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Analysis of Primary Safety Barrier on Workover Operations Using MCD on Deepwater Scenarios – Design and Execution

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Abstract

Intelligent completion installed in Brazilian pre-salt wells presents some challenges for workover. Pre salt ultra-deep-water wells are commonly equipped with two or three zones of integral intelligent completion, where severe fluid losses after acid stimulation, in depths is present on all wells.

The usual methods to remove the intelligent completion string requires controlling fluid losses to the reservoir or installing a mechanical barrier to isolate the reservoir. Both options have a high risk of non-productive time and safety risks.

A new approach is to remove the completion string in a single trip while dealing with losses. The reservoir would be communicated with the drilling riser while pulling the completion string. Clamps and flatpacks will be in front of the BOP during this trip. To control the risks, the project team developed tools and procedures to use MPD equipment and Mud Cap techniques during the critical parts of the operation.

One of the challenges faced was to prove that ALARP (As Low as Reasonably Practicable) was achieved in non-normative operations. This article will describe the concept and equipment used on the successful intervention. The objective is to present a new use of current MPD techniques for well maintenance operations. There will be special focus on the primary safety barrier during the operations and contingencies since there is no similar operation reported in the industry.

Introduction

A typical Brazilian pre-salt well is a deepwater oil well located off the coast of Brazil, beneath a layer of salt under the seabed. These wells are known for their challenging drilling conditions and significant hydrocarbon reserves. Most of the wells are in the Santos Basin and Campos Basin at a water depth ranging from 2,000 to 3,000 meters (6,560 to 9,840 feet). The total depth of the well, including the subsea, can reach up to 7,000 meters (22,965 feet) or more.

There are 3 main sections of a pre salt well, post salt, salt and pre salt. The post salt layer is composed mostly of shale stone, with some intercalations of sandstone. Following the post salt is the salt layer with usually more than 2,000 meters (6,560 feet) of thickness. The salt layer covers the carbonate reservoirs. A pre salt carbonate reservoirs present different technical challenges when compared to sandstone.

The typical operational window of a pre salt well, minimal, and maximum pressure that can be safely exerted in the well without operational problems, such as influxes and losses, is reduced when compared to other wells from sandstone reservoirs. These characteristics demanded that different drilling techniques to be used to conclude the well objectives. Fernandes et al [1] and [2] describes how the Managed Pressure Drilling (MPD) can be used in challenging scenarios and its importance on pre salt development depending on the well conditions in terms of operational window and reservoir pressure.

In summary, MPD is an adaptive drilling process designed to precisely control the annular pressure profile throughout the wellbore. MPD techniques enable immediate adjustments to the wellbore pressure, allowing operators to dynamically respond to changing conditions and maintain a narrow pressure window. This is achieved using specialized equipment such as rotating control devices (RCDs) for pressure retention, MPD chokes for pressure control, and flow spools for flow deviation.

Surface Backpressure (SBP) is the most common technique in MPD. SBP involves applying additional pressure at the surface to control well pressure. By manipulating the surface backpressure, operators can maintain a desired pressure profile in the wellbore, effectively managing formation pressures and preventing influxes or losses.

In deepwater applications, Pressurized Mud Cap Drilling (PMCD) and Floating Mud Cap Drilling (FMCD) are used for drilling carbonate reservoirs offshore. According to the International Association of Drilling Contractors (IADC) and the American Bureau of Shipping (ABS), FMCD involves drilling without returns while continuously pumping sacrificial fluid down the drill string and annulus. This technique prevents the migration of formation fluids to the surface as the open-hole formation absorbs all injected sacrificial fluid and drilled cuttings without surface pressure assistance. During FMCD operations, the fluid level remains below the surface because the fluid pumped into the annulus has a higher density than the equivalent pore pressure density. As a result, there is no direct indication of annulus conditions, leading to the term "blind drilling." To prevent hydrocarbon inflow or migration, a minimum downward flow rate to the annulus is necessary, calculated using hydraulic simulators. Currently, there is no industry standard procedure to ensure that any hydrocarbon migration in the annulus is contained at the bottom of the well.

Pressurized Mud Cap Drilling (PMCD), also defined by IADC and ABS, is a drilling technique that involves drilling without returns by balancing the full annular fluid column using a Light Annular Mud (LAM) cap in the annulus. This method allows the formation to absorb all injected sacrificial fluid and drilled cuttings with the aid of surface pressure. The density of the LAM is selected to maintain and observe surface pressure. Periodic injection of the same fluid into the annulus helps control surface backpressure within operating limits and reinject formation fluid.

