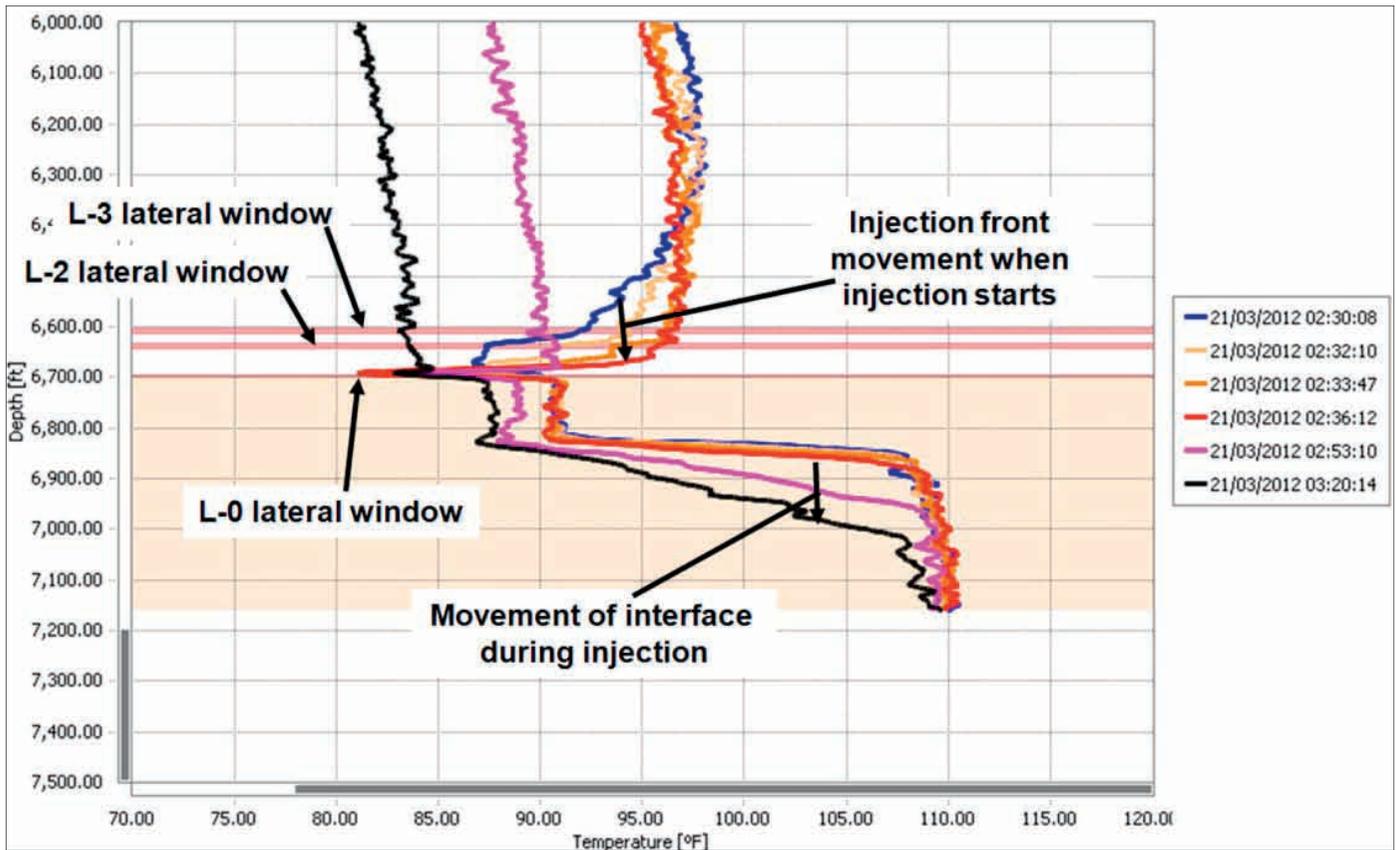


Fig. 17. DTS monitoring during water injection while CT is stationary across L-1.

Monitoring Well Injection in L-1

After L-1 stimulation, the intervention was completed. The well was put to injection by pumping water at 8 bpm while recording a DTS to observe changes in the temperature profile by comparing temperatures while injecting fluids with those recorded during the shut-in period.

Figure 17 shows the results of the DTS acquisition. L-0 remained the coolest spot, and the temperature of the injected fluid quickly dissipated into it, indicating that fluid intake was still taking place. When looking across the open hole interval of L-1, it is possible to observe that the fluid temperature of 110 °F got displaced toward the toe, indicating fluid injection over 200 ft, but it was not reaching the toe of the well.

CONCLUSIONS

Since this was the first time a quad-lateral stimulation was conducted, a lot of challenges were encountered.

- The main challenge was how to properly identify the laterals. At first, the main focus was to see and find the main GR responses to be able to match them with the reference logs; after entering each lateral and overlapping the acquired log vs. the reference log, it was possible to validate the procedure with confidence.
- The use of CT with a fiber optic line to provide re-

al-time data during the intervention and to assist with MLT operation proved to be the best solution to tackle the issue of positive indication of tool performance. This approach allowed for accurate indexing and for finding data on the laterals.

- A combination of GR and CCL with the MLT provided a cutting-edge accuracy in viewing downhole parameters in real time, allowing decisions to be made at an early stage of the operation and allowing for the targeting of the correct lateral.
- Real-time downhole data, including DTS results, was successfully used during the CT stimulation of a quad-lateral water injector well for the first time.
- Doing DTS after stimulating all the laterals provided a clear picture of the treatment performance.
- The success of this project led to the stimulation of several wells of the same kind using the same approach and lessons learned from this job.

ACKNOWLEDGMENTS

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BIOGRAPHIES



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Ayedh M. Al-Shehri is a General Supervisor of the Khurais Production Engineering Division in the Southern Area Production Engineering Department (SAPED) of Saudi Aramco. Since beginning his career in 1999, Ayedh has received extensive and diversified experience in well integrity, well intervention, stimulation, production optimization, artificial lift and intelligent fields across different Saudi Aramco oil fields.

In his 18 years with Saudi Aramco, he has published many Society of Petroleum Engineers (SPE) papers in the areas of well integrity, well intervention, stimulation, production optimization and much more. Ayedh has chaired technical sessions in several different international conferences in the oil and gas industry. Currently, he is the head of the Technical Publication Committee in SAPED.

In 1999, he received his B.S. degree in Petroleum Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia.



Nayef S. Al-Shammari is currently assuming the position of Production Engineering Manager in Saudi Aramco's Southern Area Production Engineering Department. Dealing with the largest onshore oil fields in the world, he has led many major projects as a Production Engineer, including the Haradh GOSP-2 and -3 increments, development of the Khurais mega-project, and Saudi Aramco's Gas Development Program. Since joining Saudi Aramco in 1995, Nayef has assumed several management positions, including Well Completion and Producing & Production Engineering.

He has coauthored and published multiple publications and technical reports to promote technical excellence in the industry. In addition, Nayef is a Board member of the local chapter of the Intervention and Coiled Tubing Association (ICoTA) Middle East/North Africa.

He has over 20 years of experience in the oil and gas industry, with in-depth experience in production engineering, rig-less well interventions, and well stimulation, including fracturing, well performance evaluation, and production optimization.

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Salman D. Al-Gamber has more than 27 years of experience in production engineering operations related to well treatment, coiled tubing operations and new field commissioning. His experience also includes more than 10 years in electrical submersible pump (ESP) operations, including ESP design, installation on the rigs and troubleshooting. Currently, Salman works as a Senior Production Engineer providing technical support to the Abqaiq Production Engineering Division.

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Khaled M. Al-Mutairi is a Production Engineer and an Electrical Submersible Pump (ESP) Specialist working in Saudi Aramco's Northern Area Production Engineering and Well Services Department. He started his early career with TECHNIP Company, upgrading one of the major gas plants in the Kingdom. Khaled joined Saudi Aramco in 2005, and since then he has held several different positions, including Production Engineer, Acid Stimulation Specialist and Well Site Operation Foreman. As part of his ESP specialty program, Khaled worked with several departments, including Reservoir Management and Production Facility & Development.

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Rifat Said has more than 20 years of experience in the oil and gas industry, specifically in cementing, coiled tubing operations and stimulation services, including matrix stimulation and fracturing. He worked for Schlumberger for 18 years before joining Saudi Aramco in September 2006. Currently, Rifat works as a Stimulation Engineer providing technical support to the Southern Area Production Engineering Department.

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Danish Ahmed has been working at Saudi Schlumberger since 2007. He is a Senior Intervention Optimization Engineer with Schlumberger Well Services – Coiled Tubing Services, supporting the ACTIVE Services Platform. Danish's experience includes working as a Field Engineer with Well Production Services (Fracturing and Pumping 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 called Data and Consulting Services) in Dhahran, Saudi Arabia.

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

Offshore Drilling Operation Time Optimization Using PDC Bit Shear Cap Technology

Musab A. Al-Jamea, Hatem M. Al-Saggaf, Hocine Boussahaba and Bruno Cuillier de Maindreville

ABSTRACT

For many years, Saudi Aramco has searched for a way to replace the practice of drilling out the differential valves and shoe track with a tricone bit, followed by using a polycrystalline diamond compact (PDC) bit to drill the new formation to the next casing point. Many bit manufacturers have conducted trials to overcome the challenge, with limited success. This article discusses a successful, single-run technology to drill out and continue drilling using only a PDC bit.

Investigations of the root causes of the failure and the erratic performance of the PDC bit led to extensive review of bit design and drilling practices, but failed to overcome the single-run challenge posed by the cutter wear and damage experienced during the drill out.

Recently developed shear cap technology provides a means of installing high-grade tungsten carbide caps on the PDC cutters. The caps protect the cutters during the drill out, and then wear away to expose the cutters in pristine condition for drilling the formation.

The shear cap technology has been tested extensively and optimized using various bottom-hole assemblies. The result has been a considerable breakthrough in the success rate for drilling the formation section in a single run, accompanied by a time reduction that has resulted in huge savings in offshore oil drilling operations.

The standard PDC bits fitted with the protective technology are successfully providing a one-trip capability, saving a round trip to change the bit and achieving a 100% success rate in drilling to the next casing point. When drilling in the casing, the tungsten carbide shear caps are effectively mitigating the cutter damage typically experienced while drilling out the shoe track. Subsequent drilling performance in the formation, including the ability to efficiently drill the full section, demonstrates the undamaged condition of the cutters when the bit exits the casing. By drilling both shoe track and formation in a single run, the novel technology is overcoming the long-standing efficiency challenge with its ability to achieve optimal formation drilling by protecting cutters during the shoe drill out.

INTRODUCTION

The conventional methods used to spud well sections have been in question for several decades. More specifically, the practice of drilling the shoe track with a tricone bit, followed by using a polycrystalline diamond compact (PDC) bit to continue drilling the formation, seemed inefficient as well as uneconomical since it relied heavily on time, which is the most influential parameter in determining overall drilling cost. Although it was possible to drill with a single PDC bit, this also encountered some strong limitations. The first method with two drill bits takes a substantial amount of extra time, as two trips are needed to complete the drill hole. Alternatively, using a single PDC bit takes a heavy toll on its primary cutters, causing wear that results in a slow rate of penetration (ROP) while drilling in the formation. This shared dilemma prompted this article's objective.

Shear cap technology shields the PDC cutters during drill out and wears away quickly while drilling in the formation to expose the cutters in pristine condition. Performance in the formation is enhanced by cutters that survive the shoe drill out with minimal or zero damage. In addition, bit selection can be based appropriately on the formation and not limited by compromises required to address drill out requirements. The shear caps are easily retrofitted to existing drill bits for significant cutter tip and cutter face protection; they enable effective and rapid shoe drill out; and they afterward achieve predictable and complete detachment from the cutters. Furthermore, during shoe drill out, the shear cap design provides edge sharpness and a high rake angle for a shearing action that results in a timely, effective clean out.

This article discusses the advent of the single-run shear cap technology and documents its ability to enhance PDC performance so this once challenging task can be accomplished with little to no constraints. The essential design of the shear cap technology is presented, along with supporting data on drilling results with and without the shear cap technology.

CONVENTIONAL DRILLING METHODS

Most of the time, efforts to drill out the casing equipment using a standard PDC experience stunning failure. Figures 1 and

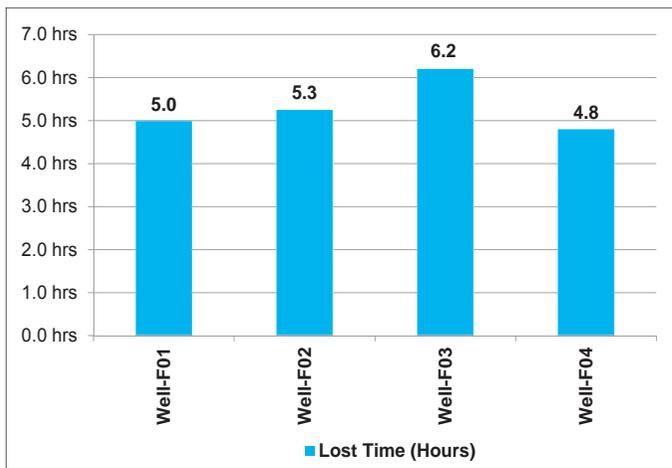


Fig. 1. Lost time while drilling out 13 $\frac{3}{8}$ " casing equipment with standard PDC bits.

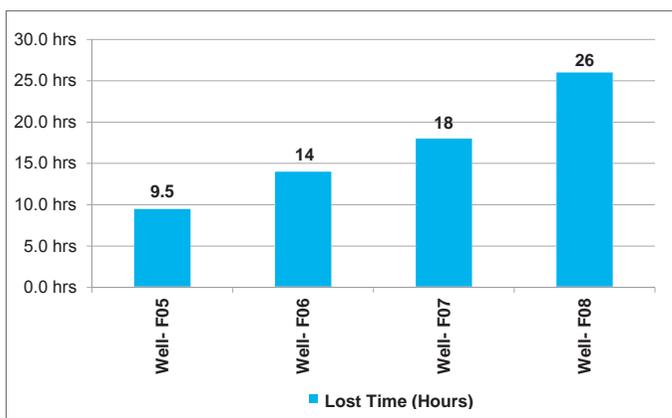


Fig. 2. Lost time while drilling out 9 $\frac{5}{8}$ " casing equipment with standard PDC bits.

2 illustrate the time lost on a series of wells that were incapable of cleaning out the differential valve cementing tools using standard PDC drilling bits. The wells were dressed with differential valves — from various manufacturers — that were not drillable when standard PDC bits were used inside the 13 $\frac{3}{8}$ " and 9 $\frac{5}{8}$ " casings.

An average of 5.3 hours, Fig. 1, was spent on failed attempts to drill out the tools inside the 13 $\frac{3}{8}$ " casing. This considerable amount of lost time impacts the well economics, especially in offshore applications where high rig rates apply.

An average of 16.9 hours, Fig. 2, was spent on failed attempts at a 9 $\frac{5}{8}$ " casing drill out. Well-F08 had a cumulative 26 hours of lost time. The estimated loss was significant, even when factoring in only the rig rate calculations and excluding various multiple standby and other indirectly related costs.

Figure 3 shows a PDC bit damaged by drill out, with several teeth broken in an unpredictable pattern, which indicates a lack of even force distribution on the bit's cutting structure and improper drilling practices while performing the clean out job. Furthermore, while this article stresses the PDC bit's inability to achieve the objective, tricone bits are also sometimes incapable of efficiently drilling out the differential valve tools. High wear in conjunction with additional trip time not only results in lost money due to the increased rig time, but also re-



Fig. 3. Broken cutter teeth in an unpredictable pattern¹.

quires replacement of a bit that might have very few k-revolutions, thereby losing the option to rerun it.

SHEAR CAP TECHNOLOGY OVERVIEW

First and foremost, it is critical to understand the key issues that arise when cement tools are drilled out with a standard PDC bit. It is also important to keep in mind that the PDC bit is designed to be most competent when drilling the formation. That implies that the decisions taken by the designers in determining a bit's precise geometry matter to a great extent with regards to drilling performance. Any hindrance in the rounding of its structure compromises the penetration rate and can result in an uncompleted section.

Although improvements in cementing tools, such as the use of aluminum and phenolic materials, have been incorporated, damaged PDC bits are still a recurring motif in the drill out process simply because they are not made for it. In cases where the PDC bit has been modified to help the drill out process, the result has been a substantial decrease in drilling performance in the formation, which is where the bit essentially spends the majority of its time. After many trials with a modified bit, we came to the realization that the accumulated lost time presents a huge loss in the long run: not only are multiple trips needed when a bit cannot complete a section, but a tremendously low ROP also translates to more lost time and a higher cost per foot.

The shear cap technology works by providing a shield surrounding the primary cutters on the PDC bit to preserve the cutting structure while drilling out the casing.

Figures 4 and 5 show the inner and outer portions, respectively, of the shear cap. The shear cap is lightly welded on top of each PDC cutter to protect the diamond cutting structure from impact or wear during the clean out job. Also, the shear cap's edge sharpness as well as its high rake angle are specifically designed to facilitate the clean out in a safe and timely manner.

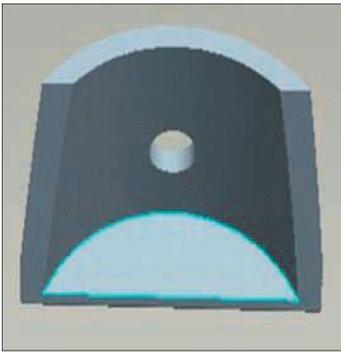


Fig. 4. Inner view of the shear cap.

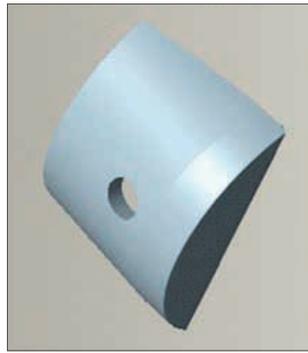


Fig. 5. Outer view of the shear cap.

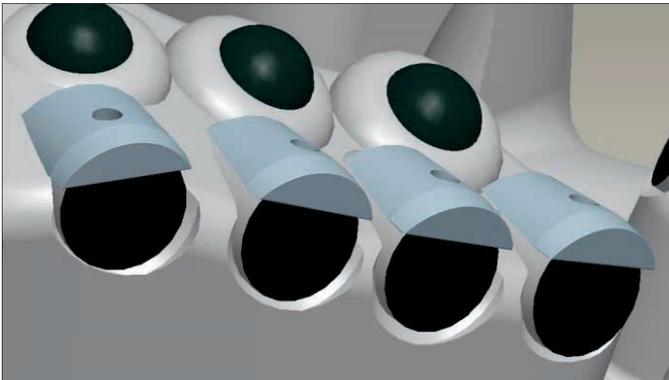


Fig. 6. Shear caps on a series of PDC cutters showing the back rake angle¹.

The shear caps are made of a very tough, abrasion-resistant tungsten carbide material with 14% to 18% cobalt. An appropriately sized cap, once fitted, becomes an integral part of the existing cutting structure of the PDC drill bit. A key aspect of the technology is the means of mounting the cap to the substrate so that it covers the diamond cutter face without directly bonding to it. The cap is secured to the cutter using a braze material with a lower melting point than the material used to braze the PDC cutter into the bit body. This provides a strong bond between the cap and the PDC cutter substrate that is nonetheless weaker than the bond between the cutter and the bit. This allows the shear cap to be quickly worn away once the bit enters the formation, so that it does not degrade cutter performance. The cap can be fitted to any PDC cutter that includes a diamond face mounted on a substrate such as tung-



Fig. 7. Top view of the PDC bit.



Fig. 8. Side view of the PDC bit.



Fig. 9. Shear caps on a new PDC bit.

sten carbide. It can be used with non-leached, shallow leached, deep leached, and resubstrated, fully leached diamond face types.

The shear caps have faces that are inclined to produce a lower back rake angle relative to the back rake angle of the underlying PDC cutters, Fig. 6. The more aggressive angle enhances the capped bit's ability to effectively cut through wiper plugs and float equipment. Since the composition of the cement differs from that of the formation, which is much harder, the shear caps wear away rapidly once the bit is in the formation. The ultimate effect of having the cutters protected during the drill out process is that the formation drilling starts with the cutters in virtually immaculate form. Cutters in good form yield better performances, and bits can be rerun as they have a higher probability of finishing the section in a condition that still merits a good International Association of Drilling Contractors dull grading. The versatility of the shear cap design, which makes it easy to fit on different existing bit designs with their various nomenclatures, makes it a very feasible add-on whenever they are needed on any given bit.

Figures 7 and 8 depict the PDC dressed with shear caps. The caps are meant to cover each cutter on the bit that has direct contact with the casing equipment. This is done for numerous reasons, but mainly to facilitate the clean out job and to protect the PDC cutters so they can drill the next section optimally.

Figure 9 shows the shear caps on a new PDC bit. Theoretically, the caps will be sheared off after the drill out operation and before drilling into the new formation.

OPTIMIZATION AND RESULTS

Figure 10 shows the number of hours utilized to drill out the differential valve tool and cement of varying lengths in 13 wells. As illustrated, the shear cap dressed bits executed the task in a straightforward manner. Even in Well-K, where the cement footage is more than 265 ft, only a matter of 2½ hours was needed to completely drill the cement and the float collar.

