AADE-24-FTCE-085

Ultra Heavy-High Performance Water Base Fluid Improves Wellbore Stability while Drilling Unstable Pressurized Formation in an Offshore Exploration Well

Lucio Bussaglia, Franco Arpini, Salvatore Buononato, Constantin Grama, Cascone Alessandro, Vance Smith, Newpark Fluids Systems

Abstract

In southern Europe, the operator successfully and safely drilled an exploration deep offshore well characterized by highly unstable formations with a specialized ultra-heavy high-performance water-based fluid (HPWBF). Prior to formulating and pilot testing the HPWBF, detailed analyses of previous experiences, lessons learned, XRD and CEC of cuttings collected from similar fields with highly wellbore instability was conducted. Offset wells drilled in those fields, faced severe borehole instability issues that in some cases endured costly and untimely sidetracks caused by mechanical stuck pipe events and collapsing wellbores. This led to a significant financial impact due to the NPT that greatly reduced the profitability of the wells.

Using customized package of shale inhibitors and high-performance drilling lubricant, the proposed HPWBF minimized the borehole instability and delivered optimized fluid properties and stability even when the mud weight was increased to 17.9 ppg required to control wellbore pressures. The HPWBF was also formulated with a natural polysaccharide to maintain rheological properties for improving hole cleaning and customized with polymers package together with bridging materials to minimize fluid invasion toward the troublesome formation. Despite its ultra-high density, the fluid exhibited excellence tolerance to drill solids and tolerance to calcium ions while drilling anhydride formation.

A sweep pill program that foreseen the utilization of WSM, Bridging, anti-sticking and high viscosity fluids helped to respectively alleviate wellbore instability, fix the bit balling issues and ensure the hole was properly cleaned.

During the drilling operations, various differential stuck pipe incidents occurred most likely induced by the ultra-high mud weight. An environmentally friendly pipe release fluid pill (oil free fluid) at 17.5 ppg was engineered and successfully utilized allowing the pipe to get free in very short time below one hour.

This project presented additional logistical and supply chain challenges, as there were no dedicated facilities in this new emerging area to support offshore projects. LMP and Bulk Facilities were installed and commissioned at the supply base together with the setup of a covered warehouse to store materials used in this project.

XRD and CEC analyses was also carried out on cuttings received from this explorative well for mapping the lithology of the field. Furthermore, laboratory testing was conducted to evaluate the inhibition properties of HPWBF on cuttings samples for further fluid optimization may be required for future projects.

Introduction

Shale instability represents one of the major technical problems in drilling activity that highly contributes to increase the NPT and project cost. Operational challenges deriving from presence of unstable formations are multiple such as excessive cavings, hole enlargements with consequent hole cleaning problems, pack-off, prolonged reaming, overpull, torque and drag, induced losses for excessive ECD, difficulties in running casing, and in some situations stuck pipe events that may require drilling costly sidetracks (Van Oort 2003, Mohiuddin et al. 2006, Van Oort et al. 2017). From drilling fluid prospect, selection of correct mud weight before entering the new formation represents the first weapon against hole instability. Minimizing pore pressure transmission by limiting the invasion of fluids and mud's filtrate toward native architecture by selecting proper package of bridging and sealing agents is another relevant aspect to consider when design the fluid formulation (Stowe et al. 2001). Shale inhibition required to limit chemical interactions of shales present in the formations with fluids is another important factor to be addressed (Bussaglia et al. 2017).

In southern Europe, a legacy operator required a water-based fluid solution to minimize the foreseen wellbore instability on a complex explorative deep offshore well exacerbated by develop of high overpressure as well as high temperature gradient in the deeper sections. After an accurate analysis of data and information gathered from offset wells drilled in similar fields united by wellbore instability issue, the answer came in the form of HPWBF designed with selected package of chemicals that would stabilize the wellbore.

There will be a general discussion of previous experiences clay characterization overview and drilling fluids used on similar wells in two representative fields that experienced borehole instability prior to customize the fluid formulation used in this explorative project.

Selected HPWBF, pills and sweeping fluids design, their field performance and well's achievements will be analyzed.

There will be an overview of logistics plan involved to improve project efficiencies and economics supported by the utilization of covered warehouse and installation of a LMP and Bulk Plant in a region were no dedicated facilities and infrastructures were present to support offshore projects.

XRD and CEC analyses carried out on cuttings and cavings samples received from well site used for mapping the lithology of the field in question will be discussed. Furthermore, a summary of laboratory work performed to evaluate the inhibition properties of the HPWBF on received rock samples for any further fluid optimization for future projects will be then presented and concluding statements will be conveyed.

Offset Experience

Offset wells drilled in similar fields in Southern Europe experienced common, in some cases unpredictable, challenges such as severe wellbore instability, tectonic stress and lithology variability with an intrinsic complex structure, etc. Borehole instability mechanism was also associated to the presence of shales that were sometimes reactive, dispersible and time sensitive.

Main consequence of this scenario was the occurrence of big quantity of cavings and associated drilling problems. In some wells, this very unpredictable and precarious drilling environment lead to costly sidetracks due collapsing wellbores, stuck pipe incidents and in some cases the loss of the well.

The design of a state of art HPWBF for this explorative well has been carried out after a detailed analyses of borehole instability data and XRD study of offset wells drilled in two representative fields (Field A and Field B) where similar operational problems occurred. A summary of main wellbore challenges, clay characterization and fluids utilized on those fields, are highlighted below.

Field A

Since 1980, the drilling operation in the Field A experienced operational challenging caused by the presence of complex allochthonous geology structures characterized by highly tectonic stress sometimes with the presence of fractures and stringers of water-sensitive clays. Another characteristic of this field is the variability of lithology sequence and clay type on neighbor wells so drilling scenario was quite variable and unpredictable.

The XRD clay analyses and the CEC were used to provide useful information about the nature of the clay and their reactivity. Figure 1 and Figure 2 show respectively the average Bulk composition and clay characterization with CEC of drill cuttings received from recent offset wells of Field A (Well#01, Well#02 and Well#03)

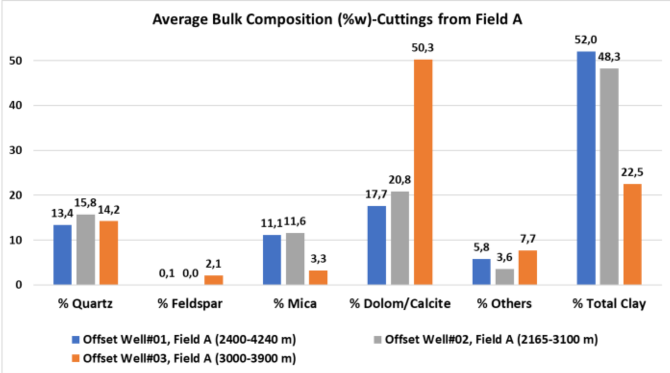


Figure 1 - Bulk Composition of Cuttings from Field A

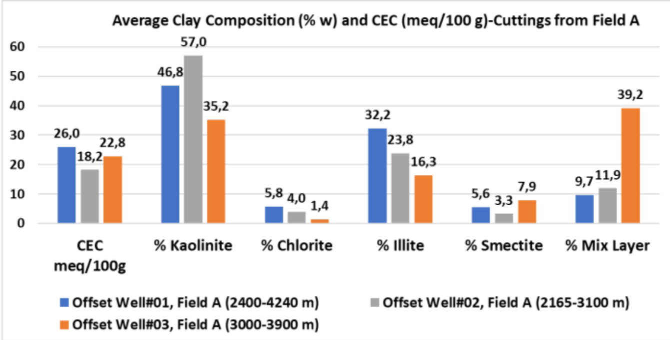


Figure 2: Clay Composition of Cuttings from Field A

Drill cuttings from Well#01 and Well#02 were reach of clay, while cuttings from Well#03 presented a moderate clay content.