Most of presalt wells have been equipped with intelligent completion in cased hole, with 2 or 3 zones, as it is shown by Schnitzler, 2019. All wells present high injectivity, result of the high porosity carbonates exposed to matrix acid treatments.

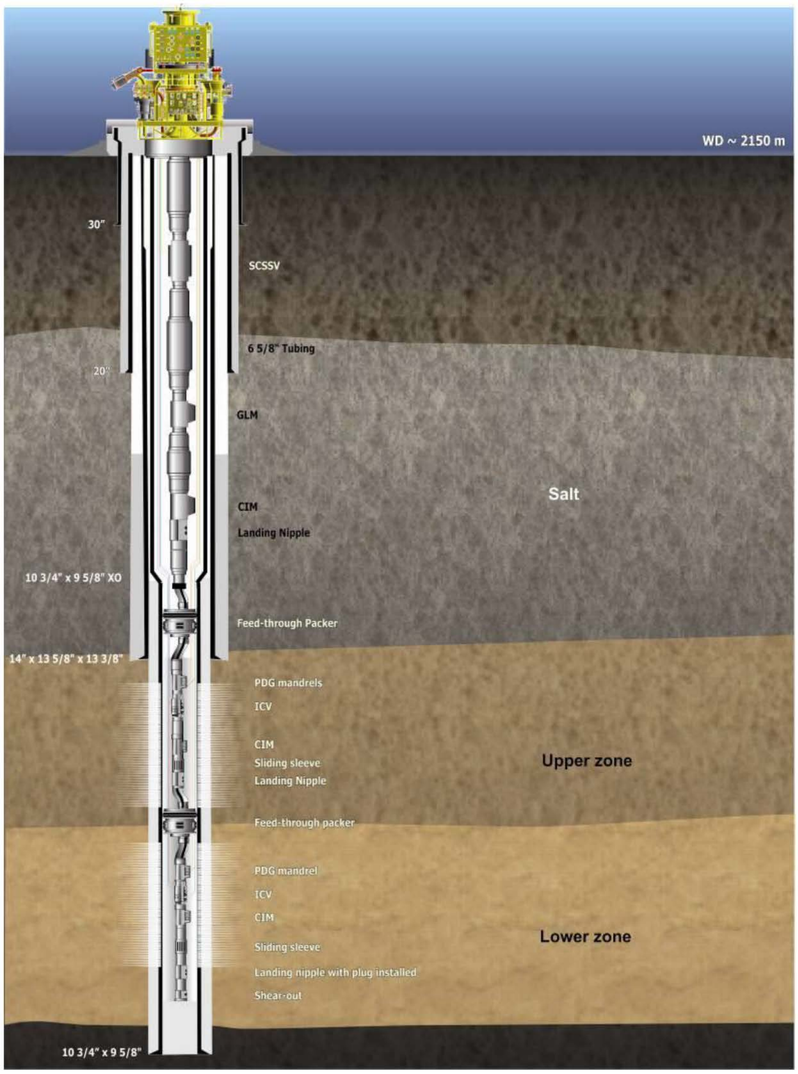


Figure 1—Typical presalt for cased hole intelligent completion.

Petrobras has used several MPD techniques and adopt completion configuration to deal with losses, as was shown by Schnitzler et al, 2017, Alonso et al, 2021. The use of MPD techniques for workover operations has been suggested by Schnitzler et al, 2018, where the retrieval of an intermediate completion and installation of a, additional intermediate completion used MCD techniques with total losses.

The overall operation that will be discussed in this paper has been presented by Pereira et al 2024, this paper will focus on the first barrier analysis for the retrieval of the upper completion.

Use of MCW in Presalt Wells

Floating Mud Cap Drilling (FMCD) is a specialized drilling technique utilized in certain challenging environments, particularly in deepwater carbonate reservoirs. This method is often used when conventional drilling methods are not feasible due to high pressure, lost circulation zones, or other geological complexities. While FMCD offers a viable solution for these challenges, it significantly impacts the primary safety barrier system of the well, necessitating careful consideration and management to ensure operational safety.

In FMCD, drilling is performed without returns, meaning that the drilling fluids and cuttings do not circulate back to the surface. Instead, sacrificial fluid is continuously pumped down the drill string and annulus, allowing the formation to absorb the fluid and cuttings. The technique is designed to prevent the migration of formation fluids to the surface by maintaining a fluid level below the surface, relying on the high density of the pumped fluid to counteract formation pressures. On deepwater environments FMCD technique is used on deleted wells with seawater serving as a sacrificial fluid.

