Drilling a Deep-Water Well in a Subsalt Structure in Mexico


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Summary

In the Gulf of Mexico, large oil and gas reservoirs are associated with sub-salt structures and are very attractive for potential hydrocarbon reservoirs. In 2009, Pemex pursued drilling a prospective location identified with 3D seismic located in a subsalt structure in the Tertiary formations. The Kabilil-1 well was located in 740 m water depth and the plan was to drill to the Lower Miocene and Upper Oligocene alluvial sediments. The well was drilled with the Ocean Voyager (3rd generation) in 94 days and reached a TD of 5350 m.

Although sub-salt drilling is a challenge in itself, it is not uncommon for operators in the deep-water Gulf of Mexico (GOM). The Pemex Kabilil-1 well was a deep-water subsalt first for Pemex in this challenging environment. The decision was taken to avoid the drilling risk through the salt and the trajectory was planned to go around the salt flank. This alternate strategy also posed challenges such as drilling through the sheared zone (rubble zone) that is commonly found underneath salt tongues or adjacent to salt diapirs where there is always a risk of getting stuck. In the well preparation phase, a finite-element numerical model was employed along with a 3D-MEM simulator (Stonefish and Visage) to predict the effects of the initial in-situ stresses and induced increases in stress as a result of the salt intrusion. The induced stresses increase near the salt intrusion and result in subsalt overpressure, pressure reversion formations, and wellbore stability problems. The pre-drill model was updated in real time using the Stonefish-RT geomechanics real time software that has the ability to assimilate logging-while-drilling sensor data (sonic, resistivity, density, porosity, seismic while drilling) to allow calibrating the pore pressure and breakdown pressure against pre-drill model. According to the pre-drill geological well prognosis, the salt proximity to the well was within 200m of the well trajectory, but reliable calibration was needed to verify top of salt and salt flank proximity in real time. In an effort to reduce the geological uncertainties, the SVWD-seismic (Seismic Vision While Drilling) while drilling was employed to look ahead of the bit to determine the salt distance to well in real time. This service was acquired for the first time in Mexico deep-water basins and was employed to mitigate the drilling risk associated with drilling near salt domes.
It was necessary to set the intermediate casing strings at the appropriate depth to improve the drilling performance of the subsequent well sections (maximize drilling window), segregate the overpressure intervals induced by the salt intrusion, and separate the incompatible formations divided by regional unconformities. During the drilling phase, drilling optimization service and real time geomechanics surveillance was performed using onsite drilling optimization engineers on the offshore rig along with geomechanics/geological support at the operator’s office. The operation also employed real time data transmission, advanced PDC drill bits, rotary steerable systems; logging-while-drilling, seismic while drilling service, APWD-annular pressure while drilling and hydraulic reamers for hole enlargement.

Introduction

In the Gulf of Mexico, successful deep-water exploration and development has been ongoing for almost 20 years, but the experience and knowledge lies predominantly with those involved in deep-water GOM USA, Brazil, and West Africa projects or commonly known as the Golden Triangle. PEMEX (Petróleos Mexicános) a National Company is embarking with a campaign to explore the high potential deep-water GOM Mexican waters to offset declining production and improve Mexican reserves. The exploratory wells drilled have faced many of the known deep-water problems and the learning curve has been steep and expensive. Leveraging deep-water knowledge and experience is vitally important in reducing technical and financial risk with these costly projects.

According to international classifications, a well is considered deep-water when the water depth is greater than 500m (1640 ft). In Mexico, these deepwater well types were commenced in 2006 and continue to be drilled in Mexican Gulf of México employing sixth generation semisubmersible rigs.

A risk assessment was performed with subsalt/through salt drilling scenarios. Multiple casing strings were implemented in the design to be able to isolate problematic areas and also manage the narrow mud weight drilling window between pore pressure and fracture pressure.

In summary, the Pemex Kabilil-1 well results demonstrated the ability to drill a challenging sub-salt well that faced many potential drilling problems. The application of new technologies, effective pre-drill modeling, and real time monitoring resulted in exceptional drilling performance.

Geological Setting and Structure

The Kabilil-1 well is located in the Mexican portion of GOM approximately 105.5 km north east of Coatzacoalcos, Veracruz and 253 Km northwest of Ciudad del Carmen, Campeche. The water depth is 739 m. (Figure 1). The key structural features in the well location are a salt dome with overhang feature that is covered by a large regional unconformity as shown in the geological section. The well was located in a structural trap on the east flank of a large anticline deformed by the effect of salt intrusion created during the salt tectonic activity in the Late Miocene and Lower Pliocene. The target reservoir consists of turbidites, commonly arranged in thickening-upward packages, and amalgamated turbidites in channels that commonly have an initial lateral accretion phase with interbedded sandstone and mudstone deposits, and a subsequent vertical aggradation phase.
Geomechanics Modeling

