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Case Study: First Deepwater Surface Applied Back-Pressure (ABP) MPD Gravel Pack Operation - Design, Execution and Lessons Learned

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Abstract

Recently an operator embarked in drilling its first Deepwater Appraisal well in an area of the Caribbean Sea. The well objective was to obtain sufficient quality data from target reservoirs to verify the viability of the new asset. The base plan contemplated drilling two legs utilizing a Below Tension Ring (BTR) ABP MPD system for Early Kick and Loss Detection (EKLD) and optimized Bottomhole Pressure (BHP) control. One of the well main objectives was to well test the main reservoir, for which an Open Hole Gravel Pack (OHGP) concept was selected for sand control and a Drill-In Fluid (DIF) system was designed to minimized formation damage. The lower completion run and OHGP job were planned to be executed with a column overbalanced to the pore and stability gradients, however realized bottomhole pressure condition during the drilling phase indicated that a higher effective DHMW was needed to prevent open shales deterioration and hole collapse. The adopted solution to manage the higher-pressure requirement, minimize formation damaged, optimize operation and available resources was to use MPD to run the lower completion and execute the OHGP job. Some of the challenges to overcome included, well control considerations, reverse circulation method, among others.

This paper explores the challenges, planning, execution, and results of the first Deepwater OHGP operation utilizing an ABP MPD system, provides a valuable precedent for future similar applications and presents another example of how the used MPD systems can be extended beyond the drilling phase in well construction operations.

Introduction

The Managed Pressure Technology (MPT) has been utilized to drill oil and gas wells for many years to this date. The origins of the Surface Back Pressure (SBP) control philosophy remounts to those days in which Underbalanced Drilling (UBD) technology was commonly used to drill wells targeting naturally fracture reservoirs, or in depleted areas where full circulation of a single-phase column wasn't feasible. The development of reliable Rotating Control Devices (RCD) that permitted diverting safely well returns to a drilling choke gave way to the hability to control Bottomhole Pressures (BHP) while drilling safely via surface pressure manipulation. In those early days of the surface pressure control, underbalanced columns (single or multiphase) would be utilized and designed to deliberately allow the well flow while drilling, and in these operations the SBP manipulation goal was to maintain appropriated Drawdown (DD) levels at the face of the formation to promote a constant production rate and enable the needed hole cleaning to drill.

The valuable experience gained in these early days of drilling controlling surface pressures, helped the industry finding new ways to utilize the equipment and ability to control BHP proactively while drilling via SBP manipulation to address multiplicity of challenges related to bottomhole pressure boundaries and drilling hydraulics in areas and formations that wouldn't necessarily need a UBD approach. Having the capability to instantly adjust BHPs via choke manipulation to drill and adapt to uncertain and variating downhole pressure conditions with single phase column has proven to be a powerful tool to help optimizing the overall drilling process. This is what we know today as that adaptative process called Managed Pressure Drilling (MPD).

The MPT has proven its benefits with countless successful applications demonstrating to be a very efficient way to drill wells safely mitigating unnecessary high NPT levels. Nonetheless, the technology from its origins and until not long ago was considered as a tool mainly intended for drilling and seldom was considered for operations beyond the scope of making new hole; however, this ability to control the well pressure profile with precision, when properly implemented can be used to address challenges not just present while drilling. Nowadays for instance, utilizing the managed pressure technology during primary cementing operations has helped achieving the isolation objectives in many challenging applications mitigating high peak ECD levels while implementing what has been defined as Managed Pressure Cementing (MPC) (Valecillos, Teoh et al. 2018). The MPT has been also used to assists in many applications to this date during coring operations, wireline, drilling with casing and during completion operations.

This case study presents an overview of how the MPT helped an operator overcoming challenges present to execute successfully the lower completion run and OHGP operation in a very remote location in the Offshore Colombia area. Based on the predrill PPFG prognosis, the completion team designed and had test results for the Drill In Fluid (DIF) Production Screen Test (PST) quality completion system showing that densities ranging between 9.4ppg and 10.2ppg were feasible without compromising the quality of the job due to solid content, however a lost hole and a sidetrack during the drilling phase gave sufficient data to the team to know that a minimum of 10.8ppg DHMW was required during the completion operation to prevent the hole deterioration and collapse due to shales being under tectonic stresses. Operating in a remote location which caused logistic constrains, with no easy access to additional material or testing resources, made adjusting the DIF PST fluid density to 10.8ppg not feasible without compromising the success of the job. Having the MPD technology available, the project team adopted solution was to execute the lower completion run and OHGP operation utilizing a 10.2 ppg DIF PST column managing surface pressures utilizing the MPD equipment on the rig to maintain the minimum ESD required of 10.8ppg throughout the job. Integrating the two technologies was challenging however as this study will show, the great synergy and ingenuity of the Drilling, Completion and MPD team enabled a successful integration that permitted the operator achieving the goals of this operation safely.

In the following section this document will provide background information on this operation, an overview of the application, the MPD system in place, information and details of the challenges that arose for the team based on the realized conditions during the drilling phase, the challenges to integrate the technologies, including the reverse circulation issue and the novel approach created, and an overview of the plan, execution, and results obtained.

Background

We will call the subject well of this case study Well-X. This well represented the operator's first appraisal in this area of offshore Colombia. The potential on this field was discovered via data gathered from drilling three exploratory wells in the years prior operations on Well-X. Two of these previous offsets were drilled with a different rig however using a similar ABP MPD system. The offsets drilled with MPD, regardless of the high uncertainty levels regarding the PPFG profiles in the area, no significant NPT was recorded from events related to severe or total losses nor kick or well control events. Also, on these wells the MPD system was used extensively to assist with DLOTs, Drilling, Tripping, Cementing and Coring operations. The location for this appraisal well was selected based on the strong data obtained from all the offset wells, and the MPD technology was considered as an enabler to optimize the operation based on the operator's good track record using the technology and offset wells good results.

The top objectives for Well-X were to test reservoir connectivity, deliverability, and aquifer properties, for this an extensive and complete data acquisition plan was designed considering all the subsurface uncertainties and included advanced wireline logs and rotary cores across full reservoirs, cores on the fly, wireline formation testing, low skin open hole gravel pack and well testing in the main target reservoir. The well design was driven by the data acquisition objectives, and based on these included a dedicated pilot hole to take cores and wireline and a sidetrack wellbore, called main hole, intended for additional logs and well testing. The trajectory for both legs were designed with a low inclination with paths intercepting main targets. Reservoir of interests were expected to be normally pressurized, and temperature were expected to be low. Water depth in the area was approximately ~2000m.

