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Managing Drilling Risks in Ultra-Shallow Horizontal Well in Delta Steam Flood Field

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Abstract. Delta Field, a mature heavy oil Field, is one of the world's most extensive steam flood operations. The pay zones in “R” and “PK” formations range from 300 ft to 700 ft. The 172 horizontal wells, categorized as ultra-shallow horizontal and extended reach wells, had been drilled to ramp up oil production in the Delta Field since 2009. The primary drilling challenge in ultra-shallow horizontal wells is the high dogleg severity, up to 21°/100 ft, causing borehole geometry-related problems such as a tight hole, parted BHA, and casing tag. The complexity of the drilling challenges escalates with the characteristics of the formation in the Delta Field. The depleted unconsolidated sand formations caused the risk of severe lost circulation. Statistically, 46% of the drilling problems were total lost circulation cases and had caused several hole stability and stuck pipe cases. In addition, the matured steam injection to the pay zone formations adds the potential for a steam kick. As the drilling penetrates the steam pocket, the drilling mud is exposed to a temperature of up to 250°F. Steam kick ranks third in the highest occurrence of drilling problems in all drilling operations in the Delta Field. Therefore, it is crucial to develop improvements to manage these drilling risks for the next campaign.

A lessons learned-based study from previous drilling campaigns was conducted to improve drilling strategy to manage those significant drilling risks in ultra-shallow horizontal wells in the Delta Field. This paper elaborates on three main improvements developed and implemented in the 2022 horizontal drilling campaign: well design and drilling program, steam injector shut-in strategy, and drilling procedure in lost circulation conditions. After implementing these improvements in nine horizontal wells, the well geometry-related problems still occurred during the drilling landing section in two wells. However, the drilling could proceed to the target depth. The lost circulation still occurred, but the implementation of the blind drilling strategy allowed the drilling to reach the target depth without further problems. Furthermore, the steam injector shut-in strategy reduced the severity of lost circulation and eliminated well control events. In the end, the average non-productive time caused by well problems decreased by 23 hours per well in 2022.

Keyword(s): drilling, ultra-shallow horizontal well, steam flood, extended reach drilling

1 Introduction

Delta Field, one of Indonesia's oldest discovered heavy oil fields and one of the world's largest steam flood operations, covers about 64.75 sq km with 10,700 wells consisting of 6500 active shallow produce wells and 700 injector wells. There are no less than 150 surface wellheads in one squared kilometer in Delta Field. With the challenge of surface location and the necessity to improve drainage capability, horizontal wells have become preferable to directional or vertical wells [1].

The reservoirs are categorized as depleted formations, much lower than the water gradient. The “R” sand has pore pressure from 4 ppg to 6 ppg and fracture pressure from 10 ppg to 11 ppg. Meanwhile, the “PK” sands have lower pore pressure ranging between 1 to 5 ppg but higher fracture pressure from 11 to 13 ppg.

The pay zones in "R" and "PK" formations range from 300 ft to 700 ft, where most of the oil-water contact is located. After being steam flooded since the area development started, most of the reservoir unit in Delta Field is already mature, with steam chests developed at the upper part of it. This condition results in remaining bypass oil that may drain slowly or not effectively [1]. The horizontal wells in Delta Field improve oil recovery by producing bypassed hot oil at the bottom of the mature reservoir. With twice the budget and five times the production, horizontal wells became favorable to directional or vertical wells.

Delta Horizontal Well is one of the pioneers of Ultra-Shallow Horizontal Wells. With the horizontal displacement and TVD ratio up to 3:1, the wells are classified as extended-reach wells. Since the first campaign in 2009, Delta horizontal drilling has faced repetitive loss circulation, multiple geometry issues, and BHA problems with intentionally and unintentionally sidetracks. The worst case would be abandoning the well due to the wellbore collapse. On top of that, the matured steam injection in the Delta Field aggravated the drilling with steam kick risk. The drilling mud will be exposed to a temperature up to 250°F as the drilling penetrates a steam chest. If the bottom hole temperature and pressure reach the boiling point, the steam is generated, and a steam kick occurs [2].

2 Drilling Problems

Based on drilling problem data since 2015, illustrated by Figure 1, the most common drilling problem in Delta Field is lost circulation with 45%, while the second and the third are tight hole and well control events with 30% and 9% of the total drilling problems. These data were derived from all types of well, including vertical, "J" type, and horizontal wells.

