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Unlocking Oman's Tight Gas Potential using State-of-the-Art Underbalanced Coiled Tubing Drilling Technologies

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Abstract

With the large amount of tight gas reserves remaining in Oman, new innovative techniques and methods to unlock these reserves have become imperative for the future economic success and stability of the country.

Among the various technologies considered, the concept of underbalanced coiled tubing drilling (UBCTD) was introduced. In order to address the harsh downhole challenges such as high temperatures, deep burial depths, under pressured reservoirs, abrasive and hard sands and logistical constraints; a fully integrated well delivery solution was developed jointly by the operator and energy service company.

In accordance with this strategy, best in class downhole drilling tools, a state-of-the-art fully automated coiled tubing drilling unit together with technical and project management experts were deployed. Application specific solutions to the challenging subsurface conditions included utilization of underbalanced drilling (UBD) techniques, deployment of high temperature drilling assemblies, fit-for-purpose bit drive mechanism and a robust integrated management system. All of the above was achieved whilst ensuring the safety of all personnel during the project and reducing carbon emissions through a flare minimization strategy and diesel consumption reduction initiatives.

Over the course of the pilot campaign, reservoir exposure per well was doubled, average penetration rate compared to conventional rotary drilling was more than tripled and incremental production improvements of up to 230% were observed. This paper discusses the challenges faced and the solutions implemented during this three well pilot campaign.

Introduction

The large remaining tight and deep gas reserves existing in Oman necessitates the need to find optimal development techniques that maximize reservoir deliverability. Developing tight and deep gas reserves is associated with many challenges; a key difficulty with many tight gas formations is the fact that they are water-wet and under-saturated where the initial water saturation is less than the equilibrium irreducible water saturation (Gupta, 2009). Therefore, the use of extensive volumes of water-based drilling or stimulation fluids causes water to be trapped in the near-wellbore region, causing significant impairment to the gas relative permeability and very slow and costly post-drilling or stimulation cleanout. In August of 2017 a multi-disciplinary team was assembled in Muscat to plan and execute the implementation of UBCTD techniques for deep, under pressured gas producers within Oman's interior gas fields. A pilot campaign was designed and aimed at determining if multi-lateral drain holes drilled underbalanced could provide development cost savings and productivity increases compared to the traditional drilling and hydraulic fracturing process currently being employed.

The fields of the selected UBCTD candidates are located in the Ghaba Salt Basin, a Geological province of central Oman. They are part of gas condensate accumulations sourced from Cambrian Nafun sediments. The reservoir is characterized by low permeability clastics of the overlying Haima Supergroup. The primary reservoirs include the Amin and Miqrat sandstone.

Amin reservoir has a strongly layered character, dominated by variable quality sandstone, and has localized intervals of poor to occasionally moderate permeability encased in generally very poor permeability.

Miqrat reservoir comprise low quality silty sands within background of siltstone/mudstone and consists of multiple sandstone layers interbedded with thin to medium shale beds.

Three candidate wells in different fields have been piloted in this trail. The first well (Well 1) was originally drilled as a vertical gas producer well targeting the tight Amin sand. The well was completed in 2006 with 4 ½" cemented liner (13% Cr) across the reservoir with 5 ½" tubing (13% Cr) stabbed into top of the liner. The well was attended for frac job followed by well cleaning in 2008 after which it was opened for production in the same year. In the first years, the gas production rate decreased to approximately 20% of the initial rate. The well remained producing at this level intermittently until mid-2016 after which the well was shut-in.

The second well (Well 2) was drilled in 2015 as a horizontal gas producer targeting Amin formation. The well was completed with 5 1/2" × 4 1/2" cemented completion and horizontal section of around 350 m. Initially, the well was expected to flow without hydraulic fracturing. After adding the three perforation intervals, the well didn't flow at all. Upon investigation, the horizontal section was suspected to have been damaged by the excessive overbalance during the drilling and completion phases which resulted in severe formation damage. Several restoration attempts were performed without success. Hence, the team decided to handover the well to the UBCTD project in order to target a new virgin zone using the UBCTD technology.

The last well (Well 3) was drilled in 2010 as a vertical gas producer targeting two formations (comingled with one hole). It was completed with tapered 5-1/2"x 4-1/2" cemented completion and fraced on both reservoirs. The well was found to be a poor producer from day one. The team decided to sidetrack this well to access more reserves within the lower reservoir (Miqrat) using the UBCTD technology while keeping the top reservoir open during the drilling operations to enhance the underbalanced window through the additional gas lifting effect.

The underpressured gas wells drilled during this campaign were drilled using a new generation coiled tubing unit specifically designed for drilling applications in combination with separation process equipment, a gas production compression package, a two-phase pumping package and thrutubing drilling assemblies. Tools within the drilling assembly were controlled via electric line injected through the length of the coiled tubing strings. Wells were logged for integrity prior to re-entering with the underbalanced drilling package.

With confirmed integrity and cement coverage over the planned window depth, a thru-tubing whipstock was anchored in the cemented tubing. The previous hydraulic fracturing design criteria had necessitated thick-walled tubing and as a result the difference in diameters between whipstock, window mill, and drill bit were small. While well designs varied slightly between fields it most frequently resulted in 0.05" difference between window mill and drill bit. Open hole sizes were drilled to 3-5/8" or 3-1/2" and required build up rates outside of the window of 20 – 31 °/30m before flattening out to drill horizontally through the sand layers. The tight restrictions and high dog-leg requirements necessitated dual-bend steerable assembly designs to allow passage through the window whilst also delivering upon the directional requirements. The slim drain holes remained open-hole and thus did not have completion bending limitations placed on them.

The deep burial depths of the gas reservoirs and the reduced pressure from drainage necessitated a two-phase fluid circulation system to adequately reduce the hydrostatic pressure while drilling. Circulation of nitrogen continued until adequate gas was capable of producing from the formation being drilled to support natural gas flow in the presence of the circulated drill water. Due to the potential for extended two-phase circulation periods and sand hardness reaching up to 207 MPa drilling turbines were deemed the most appropriate bit drive mechanism. Box-up, long gauge PDC bits with high cutter density and low depth of cut were designed for use with the drilling turbines. The turbine design and number of stages were customized to the fluid-phase fractions planned for the wells to ensure adequate bit drive energy while circulating at liquid rates as low as 175 lpm and nitrogen rates exceeding 28 m^3/min.

Returns management was a key process that required attention throughout the project, particularly when attempting closed-loop circulation which was the primary desired drill water management process. Well effluents were routed through a drilling choke to allow for surface back pressure control and to provide the first pressure drop before returns routed through the solids catcher for geologic sampling. Returns were directed through a high pressure first stage separator followed by a second stage low pressure separator to adequately separate solids, water, liquid hydrocarbons and gas. Dependent on surface well pressures gas was directed to the production manifold via direct pressure shipping or through a gas compression package to mechanically boost the shipping pressure. Residual gas in the second stage separator was flared. Condensate and water were separated in the low pressure separation stage. Condensate was stored on location and pumped to the production line at controlled rates to minimize erosional effects. Water then passed to closed top-side manifolded settling tanks to further allow solids to fall out of suspension. To safeguard against high atmospheric gas levels water which was returned from the well did not pass into open-top tanks. Similarly, shakers were not utilized for solids separation. Due to low water production and circulation rates relative to surface volumes, retention time was over 24 hours. Water in the final settling tank was pulled directly to the rig's quintuplex pumps. A liquid additive manifold and chemical injection pumps were plumbed into the line from the final settling tank and the rig pumps to facilitate treating the water. Nitrogen was added to the fluid stream downstream of the rig pumps.