The base plan for Well-X involved drilling a pilot hole (ST00) consisting of two MPD sections below the 22″ casing, an 18-1/8″ hole to be isolated with a 14″ casing, and a 12-1/4″ open hole intercepting main lower target. The first section would be drilled maintaining an ECD target of 9.6ppg, and the second at target DHMW of ~10.2ppg, both with MPD and hydrostatically underbalanced MWs. The plan for 12-1/4″ pilot was to be P&A after acquiring cores and wireline logs. The base plan sidetrack (ST01) involved drilling a 12-1/4″ hole kicking off in Open Hole from the plugged main wellbore, in this case holding a 10.8ppg DHMW, to be isolated with a 9-5/8″ liner, and drilling a 8-1/2″ short open hole interval holding ~10.1ppg, as well using light MWs with MPD for CBHP. This last section was intended for the well testing operation. All DHWM targets were design to honor initial PPFG prognosis. Figure 1 (a) shown below shows the based plan well design for Well-X. This figure is not to scale.

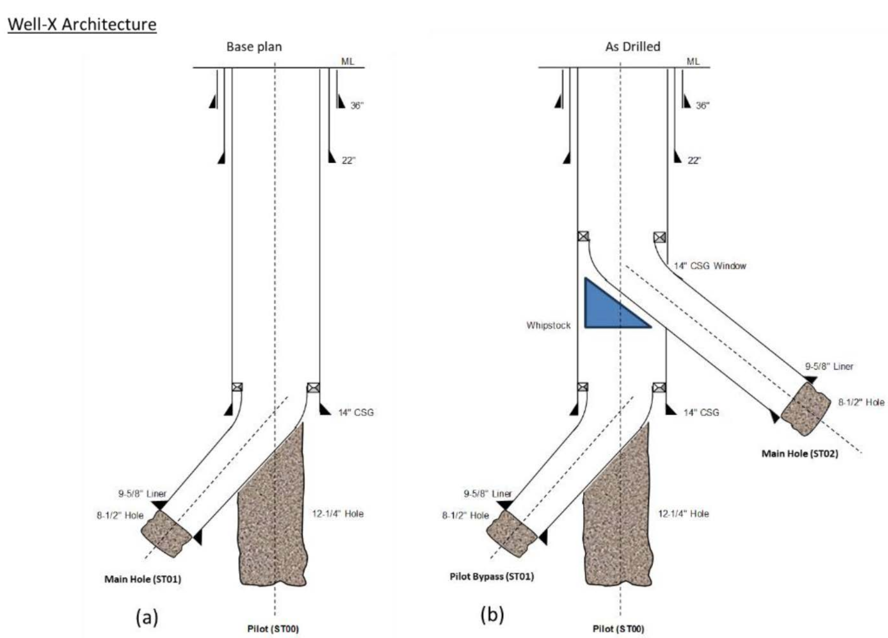

Figure 1—Wellbore Schematic Well-X: (a) Base Plan design; (b) As Drilled configuration.

As mentioned earlier, initial drilling target ECD for the 12-1/4″ Pilot was 10.2ppg however, hole conditions showed that higher effective DHMW was needed to prevent the whole getting tight and having stuck pipe events. MPD helped adjusting ECDs while drilling in the meantime MW could be gradually increased to reduce circulation time. The 12-1/4″ pilot ST00 was drilled to TD with relative success with a 10.6ppg DHMW, nonetheless while conducting a conditioning trip prior the wireline logs, the pipe got stuck being unsuccessful to get it free. This led to P&A the ST00 wellbore and a contingency "pilot" hole sidetrack ST01 was drilled to acquire needed logs on the lower main target. Figure 1 (b) shows the as drilled configuration for Well-X.

The contingency pilot hole ST01 was drilled and successfully isolated running a 9-5/8″ liner, with MPD holding a minimum target ECD of 10.8ppg using a fluid density of 10.2ppg of SBM. This confirmed that the initial WBS line prediction was too low, and that an effective ~10.8ppg DHMW was needed for subsequent operations, including the lower completion run and Gravel Packing operation. The mechanism to which the original pilot hole collapse was attributed to in situ tectonic stresses acting on the interval's open shales which cause them to deteriorate (fracture) and close over time if the effective DHMW was below ~10.8ppg.

Sand Control Strategy and OHGP Fluid

One of the primary objectives of Well-X was to well test the main reservoir as discussed earlier. Given the expected weak nature of this rock, sand production was identified as one of the key risks for the well test operation. To mitigate any constrains to measure the production potential and to promote maximum productivity, an Open Hole Gravel Pack (OHGP) was selected as a reliable and low skin concept, proven by the operator in a large number of high-rate gas fields. The OHGP operation and subsequent well test was intended now to be done in the 8-1/2″ hole section of ST02 (Figure 1 (b)) drilled through the main reservoir.

In general gravel packing consists of installing a downhole filter in the well to control the entry of formation material but allow the production of reservoir fluids. The gravel-packed completion is perhaps the most difficult and complex routine completion operation because it consists of many interrelated completion practices. The productivity of an open hole gravel-packed completion is determined in part by the condition of the filter cake on the face of the formation and the ability to keep the wellbore stable until completion of OHGP operations. For this reason, it can be said that the completion operation begins during the drilling phase, while making sure to drill the production hole preventing losses, maintain a stable wellbore and utilizing a tested fluid system designed to minimize damaged. The OH drill in fluid system must be designed, prepared, and tested to ensure it maximizes return perm on flow back and does not plug the screens to be run in hole prior pumping the gravel pack filter in place.

The fluid system selected to drill the 8-1/2″ production interval, be tested to meet PST quality, be left in the hole to run the screens and pump the OHGP job was a Synthetic Based Drill-In-Fluid. The system was specially designed to optimize the completion and posterior well test performance minimizing damaged to the formation face and to be ultra-PST to mitigate any potential for plugging of the screens during and after the job. Based on the pre-drill PPFG and WBS profiles prediction, extensive fluid testing and preparations were made to ensure a wide density range covering the most likely PP and WBS stability scenarios. The premixed mud standing by onshore and ready for deployment was 9.4ppg DIF fluid and based on all the testing, its density could be increased without compromising its PST quality up to approximately ~10.2ppg.

Conventional OHGP Limitations

Losing the original 12-1/4″ pilot hole ST00 with effective DHWM below ~10.8ppg and being successfully drilling the 12-1/4″ by pass ST01 and running the 9-5/8″ liner to bottom with MPD maintaining target ECD line above 10.8ppg, provided the project team evidence that the DHMW plans for the last leg, including running the lower completion and OHGP job, needed to honor this higher EMW requirement to preserve well integrity, prevent losing additional tools downhole and achieving the primary objective of testing the well. Caliper logs ran showed shales being "under-gauge" and sands "in-gauge", this information coupled with the fact that the rock failure seem to occur over time or slowly, not suddenly or abruptly, suggested that the mechanism driving the failure was the open shales being "Tectonically Stressed" when below ~10.8ppg DHMW.