The primary safety barrier in conventional drilling operations typically consists of the drilling fluid column, which exerts hydrostatic pressure to counterbalance formation pressures and prevent unwanted influxes (kicks) or blowouts. This barrier is complemented by the blowout preventer (BOP) system, which can seal the well in case of a significant pressure anomaly or hydrocarbons inside the well.

During FMCD deepwater operations the sacrificial fluid is continuously pumped in the annular over a variating fluid level. This fact impedes the conventional hydrostatic pressure as continuous fluid column extending to the surface is not present. Which means the conventional hydrostatic pressure control is not in place. The sacrificial fluid must be of sufficient density and speed to maintain control over the formation pressures without traditional hydrostatic support.

FMCD technique relies on the formation's ability to absorb the sacrificial fluid and cuttings, which introduces uncertainty regarding the wellbore conditions. Maintaining a minimum downward flow rate is critical to prevent the influx of formation fluids (hydrocarbons) into the wellbore, posing a significant challenge in ensuring the integrity of the primary safety barrier.

FMCD is often referred to as "blind drilling" because there is no direct indication of annular conditions or the ability to monitor returns at the surface. The lack of real-time data on wellbore conditions increases the complexity of managing the primary safety barrier, necessitating advanced modeling and simulation to predict and maintain the required flow rates and pressures.

The use of MPD techniques for workovers has been called MCW (Mud Cap Workover) by Pereira et al 2024. In scenarios with total losses to the reservoir and integral well completion, the use of LCM could jeopardize the retrieval of the completion. The proposal is to retrieve the whole completion in one trip, without isolating the reservoir. Similar to FMCD/PMCD mode, a sacrificial mud is used in the annulus in order to prevent influx.

To do so, a THMRT (Tubing Hanger Mechanical Retrieving Tool) had to be developed. It is a tool that provides access through tubing, allows unlocking and retrieving the TH (Tubing Hanger). Additionally, the DPR (drill pipe riser) must be compatible with the sealing device of the MPD system. For pre salt wells, DPR are 6 5/8″ with HP connections.

The first phase of the workover, access through the X-tree with EDP-LRP. In this phase the well is cleaned (tubing and annulus) and barriers are installed and tested to compose 2 barrier envelopes and allow retrieval of the X-tree.

The second phase, the BOP is installed to perform the retrieval of the completions, the steps are the following:

1. BOP test.
2. THMRT running, landing and test.
3. Retrieval of barriers.
4. Shift-and-pump to release packers.
5. Cut above the lower packer (specific to this first well, the lower zone would be permanently isolated).
6. Punchers to communicate tubing / annulus above and below packers.
7. Install non-return valves "NRV"s (BRV);
8. Pull out completion in MCW mode.
9. Install new completion in MCW mode.

This paper will focus on the discussion for steps 8 and 9 and the requirements to turn this operation ALARP.

After retrieving the completion, in this case, a BPP (permanent bridge plug) would be installed to allow cement logging.

First Barrier Analysis - Design considerations

In this first well, the reservoir was depleted at around 7,9 ppg. This means that when filled with abundant sea water the static level would be ~1000 m below the rotary table. The first barrier design was made also considering a higher pore pressure, in such scenario there would be pressure on the surface when filled with seawater, however this scenario won't be detailed in this paper.

Usual FMCD techniques require two NRVs inside the drilling string to prevent migration of fluids during trips and pumps stop. For installing lower completion, the same consideration was done. For the workover, the tubing itself is part of the working string, so to achieve a barrier inside the tubing it must be inserted by means of a through tubing operation. The team assessed each phase of the retrieval of the tubing to identify the need for mechanical barriers.

To state the problem and clarify it to the reader, Figure 2 - Left: flow paths before unsetting packers. Right: flowpaths while triping out. shows a general schematic of the operation. In the left-hand side, it is shown the situation before pulling out the completion. The THMRT and DPRs provide hydrostatic continuity from surface to the tubing. On surface, a RCD with a sealing device (bearing assembly) provides sealing against the DPR in the annulus. Inside the tubing, right bellow the tubing hanger there is a DHSV (Downhole Safety Valve) with its control lines. Above the packers there is a landing nipple. This tubing was equipped with a gas lift mandrel, and the gas lift valve would be replaced by a dummy in the first phase of the workover.

