BC-10: MEETING DRILLING CHALLENGES IN SHALLOW EXTENDED REACH WELLS

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Abstract

Shell Brazil is developing a structurally complex reservoir in a deepwater, shallow overburden setting. Based on data from one vertical exploration and one appraisal well, the development plan called for completion of six 600-m to 1,200-m long horizontal producers.

The shallow nature of the field (900 m to 1,100 m TVD below mudline) resulted in the need to start the buildup section near mud line. Building the 17½-in hole to 40 degrees inclination in the initial 550 m true vertical depth subsea was found to be very challenging in soft Pliocene and Miocene sediments using the original BHA design.
As problems were identified, Shell well engineers and subsurface teams together with the Schlumberger drilling team worked to optimize drilling parameters through the integration of drilling and subsurface data. Understanding the drilling behavior of specific formations and the lithology at various depths helped in the redesign of BHA's and well paths, refinement of the steering program, and updating of the LWD requirements.

3D and 2D displays of seismic, wellbore lithology, and drilling data such as steering ratio, build rates, and ROP were used to better understand the relationship between geologic formations, lithology, and drilling behavior. Integration of drilling, directional drilling, and subsurface data was critical in overcoming the challenges and led to significantly improved drilling performance and well placement in some of the most difficult deepwater extended-reach wells ever drilled.

The world’s first point-the-bit RSS BHA from Schlumberger with 17½-in under-reamer was used to directionally drill to the limits of shallow extended reach drilling experience for deep water. Modeling software to project and visualize drilling data across the field was required to predict drilling environment and hazards and be able to construct the correct wellbore is complex lithology avoiding loss of directional control and mud losses while maximizing net to gross.

1. Introduction

BC-10 is located in the Campos Basin off the coast of Brasil and the fields lie in water depths of up to 1950 m. The development concept for the BC-10 block is a cluster development of the fields known as Ostra, Abalone, and the Argonauta complex (B-West and O-North) via subsea tiebacks to the FPSO Espirito Santo (Figure 1). To date 13 wells have been drilled, discovering 5 separate oil accumulations.

The Ostra field is located on top of a salt dome, and the trap is formed by a complexly faulted four-way dip closure. There are two main normal faults on the crest of the structure running northwest to southeast, which form a central graben area. The highest part of the Ostra dome is created by these 2 normal faults forming a horst block. In addition to the 2 major faults, there are numerous smaller normal faults radiating from the crest. Some faults reach near to the seafloor, which is only 850m above the reservoir. A top structure map of Ostra is shown in Figure 2.

The discovery well penetrated the amalgamated Maastrichtian turbidite channel sands in a seismic thick on the southern side of the central-graben fault and encountered approximately 200 m of massive reservoir and confirmed the oil/water contact. The appraisal well, drilled on the northern side of the central-graben, found thinner though still massive sands of approximately 60m thickness. At the time of the drilling of the appraisal well, it was unknown if the sand thickness changes were caused by stratigraphic variation relative to location within the depositional channel or by thinning of the section onto the active salt dome.

The Ostra Field contains oil of 24º API oil and moderately heavy viscosity (8 cP). As part of the BC-10 Phase-I development, six production wells were drilled and completed in the Ostra Field Development area. Three of these wells #1, #2, and #3 were drilled on the southwest side of the Ostra accumulation in 2008, while #4, #5, and #8 were drilled on the north side in mid 2009.

Crafting a well drilling and completions design around the many complexities was a challenge. Due to the massive nature of the sand, the possibility of compartmentalization, and the impact of heavy oil on the flowrates and ultimate recoverable volumes, horizontal wells were chosen as the preferred drainage option. The shallow depth below mudline of the reservoir presented specific challenges to the design such as shallow kick-off points and low drilling margins. The low fracture gradient and lengthy openhole sections limited the gravel packing options. These issues in addition to the ultra-deep water made these wells some of the most difficult Shell Brasil has drilled.

2. Presentation of Data and Results

2.1. Development Wells #1, #2 and #3

The Ostra development wells #1, #2 and #3 were drilled and completed from April to October 2008 as part of the Production Manifold #1 (PM1) cluster. The drilling operations were performed in a batch sequence to best optimize
riser runs and concurrent operations with the FPSO and flowline installation vessels. In this way, the tophole riserless sections for each well were drilled, followed by the risered 12 ¼” sections, and finally the 8 ½” horizontal sections.

The first sections of the PM1 wells drilled were the tophole sections. These sections required aggressive build angles to avoid higher dog-legs deep in the well that could have negatively impacted drillability or completions quality. The initial design of the drilling assembly was a 16” bit and a mud motor with 1.5 deg of bent housing to achieve desired inclinations of approximately 30º at the end of the 500-600m sections.

