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MPD Helped Successfully Drill a Central European Well to TD After Multiple Failures in a Formation Fraught with Wellbore Instability and Formation Pressure Uncertainties

O. Kaldirim, S. Nauduri, G. Guefack, J. Morris, D. Fisher, M. Spahn, R. Howell, and M. Parker, Pruitt Tool and Supply, Fort Smith, Arkansas, USA; P. French, Shell Upstream Albania B.V., Tirana, Albania; C. Leggett, Blade Energy Partners, Frisco, TX, USA

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Abstract

MPD successfully delivered the first well in a remote Balkan region of Central Europe after multiple failed conventional drilling attempts into a reservoir fraught with formation pressure uncertainties and significant wellbore breakout. This paper discusses the MPD planning and execution strategies for managing the formation pressure uncertainties and borehole breakout, as well as the performance of the MPD system in handling larger cuttings and cavings.

MPD offers many opportunities, such as using a reduced mud weight and tracking the lower pressure boundary, coupled with the ability to respond rapidly to changing formation pressures. Challenges arise when wellbore stability pressure is uncertain, leading to breakouts at the borehole wall. This results in larger cuttings and cavings that can potentially plug the choke, causing pressure fluctuations and potentially leading to charged fractures, thereby further exacerbating the situation. These scenarios require detailed analysis, extensive planning, and rapid response.

The engineering team's planned response to the formation and fracture pressure uncertainties, combined with field execution and MPD system performance, enabled Shell Upstream Albania B.V. to successfully drill the well to the planned TD and secure and isolate multiple fracture zones with liner and MPC for stimulation and testing for the first time in the region. The well was drilled and completed with minimal losses while encountering major borehole breakout and with "0″ NPT due to choke plugging. MPD also enabled the client to obtain the first set of logs for the reservoir in this region with LWD. The liner was successfully run to TD, and bottom hole pressures were managed while cementing with MPD.

Introduction

The case discussed in this paper involves the fifth well drilled as part of a development project. The first two of the five wells were drilled by another Energy Production Company (EPC) before the field was acquired by Shell Upstream Albania B.V. (the client), who continued to develop the field.

The client experienced challenges related to pore pressure uncertainty, wellbore instability, moderate to severe losses, and gas influxes, making it impossible to drill these wells conventionally to the target depth (TD). The client chose to use Managed Pressure Drilling (MPD) technology and its variations, Constant Bottomhole Pressure (CBHP)/Anchor Point (AP) to address these challenges. The CBHP/AP MPD solution would allow the client to rapidly respond to changes in pore pressure, minimize losses, manage wellbore stability issues, and detect and minimize gas influxes while drilling, reaming, stripping, and during connections. These operational benefits can also be applied while running casing/liner and cementing.

This paper presents the design and execution of the MPD plans that allowed the client to successfully drill to TD, run liner, and cement the well while also providing the opportunity to obtain a full set of open hole logs with Logging While Drilling (LWD) for the reservoir.

MPD Objectives and Challenges

The well was drilled vertically to the top of the reservoir. In the reservoir section, a 45° inclination was maintained to achieve the required outstep and assess potential fractures. The reservoir consisted of fractured carbonate rocks with marl, claystone, and chert. Potential risks associated with drilling the reservoir section included:

1. Potential for high-side pore pressure and pore pressure uncertainty.
2. Challenges in maintaining Bottom Hole Pressure (BHP) within the operating window.
3. Wellbore instability.
4. Uncontrolled losses (kick loss scenario) and reservoir damage from loss of circulation material (LCM).
5. Open fractures and faults.
6. Fault activation.
7. Fractured bitumen zones.

These risks could lead to stuck pipe, lost Bottom Hole Assembly (BHA), or the inability to run the liner to the bottom. The MPD plan was designed to mitigate or minimize the impact of these risks and prevent failures while drilling the reservoir section. Previous wells drilled into the reservoir encountered multiple failures and were lost due to the use of high mud weight (MW) to combat borehole stability, which led to catastrophic losses and subsequent hole collapse. This was one of the key drivers for MPD, to be able to run at the minimum acceptable borehole collapse to mitigate the risk of catastrophic losses.

MPD Hydraulics Design

The MPD drivers for this well were uncontrolled losses and kick-loss scenarios at the fractures and faults, formation pressure uncertainty with the potential for higher-than-expected pore pressure, and wellbore instability and borehole collapse. The MPD Well Engineering team prepared MPD plans for this section that accounted for the need to reduce Surface Back Pressure (SBP) to control losses while maintaining BHP within the operating window and providing continuous monitoring for losses, pack-offs, and formation kicks.

Due to pore and fracture pressure uncertainties, various kick-loss and wellbore stability, scenarios specifically borehole breakout in fractured carbonate zones due to complex geological setting (fold-thrust belt), were simulated to determine the optimum mud weights (MW) and necessary SBPs. The ability to reduce SBP in a significant loss scenario was also simulated to validate that the BHP remains above the pore pressure while trailing the wellbore stability line and managing wellbore breakout issues. These results played a crucial role in the successful planning and execution of the project.