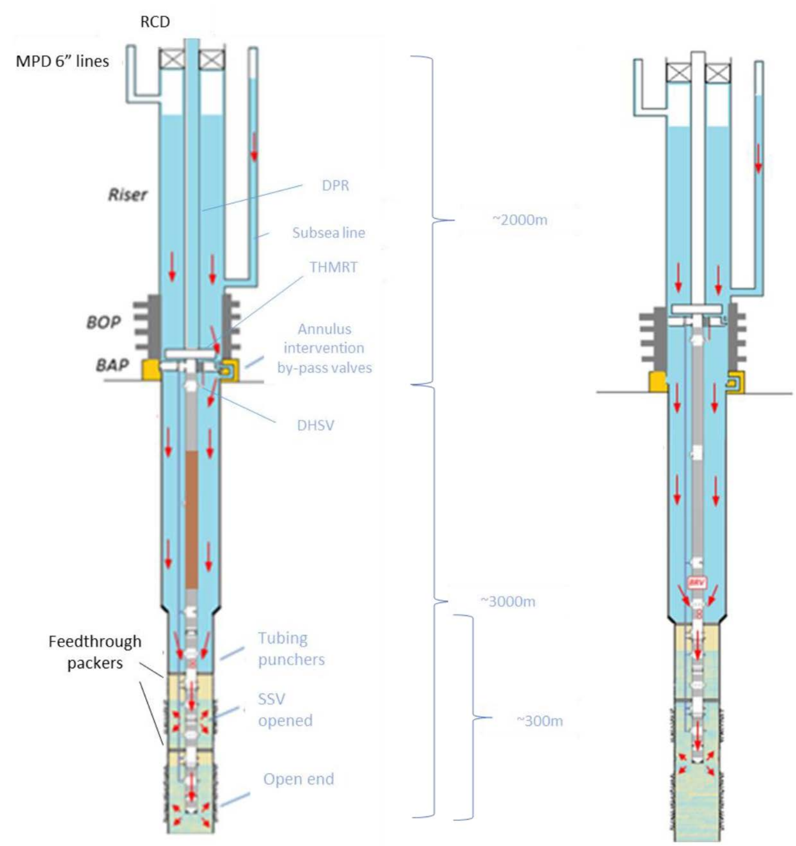


Figure 2—Left: flow paths before unsetting packers. Right: flowpaths while triping out.

Annulus hydraulic access is done via the annulus intervention valves (AI). The THMRT was designed to allow communication between the AI bypass and the riser. Before unsetting the tubing hanger, the annulus can be cleaned opening the AI valves. The packers are set in a 9 5/8″ casing and ~100 m above the upper packer the casing is 10 ¾".

It is not shown in the drawing, but a complex surface manifold is required to perform all the through tubing operations, including a surface flow tree, wireline or slickline pressure equipment.

In the right-hand side of the Figure 3 it is shown the tubing being retrieved in the first 100 m, where the packers are still in the 9 5/8″ casing section.