Figure 11 provides the applied mechanical parameters for the shear cap dressed bits during the clean out of the cement

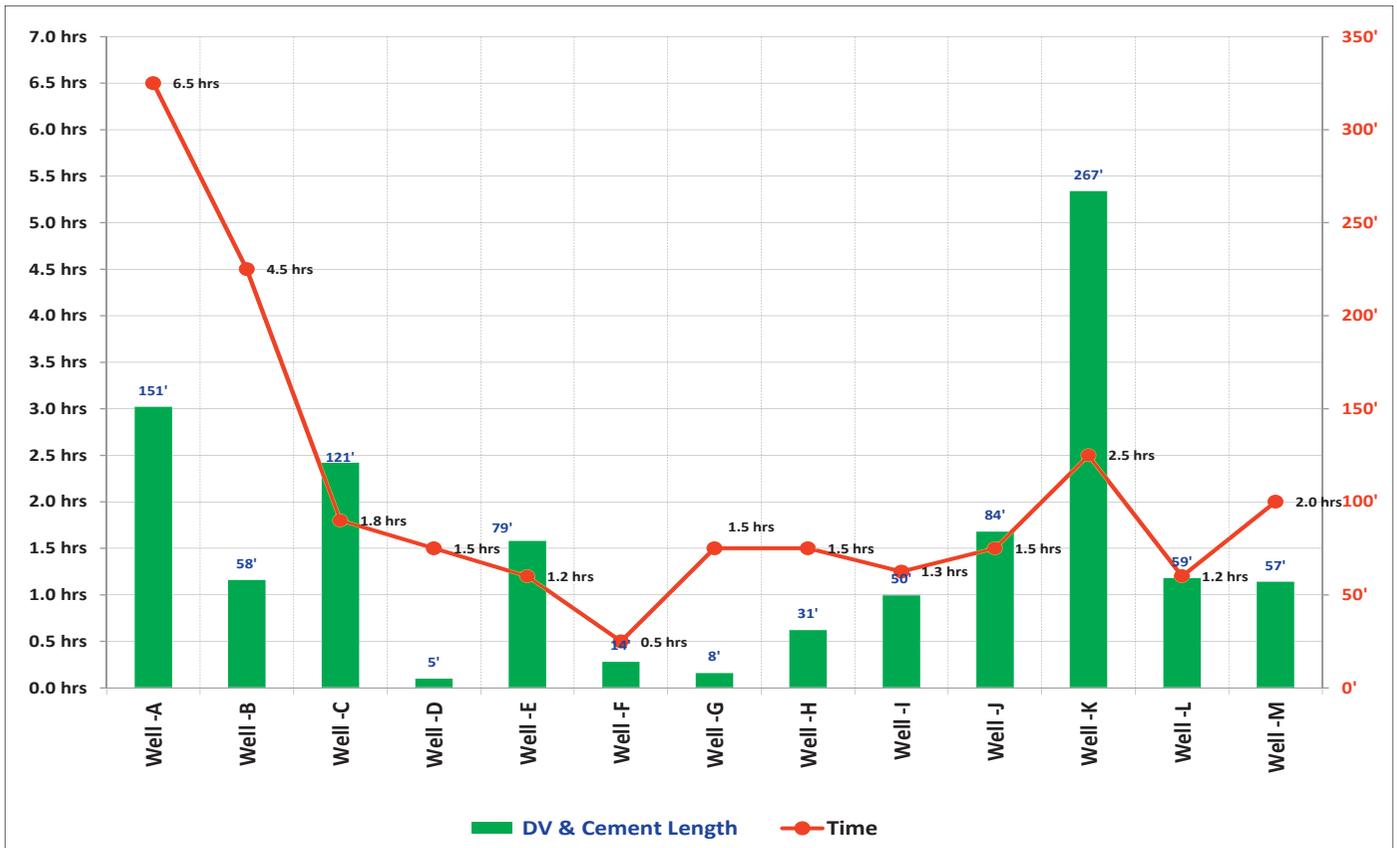


Fig. 10. Clean out performances of bits with shear caps when drilling the differential valve tool and the cement.

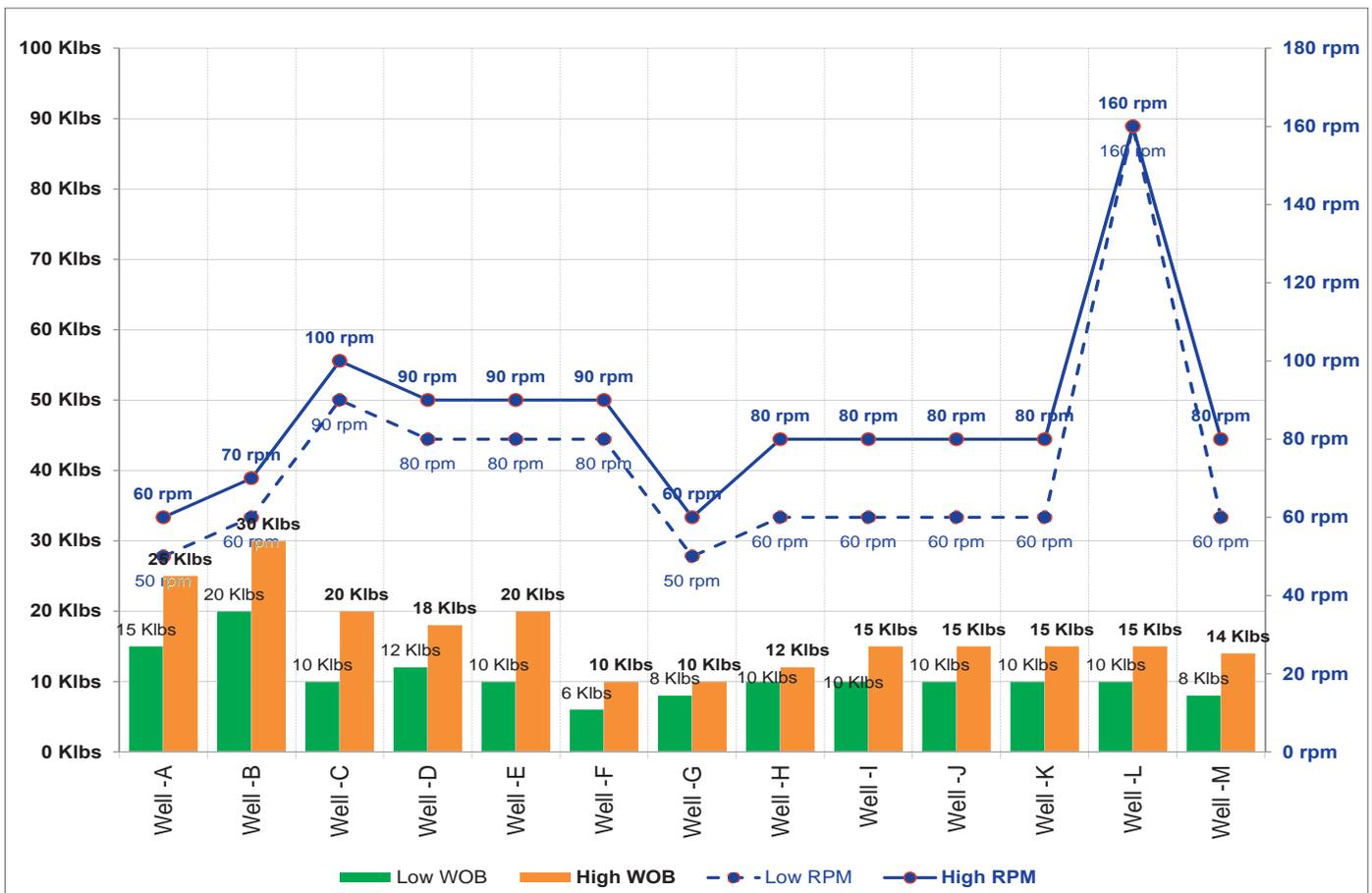


Fig. 11. Mechanical drilling parameters for bits with shear caps.

with the differential valve tools in the same wells. In the early runs, a higher weight on bit and a lower rotation per minute (RPM) were applied, as shown in Well-A and Well-B, resulting into long spinning hours to go through the differential valve tools. These differential valve tools include a pressure bomb, which is a drop-off component that typically requires a higher rotation to enable the shearing action of the shear cap to work efficiently, so spinning will occur whenever a lower RPM is applied. Based on this understanding, the best drilling parameter, one that can accelerate the operation in a safer mode, is the higher RPM. Also seen in Fig. 11, the RPM is the predominant parameter determining the effectiveness of the drill out of the cement and the differential valve tools. The hydraulic parameter must be considered because it is of high importance.

Moreover, a faster and safer drill out of the differential valve and cement has been accomplished using PDC bits dressed with shear caps in offshore oil drilling, with a 100% success rate, Fig. 12.

The same case study showed PDC bits with shear caps successfully cleaning out the 9%” differential valve tools in offshore wells, Fig. 13. Well-K, for example, was cleaned out prior to successfully using the PDC bit for drilling into new formations to total depth (TD).

The chart in Fig. 14 depicts the cost of drilling out a 13%” differential valve tool using a PDC bit with shear caps vs. a conventional clean out using a bottom-hole assembly plus a PDC bit run. Comparing the cost calculations shows the total savings is \$46,000, an approximate cost decrease of 58%.

Figure 15 depicts the cost of drilling out a 9%” differential valve tool using a PDC bit with shear caps vs. using a conventional cleaning assembly plus a PDC bit run, this time in a

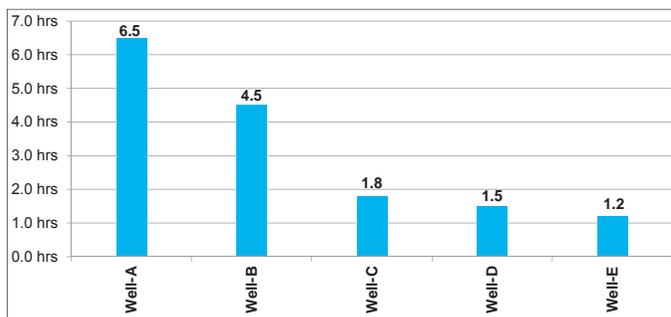


Fig. 12. Drill out time of bits with shear caps in offshore wells.

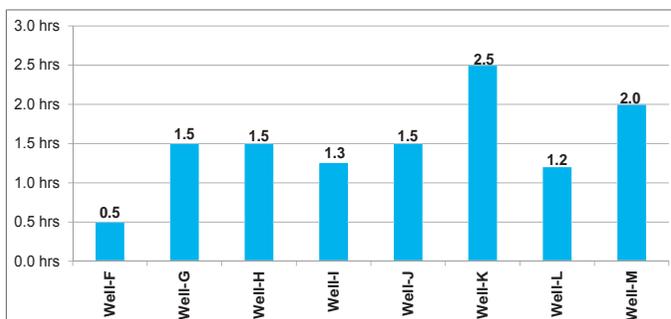


Fig. 13. Drill out time of bits with shear caps for 9%” differential valve tools in offshore wells.

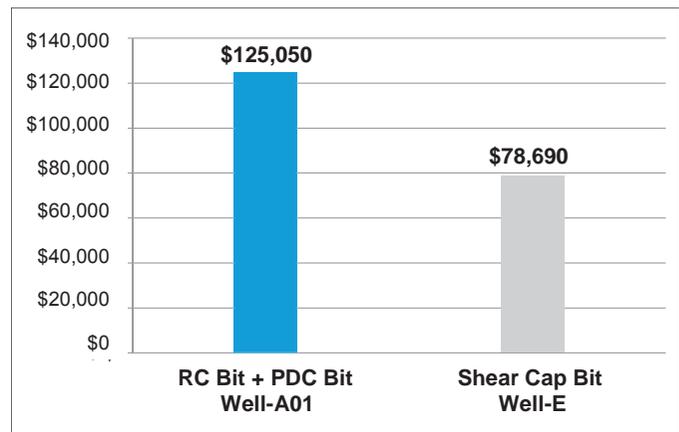


Fig. 14. Cost comparison of drill out for 13%” casing, conventional vs. PDC bit with shear caps.

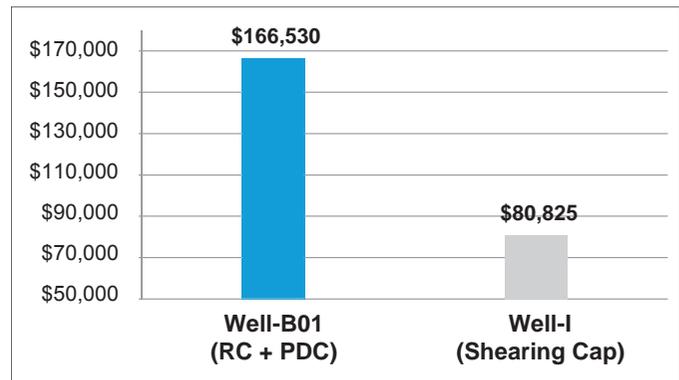


Fig. 15. Cost comparison of drill out for 9%” casing, conventional vs. PDC bit with shear caps.

batch drilling platform application. The total savings is more than \$85,000, which is a huge decrease in cost for a neck-to-neck drilling application. In addition to cost, rig time is considerably optimized through the utilization of this newly introduced technology. When cost savings is combined with the optimized drilling parameters, this approach adds great value to the overall key performance indicators (KPIs) while drilling, as per the program.

Figure 16 depicts a comparison of the ROP achieved using

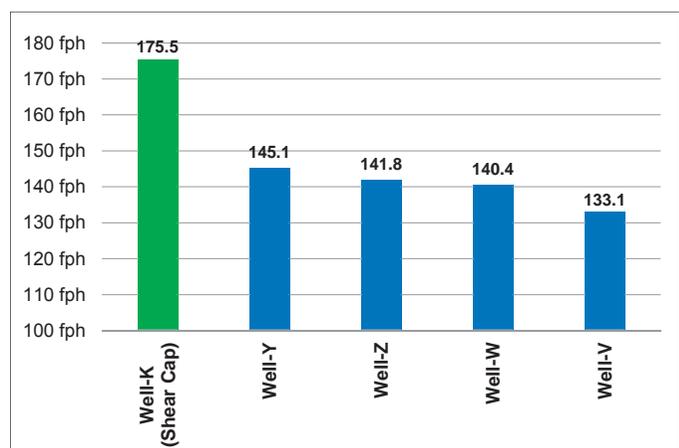


Fig. 16. ROP comparison in one offshore oil field horizontal application using a bit with shear caps (Well-K) and bits without them.

a PDC dressed with shear caps vs. standard PDC bit runs. In Well-K, the dressed bit achieved a new milestone in terms of ROP. Comparing the best performance of a standard PDC bit to the shear cap dressed bit reveals an approximately 21% differential between the two in terms of ROP increase. The new benchmark in terms of ROP is very substantial, since the differential gap between the two bits will continuously and drastically increase as a function of time when more footage is drilled. Drilling two sections in succession has proven to be of great value, not just because of a faster and safer clean out job, but also because it allows drilling throughout the competent formations. The ROP achieved here is also significant because these were horizontal applications, directionally using complex rotary steerable systems that were loaded with sensitive gamma ray and measurement while drilling tools.

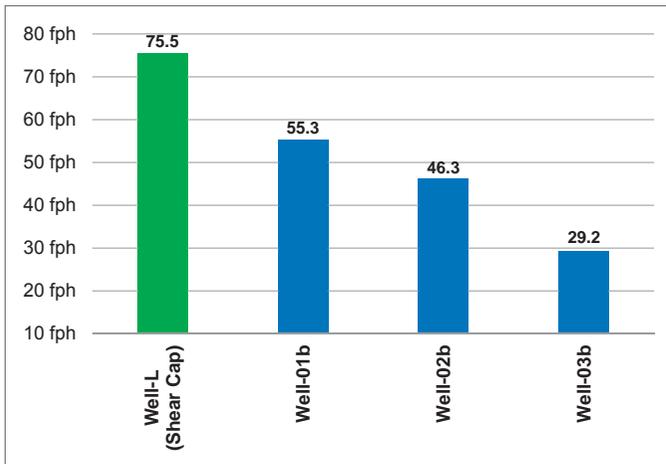


Fig. 17. ROP comparison in one offshore oil field vertical application using a bit with shear caps (Well-L) and bits without them.

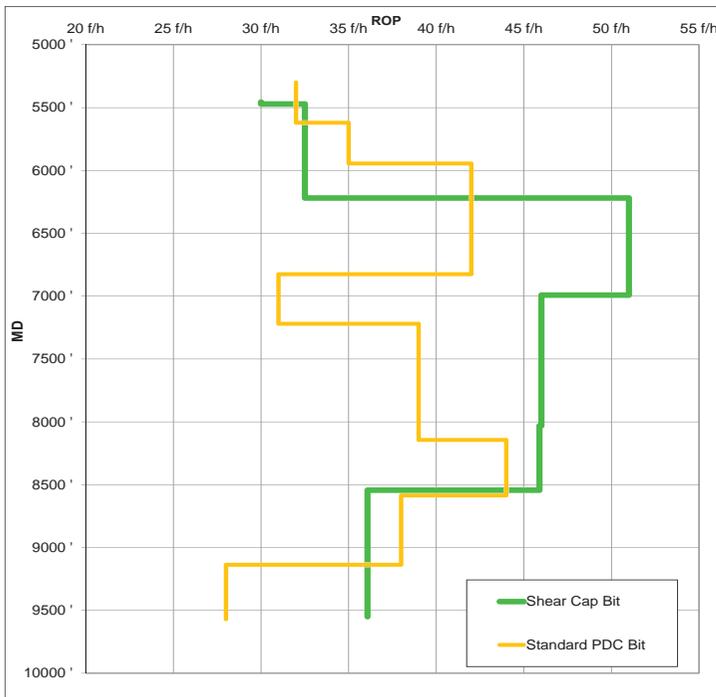


Fig. 18. Drilling performances comparison, standard PDC bit vs. PDC bit dressed with shear caps.

In a vertical application, a bit fitted with shear caps added greater value not only by drilling out the casing equipment in record times, but also by achieving new benchmarks in terms of ROP improvement, as shown in Well-L, Fig. 17. The overall increase in terms of ROP for drilling the entire section using a bit fitted with shear caps is 37% in comparison with the best offset. Considerable cost reductions would be achieved by drilling the section to TD at the higher drilling rate.

Figure 18 shows how much faster a PDC bit dressed with shear caps drills, overcoming a standard competitor PDC bit at the same depth using the same drive system on a batch drilling sequence. More importantly, the drilling progress is much better in the lower part where competent formations are encountered. This is definitely due to the cutter shapes, which are, as expected, still in pristine condition once the bit is out of the casing shoe. Subsequently, the greater progress is an effect of the shear cap, which protects the cutting structure and preserves its sharpness for efficiently drilling the section to the casing point.

DULL GRADING ANALYSIS

Based on the presented information, we can say that the shear caps are not only efficient while cleaning out the casing equipment, but also successfully keep the bit's cutting structure in brand new condition. This is definitely another advantage since it both preserves the bit life for drilling the most competent formation and avoids tripping out for a bit change.

Figure 19 shows a bit that was pulled out of the hole after reaching the 9% casing point. It could be categorized as "green," referring to the splendid condition of the cutting



Fig. 19. Shear caps on a bit pulled out of the hole after reaching the casing point.



Fig. 20. Shear caps after completing a clean out job.

structure. The same excellent condition is also observed on the surrounding matrix elements. Expectedly, remains of the shear caps are visible on the back of the primary cutters with no dull areas. This residue from the shear caps does not hinder the bit's capabilities or the overall drilling performance. Under these conditions, the bit can be considered as re-runnable for further applications.

Figure 20 shows a 12¼" PDC bit dressed with shear caps that was pulled out of the hole due to downhole tool failure (DTF) after drill out of the equipment. Since the cutting structure did not exhibit any dullness, this bit was graded as 1-1-NO-A-X-I-NO-DTF for its inner and outer rows. The images show considerable breakage of the shear caps on the most exposed bit areas, whereas the outer areas show no noticeable dullness. Consequently, it is of high importance to focus on the PDC cutters' dull grade and not on the shear caps while evaluating these particular bit designs.

In general, the dull character is not related to drill out jobs, as shown in the sequence in Table 1. The table clearly depicts the overall bit runs were accomplished with minimal dull

wear. The higher dull rate is directly related to the longer sections drilled, with intermittent formation hardness and abrasiveness. Wear was none to minor in both the 12¼" and 8½" sizes. Most of the time, the PDC bits used for the clean out job drilled successfully to either the casing point or TD and were in a re-runnable condition.

CONCLUSIONS

In summary, it is valuable to reflect on some of the key points that were mentioned earlier to emphasize the importance of the newly emerged shear cap technology in the bit business. The initial challenge for many decades was how to avoid making two trips before drilling the hole, either to the next casing point or to the TD, in a way that would not compromise the bit's capacity if a single PDC was used for both tasks. Most solutions attempted were not viable enough to have any significant impact; however, the shear cap technology has completely changed that situation. Not only has drilling the cement and differential valve tool become more effective, but the shear cap technology also has provided a means for preserving all of the bit's cutters in 100% form, able to be used strictly for drilling the formation².

Beyond the clean out job performed by the 8½" PDC bit dressed with shear caps on Well-L, a new milestone was achieved in terms of ROP in one of the offshore fields. Additionally, we saw a tremendous increase in performance throughout, as a result of having pristine cutters when drilling the formation, which led to a considerable improvement in cost savings. The savings added great value to the well delivery and to the operator's KPI. Most of the time, bits dressed with shear caps complete wells with an improved post-run condition and with a minimal wear pattern, which contributes to the overall savings, as the bits can be rerun in the next well.

| Well # | Dull Grade | | | | | | | RP |
|--------|------------|---|----|---|---|---|----|-----|
| | I | O | DG | L | B | G | O | |
| Well-A | 1 | 1 | WT | A | X | I | NO | TD |
| Well-B | 1 | 1 | CT | A | X | I | NO | TD |
| Well-C | — | — | — | — | — | — | — | LIH |
| Well-D | 3 | 1 | BT | N | X | I | CT | TD |
| Well-E | 2 | 3 | BT | A | X | I | WT | TD |
| Well-F | 1 | 1 | BT | A | X | I | NO | CP |
| Well-G | 1 | 1 | NO | A | X | I | NO | TD |
| Well-H | 1 | 1 | WT | A | X | I | NO | CP |
| Well-I | 1 | 2 | CT | A | X | I | NO | TD |
| Well-J | 1 | 1 | WT | A | X | I | NO | TD |
| Well-K | 1 | 1 | CT | A | X | I | NO | TD |
| Well-L | 1 | 1 | CT | A | X | I | NO | TD |
| Well-M | 2 | 2 | CT | A | X | I | NO | TD |

Table 1. Dull grading of bits with shear caps after reaching casing point/TD

The points demonstrated throughout the article are that shear cap technology will greatly advance performance in its typical application and will positively impact the overall costs savings in years to come.

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BIOGRAPHIES



Musab A. Al-Jamea joined Saudi Aramco in September 2005. He began his career as a Petrophysics Engineer for the Northern Area fields as part of the Reservoir Description & Stimulation Department. In 2007, Musab worked as a Production Engineer on

the AFK increment as part of the Northern Area Production Engineering Department. In 2008, he went on to work as a Reservoir Engineer at the Shaybah field, which had an increment at that time.

In 2009, Musab joined the Offshore Drilling Department and worked as a Drilling Engineer and in Operations. Following that, he went to work as the Budget Team Leader in the Well Scheduling, Budgeting & Accounting Group. In March 2016, Musab joined the Exploration & Oil Drilling Engineering Department and worked as an Offshore Drilling Engineer for five months before moving into his current position as a Drilling Engineer in the Northern Area Oil Drilling Engineering Division.

He received his B.S. degree in Petroleum Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia, in 2005.



Hatem M. Al-Saggaf joined Saudi Aramco's Drilling Department in 2002. He is now a Drilling Engineering Supervisor for the Offshore Drilling Engineering Department. Hatem's experience includes work on several drilling projects, such as the Qatif field development and Khurais increment, and he was a team leader for the Nuiyyem field development.