Colombia was a remote location for the operator and shore support was limited near the job site and far away US natural shore support, and there was limited accessibility to materials and labs. The success of the gravel pack relied on the mud being PST quality. During the planning phase, complete lab test results were obtained confirming that the DIF completion fluid density could be increased all the way up to 10.2 ppg without compromising its PST quality (10.2ppg represented the High PP case line based on the PPFG pre-drill predictions). The realized DHWM level requirement of 10.8ppg to prevent shales to fail and collapse brought a significant challenge to the project team, not having a viable solution to safely increase the DIF fluid density to this higher level and achieving one of the operation primary objectives. It was simply considered unfeasible or too risky increasing the DIF system density to this level without compromising its PST quality due to solid contents.

Team Approach - The Managed Pressure Solution

The By-pass ST01 was drilled successfully with 10.2ppg surface MW with MPD maintaining ~10.8ppg ECD constant at the bit. The 10.2ppg fluid was adjusted increasing its bridging agent content reaching a total solid loading of ~112ppb of carbonated agent. While drilling the section regular sweeps were pumped to improved hole cleaning and filter cake performance, and the caliper logs observed a much better hole condition and a "slicker" hole. By successfully running the 9-5/8″ liner to TD and cementing it in place without issues proved the concept of potentially drilling the production section with 10.2ppg DIF and running the lower completion to TD with MPD maintaining DHMW above 10.8ppg throughout.

Two main factors attributed to the successful drilling of the bypass and preventing open shales failure were the higher effective DHMW achieved with MPD, and the adjustments made in the fluid bridging agent content. It was believed by the project team that beside the higher effective annular pressure, the higher bridging agent content which decreased mud spurt loss from 1.2ml to 0.0ml may have had a positive impact preventing the shale failure by mitigating lubrication of microfractures.

Based on the information available after drilling both the original and bypass pilot, the logistic constrains in this remote location, the high risks involved in further increasing the DIF solid content to achieve the required effective DHMW of 10.8ppg and simply the extremely short timeframe to get into the completion phase, the decision was made to challenge the project team, particularly the completion and MPD teams, to design a solution and a feasible plan to utilize a 10.2ppg DIF PST system coupled with the Managed Pressure technology to keep annular pressures above 10.8ppg, and assist running lower completion and pumping OHGP job effectively.

Integration Challenges

One of the first challenges to overcome by the team was getting familiar with each other's technologies; the MPD team needed first to understand all steps, processes and tools involved into the lower completion operation and OHGP job, and the completion team needed to understand the MPD equipment in place, capabilities and constrains while executing the completion work. The two main challenges identified early by the joint project team to use the MPT for OHGP operations were, how to isolate the string to prevent backflow up the string while holding SBP running in hole and then selectively opening this isolation to reverse circulate when required prior and after pumping the gravel pack operation, and secondly how to actually reverse circulate under the MPD circulating configuration.

String Isolation:

For well-known reasons to any drilling professional that has been in touch with the MPD technology, an effective seal in the drillstring is necessary to conduct MPD operations. An effective string seal prevents back flow up the pipe during connections while maintaining SBP levels on the back side and ensures no flow up the drillstring would occur under a well control event in case the primary barrier while drilling is compromised. A general rule of thumb for MPD operations is to include at least two float valves in the drillstring, and in deepwater operation often three None Return Valves (NRVs) would be used to increase reliability of the string seal. So, it is very clear that during regular MPD operations flow up the pipe is very undesired, and reverse circulation is not even a consideration under normal circumstances, however in this application to conduct the OHGP job with the MPT, the reverse circulation was a necessary step.

To be able to run the screens with the 10.2ppg DIF PST fluid with MPD maintaining the effective DHMW above 10.8ppg via SBP application, a seal evidently was necessary within the landing string while tripping in hole to prevent back flow up the drillpipe, however this seal needed to be disable at will by the time the reverse circulation was required prior the OHGP job. The solve this challenge a "Pressure Test Valve" (PTV) sub was run at the bottom of the landing string. The sub selected had the hability to run in a closed position, providing the necessary string seal while running in with the screens and could be open when needed while bursting a rupture disk that would set the valve permanently open. The valve would be burst open after the screens reached the bottom, and the surface GP equipment was rigged up and pressure tested. To burst the PTV rupture disk and open the valve, SBP would be used and increased as needed to achieve the required pressure differential across the valve as per its specifications.

One important aspect of OHGP operations is that once at TD and after spacing-out and connecting the pump-in stand, no connections are made-up or broken at surface until the end of the OHGP operations. This means that once the gravel pack manifold and top drive are connected and tested, the SBP could be held in the manifolds at surface after the PTV was opened and removing our down hole seal. One concern was how to drop the packer setting ball which had to pass through the open PTV and as such required to PTV to open prior to dropping the ball. To allow for dropping the ball with pressure at surface, the packer setting ball was preinstalled on top of the upper TIW. After pressure testing all surface lines to ensure pressure integrity, the PTV was opened by increasing the SBP to required burst pressure. Once the PTV was confirmed open by circulating through the service tool out the bottom of the wash pipe, the pumps were lined up to pump through the top drive. The pressure in the TDS was brought up to match the SBP and then the upper TIW was opened to allow the ball to gravitate on seat.

Once on the packer setting ball was confirmed on seat, the packer setting operations as set out by the service company were followed but each pressure at surface was increased to account for the surface back pressure. So, instead of starting a zero-surface pressure as is typical in non-MPD operations, the SBP pressure was the start pressure, and all other pressure were added to the starting SBP. As packer setting and testing involves several steps such as packer setting, pull/push tests, service tool release, packer testing, establishing circulate, blank and reverse positions, a systematic process of changing valve line-up to ensure pressure at surface was always maintained was established and rigorously followed.

The MP Reverse Circulation:

Cleanliness may be one of the most important considerations for gravel packing. Because a gravel pack represents the installation of a downhole filter, any action that promotes plugging the gravel pack is detrimental to well productivity. Many advances have been made in improving the cleanliness of gravel-pack operations, particularly in completion fluids, however beside using a clean fluid, steps must be taking to ensure the whole circulating system is cleaned properly prior GP job, and this includes the casing and the work string. Reverse circulation is the preferred method of circulation for cleaning the casing and landing string, and for different reasons is considered more effective than direct circulation. A common source of contamination of the gravel pack is thread dope lubricant within the work string. To remove the excess dope from the pipe, reverse circulating a string volume up at max rates prior to pumping gravel was an important step. Another important step in which reverse circulation is necessary is to remove the excess of gravel packing material left in the string after spotting the job in the open hole.