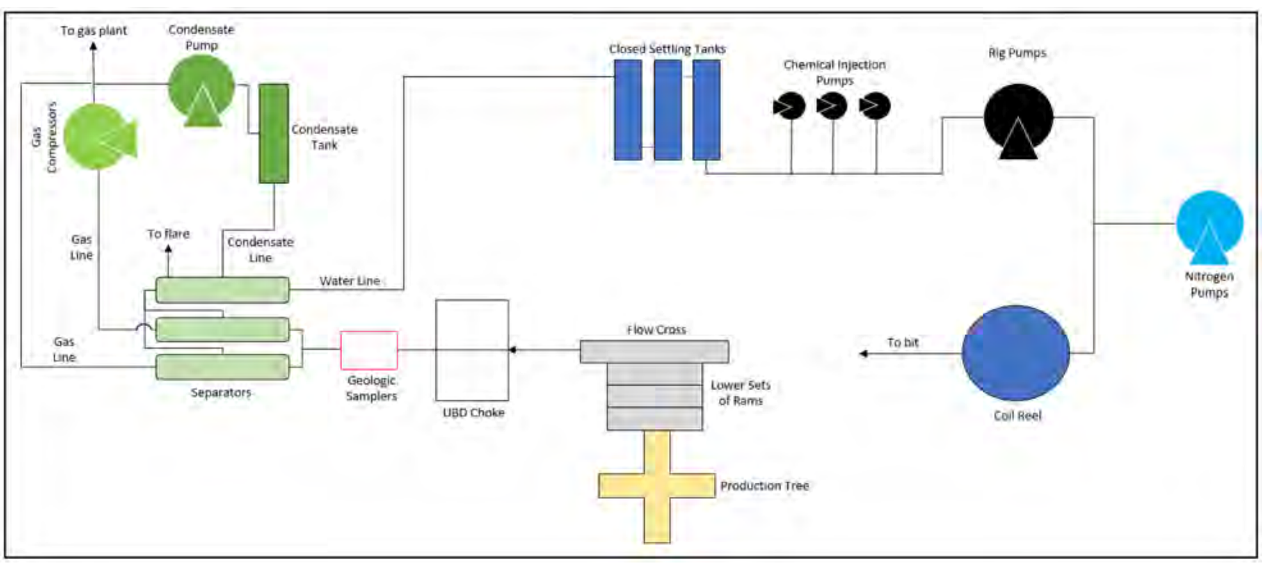

Figure 1—Generalized UBCTD drilling fluid routing

Figure 2—UBCTD equipment layout

Selected Solution and Rationale

To undertake this project and to overcome its key challenges, a fully integrated well intervention solution was developed jointly by the operator and energy service company. The pilot campaign was planned and designed with the key purpose to establish UBCTD and its ability to unlock tight-gas potential in Oman. All the wells selected for the pilot campaign were based on a number of geomechanical studies, and the feasibility of UBD in the target reservoir based on data analyzed from offset wells. The key decision to utilize underbalance drilling was to mitigate reservoir damage and for its ability to provide early critical information on the availability of movable hydrocarbons in the targeted reservoir.

To be able to access the deep reservoirs for the project, a new generation, fully automated coiled tubing drilling rig was deployed from Canada. The primary criteria for coiled tubing rig selection was its ability to handle the length of coil specified to carry out the job. The coil selected for this project was 2-3/8" in size, 6,400 m in length and with a tapered-wall thickness to reduce drag in the open-hole. As the existing completions were cemented in the wells, the thru-tubing capabilities of coiled tubing was a driving factor in the selection of coiled tubing drilling methods.

The solutions provided for downhole tools were 4 ½" monobore whipstock, 3" super slim drilling assembly, 2-7/8" turbine and 3 ½" bits. On surface a full underbalanced separation package was utilized to manage the returns from the wellbore in a closed loop system, and to also export produced gas and condensate to the gas plant while drilling.

A project management team of experts were assembled from the service company side to drive the project in collaboration with the operator. As part of planning, a process flow diagram, process event cause and effect matrices, layout drawings and detailed operating procedures were developed. Detailed workshops for hazard identification and operability were held prior to spudding the first pilot well.

Project Team Structure

In recent years, the oil and gas industry has been facing daunting challenges executing large projects. This holds especially true when activity moves to unconventional ways to extract oil and gas, thereby making the project more complex and demanding. To manage such projects the operator awards an integrated services contract to the energy service company to manage the full scope of the project.

To define the project team structure, the Integrated Well Services Project Management team collaborated with the operator to identify and outline key stakeholders and their specific roles in the project. During project execution the key stakeholders from the operator side were the Drilling Team Leader and the Reservoir Team Leader, whose expectations and objectives were managed by the Integrated Well Services Project Management Team (PMT).

To select the right well candidates a range of integrated solutions offered to the operator were geomechanical studies, reservoir analysis, production forecasting based on simulations and the overall ability to drill the selected well underbalanced. The solutions were presented and discussed during detailed design endorsements and deep dives involving various stakeholders from both reservoir and drilling teams. Once the ideal candidates were identified, the service provider began developing the drilling program in collaboration with the operator. Pre-spud meetings and drilling well on paper (DWOP) workshops were conducted prior to spudding of each well.

The project team structure is shown below. It is an overview of both the office and rig team structure utilized to deliver this project.