Mitigation plans for hole stability issues were also prepared, and the MPD equipment was designed with differential pressure transducers across junk catchers to indicate when the catchers were approaching being full, easy-to-clean junk catchers upstream of the chokes and flow meters to catch cavings larger than 1.0 inches. Utilizing the SBP pump to prevent rapid choke swings and pressure surges and clear cuttings buildup was discussed and adopted during execution.

The initial objective was to drill out the shoe and penetrate the reservoir with equivalent mud weight (EMW) sufficient for the realistic high pore pressure. Once the reservoir was penetrated, the EMW would be reduced to confirm overburden at the lowest acceptable MW for borehole breakout. Starting with this objective, MPD planning was conducted and tested multiple scenarios with a wide range of MWs and target EMWs. The final MPD plan targeted an EMW of 1.7 sg with 1.45 sg mud weight, requiring 1,750 psi static SBP and 1,100 psi dynamic SBP. After penetrating the reservoir, the plan was prepared to stage down the EMW to 1.59 sg (1,150 psi static SBP and 230 psi dynamic SBP) and to monitor the well to ensure the EMW would be sufficient, allowing for minimum borehole breakout.

Furthermore, the MPD Team provided the client with drill-ahead modeling to determine the depth at which MPD would hold minimal dynamic SBP. This was to ensure that the MPD system could reduce SBP almost instantaneously during a severe loss case. Following this drill-ahead modeling, the decision was made to lower the MW, in order to leave sufficient SBP as working margin for loss mitigation, from 1.45 to 1.41 sg, maintaining 1.59 sg equivalent circulating density (ECD)/equivalent static density (ESD) (1,400-1,500 psi static SBP and 450-650 psi dynamic SBP) after drilling 550 m-MD.

MPD Equipment Selection

During the planning phase, equipment selection was primarily driven by the possibility of H2S in the reservoir section, wellbore stability issues, rig layout, limited supplies, and accessibility due to the region and designed to be modular to simplify shipping, storage, rig up and rig down, in remote mountain setting. The MPD Team provided the following equipment:

1. Dual differentially pressure-monitored debris catchers (Junk Catcher) (3,000 psi Maximum Allowable Working Pressure (MAWP)) (Figure 1).
2. Independent remote programmable Pressure Relief Valve (PRV) (Figure 1).
3. Two high-pressure Coriolis meters (3,000 psi MAWP) (Figure 1).
4. Dual Pruitt MPD electric chokes (3,000 psi MAWP) (Figure 1).
5. ASME VIII U Stamped Mud Gas Separator (MGS) (16 ft liquid leg, 30 psi MAWP) with real-time level monitoring and alarms (Figure 2).
6. Flare stack (30 ft) with flame arrestor and real-time gas flow meter due to potential for H2S and the location proximity to nearby villages (Figure 3).
7. Four dual rotating control device (RCD) bearings.
8. RCD bowl assembly with clamp station.
9. RCD rebuild kits with RCD rebuild workshop.
10. On-site RCD pressure test vessel and equipment.
11. High closing ratio (HCR) valves.
12. Pipework and sensors.
13. MPD control container.

Figure 1 displays the modular choke manifold with Dual MPD electric chokes (A), junk catchers (B), flow meters (C), PRV (D), bypass lines, and pressure transducers. While operational, the flow was directed through both junk catchers and flow meters through one MPD choke while the MPD choke B was maintained closed. Once the differential pressure across a junk catcher reached a clean-out threshold, MPD choke B was opened, and choke A was closed in a controlled procedure while continuing drilling operations. Once choke A was closed, the junk catcher with the full catcher was isolated, drained, and cleaned out after performing the necessary job safety analysis, permitting, toolbox talk, and H2S sniff test.

Figure 1—Pruitt MPD Choke Manifold with instrumentation, A- Dual Pruitt MPD electric chokes, B- Dual differentially pressure-monitored debris catchers, C- Two high-pressure Coriolis meters, D- Independent remote programmable Pressure Relief Valve (PRV).

The PRV system installed on the manifold operated independently from the choke control system for redundancy to allow for overpressure protection for the surface equipment and the rig crew. The engineering team created a logic to have the PRV release the pressure into the downstream line once overpressure was detected and automatically swap chokes to manual mode to hold their positions until the pressure dropped to reset pressure. This process would trigger the driller to shut in the well on the blow-out preventer (BOP). Once at reset pressure, the PRV would close and reset itself to protect from another overpressure event. The PRV control system hydraulic power unit (HPU) was designed with multiple open-close cycles for overpressure protection in the event of a power failure; the human-machine interface (HMI) also included battery backup to monitor for overpressure protection during an event.

The MPD system rig-up is displayed in Figure 2 with flow diverted from the well through the RCD bowl and bearing assembly (A), to the MPD choke manifold (C). At the downstream end of the MPD choke manifold, the flow enters the mud gas separator (MGS) (D) with mud returning to the shakers from the MGS. The MGS level was monitored in the MPD control unit with level sensors and pressure transducers installed on the MGS.

Figure 3 displays the flare stack with the flame arrestor and real-time gas flow meter installed. The flare stack was included due to the potential for H2S in the well and the proximity of the well location to the nearby villages and homes. The flame arrestor can be instrumented with sensors to monitor the temperature and prevent burn back in the line due to the vacuum degasser being hooked up to the flare.