Figure 2 (a) and (b) illustrates respectively the circulating system set up to reverse circulate during conventional GP operations and the set up designed and used to reverse circulate with the MPD system in this application.

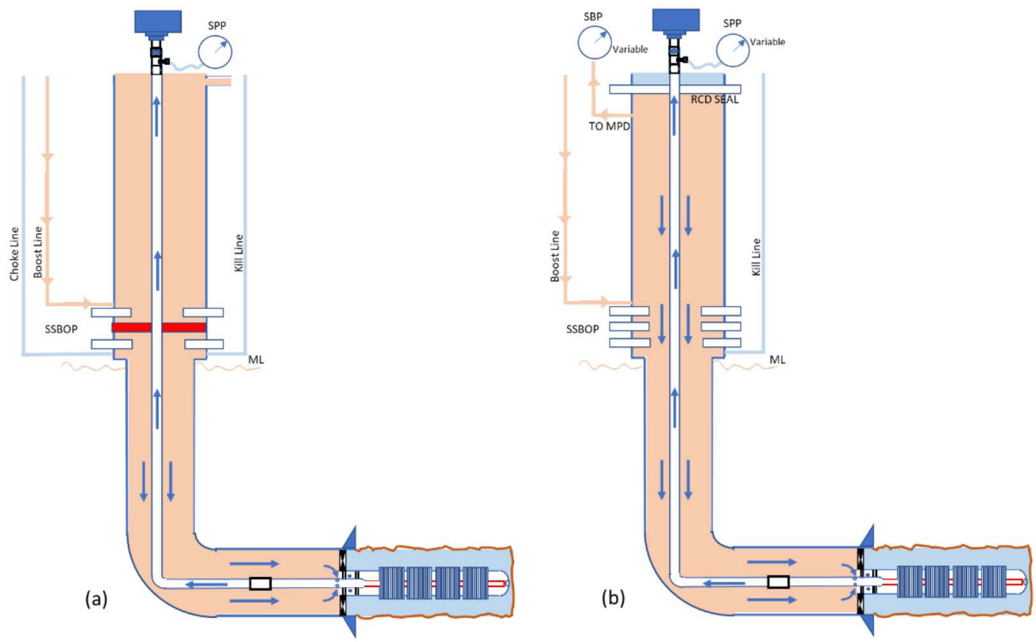

Figure 2—Reverse Circulation Well Diagram: (a) Conventional OHGP; (b) As Reverse Circulated for ABP MPD OHGP.

During conventional OHGP operations, meaning operating with a hydrostatic column overbalanced to the downhole min EMW limit, the reverse circulation is relatively straight forward. Once setting the service tool in the appropriated position, closing the well at the SSBOP and pumping whether through the kill or choke line will suffice to get fluid flowing down the annular and up the drill pipe to surface with relative ease (Figure 2 (a)). When using a mud density below the target minimum EMW and SBP to maintain required DHMW at the well bottom, the reverse circulation is more challenging. For the MPD system to be able to maintain and control surface pressure, flow through the MPD choke must be maintained at all time, and this is generally accomplished having constant flow through the boost line, up the riser and back through the MPD system. In a following section more details of the set up in question will be provided.

To achieve the reverse circulation without closing the well at the SSBOP and using the MPD system regular line up, flow up the pipe was obtained by creating a controlled pressure drop, or a "U-tube" unbalanced, between on both sides of the pipe (string and annular) by increasing the annular pressure, and reducing the pipe pressure as needed to promote and control the flow rate up the drillstring. This novel approach to reverse circulates with Annular Backpressure assistance constituted the first implementation ever of this technique and consisted of monitoring and manipulating the four main variables involved in this process. These variables were the Annular Surface Backpressure or SBP controlled by the MPD crew, the Drill Pipe pressure read and controlled at the Gravel Pack manifold, and the flow in and out measured with the MPD system. Figure 3 below shows the relationship between the three main variables.

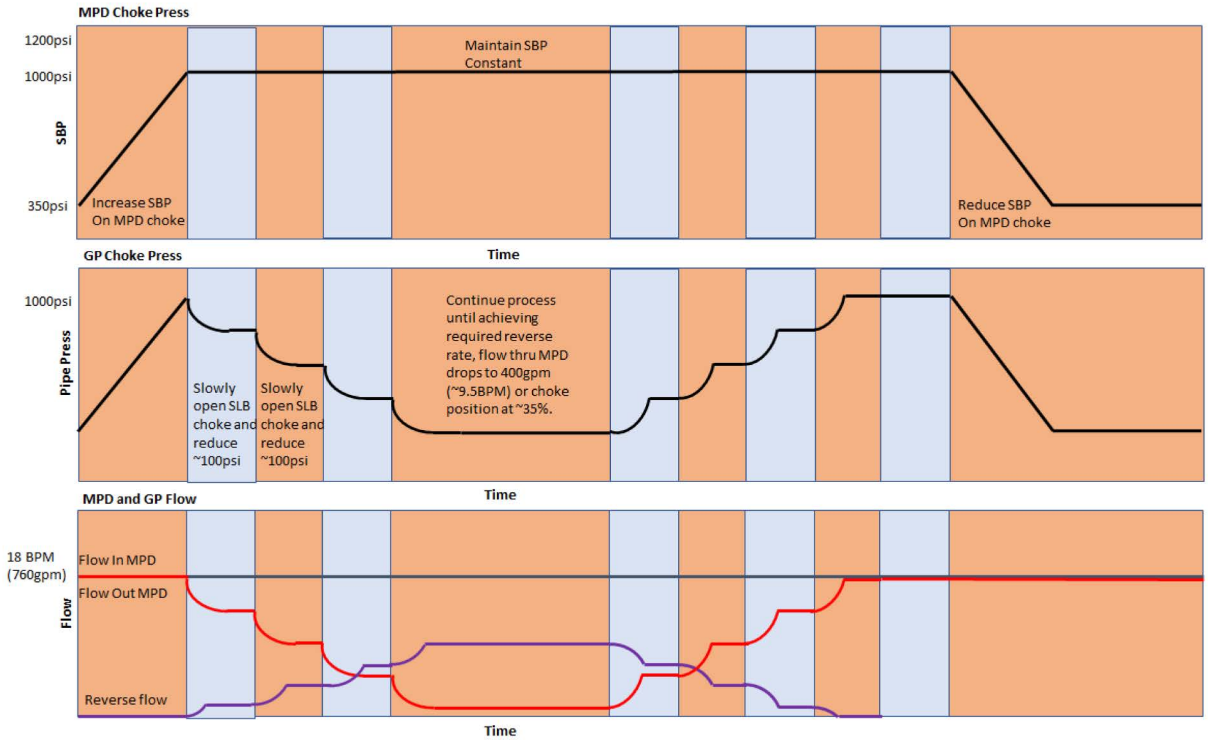

Figure 3—Managed Pressure Reverse Circulation Well-X–Variables Relationship

The diagram shows the main variables controlled during the Managed Pressure reverse circulation process created for well-X. To promote reverse flow up the string once the service tool set in position, the first step was to increase the SBP as shown in the top track to a predetermined level. At this point the pipe pressure is being read at the Gravel Pack manifold with its choke in a close position. Once the pressure equalized at the GP choke to the MPD SBP, at this point the GP choke was to be open in steps to reduce the system "downstream" pressure as needed to promote and control flow up the pipe. The constant flow to the well would be provided by the boost pump which would be running the entire time since the MPD system was brough online to run the lower completion.