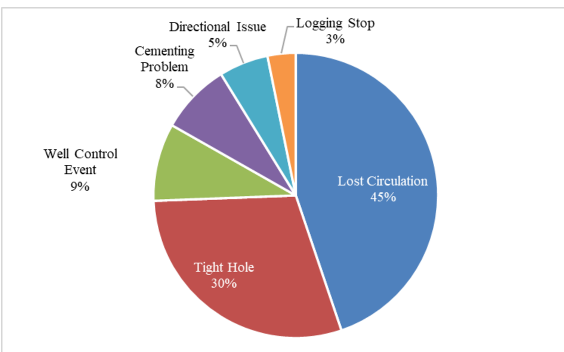

Figure 1. Drilling problems from all drilling operations in Delta Field from 2015 to 2021

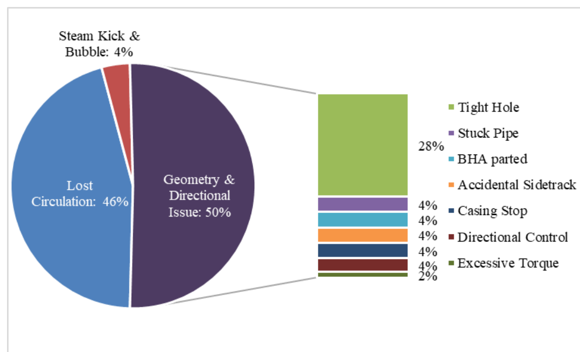

Figure 2. Drilling problems from all ultra-shallow horizontal wells in Delta Field

The first horizontal well in the Delta Field was drilled in 2009, and the latest horizontal drilling campaign was in 2016. Historical drilling problems specifically for horizontal wells have been gathered and summarized, shown in Figure 2. It indicates that the first significant drilling problem in horizontal wells is geometry and directional issues with 50%, including tight holes, stuck pipe, BHA parted, accidental sidetrack, casing tag, loss of directional control, and excessive torque. Lookback reviews from previous campaigns reveal the well design and BHA design as the root causes of these problems. The second major drilling problem is lost circulation, contributing to 46% of all cases. Furthermore, steam kick and bubble follow as the third significant contributors. Based on these reviews, a set of improvements focusing on those three major drilling problems must be developed to manage the drilling risks for the upcoming horizontal drilling campaign in the Delta Field.

3 Well Design and Drilling Program

In the 2022 horizontal drilling campaign, nine wells were planned to be drilled. Five wells targeted the "R" formation, and four wells targeted the "PK" formations. The well design differs for each sand target, as shown in Figure 3 and Figure 4. The main difference is that “R” wells used two casing strings and one liner string, while “PK” wells used three casing strings and one liner string as the TVD is deeper than “R” wells.