Figure 2—MPD System Rig up with A- RCD Bowl, RCD Bearing, HCR Valves and pipework, B- MPD Transformer skid, C- MPD Choke Container, D- ASME VIII U Stamped Mud Gas Separator (MGS) (16 ft liquid leg, 30 psi MAWP) with real-time level monitoring and alarms

Figure 3—Pruitt Flare Stack (30 ft) with Flame Arrestor and Real time Gas Flow Meter

MPD Execution

Summary

Prior to and upon arrival at the well location, the MPD team held comprehensive discussions with the rig personnel to ensure the installation and commissioning of the MPD system was performed within the safety and environmental guidelines. Once the MPD system rig-up was completed, the system was successfully pressure tested, and fingerprinting was conducted according to standard operating procedures. All personnel involved received thorough training on MPD concepts, procedures, limitations, and objectives.

Drilling operations began after a formation integrity test (FIT) confirmed the 1.89 sg Upper-Pressure Boundary (UPB). The shoe was drilled out and the reservoir was penetrated with the planned EMW, sufficient for the realistic high pore pressure, with MPD maintaining 1.70 sg ECD/ESD at the bit. The ECD/ESD was then staged down following the MPD engineering plan and based on the formation response, to 1.67 sg, then 1.62 sg, and finally to 1.59 sg with a MW of 1.45 sg to confirm the overburden MW at minimum borehole breakout.

Following evidence of increasing hole stability, the target ECD was established as 1.59 sg with 1.57 sg as the Lower Pressure Boundary (LPB). The anchor depth was adjusted accordingly, requiring a dynamic SBP of ±230 psi and a static SBP of ±1,150 psi. MPD was utilized while drilling, logging, running liner, and cementing. Pressure while drilling (PWD) data was simultaneously used for close ECD/ESD monitoring, and the hydraulic model was continuously adjusted in the field based on the PWD data to ensure precise, real-time ECD control.

Formation Integrity Test and Confirmation of Overburden at Minimum Borehole Breakout

Operations began with drilling out the shoe, and the MPD chokes, and flow meters were bypassed until it was confirmed all cement debris was cleared from the well. Once the cement was removed, the flow path was lined up to the MPD system with the choke fully open initially. The pressure was staged up to 1.7 sg ECD at PWD, holding 1,100 psi dynamic SBP and 1,750 psi Static SBP. After drilling the cement shoe, the bit was tripped back into the shoe, and the SBP was staged up to the planned static pressure as the driller staged down the pump rate. The rig lined up to the cement pump to perform the FIT. After the successful FIT, the stand was drilled down maintaining 1.7sg ECD/ESD.

Mitigating Wellbore Instability Issues with MPD

After drilling 10 m-MD of open hole, the ECD was staged down to 1.66 sg holding 855 psi dynamic SBP and 1,400 psi static SBP. The ECD was further staged down to 1.62 sg (320-350 psi dynamic SBP and 1,150 psi static SBP). The final ECD stage-down occurred at the end of the BHA run due to PWD tool failure. The ECD was staged down from 1.62 sg to 1.59 sg based on hydraulics modeling with no real-time PWD data transmission, requiring 175 psi dynamic SBP and 955 psi static SBP. MPD field supervisors were monitoring the well during circulation and reported slight fluctuations. The driller could not establish rotation. MPD responded by increasing the ECD back to 1.62 sg to improve hole stability and assist with freeing the pipe. The driller began performing the stuck pipe procedures. Once the pipe was freed, the driller circulated the well clean and began reaming. A 25-bbl. high-viscosity sweep was pumped. MPD supervisors closely monitored the MPD choke behavior and SBP for any indications of choke plugging. The MPD supervisors instructed the driller to bring the SBP pump online at 200 gpm to allow the choke to maintain a greater open position to prevent potentially packing off the choke and to assist in clearing the choke of any cuttings or fines build-up.

Figure 4 demonstrates the choke behavior and the resulting BHP and ECD while the sweep is circulated through the well.

Figure 4—Choke Behavior and BHP while circulating a 25 bbl Hi-Vis Sweep

At 11:38 AM, the SPP spiked, indicating the sweep was traveling through the Measurement While Drilling (MWD) tools and bit, and at 12:41 PM, the choke began reacting with the top of the sweep arriving at the choke, causing the pressure to increase. To compensate for the pressure spike, the choke position was adjusted to maintain the desired target pressure, and the MPD supervisor adjusted choke-B to 37% to allow the returning flow to pass through both chokes simultaneously to assist the choke. The pressure surge from the sweep arriving at the choke resulted in the BHP spiking up and down 206 psi, corresponding to 0.03 sg cycle.

After the sweep was circulated out, the bit was tripped to the rollover depth inside the casing, maintaining 1.62 sg ECD/ESD at the bottom hole. While in the casing, the ECD/ESD was staged down to 1.59 sg, and the well was monitored for gains. After a successful test, 1.60 sg mud cap was circulated into the well to trip out of the hole conventionally.

While the bit was out of the hole, the MPD supervisors cleaned out the strainers and chokes. The strainers contained cavings (Figure 5) varying between 0.75″ and -1.25″ in diameter.