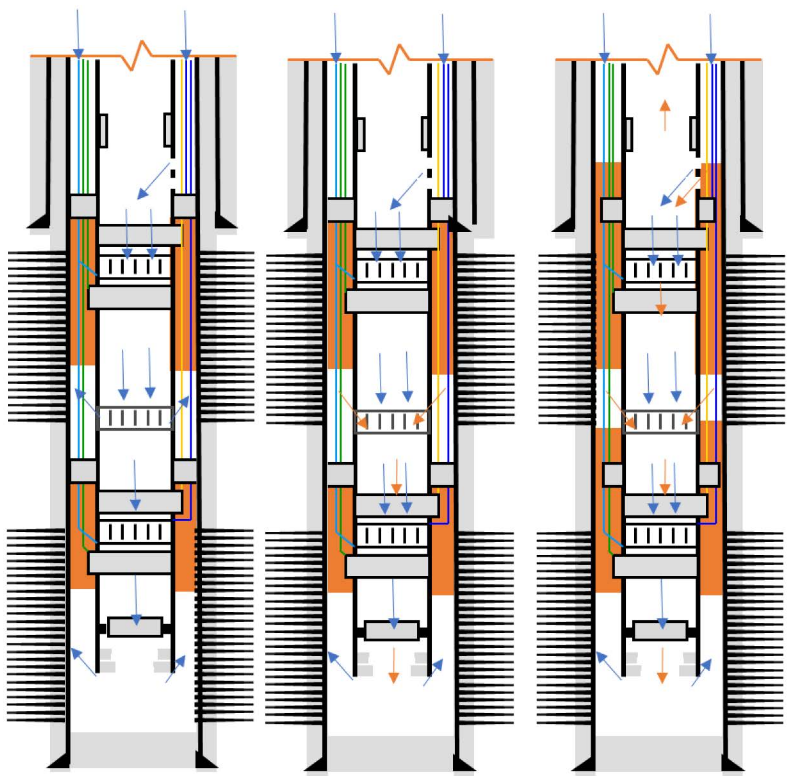


Figure 3—Hydraulic schematic of oil traps and crossflow

The fluid used (8,5 ppg) with a flowrate that guarantees no oil migration, could be considered the first barrier while retrieving the completion. The flowrate used considers the full casing being communicated, this guarantees that in all conditions the oil would be pushed downhole. Since the fluid hydrostatic is not continuous up to the surface, the BOP pressure sensor would be the only indicator of a failure of the first barrier. There are a few issues with this approach, as there is way to set an alarm, and this kind of pressure sensor is not designed to be part of a safety system, additionally, in case of undetected oil migration, it would only be perceived in the sensor when the oil starts to release gas, it only happens near the BOP depth and more intensively in the riser. This leads to very limited time of response after detection of abnormality. Thus, a more detailed analysis is required.

The figure bellow shows the lower part of the completion and possible oil traps that could happen and the flow direction when the packers are unsetted. In blue is the SAC pumped from the surface through the flowline->AI->annulus, and in orange is the oil traps and potential oil flow. Before unsetting the packers, the tubing has been cleaned and is continuously fed with SAC from surface, but in the chambers between the packers and the opening tubing there could be some oil trapped.

Both zones communicate with the same reservoir but could have different depletions, so crossflow between the two zones was considered highly likely. In the middle drawing, it is shown that oil might be flowing from one zone to the other before unsetting the packers. While continuous flowrate is kept through this flow path, no oil migration is expected, but in the event of a failure in the flowrate, oil might start migration through the tubing and annulus, thus mitigations have to be in place to prevent arrival in surface.

Once the packers lose sealing capability, since the oil has lower density than the SAC, it rapidly moves upwards (right hand side). In this situation, if there is no flow from the tubing, some migration could happen through the tubing, also demanding some mitigation.

This kind of packer unset when overpull is applied. But several times the barrier element of the packer doesn't retract completely, so a swab effect is expected while the packer is in the 9 5/8″ casing section. Due to this fact, the team considered that during the whole trip inside the 9 5/8″ section there would be crossflow and oil trapped bellow the packers. This swab effect would not be instantly noticeable from surface due to the hydraulic communication above and below the packers. There might be some change in BOP pressure reading.

After unsetting the tubing hanger and packers, the surface equipment used for the wireline operations must be demobilized. This operation takes around 12 hours, during most of the time there might be no means to access the inside of the DPR, so if some oil migrates through the tubing in this moment, it might achieve surface if no mitigation is added.

Up to the point where both packers are in the 10 ¾" section it is critical to have mitigations of oil migrations both inside the tubing and in the annulus.

After both packers are above the 10 ¾" casing section, the magnitude of swab effect is much lower. Nevertheless, there might be crossflow across the reservoir. Even without differential depletion, in such a thick reservoir, the difference of hydrostatic between the SAC and formation oil might lead to crossflow, as might be seen in Figure 4.

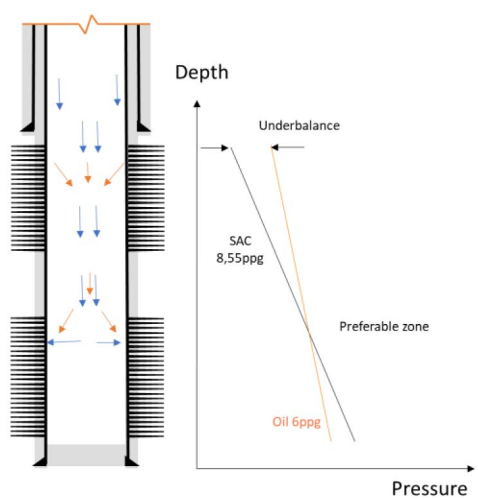


Figure 4—Hydrostatic analysis showing underbalance in top of reservoir due to SAC weight.

Figure 5 sums up the different moments of the tubing retrieval. In moment a, TH is still in position and the tubing can be fed with flow from surface. Also, in this moment several through tubing operations are performed. Surface pressure equipment is required for the through tubing operations.