The average CEC values of all three wells were low to medium indicating moderate reactivity of the clays.

Mineralogy analysis of Well#01 indicated that the clay was mainly composed by kaolinite (non-swelling, some dispersion) and Illite (some swelling, dispersible) with minor components like Mix Layer (swelling, dispersible), Chlorite (non-swelling) and smectite (swelling).

The XRD analyses of cuttings from Well#02 showed that the clay is mostly composed by kaolinite (non-swelling, some dispersion) and Illite (some swelling, dispersible) with some mixed-layer (swelling, dispersible) and low content of smectite (swelling) as well as chlorite (non-swelling).

Mixed-layer (swelling, dispersible) and kaolinite (non-swelling, some dispersion) were major constituents of cuttings from Well#03 with presence of illite (some swelling, dispersible) and some smectite (swelling). Chlorite (non-swelling) is also present at very low concentration.

The drilling problems encountered though the allochthonous structures highlighted the same characteristics such as highly borehole instability, tectonic stress, tight hole, excessive reaming, sloughing shale, heavy occurrence of cavings (Figure 3), high torque, pack-off followed by stuck pipe.

Figure 3: Cavings on shakers

While in some wells those operational issues were minimal, in others they were quite severe with occurrence of excessive cavings on shakers and additional time spent to clean the wellbore and sometimes with more problematic issues like stuck pipe and drilling multiple sidetracks.

The allochthonous formations are not only highly unstable but also very time-dependent, so formation of cavings become more problematic over time. The most important factor to minimize borehole problems was to use the correct mud density regardless the mud type and drill the section as fast as possible. Where the mud weight was correct, the instability mechanism was maintained at low level. In all those wells where the wrong mud density was utilized, the problem was a big concern negatively affecting the operational costs. Geo-mechanical studies, geo-stress software simulations and analyses of data from offset wells were utilized for mud density selection. Mud weights required to stabilize the wellbore on Field A were typically in a wide range 10.9-10.2 ppg depending on geological structure.

In addition to hole instability problems, other common drilling challenges associated with the drilling of wells in Field A are summarized as following:

- Potential contamination of surface aquifer
- Presence of hard, abrasive formation (like chert) resulting in Low ROP and high torque
- Interbedded highly reactive clay
- Hole cleaning issues while drilling surface large hole diameter with partial losses
- Potential severe losses when changing formation
- Experiencing severe to total losses while drilling the fractured carbonate reservoir
- H_2S/CO_2 environment
- Severe corrosion with associated equipment damaging
- Environmental sensitive area with extreme high-profile exposure due to touristic and landscape beauty, thus putting any event directly in the public eye.

Originally on first wells in the area, these complex formations were drilled using potassium chloride or potassium carbonate-based fluids with shale stabilizers. Potassium chloride/ silicate muds were also utilized. Those wells suffered severe borehole instability. Different options to mitigate the wellbore instability included the use of NADF. Results in using NADF were very contrasting with not evident advantages. In fact, while in one well the NADF performed very well, in a neighbor well (only 1 kilometer distance), it did not provide any operational benefits with several hole instability problems, such that it was replaced by a HPWBF.

After three mechanical stuck pipes events followed by drilling expensive sidetracks, the challenging formation from 2479 to 4280 m of Well#01, was finally drilled with 15.2 ppg HPWBF formulated with polyalcohol base shale stabilizer, amine shale inhibitor, PVA shale stabilizer, 2-4% potassium chloride, sulfonated asphalt and sized graphite. Gypsum was also used to provide calcium ions to stabilize the Kaolinite clays.

On Well#02, after one stuck pipe incident and sidetrack drilling, this troublesome formation from 2035 to 3266 m, reach of kaolinite and illite, was drilled with 14.3 ppg HPWBF with similar formulation used ono Well#01 but with low content of potassium up to max 4,000-5,000 ppm.

On latest well drilled in the area, Well#03, the use of 15.5 ppg Potassium Formate HPWBF designed with an amine-based shale inhibitor, sealing materials (Marble calcium carbonate and sized graphite) and high-performance synthetic lubricant enabled to successfully and safely drill the 12 ¼” challenging section from 2770 m to 4130 m (Bussaglia et al. 2017).

Field B

One of the major challenges when drilling wells in Field B was the presence of unstable Flysch formation with a development of the tectonic stress with depth. Figure 4 and Figure 5 show respectively the average Bulk composition and clay characterization with CEC of drill cuttings received from the most representative offset wells of this specific field (Well#04, Well#05 and Well#07). Cuttings were not available from Well#06.

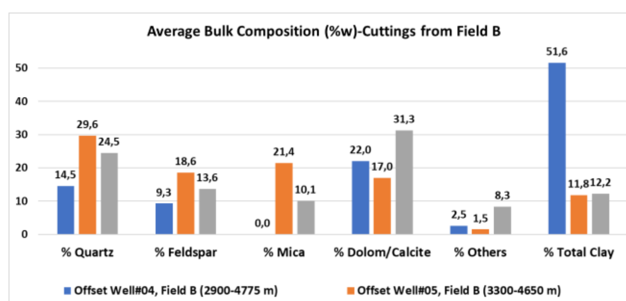


Figure 4 - Bulk Composition of Cuttings from Field B

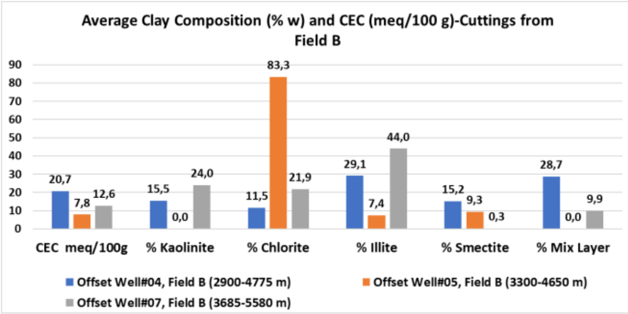


Figure 5: Clay Composition of Cuttings from Field B

Drill cuttings received from Well#04 were reach of clay, while cuttings from Well#05 and Well#06 presented low clay content.

The average CEC values of all three wells were low to medium indicating moderate reactivity of the clays.

Clays of Offset Well#04 were mainly composed by illite (some swelling, dispersible), mixed-layer clays (swelling, dispersible), significant amount of smectite (swelling clay), Kaolinite (non-swelling, some dispersion) and Chloride (non-swelling). Clay types present in the samples and the medium CEC value indicated reactive nature of this formation.

Clays found on cuttings of Offset Well#05 were mainly composed by high content of chlorite (non-swelling) with presence of some Illite (some swelling, dispersible) and Smectite (swelling). The CEC value and type of clays indicated a low reactivity with a dispersion behavior.

Clays of Offset Well#07 were mainly composed by Illite (some swelling, dispersible) and Kaolinite (non-swelling, some dispersion). Chlorite, a non-swelling clay, and some mixed-layers (swelling, dispersible) were also present. Smectite was almost nil. The low CEC and nature of the clay indicated the low reactivity of the clays with some dispersion tendency.

The wellbore instability recorded on offset wells had a mechanical origin. On Offset Well#04, problem was exacerbated by the presence of reactive clays,

The first action for managing this problem was utilizing the proper mud weight. Hole condition as well as the size, volume and shape of cavings were monitored and analyzed carefully to tune the mud weight, optimizing hydraulics, customize fluid composition and adopted correct drilling practice (Kumar et al. 2012, Skea et al. 2018). Figure 6 shows cavings with different shapes (Angular, Splintery & Tabular) collected on shakers while drilling the unstable Flysch formation on Well#05.