The lower track shows the expected behavior between the flow measurement in and out of the well. The flow in to the well remain only the provided by the boost pump. With communication established between annular and pipe via open string and entry sub, with GP choke closed, MPD flow in and out would be equal and no reverse flow would occur. Opening the GP choke would lead to a flow path for flow to scape via the GP manifold due to the pressure differential created via SBP. With flow going up the string and GP manifold, the flow reading at the MPD Coriolis meter will drop in the same amount appearing as a "loss". Further GP choke opening would lead to higher flow and so on. Reverse flow would increase based on the pressure and the "loss" on the MPD side would be proportional to the flow going up the pipe.

Application Overview

The mobile offshore drilling unit (MODU) used to drill the wells was a "Ship Shaped Drilling Unit" with DNV 1A1 classification and described as DSME 12000 Ultra Deepwater Drillship. The Rotating Control Device (RCD) used for this application was a Below Tension Ring (BTR) type, complemented with an Applied Back Pressure (ABP) MPD system at surface which included a PLC controlled automated drilling choke (Moghazy et al. 2018). Figure. 4 shows a schematic representation of the closed loop MP surface equipment layout used to drill and OHGP operations on Well-X.

Figure 4 shown below illustrates schematically how the BTR ABP MPD system used to drill Well-X was laid out. It shows also the surface rigged up used for OHGP operations assisted with MPD.

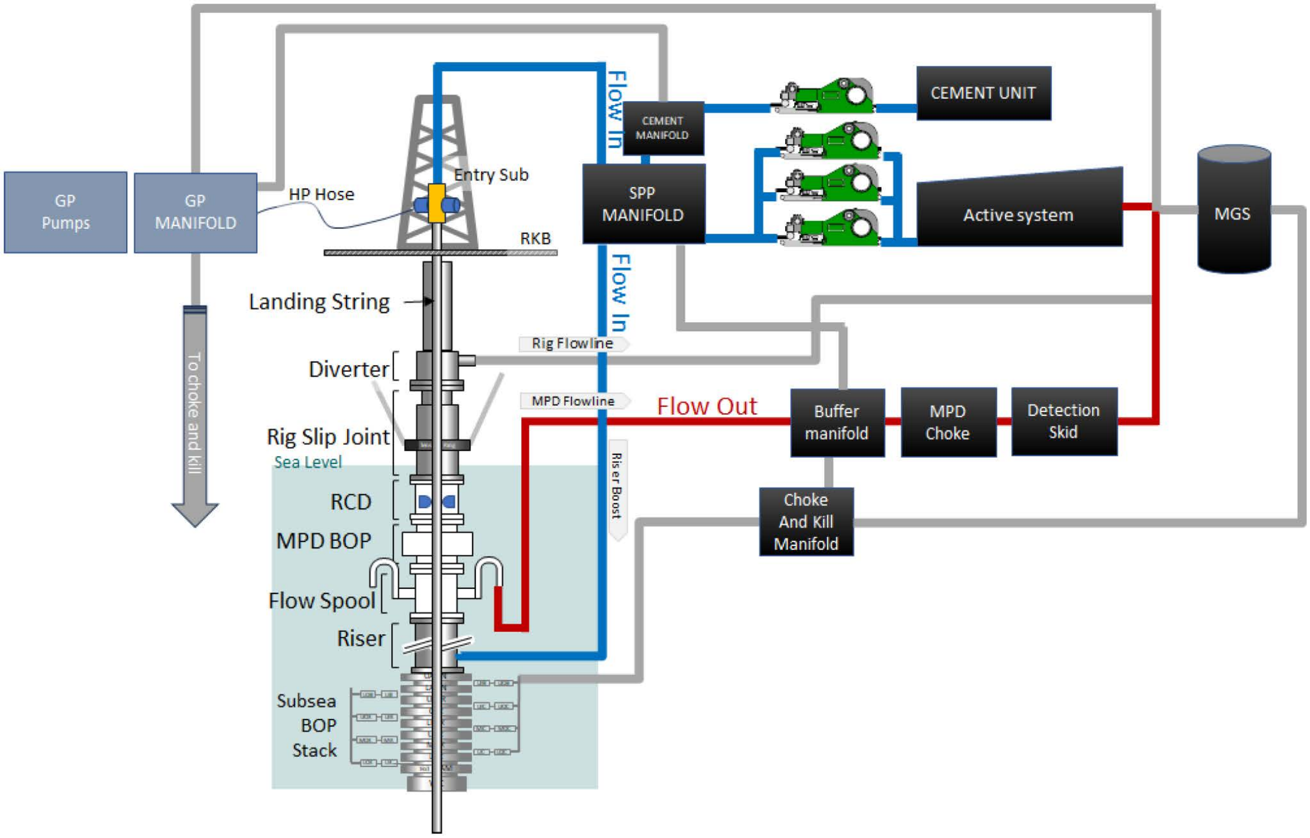

Figure 4—MPD system Schematic Lay Out OHGP Operations Well-X

Figure 5 shown below illustrates the Gravel Pack Manifold and the Pump-In or Entry Sub configuration used during MP OHGP operations on Well-X.