Moment b is the most critical due to the uncertainties in the flow path, swab effect and lack of control of fluid barrier. These concerns lead to the mandatory use of RCD with a BA. If some migration happens undetected, the oil will remain trapped bellow the RCD and would be diverted to the mud gas separator.

Inside the tubing, it was discussed if a mechanical barrier was needed. The implementation of mechanical barriers implies in additional through tubing operations for their installation. When retrieving the tubing with both packers one of them could get stuck and lead to cutting and fishing operations. If there is a barrier inside the tubing, it must be removed before the cutting operations, adding risks to an already complex situation.

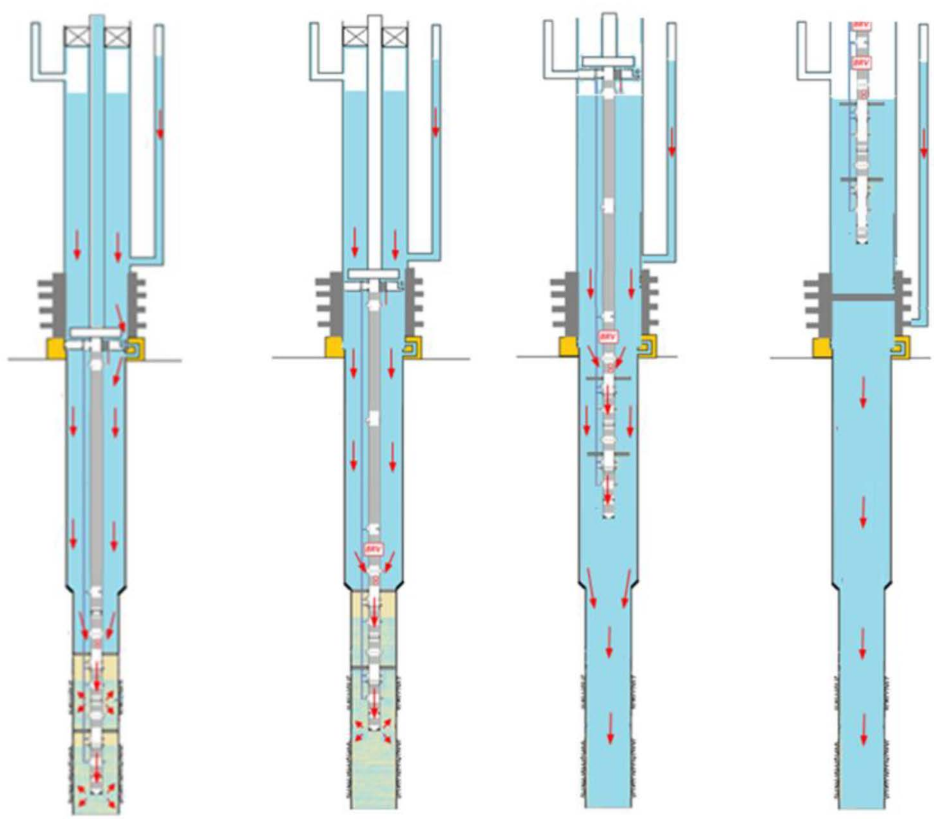
The options of mechanical barriers inside the tubing are listed below:

DHSV: The DHSV is already in place in the tubing and could be a barrier. In order to use MPD sealing against the DPR, there can be no hydraulic umbilical to control the downhole equipment, so in this scenario the DHSV will remain closed due to its fail-safe close design, and would still allow pump through it. The ability to close and seal must be verified beforehand.

BRV: bottom retention valve, is a flapper type valve insertable through tubing. It is usually used as a barrier for underbalance operations and to dissociate hydrates. This valve might be installed in one of the landing nipples profiles above the packer, above DHSV or in the TH. Additionally there are nippleless locks that could be used.

The team discussed the pros and cons of adding insertable barriers. Looking closely to each operation and applying preventive procedures, it could be acceptable to not use any additional barrier, but since this was the first time using this concept and the potential unpredicted risks, it was decided to use two mechanical barriers. All the options were available at the rig, but the preferred combination was to use a BRV in the lower nipple and de DHSV.

In moment C, the packers are already in a position where there is a generous flow area and low probability of stucked pipe. There might be crossflow between zones, so mitigations must be in place in case of losing flowrate.



a b c d

Figure 5—Different moments of retrieving tubing.