Figure 5—0.75-1.25″ Cavings removed from the strainers after stuck pipe event

During the second bit run, the bit was tripped conventionally to the casing shoe, and the 1.60 sg mud cap was displaced with a 1.45-sg active mud. The bit was tripped and reamed to the well bottom, maintaining 1.59 sg ECD/ESD at the bottom hole. The MPD supervisors closely monitored the well condition and the surface sensors for any indication of choke plugging, kicks, losses, or stuck pipes. After reaming to the well bottom, the MPD supervisors observed that the differential pressure on the strainers reached a clean-out threshold and swapped chokes to allow for continuous operations while servicing the partially blocked strainer. Figure 6 displays the full strainer and its contents.

Figure 6—Full Strainer and Cavings captured by the strainers while reaming to well bottom.

At the conclusion of the 2nd BHA run, the decision was made to reduce the Active Mud Weight from 1.45 sg to 1.41 sg. This adjustment would increase the necessary SBP both dynamically and statically, providing a buffer in the event severe losses are encountered, allowing MPD to react quickly to control losses by reducing SBP. The plan was discussed with the field team, and new pressures were obtained from hydraulic modeling, which required 500-600 psi dynamic SBP and 1,400-1,500 psi static SBP.

The following sections discuss other performance indicators for the MPD choke system and its crews while performing rollovers, stripping, and making connections.

MPD Choke Performance. The MPD choke performance was highlighted by the choke's behavior and reaction to downhole issues, along with the proactive actions taken by the MPD team, rig crew, and client. The MPD team maintained the BHP within the client's requested limits by adjusting the hydraulics model and HMI based on PWD data and monitored choke behavior, SBP, flow rates, Delta Flow, and other drilling parameters. MPD choke and flow meter plugging was prevented via strainers installed upstream of the choke, with continuous monitoring of strainer pressure for plugging and cleaning out the strainer when necessary to prevent pressure surges. Downhole issues were identified through flow rates, Standpipe Pressure (SPP), and torque monitoring, with adjustments made to the choke to minimize/prevent pressure surges and drops.

The MPD team, along with the client's MPD advisor and client field team, met regularly for planning and updates, to review and adjust target ECD/ESD and the required pressures to compensate for stuck pipe, downlinks, bit trips, and rollovers.

Choke Performance During Connections. Prior to the start of drilling operations, training was conducted with the rig crew to familiarize everyone with the necessary steps required to make a connection with MPD. Handheld radio commands were also reviewed to ensure the crews were familiar with the connection process and to highlight the risks associated with diverging from the plan due to lack of or miscommunication. The connection procedures were optimized using the input provided by the MPD well engineering team, client engineers, and MPD field supervisors. These were necessary steps, as maintaining the BHP within the required limits was the key to preventing formation collapse and kicks from entering the well.

Figure 7 illustrates a connection performed, plotting the SBP and Pump Ramps along with ECD/ESD and BHP data. At the beginning of the connection, the MPD supervisor instructed the driller to ramp up the SBP pump to 200 gpm, then begin ramping down the rig pumps. The HMI in auto-ramp mode followed the ramp table, staging up the SBP as the pump rates were staged down to 0 gpm. The SBP pump was maintained at 200 gpm to maintain CBHP. Once the driller killed the pumps, he instructed the rig crew to bleed SPP to 200-300 psi to test the floats, then bleed the SPP to 0 psi. While the pumps were off, the MPD supervisor monitored flow out, SBP, and choke position for any changes that could indicate a gain or loss.

Once the driller was ready to turn on the pumps, he would fill the pipe at 30 strokes/min (stk/min) until SPP began rising. Then, he would ramp up the pumps to full rate while the MPD Choke Controller began ramping down SBP to the circulating SBP. Once the driller reached full rate, he would start staging down the SBP Pump to 0 gpm and resume drilling.

Figure 7 demonstrates each stage of the connection maintaining 0.01 sg ESDMax-ESDMin (BHPMax - BHPMin = 90 psi). The target ESD for the connection was to remain within 1.6-1.61 sg ESD.