Hatem received his B.S. degree in Applied Mechanical Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia.



Hocine Boussahaba joined Varel International in July 2005 in Saudi Arabia. He began his career as a Coring/Bit Engineer with Halliburton working in Algeria in 1999. Hocine then worked as an Application Engineer in 2001. From early 2003 to June 2005, he worked as a Sales Engineer for International Oil Companies (IOC) in Algeria based in Hassi Messaoud.

Upon joining Varel, Hocine worked as a Sr. Technical & Sales Engineer based in Saudi Arabia. In 2008, he became an Account Manager. Then in 2012, Hocine became the Operations Manager covering the Northern and Southern Areas of Saudi Aramco along with the Oil and Gas Offshore and Workover divisions.

In 1996, he received his B.S. degree in Engineering from Constantine University, Constantine, Algeria, and in 2016, Hocine received his MBA from Northampton University, Northampton, U.K.



Bruno Cuillier de Maindreville spent 10 years with DBS, including time with Security DBS. He started his career in 1989 as a Service Engineer (coring, bits, and downhole tools). In 1992, Bruno took on the role of Product Engineer for Africa, Continental Europe and the CIS area. Then, in 1997, he was assigned as the Application Design Engineer for the same areas.

In late 1998, Bruno moved on to the position of Senior Technical Professional within Security DBS for Europe and Africa. He remained in this position until joining Varel International in 2000 as the Product Manager for the Eastern Hemisphere. In 2016, Bruno was promoted to the position of Global Product Engineering Director.

He received his B.S. degree in Geology from Bordeaux University, Bordeaux, France, in 1987.

Best Practices in Pre-Fracturing Coiled Tubing Intervention Operations Increase Success Rate of Hydraulic Fracturing Treatments

Pablo H. Guizada, Dr. Zillur Rahim, Adnan A. Al-Kanaan, Rifat Kayumov and Mohammad Arifin

ABSTRACT

Well stimulation and intervention are typical activities undertaken to enhance the productivity of gas-bearing sandstone reservoirs and to meet the increasing demand for energy. Many wells target sandstone formations that require stimulation to produce gas at an economical rate. Proppant fracturing is the preferred stimulation method for such reservoirs because it creates highly conductive pathways between the wellbore and the reservoir. Prior to any fracturing treatment, however, sufficient injectivity at an acceptable bottom-hole treating pressure (BHTP) needs to be established. Depending on the reservoir quality, the task of breaking down the formation and establishing a high enough injection rate can be challenging due to the high in situ stress and compressive strength of the reservoir rock. In particular, formation breakdown pressure can exceed the completion pressure limitation due to stress alteration zones around the wellbore. For such cases, interventions using coiled tubing (CT) are often required before proceeding with the hydraulic fracturing operation.

Two well-known remedial CT treatments are typically used to address wells with high breakdown pressures or low injection rates. The first is treatment by chemical means. Chemicals containing organic solvents or acids are squeezed into perforated intervals in the wellbore; allowing such chemicals to soak in those areas can help remove some of the near wellbore damage induced by drilling. The second is treatment using a mechanical approach. Abrasive fluids containing gelled fluids and sand are jetted at high pressures through a nozzle at the target depth to create a cavern that connects the wellbore with virgin sections of the reservoir free of stress alteration zones.

More than 10 interventions performed over the past five years are analyzed in this article. These include both abrasive jetting jobs and chemical squeeze jobs. The analysis indicates that only half of the abrasive jetting jobs were successful, and none of the chemical squeeze treatments provided positive results. A more detailed analysis identified ways forward that will improve the success ratio for remedial actions using CT. The proposals included employing fiber optic real-time telemetry to precisely place the bottom-hole assembly and perforating with CT to optimize operational efficiency.

This article provides an analysis of the well intervention

practices that aid fracturing operations and prevent challenging situations from arising, such as the high breakdown pressure that results in unsuccessful fracturing treatments. The knowledge obtained from this analysis can be extended to other regions where similar breakdown challenges exist.

INTRODUCTION

Within the fields under study, most of the gas-bearing zones are deep, high-pressure (up to 8,500 psi), high temperature (up to 350 °F) and highly heterogeneous sandstone reservoirs. Significant efforts are underway to develop the tighter areas on the edges of existing reservoirs in these fields. The areas are characterized by low reservoir quality, often with highly laminated net pay zones that have multiple permeable streaks across a larger gross height. Such tight formations require proppant fracturing treatment to produce gas at sustainable rates¹. It is common to perform an injection test before any proppant fracturing treatment. For such tests, treated water or a linear gel is injected into a formation until the moment when the formation cracks and a fracture begins propagating. This moment is called the “breakdown,” and the pressure at which it occurs is called the “breakdown pressure.” After breakdown, treating pressure drops sharply and fracture propagation continues at much lower pressures, Fig. 1.

The task of breaking down the formation and establishing a sufficient injection rate may sometimes be challenging, es-

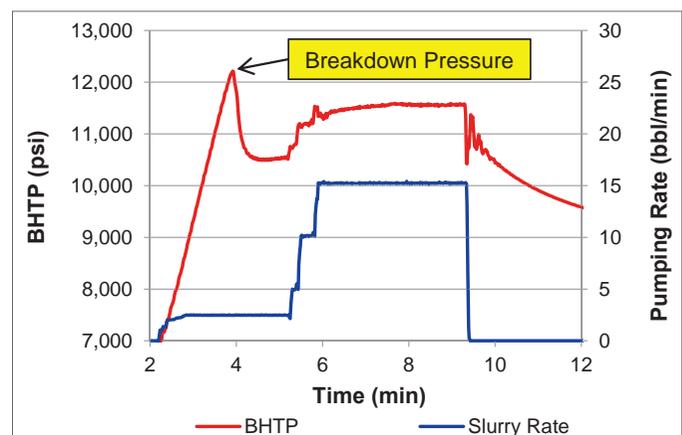


Fig. 1. Breakdown pressure achieved.

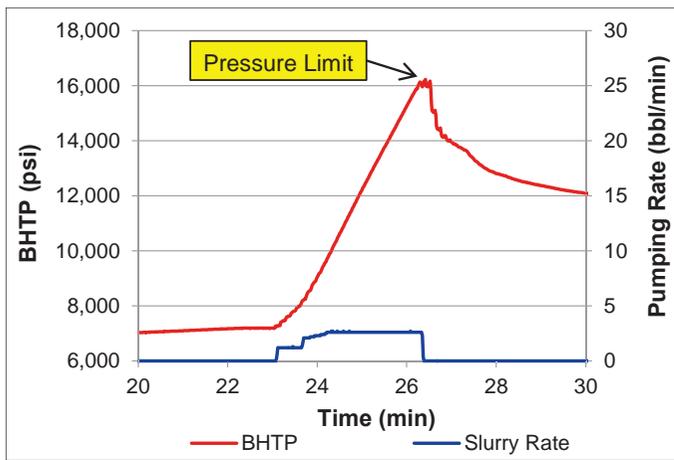


Fig. 2. Breakdown pressure not achieved.

pecially when high in situ stress and a drilling-induced stress alteration zone are present around the wellbore. Sometimes formation breakdown pressure can exceed the pressure limitations of a completion, making it impossible to proceed with a proppant fracturing treatment. Figure 2 presents one example in which the liner strength limited the bottom-hole treating pressure (BHPT) to 16,000 psi, and breakdown was not yet achieved when the BHPT hit this limitation.

In the tight formations that are being newly developed today, more than 30% of all proppant fracturing treatments encounter breakdown issues. A significant number of these challenging wells can still be successfully fractured and consequently produced at an economic rate if the breakdown pressure can be reduced. For such a purpose, when an injection test reveals the fracturing treatment's inability to achieve breakdown pressure, a coiled tubing (CT) operation is usually conducted. Typically, a CT operation consists of a chemical wash in the near wellbore area, the creation of a cavern with abrasive jetting or a combination of both of these techniques.

A chemical wash applies either solvent or acid as the treatment fluid. Solvent is used when filter cake from the drilling phase was not removed properly during well completion. The solvent type is dictated by the kind of drilling mud used in the field. An oil-based mud system is commonly used in the studied reservoirs. In this situation, the solvent is typically a combination of mutual solvent, surfactant and organic dissolver in a brine solution, and normally 50 bbl of this solvent is pumped through the CT and injected into the formation. An acid solution is sometimes selected instead of solvent to improve the injection. Acid is selected when the sandstone formation is believed to have some scales or minerals that can be dissolved in acid and when removing the minerals will improve the injection.

Once the fluid has been injected and adequate reaction time is allowed, an injection test is performed, and the results are compared with previous injection test data to determine whether the treatment has been effective. If there is no improvement in injection pressure and a fracture cannot be ini-

tiated due to the hardness of the rock, the zone is usually isolated and then opened up with perforation. In cases where the injection has improved to an acceptable level, the fracturing treatment is conducted after the chemical treatment. It is common to repeat the chemical treatment to further improve injectivity until it reaches an acceptable level as long as the fracture initiation and propagation do not become risky.

In the second technique, an abrasive jetting tool is used to create holes that penetrate past the near wellbore regions to directly communicate with the virgin formation. This process allows injection fluid to bypass the damaged area, so the fracture creation is dependent only on the far field's in situ stress. Typically, this process involves conveying high-pressure jetting tools with CT to the target depth and using them to jet abrasive fluid until the perforations have been created. A 20/40 or 100 mesh sand is normally utilized for the fluid due to its abrasive properties and relatively low cost. These types of sand are abrasive enough to create holes but not abrasive enough to damage the CT pipe or the high-pressure jetting tools. Other materials such as artificial sand — bauxite, ceramics — are normally too abrasive and cause excessive wear on the jetting nozzle.

The abrasive material is conveyed within a gelled fluid to keep it in suspension during mixing and pumping, which enables the sand to be transported back to the surface during the jetting operation. Jetting time is calculated based on rock compressive strength; when data are not available, the time is estimated from similar, previously executed jobs. An important parameter to ensure that the operation is successful is the pumping rate, which is adjusted to provide a 2,200 psi to 2,500 psi pressure differential across the nozzle. The annular velocity also must be adequate to carry the abrasive material back to the surface during the job.

Once the abrasive jetting procedure has been designed and finalized, the next important job parameter is placement of the high-pressure jetting tools. Achieving the correct perforation depth is a challenge because depth correlation with CT is measured at the surface, and the surface depth measurement has an error margin of approximately 0.1% relative to the total reached depth. Other factors, such as the CT pipe helical buckling shape and pipe elongation due to tension and temperature, make the surface depth correlation even less accurate. It is not uncommon to have 10 ft or more of offset when using the surface measurement. Jetting depth accuracy is not always important, however, because some operations, such as punching holes in the tubing to allow fluid circulation, do not require great precision.

When accurate depth placement is needed, bottom-hole depth measurement is required, and several approaches have been developed to get that measurement. The first method is to tag something at a known depth that is close to the setting depth, such as a bridge plug. The high-pressure jetting tool is first run to tag the object at the known depth and then is reset to match the known depth. Subsequent placement of nozzles at

this target depth assumes that short CT pipe movements will not have a large depth error. Another method is to perform an initial CT run with a memory gauge that is completed with depth measurement tools, such as a casing collar locator (CCL) and a gamma ray (GR) tool. Once the CT is retrieved to the surface and the memory data are downloaded, the results are compared with the surface measurement depth to calculate the depth offset at the target interval, taking the bottom-hole assembly length into account. This offset is then applied to the next CT run with the high-pressure jetting tool. These two approaches have historically been the most common techniques to obtain better depth accuracy.

DATA ANALYSIS

As previously mentioned, proppant fracturing treatments in these tight formations face breakdown challenges. Many wells have multiple production targets, so if breakdown cannot be achieved in a particular zone, the simplest decision often is to isolate that zone and move to the next production target. Still, this approach is not optimal because it results in a significant amount of unproduced reserves left behind. CT intervention is therefore employed after an unsuccessful breakdown attempt to improve well injectivity. An evaluation of the effectiveness of a number of executed CT interventions is described in this article, along with a discussion of opportunities for improving future operations.

Only wells with pre-CT and post-CT intervention injectivity data were considered for this analysis. The effectiveness of the treatments was determined using an injectivity improvement factor (IIF) calculated by the following equations:

$$IIF = \frac{dQ_{max}}{dP_{max}}, \quad (1)$$

where

$$dQ_{max} = \frac{Q_{max_after}}{Q_{max_before}} \quad (2)$$

$$dP_{max} = \frac{P_{max_after}}{P_{max_before}} \quad (3)$$

where Q_{max_before} and Q_{max_after} are the maximum injectivity rates achieved during an injection test, respectively, before and after the CT intervention, and P_{max_before} and P_{max_after} are the maximum BHTPs achieved during the same test, respectively, before and after the CT intervention.

IIF quantifies how much the injection rate was improved by the CT intervention by using the change in treatment pressure. If the IIF is close to 1 or less, then the CT intervention provided no improvement in well injectivity. If the IIF is more than 1, then the CT intervention provided some effect. Higher IIFs indicate even better effects were achieved.

The data from eight wells with 12 different CT interventions were analyzed for this study. Table 1 lists these wells and

| Well | Type of CT Operation | IIF |
|------|-----------------------------|------|
| X-1 | Solvent wash | 0.77 |
| | Acid wash (15% HCl acid) | 0.77 |
| X-2 | Solvent wash | 0.95 |
| | Acid wash (15% HCl acid) | 0.99 |
| | Abrasive jetting | 0.51 |
| X-3 | Acid wash (10% Acetic acid) | 1.05 |
| X-4 | Acid wash (10% Acetic acid) | 0.99 |
| | Acid wash (20% HCl acid) | 0.99 |
| X-5 | Abrasive jetting | 0.62 |
| X-6 | Abrasive jetting | 1.67 |
| X-7 | Abrasive jetting | 5.74 |
| X-8 | Abrasive jetting | 5.56 |

Table 1. CT interventions performed on subject wells

shows the types of CT operations performed on each well as well as its calculated IIF. Some of the wells had multiple CT operations performed because initial operations did not improve well injectivity so additional attempts were required. Figure 3 shows the IIF values for all the analyzed treatments, with orange bars representing chemical treatments and blue bars representing abrasive jetting operations; the green dotted line indicates the IIF threshold value of 1. As Fig. 3 illustrates, none of the chemical treatments provided positive results, while the abrasive jetting delivered mixed results with some injectivity improvement for three out of five wells.

The analysis indicated that chemical washes in the near wellbore area did not effectively reduce breakdown pressure or improve well injectivity. Different types of acids and solvents were used, with different volumes and soaking times, conveyed with and without a jetting nozzle tool, but none provided a positive result. It is likely that the near wellbore damage was overestimated for these wells, meaning the high breakdown pressure was primarily related to far field in situ stress; therefore, use of chemicals could have little impact. It is important to mention that the results of the same chemical treatments can be different in carbonate formations or in oil reservoirs, where treating the near wellbore zone with acids and solvents might

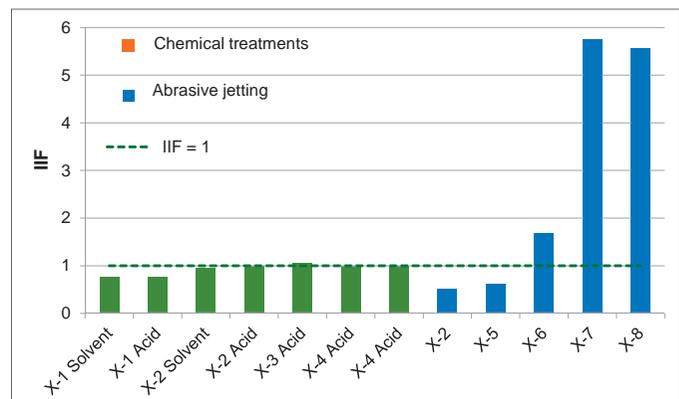


Fig. 3. IIF values for performed CT interventions.

provide more benefit. For the gas-bearing sandstone reservoirs described in this study, a mechanical approach using abrasive jetting was found to be more effective.

As can also be seen in Fig. 3, Wells X-7 and X-8 showed much improved well injectivity after the abrasive jetting operation. Well X-6 showed moderate improvement, while Wells X-2 and X-5 showed no improvement. Many parameters were assessed to ascertain the operational factors that might influence abrasive jetting treatment success, and a few parameters were identified as potential root causes for such a difference, as is presented next.

Nozzle Diameters

Smaller nozzles, with 0.125" diameters, were used in Wells X-2 and X-5, whereas larger nozzles, with 0.141" diameters, were used in Wells X-6, X-7 and X-8. All of the wells with significantly improved injectivity were jetted with bigger nozzles. The difference in surface area affected using these two nozzle sizes is substantial at 27%, leading to a significant difference in the geometry of the created hole. Assuming the same jetting time, the expected cavern diameter for the 0.125" nozzle will be 0.3" to 0.4" and for the 0.141" nozzle it will be 0.5" to 0.6". Potentially, a wider cavern may have more effect on decreasing the breakdown pressure.

Number of Stations and Interval Length

Figure 4 shows the IIF along with the number of jetting stations and the length between the top and bottom stations for wells that had abrasive jetting treatments. It should be noted that the two wells with an IIF of less than 1 had fewer stations than the more successful operations. Using more jetting stations can compensate for uncertainties about nozzle placement by increasing the likelihood that nozzles will face intervals with better reservoir quality and less in situ stress.

On the other hand, Well X-6 had more stations than Well X-8, but its IIF is lower. This can be explained by the fact that the stations in Well X-6 were placed across a shorter interval compared to the intervals in Wells X-7 and X-8. In this case,

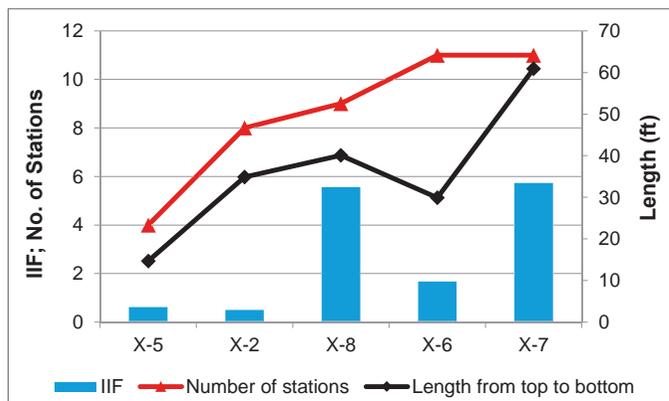


Fig. 4. Influence of number of stages and interval length on IIF.

the stations, while greater in number, had fewer opportunities to contact better rock quality. These results suggest that when achieving good CT depth and an accurate correlation for nozzle placement is difficult or uncertain, then placing more stations across a longer depth interval increases the likelihood of reducing breakdown pressure.

Depth Correlation

The stress profile and the reservoir quality along the wellbore sometimes can vary significantly within a short interval due to heterogeneity and high lamination. In such circumstances, the precise placement of the nozzles for abrasive jetting is critical. For example, Well X-7, Fig. 5a, is located in a tight sandstone reservoir with low porosity and high lamination. For this well, the precise placement of the nozzles at X,896 ft was crucial because there is a low stress zone with good porosity at that point. As noted earlier, good CT correlation techniques are often neglected, resulting in a placement margin of error of 10 ft to 15 ft. In the example of Well X-7, an offset that large would have led to jetting the holes away from the low stress zone at X,896 ft and resulted in a failure in achieving the CT intervention objective to reduce breakdown pressure. But even good depth correlation techniques cannot guarantee success-

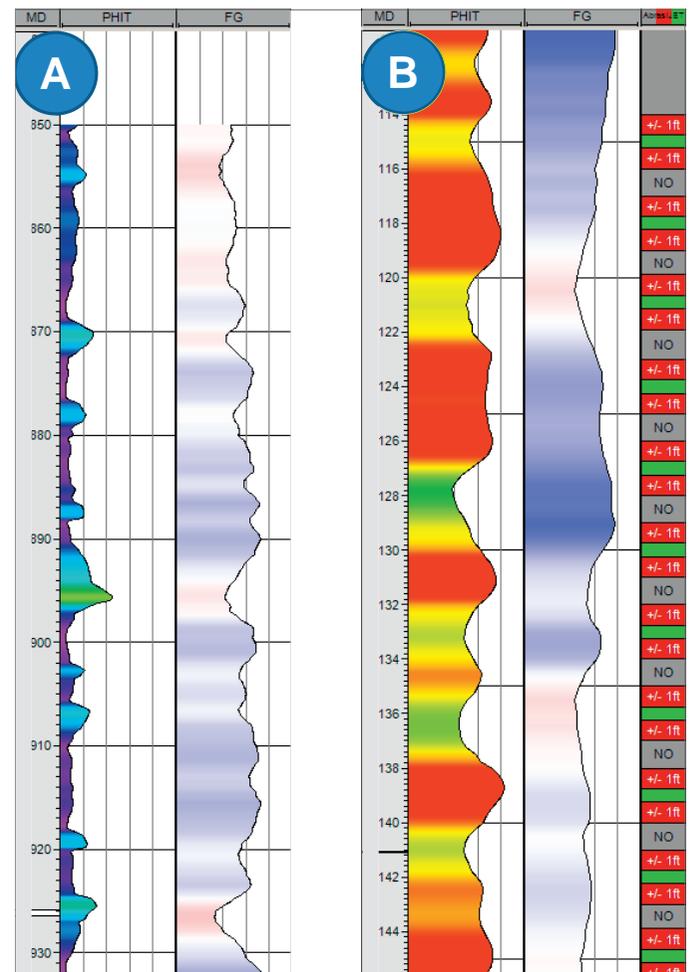


Fig. 5. Log data for Well X-7 (a) and Well X-6 (b).

ful results without good CT intervention design. Figure 5b presents the log data for Well X-6, where the rightmost track shows the depth of the abrasive jetting stations: the green area is the planned location, and the red areas on either side indicate the range of uncertainty of the actual nozzle placement. In this case, the uncertainty was only +/- 1 ft because a wireline memory gauge was used for CT depth correlation. This formation is quite heterogeneous with lower porosity streaks across the entire pay zone. Instead of designing the CT intervention according to log data, however, notches were placed geometrically, with an equal distance between them, across the entire pay zone. Many of these stations fell in less porous zones, where the chances for breakdown are lower, and some of the higher porosity zones were not covered at all by the abrasive jetting placements. Selection of optimal locations for abrasive jetting based on available log data should be routine for this type of intervention, especially when a proper CT depth correlation technique is available.

Figure 6 shows the IIF along with estimated depth uncertainty based on the CT depth correlation method used for each well. The two wells that showed no injectivity improvement used no depth correlation method and relied solely on CT depth, whereas in operations where CT depth correlation was used, the jetting results were successful. The moderate IIF for Well X-6 may have resulted from the geometrical placement of the abrasive jetting stations, as previously described.