The salt diapir and the mechanics of the deformation of sediments adjacent to salt are complex. Models created in the pre-drilling design were applied to assist with the well planning and to ascertain the best strategy to reach the subsalt target. The initial 1D Mechanical Earth Model (MEM), Plumb, R et al (2000) was determined insufficient to model the predicted geology, the ability to examine the influence of the salt intrusion, and ability to characterize the induced pressure and earth stresses. The better approach was to create a 3D MEM with a 3D finite element geomechanical simulator for a stress-strain analysis on a 5 x 5 km2 cube including sedimentary layers and salt bodies (Figure 2). The geomechanical simulations were performed using the 3D numerical/geomechanical software and the finite element models were meshed directly from geologic structure maps in 3D geological software. A complete description of the geomechanical modeling developed for Kabilil-1 well was published by Aguilera et al, 2011. The 3D MEM approach consisted of using multiple 1D MEM’s from offset wells, property
propagations using 3D seismic data (velocities and structural), 3D finite element MEM modeling, and wellbore stability analysis along the proposed well path that considered the stresses and pore pressures obtained from the 3D MEM. (Figure 4).

According to Aguilera et al (2011), the stress-strain analysis revealed a significant variation in stress orientation and stress magnitude around the salt bodies. Results indicated that vertical and horizontal stresses were not the principal stresses initially assumed from the 1D modeling. A stress profile created along the planned well trajectory shows a clear increase in horizontal compressive stresses as a result of salt perturbations. It also shows a distinct increase in shear stresses at 1500 to 2100m (TVD) where maximum shear was noted. This depth range coincides with a decrease of vertical effective stress and was interpreted as a high deformation zone with a fault at 2100m. The stable mud-weight window from the 3D analysis expressed a distinctly different behavior compared to the 1D model. The 3D model results displayed a higher breakout pressure prediction where the proposed trajectory was close to the salt bodies signifying that the salt body influenced stress in the surrounding sediments more than 1.5 km from the salt domes.

The mud-weight window obtained from the 3D analysis and sensitivity analysis was prepared considering the stresses that included the in-situ and those generated by the salt intrusion resulting in a defined drilling optimization plan with adequate mud weights for safe drilling. (Figure 3 and Figure 5).
Figure 3. In this graphic, the strong variation of the stress direction can be appreciated from the effect of the surrounding salt bodies. This variation makes it challenging to model the drilling operative mud window considering the additional effects of changing well trajectory (azimuth and inclination).

Figure 4. Geomechanics Modeling work flow. A. 1D Wellbore Stability analysis performed over three offset wells. B. Modeling of the Pore Pressure in a 3D space. C. 3D finite element modelling. D. Wellbore stability analysis along the proposed well trajectory.
Drilling Optimization & Real Time Surveillance

A fit-for-purpose drilling optimization service was introduced and executed for the drilling of the first deepwater sub-salt well in Mexico, Kabilil-1. The drilling optimization and real time geomechanics services comprised of work flows implemented during the drilling of the well.

The real-time drilling optimization scheme is founded in a risk management workflow that consists of creating models for geomechanics, geology, geophysics and drilling parameters (hydraulics and torque & drag) and calibration of the same models by using drilling events gathered from offset well analysis (Pre-Drill Phase) and on real time during the well execution (Execution Phase). Real time calibration of these models and controlled adjustments to the drilling program during well execution is one of the most critical tasks to ensure positive results with the drilling optimization and real time geomechanics services scheme, but this requires an attitude and alignment from the team for the shared objective of continually improving the drilling practices when drilling the conventional well. A key component is establishing a clear and agreed communication protocol between the multi-disciplinary operator and service company team members that include the operating and office based project organization. The severity and potential risk of drilling events are classified and rated by importance with a color coded system. Examples include low ROP, hole cavings, well influxes, unexpected lithology changes, mud losses, BHA vibrations, etc. These events are communicated from the Drilling Optimization engineers and Real-Time Geomechanics to specific identified team members involved with the decisions based on order of importance and priority. (Figure 6a). This ensures
that decisions are taken by the right technical expertise/hierarchy and the adjustments to the drilling program are properly communicated to the rig.

For the Kabilil-1 well, the communication protocol included team members of different disciplines within the operator and service company organization (drilling engineering, geosciences, drilling operations and rig crew). This protocol resulted in additional benefit by alleviating the additional complexity that team members were not co-located and in different cities. Good communication and decision making required a structured methodology.

**Pre-drill planning phase:** The NDS™ process applied for the well Kabilil-1 supported PEMEX multi-disciplinary workflows known as “VCD-SE” (Visualization Conceptualization Development – commonly known as FEL Front End Loading) to identify the most critical risks and important considerations during the Pre-drill Planning Phase by building 3D and 1D MEM with input data from the offset wells Lakach-1, Lakach-2DL, Holok-1 and Labay-1.