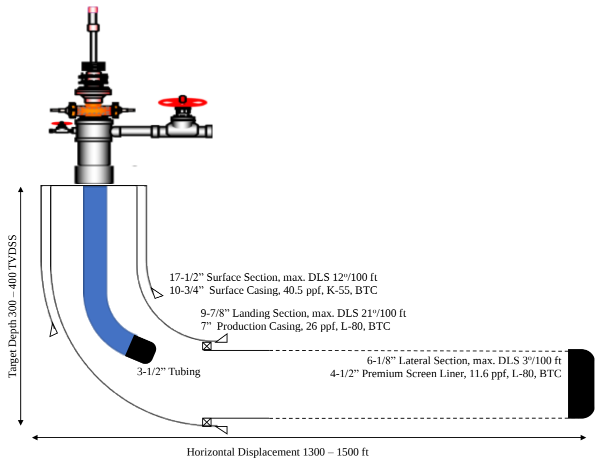

Figure 3. Basic well design for “R” formation

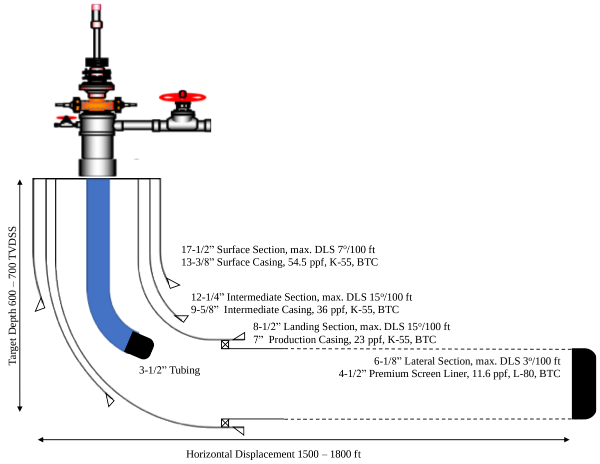

Figure 4. Basic well design for “PK” formation

Directional design

A higher dogleg and shallow kick-off design will be needed to achieve shallow horizontal targets. This high dogleg curve is designed based on optimized tools and best practices. The highest dogleg currently designed is 21°/100 ft to achieve the shallowest target, around 360 ft TVD from the rotary table. A pump section is required with a minimum of 40 ft of the tangent section, with 84° of inclination. The landing point will be set at 91° - 92° of inclination, while the lateral section has 1° - 2° dipping up to allow the oil to flow with gravity along the lateral section.

Hole size design

The production target of the horizontal wells allows for drilling the lateral section with a 6-1/8” hole size. This hole size plays a significant role in designing the drilling string to achieve the target dogleg, as the higher dogleg needs flexible pipes or a smaller pipe size. In contrast, conventional hole sizes are opted for the surface section to the landing section concerning the BHA and casing availability in the market.

Bottom Hole Assembly Design

Achieving high dogleg led us to use smaller strings, and the critical section on high dogleg is the landing section. In this section, 8-1/2” or 9-7/8” hole size will be drilled, which means a 6-3/4” mud motor is used with a high bend setting up to 3°. The weight-on-bit is also a concern for these shallow wells as the pipe weight is limited. A combination of drill collars, heavy weights, and drill pipes is critical for delivering weight-on-bit. MWD with slim pulses is needed to run the LWD tool (Gamma Ray-Resistivity-Nuke). The bit used to drill all sections are roller cone bit. This type of bit will be more capable of delivering the dogleg than the PDC bit due to the shallow and soft formation.

Mud Design

Unweighted KCL Polymer mud is designed to drill the surface section to the landing section, as this formation's clay content is reactive. The mud system is then converted into Drill-In-Fluid to drill the lateral section as this system provides minimum formation damage [3]. The mud weight required for “R” formation is 9 ppg, while the mud weight for “PK” formation is 8.7 ppg. Further, Calcium Carbonate, a formation-friendly lost circulation material, is added to the mud system to mitigate the losses. However, mud volume became an issue because most lost circulation in the Delta Field is a total loss. Therefore, 1000 bbls of additional tanks are required to accommodate blind drill operation.

Flow Rates Design

Drilling high dogleg well with soft formation requires lower flow rates yet reduces the hole-cleaning capability [4]. As mitigation, the strategy to maintain hole cleaning is with high viscosity sweeps as required while reaming before connection. The flow rate design for drilling the landing section is 350 GPM, and the lateral section is 250 GPM.

Casing and Cementing Design

The casing will cover the surface and landing section for the "R" formation well, and the intermediate casing will be added for the "PK" formation well to cover and separate with the shallower "R" formation. The casing is chosen based on the capability to handle the worst load, which is the axial stress due to the high dogleg [5]. The design uses the regular API casing with buttress connection for all casing strings except the landing section for "R" wells that use higher grade casing. The wells use regular cement design with 15.8 ppg slurry and are backed with 12.5 ppg lightweight slurry when losses happen. In addition, top job cementing is prepared as contingency if the primary cement is not return to surface.

Completion Design

The lateral section completed open hole with a premium screen liner installed to control sand production and give more reliability for longer production. The liner top packer is installed to the overlap section. The sucker rod or tubing pump is run as the artificial lift equipment inside the 7" casing above the top liner. This type of pump can deliver a low pump rate and has a higher capability of handling sand production resulting in a longer lifetime.

4 Steam Injector Shut-in Strategy

A review was undertaken and found that the sources of the steam kick came from the surrounding steam injectors. Therefore, a procedure is introduced to identify steam injectors required to be shut-in three days prior to commencing drilling operations. Six criteria were established to decide whether a steam injector must be shut-in, which is divided into two categories based on the injection pattern type (table 2).

Table 2. The six criteria to identify a shut-in injector.