WAY FORWARD

With the evolution of new techniques and tools, fiber optic real-time telemetry CT has become accessible for different types of operations². The fiber optic system can transmit real-time CCL and GR data when these tools are placed with a high-pressure jetting tool and so can provide real-time depth data for accurate depth placement in the same run. Typically, the CT with the high-pressure jetting tool is run to the target depth. At the same time the CCL readings are monitored against objects at a known depth, such as short joints or a packer; when it reaches that object, the CCL tool provides a signal at the surface. Once the signal is received, the correla-

tion step is performed by matching the CCL signal with the known depth to get the accurate bottom-hole depth measurement. When GR log data from the well become available, the GR tool reading is correlated against the GR logs so the offset can be adjusted to provide accurate bottom-hole depth correlation. The accuracy of this technique is comparable to that of electric logging tools.

Another benefit of using fiber optic real-time telemetry CT is the ability to monitor bottom-hole temperature and bottom-hole pressure (BHP) both inside the CT and in the wellbore. These data allow the CT operator to monitor the differential pressure across the nozzle by comparing the pressure inside the CT to the pressure in the wellbore. Knowing the differential pressure across the nozzle enables the operator to adjust the pumping rate to keep the pressure differential within the optimum range and also to monitor the jetting performance, which can be affected by erosion from the abrasive material. In the past, the rule of thumb was to replace the high-pressure jetting tool with a new one after approximately 200 minutes of jetting time. The ability to monitor differential pressure allows operators to maximize jetting time before retrieving the high-pressure jetting tool to the surface.

CT may also be used to convey perforation³. This technique has been available for some time, especially to perforate zones in the horizontal section, but improvements have been made in depth accuracy, perforation control and perforation activation. In addition, multiple zones can be perforated selectively, and the formation can be preconditioned before treatment by adjusting the BHP to a state of balance, overbalance or underbalance. Breakdown chemicals such as solvent or acid can be spotted across the perforated section prior to the perforation treatment to clean up near wellbore damage immediately after perforating, thereby improving injectivity. The improvement in prefracturing perforation enabled by CT may reduce the likelihood of breakdown problems. Additionally, treatments such as setting a plug to isolate a zone can be combined with perforation in the same CT run to optimize the treatment time. When the formation does not react positively to perforation and acid/solvent treatments, additional CT runs for abrasive jetting can be performed.

The selection of which intervals to perforate or jet with the CT fully relies on the available log data. Improvements in log interpretation therefore can reduce the possibility of breakdown problems in a particular well. For example, formation imaging logging may help to identify formations with existing fractures, which are likely to be areas with lower breakdown pressure. Advanced acoustic logging tools enable the adjustment of the stress profile based on estimated formation anisotropy. This is especially important for tight formations where isotropic calculations may provide incorrect stress gradients for shaly zones as compared with adjacent clean sandstone layers⁴, resulting in the selection of the wrong intervals to perforate or jet with CT. Further improvement of the stress profile is possible by using core testing for the targeted formations, where

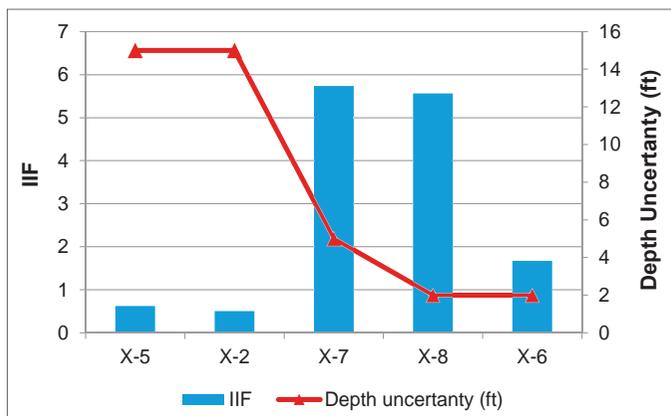


Fig. 6. Influence of CT placement depth uncertainty on IIF.

static mechanical properties can be measured in the laboratory to determine a correlation with dynamic properties.

CONCLUSIONS

1. Abrasive jetting operations with CT can significantly reduce breakdown pressure.
2. Good depth correlation is critical to the success of abrasive jetting operations.
3. In cases where good CT depth correlation for nozzle placement is not available, placing more stations across a longer depth interval is more likely to reduce breakdown pressure.
4. Acid and solvent chemical treatments did not provide a noticeable decrease in breakdown pressure for some wells in gas-bearing sandstone reservoirs.
5. Fiber optic real-time telemetry CT systems can optimize abrasive jetting operations by:
 - Improving depth correlation.
 - Optimizing pump rates by monitoring pressure differential across nozzles.
 - Improving perforation operations.

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BIOGRAPHIES



Pablo H. Guizada is a Senior Petroleum Engineer who joined Saudi Aramco's Gas Reservoir Management Department in 2013. Currently, he is the Team Leader for Khuff Reservoirs in the 'Utmaniyah Gas Unit, focusing on field development for carbonate

and clastic reservoirs. Pablo has over 20 years of experience in the oil and gas industry, and prior to joining Saudi Aramco, he worked with several international oil and gas operators — Petroleum Development Oman, Petrobras Argentina and Pluspetrol — as a Petroleum Engineer and Reservoir Engineer. Pablo's experience includes working on different projects for oil and gas field developments, both onshore and offshore.

He is an innovative engineer experienced in leading teams and managing projects integrating several technical disciplines to develop reserves, creating strategies to optimize site development, and performing assessments to identify potential reserves. Pablo's areas of expertise include reservoir engineering, well stimulation, well testing, reservoir modeling, field development, unconventional resources, production engineering, reserves assessment, strategic planning and team leadership, among others.

He is Certified Petroleum Engineer with the Society of Petroleum Engineers (SPE), and he is a member of Instituto Argentino del Petroleo y Gas (IAPG), Society of Petroleum Engineers (SPE) and Saudi Council of Engineers (SCE). Pablo has published several technical papers related to reservoir engineering, well testing and well stimulation and completion.

In 1996, he received his B.S. degree in Chemical Engineering from Universidad Nacional de Salta, Salta, Argentina, and in 2010, Pablo received an M.S. degree in Petroleum Engineering from Instituto Tecnológico de Buenos Aires, Buenos Aires, Argentina. He also holds an MBA from Universidad de Alcalá de Henares, Madrid, Spain.



Dr. Zillur Rahim is a Senior Petroleum Engineering Consultant with Saudi Aramco's Gas Reservoir Management Department (GRMD). He heads the team responsible for stimulation design, application and assessment, both for conventional and

for tight gas reservoirs. Rahim's expertise includes well stimulation, pressure transient test analysis, gas field development, planning, production enhancement and reservoir management. He initiated and championed several novel technologies in well completions and hydraulic fracturing for Saudi Arabia's nonassociated gas reservoirs.

Prior to joining Saudi Aramco, Rahim worked as a Senior Reservoir Engineer with Holditch & Associates, Inc., and later with Schlumberger Reservoir Technologies in College Station, TX, where he consulted on reservoir engineering, well stimulation, reservoir simulation,

production forecasting, well testing and tight gas qualification for national and international companies.

Rahim is an instructor who teaches petroleum engineering industry courses, and he has trained engineers from the U.S. and overseas. He developed analytical and numerical models to history match and forecast production and pressure behavior in gas reservoirs. Rahim also developed 3D hydraulic fracture propagation and proppant transport simulators, and numerical models to compute acid reaction, penetration, proppant transport and placement, and fracture conductivity for matrix acid, acid fracturing and proppant fracturing treatments.

He has authored more than 100 technical papers for local/international Society of Petroleum Engineers (SPE) conferences and numerous in-house technical documents. Rahim is a member of SPE and a technical editor for SPE's *Journal of Petroleum Science and Technology (JPSE)* and *Journal of Petroleum Technology (JPT)*. He is a registered Professional Engineer in the State of Texas, a mentor for Saudi Aramco's Technologist Development Program (TDP) and a member of the Technical Review Committee. Rahim teaches the "Advanced Reservoir Stimulation and Hydraulic Fracturing" course offered by the Upstream Professional Development Center (UPDC) of Saudi Aramco.

He is a member of GRMD's technical committee responsible for the assessment, approval and application of new technologies, and he heads the in-house service company engineering team on the application of best-in-class stimulation and completion practices for improved gas recovery.

Rahim has received numerous in-house professional awards. As an active member of the SPE, he has participated as co-chair, session chair, technical committee member, discussion leader and workshop coordinator in various SPE international conferences.

Rahim received his B.S. degree from the Institut Algérien du Pétrole, Boumerdes, Algeria, and his M.S. and Ph.D. degrees from Texas A&M University, College Station, TX, all in Petroleum Engineering.



Adnan A. Al-Kanaan is Manager of the Gas Reservoir Management Department (GRMD), overseeing three divisions with more than 120 engineers and technologists. He is directly responsible for strategic planning and decisions to enhance and

sustain gas delivery to meet the Kingdom's ever increasing energy demand. He oversees GRMD's operating and business plans, new technologies and initiatives, tight and unconventional gas development programs, and the department's overall work, planning and decision making.

Adnan has 22 years of diversified experience in oil and gas reservoir management, full field development, reserves assessment, production engineering, mentoring of young professionals and effective management of large groups of professionals. He is also a key player in promoting and guiding the Kingdom's unconventional gas program.

Adnan also initiated and oversees the Tight Gas Technical Team to assess and produce the Kingdom's vast and challenging tight gas reserves in the most economical way.

Adnan started his career at the Saudi Shell Petrochemical Company as a Senior Process Engineer. He joined Saudi Aramco in 1997 and was an integral part of the technical team responsible for the on-time initiation of the two major Hawiyah and Haradh gas plants that currently process more than 6 billion standard cubic feet of gas per day (Bscfd). Adnan also directly managed the Karan and Wasit field developments — two major offshore nonassociated gas increment projects — with an expected total production capacity of 5 Bscfd, in addition to the new Fadhili gas plant with 2.5 Bscfd processing capacity, expected online in 2019. Adnan also served on assignment in the position of General Manager for the Unconventional Resources Group.

Prior to the inception of GRMD, he was the General Supervisor for the Gas Reservoir Management Division under the Southern Reservoir Management Department for 3 years, heading one of the most challenging programs in optimizing and managing nonassociated gas fields in Saudi Aramco.

He actively participates in the Society of Petroleum Engineers (SPE) forums and conferences, and has been a keynote speaker and panelist for many such programs. Adnan's areas of interest include reservoir engineering, well test analysis, simulation modeling, reservoir characterization, hydraulic fracturing, reservoir development planning and reservoir management.

In 2013, he chaired the International Petroleum Technical Conference, Beijing, and in 2014, Adnan was a keynote speaker and technical committee member at the World Petroleum Congress, Moscow. In 2015, he served as Technical Conference Chairman and Executive Member at the Middle East Oil Show, Bahrain.

Adnan received the international 2014 "Manager of the Year" award conferred by *Oil and Gas Middle East (OGME)* magazine for his outstanding contribution in the oil and gas industry. He also received two prestigious SPE awards: a 2015 "Service" award and 2016 "Management and Information System" award. In addition, under his direct supervision and management, GRMD received OGME's "Best Project Integration" award in 2013 and the Abu Dhabi International Petroleum Exhibition and Conference's "Oil and Gas Innovation" award in 2016 for its work, respectively, on the Karan and the Arabiyah/Hasbah projects, two major offshore gas projects.

He has authored more than 45 technical papers on reservoir engineering and hydraulic fracturing.

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



Rifat Kayumov started his career in 1999 working in the Production Enhancement Department at one of the Russian service companies in western Siberia. In August 2004, he joined the Well Services Division in Schlumberger. Rifat spent 3 years in

western Siberia, then 6 years in the Volga-Urals region of Russia, working in different technical positions. In June 2013, he moved to Saudi Arabia and a position as the Production Stimulation Engineer in charge of stimulation activities for Saudi Aramco. Rifat is involved in implementation of new technologies for hydraulic fracturing and matrix acidizing, the candidate selection process, results evaluation and interactions with involved divisions and departments.

He is the author of 15 technical papers published by the Society of Petroleum Engineers (SPE) and the International Petroleum Technology Conference (IPTC) and actively participates in different workshops and conferences.

In 1999, Rifat received his B.S. degree in Mechanical Engineering from the Russian State University of Oil and Gas, Moscow, Russia.



Mohammad Arifin is working in Schlumberger Saudi Arabia as the Coiled Tubing Services Technical Manager for the Kingdom of Saudi Arabia and the Kingdom of Bahrain. He joined Schlumberger in March 2000 and has had several assignments,

including in Coiled Tubing Services, Stimulation and Cementing Services, and other segments in the oil field involving testing, wireline and artificial lift.

Mohammad has nearly 17 years of oil field experience, which covers a broad range of operations, including assignments offshore as well as in the desert, swamp and jungle. He also spent three years at the Schlumberger headquarters working in the Global Technical Support Group of InTouch, providing technical, operational and safety support for the company's worldwide operations.

Mohammad has coauthored several training modules for coiled tubing (CT) operations, a number of Society of Petroleum Engineers (SPE) papers and the documentation of InTouch Best Practices.

He is currently involved in several joint projects between Schlumberger and Saudi Aramco where he uses his expertise in CT and stimulation.

In 2000, Mohammad received his B.S. degree in Chemical Engineering from Gadjah Mada University, Yogyakarta, Indonesia.

Intelligent Completion in Laterals Becomes a Reality

Brett W. Bouldin, Robert J. Turner, Isidore "Ike" Bellaci, Yousif M. Abu Ahmad, Steve Dyer, Thales De Oliveira and Ali Bin Al-Sheikh

ABSTRACT

For many years, Saudi Aramco and Schlumberger have collaborated to develop a downhole system to merge multilateral technology and intelligent completions to create the world's first "smart laterals." This was the vision behind Saudi Aramco's push to drive ever higher recovery factors by taking an extreme reservoir contact (ERC) approach to reservoir management. ERC wells, which can contain upward of 20 km of reservoir contact, require appropriate compartmentalization to ensure uniform heel-to-toe production throughout the reservoir.

Proactive reservoir control is crucial for the efficient sweep of heterogeneous formations. This article describes a full-scale, multilateral, multicompartiment intelligent completion where many new practices and technologies were integrated and demonstrated:

- Well construction and deployment practices to allow electrical umbilicals to be branched into laterals using inductive couplers.
- Deployment of revolutionary low power, infinite position, electrical flow control valves (FCVs).
- Validation of a fully integrated production monitoring system providing direct downhole measurements of pressures, temperatures, flow rates and water cut for each compartment.
- Integration of the surface acquisition and monitoring system with production supervisory control and data acquisition (SCADA) to provide real-time downhole production information and health status.

The ability to finely control downhole flow, measured directly at the reservoir face, has changed the way the industry approaches reservoir management. The sensing system has been validated with a continuous compartment productivity index (PI) and multirate testing without shutting in the well. The SCADA integration allows a real-time management function, where a compartment can be controlled to a target flow rate or drawdown directly without resorting to traditional well system models to estimate choke orifice settings.

This article highlights the development, installation and validation of this new ERC well system and identifies some of the immediate production impacts emerging from this level of visibility and control at the formation face.

INTRODUCTION

Since the early 2000s, the application and evolution of maximum reservoir contact (MRC) wells in low permeability carbonate formations in Saudi Arabia has continued unabated. Wells now routinely exceed 10 km of total reservoir contact in multilateral configurations and are equipped with hydraulic internal control valves (ICVs) and permanent downhole monitoring systems. An intelligent MRC well has been shown to have lower unit development costs and deliver higher well rates¹.

Drilling technology has enabled large footprint multilateral wells to produce at impressive rates. Intelligent completion technology has not kept pace, however, forcing the reservoir engineer to manage higher rate wells with less data:

- Vertical wells — Pattern developments with vertical wells gave the reservoir engineer a large number of discrete measurement points for rate, pressure, saturation and production logging, offering a rich source of data to understand reservoir architecture, drive mechanisms and fluid movement.
- MRC wells — Correct placement of a 10+ km multilateral footprint with only a few discrete measurement points created an enormous challenge for the reservoir engineer.
- Extreme reservoir contact (ERC) wells — These wells provide the best of both worlds by combining the large footprint of MRC wells with the rich reservoir data and flow control of vertical wells. The ERC completions' greater functionality will enable footprints to increase beyond 20 km.

Saudi Aramco collaborated with Schlumberger to create ERC completion technology, segmenting laterals into multiple compartments to provide flow rate, pressure, temperature and water cut measurements, together with variable choking,

in each compartment. ERC completion technology delivers improved sweep efficiencies and higher recovery factors for high rate multilateral wells, advances that could never be accomplished by drilling technology alone.

TECHNOLOGY DEVELOPMENT PROGRAM

The development of the ERC system was a multidisciplinary program that required a robust combination of engineering development, qualification and field trial evaluation. A simple product development exercise can adopt a “do it right the first time” approach, but this is not appropriate for a complex project because it leads to unrealistic management expectations that could put its future in jeopardy.

Even the most experienced and diligent development teams cannot deal with the “unknown unknowns,” a reference to serious problems so deeply hidden that they elude discovery by all laboratory prototype test methods². Therefore, full-scale tests and preliminary field trials must be conducted early as part of the development exercise, in an effort to discover unknown problems and resolve them before they pose delays to critical path activities. This early field trial approach was successfully employed in Well Trial 1, which verified well construction practices³, and Well Trial 2, where prototype electrical control valves were tested¹. The return on experience from these trials was extremely valuable, and the knowledge was integrated into the continuing technology development and operational field practices.

Executing Well Trials 1 and 2 revealed “unknown unknowns” in the pressure gauge electronics and in the assembly of the water cut sensor. Since these were tool failures, they were relatively simple to correct. During Well Trial 3, an application failure was encountered when the drill-string’s bottom-hole assembly (BHA) tracked the liner outer diameter for several hundred feet after exiting the casing window. The BHA’s resulting intersection with the electric umbilical on the outside of the 7” intelligent liner destroyed the downhole communications capability in

the well. This serious “unknown unknown” problem could not have been foreseen and prevented by effective planning; because it was an application failure, it could only be discovered by performing a field trial.

The flowchart in Fig. 1 shows an expansion of the planned evaluation for Well Trial 3. The application failure caused a program halt, indicated by the red “X.” Significant project resources were diverted to examine the failure, and the root cause was quickly determined. A team was formed to redevelop lateral exit methods and revise drilling sensor usage to eliminate a recurrence of the application failure. A new project plan was made requiring three additional parallel trials. Well Trial 4 was devised to confirm umbilical avoidance using resistivity logging and revised procedures; further details are contained in the ERC well construction section of this article. Well Trial 5 was a reduced scale trial. Well Trial 6 was a test of the full-scale installation similar to that previously attempted in Well Trial 3 and is the primary focus of this article.

ERC WELL DESIGN

Well Trial 6 was conducted on a trilateral open hole producer for a low permeability carbonate reservoir, Fig. 2a. Intelligent completions were installed in each of the three horizontal laterals and connected to the 7” wired liner using inductive couplers. The well plan with the three laterals (L-0, L-1 and L-2) is shown in Fig. 2b.

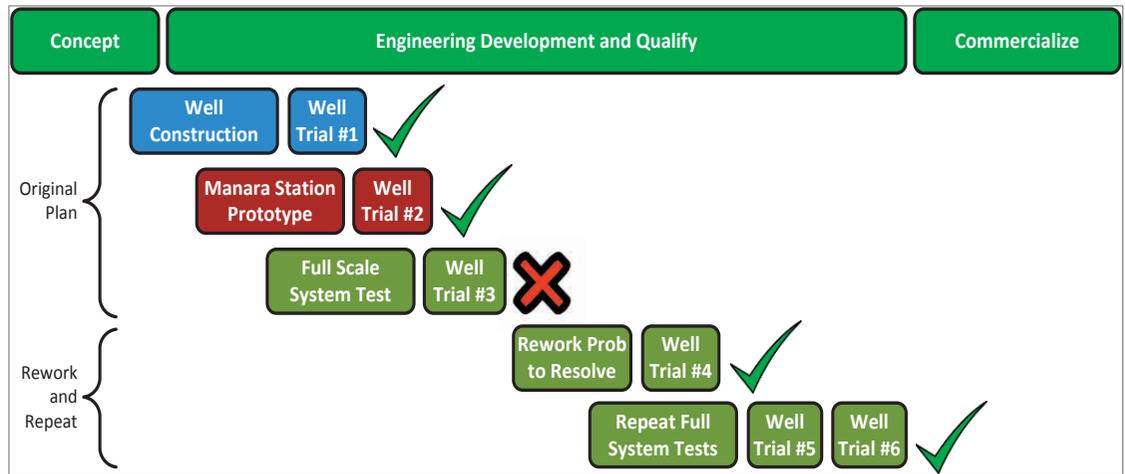


Fig. 1. Well trial flowchart.



Fig. 2a. Side view of the tested ERC well.

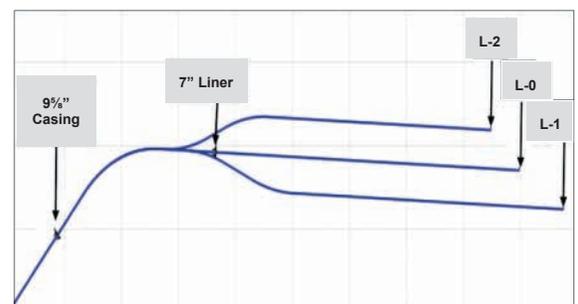


Fig. 2b. Plan view of the tested ERC well with three laterals visible.

Table 1 lists the operational steps that were used to construct this ERC well.

This well construction method became known as a DRILL-PLETION because of the repeated interweaving of drilling and completion activities. The ERC well schematic in Fig. 3 highlights the electrical path along the 7" wired liner to

each female inductive coupler. Each intelligent lateral connects to the 7" wired liner via a male inductive coupler.