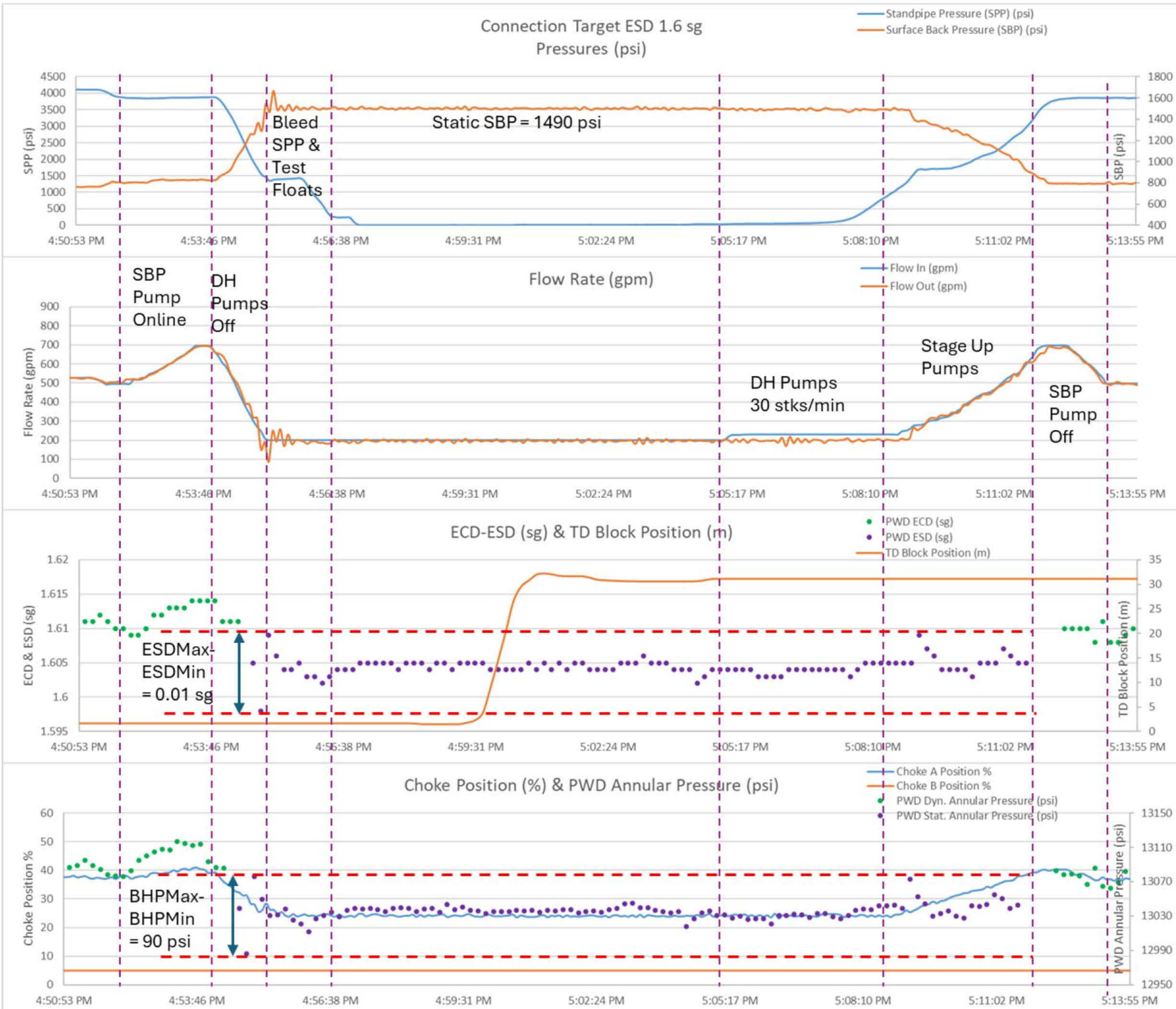

Figure 7—MPD Connection Stages and Performance, with pump stage down, SBP ramping from ±790 psi to 1,490 psi static SBP, maintaining 1.6 sg target ESD with SBP pump while downhole pumps are off, and then staging downhole pumps up to full rate and ramping down SBP from 1,490 psi static SBP to ±790 psi dynamic SBP.

Choke Performance While Displacing 1.60 sg Mud Cap With 1.41 sg Active Drilling Mud. After the bit was tripped conventionally from the surface to the bottom of the 1.60 sg mud cap, 1.41 sg active mud was pumped in to displace the mud cap and resume stripping to the bottom of the well. MPD well engineering team prepared detailed rollover procedures and plans for the team to execute and distributed them to the client representative, rig manager, driller, mud engineer, and derrick man. Prior to beginning the rollover, the MPD team held detailed toolbox talks with the rig crew and other third-party parties involved to discuss procedures, key points in the plan, associated risks, and everyone's role in the operation.

During the execution of the rollovers, the driller staged up the pump rate to 50-100 gpm to fill the pipe and verify flow through the MPD system and shakers. After verification, while pumping out the mud cap, the driller would increase the pump rate to 200 gpm and follow the schedule and instructions from the MPD supervisors. At the point when the driller is to stage up pump rates, the MPD supervisor would instruct the driller to increase the rate in 25 gpm increments until the full rate was achieved. The MPD supervisor would then begin closing the choke until it reaches the fluid interface and place the choke in auto mode for operation, adjusting SBP pressure based on the plan. If real-time PWD data transmission is available, the MPD supervisor would compare results in the hydraulic model and adjust based on these results. Figure 8 illustrates the fluid displacement executed to replace 1.60 sg mud cap in the well with 1.41 sg Active Mud.