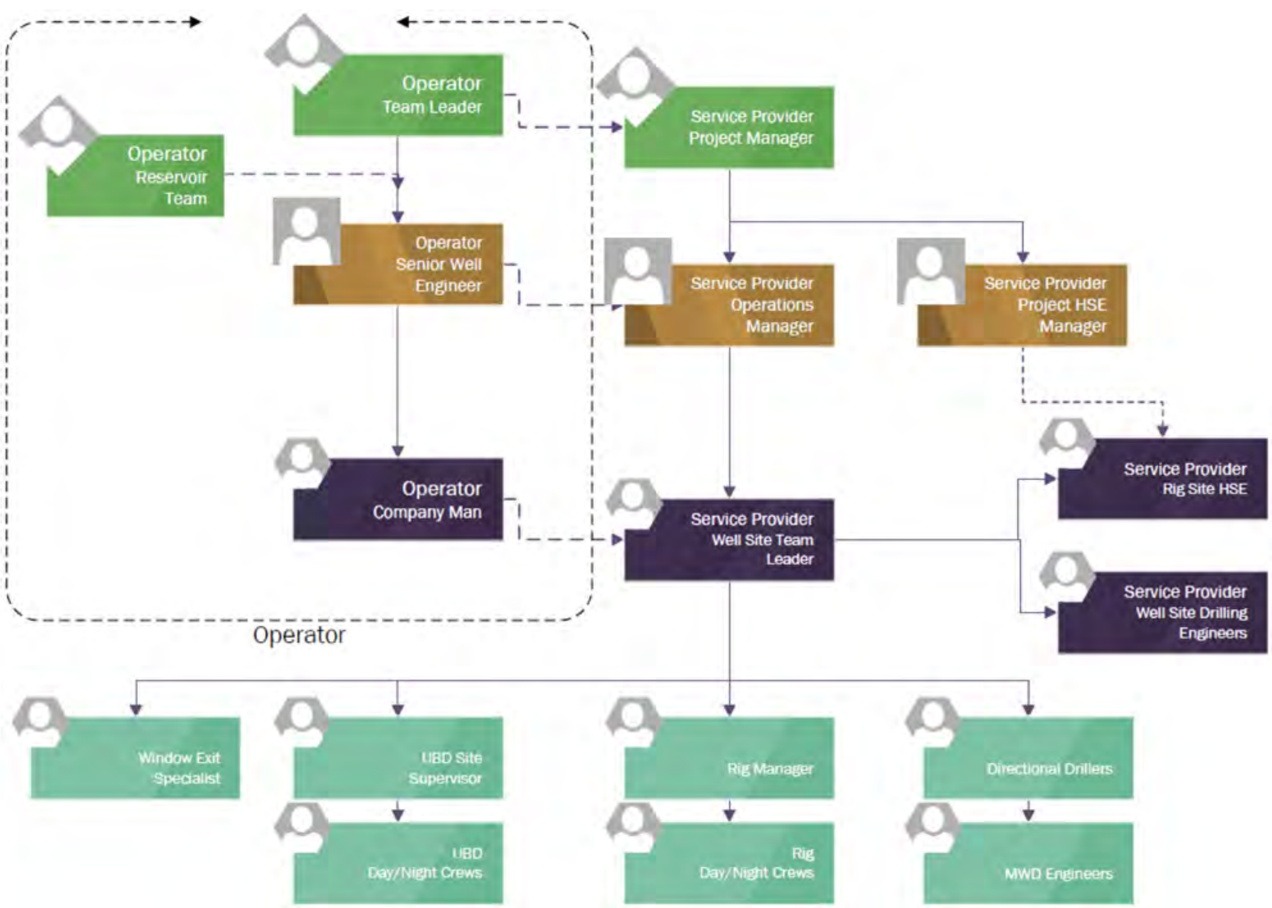

Figure 3—Integrated project organization chart

Coiled Tubing Drilling Rig

To access the deep lying horizontal reservoirs in Oman, a new generation coiled tubing unit with an electric injector head was mobilized from Canada. The rig was purpose built for greater depths and extended reach, yielding longer laterals. This was achieved with the help of an AC electric injector, with a pull capacity of 160,000 lbf. PLC controls and advanced software allowed the rig to be highly automated, with key focus on precision while drilling on bottom. The weight on bit, motor differential and string weight are controlled closely with the help of the software which reduces motor stalls and stuck pipe situations. Triple redundancies available in key components of the rig such as strippers, rig pumps, VFD's and generators allowed maintenance to be performed without having to stop operations midway due to lack of backups.

The entire rig was able to be rigged down and ready to mobilize in less than 24 hours. With its 44.2 m mast, the rig was capable of deploying tools up to 28 m long on a 9.1 m tree/BOP stack. The pressure control equipment utilized for this project consisted of one annular, four sets of pipe rams (two of each 2-3/8" & 3" rams) and two sets of shear rams. The entire stack was rated 15K psi. Mud tanks were designed to mix chemicals on the fly and pump them using the rig's three quintaplex 15K psi pumps (two diesel, one electric).

Figure 4—Masted coiled tubing unit designed specifically for UBCTD

A key safety feature of the rig was its ability to deploy tools without crew having to go to the rig floor and expose themselves to any wellbore risks as well as reduced manual handling and drops hazards. This is achieved with the help of 31 m lubricator, which can deploy tools from the tool rack, which is positioned 30 m away from the BOP. The entire lubricator is then picked up by the injector and stabbed on top of the BOP.

Figure 5—BHA being picked up within lubricator

Coiled Tubing BHA

The coiled tubing BHA was selected from the energy service provider's fleet. The super slim 3" coiled tubing drilling assembly provides state of the art drilling and evaluation services for coiled tubing re-entry application. To provide more RPM required to drill the extremely hard and abrasive formations present in Oman, a customized 2-7/8" turbine power drive system was sourced and added to complement the coiled tubing drilling assembly. All tools selected for the project were rated to withstand bottom hole temperatures of 157 °C.

Wells selected for the project all required casing exits. To be able to exit the chrome tubings in Oman, a customized solution tailor made for the project was offered to the operator which involved a 4 ½" Monobore whipstock along with a various range of milling assemblies needed to perform the window exit.

Once the window exit was confirmed and access to the open hole was achieved, the first drilling assembly was deployed to drill the build up section. The major components of the 3" drilling assembly are listed in the diagram below. The BHA provides directional, gamma ray, temperature, depth control, casing collar locator services, downhole weight on bit, string and annular pressures as well as vibration dynamic sensors.

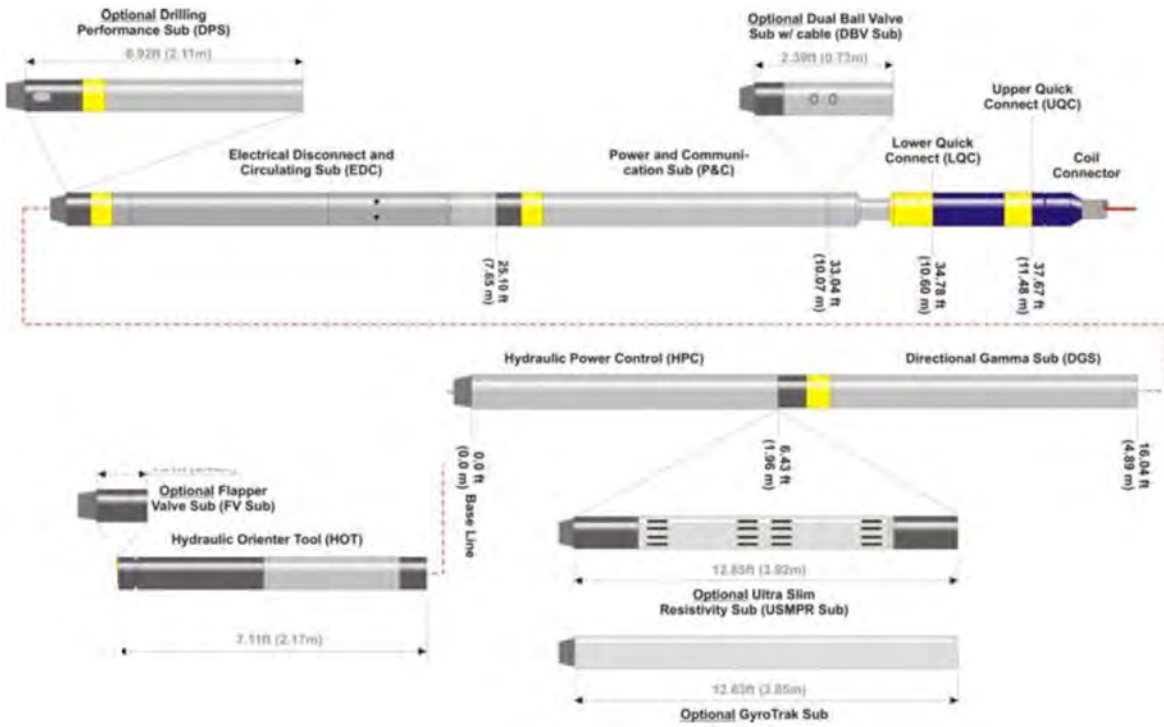

Figure 6—Drilling BHA main components

The motor/drive system utilized for this project was 2-7/8" turbine capable of rotating at 2000+ RPM. The biggest challenge in selecting the right drive mechanism was the low reservoir pressures and the need to remain underbalanced during operations. This would mean a low volume of liquid and high volume of nitrogen to be pumped during drilling to remain underbalanced. Keeping this challenge in mind a customized power drive system was developed for the project.