Once the TH is in the rotary table, the RCD/BA cannot be used anymore (moment c). Thus, before removing it, a new generous bullheading is performed to guarantee absence of any remaining oil inside the casing. The team evaluated the option of using LCM in this stage to regain level in the riser and control the rest of the trip in conventional mode, but considered it to be unnecessary or even fruitless. Historically this type of well needs several batches of high solid concentration and granulometry to deal with the losses, so it would be a costly operation with low gains. It could also lead to stuck pipe or obstruct the tubing itself, leading to new risks. The mechanical and hydraulic risks in situation c was considered low.

After all the completion is above the BOP (moment d), the shear ram can be closed to isolate the riser from the reservoir.

The practices below were used to control the fluid flow rate along all the operation:

1. Keep continuous bullheading of completions fluid (SAC) with minimum 150 psi of overbalance, through the annulus, maintaining at least 2 times the minimum flow rate to keep hydrocarbons from migrating in the well. This minimum rate is determined through simulations using specific software.
2. Careful management of mud pumps and mud pits to always have backups in case of any equipment failure.
3. Double checking of the actual pump rate, measuring directly on the mud pits volumes.
4. Perform preventive bullheading through the inside of the string before the tubing hanger arrives at the rotary table and after the removal of this element, mitigating the risk of any hydrocarbon migrating inside the tubing.
5. Guarantee plenty fluid for the whole operation, this step is critical, especially if the reservoir pore pressure is such that only seawater would not be enough to kill the well with 150 psi overbalance.
6. Optimize the tripping time, racking back the tubing by stands.
7. In case of a well control incident, make use of the surface blow out preventer or drill string isolation tool (DSIT) that is part of the MPD integrated riser joint to isolate the well from the surface and perform bullheading to get rid of any hydrocarbon.

Although this design is presented considering retrieval of two packers, in fact for this first well, the lower zone had to be isolated, so only the upper packer had to be retrieved.

First Barrier Analysis - Execution

This intervention was executed in 2023. The first phase occurred with no major problems, and the ICVs and the DHSV were found to be sealing, thus they were used as barriers to remove the Xtree. The well was cleaned, and gas lift valve replaced by a dummy.

The BOP was installed and tested with no problems.

The THMRT was run with DPR string and before setting over the TH the BA was installed and tested. The THMRT was successfully landed on the TH and its interface tested. While running the THMRT it was noted that the AI valves (annulus interventions valves) could not be opened. Several attempts were made without success. Destructive methods of opening the valves were addressed, but were not considered safe.

With this issue, the ability to feed the annulus with the TH in position was lost. The team evaluated that is this scenario, there were some risks:

- If the packer lost sealing capability, the A annulus could be filled with oil, and this would only be pumped back to the reservoir after unsetting the TH.
- The riser would be filled with SAC. This would imply in a pressure differential in the TH that could be difficult to overcome.

All the through tubing operations were done successfully, with installation of BRV in the lower nipple and use of DHSV as second barrier. The injectivity to the reservoir was found to be extremely high and pore pressure was low, as expected.

When applying overpull to unset the TH, it didn't release within the limits available. The team then refined the calculation of the pressure on the TH. Since the A annulus was still filled with original brine (9,7 ppg) and the riser was filled with SAC 8,6 ppg, the pressure differential over the TH could be up to 1300 psi, which caused 140 kips of slackoff on the TH. Additionally, the cooling of the tubing with the flow could add a downward force of up to 100 kips if the packer was not unset.

To try to lower this force, a lower weight mud was positioned in the subsea kill line and BOP with BOP closed, reducing the pressure above the TH. Additionally, it was attempted to apply pressure from below injecting to the reservoir. All these effects combined reduced the hydraulic slackoff but were not sufficient. It was evaluated that performing a punch in the tubing and replacing the 9,7 ppg fluid of the annulus with 8,55 ppg SAC would reduce ~65 kips the slackoff. After all attempts to unset the tubing hanger were unsuccessful, the team decided to perform the puncher. It was done bellow the DHSV to have one mechanical barrier inside the tubing, but the BRV installed close to the packer was bypassed by this puncher. After bullheading the annulus fluid and repla 8,55 ppg, it was possible to unset the TH and retrieve the tubing.

After unsetting the TH, a generous bullheading of tubing and annulus was performed. The tubing was retrieved without abnormal drag, and the injectivity remained high during the whole trip. The BOP pressure can be seen in Figure 6, from the moment when the TH was released up to the BOP closure. In the beginning some increasing in pressure is seeing due to preventive bullheadings and an oscillation of the pressure occurs on some occasions, while the tubing is still inside the 9 5/8″. When the packer is inside the 10 ¾", the pressure in the BOP stabilizes in a lower value around 2500 psi throughout the rest of the operation. This behavior confirms the expectation of low risk of inflow during tripping out.