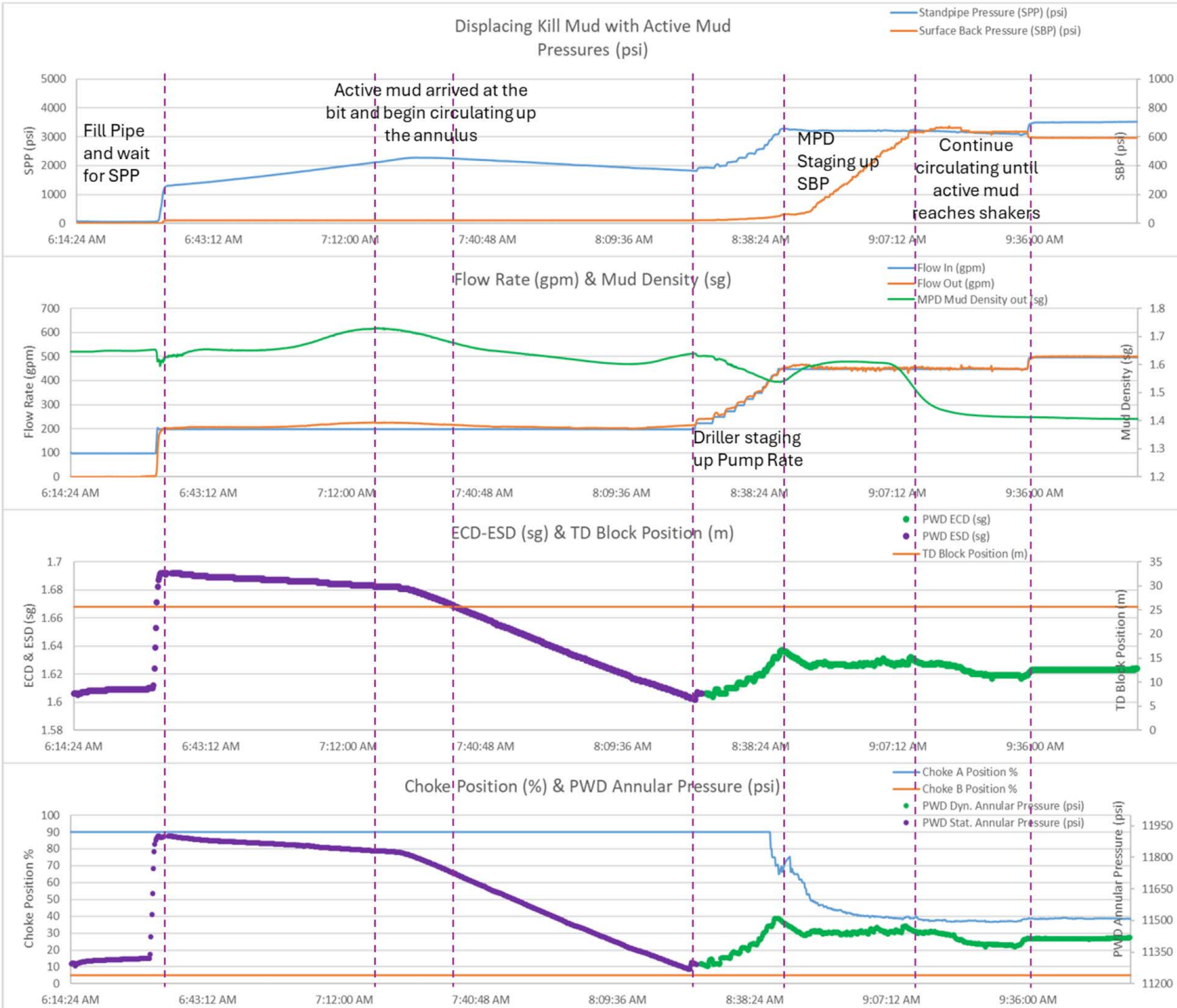

Figure 8—Displacing 1.60 sg mud cap with 1.41 sg active drilling mud to resume tripping in, with downhole pump and SBP ramping, choke behavior and PWD ECD/ESD data.

Choke Performance While Stripping. At the end of each bit run, the well was circulated clean, and the bit was reamed/tripped to the shoe to pump the mud cap. MPD team maintained the necessary pressure while reaming and stripping out. Choke adjustments were made based on hydraulics modeling updates in the field due to a lack of real-time PWD data while pumps were off. The bit was reamed/stripped from well bottom to the shoe maintaining CBHP with MPD compensating for swab. In the casing, the weighted mud cap was circulated in to allow for conventional trip out to change BHA.

After the BHA was changed out, the bit was tripped in conventionally to the bottom of the weighted mud cap. The weighted mud cap was displaced with active drilling mud. Following the displacement, the bit was stripped to well bottom with MPD adjusting SBP to maintain 1.60 sg EMW at bottom hole. Figure 9 demonstrates the MPD choke behavior and ESD/BHP changes while stripping to bottom after displacing the mud cap from the well. The static SBP was 1,490 psi while the strip-in pressure was 1,330 psi to reduce the effects of surging the well while stripping to the bottom.