Underbalanced Surface Separation Package

During UBD operations, the returns from the wellbore need to carefully managed. The drilling returns consist of drilling fluid, drill cuttings and reservoir fluids (formation water, gas, condensate). The underbalanced surface separation package selected for the project was capable of managing reservoir returns during the course of the operations. The main components of the package were the drilling and well control chokes, separation package, data acquisition (DAQ) system, compressors (to pump gas to the gas plant) and nitrogen package. In this section we will deep dive into each of these primary components and the rationale behind their selection.

The primary component of an underbalanced surface package is the choke package. Standard underbalanced operations require two sets of chokes, one 10K well control choke and one 5K drilling choke. The 10K fixed-bean well control choke, is mainly utilized during well control operations and to divert any hydrocarbons away from the rig. The 5K adjustable drilling choke is the primary choke which is critical during drilling operations and it is designed to maintain annulus surface back pressure during drilling operations. Placed downstream of the drilling choke manifold is the geological sample catcher rated to 1,440 psi. The sample catcher is capable of catching formation samples on the fly.

A four-phase separation package was deployed to manage wellbore returns. It utilized three horizontal separators and four tanks to manage the returns effectively. The separators were designed to step down the pressure returning from the well and more importantly to separate the gas, solids, water and condensate coming from the well.

1. 1440 psi Separator - This high-pressure vessel is included to measure high gas rates and allow the provision to export gas directly to the production header under natural drive from well pressure.
2. 500 psi Separator - Enables all drilling fluid, cuttings to be separated. Free gas can be diverted to either the flare stack or compressed to the production header if the supply pressure / volume meets the minimum requirement for the gas compressors. All drilling fluid is transferred to the 275 psi separator. All cuttings and solids are retained in the hopper section of this separator, which is removed & cleaned out at the end of well. Drilling fluid is transferred by either pressure shipping or via a mission pump to the 275 psi Separator.
3. 275 psi Separator - The primary task of this vessel is to separate condensate and drill fluid. There exists a partition compartment to have any separated condensate collected, which can be transferred to the condensate tank by either pressure shipping or via a mission pump.
4. Drill Fluid Tanks - Three 63.6 m^3 drilling tanks are manifolded together to manage drilling fluid. Each tank has 2 compartments whose primary purpose is to allow maximum retention time, which allows solids to drop out to the bottom of the tanks. The rig pumps took suction from the third drill fluid tank, thereby completing the closed loop system.

For this project two nitrogen delivery systems were trialed, the membrane unit and the cryogenic unit. The nitrogen membrane unit was first deployed with the intention to be self-sufficient on site and to avoid the dependency of cryogenic units having liquid nitrogen transported daily in large quantities from remote stations. The nitrogen membrane unit was capable of producing 95% nitrogen purity at high pump rates.

Solution Implementation

As the risk associated with UBD is higher than conventional drilling, it was critical to identify all the hazards associated with operations and to develop sound processes and procedures for the project. After equipment selection, a valve numbering diagram (VND), equipment layout drawings and detailed standard operating procedures (SOP's) were generated. A HAZOP workshop was organized with the operator, energy service company and major subcontractors. At the workshop, detailed hazard analysis was conducted by analyzing the various nodes of the system, followed by operability studies being carried out. All action items from the HAZOP were closed out prior to commencement of operations.

At the rig site once all equipment was spotted and rigged up, an extensive audit was conducted by a 3rd party auditor. All services had to be accepted and commissioned by the auditors prior to spudding the well. The audit planned was thorough and extensive, with over 30 procedures developed for commissioning. A training session with both day and night crews were also conducted to familiarize them with the processes and procedures tailor made for the project, with a key focus on hazard awareness, communication and integration between all services.

On 17th February 2019, the first well of the project was spudded.

Main Operational Phases

The key phases of operations were defined as Window Exit, Drilling and Flow Test. In between these operational phases, BOP function test and pressure testing were conducted every three weeks to maintain integrity of the well control equipment.

Window Exit. A critical phase of the operation, 'Window Exit' needs to be successful to exit the tubing/casing and gain access to open hole. Without a window exit, operations cannot move forward to the next phase and run the risk of prematurely abandoning the planned well program and activities. The mono-bore whipstock assembly chosen for the project enables window exit without needing to pull existing completion or production tubing.

Figure 7—Monobore Whipstock Assembly and Diamond Speed Mill

A variety of mills were trialed in this project, with the most successful mill design being a non-aggressive diamond speed mill. Another major challenge in the window exit phase was the requirement to mill out chrome tubing and exit into a hard abrasive formation. Once a window exit was confirmed, a 2.5m rat hole length was drilled to accommodate the bend of the upcoming drilling assembly. Per procedure, multiple drift passes through the window with the string mill were performed to ensure a full-gauge finish before concluding window exit operations and tripping out of hole.

Drilling. The first drilling assembly to be deployed during operations is the short-radius build section assembly, which is designed to provide the required dogleg and build rates needed to land the well in the target reservoir. During the build section, drilling challenges such as low pressured zones, potential shale zones and hard abrasive formations were expected and mitigations were in place. Once the buildup section landed in the target reservoir the BHA was tripped out of hole to pick up a stiffer and straighter drilling assembly to drill the lateral section.

The lateral section was drilled with a turbine bend setting of 1° or lesser. Because string rotation is not possible with coiled tubing drilling this reduced the total tortuosity in the lateral to as little as possible.

Once the first lateral drilling is complete, the drilling assembly is picked up to a pre-determined depth to begin open hole sidetracking. Sidetracking is a delicate process, and the best practice to ensure a successful sidetrack is to adopt time-drilling process. Once near bit inclination readings confirm that the drilling assembly is in the new lateral, the drilling assembly is picked up to polish/clean the sidetrack ledge using various tool faces. The sidetrack is then confirmed, and the drilling BHA continues drilling the new lateral as per plan. Open hole sidetracks drilled with coiled tubing BHAs proved successful whereas it had previously proven unsuccessful with conventional drilling BHAs in these hard formations.

Flow Test. The final phase of operations after concluding drilling operations, is to flow test the well until operator criteria are met. For UBCTD operations, the flow test phase is a short sequence of operations designed to quickly evaluate the post intervention production rates. For this project the flow test designed could be covered in maximum 2 days. With the main criteria being clean up flow until basic sediment and water (BS&W) is below 10%, proceeded by flow periods at different choke sizes or pressure intervals dictated by the operator reservoir team.

During the entire flow test phase, the operations team attempts to export maximum allowable gas and condensate to the gas plant which will reduce and minimize the gas flaring operations at site. This was done to ensure one of the major KPI's of the operator is met, to minimize flaring and emissions.

After flow testing criteria is met the X-mas tree master valve is shut, and operations begin rigging down to demobilize equipment from the site bringing an end to operations for the well.

Drill Water Management

A key project KPI was to have a closed loop fluid system, which was designed to fulfill the operator's environmental water consumption reduction goal.