It was evident immediately when drilling the first section in the #1 well that the sediment near the seafloor was not competent enough to support an extremely shallow kickoff with the mud motor and large bit. Even with more aggressive bent motor subs of 1.83 degrees tried on the #2 and #3 wells tophole drilling, the difficulty achieving the shallow build-ups desired persisted (Figure 3 displays atypical seismic section of the field with a wellpath transecting the various lithology intervals). The results were angles only up to an average of 20 degrees inclination versus the desired 30º, mostly achieved during the final 200m of the tophole section when the sediment became more consolidated. In addition, all of the well sections ended still with a final trajectory that would require more aggressive steering in the 12 ¼” sections. Figure 4 shows the planned versus the actual tophole wellpaths.

The 12 ¼” sections of the PM1 wells land the well into the top of the reservoir, preparing for the drillout into the production interval. It was critical that the wells reached the targeted section final depth within the top of the reservoir under the right inclination to drill the reservoir section. The design basis for the landing sections was to utilize a “push-the-bit” system drilling the well 30m into the reservoir, landing the wells between 87 and 89 degrees utilizing less than 4 degrees/30m dogleg severity (DLS).

Achieving the planned trajectories in the 12 ¼” sections also proved to be difficult. While the sections landed in the approximate desired locations, significantly more directional work was required than was predicted, requiring steering ratios in a range of 80 to 100% of the steering cycle. The Miocene and Oligocene sands (shown on the seismic cross section in Figure 3), located just under the tophole casing are soft and difficult to steer in and building angle did not occur until deeper in the well. Defining the proper parameters to get the necessary response from the rotary steerable system proved to be a struggle through the different lithology tendencies found. Figure 5 shows the planned versus the actual 12 ¼” wellpaths.

The horizontal sections were designed to be directionally straight from the casing shoe at the heel of the horizontal to the planned toe of the well with no active geosteering intended. This was based on the results from the vertical exploration and appraisal wells showing massive sands with limited interbedded shale. The drilling assembly was planned as a “push-the-bit”, but after seeing the difficulties in the landing sections, this was changed to a “point-the-bit” rotary steerable system, which delivers a more aggressive steering response under unconsolidated environments. The logging while drilling tools consisted of a triple combo and NMR.

While drilling the horizontal section, it was found that the rotary steerable drilling assembly had a tendency to drop within soft sands and build within shales. This made holding a steady path with no doglegs impossible, complicating the drilling of the horizontal section. The wellpath was further complicated by attempting to geosteer to limit the amount of shale penetrated using seismic amplitude information.

The shale seen in the reservoir bought difficulties with the mud system as the clay was found to be dispersive in the sodium chloride (NaCl) based drill-in-fluid and the system had to constantly be diluted. This resulted in a loss of rheological properties of the mud system and made the wellbore more difficult to keep in gauge as well as to clean and caused mud weight fluctuations. To compound the problem, the wellbores often experience mud losses when crossing the various faults. With already narrow drilling margins, finding the correct mud properties while not inducing mud losses was challenging.

Key learnings from the PM1 wells were:
1. planned build rates in the tophole sections trajectories were difficult to achieve
2. the geologic model showing only massive sands with infrequent thin shale laminae was too simplistic
3. mud system needed to be reviewed for the amount and type of shale seen within the reservoir, and
4. straight hole designed for the horizontal reservoir section was impractical.
As the northeastern side of the graben was thinner and more geologically complex than the reservoir encountered in the southwestern wells, it was critical that these findings had to be incorporated prior to the start of the wells (#4, #5, and #6) drilled from the Production Manifold #2 (PM2).

2.2. The Learning Curve - Development Wells #4, #5 and #8

After a great deal of work to understand the issues and possible solutions, the following changes were implemented to address the challenges encountered during the drilling of the PLM#1 wells:

1. The drilling assembly was changed to a first time ever 12 ¼" bit with a 17 ½” Halliburton’s reamer and Schlumberger’s “point-the-bit” rotary steerable system BHA design. Allowing increasing build capabilities in the tophole sections (Figure 4)

2. To better achieve the planned trajectories on the 12 ¼” landing section, a study was undertaken to analyze the drilling parameters and compare them to the seismic attributes. By understanding what parameters were successful and unsuccessful in certain lithology and seismic sections, better wellpaths could be designed, directional drilling management program crafted, and results achieved. Figure 5 shows an example of this type of chart and Figure 6 shows a cross section of some of the drilling parameters plotted against the seismic data.