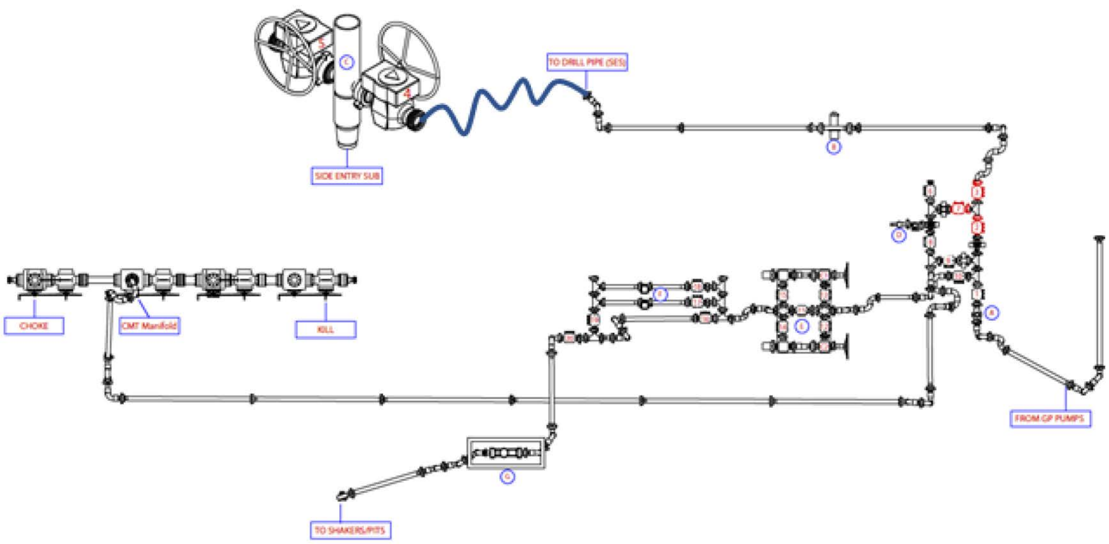

Figure 5—OHGP Surface System Schematic Lay Out Well-X

Once reaching the well bottom with the lower completion screens, the landing stand including the side entry sub, upper and lower TIWs and 6-5/8″ and 5-7/8″ DP pup joints would be made up to the landing string. Then the string, via entry sub connected to the gravel pack manifold by means of high-pressure hoses.

Plan and Execution

The mud density of the DIF system to drill and be left in the hole to run the screens and conduct the OHGP job as discussed earlier was 10.2ppg. An effective DHMW above 10.8ppg was to be maintained in the open hole with MPD throughout the entire process to prevent shales collapse, to pull the BHA, run the screens to bottom and OHGP. To further mitigate any issues with the hole closing on the BHA while pulling out or going in with the screens, the DHMW target was increased to 11.0ppg for the entire process.

A good integrity for the 8-1/2″ was observed achieving a shoe DFIT with MPD of 11.7ppg at the 9-5/8″ liner shoe. No losses while drilling previous legs of the ST02 were observed. To be able to test the packer seal and burst open the PTV seal an integrity of at least 11.7ppg was needed, for this purpose, an additional DFIT was conducted from the TD prior pulling out 8-1/2″ BHA with MPD up to 12.0ppg. In this way the absolute boundaries for the MP OHGP operation were very clear at this point. The BHP control strategy chosen was based on focusing in preventing the DHMW to fall below 10.8ppg to ensure success running the screens to bottom and spotting the gravel in place and was decided to minimize pressure adjustments based on annular frictions while circulating at the expected low circulation rates to be used.

The SBP was planned to be between 350psi (to maintain a min ESD of ~11.0ppg) and 1200psi. Surface pressures were to be adjusted as needed based on all the engineering planning to prevent DHMWs falling below min target of 10.8ppg or exceeding 12.0ppg during all operations involved. This included pulling out the 8-1/2″ section drilling BHA, conducting OH DFIT, running the screens to TD managing surge pressures, bursting the PTV rupture disk open, testing the packer, maintaining OH pressure while maneuvering with the service tool as needed and reverse circulating up the strings as needed. Main general steps included:

- Circulate Well to PST quality mud.
- POOH Drilling BHA
- RIH Screens to TD
- Burst PTV disk and establish string communication (Req for setting ball to pass through and reverse circ.)
- Set packer.
- Locate and mark tool positions.
- Reverse circulate Dope from landing string.
- Assist during service tool maneuvering (Step rate, CP circ and strip tests)
- Spot Gravel Pack job
- Reverse out excess GP in string.

The lower completion operation started once reaching TD of the 8-1/2″ interval of leg ST02. At this point the well was circulated clean, and BHA pulled back to the shoe with MPD maintaining min DHMW 11.0ppg with 10.2ppg DIF MW in the hole. Once at the shoe circulation continued until confirming PST quality on the fluid. Prior stripping out BHA, conducted a DFIT with MPD to 12ppg to confirm the PTV valve could be opened when required without breaking the formation. From this point, pulled the BHA above the SSBOP, flow check and closed the BSRs trapping the required pressure to maintain an EMW of ~11.0ppg at bottom. From this point MPD would get offline and operation would carry on conventionally laying down BHA and picking lower completion and running in hole. Once above SSBOP, MPD would get online, pressures across the BSRs would be equalized and MPD would resume operations maintaining 11.0ppg DHWM managing surge pressures while RIH with the screens.

Figure 6 shows the MPD system user interface time-based plots, showing part of the trip in with screens and the entire OHGP operation.