Figure 6: Cavings from Well#5 (Angular, Splintery & Tabular)

Together with selection of correct mud weight, adequate hole cleaning was crucial to limit the risk of high torque and drag, packing off and stuck pipe. Furthermore, drilling and tripping practices were optimized to minimize the risk of destabilizing the hole due to swab/surge pressures, drill string impacts, etc. Addition of fracture-sealing products was necessary to prevent fluid's invasion and pressure propagation into the fractures present in the shale.

Other common drilling problems experienced on offset wells of Field B are highlighted as following:

- Potential contamination of surface acquirer
- Presence of hard, abrasive formation chert formation resulting in low ROP and high torque
- Hole cleaning issues while drilling large hole diameter on top hole carbonate sections
- Potential severe to total losses while drilling top hole fractured carbonate formations
- Potential overpressure in carbonate reservoir that requires heavy non-damaging drilling fluids
- Formation losses in carbonate reservoir section
- Potential H_2S contamination in carbonate reservoir
- Potential presence of Flysch imbricates in the carbonate reservoir just below (around 200-300 m below) the casing shoe

The Flysch section from 2764 m to 4070 m of Offset Well#04 was successfully drilled using an inhibitive HPWBF based on polyalcohol technology with final MW of 17.1 ppg (Isinak et al. 2005).

On Offset Well#05, NADF was successfully used for drilling the Flysch shale from 3270 m to 4177 m reaching the final MW of 14.0 ppg. Wellbore instability was recorded with frequent stuck pipe tendency and huge quantity of caving. The well was temporary abandoned after encountering Flysch imbricates in the carbonatic reservoir section.

On Offset Well#06, after 7 sidetracks due to pack-off and stuck pipe incident, operator decided to temporary abandon the project due to the impossibility to complete the drilling of Flysch formation with the use of 15.9 ppg Potassium Silicate Fluid.

On a more recent well, Offset Well#07, close to Offset Well#06, this troublesome formation was successfully drilled from 3422 m to 4927 m with a NADF by running the correct MW up to 16.5 ppg and using a blend of bridging agent and polymeric sealing agent to prevent fluid invasion into formation.

Planning Phase

This explorative offshore vertical well was considered as high-pressure well, where the bottom hole pressure was estimated to be in the range 13800-17400 psi and estimated bottom hole temperature of 257 °F. The most critical fluid-related concerns were:

- Narrow pore pressure/fracture gradient window with risk of lost circulation
- Overpressure development by depth
- Severe wellbore instability due to possible presence of reactive and dispersible clays
- Hole instability consequences such as hole pack-off due to cavings, high torque, excessive reaming, overpulls, suck pipe tendency, ineffective hole cleaning, etc…
- Enter into the formation with selection of correct mud density
- NPT for addressing wellbore instability
- Addressing unique environmental and logistics considerations in an emerging offshore area
- Be ready to have on location in a short time frame (48 hrs), NADF in case of ineffective of Water based Mud to drill the unstable formations
- Set up and commissioning a LMP to store NADF and Bulk Plant for handling barite at the offshore supply base in an area where no dedicated facilities and infrastructure were available to support offshore projects
- Supply base placed in a very sensitive and touristic area (Figure 7)

Figure 7: Supply Base Area

Upon reviewing lessons learned and results achieved on all offset wells and considering the project's requirements, the fluid team established the following benchmark for the design of suitable HPWBF:

- Provide wellbore stabilization and shale inhibition
- Thermal stability at BHCT and BHST conditions
- Mud stabilization after prolonged time logs acquisition
- Minimum sag tendency after prolonged period of static ageing
- Enhanced rheology allowing minimal difference between ESD and ECD
- Mud stability against calcium contamination when crossing potential anhydride layers
- Possibility to increase MW above 16.7 ppg if hole would dictate the requirement
- Fluid Cost optimization
- Easy Mud Logistics and Management in case of Formation Losses

Table 1 shows the planned well profile with mud type selection, estimated bottom hole temperature, anticipated MW and potential drilling challenges.

Table 1: Well design

MD (m)	Hole size	CSG	Possible Challenges	Mud Type	BHST °F	MW (ppg)
700	8 1/2"	Pilot Hole	Hole Cleaning shallow gas-water flow	SW-KCl-PO PAD Mud	63	8.8/10/ 11.7
210	36"	30" CP	Hole Cleaning Hole Instability	SW-KCl-PO PAD Mud	63	8.8/10/ 11.7
700	26"	20" CSG	Hole Cleaning shallow gas-water flow	SW-KCl-PO Kill Mud	63	9.2/11.7
2000	17 1/2"	16" CSG	Hole Cleaning Shale Inhibition	HPWBF	111	9.8
3500	14 3/4"	13 3/8" CSG	Hole Cleaning Shale Inhibition	HPWBF	152	11.5
4850	12 1/4" x 13 1/2"	11 3/4" LNR	Hole Cleaning Shale Inhibition	HPWBF NABF (conting.)	200	12.6
6100	10 5/8" x 12 1/4"	9 5/8" CSG	Hole Cleaning Shale Inhibition High Temp.	HPWBF NABF (conting.)	246	13.9
6525	8 1/2"	OH	Hole Cleaning Losses in carbonates High Temp.	HPWBF	257	13.2

Drilling Fluid Design

The operational conditions outlined in the previous paragraph indicate that the fluid system was crucial for the success of this project. The drilling fluid answer came in the form of a specialized and cost-effective HPWBF engineered with a unique blend of additives designed to address the required characteristics:

- Potassium chloride was chosen as primarily shale inhibitor
- An amine-based product was chosen as secondary shale inhibitor

- Liquid Blend of Polyglycerols and PVA polymer was selected to stabilize the formation
- A dry cationic PVA polymer was also used to further stabilize the formation
- A High-Performance Lubricant compatible with calcium ions was introduced to increase lubricity, reduce torque values, and maintain the desired lubricity coefficient.
- Package of fluid loss reducers with thermal stability up to 257° F were selected
- Polysaccharide viscosifier was chosen to maintain rheological properties for optimum hole cleaning
- Modified polymers combined with WSM were selected to minimize fluid invasion into formation and mitigate wellbore instability
- Marble sized calcium carbonate was selected to provide bridging
- Barite was chosen to control the Mud Weight

Since this well was explorative with no previous offset wells drilled in the area, it was not possible to have access to cutting samples to conduct detailed inhibition testing (shale inhibition dispersion, accretion, CST).

Extensive Lab testing using HPWBF samples and cuttings/cavings received from the rig site, were carried out during execution of the project. Results of this study are showed on a dedicated paragraph at the end of this document.

During planning phase, standard lab testing (not reported on this case study) of fluids proposed for each section was conducted to address the required rheology, thermal stability and filtration properties.

Facilities, Offshore Equipment and Logistics Overview

Based on previous offshore experience on large scale (Bussaglia et al. 2018), to fulfill the project's requirements, a LMP and Bulk Plant were installed at the supply base area and commissioned before staring the operations (Figure 8 and Figure 9).

Figure 8: LMP for storing and mixing fluids at the supply base

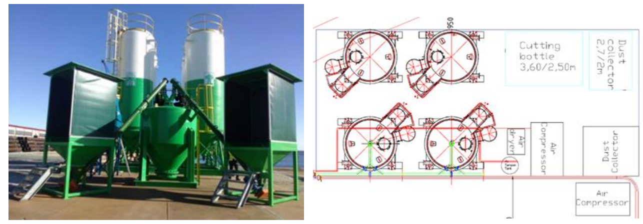


Figure 9: Bulk Plant at the supply base

The primarily reason to set up the liquid mud plant was to eventually store and handling NADF to be used as contingency fluid in case of severe borehole instability would have occurred with HPWBF. The LMP was composed by one mixing tank and 4 storage tanks for a total capacity of 350 m^3 (2201 bbl). The Bulk facility was composed by four vertical silos with a storage capacity of 148 m^3 (931 bbl), equipped with a dust collector, compressors, air tampon and air dryer. A covered warehouse with a surface of 1000 m^2 placed inside the harbor at less than 1 kilometer from jetty area (Figure 10) was used for storing and handling products, assets and equipment, fully dedicated for this project.