The key components of an intelligent lateral completion are the male inductive coupler, feedthrough swell packers and flow control valves (FCVs) used to deliver flow monitoring and flow control capability, Fig. 4.

| Phase | Operation |
|----------|--|
| Complete | Install the 7" wired liner. |
| Drill | Drill a 6 1/8" open hole (L-0). |
| Complete | Install a two-compartment intelligent completion into L-0. |
| Drill | Mill the casing window and drill a 6 1/8" open hole (L-1). |
| Complete | Install a two-compartment intelligent completion into L-1. |
| Drill | Mill the casing window and drill a 6 1/8" open hole (L-2). |
| Complete | Install a two-compartment intelligent completion into L-2. |
| Complete | Install an upper completion, tie it into a 7" wired liner. |

Table 1. Steps of the DRILL-PLETION, alternating drilling and completion operations

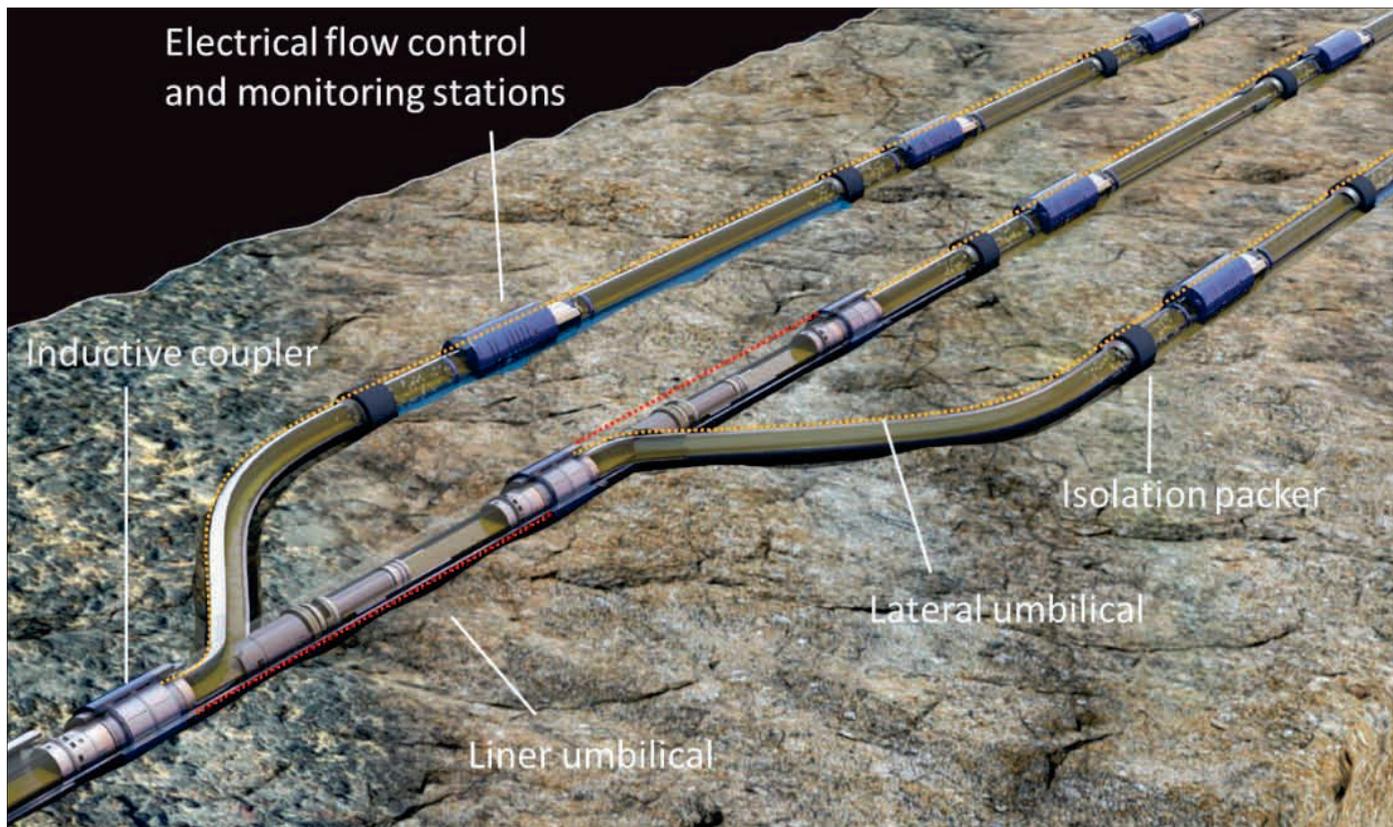


Fig. 3. ERC electrical path along the 7" wired liner to each female inductive coupler.

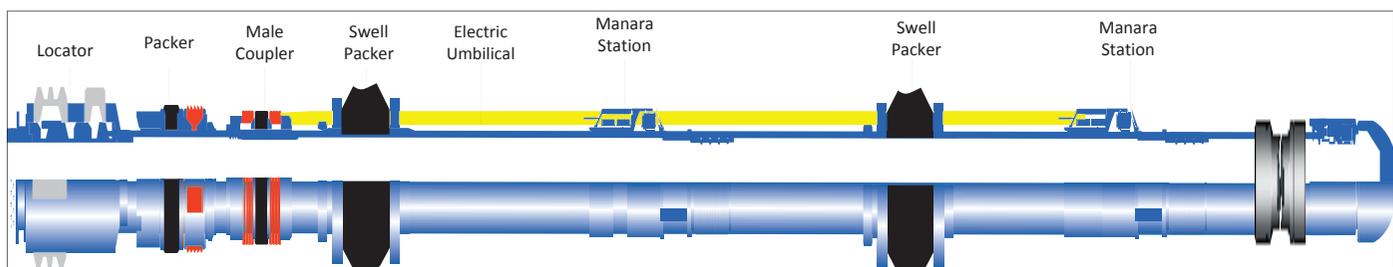


Fig. 4. Intelligent lateral completion.

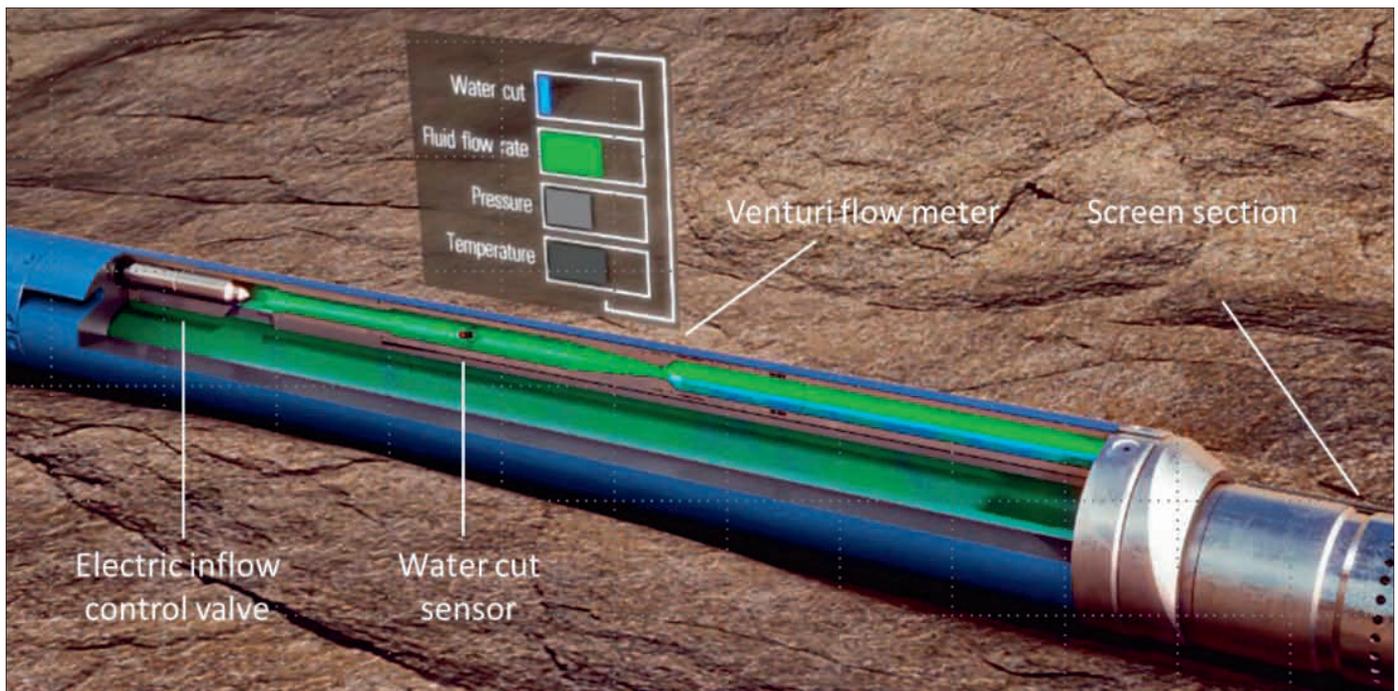


Fig. 5. Section view of a FCV.



Fig. 6. Section view of an inductive coupler.

Figure 5 is a section view through the FCV that shows the compartment's flow entering the completion by means of a parallel instrument tube. The instrument tube contains a Venturi flow meter to measure flow; sensors to measure pressure, temperature and water cut; and a variable electrical choke, which acts as an ICV to control compartmental flow.

Figure 6 illustrates an inductive coupler connector system that is “non-wet” and so does not require contacts. This “non-wet” connection is accomplished by bringing two coils together and passing alternating current (A/C) magnetic fields between them like a transformer. While inherently more reliable than a wet mate connector, it does come with its own complications: downhole power and telemetry must be A/C to pass through the coupler, and no digital electronics were used. This further enhanced reliability.

ERC WELL CONSTRUCTION

The 7” wired liner provides multiple electric sockets that act as connection points for the intelligent laterals and the upper completion — they are linked together with an external electrical umbilical. Each socket contains a female inductive coupler and an indexed casing coupling (ICC), which are paired in a previously spaced out assembly. The ICC acts as a landing profile to ensure alignment of the male and female couplers. Use of the inductive couplers, umbilical and protectors required the hole size to be increased from 8½” to 9” to improve liner deployment and cement job quality. This was achieved by running a 9” underreamer with the drilling BHA, which saved a dedicated hole opening trip. To provide exit options for window milling on laterals L-1 and L-2, the electrical umbilical

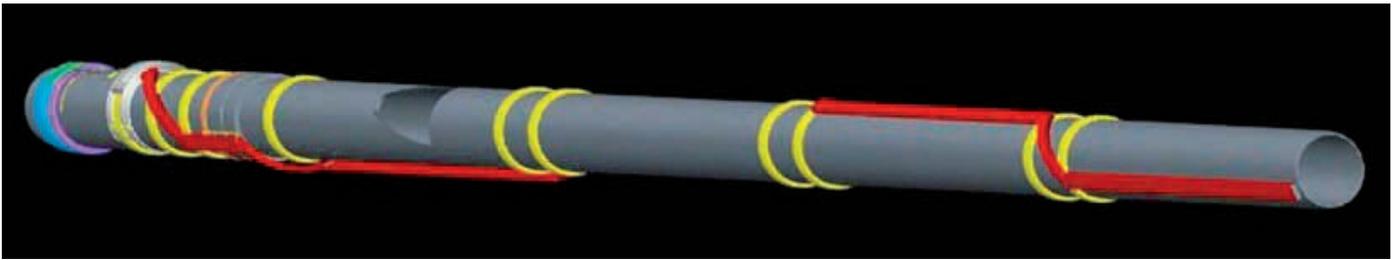


Fig. 7. Umbilical wrapping on the 7" wired liner.

was wrapped on the 7" liner, Fig. 7.

The 7" wired liner was run to total depth (TD) without rotation. The hanger was set, and the female couplers were electrically tested. The liner was cemented in place, a clean out trip was performed, and jetting of the ICCs was conducted as nec-

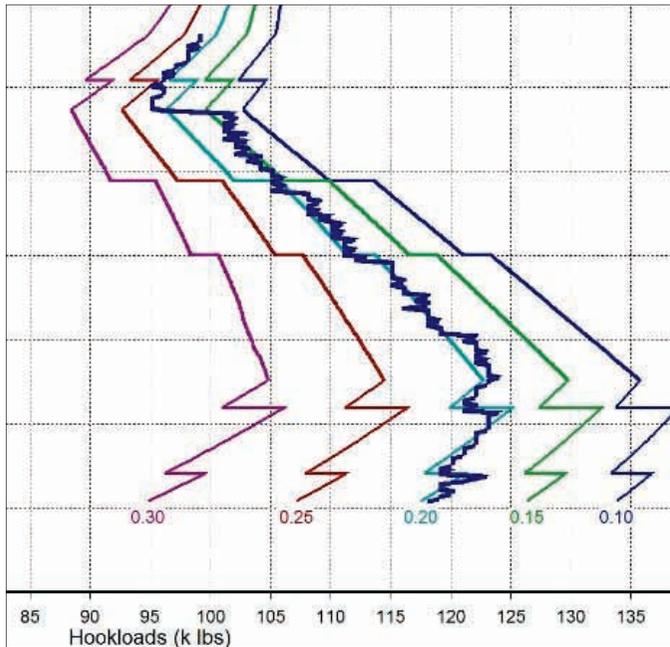


Fig. 8a. Broomstick chart of final drilling BHA clean out trip for L-0.

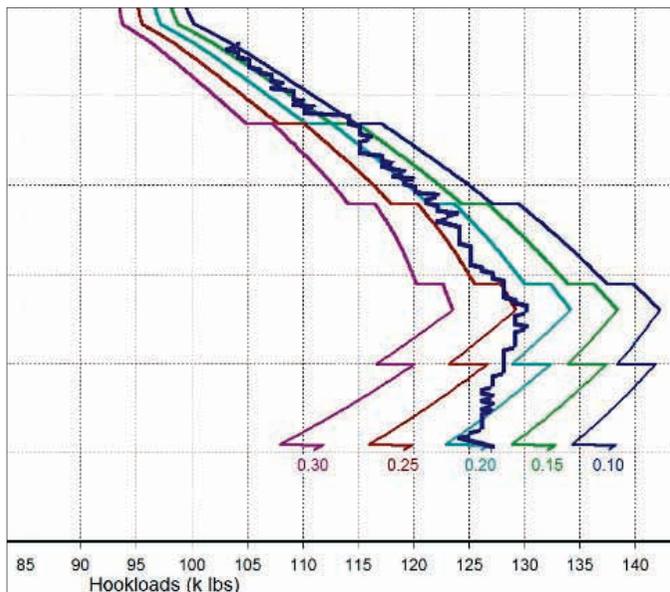


Fig. 8b. Broomstick chart of BHA completion run for L-0.

essary to ensure a positive landing. The electrical test was then repeated.

The 6½" open hole motherbore (L-0) was drilled using a conventional rotary steerable system (RSS) to maximize the rate of penetration (ROP). Clean out runs were then conducted on the 6½" open hole. Torque and drag software was used to generate models for both the clean out BHA and the completion string. Well Trials 1 to 3 showed good correlation between the clean out BHA and completion string friction factors, Figs. 8a and 8b, enabling the final clean out trip to be used as a completion dummy run. Note the zigzag nature of the chart produced using the torque and drag model, which accounts for tubing filling points while running in hole.

Clean out runs were conducted until the required friction factor was achieved. The L-0 completion, with a male inductive coupler, two FCVs and two swell packers, was made up and run to TD without rotation. Electrical tests confirmed the inductive couplers were mated and the FCVs were functioning. The packer was hydraulically set to anchor the inductive couplers in place. The running tool was released, and electrical tests were repeated prior to pulling out of the hole. L-0 was finished.

The L-1 whipstock was run and located axially and rotationally using the ICC as a downhole reference point³. This allowed a window to be milled in an upwards direction opposite of the external electrical umbilical.

For the initial lateral departure downhole, resistivity was used to eliminate the possibility of tracking the casing, as had been experienced in Well Trial 3. This involved closely monitoring real-time downhole resistivity tool data to confirm wellbore separation from the liner, taking advantage of the measured contrast between the high formation resistivity and the low resistivity response when next to the metallic liner.

Figure 9 shows a log of the successful lateral departure, in which low resistivity at the casing exit gradually increases and

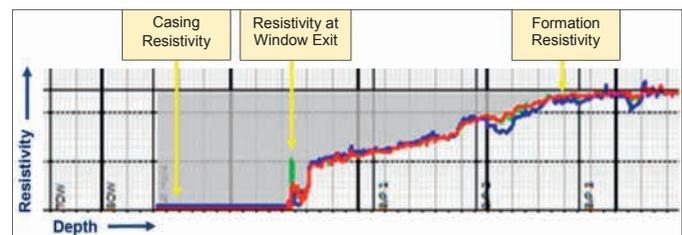


Fig. 9. Downhole resistivity response for initial lateral departure.

stabilizes at the higher formation resistivity. Should the converse occur, i.e., if low resistivity readings continued, indicating casing tracking of the BHA, drilling would be stopped to avoid collision with the umbilical.

A RSS was used to ensure a low dogleg severity for the initial lateral departure. Once reliable magnetometer directional surveys were obtained, the close monitoring of resistivity data was relaxed. This typically occurred once the BHA was 15 lateral feet beyond the liner.

L-1 was drilled to TD, and the intelligent lateral completion was successfully run and electrically tested, using the same practices described for L-0. L-1 was finished.

The L-2 window was milled and drilled to TD, and the intelligent lateral completion was successfully run and electrically tested using the same practices described for L-1. L-2 was finished.

The upper completion, including the electrical umbilical, production packer, and male inductive coupler, was run in hole and mated to the 7” wired liner inductive coupler. Total completion connectivity in all three laterals was proven by performing function tests on the six FCVs. The production packer was hydraulically set, and the electrical test was successfully repeated. ERC well construction was completed.

The procedures described here clearly illustrate the multiple handovers back and forth between drilling and completion operations. This required a new level of collaboration to ensure that the ERC well requirements were met. In many instances, completion requirements dictated the drilling procedures. This was particularly important to delivering completion friction factors for the 6½” open hole. The drilling and clean out operations had to be optimized as a joint operation since they influenced each other. Much focus was placed on using the optimum BHA, combined with effective mud conditioning and cuttings removal practices. The resulting lower ROP increased the drilling time, but the improved hole quality required fewer clean out runs to meet the friction factor requirements, so a net gain was achieved.

Other areas where completion requirements heavily influenced rig procedures included:

- The need for a 9” underreamed hole for the 7” wired liner.
- Whipstock orientation checks to avoid intersecting the umbilical.
- The need for constant velocity as opposed to weight on bit for improved window milling quality.
- Dedicated runs to perform electrical checks.

CONTROL AND MONITORING

The control and monitoring system for an ERC well can be divided into two tiers, Fig. 10. Tier-1 represents the acquisition of raw production data from the downhole FCV, which is sent to the surface control unit (SCU) located at the well site. The SCU can be regarded as a computer interface, one that routes control instructions to the downhole choke and receives downhole monitoring information. A remote terminal unit (RTU) acts as a router between the contractor’s well site equipment in Tier-1 and the operator’s network in Tier-2.

Tier-2 shows how an ERC well is controlled and monitored. The fundamental user is a control room operator located at a gas-oil separation plant who uses a real-time acquisition and control (RTAC) system server to control the FCVs. For optimal decision making, the fundamental user is provided with downhole production data, feedback data from ICV changes and health check information from the electronic circuits of the FCVs. This data is then stored in a plant information database and made available to the advanced user using the Well-Watcher Advisor visualization tool. The advanced user can be any petroleum engineer involved in well and reservoir management monitoring, from the production engineer in the local Production Group office, who looks after day-to-day well activities, to the reservoir engineer in the Reservoir Group office, who takes a longer term view of reservoir performance.

Optimum well and reservoir management requires that key performance parameters be measured at the reservoir and made available in real time, with a simple user interface available that can quickly adjust downhole flow. The ERC well

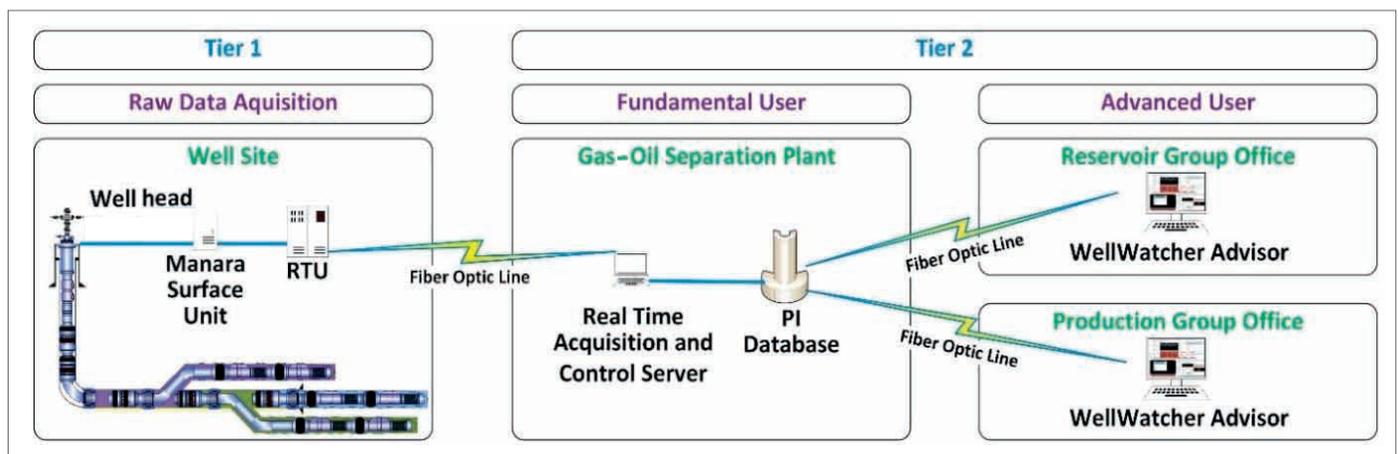


Fig. 10. The two tiers of the control and monitoring system for an ERC well.

seamlessly delivers on all these fronts. For the first time in the oil industry, the petroleum engineering user has been given the capability to truly monitor and adjust real-time production performance at the reservoir. WellWatcher Advisor converts the FCV data, monitoring data streams of flow, pressure, temperature and water cut, into real-time compartmental reservoir performance parameters, such as flow rates, drawdowns and productivity index (PI). This provides 24/7 real-time well testing and eliminates the need to perform time-consuming surface well testing or nodal analysis work. The WellWatcher Advisor visualization tool can be customized for the different users in terms of chart, graphics, alarms and tailor-made workflows.

The RTAC software allows the user, at a click of the mouse, to adjust the ICV to the required flow rate. Choke positions are now irrelevant because the measured flow rate immediately shows the result of the ICV adjustment. As flow rates are measured downhole at the compartment level, flow stabilization times are reduced to tens of minutes as opposed to hours. Some reservoirs may require an alternative production control strategy, such as drawdown control. In this instance, the ICV is adjusted to a specific drawdown, and the corresponding flow rate is monitored.

A FCV can be viewed as a completion tool that allows well and reservoir management to be performed in high definition. An improved user interface enables more frequent adjustments, giving further insights into reservoir performance. These optimizations, if applied correctly, should yield increases in reserves recovery. This improved functionality opens the door to a new way of working: “cause and effect” monitoring. Most value loops take the following form: obtain data, perform modeling exercise, make an adjustment, and review change(s). Cause and effect monitoring replaces the modeling step with adjustment sensitivity. In other words, why perform a time-consuming modeling approximation when adjustment sensitivity is quicker and easier, and gives actual results? Cause and effect monitoring also provides the user an easily assimilated learning experience, which yields further insights at all production performance levels, including compartment, lateral, reservoir, and well.