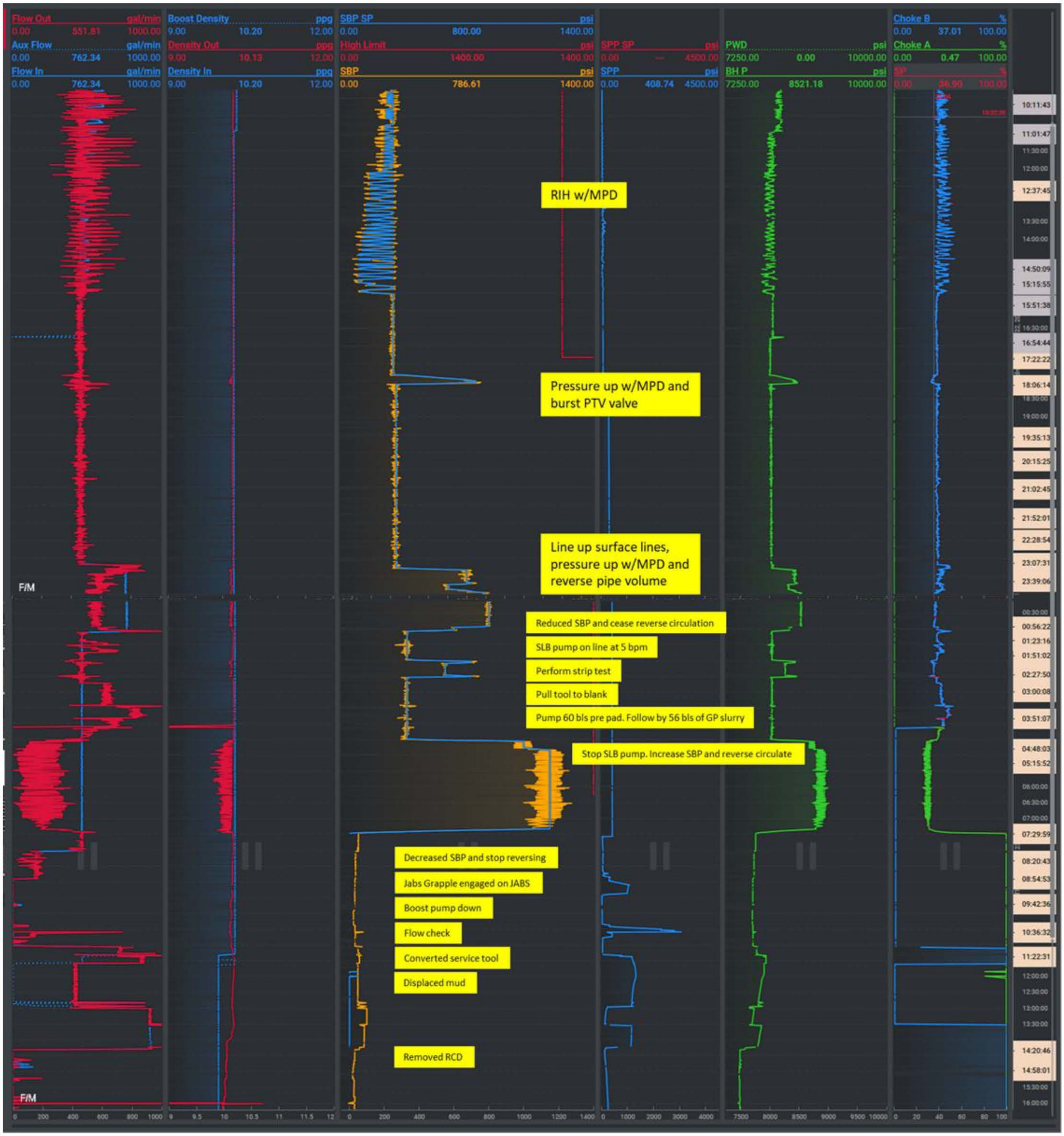

Figure 6—MPD system user interface time-based plots – Screens RIH and OHGP Well-X

As shown in the figure, SBP would be reduced while running in with screens and packer to suppress surge pressures and prevent exceeding limit of 12.0ppg at bottom. With screens at bottom, next step was to make up DP stand with Pump-in-Sub equipped with side entry valves and upper and lower TIWs. After this, surface equipment including GP manifold and hoses were rigged up and pressure tested. Once the Gravel Packing surface equipment and lines were rigged up, the SBP was increased to achieve a bottomhole pressure of ~8,700psi to burst the rupture disk and set the PTV valve open. From this point forward, there was open communication between the annular and pipe or landing string. The pipe pressure wouldn't be read at the SPP gauge as the upper TIW above the entry sub would be closed. Pipe pressure reading was available upstream the gravel pack manifold at this point.

Next step after confirming that PTV valve was open, was to set the packer pumping down the setting ball. The ball was pre-placed above the close upper TIW, and at this point was released opening and closing the TIW. The packer was set following standard setting pressure plus the addition of SBP and then service tool was released as per the GP team procedures. Two attempts were needed to release the tool. After the tool was confirmed released, the packer was tested. Base plan for the packer test was to do it with MPD, however project team decided to execute with SSBOP to achieve a higher test value. After this was done, the tool positions were located and marked as per GP team procedures.

With the service tool in Reverse Position (RP), the annular pressure was increase to reverse circulate clean the drill pipe. Then with the tool in the same position, started pumping down the string to conduct a step rate test increasing the circulation down the pipe from 1 to 5 bpm, then the service tool was moved slowly to find the Circulating Position (CP). Next step was to conduct the strip test, and after these pumped Gravel Pack fluid (Pre-Pad, Slurry, and Post-Pad) with the service tool in RP. Once the leading edge of the GP fluid pre-pad was at the cross-over, the tool was moved the CP position to place the Gravel Pack slurry in the open hole as per plan. After screen-out, the SBP was increased to ~1,200psi, the tool was pulled up to RP to reverse the excess proppant from the string. With the screens and gravel pack fluid placed successfully in the open hole, the MPD assistance was concluded at this point.

Results

Figure 7 shown below illustrates the distribution of pressure sensors ran with the lower completion string. Three washwipe and one drillpipe gauges were run to measure downhole pressures during and after the OHGP operation. The upper gauge placed above the packer read tubing and annular pressures.

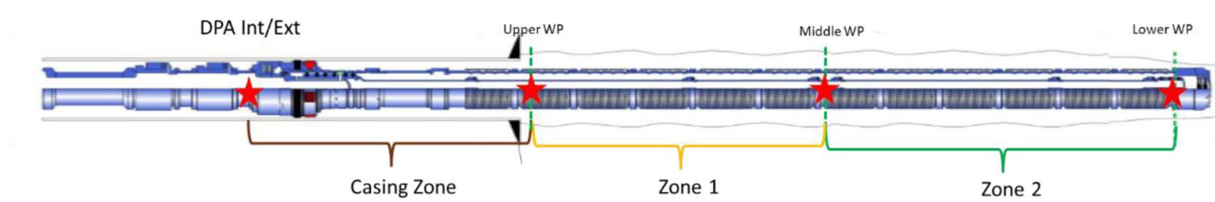

Figure 7—Lower Completion String Downhole Gauges Distribution

Figure 8 shows the DHMW throughout the downhole gauges pre OHGP operation while maintaining MPD SBP. 10.8ppg DHMW was maintain effectively the entire time prior pumping the OHGP, except while pulling through the Packer Pressure Test (PPT) position. Pulling through the PPT creates a swabbing effect as the tool recoils from ~40ksi overpull to shear through.