Figure 10: Covered Warehouse

Two decanting centrifuges for drill solids discharge and possibility to set up in Barite recovering mode along with screw conveyors system were installed at the rig platform (Figure 11).

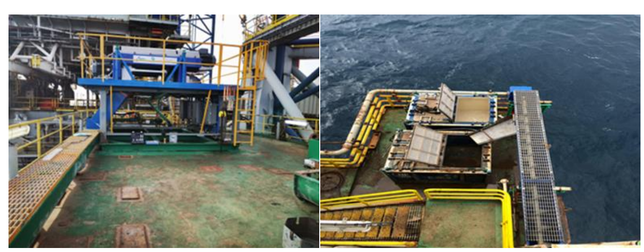


Figure 11: Centrifuges and screw conveyor system

During execution of the project, although NADF was not utilized thanks to the excellent performance of the proposed HPWBF, the LMP was however deployed to handle and store the excess of fluid volumes received from well site at the end of each section for final disposal.

A supply chain process was put in place to identify the suppliers, products availability and lead time of products. Due to the remote location of the supply base and distances from suppliers and warehouses, chemicals were ordered in advance and shipped to destination without any delays in delivering. Table 2 presents an overview of metrics of the supply chain for provision of additives and mud volume handled in this offshore project.

Table 2: Supply chain metrics during execution of the project

	Chemicals (Metric Ton)	Barite (Metric Ton)	WBM (m^3)
Received	1455.2	4351.5 (Big Bag)	6131
Loaded out	-	4311 (Bulk)	-
Back Loaded	-	40.5 (Bulk)	-

Case Study (Drilling Results and Fluid Performance)

The actual well design is shown on Figure 12. The well was successfully drilled to TD allowing to the acquisition of logs data for reservoir evaluation.

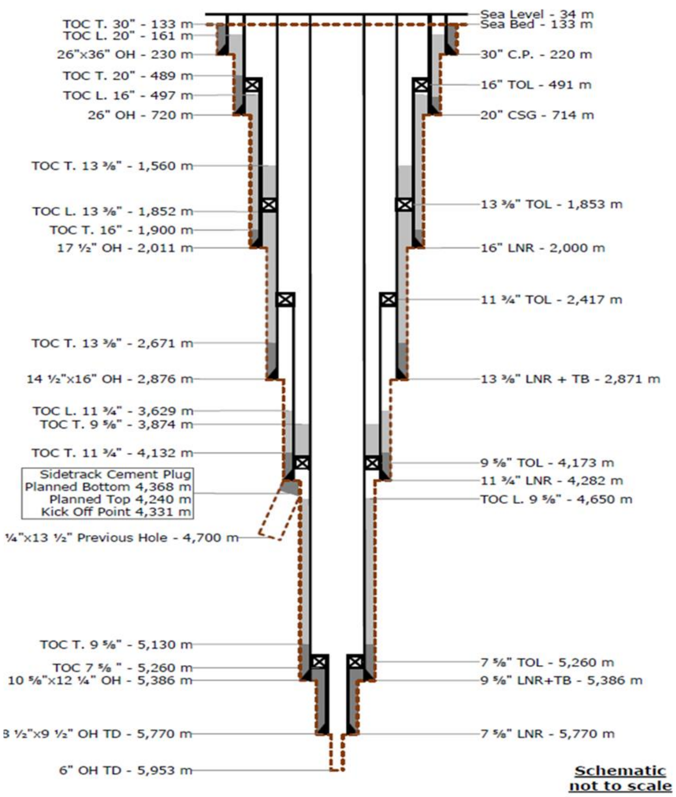


Figure 12: Actual Well design (vertical)

Brief description of operations of each hole section is outlined below.

36" Riserless Hole to 230 m

The operator drilled the riserless 8 ½" pilot hole to 230 m and then enlarged to 36" with seawater and sweeps. 10 ppg inhibitive PAD Mud was displaced downhole for wellbore stabilization before RIH the CP. The 30" CP was run and cemented.

26" Hole to 720 m

The 8 ½" pilot hole was drilled to 720 m with return to surface and then enlarged to 26" hole using SW-KCl-PO with a max mud weight of 9.7 ppg. While drilling, a remediation cement job was done to cure leaking problem occurred around the 30" CP in the proximity of seabed. The 20" CSG was run and cemented.

17 ½" Hole to 2011 m

Starting from 17 ½" hole, operator deployed the engineered HPWBF. Section was drilled to 2011 m with mud weight of 9.7 ppg. No sigh of borehole instability was recorded. The 16" LNR was run and cemented.

14 ½" x 16" hole to 2876 m

The 14 ½" x 16" hole was drilled with 11.5 ppg HPWBF without any problems until 2876 m where first signs of wellbore instability occurred with sudden increase of torque followed by mechanical stuck pipe. Pipe got free after applying 26 Ton overpull. Drilling continued to 2876 m where operator decided for a wiper trip. While POOH, severe borehole instability occurred with evident hole restrictions and pack off that required extensive backreaming until the casing shoe and when RIH to bottom. Rounded cavings, indication of poor hole cleaning, were seen on shakers with a max size of 1 cm (Figure 13).

Figure 13: Cavings observed on shakers

Operator decided to POOH to surface to check the BHA. Upon reaching bottom with some reaming down, the mud density was progressively increased to 11.9 ppg and no further hole instability was recorded. Operator decided to set the 13 3/8" LNR at 2876 m rather than continuing drilling to 3500 m as per program. 13 3/8" LNR was successfully run and cemented followed by Tie Back job. While drilling this section, calcium contamination occurred due to presence of anhydrite formations.

Mud parameters were promptly controlled by chemicals addition. During the wellbore instability problems, a high-performance calcium resistance lubricant was added to improve lubricity of the mud, while the potassium chloride was increased to 7% w/w as per operator requirement.

12 ¼" x 13 ½" hole to 4700 m

After drilling out cement, CSG shoe and few meters of new formation to 2881 m, the HPWBF was weighted up to 12.9 ppg and implemented with addition of sized marble calcium carbonate for bridging.

Drilling operations proceed without any problems until 3640 m where operator decided to perform a wiper trip to CSG shoe. Due to some tight spots, the mud density was increased 13.4 ppg upon reaching the bottom, drilling continued to 4150 m where fluid was treated with soda ash to prevent further calcium contamination coming from the presence of anhydrite layers.

At 4328 m, operator decided to pool out of the hole for changing the BHA. High abundance of cavings were recorded on shakers (Figure 14).

Figure 14: Cavings seen on shakers while circulating at 13 3/8" CSG shoe

Mud weight was increased to 13.7 ppg and high vis pills were pumped for hole cleaning. During POOH at the depth of 2943 m with the stabilizers inside the casing, recorded increase of circulating pressure with drill string stalled out. After working string applying 170 Ton, POOH resumed. This problem partially persisted even with the bit was inside the casing. During circulation inside the casing noted modest quantity of cuttings/formation debris on shakers. Once on surface, the BHA and bit were found to be balled (Figure 15).

Figure 15: Bit and BHA on surface with clear indication of Bit Balling

While performing RIH, just below the CSG shoe, recorded obstruction. Reaming down to bottom was necessary with pack off events and increase of pressure. Big cavings were recorded on shakers with splintery shape indicating insufficient mud weight (Figure 16).