INITIAL LEARNINGS

New insights into ERC well monitoring capabilities were gained from a seven-day well cleanup program. Being able to directly view key production parameters in real time gave immediate clarity on downhole performance. One user stated, “This is how we should be performing well management on all our intelligent wells.” The improved knowl-

edge allowed the user to make timesaving program amendments. Figure 11 shows real-time data from a single FCV, including liquid rate, pressure, water cut and choke position; changes to liquid rate and pressure are observed as the choke position is changed.

The FCV capabilities can also be used to assist completion operations, providing more options for circulating fluids and identifying whether packers are properly set. In the following example, the downhole pressure responses indicated whether the compartmental swell packers were sealing. While performing the L-0 brine unloading operation, the pressure data, Fig. 12, for the two shut-in L-2 compartments showed the following:

- The upper swell packer was not sealing. The pressure responses from the L-2 upper and L-0 upper compartments were tracking, indicating communication in the wellbore.
- The lower swell packer was sealing. The differing pressure responses between the L-2 upper and L-2 lower compartments clearly indicated isolation.

The differing swelling response was because the swell packers were sitting in different fluids: the L-2 lower packer was in hydrocarbon fluid and the L-2 upper packer was in brine.

The shut-in reservoir pressures further revealed the lower compartments in each lateral to have a slightly higher reservoir pressure than the upper compartments. Figure 13 shows the buildup response for the L-0 lower compartment and the drawdown response for the L-0 upper compartment when both L-0 Manara Stations were shut-in. This pressure difference along the lateral will cause crossflow between the two L-0

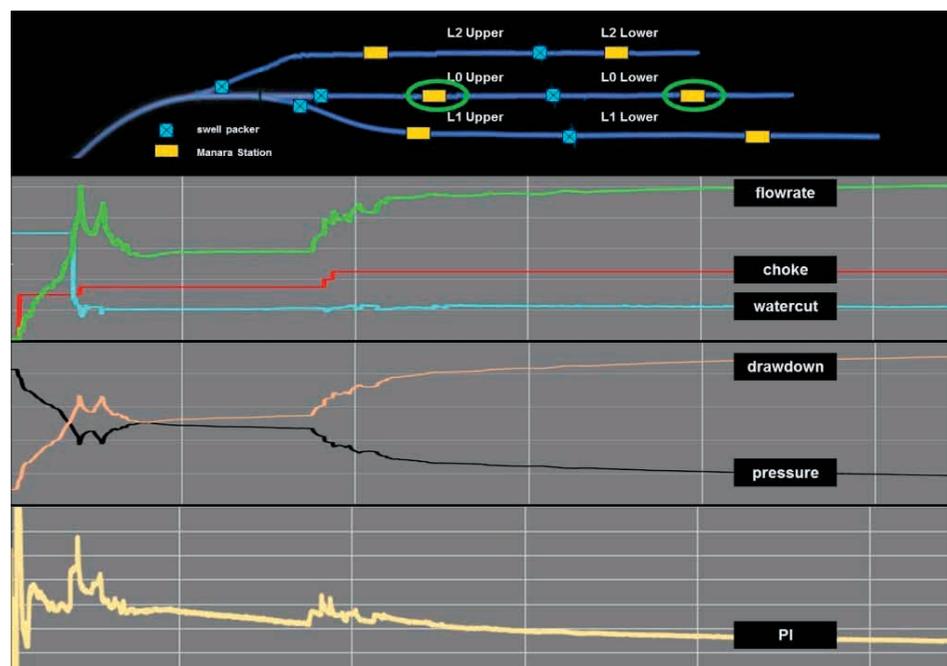


Fig. 11. Production performance plots for the L-0 lower compartment.

compartments should a surface shut-in occur during normal production. The improved pressure monitoring coverage from ERC wells will allow interference testing to be evaluated at different levels, between compartments, laterals, and wells.

Typical well cleanup operations use water cut as the cleanup criteria to indicate that the completion brine and drilling fluid losses have been produced out of the well. Typical well cleanup operations involve flowing the well until the water cut has been reduced to a low value (say, 5%), indicating that the majority of the completion brine and drilling fluid losses have been produced out of the well. As ERC wells have FCVs taking flow and pressure measurements directly at the reservoir, the cleanup criteria can now be changed to the PI. Monitoring the PI vs. time response in real time will indicate, by means of obtaining a stable PI reading, when the compartment has been fully cleaned up. PI is a much better cleanup criteria than water cut because it also determines the optimum draw-down required for filter cake removal and it identifies those zones with lower than expected PI, which may require further cleanup or stimulation. While performing cleanup by monitoring PI, the actual compartmental water cut can also be monitored and totalized. This is a huge improvement over taking grab samples during cleanup tests, which are only water cut indicators and cannot be totalized to determine if all mud losses have been recovered.

The next step is to place this ERC well onto long-term production. It is proposed to initially produce each compartment at a flow rate proportional to its length, the goal being to ensure uniform inflow into the well. Figure 14 shows these normalized production flow rates. The differing compartmental flow rates are dependent on lateral length, and compartment partitioning can be easily accommodated as the FCV can dial in the required flow rate for each compartment.

COLLABORATION AND PROGRAM MANAGEMENT

Top tier projects are often not pursued because their risk cannot be understood or managed. High level operator support only goes to top tier projects that meet the operator’s vision of how to maximize recovery. Collaboration is the key metric to articulate value and minimize risk, enabling the operator and service company to preferentially seek out and engage top tier projects.

The ERC system is a top tier project. A look back over the

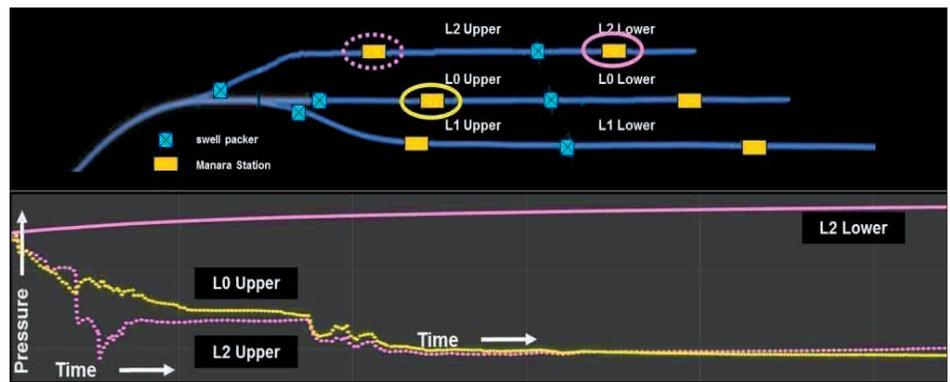


Fig. 12. Pressure in L-2 upper and lower compartments.

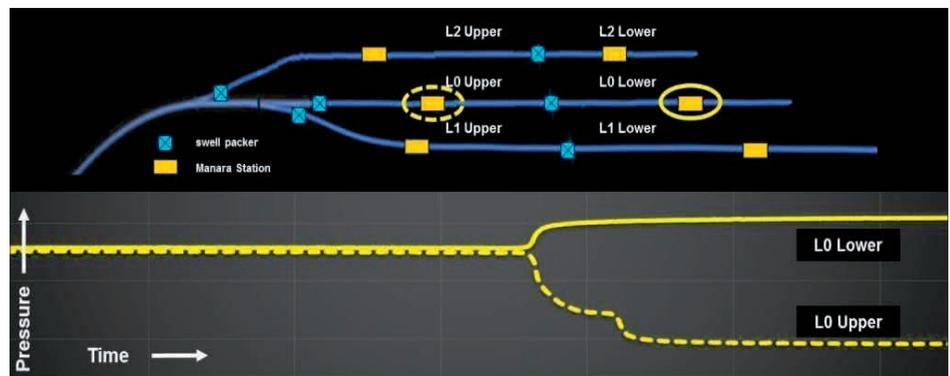


Fig. 13. L-0 upper and lower pressures.

nine-year program shows that both operator and service company provided essential contributions necessary for a successful conclusion:

- Service company risk was reduced by operator assistance with funding, alignment of application requirements and prompt field trials.
- The service company gained valuable insights into operator gatekeepers who set field requirements, which led to “buy” decisions.
- The operator obtained a better understanding of the inner workings of a service company’s development organization — a proactive culture that responds to business opportunities and not demands.
- Both parties knew that problems could occur and that close collaboration was the only means to resolve them without resorting to blame finding.

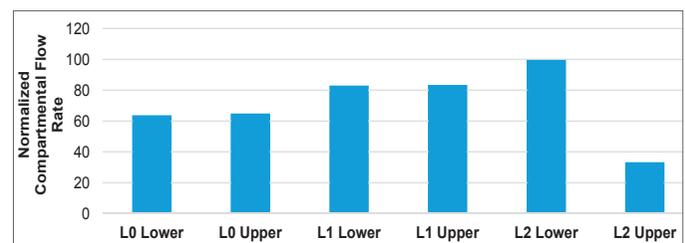


Fig. 14. Initial flow rate settings.

The project utilized a two-tier organizational structure that consisted of a project management committee and a steering committee, each with members from both operating and service companies. The project management committee created the project plan, provided monthly reports, executed day-to-day operations and acted as gatekeepers for intercompany communications. The steering committee looked after vision, project oversight, budget planning, manpower adjustments and problem resolution.

The following key learnings were very important for the successful completion of the project. They are listed here as a profound reminder about their importance when executing complex projects:

1. Make requirements run the project: The ERC team used project requirements as the authority when making day-to-day decisions. All plans were actively defended, and the team primarily used peer consensus to reach decisions. In other words, the requirements were the decision maker, not any one individual. This helped to reduce interpersonal bias and company culture clashes. This approach was particularly useful when traditional methods had to be abandoned, requiring people to work outside their comfort zones. Developers have a natural bias to work on what they know. Prioritizing requirements forced team members to focus on the necessary, rather than the familiar.
2. Integrate research and development: Multiple development teams in different locations worked together to design and validate the ERC subsystems, including the inductive coupler, multi-chip module electronics, electromechanical actuator, water cut sensor, telemetry and SCU. These subsystems were integrated into a preliminary downhole package and run in Well Trial 2 to expose “unknown unknown” problems and for early evaluation. Surface evaluations were also conducted to calibrate the measurement accuracy of the water cut sensor⁴. Successful results meant that confidence was increased and the maturity of the subsystems was proven. Conversely, problems exposed could be corrected before building final configurations.
3. Use phased well trials: Early field tests were conducted in Well Trial 1 to provide proof of a powered junction, including umbilical branching, umbilical orientation behind the liner and horizontal open hole conditioning. Well Trial 2 tested a pre-production version of the FCV and sensing platform. Without these phased tests, the impact of severing the umbilical in Well Trial 3 might have derailed the project. Return on experience through phased field trials was an essential complement to traditional design validation and verification processes.
4. Recognize post-trial responsibilities: Development and implementation teams must continue working until product functionalities are fully embedded into the operator’s processes, so that optimum value is obtained.

5. Expect problems, problems, and more problems: Complex development projects can generate so many problems that team members become discouraged. Leaders must “stay the course,” convincing team members and stakeholders that all problems can eventually and fully be solved. This encourages team members to highlight concerns as soon as possible. Early problem identification and resolution are core team values to be pursued.
6. Know that uncertainty is a given: No one can accurately predict the future; projects change, work estimates are wrong, specifications are not attainable, requirements creep, markets evolve, etc. Concrete decisions must be made from imperfect information to keep the project moving forward. The team leader must primarily be a consensus builder, but there will be times when the team leader must be the sole decision maker. Making a wrong decision is still better than making no decision, as lessons learned will provide guidance to making the right decision.

CONCLUSIONS

1. The ERC project combined the capabilities of multilateral wells and intelligent completions. A full-scale system was developed and successfully tested in a Saudi Arabian well. Initial flow testing with the system has just begun.
2. Flow measurement and control capabilities were integrated into a single electrical module. The FCV was designed to measure pressure, temperature, flow and water cut, and to control flow with an infinitely variable orifice.
3. A new generation connector system based on inductive coupling was developed. The inductive coupler can be used to branch umbilicals (ERC) or to provide two trip capabilities for extended reach wells or for electrical submersible pump/safety valve replacements.
4. The ERC system should solve many basic industry problems, increase well production rates, increase recovery factors and reduce field development costs.
5. A new level of collaboration was required to complete this long and expensive project. Many best practices were documented for how best to select, plan and execute high risk/high reward projects.

ACKNOWLEDGMENTS

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BIOGRAPHIES



Brett W. Bouldin has been with Saudi Aramco for 7 years, working as a Petroleum Engineer Consultant in the Production Technology Division of Saudi Aramco's Exploration and Petroleum Engineering Center – Advanced Research Center (EXPEC

ARC). He has over 34 years of product development experience in the completions industry, first with Baker Hughes, then as a founder of WellDynamics, later acquired by Halliburton.

Brett currently initiates and manages completions development projects, focusing on new tools and systems that improve production recovery, mainly dealing with next-generation intelligent completion systems.

He has authored or coauthored seven technical papers and over 35 U.S. patents.

Brett received his B.S. degree in Industrial Engineering from Texas A&M University, College Station, TX, and is a Registered Professional Engineer in Texas.



Robert "Rob" J. Turner is a Petroleum Engineering Specialist in the Advanced Completions focus area of the Production Technology Team of Saudi Aramco's Exploration and Petroleum Engineering Center – Advanced Research Center (EXPEC

ARC). During his 30 years in the oil industry, he has worked in the U.K., Australia and Southeast Asia for operators Shell, BHP Billiton and Chevron. This has enabled Rob to gain experience in land, platform and subsea operations for a variety of oil and gas, brownfield and greenfield projects. He has held positions in all life cycle stages of hydrocarbon development, including project development,

completion operations and reservoir management.

For the last 10 years, Rob has specialized in smart fields, from smart well justification, functional specification, project engineering and installation to commissioning and reservoir management. Prior to joining Saudi Aramco, he was the smart fields' technical expert for Brunei Shell Petroleum, the leading operator in the Asian region for smart well installations.

Rob received his B.S. degree in Chemical Engineering from Leeds University, Leeds, U.K., and an M.Eng. degree in Petroleum Engineering from Heriot-Watt University, Edinburgh, U.K.



Isidore "Ike" Bellaci has 34 years of oil and gas industry experience, predominantly in a reservoir engineering capacity. His extensive experience includes 15 years with the ARCO Oil & Gas Company in Houston, London, Bakersfield and Anchorage

before joining Saudi Aramco in 1998.

As a Senior Petroleum Engineering Consultant in the Northern Area Reservoir Management Department, Ike has worked on mega-projects and several expansions, including Abu Hadriyah/Fadhili/Khursaniyah (AFK), Manifa and Shaybah fields. He is currently the Reservoir Management Supervisor for the Shaybah field, which has over 100 multilateral wells equipped with intelligent completions.

Ike received his B.S. degree in Petroleum Engineering from Louisiana State University, Baton Rouge, LA.



Yousif M. Abu Ahmad joined Saudi Aramco in 2005 as a Tool Pusher and Foreman working in the Southern Area Drilling Operations Department. His field experience includes onshore, offshore and workover operations. In 2010, Yousif was selected for a one

year out-of-Kingdom developmental assignment with Baker Hughes, gaining practical experience from working in U.S. drilling operations.

He has 11 years of experience, including work as a Rig Foreman, Drilling Optimization Engineer, Workover Engineer and Senior Drilling Engineer in Saudi Aramco's Exploration and Oil Drilling Engineering Department. Yousif is currently on a developmental assignment with the Contract Administration Division as a Contract Advisor.

He was a key member in the Manara team and was a major contributor to the planning, execution and successful delivery of the first extreme reservoir contact (ERC Manara) well in the world.

Yousif has published several technical papers on drilling optimization, technologies and field studies. He is an active member of the Society of Petroleum Engineers (SPE) and is a certified SPE Petroleum Engineer.

In 2004, he received his B.S. degree in Science in Mining Engineering from the University of Arizona, Tucson, AZ.



Steve Dyer has worked with Schlumberger since 1991, and is currently the Product Line Manager for Intelligent Completions, Isolation and Safety Valves in Houston. From 2007 to 2014 he ran a carbonate research program in Saudi Arabia

focused on stimulation, smart water enhanced recovery methods and next generation intelligent completion systems for extended reach and multilateral wells.

He received his B.S. degree (with Honors) in Mechanical Engineering from Loughborough University, Loughborough, U.K.



Thales De Oliveira has 15 years of oil field experience with Schlumberger, running field trials on newly developed completions and multilateral equipment. In 2008, he joined the Multilateral Product Group in Houston to provide technical

support for complex projects.

In 2013, Thales transferred to Saudi Arabia as Technical Champion and Field Coordinator for the Manara Monitoring and Production Control System. Currently, he is a Project Manager in Saudi Arabia and Bahrain for special completion projects.

Thales has a B.S. degree in Electromechanics from the Federal Institute of Technology of Rio Grande do Norte, Natal, Brazil.



Ali Bin Al-Sheikh is a Completion Project Manager working for Schlumberger in Russia. He has 9 years of oil field experience, which includes running intelligent completions, permanent downhole monitoring systems and new

completions technology. In his current position, Ali is responsible for managing a Manara System installation.

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

From a Technology User to an Innovation Leader

Julie L. Springer

To remain a leader in the energy sector, Saudi Aramco must continue to create technologies that are commercially viable and globally competitive. This can only be accomplished through a balanced portfolio of world-class, high-value intellectual property (IP).

A patent, just one form of IP, is an exclusive right granted by governments for an invention, which may be a product or a process that provides a new and inventive way of doing something or that offers a new and inventive technical solution to a problem. For an idea to become a patent, the idea must demonstrate four characteristics: It must be novel, non-obvious, applicable and useful.

A well-developed IP portfolio gives Saudi Aramco a competitive advantage, validates the contributions made by our scientists and researchers, solidifies our position as a technology leader in the energy and chemicals fields, and provides commercialization opportunities. Patents provide value to the company and the Kingdom by enabling Saudi Aramco to deploy the patented technologies without the fear of competitors taking the idea to develop the same or similar technology. Patents also enhance the company's reputation as a technology leader. A patent furthermore can stimulate the local economy by creating opportunities for new business that leverages the patented advanced technology.

For Saudi Aramco, the journey to secure patents began over 65 years ago.

In 1950, Saudi Aramco received its first patent — for the invention of the oil and gas separator by Aramco employee Edward Van Dornick.

Between that time and 2000, however, the company was only granted a total of 16 patents. This low number spurred the development of a process and the creation of a team that would capture, protect and facilitate patents. The Intellectual Assets Management team was created to oversee and manage the entire IP process — from idea, to patent approval, to technology deployment and commercialization. The team established an Idea Management System (IMS), an online system that allows tracking of ideas from submission to potential implementation. All employees were encouraged to access the system so they could submit ideas, track their progress and read ideas submitted by others.

Shortly thereafter, Saudi Aramco launched the Corporate

Innovation Initiative. The 14-member Corporate Innovation Committee developed and coordinated the initiative. Its goal was to inspire innovation in employees at all levels and to regularly recognize Saudi Aramco employees for noteworthy creative achievements. The first patent ceremony providing that recognition was held in 2003, celebrating 22 cumulative patents. Patent awardees and top innovators were recognized by corporate management.

In 2004, 22,000 suggestions were submitted to the company's IMS, resulting in improvements that saved the company more than \$600 million.

Saudi Aramco celebrated the 100th patent granted to the company in 2010 with an event that reviewed the history of the company's growth in IP, showcased the company's patent progress and recognized inventors.

The following year, Saudi Aramco launched the Accelerated Transformation Program, which would make technology a key priority imperative for the company.

But with the increase in patent activity came numerous challenges, due to the slow and arduous process of patent filing. It could take up to a year to file a patent, so the IP Law Group was established in 2012, and the process to acquire patents was optimized to ensure we maintained a best-in-class patent application "time-to-file" average of three to four months.

In 2014, the company was granted 99 patents, and it filed 154 new patent applications. The patents related to a diverse selection of Saudi Aramco's businesses and operations, including oil and gas upgrading, drilling, refining, pipelines, and petroleum engineering. The increase in patents granted was indicative of the progress made as a result of the initiatives launched to support the filing process.

That same year, the company made the goal of 100 patents granted per year a key performance indicator. Measures were also put in place to ensure the company only sought patents for quality ideas that delivered a true breakthrough, unique approach or unique solution.

Last year, the company was granted 175 patents by the United States Patent and Trademark Office, 52 more patents than 2015, which puts Saudi Aramco third among oil and gas companies worldwide in the number of patents granted. This ability to create high-impact patents positions Saudi Aramco as a leader in the area of innovation.

To date, 768 patents have been granted to Saudi Aramco.

Contributing to the company's success is the "open network" innovation model that facilitates strategic alliances with world-class organizations, enabling Saudi Aramco to enhance our competitiveness and to expand our global technology footprint. The collaborations that resulted have contributed to the rise in the number of patented technologies that have been developed in shared efforts between Saudi Aramco and its partners, including leading technical innovators in the industry as well as leading academic institutions in-Kingdom and around the world, in particular, our Global Research Centers that are strategically located to leverage these types of partnerships.

At Saudi Aramco, we continuously strive to leverage our IP portfolio, practices and processes to position the company as a global technology leader. We pursue patents in areas where IP protection provides a competitive advantage, global recognition, strategic positioning and product differentiation.

Our journey to acquiring 100 patents per year through our high-value patent activity highlights the efforts of the people of Saudi Aramco, who work hard applying their expertise and ingenuity to create solutions to some of society's most pressing challenges.

BIOGRAPHY



Julie L. Springer is a Communications Strategist for the Technology, Oversight and Coordination (TOC) Planning Department managing the communication needs in support of the company's downstream, cross-business and sustainability technology portfolios. She has over 16 years of experience providing communications and public relations support to some of the world's most high profile companies, including Shell, Halliburton and Dell.

Julie is the recipient of both the Public Relations Society of America (PRSA) Bronze Quill Award and the American Marketing Award for the re-branding and positioning of Shell subsidiary Shell Energy North America.

She received her B.A. degree in Mass Communications and English from Texas State University, San Marcos, TX.