Criteria	Injection Pattern: Big Pattern 15.5 acres Seven Spot and 11.5 acres Nine Spot	Injection Pattern: Small Pattern 5.5 acres Seven/Five Spot
1	Injector(s) that are located < 75 meters from the drilling location need to be shut-in	Injector(s) that are located < 52 meters from the drilling location need to be shut-in
2	If there is an eruption history ≤ 250 m from the drilling location, offset injector(s) from the eruption site need to be shut-in	
3	If the injector location is in the proximity of a fault within 125 m and the drilling location is located ≤ 125 m from the fault, injector(s) need to be shut-in	If the injector location is in the proximity of a fault within 80 m and the drilling location is located ≤ 80 m from the fault, injector(s) need to be shut-in
4	If there is a killing issue on an offset well within 250 m from the drilling location, offset injector(s) from the well with the killing issue need to be shut-in	If there is a killing issue on an offset well within 160 m from the drilling location, offset injector(s) from the well with the killing issue need to be shut-in
5	If the area has a withdrawal issue and injectivity problem within ≤ 250 m where drilling is taking place	
6	If offset well data (recently drilled) and the well being drilled requires Mud Weight above 9.7 ppg (within ≤ 250 m)	If offset well data (recently drilled) and the well being drilled requires Mud Weight above 9.7 ppg (within ≤ 160 m)

5 Drilling Procedure in Lost Circulation Condition

Lost circulation had been anticipated while drilling in the landing and lateral section, which is when penetrating the depleted reservoir. Therefore, the following contingency plan will be executed when the lost circulation occurs, as shown in Figure 5 and Figure 6. In the event of a total loss, blind drilling will be executed with several limitations since it can lead to other hole cleaning complications, i.e., stuck pipes, since no cutting is transported to the surface. In the landing section, the limitations for blind drilling are mud volume and the drilling parameter. First, the blind drilling must be stopped when the mud volume is less than 50% of the tank volume to allow the rig to establish circulation when it is needed while pulling out the drill string. Second, the blind drilling must be stopped when observing a 20% hook load increase, 20% torque increase, or 10% pressure increase. Finally, in the lateral section, a limitation is added. It is only allowed to blind drill a maximum of 600 ft, which is the minimum lateral length value to achieve the well's economics. In addition, the requirement to pull out and lay down Nuke before executing the blind drilling is necessary to eliminate the risk of radioactive contamination if a stuck pipe occurs and the Nuke cannot be recovered. The release of abandoned radioactive sources in the ground could lead to contamination of the environment [6].