The entire drill water management system for the project can be broken down to two main stages, as below:

- Treatment of drill water – Rig tanks
- Well bore returns separation – Underbalanced separation package and tanks

Wellbore returns are a mixture of solids, gas, condensate and drill fluid. The 1440 psi separator only separates most of the gas from the wellbore returns. Residual gas, solids, condensate and water were further separated by the 500 psi and 275 psi separators. Condensate was collected directly from the 275 psi separator into a 63.6 m^3 tank. A triplex pump was utilized to selectively ship condensate to the export line commingled with gas exports.

From the 275psi separator, the drill fluid is transferred to a series of cascaded tanks with the help of mission pump or with the assistance of pressure available in the 275 psi separator. Each of these tanks follow a cascade system, which relies on time and gravity to allow any solids to drop out of suspension. The below diagram shows how the cascade system is setup and shows the path of the drill fluid which allows it maximum time for solids dropout in the tanks. The rig takes suction from the third tank to complete the closed loop system.

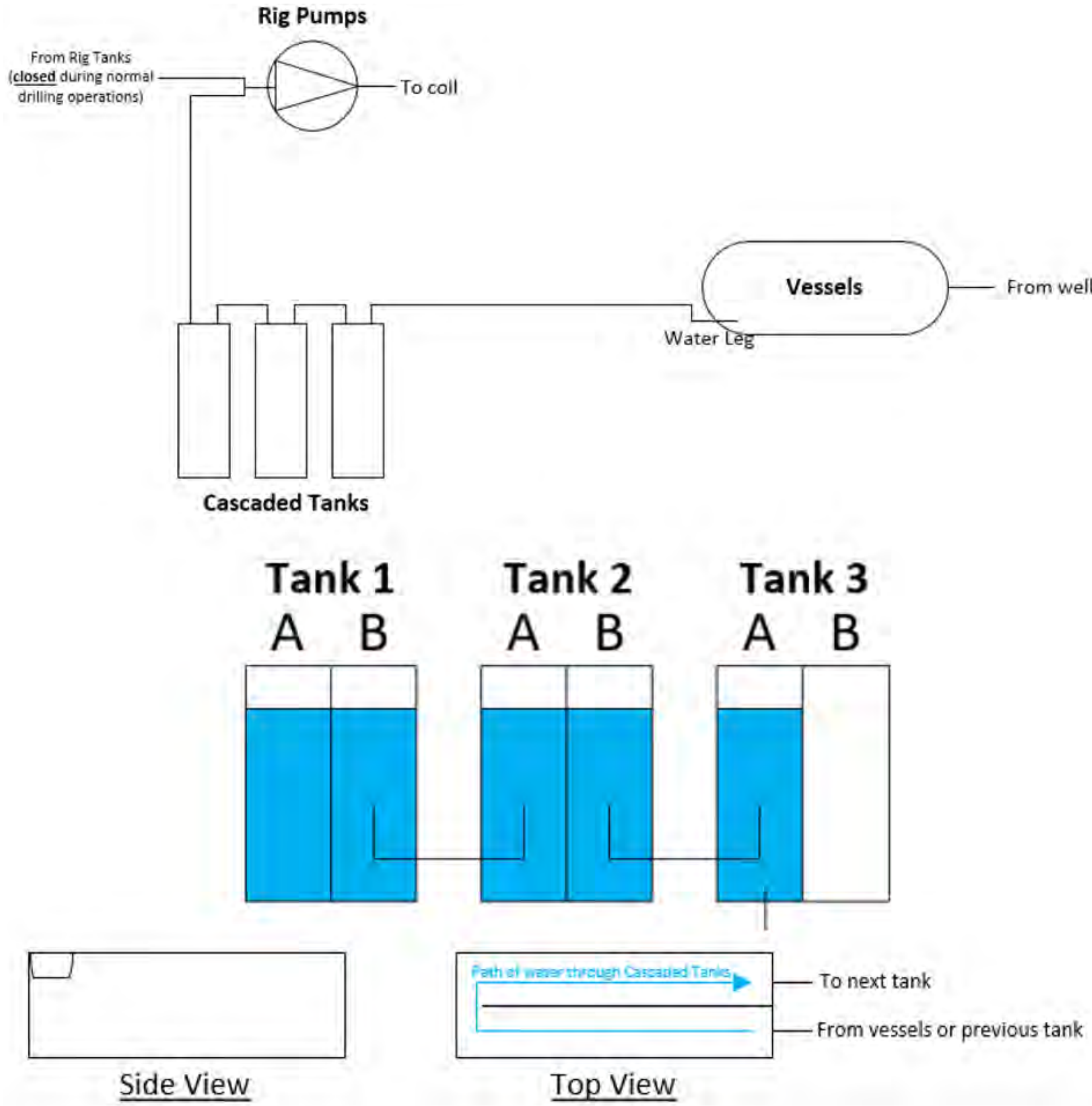

Figure 8—Drill water tanks and closed loop return system to rigs

Closed Loop vs Open Loop Systems. Initially, downhole conditions allowed the closed-loop system for drill fluid management to function well. During scenarios such as drilling with losses or a high content of solid in drill fluid system, there were procedures in place to manage such situations. In the event of losses, additional water needed was directly taken from the make up water tanks by the rig.

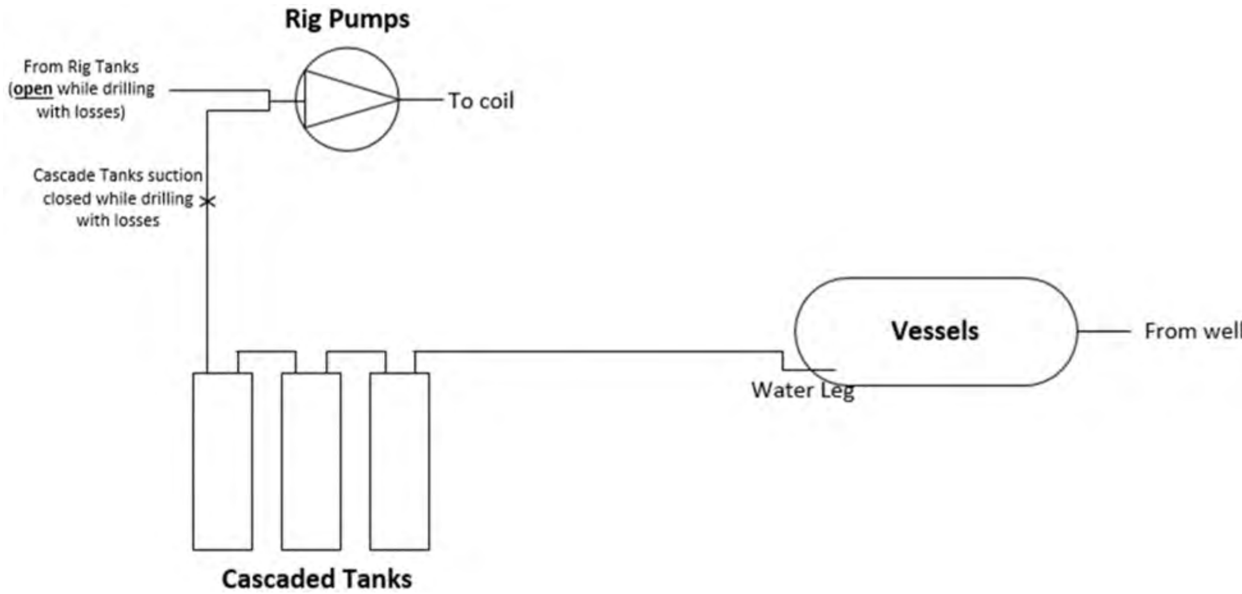

Figure 9—Suction is taken on only the Rig Tanks during drilling with losses

During closed loop system if the solids content in the drill fluid was too high, the process was to dilute the fluid system with clean drill fluid. This was achieved by dumping fluid from one of the cascade tanks and switching rig suction to the next cascade tank as shown in the figure below.