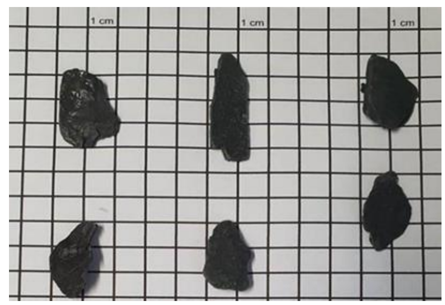


Figure 16: Cavings on shakers from 4042 m while RIH in reaming mode

On bottom, pumped a high vis pill. Drilling restarted and in the interval 4335-4496 m severe calcium contamination up to 600 mg/lt occurred due to presence of 10% to 70% anhydrite in the cutting samples. Mud contamination was treated out with soda ash and chemicals additions. An effective thinner was required to lower the high mud viscosity resulted from this contamination. The fluid showed good stabilization to calcium contamination.

Operator continued drilling to section TD at 4700 m where the MW was increased to 13.9 ppg and then to 14.4 ppg due to severe borehole instability.

Starting from 4356 m to section TD at 4700 m, a wellbore strengthening plan was adopted by sweeping the hole every two stands with 32 bbl WSM pills designed with a package of bridging and sealing agents (Table 3). 32 bbl High viscosity pills were also pumped for hole cleaning. Sweeping plan is shown on Table 4.

Table 3: Wellbore Strengthening Material Pill Composition

WSM Pill formulation	ppb
Circulating Fluid	1 bbl
Sized marble Calcium Carbonate	12.3
Blend of fine to medium cellulosic, graphitic, and elastomeric granules	5.3
Sized natural graphite	3.5
High performance Lubricant	7.0
Blend of medium to coarse cellulosic, graphitic, and elastomeric granules and micronized	3.5-7.0

Table 4: Sweeping Plan 12 ¼" x 13 ½" hole

Depth (m)	WSM Pill	High Vis Pill
4356	x	-
4415	x	-
4474	x	-
4504	-	x
4533	x	-
4592	x	-
4651	x	-
4700	-	x

At TD, before pulling out, an anti-sticking pill was pumped (2 x 32 bbl) using high Vis Pill (circulating fluid plus a polymeric viscosifier) as base fluid with addition of 6.0 ppb aluminum tri-stearate product in organic solvent carrier.

Experienced severe hole instability events during POOH in the interval 4664-3020 that caused several overpulls, pack off and well restrictions leading to induced formation losses.

During back reaming operation, from 3150 to CSG shoe, eleven high viscosity pills implemented with 3% high performance lubricant and 0.7 ppb anti sticking agent were pumped at each stand.

Observed medium to high amount of cavings with angular and splintery shape.

Furthermore, a mechanical stuck pipe occurred 32 m below the casing shoe at 2908 m. The pipe got free after applying 37 ton overpull.

Once on surface, the BHA didn't show any sign of bit balling thanks to the efficiency of the anti-sticking and High Vis pills.

The 11 ¾" LNR was run, with tight spots and restrictions recorded in the interval 3170-3636 m, to 4282 m where LNR stalled.

Due to the impossibility to rotate and move up and down the LNR, operator decided to set the LNR at this depth and perform the cement job.

10 5/8" x 12 ¼" hole to 5386 m

After drilling out cement and shoe, reaming down was performed to 4415 m inside the previous hole where overpulls were recorded. Operator decided to set a cement plug from 4168 to 4338 m to isolate part of previous hole not cased.

After drilling out cement prior to drill the sidetrack through the new formation, the mud weight of HPWBF was increased to 15.5 ppg. Anhydrite up to 10% of cuttings was encountered in the interval 4335-4496 m. At 4470 m, the MW was raised up to 15.6 ppg and then to 16.0 ppg at 4850 m and to 16.2 ppg at 4950 m.

At 5150 m mud density was increased to 16.5 ppg and then to then to 16.7 ppg at 5215 m. While POOH, recorded severe tights spots from 5155 with abundance quantity of cavings on shakers starting from 4572 m (Figure 17).

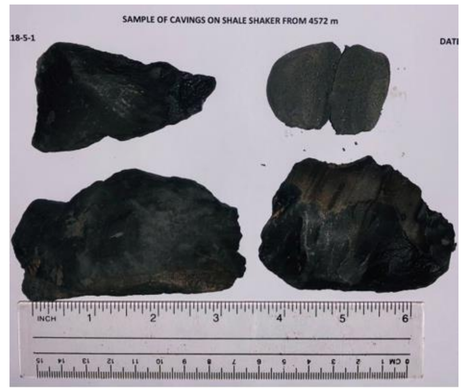


Figure 17: Cavings on shakers while circulating at 4572 m while POOH

Pack off occurred while back reaming in the interval from 4403 m to 4397 m that required to work string to get the pipe free. At 4397 m, a high vis pill was pumped with increase of caving on shakers. Continued back reaming until 4318 m with overpulls, POOH continued in pump out mode to the CSG shoe, where a viscous pill was pumped until shakers were cleaned before pulling out to surface. Bit and BHA was cleaned without any sign of bit balling.

After RIH, drilling resumed without significant problems until 5386 m where a gas kick occurred with a max gas background of 0.6% through sands formation and increase of mud tanks levels. The kick was successfully controlled displacing the hole with 17.9 ppg HPWBF.

However, the extreme high mud density required to overbalance the well pressure, lead to differential stuck pipe. After many mechanical attempts to solve the problem without success, an environmentally friendly water-based spotting fluid was proposed in substitution of common invert emulsion pill strictly forbidden in the area. This fluid was engineered using a hydrocarbons-free, low toxicity product combined with high performance lubricant in the ratio of 90/10. The fluid itself provided the required rheological properties to keep barite in suspension up to 17.5 ppg without using any viscosifier agent. The pill was spot downhole and in less than two hours, pipe released. During circulation the pill out of the hole, 0.3% gas and 6% CO_2 was recorded.

The bit was pulled out of the well successfully without any hole instability related problems.

When drilling across troublesome interval from 5042 to section TD at 5386 m, to alleviate the hole instability issues, minimize bit balling and provide optimal hole cleaning, 32 bbl of each pill (same recipes used in previous section) was pumped downhole in according with the following sweeping program (Table 5).

Table 5: Sweeping Plan 10 5/8" x 12 ¼" hole

Depth (m)	WSM Pill	High Vis Pill	Anti-sticking Pill
5042	x	-	-
5096	x	-	-
5110	x	-	-
5157	x	-	-
5170	-	-	x
5185	x	-	-
5190	-	-	x
5205	-	-	x
5215	-	x	-
5220	x	-	-
5275	x	-	-
5364	x	-	-
5386	-	-	x

The 9 5/8" LNR was run to bottom facing minor hole restrictions in the interval 4789 m- 4872 m. Cement job and tie back operations were executed as per program.

In this section, centrifuges were set up at barite recovery mode to minimize waste volumes and recover Barite for cost optimization (Figure 18).

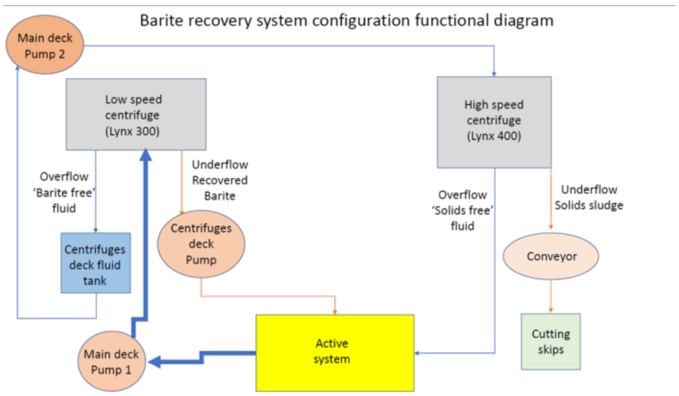


Figure 18: Barite recovery system layout

8 ½" x 9 ½" hole to 5770 m

After milling cement, casing shoe and 5 meters of new formation were drilled with using 17.9 ppg HPWBF.