3. To account for the dispersivity of the shale, the mud system was changed to include potassium chloride (KCl) as shale inhibitor and small amounts of calcium carbonate were also included to prevent mud losses.

4. To maximize the amount of sand encountered in the reservoir section, the wells would be actively geosteered. Schlumberger’s Periscope™, a deep reading azimuthal resistivity tool, was added to the drilling assembly to enable a better understanding of the lithology around the wellbore. Pre-drill, real-time, and post-well modeling would be done using the RTGS™ software by a Well Placement Team working closely with the Shell Operations Team. Figure 8 shows an example of the pre-drill modeling used to refine the wellpath and Figure 9 shows an example of the real-time modeling performed by Schlumberger’s Well Placement Team.

5. Seismic amplitude body extractions were used to design the wellpath in 3D (Figure 7) to maximize the reservoir encountered in the more complex northern fault block.

6. Wellpaths were designed to be more flexible and the drilling tendencies for the sands and shales incorporated into the drilling design to give the highest possibility of both achieving the planned trajectory and allowing geosteering within the reservoir.

Implementing these changes showed very promising results for the shallower sections in the PM2 wells. The desired drilling angles were achieved in the tophole sections ahead of direction drilling plan (Figure 4) which allowed some margin for error in steering the 12 ¼” landing section. Using the seismic-to-drilling parameters correlations, the 12 ¼” landing sections were drilled on plan.

The horizontal reservoir sections of the #4, #5, and #8 wells were drilled with few problems. The more difficult wellpaths were drilled with minimal difficulties, connecting many of the amplitude bodies seen from the seismic extractions. The Shell Operations team and the Schlumberger Drilling Engineering and Well Placement Teams worked closely through the planning and drilling of the wells, constantly updating the models and analyzing the Real-Time data to take advantage of all of the available data, thereby minimizing the amount of non-reservoir interval penetrated. The wells found an average of 68% NTG and as in the PM1 wells, the quality of the sands was good and permeability and porosity close to predicted.

The efforts taken between the PM1 wells and the PM2 wells maximized the productive reservoir drilled and resulted in more efficient drilling operations and improved performance versus plan. The diligent approach taken to make these wells successful also increased the understanding of the suitability of the drilling assembly for the well objective, the drilling parameters in certain lithologies, and the drillability of the wellpaths enabled faster and more efficient drilling.

2.3. Conclusions

The Ostra wells in Parques das Conchas are amongst some of the most difficult deepwater extended-reach wells drilled in the industry (as compared to industry data compiled by K&M Technology (Figure 10) and with the added
complexity of a shallow (~ 850m below mud line) faulted reservoir and turbidite depositional environment, executing the Ostra development proved to be a challenge.

During the drilling of the first development well, it became apparent that the field was more geologically complex than previously assumed and that the drilling program required significant adjustments. The use of real-time data by integrated, multi-disciplinary teams improved the understanding of the formation and the challenges associated with drilling the wells. This resulted in improved drilling programs, maximizing the productive reservoir penetrated by the wells. Liaising with all vendors to gather and analyze the data, lay out all the options, then formulate an optimized plan for achieving the goals demonstrated a successful strategy which enabled a smooth modification of the plan between the drilling of the PLM#1 and PLM#2 wells.

The Ostra wells show that successfully drilling complex 3-D wells in deepwater shallow sediment can be done while delivering excellent drilling performance and quality well results.

3. Figures

Figure 1. BC-10 – Parque das Conchas Concession
Figure 2. The Ostra Field – Development wells #1, #2, #3, #4, #5 and #8

Figure 3. Cross section of the seismic through one of the proposed wellpaths shows the various layers transacted by the wells. The wells experienced steering difficulties in the shallow Pliocene and the water-bearing sands in the Miocene and Oligocene aged sediments.
Figure 4. Tophole planned trajectories versus actual achieved results. The plots for the first three wells show the actual well results (in red) reach section depth either behind the directional plan, at angles less than planned, or both. In the second three wells, once the drilling assembly was changed for a smaller bit with hole opener and a rotary steerable system, the wells achieved the planned angles ahead of plan.