SAUDI ARAMCO PATENTS GRANTED 2016

Integrated Hydroprocessing and Steam Pyrolysis of Crude Oil to Produce Light Olefins and Coke

Granted Patent: U.S. Patent 9,228,139, Grant Date: January 5, 2016

Raheel Shafi, Abdennour Bourane, Abdulrahman Akbras, Essam Sayed and Ibrahim A. Abba

Integrated Hydroprocessing, Steam Pyrolysis and Catalytic Cracking Process to Produce Petrochemicals from Crude Oil

Granted Patent: U.S. Patent 9,228,140, Grant Date: January 5, 2016

Ibrahim A. Abba, Raheel Shafi, Abdennour Bourane, Essam Sayed and Abdulrahman Akbras

Integrated Hydroprocessing, Steam Pyrolysis and Slurry Hydroprocessing of Crude Oil to Produce Petrochemicals

Granted Patent: U.S. Patent 9,228,141, Grant Date: January 5, 2016

Essam Sayed, Raheel Shafi, Abdulrahman Akbras, Abdennour Bourane and Ibrahim A. Abba

Completion Method to Allow Dual Reservoir Saturation and Pressure Monitoring

Granted Patent: U.S. Patent 9,228,427, Grant Date: January 5, 2016

Fahad A. Al-Ajmi

Methods Program Code, Computer Readable Media and Apparatus for Predicting Matrix Permeability by Optimization and Variance Correction of K-Nearest Neighbors

Granted Patent: U.S. Patent 9,229,127, Grant Date: January 5, 2016

Nicolas Leseur

Olefin Hydration Process with an Integrated Membrane Reactor

Granted Patent: U.S. Patent 9,233,349, Grant Date: January 12, 2016

Ibrahim Abba, Aadesh Harale, Abdulrahman Vogel and Wei Xu

Process for the Gasification of Heavy Residual Oil with Particulate Coke from a Delayed Coking Unit

Granted Patent: U.S. Patent 9,234,146, Grant Date: January 12, 2016

Omer R. Koseoglu

System, Method and Apparatus for Combined Ball Segment Valve and Check Valve

Granted Patent: U.S. Patent 9,234,598, Grant Date: January 12, 2016

Omar M. Al-Amri

Apparatus for Evaluating Rock Properties While Drilling Using Drilling Rig-Mounted Acoustic Sensors

Granted Patent: U.S. Patent 9,234,974, Grant Date: January 12, 2016

Yunlai X. Yang

Systems, Methods and Computer Medium to Securely Transfer Backup Data between Physically Isolated Networks Having Different Levels of Network Protection

Granted Patent: U.S. Patent 9,235,724, Grant Date: January 12, 2016

Paul Mevec and Ibrahim Marhoon

Carbon Dioxide Conversion to Hydrocarbon Fuel via Syngas Production Cell Harnessed from Solar Radiation

Granted Patent: U.S. Patent 9,238,598, Grant Date: January 19, 2016

Ahmad Hammad, Zaki Yusuf, Stamatios Souentie, Nayif A. Al-Rasheedi, Bandar A. Fadhel and Atef S. Al-Zahrani

System, Methods and Computer Medium to Enhance Redeployment of Web Applications after Initial Deployment

Granted Patent: U.S. Patent 9,239,717, Grant Date: January 19, 2016

Hussain Al-Saeed

Outer Surface Inspecting Robot with Flipping Over Flange Mechanism

Granted Patent: U.S. Patent 9,239,297, Grant Date: January 19, 2016

Fadi Sibai

Sulfur-Modified Polyvinyl Acetate

Granted Patent: U.S. Patent 9,243,167, Grant Date: January 26, 2016

Mohammed H. Al-Mebthel, Saleh H. Al-Idi, Hamad I. Al-Abdulwahhab, Ibelwaleed A. Hussein and Mohammed A. Suleiman

Flow Line Mounting Arrangement for Flow System Transducers

Granted Patent: U.S. Patent 9,243,942, Grant Date: January 26, 2016

Michael John Black, Mohamed N. Noui-Mehidi and Talha J. Ahmad

Heavy Oil Ash in Roofing, Damp-Proofing and Waterproofing Applications

Granted Patent: U.S. Patent 9,249,304, Grant Date: February 2, 2016

Mohammed H. Al-Mebthel, Saleh H. Al-Idi, Ibelwaleed A. Hussein and Hamad I. Al-Abdulwahhab

Method and Tracking Device for Tracking Movement in a Marine Environment with Tactical Adjustments to an Emergency Response

Granted Patent: U.S. Patent 9,250,329, Grant Date: February 2, 2016
Peter R. O'Regan and Ali A. Al-Mohsen

Integrated Hydrotreating and Steam Pyrolysis Process for Direct Processing of a Crude Oil

Granted Patent: U.S. Patent 9,255,230, Grant Date: February 9, 2016
Raheel Shafi, Julio Hasselmeyer, Abdenmour Bourane, Ibrahim A. Abba and Abdulrahman Akhras

Systems, Computer Medium and Computer-Implemented Methods for Providing Health Information to Employees via Augmented Reality Display

Granted Patent: U.S. Patent 9,256,711, Grant Date: February 9, 2016
Samantha Horseman

Process for the Treatment of Heavy Oils Using Light Hydrocarbon Components as a Diluent

Granted Patent: U.S. Patent 9,260,671, Grant Date: February 16, 2016
Raheel Shafi, Esam Z. Hamad, Stephane C. Kressmann and Ali H. Al-Zaid

Automatic Recovery of Reservoir Simulation Runs from Processing System Failures

Granted Patent: U.S. Patent 9,262,560, Grant Date: February 16, 2016
M. Ehtesham Hayder and Majdi Baddourah

Utilization of Heavy Oil Ash to Produce Self-Consolidated Concrete

Granted Patent: U.S. Patent 9,266,776, Grant Date: February 23, 2016
Mohammed Al-Mehthel, Fahad R. Al-Dossari, Mohammed Maslebuiddin, Rizwan Ali and Mohammed S. Barry

Emission Reduction from Mobile Sources by On-Board Carbon Dioxide Conversion to Fuel

Granted Patent: U.S. Patent 9,267,429, Grant Date: February 23, 2016
Hasan Imran, Musaed S. Al-Ghrami, Aadesh Harale, Jean-Pierre R. Ballaguet and Aqil Jamal

Apparatus, Method and System for Detecting Salt in a Hydrocarbon Fluid

Granted Patent: U.S. Patent 9,267,909, Grant Date: February 23, 2016
Naim Akmal, Rashed M. Aleisa and Milind M. Vaidya

Real-Time Dynamic Data Validation Apparatus and Computer Readable Media for Intelligent Fields

Granted Patent: U.S. Patent 9,268,057, Grant Date: February 23, 2016
Abdel N. Abitrabi, Fahad Al-Ajmi, Majed Awajy and Marc Lamontagne

High Density Cement Formulation to Prevent Gas Migration Problems

Granted Patent: U.S. Patent 9,273,242, Grant Date: March 1, 2016
Abdullah S. Al-Yami and Ahmed Al-Humaidi

Integrated Hydrotreating and Steam Pyrolysis Process Including Hydrogen Redistribution for Direct Processing of a Crude Oil

Granted Patent: U.S. Patent 9,279,088, Grant Date: March 8, 2016
Raheel Shafi, Abdenmour Bourane, Ibrahim A. Abba and Abdulrahman Z. Akhras

Polymer-Enhanced Surfactant Flooding for Permeable Carbonates

Granted Patent: U.S. Patent 9,284,480, Grant Date: March 15, 2016
Ming Han, Ali A. Al-Yousif, Alhasan Fuseni and Salah H. Al-Saleh

Catalyst for Enhanced Propylene in Fluidized Catalytic Cracking

Granted Patent: U.S. Patent 9,284,492, Grant Date: March 15, 2016
Musaed S. Al-Ghrami, Cemal Ercan, Abdullah M. Aitani, Sulaiman S. Al-Khattaf and Mohammed Siddiqui

Integrated Solvent Deasphalting and Steam Pyrolysis Process for Direct Processing of a Crude Oil

Granted Patent: U.S. Patent 9,284,497, Grant Date: March 15, 2016
Abdenmour Bourane, Raheel Shafi, Essam Sayed, Ibrahim A. Abba and Abdulrahman Akhras

Integrated Slurry Hydroprocessing and Steam Pyrolysis of Crude Oil to Produce Petrochemicals

Granted Patent: U.S. Patent 9,284,501, Grant Date: March 15, 2016
Essam Sayed, Raheel Shafi, Abdulrahman Akhras, Abdenmour Bourane and Ibrahim A. Abba

Integrated Solvent Deasphalting, Hydrotreating and Steam Pyrolysis Process for Direct Processing of a Crude Oil

Granted Patent: U.S. Patent 9,284,502, Grant Date: March 15, 2016
Abdenmour Bourane, Raheel Shafi, Essam Sayed, Ibrahim A. Abba and Abdulrahman Akhras

Characterization of Crude Oil by Ultraviolet Visible Spectroscopy

Granted Patent: U.S. Patent 9,285,307, Grant Date: March 15, 2016

Omer R. Koseoglu, Adnan Al-Hajji and Gordon Jamieson

Wastewater Treatment Process Including Irradiation of Primary Solids

Granted Patent: U.S. Patent 9,290,399, Grant Date: March 22, 2016

William G. Conner, Osama I. Fageeha and Thomas E. Schultz

Process for High Severity Catalytic Cracking of Crude Oil

Granted Patent: U.S. Patent 9,290,705, Grant Date: March 22, 2016

Abdenmour Bourane, Musaed S. Al-Ghrami, Ibrahim A. Abba, Wei Xu and Kareemuddin M. Shaik

Process to Reduce Acidity of Crude Oil

Granted Patent: U.S. Patent 9,295,957, Grant Date: March 29, 2016

Ki-Hyouk Choi and Ali H. Al-Shareef

Targeted Desulfurization Process and Apparatus Integrating Oxidative Desulfurization and Hydrodesulfurization to Produce Diesel Fuel Having an Ultra-Low Level of Organosulfur Compounds

Granted Patent: U.S. Patent 9,296,960, Grant Date: March 29, 2016

Abdenmour Bourane, Omer R. Koseoglu and Mohammed I. Katheeri

Integrated Hydrotreating and Steam Pyrolysis Process Including Residual Bypass for Direct Processing of a Crude Oil

Granted Patent: U.S. Patent 9,296,961, Grant Date: March 29, 2016

Rabeel Shafi, Abdenmour Bourane, Ibrahim A. Abba, Esam Sayed and Abdulrahman Z. Akbras

Direct Densification Method and System Utilizing Waste Heat for On-Board Recovery and Storage of CO₂ from Motor Vehicle Internal Combustion Engine Exhaust Gases

Granted Patent: U.S. Patent 9,297,285, Grant Date: March 29, 2016

Esam Hamad

Method to Determine Trace Amounts of Crude Oil by Spectroscopic Absorption

Granted Patent: U.S. Patent 9,297,747, Grant Date: March 29, 2016

Ming Han, Ali Al-Yousef, Salah Al-Saleh, Mohammed Algeer and Abdullah Alboqmi

Submersible Pump Systems and Methods

Granted Patent: U.S. Patent 9,303,496, Grant Date: April 5, 2016

Jimjiang Xiao and Randall A. Shepler

Downhole Wireless Data and Power Transmission System

Granted Patent: U.S. Patent 9,303,507, Grant Date: April 5, 2016

Michael J. Black, Brett W. Bouldin and Mohamed N. Noui-Mehidi

Sulfur Asphalt in Roofing, Damp-Proofing and Waterproofing

Granted Patent: U.S. Patent 9,309,441, Grant Date: April 12, 2016

Mohammed H. Al-Mehthel, Saleh H. Al-Idi, Ibmehwaleed A. Hussein and Hamad I. Al-Abdulwahhab

Method to Improve Conformance Control in Carbon Dioxide Flooding

Granted Patent: U.S. Patent 9,309,754, Grant Date: April 12, 2016

Fawaz Al-Otaibi and Sunil L. Kokal

GSM/GPRS Based Method, System and Computer Programs to Determine and Locate High Impedance Faults on Medium Voltage Distribution Networks in High Resistivity

Granted Patent: U.S. Patent 9,310,416, Grant Date: April 12, 2016

Sami H. Al-Ghannam and Yasin Khan

Automated Saw Cut Correction for 3D Core Digital Modeling from Computerized Tomography Scanner (CTS) Images

Granted Patent: U.S. Patent 9,311,720, Grant Date: April 12, 2016

Mokhles M. Mezghani

Asphalt Production from Solvent Deasphalting Bottoms

Granted Patent: U.S. Patent 9,315,733, Grant Date: April 19, 2016

Omer R. Koseoglu, Salman Al-Khaldi, Adnan Al-Hajji and Ali Al-Hamad

Ebullated-Bed Process for Feedstock Containing Dissolved Hydrogen

Granted Patent: U.S. Patent 9,315,745, Grant Date: April 19, 2016

Omer R. Koseoglu

Hinged Vehicle Chassis

Granted Patent: U.S. Patent 9,321,306, Grant Date: April 26, 2016

Ali Outa, Brian J. Parrott, Pablo Carrasco and Fadl Abdel Latif

Energy-Efficient and Environmentally Advanced Configurations for Naphtha Hydrotreating Process

Granted Patent: U.S. Patent 9,321,972, Grant Date: April 26, 2016

Mahmoud B. Noureldin and Ahmed S. Bunaiyan

Economical Heavy Concrete Weight Coating for Submarine Pipelines

Granted Patent: U.S. Patent 9,322,491, Grant Date: April 26, 2016

Mohammed Al-Mehthel, Bakr Hammad, Alaeddin A. Alsharif, Mohammed Maslehuddin and Mohammed Ibrahim

Method of Determining a Formation Parameter

Granted Patent: U.S. Patent 9,322,948, Grant Date: April 26, 2016

Ed Clerke and Raghu Ramamoorthy

Non-Hyperbolic Correction of Seismic Data

Granted Patent: U.S. Patent 9,329,291, Grant Date: May 3, 2016

Ali Al-Momin, Yi Luo and Tong Fei

Synthesis of Ultra-Small Pore Aluminosilicates by Controlled Structural Collapse of Zeolites

Granted Patent: U.S. Patent 9,333,482, Grant Date: May 10, 2016

Yuguo Wang, Cemal Ercan, Rashid Othman, Minkee Choi and Hyeonbin Kim

Environment Friendly Base Fluid to Replace the Toxic Mineral Oil-Based Base Fluids

Granted Patent: U.S. Patent 9,334,437, Grant Date: May 10, 2016

Md Amanullah

High Quality Middle Distillate Production Process

Granted Patent: U.S. Patent 9,334,451, Grant Date: May 10, 2016

Omer R. Koseoglu, Adnan Al-Hajji, Ali M. Al-Somali, Hendrik Muller and Mohammed A. Al-Ghamdi

Method of Using a Non-Acidic Stimulation Fluid in High Temperature Sandstone Formations

Granted Patent: U.S. Patent 9,334,721, Grant Date: May 10, 2016

Mohammad N. Al-Dablan, Khalid A. Al-Dossary and Abdullah M. Al-Harith

Methods for Geosteering a Drill Bit in Real Time Using Surface Acoustic Signals

Granted Patent: U.S. Patent 9,334,723, Grant Date: May 10, 2016

Yunlai Yang

Integrated Nodes, Computer Readable Media and Program Products, and Computer-Implemented Methods for Providing an Integrated Node for Data Acquisition and Recovery, and for Remote Subsystem Control

Granted Patent: U.S. Patent 9,338,224, Grant Date: May 10, 2016

Soloman M. Al-Madi, Soliman A. Al-Walaie and Tofiq A. Al-Dhubaib

Wastewater Treatment System Including Irradiation of Primary Solids

Granted Patent: U.S. Patent 9,340,441, Grant Date: May 17, 2016

William G. Conner, Osama I. Fageeba and Thomas E. Schultz

Utilization of Microwave Technology in Enhanced Oil Recovery Process for Deep and Shallow Applications

Granted Patent: U.S. Patent 9,341,050, Grant Date: May 17, 2016

Khaled A. Al-Buraik

Foamed Sulfur Asphalts for Pavement Recycling and Soil Stabilization

Granted Patent: U.S. Patent 9,346,956, Grant Date: May 24, 2016

Mohammed Al-Mehthel, Saleh Al-Idi, Hamad Al-Abdulwahab and Ibtelwaleed A. Hussein

Method for Optimizing Catalyst Loading for Hydrocracking Process

Granted Patent: U.S. Patent 9,347,006, Grant Date: May 24, 2016

Omer R. Koseoglu, Adnan Al-Hajji, Hendrik Muller, Masaru Ushio and Koji Nakano

Systems and Methods for Ground Fault Immune Data Measurement Systems for Electronic Submersible Pumps

Granted Patent: U.S. Patent 9,347,311, Grant Date: May 24, 2016

Jinjiang Xiao and Mike Manning

Proactive Failure Recovery Model for Distributed Computing Using a Checkpoint Frequency Determined by a Mean Time before Failure (MTBF) Threshold

Granted Patent: U.S. Patent 9,348,710, Grant Date: May 24, 2016

Khalid S. Alwahabi

Sulfone Cracking Using Supercritical Water

Granted Patent: U.S. Patent 9,353,318, Grant Date: May 31, 2016

Omer R. Koseoglu, Abdennour Bourane and Farhan Al-Shahrani

Permeable Lost Circulation Drilling Liner

Granted Patent: U.S. Patent 9,353,584, Grant Date: May 31, 2016

John T. Allen and Brett Bouldin

Electromagnetic Assisted Ceramic Materials for Heavy Oil Recovery and In Situ Steam Generation

Granted Patent: U.S. Patent 9,353,612, Grant Date: May 31, 2016

Sameeh Issa Batarseh

Fluid Homogenizer System for Gas Segregated Liquid Hydrocarbon Wells and Method of Homogenizing Liquids Produced by Such Wells

Granted Patent: U.S. Patent 9,353,614, Grant Date: May 31, 2016

Brian A. Roth and Rafael Lastra

System, Machine and Computer Readable Storage Medium for Forming an Enhanced Seismic Trace Using a Virtual Seismic Array

Granted Patent: U.S. Patent 9,354,337, Grant Date: May 31, 2016

Ibrahim A. Al-Hukail and Luc Ikelle

Selective Single-Stage Hydroprocessing System and Method

Granted Patent: U.S. Patent 9,359,566, Grant Date: June 7, 2016

Omer R. Koseoglu

Gasification of Heavy Residue with Solid Catalyst from Slurry Hydrocracking Process

Granted Patent: U.S. Patent 9,359,917, Grant Date: June 7, 2016

Omer R. Koseoglu and Jean-Pierre Ballaguet

System and Method for Calculating the Orientation of a Device

Granted Patent: U.S. Patent 9,360,311, Grant Date: June 7, 2016

Pablo Gonzalez, Fadl Abdel-Latif and Ali Outa

Systems, Computer Readable Media and Computer Programs for Enhancing Energy Efficiency via Systematic Hybrid Inter-Processes Integration

Granted Patent: U.S. Patent 9,360,910, Grant Date: June 7, 2016

Mahmoud B. Noureldin, Mana M. Al-Owaidh and Abdulaziz Al-Nutaifi

Method and a System for Combined Hydrogen and Electricity Production Using Petroleum Fuels

Granted Patent: U.S. Patent 9,365,131, Grant Date: June 14, 2016

Aqil Jamal and Thang Pham

Carbonate Based Slurry Fracturing Using Solid Acid for Unconventional Reservoirs

Granted Patent: U.S. Patent 9,366,125, Grant Date: June 14, 2016

Hazim Abass, Abdulrahman A. Al-Mulhem, Mirajuddin Khan and Victor Hilab

Expert Systems for Well Completion Using Bayesian Decision Networks with a Multilateral Junction Design, and a Junction Classification Decision Node

Granted Patent: U.S. Patent 9,366,129, Grant Date: June 14, 2016

Abdullah S. Al-Yami and Jerome Schubert

Expert System for Well Completion Using Bayesian Probabilities and a Consequences Node Dependent on the Zonal Isolation Types, Reliability Level, Cost Level, Productivity Level, the Completion Type, and the Junction Classification Decision Nodes

Granted Patent: U.S. Patent 9,366,130, Grant Date: June 14, 2016

Abdullah S. Al-Yami and Jerome Schubert

Expert Systems for Well Completion Using Bayesian Probabilities, and a Packers Consequence Node Dependent on Wellbore Fluids, Hydrocarbon Types, Completion Fluids, Packers Decision and Treatment Fluids Nodes

Granted Patent: U.S. Patent 9,371,726, Grant Date: June 21, 2016

Abdullah S. Al-Yami and Jerome Schubert

Membrane Separation Method and System Utilizing Waste Heat for On-Board Recovery and Storage of CO₂ from Motor Vehicle Internal Combustion Engine Exhaust Gases

Granted Patent: U.S. Patent 9,371,755, Grant Date: June 21, 2016

Esam Z. Hamad

Circumventing Load Imbalance in Parallel Simulations Caused by Faulty Hardware Nodes

Granted Patent: U.S. Patent 9,372,766, Grant Date: June 21, 2016

Majdi A. Baddourah and M. Ehtesham Hayder

Expert System for the Optimal Design and Execution of Successful Completion Practices Using Artificial Bayesian Intelligence

Granted Patent: U.S. Patent 9,376,905, Grant Date: June 28, 2016

Abdullah S. Al-Yami and Jerome Schubert

Multilevel Solution of Large-Scale Linear Systems in Simulation of Porous Media in Giant Reservoirs

Granted Patent: U.S. Patent 9,378,311, Grant Date: June 28, 2016

Jorge Pita

Methods for Enhanced Energy Efficiency via Systematic Hybrid Inter-Processes Integration

Granted Patent: U.S. Patent 9,378,313, Grant Date: June 28, 2016

Mahmoud B. Noureldin, Mana M. Al-Owaidh and Abdulaziz Al-Nutaifi

Auto Thermal Reforming (ATR) Catalytic Structures

Granted Patent: U.S. Patent 9,382,485, Grant Date: July 5, 2016

Thang V. Pham, Sai P. Katikaneni, Jorge N. Beltramini, Moses O. Adebajo, Joe Da Costa and Max G.Q. Lu

Integrated Hydrotreating, Solvent Deasphalting and Steam Pyrolysis Process for Direct Processing of a Crude Oil

Granted Patent: U.S. Patent 9,382,486, Grant Date: July 5, 2016

Abdenmour Bourane, Raheel Shafi, Essam Sayed, Ibrahim A. Abba and Abdulrahman Akbras

Systems and Methods for Expert Systems for Well Completion Using Bayesian Decision Networks

Granted Patent: U.S. Patent 9,382,791, Grant Date: July 5, 2016

Abdullah S. Al-Yami and Jerome Schubert

Integrity Monitoring of 4-Way Diverter Valve

Granted Patent: U.S. Patent 9,383,032, Grant Date: July 5, 2016

Chandulal N. Bhatasana

Liquid Phase Oxidation of Aromatic Feedstocks with Manganate Recycling to Produce Carboxylic Acids