After a trip to surface, the bit was run to 5352 m, where 57% gas kick was recorded. The well was circulated using the chock line until the well become stable. RIH proceeded to the bottom where mud weighed was reduced to 17.5 ppg.

This section was drilled without any wellbore instability problem to 5770 m with final mud weight of 17.4 ppg.

Before RIH LNR, the well was displaced with 17.9 ppg fluid. The 7 5/8" LNR was run and cemented.

6" hole to 5953 m

Before commencing drilling across reservoir, the MW of the HPWBF was reduced to 17.4 ppg.

At 5810 m, while entering the carbonate formation, losses occurred from a minimum rate of 6.2 bbl/hr up to a max peak of 63 bbl/hr. Losses reduced to 5.0 bbl/hr after pumping 28.5% carbonatic LCM pill in according to the engineered LCM strategy. At 5847 m, losses occurred again with max loss rate of 232 bbl/hr. They were promptly cured pumping a second LCM pill. To minimize the risk of any further losses, MW was reduced to 16.4 ppg.

During connection while RIH, a differential stuck pipe occurred at 5835 m. The environmentally friendly free pipe fluid was pumped again allowing to release the drill string in 30 minutes.

Drilling resumed to 5953 m where differential stuck pipe occurred again. After several unsuccessfully attempts using jar, a second free pipe pill was spot downhole allowing to get the pipe free in one hour.

Operator decided to POOH before logging operations. First run of electrical logging was performed even though facing several problems with signal. The BHA was pulled out of the hole.

During RIH, at the depth of 5903 m, severe losses were recorded with max loss rate of 415 bbl/hr.

While POOH to the shoe for curing losses, differential stuck pipe occurred at 5880 m. During jarring operations needed to release the string, a total of 2654 bbl of HPWBF were lost downhole. Seawater was pumped in the annulus due to the lack of mud on surface.

The fluid team implemented the lost circulation strategy by pumping Carbonatic LCM pills at higher concentration of 35.5% up to 45% that enabled to cure losses. The theoretical volume of seawater in the hole (around 333 bbl) was displaced with new HPWBF at 14.2 ppg.

POOH was carried out after recording an increase of stand by pressure caused by partial plugging of BHA by LCM.

Operator decided to plug and abandon the well after gathering sufficient data for reservoir evaluation.

Drilling Challenges and Fluid Recap

A recap of drilling challenges of each section is outlined on Table 6. Average concentration of the key products of HPWBF is shown on Table 7 while the HPWBF properties can be seen on Table 8.

Table 6: Summary of major drilling challenges of each hole section

Section	Drilling Challenges
36" riserless	No challenges
26"	Conductor Pipe leaking
17 ½"	No challenges
14 ½" x 16"	Tight spots, high torque, overpull, pack off, hole cleaning, cavings, hole restrictions, excessive reaming, mechanical stuck pipe, anhydride contamination
12 ¼" x 13 ½"	Tight spots, high torque, overpull, pack off, hole cleaning, cavings, hole restrictions, no rotation, excessive reaming, induced losses, mechanical stuck pipe, anhydride contamination, bit balling
10 5/8" x 12 ¼"	Tight spots, high torque, overpull, pack off, hole cleaning, no rotation, excessive reaming, cavings, hole restrictions mechanical stuck pipe, gas kick, differential stuck pipe, anhydride contamination
8 ½" x 9 ½"	Gas Kick
6"	Severe formation losses, differential stuck pipe

Table 7: Average key products concentration of HPWBF

Product	Avg conc. (ppb)
Potassium Chloride	2.0-7.0% w/v
Polysaccharide Viscosifier	0.8-1.8
Amine shale inhibitor	4.6-15.5
Polyglycerols+ PVA liquid Blend	4.6-16.8
Dry cationic PVA shale inhibitor	1.0-4.6
Pure grade Fluid Loss Polymer	2.6-8.0
HT Fluid Loss Synthetic Polymer	0.0-1.9
High performance Lubricant	0-2.5% v/v
Bridging agent	0-9.5
Thinner	0-2.1
Barite	20-508
Liquid H_2S scavenger	0-0.9

Table 8: Average HPWBF properties

Properties	Unit	Average
MW	ppg	9.7-17.9
Plastic Viscosity @ 120 °F	cP	10-50
Yield Point @ 120 °F	lb/100ft²	18-30
6 rpm @ 120 °F	lb/100ft²	5-24
Gel strength (10 sec.) @ 120 °F	lb/100ft²	5-16
Gel strength (10 min.) @ 120 °F	lb/100ft²	6-24
API Filtrate	ml	3.0-5.0
HTHP Filtrate	ml	<15
MBT	ppb	1.6-11.5
pH	-	9.0-10.0

Overall Fluid Performances

Although this well presented several operational challenges starting from 14 ½" x 16" and throughout the reservoir section in 6" associated to severe formation instability, overpressure, presence of anhydrite, increase of bottom hole temperature over depth, formation losses, etc., the proposed HPWBF performed very well providing the following benefits:

- Provision of required wellbore stabilization that contributed to avoid drilling sidetracks. The contingency plan to use NADF in substitution of HPWBF was not necessary.
- Provision of clay inhibition and clay dispersion minimization. During drilling through the shales, cuttings recorded on shakers resulted dry without any indication of hydration. Furthermore, drill solids concentration in the mud resulted low.
- Rheology stability even when MW was increased to 17.9 ppg indicating an excellent tolerance to high solids content.
- Calcium stability when exposed to anhydrite contaminations
- Ensuring adequate fluid's lubricity thank to the use of a calcium resistant high-performance lubricant.
- Thermal stability. Whenever circulation restarted after tripping, barite sag was never recorded without any sign of polymers degradation.

In addition to the overall HPWBF performances outlined above, a customized sweeping plan was deployed by pumping engineered WSM pills and high vis pills, that contributed to improve hole stability by lowering pore pressure transmission and provide optimum hole cleaning.

Anti-sticking pills were also pumped at regular base to prevent bit balling.

Furthermore, an engineered oil-free environmentally friendly spotting fluid, ensured release the drill string in a very short time when differential stuck pipe incidents occurred.

Additionally, a customized loss remediation strategy of varying carbonatic products and concentrations significantly improved the ability to cure formation losses across the reservoir section.

Geological analysis

Seven samples (cuttings/cavings), taken from 14 ½" x 16" and 12 ¼" x 13 ½" intervals of the subject well in increasing depths, were analyzed by XRD and CEC. The purpose of this study was to map the lithology of the field and determine the lithology and nature of the clay for a better drilling fluid optimization while drilling and for future projects.

The laboratory's results (Figure 19) showed that the main components in all samples were Quartz (22.5%- 29.7%), calcium carbonate species (calcite and dolomite 14.4%-33.6%), Clay (11.3%-21.5%), Feldspar (10.0%-25.0%) followed my minor components like Antigorite (0.2%-11.8%), Muscovite (1.5%-16.4%) and other minerals (0.8%-9.1%).

The max clay content was recorded in the interval from 2102 m to 3565 m (increasing from 17.7% at 2102 m to 21.5% at 3565 m).

In the deeper interval from 3723 m to 4700 m a reduction of clay content with an average of 11.8% was seen.

The clay analyses (Figure 20) indicated that on all samples analyzed, Illite/mica mix layer was the main component (illite is partial swelling clay, dispersible) while Kaolinite (non-swelling, some dispersion) was the minor component. In general, both Smectite (swelling) and chlorite (non-swelling) would slightly increase by the depth.

The reactivity, measured by CEC was medium with a max value of 22,8 meq/100 gr at 2730 m and minimum value of 16.8 meq/100 gr at 4470 m.