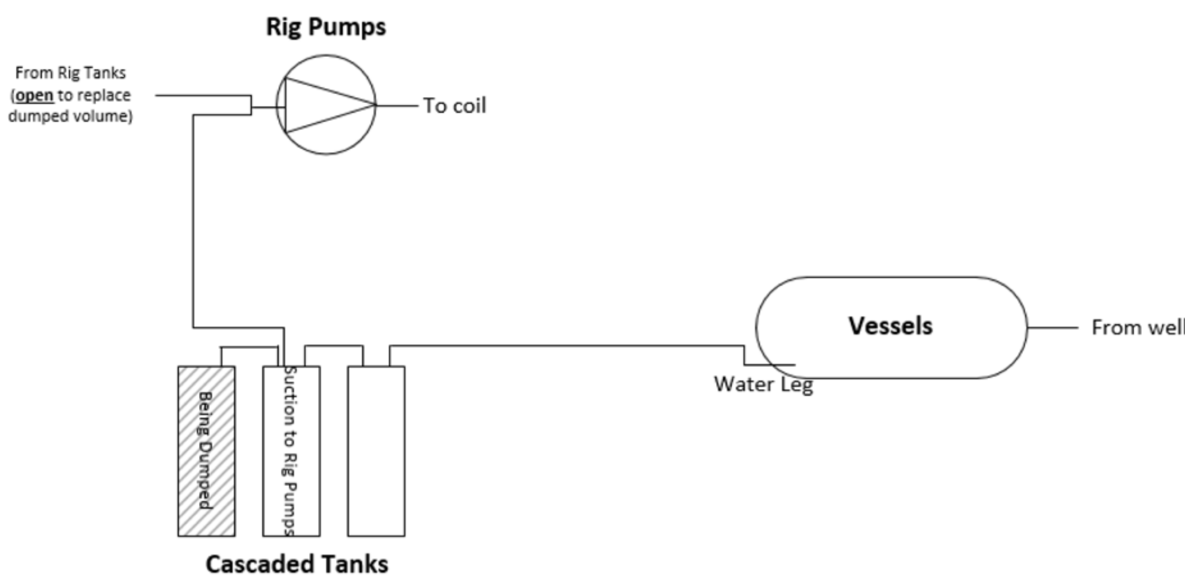

Figure 10—When dumping the third tank in the Cascade Tank system suction will be taken on the second tank as well as the rig tank in order to replace the dumped volume

In the second and third wells in the project additional challenges such as high downhole temperature and the reaction of the caustic reverse osmosis drill water to the reservoir fluid caused precipitation across the BHA and surface systems. A deep analysis on the cause for precipitation pointed to the need to conduct future studies on careful selection of water supply source and to look at further additives to manage downhole conditions. To move forward, the project decided to switch to an open loop drill fluid management system ("pump and dump") to continue operations and avoid failures and delays. The change in system resulted in the rig taking fluid directly from the rig water storage tanks

The switch to open loop systems resulted in extra chemicals being utilized and the need to have regular water supply to the rig. Logistics were managed accordingly.

Corrosion Management. The project was first designed to use a nitrogen membrane to supply the nitrogen needed for drilling. Generally, nitrogen membrane units provide 95-98% nitrogen purity depending on the rates pumped. The drill fluid management system was designed to combat any corrosion encountered; however significant learnings were still garnered once operations commenced.

During the first well in the campaign the very first coiled tubing reel used had to be retired prematurely due to excessive pitting and corrosion. The root cause for this was the high content of oxygen present in the system combined with carbon dioxide present in the reservoir fluid. To mitigate this effect the nitrogen membrane unit was replaced with a cryogenic nitrogen unit to reduce the oxygen component. Additionally, the drill fluid composition was also adjusted to combat the CO_2 present in the wellbore. General chemicals used to manage the drill fluid were as below

- Caustic Soda
- Soda Ash
- Corrosion Inhibitors
- Biocide
- Lubricant

After switching to cryogenic nitrogen unit and implementing a liquid caustic addition system, the corrosion and pitting seen in coil tubing was eliminated. Cryogenic nitrogen volumes and trucking costs were offset by the fact that diesel consumption reduced by 26% after the membrane nitrogen unit was replaced.

Downhole Temperature Impact. The operator had historic temperature data gathered while drilling these wells overbalanced, along with data acquired during subsequent interventions and offset wells pressure-temperature gauge data. To manage the high downhole temperature requirement for this project the energy service company deployed BHA components for the Oman campaign, able to withstand downhole temperatures of up to 160° C. In the second well of the campaign the temperatures experienced downhole were observed to be trending above 160°C, which resulted in premature electrical failures. To better understand the situation the project performed investigations to confirm the downhole temperatures:

- Compare downhole readings from two independent sensors in the BHA
- Install temperature stickers inside the tool and check them after they come out of the well

All the data gathered showed that the temperatures downhole were higher than expected. The root cause is suspected to be due to friction while drilling, however, the phenomenom is still not well understood and warrants further study.

Continuous Improvement

As a result of UBCTD operations necessitating technical interfaces which are non-typical for the individual service provider groups on location great importance was placed on integration, learning, and continual improvement. In addition to operational and safety-based improvements focus was also placed on continual advancement toward the overarching carbon emission reduction goal for the project. The frequency of improvement reviews is summarized in TABLE 1.

Table 1—FREQUENCY OF IMPROVEMENT REVIEWS

Improvement Reviews	
Topic	**Frequency**
Operating Procedure Reviews	Post Operation
Lessons Learned	Weekly
Bow Tie Process Improvements	Weekly
Rig Fleet Continual Improvement	Biweekly
Well Outcome Review	Post Well

Prior to each operation the onsite engineer conducted pre-job meetings to review the upcoming procedure, safety priorities and barrier compliance. While carrying out the procedure notes were drafted on potential improvements to the procedure. Small-scale after action reviews were conducted with service supervisors post-operation to discuss these improvements. Change management was initiated to formally assess the impact of the change in terms of operational complexity and risk and to garner approval from site management and operation leaders in Muscat.

To promote process safety awareness and improvement, and to encourage involvement from all onsite, weekly Bow Tie process improvement reviews were carried out during dedicated process safety focused pre-shift meetings. These reviews were based on actual events onsite, from other rigs in the fleet or on perceived events with potential to occur. The Bow Tie diagrams which developed from these sessions were then used during pre-job execution meetings to aid in communicating hazards, consequence, barriers and responsibility of managing the barriers.