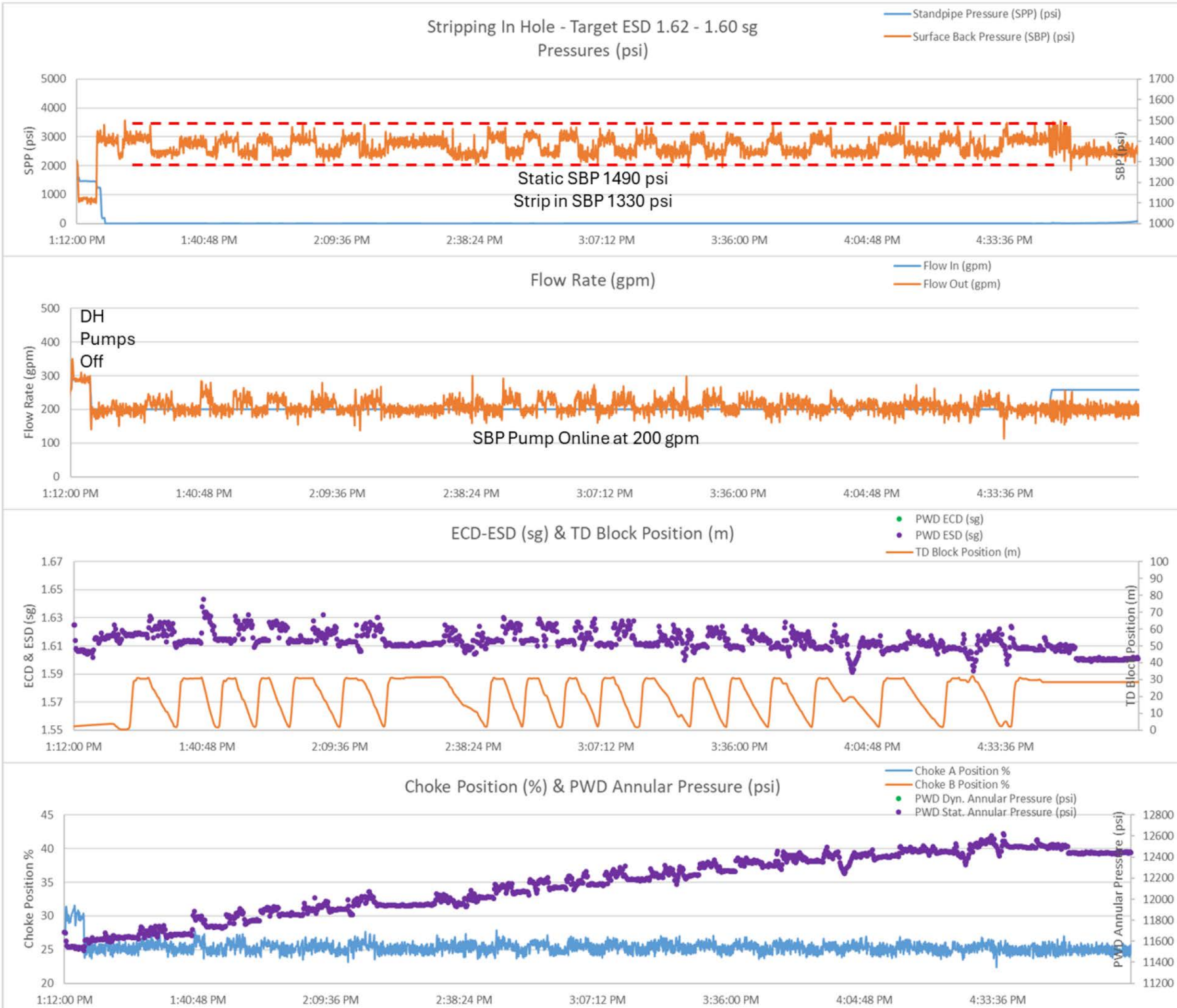

Figure 9—Stripping 18 Stands of Drillpipe in Hole on MPD, demonstrating the SBP ramping from static SBP 1,490 psi to 1,330 psi for surge relief, and the resulting PWD ESD performance.

BHP and Downlinks. Prior to MPD going online, discussions were held on how to handle downlinks. The initial decision was made to maintain SBP during downlinks and analyze PWD data to determine the necessary pressure and procedure to compensate for pressure drops due to sending downlinks.

Figure 10 displays 5 downlinks at various amplitudes sent in 2.5 hours. The figure demonstrates the effects of sending downlinks on BHP/ECD while drilling ahead without making any SBP adjustments.