Figure 21 shows a linear correlation of Total clay content %w and CEC. Clay content and its reactivity slightly reduces with the depth.

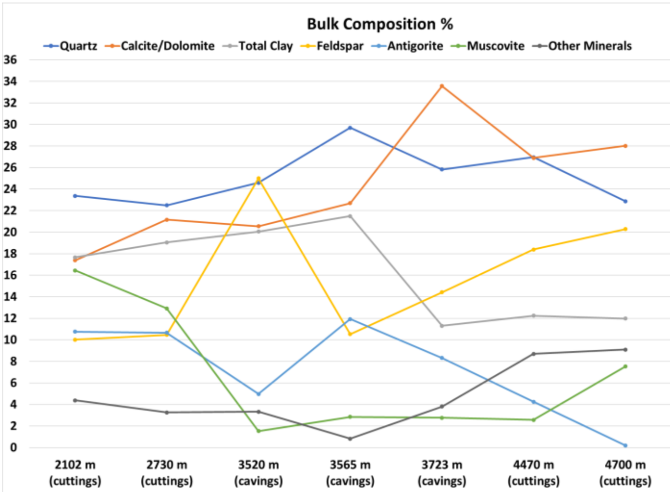


Figure 19: Bulk composition in the interval 2102 m - 4700 m

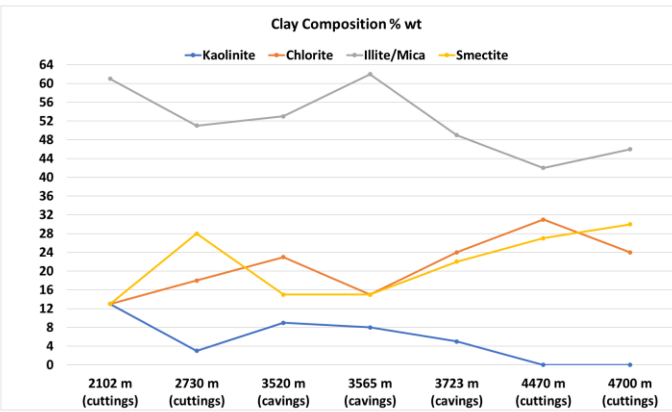


Figure 20: Clay composition in the interval 2102 m - 4700 m

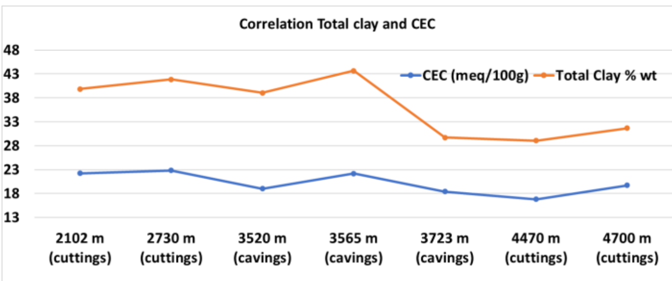


Figure 21: Correlation of Clay/CEC in the interval 2102 m - 4700 m

Shale and Geological Analysis

During execution of the project, inhibition properties of the HPWBF in use were evaluated by performing the following testing:

- CST
- Shale Recovery (or Shale Erosion Test)
- Swelling
- Accretion

The inhibition tests were carried out on cuttings/cavings samples received while drilling the 14 ½" x 16" and 12 ¼" x 13 ½" sections using either a fluid sample received from rig site and a fluid mixed at the lab with same composition in use at the field. Some of the inhibition testing were not carried out at specific depths due to the lack of sufficient quantity of rock samples. A recap of the inhibition testing is depicted on Table 9 below.

Table 9: Inhibition testing results

Sample Depth (m)	2102	2527	2583	2635	2730	3520	3565	3723	4470	4700
Section	14 ½" x 16"					12 ¼" x 13 ½"				
Shape	Cuttings					Cavings			Cuttings	
%Total Clay	17,7	-	-	-	19,0	20,1	21,5	11,3	12,2	12,0
%Kaolinite	13,0	-	-	-	3,0	9,0	8,0	5,0	0,0	0,0
%Chlorite	13,0	-	-	-	18,0	23,0	15,0	24,0	31,0	24,0
%Illite/Mica	61,0	-	-	-	51,0	53,0	62,0	49,0	42,0	46,0
%Smectite	13,0	-	-	-	28,0	15,0	15,0	22,0	27,0	30,0
CEC (meq/100g)	22,2	-	-	-	22,8	19,0	22,2	18,4	16,8	19,7
%Shale recovery	-	*97,5			-	-	98,9	-	99,0	-
%Swelling	-	*4,1			-	-	8,7	-	10,1	-
%Accretion	-	*1,2			-	-	8,1	-	5,2	-
CST 7%KCl Sol (30s)	-	-	-	-	-	24,6	52	39,1	45,3	-
CST 7%KCl Sol (60s)	-	-	-	-	-	35,1	53,7	41,7	41,1	-
CST 7%KCl Sol (120s)	-	-	-	-	-	47,2	61	43,4	49,4	-
CST 7%KCl Sol (180s)	-	-	-	-	-	48,9	70,4	39,8	34,2	-

*Shale recovery, swelling and accretion were performed on the blend of the three cuttings samples due to insufficient quantity received at each depth

Shale recovery, that measures the cuttings dispersion tendency, was very high ranging from 97.5% found in the interval 2527 m - 2635 m to a max value of around 99% at 3565 m and 4470 m. These results confirmed the excellent inhibition properties of the HPWBF to minimize the mud's cuttings erosion tendency.

CST results in the interval 3520-4470 m indicated a very low dispersion rate of all samples in 7% KCl Solution (average concentration utilized at the field). Indicatively, a highly dispersible rock sample will give high CST value (> 400 s) after stirring time of 30 s and will not increase further by increasing agitation time. On the other hand, a low reactive rock sample, will be characterized by low value of CST increasing by mixing time. CST were not carried out in the interval 2527 m - 2635 m due to the insufficient quantity of material available.

Swelling, that measures the water absorption tendency of clays, was found to be low with a trend to increase over the depth from a min value of 4.1% in the interval 2527 m - 2635 m to a max value of 10.1% at 4470 m.

Percentage of accretion, that measures the tendency of clays to adhere to bit and tubulars, would increase over the depth from 1,2% in the interval 2527 m - 2635 m to 8,1% at 3565 m and 5,2% at 4470 m.

Increase of swelling and accretion with the depth could be explained by increase of Smectite in the clay.

The above tests would confirm the good inhibition properties of the HPWBF that highly contributed to stabilize the formation.

Additional Lab Testing

Laboratory performed additional testing on HPWBF samples received from rig site to evaluate its tolerance to calcium and other properties like lubricity and corrosion.

Table 10 indicated that after Gypsum contamination, although an increase of rheology occurred, mud did not exhibit any sigh of flocculation with API filtrate still very low. Furthermore, no cheesing/greasing was observed. This indicated good tolerance of the high-performance lubricant utilized in the mud to calcium contamination.

Lubricity coefficient was low and remained stable even when mud weight was increased from 14.4 to 15.3 ppg (Table 11).

Corrosion rate was under the acceptable range and lowered with addition of an oxygen scavenger and corrosion inhibitor (Table12 and Figure 22).