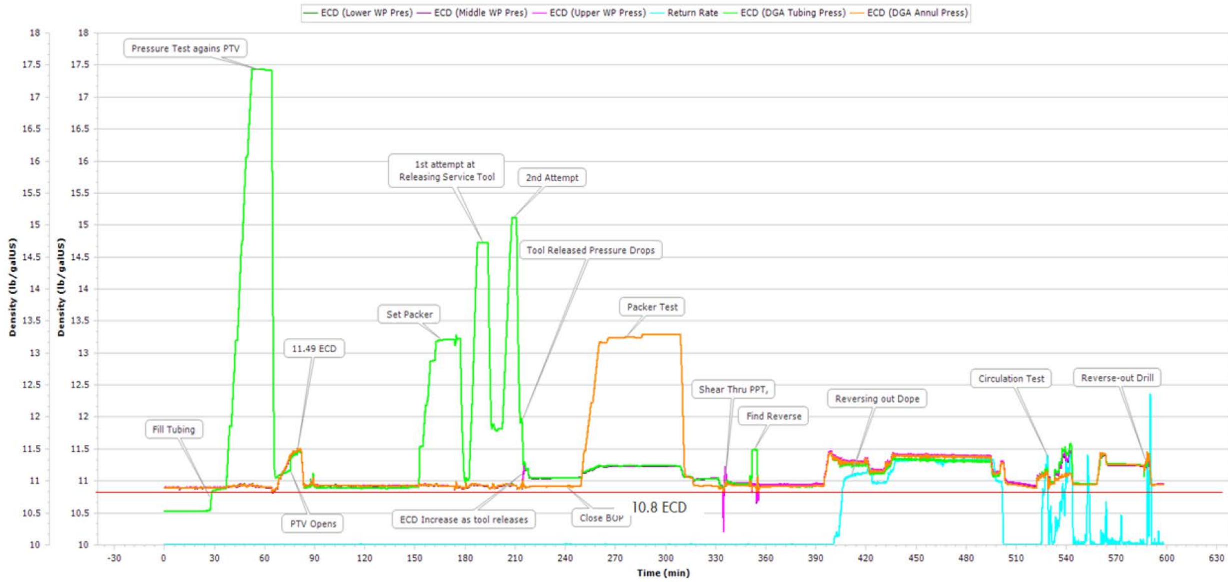

Figure 8—Gauges DHMW Readings Pre OHGP

Figure 9 below shows downhole gauges reading during the OHGP job. As shown 10.8ppg DHWM was maintained effectively during the entire OHGP operation, At the end of the GP the ESD dropped below when the pressure was to be bleed off. The max ECD in the open hole was measured at ~11.77ppg.

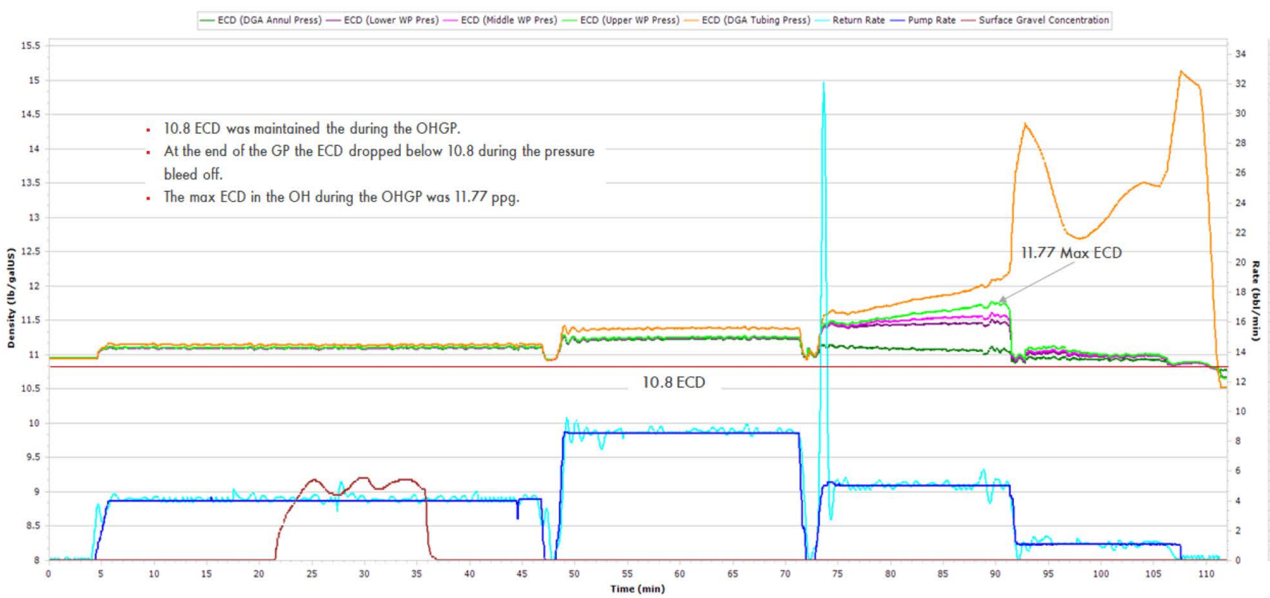

Figure 9—Gauges DHMW Readings during OHGP

Figure 10 below shows how downhole gauges reading drop below 10.8ppg as soon as reversing and MPD assistance is over. This demonstrates how effectively the Managed Pressure assistance worked throughout the entire operation, running the screens to bottom, setting, and testing the packer, reverse circulating multiple times and while pumping the Gravel Pack fluid.

Figure 10—Gauges DHMW Readings post OHGP

Conclusions

The information presented in this case study demonstrates how effective the use of the Managed Pressure Technology was to help the operator achieving the goals of this operation, by primarily enabling using the 10.2ppg DIF PST completion fluid. It was simply too risky attempting increasing the completion fluid density to 10.8ppg in this remote location without compromising the PST quality of the fluid and the success of the OHGP and posterior well test operation. The MPT help the operator maintaining effectively required min ESD throughout all the phases of the operation, including running the lower completion to TD and spotting gravel pack preventing the hole collapsing via an accurate surface pressure control. Results of this operation demonstrate the flexibility and diversity of applications in which Managed Pressure Technology can be used to optimize operations and resources and to overcome challenges in any phase of a well construction operation.

The use of MPD to assists during completion operation must be evaluated on a "case by case" basis and its use should not be assumed to be applicable to all completion or gravel packing operations.

Abbreviations / Nomenclature

MPT = Managed Pressure Technology
MP = Managed Pressure
ABP = Applied backpressure
GP = Gravel Packing
OH = Open Hole
RP = Reverse Position
CP = Circulating Position
DFIT = Dynamic Formation Integrity Test
DLOT = Dynamic Leak Off Test
OHGP = Open Hole Gravel Pack
PTV = Pressure Test Valve
TIW = Full Opening Safety Valve
NRV = Non-return Valve
BH ECD = bottomhole equivalent circulating density
BHA = bottomhole assembly

BHP	= bottomhole pressure
BSR	= Blind Shear Ram
CBHP	= constant bottomhole pressure
ECD	= equivalent circulating density
ESD	= Equivalent Static Density
EMW	= equivalent mud weight
LCM	= loss circulation material
MD	= measured depth
ML	= Mud Line
MODU	= mobile offshore drilling unit
MPC	= Managed Pressure Cementing
MW	= mud weight
NPT	= nonproductive time
RCD	= rotating control device
RKB	= Rig Kelly Bushing
ROP	= rate of penetration
SBP	= surface backpressure
SSBOP	= Subsea Blowout Preventer
TD	= total depth
TVD	= true vertical depth
WBS	= Wellbore Stability

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