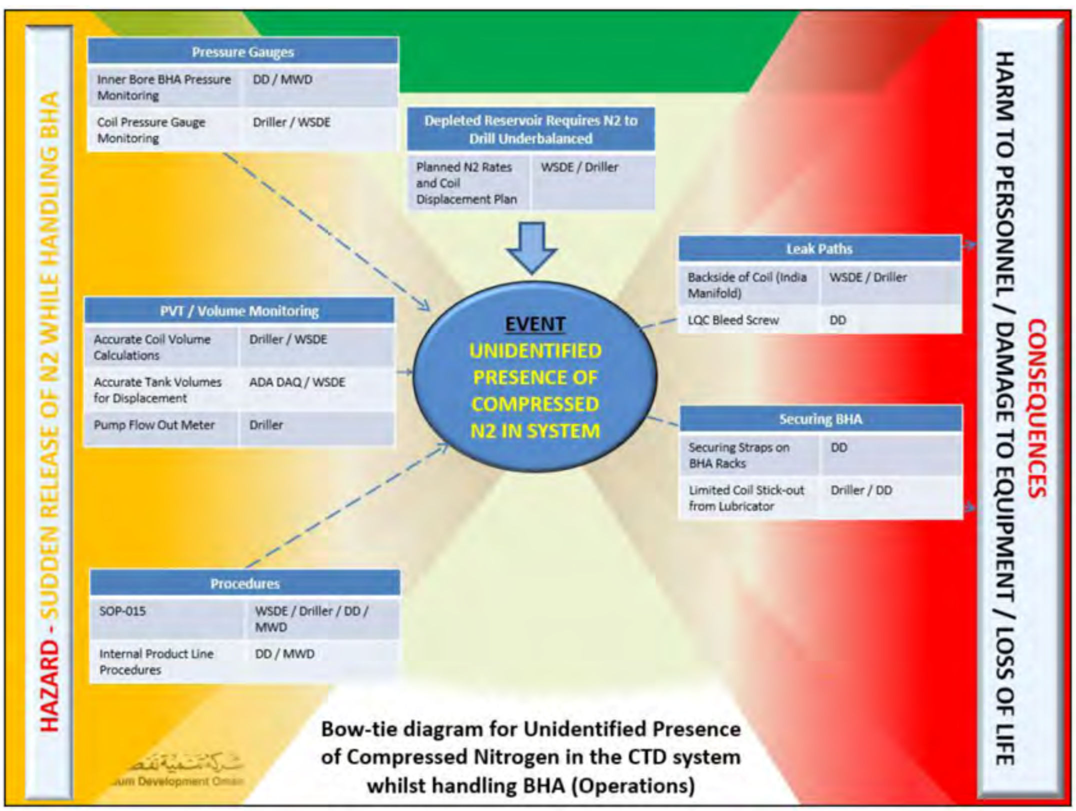

Figure 11—Example Bow Tie diagram used to facilitate improvements in safety to BHA handling after use of nitrogen

The results of continual improvement measures was an observed reduction in project non-productive time of 80% despite an increase in operational exposure hours of 55%. Additionally, it was observed that job hazard analyses and toolbox talk frequency increased. This was partially attributed to the coaching team members received from rig coaches and the strong emphasis placed on hazard awareness and tools used to assess hazards.

Environmental stewardship programs were also carried out as part of project goals of reducing flared gas to less than 5% and general reduction in diesel consumption. While efforts were made to accomplish the 5% target this goal was not met due to the feed pressure requirements for gas compressors being too high to sustain gas inflow into the well whilst drilling. While drilling, liquid loading of the well required reductions to flowing tubing head pressures. This allowed the well to clean up and facilitated continuous underbalanced conditions. This would require the well effluents to be routed to the low pressure separator and gas to be flared in order to reduce total surface backpressure on the well. Nevertheless, all attempts were made to continuously export gas under compression, rather than flare, when inflow rates which supported hole cleaning and water lift were sustainable.

In addition to flare reduction measures were also taken to minimize diesel consumption. A major change which stemmed from this effort was a change to the nitrogen package. Due to the large volumes of nitrogen required to sustain flow whilst drilling the system was originally designed for onsite nitrogen generation via a membrane nitrogen production unit and a series of pressure boosters. However, diesel requirements for continuous pumping at ambient temperatures exceeding 50°C and the subsequent need to frequently run the deluge cooling system exceeded the diesel consumption of the drilling rig. This was deemed unsustainable and accommodations were made to allow for onsite nitrogen bulk storage and a rotating fleet of bulk tanker deliveries. This also allowed for the four onsite nitrogen boosters to be replaced by a single dual-nitrogen pump unit. Together the onsite equipment reduction and the net diesel consumption of the rotating trucks reduced monthly diesel consumption by 26%.

Project Outcomes

Operations officially began on the first well in February 2019 following commissioning and acceptance. Over the following nine months, team members of 14 nationalities, from 12 companies, re-entered three wells in three separate fields and conducted UBD activities. During this period no lost time incidents, no recordable cases or accidents, no significant spills and no well control events occurred.

In total, 1,255m of new reservoir was exposed by re-entering the wells and drilling horizontal sidetracks. The rate at which additional reservoir contact was delivered improved over the project timeline due to variability in subsurface conditions, improvements to surface systems and operational learnings. It was demonstrated that underbalanced, coiled tubing drilling rates were capable of exceeding conventional overbalanced, rotary drilling rates by as much as 222% when formation strength supported the drawdown associated with production.

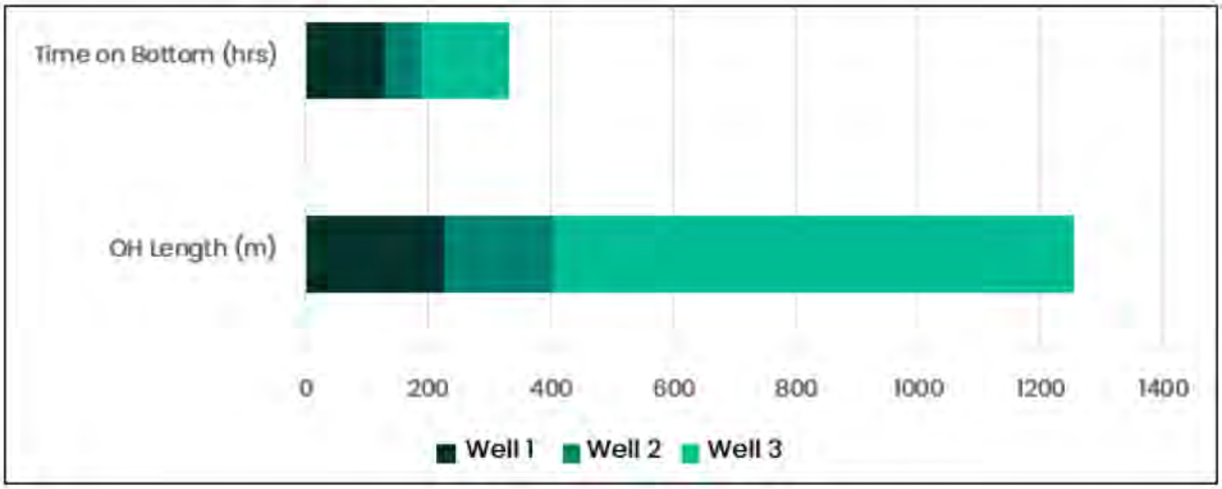

Figure 12—Improvement in drilling efficiency over project timeline

Similarly, project productivity improved over the length of the project. Several single occurrence, long duration events caused significant downtime on the first two wells. These events were associated with coil corrosion management, supplier lifting equipment recertification and replacement of a variable frequency drive. The first well of the project was also the first well for the new generation rig to drill. Considerable downtime occurred on the first well as the rig systems were first deployed for long duration operations. Deficiencies in the systems were rapidly addressed and corrected resulting in only six hours, or 0.5%, of non-productive time associated with the rig on the final well of the project.