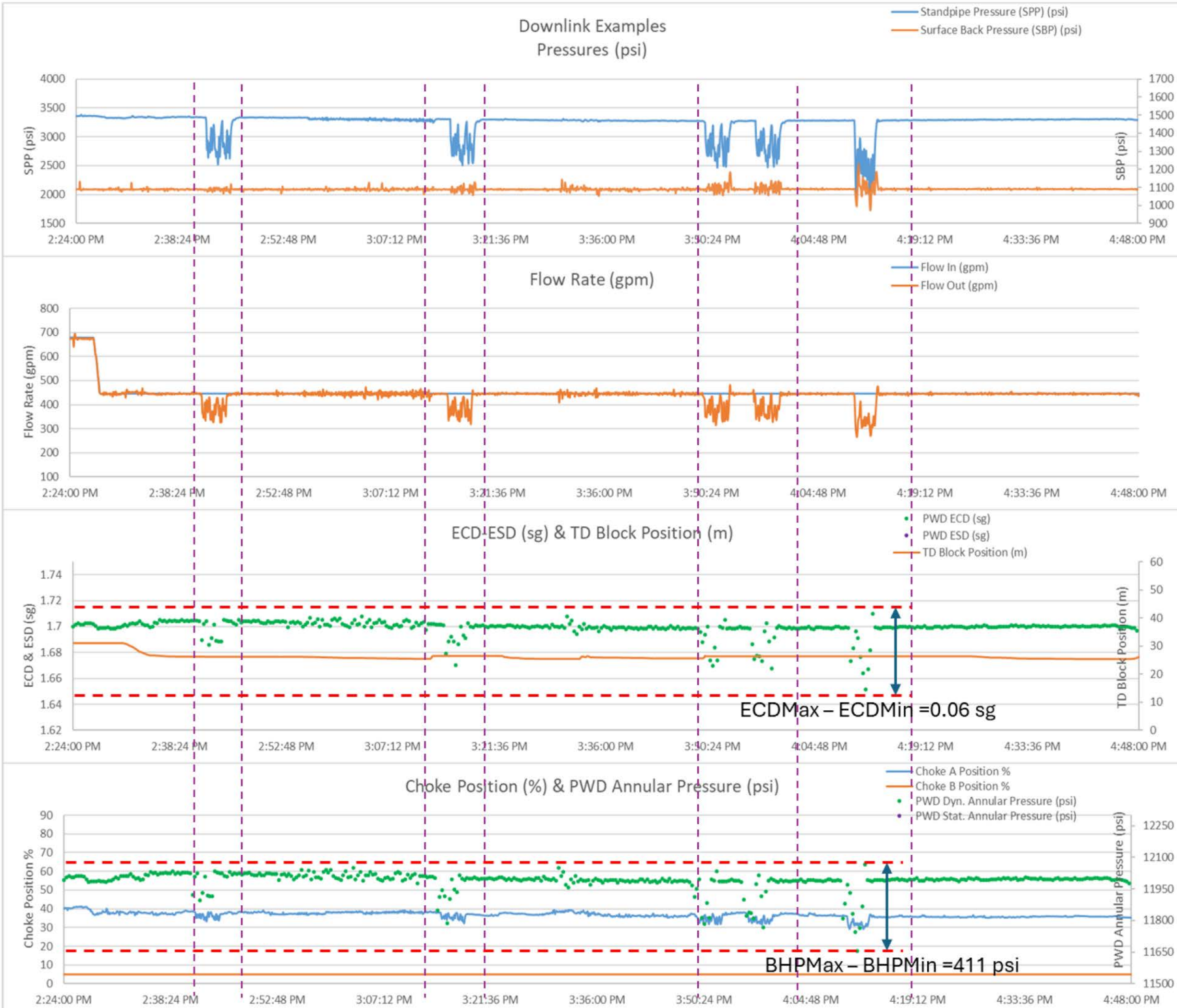

Figure 10—Impact of Downlinking on BHP/ECD while drilling with no SBP compensation

After observing the effects downlinking had on BHP, the decision was made to add 50 psi and gradually increased to 220 psi when sending downlinks to compensate for the drop in BHP. This prevented BHP from falling below the lower pressure boundary and prevented over pressuring while downlinking.

Hole Enlargement and Effects on SBP and MPC. During the 3rd BHA run, acid was pumped into the well to free the BHA. After the 4th BHA was run in the hole, the dynamic SBP provided by the hydraulic model resulted in a lower ECD compared to real-time PWD data. The MPD supervisors increased SBP to maintain PWD ECD within the target window and reported the discrepancy. The MPD supervisors, well engineers, and the client reviewed the discrepancy and the caliper log. It was observed that the hole had been enlarged from 8.5″ to 10.5″. The hydraulic model was updated with the new hole size, and the correct dynamic SBP was determined from the results.

The managed pressure cementing (MPC) plan was adjusted multiple times due to hole enlargement with acid pumped and stuck pipe. The final logging run provided the actual hole sizes, which were updated in the hydraulic model, adjusting the necessary circulating SBP to maintain the BHP within the required window. This resulted in a successful cement job that provided sufficient annular isolation to allow the stimulation strategy of, perforate, test and isolate each of the distinct target zones to be executed.

Conclusions

In summary, the project required extensive planning and collaboration among multiple teams and individuals, each offering specialized expertise to overcome multiple challenges, including wellbore instability, major loss of circulation, kick-loss scenarios with the potential for H2S, stuck pipe and difficulty running liner.

The MPD equipment team designed and built the required equipment based on the project needs and the hydraulics design performed by the MPD well engineering team. The MPD well engineering team provided detailed documentation covering operational procedures as well as multiple MPD plans with contingencies for each operation. Hydraulic analysis was performed using multiple hydraulic modeling software solutions to verify the accuracy of the results and to ensure the best data was available for planning. These plans were then updated and executed by the team of experienced MPD field supervisors assigned to the project.

A total of 7 BHA's were run to drill the 8-1/2″, 1,034m hole section, with 37 drilling connections performed in extremely challenging drilling conditions. The performance of the MPD system, along with the continuous monitoring by the MPD field team, prevented pressure surges, equipment plugging, and other potential issues from occurring with the system. The MPD field team was proactive in equipment maintenance, resulting in zero downtime with the MPD system. Their continuous monitoring of surface data, downhole data from PWD, and quick response to unplanned events allowed the well to be successfully drilled to TD and secured with a fully cemented liner mitigating many issues that would have been impossible for a conventionally drilled well to avoid.

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