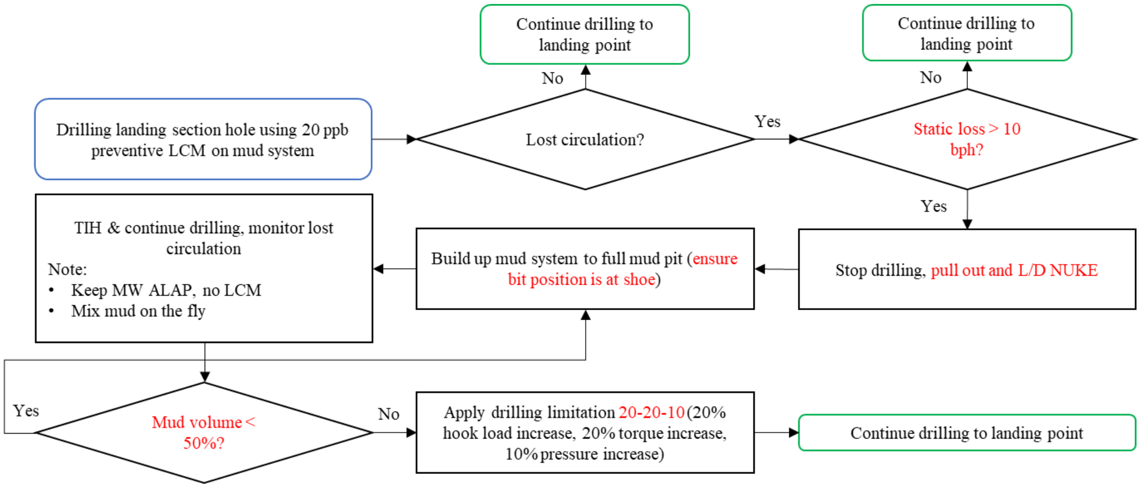

Figure 5. Loss circulation procedure in landing section

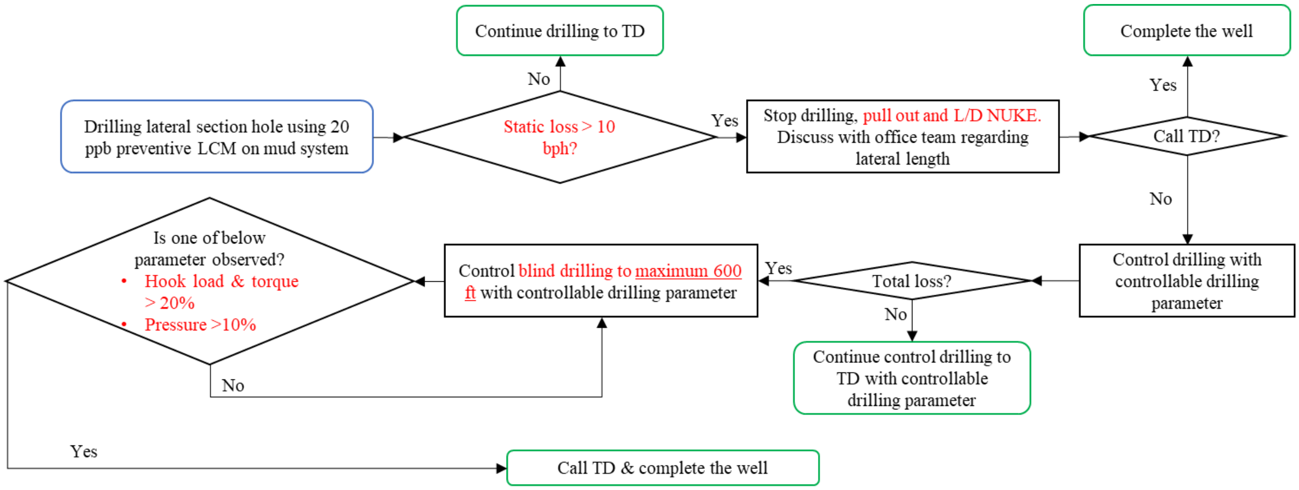

Figure 6. Lost circulation procedure in lateral section

6 The 2022 Horizontal Drilling Campaign Result

As per the project plan, nine horizontal drillings were drilled in Delta Field in 2022. The first four wells targeted "PK" sands, while the last five wells aimed "R" sand. Figure 7 shows the drilling problems that occurred during the execution of the project. First, total lost circulation became the highest occurrence in this campaign. There was only one well was drilled without lost circulation. However, five wells experienced lost circulation in the landing and lateral sections, while two wells experienced it only in the landing section and one well in the lateral section (Figure 8). In addition, one well did not experience lost circulation in both sections. Based on the annular pressure data, the delta ECD-MW was averagely 1.14 ppg in the "PK" wells and 2.11 ppg in the "R" wells when the lost circulation occurred, indicating "PK" formation is weaker than "R" formation. During these events, the drilling operations continued by implementing the lost circulation procedure. As a result, the wellbore stability could be maintained, and, most importantly, minimum complications arose during drilling to the target depth.