Table 10: Contamination test with Gypsum

Properties	Unit	Sample A	Sample A + 5.6 ppb Gypsum	AHR
600 rpm @ 120 °F	Dial reading	86	115	130
300 rpm @ 120 °F	Dial reading	54	73	84
200 rpm @ 120 °F	Dial reading	42	57	65
100 rpm @ 120 °F	Dial reading	28	38	44
6 rpm @ 120 °F	Dial reading	7	9	10
3 rpm @ 120 °F	Dial reading	5	7	8
PV @ 120 °F	cP	32	42	46
YP @ 120 °F	lb/100ft2	22	31	38
Gel (10 sec) @ 120 °F	lb/100ft2	6	7	9
Gel (10 min) @ 120 °F	lb/100ft2	9	14	15
API Filtrate	ml	2.5	-	2.8
pH	-	9.5	8.0	9
pH after adjustment	-		10	-

Table 11: Lubricity coefficient

Properties	Unit	Sample B	Sample C
Mud Weight	ppg	14.4	15.4
600 rpm@ 120 °F	Dial reading	112	131
300 rpm@ 120 °F	Dial reading	74	87
200 rpm @ 120 °F	Dial reading	57	68
100 rpm @ 120 °F	Dial reading	39	46
6 rpm @ 120 °F	Dial reading	10	13
3 rpm @ 120 °F	Dial reading	8	10
PV@ 120 °F	cP	38	44
YP @ 120 °F	lb/100ft2	36	43
Gel strength (10s) @ 120 °F	lb/100ft2	8	12
Gel strength (10m) @ 120 °F	lb/100ft2	25	32
Lubricity coefficient	-	0.126	0.125

Table 12: Corrosion rate

Properties	Unit	Sample A	Sample B + 0.7 ppb Oxygen Scavenger	Sample B+ 0.7 ppb Oxygen Scavenger + 1 ppb Corrosion Inhibitor
Corrosion rate	mpy	12.1	10.9	9.32

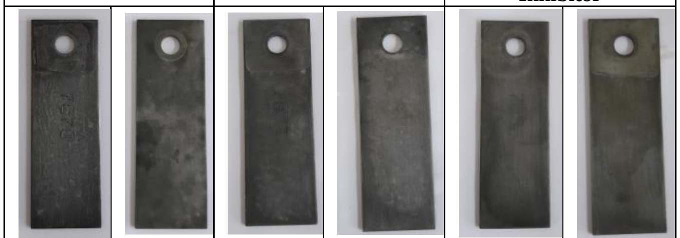
Sample A		Sample B + 0.7 ppb Oxygen Scavenger		Sample B+ 0.7 ppb Oxygen Scavenger + 1 ppb Corrosion Inhibitor	
					
Front Side	Back side	Front Side	Back side	Front Side	Back side

Figure 22: Coupon after corrosion test

Conclusion

This paper summarizes the successful application of a HPWBF in a challenging deep offshore well in southern Europe drilled in an emerging area characterized by severe borehole instability exacerbated by high pressure gradient, anhydrite contamination and high temperature environment.

The use of HPWBF helped to achieve operational objectives in a safe manner ensuring operator to reach the well TD and acquire all required data for well evaluation without the utilization of NADF that was selected in the planning phase as contingency fluid. This consistently saved operator time and money combined with reduced environmental impact.

Inhibition testing on well's cuttings, showed good performance of this fluid in terms of improved swelling inhibition and minimum shale dispersion.

Utilization of engineered WSM, Bridging, High-Vis, and Anti-Sticking fluids, pumped on a regular base, significantly contributed to alleviate hole problems.

Furthermore, the multiple differential stuck pipe events, due to the ultra-mud weight needed to control hole pressures, were always solved by spotting a customized environmentally friendly spotting fluid.

The fluid team implemented a customized lost circulation strategy that significantly reduced formation losses while drilling the reservoir section.

Fully dedicated LMP and Bulk Facility were placed at the supply base and deployed to provide onshore support throughout the entire project.

All logistical objectives were achieved on time in a safe and environmentally compliant manner.

Products and assets were quickly mobilized to the warehouse and then to the rig platform without any delays on drilling operations even when severe losses occurred.

ACKNOWLEDGEMENTS

The authors wish to thank Newpark for permission to present this paper. Special thanks to the Newpark fluid coordinators and field personnel for their excellent performance and support.

Nomenclature

API	*American Petroleum Institute*
bbl	*Volume, Barrels*
BHA	*Bottom hole assembly*
BHCT	*Bottom Hole Circulating Temperature*
BHST	*Bottom Hole Static Temperature*
CEC	*Cationic Exchange Capacity*
CP	*Conductor Pipe*
cP	*Viscosity, Centipoise*
CSG	*Casing*
CST	*Capillary suction Time*
ECD	*Equivalent Circulation Density*
ESD	*Equivalent Static Density*
F	*Temperature, Fahrenheit*
HPWBF	*High Performance Water Base Fluid*
HTHP	*High Temperature/High Pressure*
KCl	*Potassium Chloride*
$lb/100\ ft^2$	*Pound per hundred square feet*
LCM	*Lost Circulation Material*
LMP	*Liquid Mud Plant*
LNR	*Liner*
m	*Length, Meter*
m^2	*Surface, Square meter*
m^3	*Volume, Cubic Metric*
MBT	*Methylene Blue Test*
ml	*Volume, Milliliter*
mpy	*Corrosion rate, Miles per year*
MD	*Measured Depth*
MW	*Mud Weigh*
NADF	*Non-Aqueous Drilling Fluid*
NPT	*Non-Productive Time*
OH	*Open Hole*
PAD	*Pumped and Dump*
PO	*Polymer*
POOH	*Pool out of Hole*
ppb	*Concentration, Pounds per barrel*
ppg	*Density, Pounds per gallon*
PVA	*Polyvinyl Alcohol*
RIH	*Run in Hole*
ROP	*Rate of Penetration*
rpm	*Revolutions per Minute*
SW	*Seawater*
TD	*Total Depth*
WSM	*Wellbore Strengthening Material*
XRD	*X-Ray Diffraction*

References

Eric Van Oort. 2003. “On the physical and chemical stability of shales.” Shell E&P Company, New Orleans, LA, USA

M.A. Mohiuddin, K. Khan, A. Abdulraheem, A. Al-Majed, M.R. Awal 2006 “Analysis of wellbore instability in vertical, directional, and horizontal wells using field data.” Center for Petroleum and Minerals, Research Institute, King Fahd University of Petroleum and Minerals, Saudi Arabia 18 April 2006.

Van Oort E., Pasturel C., Bryla J., Ditlevsen F. 2017. “Improved Wellbore stability in Tor-Ekofish Wells through shale-fluid compatibility optimization.” SPE/IADC Drilling Conference and Exhibition, The Hauge, The Netherlands, March 14-16, 2017.

Stowe C., Halliday W., Xiang T., Clapper D., Morton K., Hartman S. 2001. “Laboratory Pore Pressure Transmission Testing of Shale.” AADE National Drilling Conference, Houston, March 27-29, 2001.

Bussaglia L., Arpini F., De Ninno E. 2017. “High Performance Water Base Fluid Improves Wellbore Stability and lowers Torque.” OMC Conference, Ravenna Italy, March 29-31, 2017.

Kumar D., Ansari S., Wang S., YiMing J., Ahmed S., Povstyanova M., Tichelaar B. 2012. “Real-time Wellbore Stability Analysis: An Observation from Cavings at Shale Shakers.” AAGP International Conference and Exhibition, Singapore, September 16-19, 2012.

Skea C., Rezagholilou A., Behnoud Far P., Gholami R., Sarmadivleh M. 2018. “An approach for wellbore failure analysis using rock cavings and image processing.” Journal of Rock Mechanics and Geotechnical Engineering, July 4, 2018.

Isinak A., Smith V., D’Alessandro F., Dearing H. 2005. “Application of a Complex Polyol Drilling Fluid in Albania.” Case Study, 2005.

Bussaglia L., Di Marino R., Smith V. 2018. “First Deepwater Campaign, Offshore Romania: Infrastructure, Design and Execution to Deliver Drilling and Completion Fluids.” SPE Annual Technical Conference and Exhibition, Dallas, April 4-5 2018.