<table>
<thead>
<tr>
<th>From TVDSS / MD</th>
<th>To TVDSS / MD</th>
<th>Formation Type</th>
<th>DLS Required</th>
<th>Max DLS Achieved</th>
<th>Steer Ratio Recom.</th>
<th>Steer Ratio Performed</th>
<th>Drilling parameters Recom.</th>
<th>Drilling parameters Achieved</th>
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<tbody>
<tr>
<td>xx22m / xx68m</td>
<td>xx67m / xx61m</td>
<td>Mid-Mio Maar to Top Oligocene</td>
<td>3.6</td>
<td>3.6</td>
<td>80% - 100%</td>
<td>30% - 70%</td>
<td>WOB 10 – 20 Kp - GPM: 700 RPM: 120 - 140</td>
<td>WOB 5 – 15 Kp - GPM: 700 RPM: 120 - 140</td>
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<tr>
<td>xx67m / xx61m</td>
<td>xx90m / xx99m</td>
<td>Top of Oligocene (Marl – but Sonic slow)</td>
<td>3.6</td>
<td>3.9</td>
<td>100 %</td>
<td>40 – 60 %</td>
<td>WOB 10-20 Kp - GPM: 700-800 RPM: 120-140</td>
<td>WOB 10-20 Kp - GPM: 700-720 RPM: 140</td>
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<tr>
<td>xx90m / xx99m</td>
<td>xx99m / xx32m</td>
<td>Mid Oligocene (HARD Sand &amp; Marl – very slow on Sonic)</td>
<td>3.6</td>
<td>2.8</td>
<td>100%</td>
<td>100%</td>
<td>WOB 10-20 Kp - GPM: 700-800 RPM: 120-140</td>
<td>WOB 10-25 Kp - GPM: 800 RPM: 130</td>
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<tr>
<td>xx99m / xx32m</td>
<td>xx67m / xx51m</td>
<td>Mid to Lower Oligocene (Layers Marl – shale sonic hards and softs)</td>
<td>3.6</td>
<td>4.1</td>
<td>80 – 100%</td>
<td>80 – 100%</td>
<td>WOB 10-20 Kp - GPM: 700-800 RPM: 120-140</td>
<td>WOB 10-25 Kp - GPM: 800-840 RPM: 130-140</td>
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<tr>
<td>xx67m / xx51m</td>
<td>xx85m / xx32m</td>
<td>Top to Lower Eocene</td>
<td>3.6</td>
<td>4.3</td>
<td>40-80%</td>
<td>80%</td>
<td>WOB 10-20 Kp - GPM: 700-800 RPM: 120-140</td>
<td>WOB 15-25 Kp - GPM: 710-750 RPM: 140</td>
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<td>xx85m / xx32m</td>
<td>xx19m / xx20m</td>
<td>Paleocene Firm Shale with thin interbeded Carbonates</td>
<td>0.0</td>
<td>0.0</td>
<td>Tendency</td>
<td>10%-20%</td>
<td>WOB 10-20 Kp - GPM: 700-800 RPM: 120-140</td>
<td>WOB 10-15 Kp - GPM: 800-810 RPM: 140</td>
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<tr>
<td>xx19m / xx20m</td>
<td>xx55m / xx51m</td>
<td>Top Cretaceous Top K Mass Shale - consistent Hard shale</td>
<td>3.5</td>
<td>3.8</td>
<td>60 – 80%</td>
<td>50 – 70%</td>
<td>WOB 10-20 Kp - GPM: 700-800 RPM: 120-140</td>
<td>WOB 10-20 Kp - GPM: 700-800 RPM: 130-140</td>
</tr>
</tbody>
</table>

Figure 5. An example of the directional drilling parameters as a function of the expected lithology as derived from seismic and logs. The team used these parameters to generate directional guidelines in each section which provided a realistic understanding of what could be achieved by the drilling assembly and direction drilling team and what range of dogleg severity could be expected. These recommendations were then used to further refine the wellpath in order to deliver successfully the next extended reach horizontal well.
Figure 6. This cross section shows an example of the directional drilling properties (ROP, DLS, Steering Ratio) overlaid on the seismic data. This allowed for the direct correlation of the drilling and steering parameters across the field.

Figure 7. Seismic body extraction was used to optimize the placement of the horizontals in stratigraphically complex areas. The amplitude extractions were calibrated to the results from the PM1 wells to allow for more accurate understanding of the seismic data for the PM2 wells.
Figure 8. Curtain section and resistivity modeling were used to refine the well path, reducing the amount of non-reservoir encountered, and prepared for the Real-Time monitoring of the horizontal sections drilling.

Figure 9. Schlumberger's RTGS software was utilized to monitor the Real-Time data and manage necessary changes to the well paths. The Well Placement Team compiled the Real-Time and tracked the progress against the pre-drill model, updating it when necessary. Faults, approaching bed boundaries, and geosteering properties were incorporated into the interpretations and resulted in Real-Time recommendations to improve the wellpath to maximize reservoir penetrated.
4. Acknowledgments

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