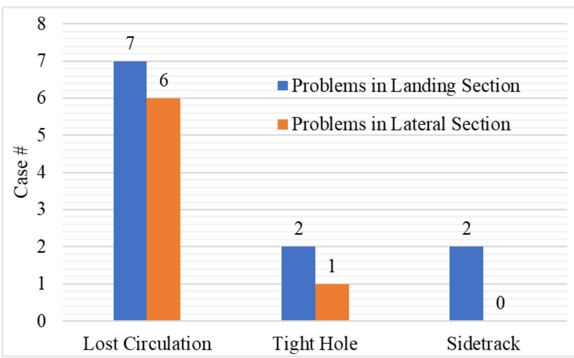

Figure 7. Drilling problems occurrence

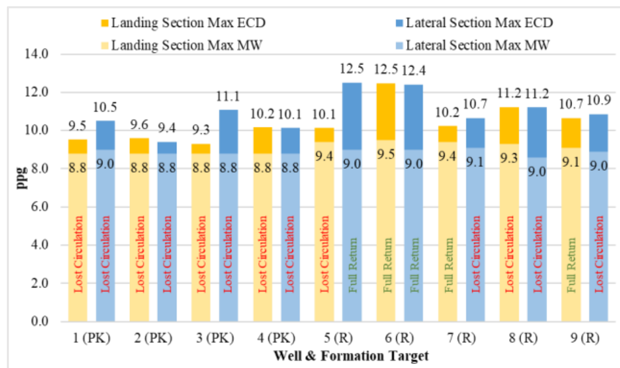

Figure 8. ECD-MW profile and lost circulation cases

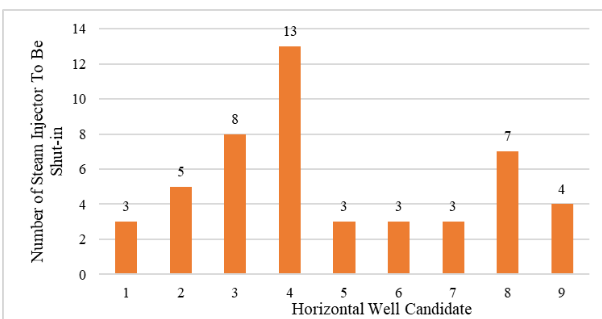

Figure 9. Number of steam injectors to be shut in 3 days prior to rig moving

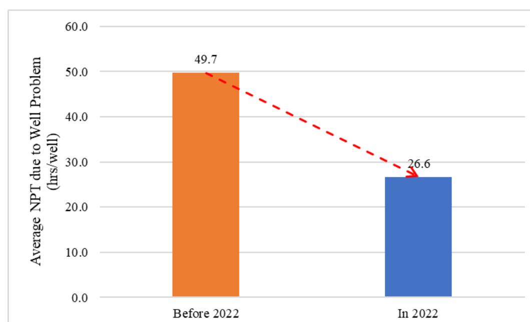

Figure 10. Comparison of NPT caused by well problems before and in 2022

Second, two tight hole cases occurred in the second and third wells; one was during drilling in the landing section, and one case happened during drilling and running liner in the lateral section. The tight hole cases were complications of the total lost circulation. The mud checks that these problems indicated wellbore collapse due to low mud properties. The lookback review revealed that the mud properties could not be maintained when mixing for blind drilling. The operation team had improved the mixing technique, and this problem was successfully eliminated in the subsequent wells.

Third, two of the five "R" horizontal wells experienced accidental sidetracks. These events happened when changing BHA with the lower AKO in the landing section. The bit could not reach the original hole. In the attempt to reach the original hole using the second BHA, the bit accidentally drilled a new hole below the original hole. One of these two wells was cement plugged, while the other one was able to continue drilling by only correcting the well plan without changing the BHA.

Furthermore, the implementation of steam injector shut-in strategy showed a positive impact. For the drilling campaign 2022, the steam injector wells had been identified to be shut-in for each horizontal well using shut-in criteria from Table 2 to support drilling operations (Figure 9). As a result, no steam kick or bubble occurred even in the lost circulation.

To conclude, the three improvements has delivered significant impact to the execution of the campaign in 2022. The data shows that the non-productive time caused by well problems decreased from 49.7 hours per well before 2022 to 26.6 hours per well in 2022 after implementing the improvements (Figure 10).

7 Conclusion

Three main improvements had been established and implemented in the nine horizontal wells drilled in 2022 with significant impacts. First, the well design and drilling program had successfully reduced well geometry and wellbore stability issues, though accidental sidetracks still occurred due to BHA issues. Second, the improvement of the injector shut-in strategy has significant effects on eliminating the steam risk. Finally, the hole stability was managed during drilling in lost circulation conditions by executing the lost circulation procedure. More importantly, the nine horizontal wells had been drilled safely within the target tolerance and put into production.

8 Recommendation

Apart from the success of the drilling, several issues occurred and must be addressed for the future campaign. First, the mud motor bend setting for the landing section needs to be evaluated since there were tagging cases that led to sidetracks. Then, it still becomes a challenge to maintain ECD 1 ppg below MW and needs further improvements on reducing lost circulation since eight out of nine wells experienced total loss. Furthermore, there is an opportunity to eliminate the use of Nuke while drilling the landing and lateral section as additional rig time is needed to pull out the Nuke when experiencing lost circulation.

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