Granted Patent: U.S. Patent 9,388,110, Grant Date: July 12, 2016

Veera Tammana, Kareemuddin Shaik and Guillaume Raynel

Two-Stage Hydrocracking Process and Apparatus for Multiple Grade Lube Oil Base Feedstock Production

Granted Patent: U.S. Patent 9,388,347, Grant Date: July 12, 2016

Vinod Ramaseshan and Ali Al-Abdul

Hydrophilic Membrane Integrated Olefin Hydration Process

Granted Patent: U.S. Patent 9,393,540, Grant Date: July 19, 2016

Aadesh X. Harale, Wei Xu and Ibrahim Abba

Methods for Recovering Organic Heteroatom Compounds from Hydrocarbon Feedstocks

Granted Patent: U.S. Patent 9,394,489, Grant Date: July 19, 2016

Zaki Yusuf, Ahmad Hammad, Stamatios Souentie, Bandar Fadhel and Nayif Al-Rasheedi

Process for In Situ Electrochemical Oxidative Generation and Conversion of Organosulfur Compounds

Granted Patent: U.S. Patent 9,394,491, Grant Date: July 19, 2016

Emad N. Al-Shafei

Pressure Cascaded Two-Stage Hydrocracking Unit

Granted Patent: U.S. Patent 9,394,493, Grant Date: July 19, 2016

Omer R. Koseoglu

Flexible Zone Inflow Control Device

Granted Patent: U.S. Patent 9,394,761, Grant Date: July 19, 2016

Fahad A. Al-Ajmi and Sultan S. Madani

Synthesis of Ultra-Small Pore Aluminosilicates by Controlled Structural Collapse of Zeolites

Granted Patent: U.S. Patent 9,403,148, Grant Date: August 2, 2016

Yuguo Wang, Cemal Ercan, Rashid Othman, Minkee Choi and Hyeonbin Kim

Catalyst Additive for Reduction of Sulfur in Catalytically Cracked Gasoline

Granted Patent: U.S. Patent 9,403,155, Grant Date: August 2, 2016

Christopher F. Dean, Musaed S. Al-Ghrami, Mohammed A. Siddiqui, Khurshid Alam and Shakeel Ahmed

Downhole Tool for Use in a Drill String

Granted Patent: U.S. Patent 9,404,326, Grant Date: August 2, 2016

Shaohua Zhou

Apparatus for Downhole Water Production Control in an Oil Well

Granted Patent: U.S. Patent 9,404,351, Grant Date: August 2, 2016

Mohamed N. Noui-Mehidi

Active Drilling Measurement and Control System for Extended Reach and Complex Wells

Granted Patent: U.S. Patent 9,404,359, Grant Date: August 2, 2016

Scott D. Fraser

Multiphase Metering with Ultrasonic Tomography and Vortex Shedding

Granted Patent: U.S. Patent 9,404,781, Grant Date: August 2, 2016

Michael Black, Mohamed N. Noui-Mehidi and Talha Ahmad

Induced Polarization Mapping with Borehole-to-Surface Electromagnetic Transmitter Data

Granted Patent: U.S. Patent 9,405,033, Grant Date: August 2, 2016

Alberto Marsala, Muhammad Al-Buali, Tang Biyan and Zhanxiang He

Methods for Determining Wettability from NMR

Granted Patent: U.S. Patent 9,405,037, Grant Date: August 2, 2016

Ahmed Al-Muthana, Gabor Hursan, Shouxiang Ma, Philip M. Singer, Benjamin Nicot, Andrea Valori, Farhan Ali and Henry N. Bachman

Drainable Sight Glass and Associated Methods

Granted Patent: U.S. Patent 9,417,161, Grant Date: August 16, 2016

Samer M. Aljohani

Surface Confirmation for Opening Downhole Ports Using Pockets for Chemical Tracer Isolation

Granted Patent: U.S. Patent 9,416,651, Grant Date: August 16, 2016

Majed N. Al-Rabeh

Multilateral Well System

Granted Patent: U.S. Patent 9,416,638, Grant Date: August 16, 2016

Shaohua Zhou

Relative Valuation Method for Naphtha Streams

Granted Patent: U.S. Patent 9,423,391, Grant Date: August 23, 2016

Omer R. Koseoglu

Methods for Estimating Missing Real-Time Data for Intelligent Fields

Granted Patent: U.S. Patent 9,423,526, Grant Date: August 23, 2016

Abdel Nasser Abittrabi and Fahad Al-Ajmi

Tomographic Imaging of Multiphase Flows

Granted Patent: U.S. Patent 9,424,674, Grant Date: August 23, 2016

Michael John Black, Talha Jamal Ahmad and Mohamed Nabil Noui-Mehidi

Hydrovisbreaking Process for Feedstock Containing Dissolved Hydrogen

Granted Patent: U.S. Patent 9,428,700, Grant Date: August 30, 2016

Omer R. Koseoglu

Downhole Salinity Measurement

Granted Patent: U.S. Patent 9,429,012, Grant Date: August 30, 2016

Talha Jamal Ahmad and Mohamed Nabil Noui-Mehidi

Relative Valuation Method for Naphtha Streams

Granted Patent: U.S. Patent 9,429,556, Grant Date: August 30, 2016

Omer R. Koseoglu

Iterative Dip-Steering Median Filter for Seismic Data Processing

Granted Patent: U.S. Patent 9,429,668, Grant Date: August 30, 2016

Shoudong Huo and Weihong Zhu

High Performance and Grid Computing with Fault Tolerant Data Distributors Quality of Service

Granted Patent: U.S. Patent 9,429,677, Grant Date: August 30, 2016

Raed Abdullah Al-Shaikh and Sadiq M. Sait

Apparatus, Computer Readable Media and Computer Programs for Estimating Missing Real-Time Data for Intelligent Fields

Granted Patent: U.S. Patent 9,429,678, Grant Date: August 30, 2016

Abdel Nasser Abittrabi and Fahad Al-Ajmi

Method and Tracking Device for Tracking Movement in a Marine Environment with Tactical Adjustments to an Emergency Response

Granted Patent: U.S. Patent 9,435,892, Grant Date: September 6, 2016

Peter R. O'Regan and Ali A. Al-Mohssen

Simultaneous Wavelet Extraction and Deconvolution Processing in the Time Domain

Granted Patent: U.S. Patent 9,435,906, Grant Date: September 6, 2016

Saleh Al-Dossary and Jinsong Wang

Cathodic Protection Automated Current and Potential Measuring Device for Anodes Protecting Vessel Internals

Granted Patent: U.S. Patent 9,441,307, Grant Date: September 13, 2016

Mohammad G. Al-Zabrani

System and Method for Forming a Lateral Wellbore

Granted Patent: U.S. Patent 9,441,420, Grant Date: September 13, 2016

Shaohua Zhou

Methods for Planning and Retrofit of Energy Efficient Eco-Industrial Parks through Inter-Time Inter-Systems Energy Integration

Granted Patent: U.S. Patent 9,442,470, Grant Date: September 13, 2016

Mahmoud B. Noureldin, Mana M. Al-Owaidh and Abdulaziz Al-Nutaifi

Two-Step Process for Production of RON-Enhanced Mixed Butanols and Disobutenes

Granted Patent: U.S. Patent 9,447,346, Grant Date: September 20, 2016

Kareemuddin M. Shaik, Wei Xu, Thamer Mohammed, Hassan Babiker and Gautam T. Kalghatgi

Inflow Control Valve and Device Producing Distinct Acoustic Signal

Granted Patent: U.S. Patent 9,447,679, Grant Date: September 20, 2016

Jinjiang Xiao

Apparatus, Program Product and Methods of Evaluating Rock Properties While Drilling Using Downhole Acoustic Sensors and a Downhole Broadband Transmitting System

Granted Patent: U.S. Patent 9,447,681, Grant Date: September 20, 2016

Yunlai X. Yang

Carbon-Based Fluorescent Tracers as Oil Reservoir Nano-Agents

Granted Patent: U.S. Patent 9,447,682, Grant Date: September 20, 2016

Mazen Y. Kanj, Md Harunar Rashid and Emmanuel P. Giannelis

Blocked Valve Isolation Tool

Granted Patent: U.S. Patent 9,447,889, Grant Date: September 20, 2016

Mohammad A. Al-Shammary

Method, Solvent Formulation and Apparatus for the Measurement of the Salt Content in Petroleum Fluids

Granted Patent: U.S. Patent 9,448,221, Grant Date: September 20, 2016

Sebastien A. Duval, Simone Less, Veera Venkata R. Tammana and Regis Vilagines

Carbon-Based Fluorescent Tracers as Oil Reservoir Nano-Agents

Granted Patent: U.S. Patent 9,453,159, Grant Date: September 27, 2016

Mazen Y. Kanj, Mohammad H. Rashid and Emmanuel P. Giannelis

Fluidized Catalytic Cracking of Paraffinic Naphtha in a Downflow Reactor

Granted Patent: U.S. Patent 9,458,394, Grant Date: October 4, 2016

Christopher Dean, Allan Fox and Daniel Longstaff

Oil Well Gas Lift by Hydrogen Production through Produced Water Electrolysis Completion

Granted Patent: U.S. Patent 9,458,704, Grant Date: October 4, 2016

Abdulrahman Al-Mulhem and Mohamed Noui-Mehidi

Systems, Computer Medium and Computer-Implemented Methods for Monitoring and Improving Health and Productivity of Employees

Granted Patent: U.S. Patent 9,462,977, Grant Date: October 11, 2016

Samantha Horseman

Catalyst Reactor Basket

Granted Patent: U.S. Patent 9,463,427, Grant Date: October 11, 2016

Omer R. Koseoglu and Salman Al-Khaldi

Carbon-Based Fluorescent Tracers as Oil Reservoir Nano-Agents

Granted Patent: U.S. Patent 9,464,034, Grant Date: October 11, 2016

Mazen Y. Kanj, Md Harunar Rashid and Emmanuel P. Giannelis

Hydrotreating Unit with Integrated Oxidative Desulfurization

Granted Patent: U.S. Patent 9,464,241, Grant Date: October 11, 2016

Omer R. Koseoglu and Abdennour Bourane

Carbon-Based Fluorescent Tracers as Oil Reservoir Nano-Agents

Granted Patent: U.S. Patent 9,469,599, Grant Date: October 18, 2016

Mazen Y. Kanj, Md Harunar Rashid and Emmanuel P. Giannelis

Bottom-Hole Assembly for Deploying an Expandable Liner in a Wellbore

Granted Patent: U.S. Patent 9,470,059, Grant Date: October 18, 2016

Shaohua Zhou

Downhole Fluid Transport Plunger with Motor and Propeller, and Associated Method

Granted Patent: U.S. Patent 9,470,073, Grant Date: October 18, 2016

Jinjiang Xiao and Abubaker Saeed

Input Parsing and Array Manipulation in Reservoir Simulation

Granted Patent: U.S. Patent 9,471,723, Grant Date: October 18, 2016

Werner A. Hahn, Usuf Middy, Henry H. Hoy and Maitham M. Hubail

Apparatus and Methodology for Continuous Downhole Sand Screen Fill Removal

Granted Patent: U.S. Patent 9,476,284, Grant Date: October 25, 2016

Majed N. Al-Rabeh and Bandar H. Al-Malki

Multilateral Re-Entry Guide and Method of Use

Granted Patent: U.S. Patent 9,476,285, Grant Date: October 25, 2016

Shaohua Zhou

Variable Capacity Multiple-Leg Packed Separation Column

Granted Patent: U.S. Patent 9,480,947, Grant Date: November 1, 2016

Samusideen Salu and Talal A. Zabrani

Positioning a Tubular Member in a Wellbore

Granted Patent: U.S. Patent 9,482,062, Grant Date: November 1, 2016

Shaohua Zhou

Plug Kit for Pressured Components

Granted Patent: U.S. Patent 9,482,476, Grant Date: November 1, 2016

Abdullah M. Al-Otaibi

High Performance and Grid Computing with Partitioning Quality of Service Control

Granted Patent: U.S. Patent 9,482,769, Grant Date: November 1, 2016

Raed A. Al-Shaikh and Sadiq Sait

Interferometric Processing to Detect Subterranean Geological Boundaries

Granted Patent: U.S. Patent 9,482,776, Grant Date: November 1, 2016

Teruhiko Hagiwara

Systems, Transmitter Assemblies and Associated Propulsion Devices to Explore and Analyze Subterranean Geophysical Formations

Granted Patent: U.S. Patent 9,482,781, Grant Date: November 1, 2016

Rami A. Kamal, Modiu L. Sanni and Mazen Y. Kanj

Systems, Methods, Transmitter Assemblies and Associated Power Supplies and Charging Stations to Explore and Analyze Subterranean Geophysical Formations

Granted Patent: U.S. Patent 9,482,782, Grant Date: November 1, 2016

Rami A. Kamal, Modiu L. Sanni and Mazen Y. Kanj

360-Degree Core Photo Image Integration and Interpretation in a 3D Petrophysical Modeling Environment

Granted Patent: U.S. Patent 9,483,871, Grant Date: November 1, 2016

Roger R. Sung and Yunsheng Li

Liquid, Slurry and Flowable Powder Adsorption/Absorption Method Utilizing Waste Heat for On-Board Recovery and Storage of CO₂ from Motor Vehicle Exhaust Gases

Granted Patent: U.S. Patent 9,486,733, Grant Date: November 8, 2016

Esam Hamad

Chemically Induced Pulsed Fracturing Method

Granted Patent: U.S. Patent 9,488,042, Grant Date: November 8, 2016

Ayman Al-Nakhli, Hazim Abass, Victor Hilab, Mirajuddin Khan and Ahmed Al-Otaibi

Apparatus and Method for Oxy-Combustion of Fuels in Internal Combustion Engines

Granted Patent: U.S. Patent 9,488,100, Grant Date: November 8, 2016

Esam Hamad and Wajdi Al-Sadat

System for Computing the Radius of Investigation in a Radial, Composite Reservoir System

Granted Patent: U.S. Patent 9,488,752, Grant Date: November 8, 2016

Noor Anisur Rahman, Faisal Al-Thawad and Saud Binakresh

Reservoir Simulation with Scalable Grid Computing

Granted Patent: U.S. Patent 9,489,475, Grant Date: November 8, 2016

Raed Al-Shaikh, M. Ehtesham Hayder, Majdi Baddourah and Omar Al-Saadoon

Chair Pad System and Associated Computer Medium and Computer-Implemented Methods for Monitoring and Improving Health and Productivity of Employees

Granted Patent: U.S. Patent 9,492,120, Grant Date: November 15, 2016

Samantha Horseman

Carbon-Based Fluorescent Tracers as Oil Reservoir Nano-Agents

Granted Patent: U.S. Patent 9,493,700, Grant Date: November 15, 2016

Mazen Y. Kanj, Mohammad H. Rashid and Emmanuel P. Giannelis

Process for Stabilization of Heavy Hydrocarbons

Granted Patent: U.S. Patent 9,493,710, Grant Date: November 15, 2016

Omer R. Koseoglu and Adnan Al-Hajji

Sequential Fully Implicit Well Model for Reservoir Simulation

Granted Patent: U.S. Patent 9,494,709, Grant Date: November 15, 2016

Ali H. Dogru

Method for Reconstructing the Total Organic Carbon Content from Compositional Modeling Analysis

Granted Patent: U.S. Patent 9,495,488, Grant Date: November 15, 2016

Peter J. Jones and Henry I. Halpern

Unsupported Metal Substituted Heteropolyacid Catalysts for Dimerization and/or Oligomerization of Olefins

Granted Patent: U.S. Patent 9,498,772, Grant Date: November 22, 2016

Miao Sun and Wei Xu

Catalyst and Process for Thermo-Neutral Reforming of Liquid Hydrocarbons

Granted Patent: U.S. Patent 9,499,403, Grant Date: November 22, 2016

Fahad I. Al-Mubaish, Shakeel Ahmed, Roberto Bittencourt, Mauri Cardoso and Vivian De Souza

Process for Oxidative Conversion of Organosulfur Compounds in Liquid Hydrocarbon Mixtures

Granted Patent: U.S. Patent 9,499,751, Grant Date: November 22, 2016

Gary Martinie, Bashir O. Dabbousi and Farhan M. Al-Shabrani

Encapsulated Impressed Current Anode for Vessel Internal Cathodic Protection

Granted Patent: U.S. Patent 9,499,915, Grant Date: November 22, 2016

Husain M. Al-Mabrouh and Mansour A. Al-Shafei

Apparatus and Method for Preventing Tubing Casing Annulus Pressure Communication

Granted Patent: U.S. Patent 9,500,057, Grant Date: November 22, 2016

Majed N. Al-Rabeh

Electrical Submersible Pump Flow Meter

Granted Patent: U.S. Patent 9,500,073, Grant Date: November 22, 2016

Jinjiang Xiao and Randall A. Shepler

Predicting Well Markers from Artificial Neural-Network-Predicted Lithostratigraphic Facies

Granted Patent: U.S. Patent 9,501,740, Grant Date: November 22, 2016

Martin Hiu, Murtada Al-Habib and Djameludin Mochtar

Apparatus, Systems, Platforms, and Methods for Securing Communication Data Exchanges between Multiple Networks for Industrial and Nonindustrial Applications

Granted Patent: U.S. Patent 9,503,422, Grant Date: November 22, 2016

Ahmad O. Al-Khowaiter, Soloman Almadi, Zakarya Abualsaud and Soliman A. Al-Walaie

Process to Produce Aromatics from Crude Oil

Granted Patent: U.S. Patent 9,505,678, Grant Date: November 29, 2016

Ki-Hyouk Choi, Joo-Hyeong Lee, Emad Shafei and Faisal Al-Faqeer

System and Method Employing Perforating Gun for Same Location Multiple Reservoir Penetrations

Granted Patent: U.S. Patent 9,506,330, Grant Date: November 29, 2016

Al-Waleed Al-Goubi

Development of Continuous Online Salt-In-Crude Analyzer

Granted Patent: U.S. Patent 9,512,370, Grant Date: December 6, 2016

Mohamed Soliman

Apparatus, Method and System for Detecting Salt in a Hydrocarbon Fluid

Granted Patent: U.S. Patent 9,513,273, Grant Date: December 6, 2016

Naim Akmal, Rashed M. Aleisa and Milind M. Vaidya

Coupled Time-Distance Dependent Swept Frequency Source Acquisition Design and Data De-Noising

Granted Patent: U.S. Patent 9,513,389, Grant Date: December 6, 2016

Shoudong Huo, Peter I. Pecholcs and Hai Xu

Systems, Machines, Program Products, Transmitter Assemblies and Associated Sensors to Explore and Analyze Subterranean Geophysical Formations

Granted Patent: U.S. Patent 9,513,401, Grant Date: December 6, 2016

Rami A. Kamal, Modiu L. Sanni and Mazen Y. Kanj

Systems, Machines, Methods, and Associated Data Processing to Explore and Analyze Subterranean Geophysical Formations

Granted Patent: U.S. Patent 9,523,789, Grant Date: December 20, 2016

Rami A. Kamal, Modiu L. Sanni and Mazen Y. Kanj

Systems, Computer Medium and Computer Implemented Methods for Monitoring and Improving Health and Productivity of Employees

Granted Patent: U.S. Patent 9,526,455, Grant Date: December 27, 2016

Samantha Horseman

Carbon-Based Fluorescent Tracers as Oil Reservoir Nano-Agents

Granted Patent: U.S. Patent 9,528,045, Grant Date: December 27, 2016

Mazen Y. Kanj, Mohammad H. Rashid and Emmanuel P. Giannelis

Energy Efficient Gasification-Based Multi Generation Apparatus Employing Energy Efficient Acid Gas Removal Plant Directed Process Schemes and Related Methods

Granted Patent: U.S. Patent 9,528,055, Grant Date: December 27, 2016

Mahmoud B. Noureldin



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Deep Reading Technology Integrated with Inflow Control Devices to Improve Sweep Efficiency in Horizontal Waterfloods

Dr. H. Onur Balan, Dr. Anuj Gupta, Dr. Daniel T. Georgi, Dr. Ali M. Alkhatib and Dr. Alberto F. Marsala

ABSTRACT

Premature breakthrough and low sweep efficiency during waterfloods result from heterogeneity in the permeability field in a reservoir. Production wells with inflow control valves/inflow control devices (ICVs/ICDs) have the ability to reduce the water-oil ratio by shutting in flow ports with high water cut. To date, this technology has been limited to providing a response only after the detection of water breakthrough at production wells. Deep reading technologies have been reported as successful in detecting an approaching waterfront before water breakthrough. The objective of this study is to investigate if the technology for early front detection combined with ICVs/ICDs can improve sweep efficiency in horizontal waterfloods.

Novel Method and Apparatus for Sticking Fluid Performance Evaluation

Dr. Md. Amanullah and Mohammed K. Al-Arfaj

ABSTRACT

Drilling fluid is the lifeline of safe and economic drilling operations that explore for oil and gas resources. It is also the root cause of various mud-related drilling problems, such as shale and drilling fluid interactions, borehole instability, loss of circulation, differential pipe sticking, etc. Differential sticking is a major drilling problem, and it is particularly common when drillpipe is passing through a high permeability zone. It is one of the primary causes of nonproductive time, which dramatically increases the total drilling cost, especially if there is a delay in recovering the stuck pipe. Delay in recovering a stuck pipe or the inability to do so may lead to other drilling problems, which then can lead to abandonment or sidetracking of a well. Therefore, every effort should be made to recover a stuck pipe as soon as possible.

Holistic Approach to Engineered, Diversion-Aided Completion Providing a New Method of Fracture Isolation

Kirk M. Bartko, Kenneth M. McClelland, Almaz Sadykov, Sobrat Baki, Mohamed Khalifa, Mohamed Zeghouani and John Davis

ABSTRACT

In the current energy market, operators of unconventional assets must explore new methods that promise to dramatically reduce the cost of recovery per barrels of oil equivalent without adversely affecting production. To meet that need, a number of technologies focusing on expanding completion thresholds and mitigating bypassed reserves have recently come on the market. This article discusses an engineered approach to utilizing one such technology. The approach taken is a holistic petrophysical analysis, coupled with a novel control pressure pumping (CPP) technique, and deployment of degradable diversion pills within each stage to maximize fracture initiations and stimulated volume.

Upstream Operations: Cybersecurity and Generation Y

Mohammed A. Al-Ghazal and Mohammad J. Aljbran

ABSTRACT

The evolving trend toward integrated technologies that connects equipment, provides information and assists operations in real-time mode has already had an impact in the oil and gas industry by providing optimized operational solutions. Information management is the backbone of upstream technology operations. The attempt to gain operational efficiency and achieve unmatched records, however, may come at a price. Those connecting systems that control physical operating environments, such as drilling or workover rigs, also mean increased exposure.