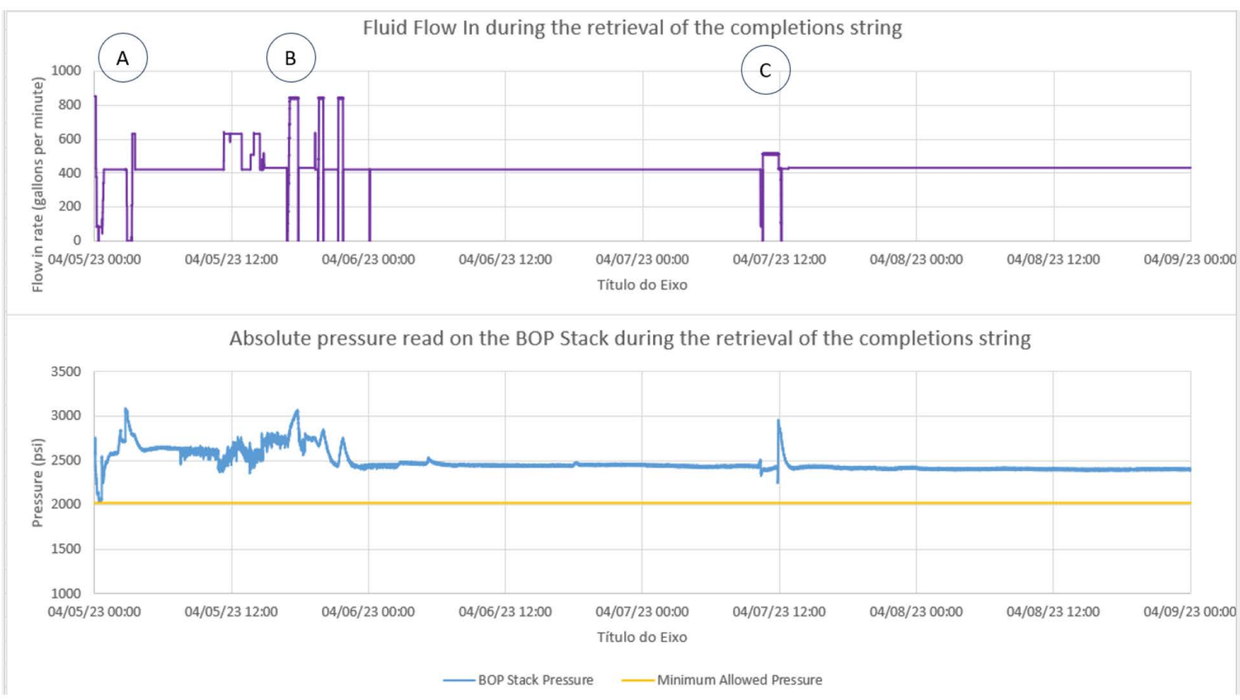


Figure 6—Plot of the BOP Stack pressure and the flow rate used on the MCW operation to keep the well under control. A, B and C, show increases in flow rate during preventive bullheadings. The Yellow line on the lower plot shows the minimum allowed pressure on the BOP (the pressure equivalent to a zero overbalance over the reservoir) Reference: OTC-35032.

No incident of oil migration was registered. The whole operation in MCW mode was successfully done without major incidents. Furthermore, the cement in this well was found to be good and a new completion was installed in FMCD mode.

Conclusions

The utilization of Mud Cap Workover (MCW) for well intervention, particularly in the case of this well, has validated the potential of this technique. By employing MCW, the installation of the new completion with minimized risks was made achievable.

The well's conditions presented relatively milder challenges, as only the upper packer of the intelligent completion needed to be recovered, and the pore pressure was lower. Some lessons were learned in the TH retrieval, for next interventions other means to operate annulus intervention valve will be in place, and the information of the mechanical override functionality will be anticipated.

The operation was safe and controlled thanks to the detailed planning. The solutions applied to the use of MPD equipment proved to be ALARP and can be improved for more challenging scenarios, with more than one packer retrieval and higher pore pressure.

This work represents a significant and concrete stride in the development and implementation of the MCW technique, which is still in its nascent stages within the oil industry. Various well configurations can benefit from this technique, including not only intelligent completions but also wells with simple completions lacking TSR (with seal-bore and extended locator), as well as scenarios presenting challenges in establishing effective well barriers.

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