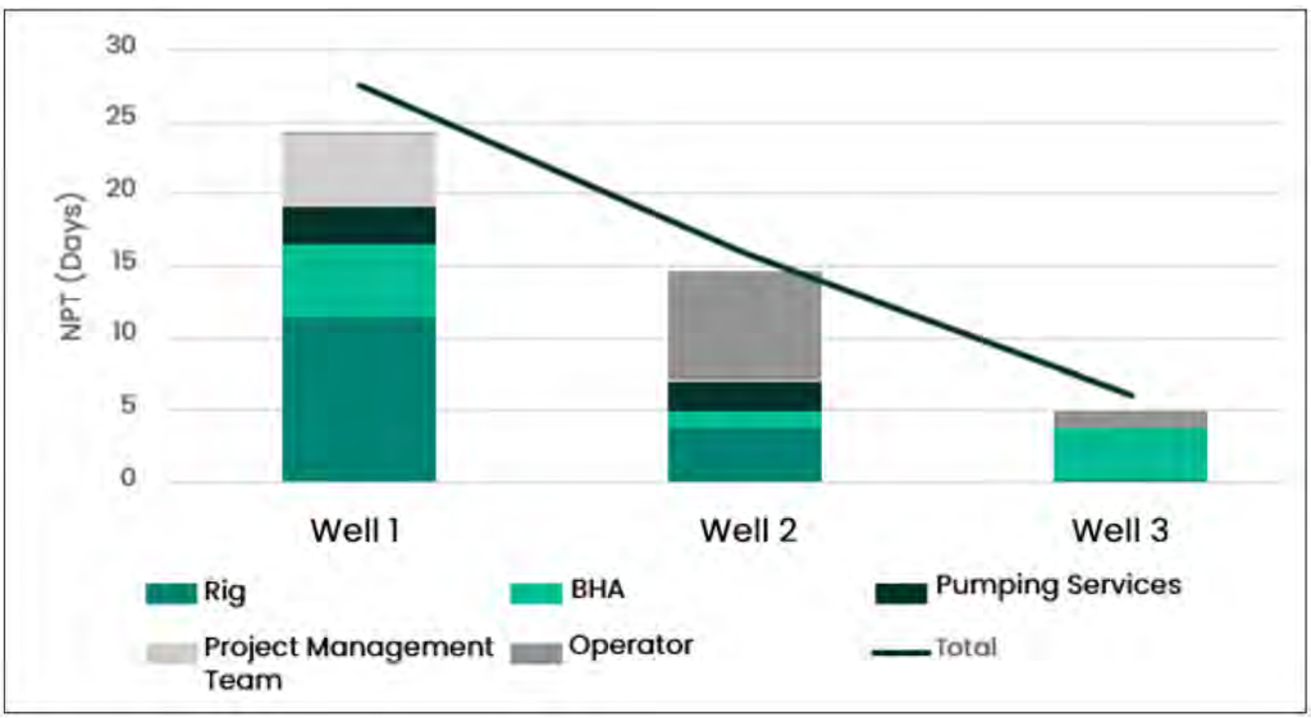

Figure 13—Largest contributors to project non-productive time

The operational phase which resulted in the most variability in delivery time and quality was milling of casing exits. Casing exit operational efficiency was a lowlight of the project. Window depths were planned at approximately 4,850m, resulting in considerable coil stretch and along-hole-depth friction. These effects when combined with the requirement to mill through thick wall, chrome 110 ksi casing were identified as a major project delay hazard during planning. This hazard was realized on all three wells with at least 4.6 days required to mill a window. In some cases as many as 14 milling BHAs were required to complete the window and rat-hole. The average time to install the whipstock and mill a window was 10.7 days with a standard deviation of 6.3 days. On the second well the first attempt as a highly deviated, high-side casing exit resulted in two fish and required a contingency whipstock be set. On the third well milling was attempted while pumping two-phase with a high nitrogen phase. While circulating two-phase the window was able to be partially milled to the casing exit mid-point but ultimately required higher motor horsepower associated with single-phase pumping to deliver the full window.

Improvement Opportunities

After single occurrence rig related non-productive time events the largest contributor to project delays was related to the drill fluid system. Corrosion management, water quality and solids management were the three aspects of the drill fluid which required improvement initiatives. Additional pH control and the introduction of cryogenic nitrogen addressed the corrosion challenges associated with oxygen levels in the membrane-generated nitrogen and the presence of carbon dioxide levels in the reservoir gas. By re-evaluating the high viscosity sweep strategy the amount of solids carried over through the settling tank system was also reduced, however, fines were not completely eliminated. Water quality control is an area of the project which required further work. Failures in water origin control occurred several times with water delivered to the rig originating from unapproved water wells rather than from reverse osmosis plants. Delivered water also had a wide range of total hardness, calcium and magnesium concentrations. When combined with downhole conditions, this resulted in substantial precipitation of solids within the small clearances of the downhole assemblies, particularly on the drilling turbine impellers. As a result, plugging of drilling assemblies was a significant cause of project downtime and warrants further investigation.

Poor reliability of the surface pressure bulkhead for the electric line running through the coil was also a high frequency incident for the project with frequent water bypassing the seal assemblies causing electrical shorts. Working with bulkhead vendors on improving the seal integrity, installation procedure, and coaching of rig personnel in maintenance is required to improve performance of the bulkhead. It was observed that leaks occurred more frequently after periods of circulating at high nitrogen rates.

Other improvement opportunities included simplification of the surface processing system to reduce rig up/down, rig move and commissioning times. Based on observed pressures during operations the separation system could be optimized to two vessels. Further to this, an improved sparging system in the separators would reduce the solid content in water returned to the settling tanks and also reduce vessel cleaning times. The drilling fluid liquid caustic mixing and additive system also has the opportunity for automation to improve pH control and better adapt to fluid changes as a result of changing production rates. For future coiled tubing drilled wells in these formations performance variability could be reduced by eliminating the need to mill casing exits through the chrome tubulars. By setting 4-1/2" production casing at the top of the target interval it would eliminate the need for milling an exit and allow the total well design to be reduce to a slim-hole design. By drilling underbalanced the need to hydraulically fracture the drain holes is also removed thus allowing for reduced production casing wall thickness and grade leading to a further reduction in tubular costs. For future projects earlier engagement between the production chemistry and drilling departments are recommended to more appropriately address potential risk associated with water quality and the interaction between the caustic drill water and reservoir fluid composition.

Conclusions

Over the duration of the project three wells were re-entered across three gas fields in Oman's northern interior. In all wells a usable window was able to be milled through the challenging thick-walled chrome tubing allowing additional reservoir to be accessed. Four horizontal drain holes were drilled within the target formations totaling an additional 1,255m of exposed reservoir. Average meters drilled per day using UBCTD techniques exceeded conventional rotary drilling rates. While not observed in each well, productivity enhancements up to incremental production improvements of 230% were seen as being possible. Proper candidate selection for UBCTD is the single most important factor to success for project such as these.

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