After the completion and validation of the MEM, it was determined that drilling close to the salt body resulted in higher than expected collapse pressures at the end of the riser-less section with potential considerable risks to the well construction. Additionally, the model highlighted several potential drilling hazards that required mitigation:

1. Potential well collapse in the 20” riser-less section required optimizing the drilling fluid. If only sea water was used for drilling fluid, there was potential well collapse in the 20” riser-less section and it impeded the ability to set the casing deeper thus achieving a higher fracture gradient for the deeper hole sections.
2. The shear stresses from the salt body influence resulted in narrower mud weight windows for the 20” and 16” open hole sections.
3. Potential for well losses due to natural fractured formations were also expected in this interval due to the presence of a reverse fault identified in the 3D geomechanical model.
4. The potential of inadvertently drilling into the salt flank would add complexity to the drilling of the well. It was recognized that the surface seismic model contained uncertainty in the precise location of the salt flank and the planned well trajectory required precise navigation around the salt body.

Preventative measures were incorporated into the pre-drill well design stage to mitigate the most important hazards. They include:

1. The application of the “Pump and Dump” technique in the riser-less section using a weighted drilling fluid that would minimize the risk of well collapse and also achieve a deeper setting depth for the 20” casing. This method utilizes a combination of sea water and weighted bentonitic mud as drilling fluid with returns to the sea floor for the entire section. The method uses mixing devices where the fluid density can be adjusted “on the fly” and results in a homogenous blend with less rig time. The “Pump and Dump” method has been performed successfully in many deep water wells, but a principal challenge is the logistics because of the requirement for a large amount of mud storage capacity that is either provided from larger floater rigs or supplemented with supply boat vessels. (P.R Roller, 2001).
2. Steps to optimize well geometry design by using unconventional intermediate casing OD’s (16” and 13 5/8”) to allow two additional contingency casing strings (11 ¾” and 5 ½”) for the interval with the narrower drilling windows (Figure 6b). A detailed decision tree chart
was prepared to define whether or not to use the contingency casing strings by analyzing all possible scenarios for wellbore instability at critical depths and formation tops. This well geometry required special under-reaming BHA designs to perform simultaneous hole opening without the need for extra pilot drilling dedicated runs. The stabilization of the BHA was optimized using drilling simulators to minimize drilling vibrations that might adversely affect the LWD tools measurements that are required for petro-physical evaluation and seismic calibration.

3. It was necessary to reduce the depth uncertainties and position the well trajectory around the salt flank and prevent inadvertent drilling into the salt body. The well depth to seismic velocity calibration was performed in real time using a seismic while drilling technology for a “bit on seismic” and “look-head check shot/VSP” that allowed real time calibration of the seismic model. The look-ahead capabilities would allow pertinent and early adjustments to the well trajectory to avoid drilling into the salt dome and compromising the final well target. The initial original well trajectory was designed to intersect the zone of interest (pay zone) under the salt, but did not account for the uncertainty of the salt flank extension.

4. Minimize mud losses due to drilling induced fractures or during the well cementing operations. It was important to maintain a constant ECD (Equivalent Circulating Density) when drilling through the drilling zones with narrow mud weight widows. The solution was to use a flat rheology synthetic oil based mud system to avoid any pressure surges or spikes that would lead to inadvertent fracturing and mud losses. As an additional preventive measure, lost circulation material was added into the mud system according to pre-planned decision tree matrix that specified the Losses treatment-LCM type and volume under different fluid loss scenarios. For the cementing operations, a foam cement system was chosen as the best options to minimize the ECD’s and optimize the cement placement with the objective of reaching full returns during the cementing operations.

5. Formalizing a well communicated plan would be required to define the potential specific drilling hazards, properly detect upcoming hazards, and identify/implement the mitigation measures. For this purpose, a DrillMap was created and agreed with each of the drilling project members where the plan was graphically displayed by hole section and agreed course of action was detailed for each of the well risks.

**Execution-Drilling Phase:**

Drilling optimization engineers (offshore) and the Geomechanics engineer (onshore) worked together to update the prediction models, they provided support for the real time drilling geomechanics, (RTDG) and ensured that the measures detailed in the DrillMAP were followed. At the offshore rig site, the responsibility of the drilling optimization engineer was to QC (quality control) and manages the full data flow for the NDS™ process. Various drilling models (mud hydraulics, torque & drag, and pore pressure) were updated and calibrated using real-time measurements provided by both surface sensors and down hole tools. All of the information was integrated using drilling optimization software that facilitated the data gathering, visualization, and measurement correlation to allow for quick analysis for optimized drilling performance.
Drilling Overview

Riser-Less section - Jetting 36” and 20” Casing

The decision to jet the 36” conductor casing was based on the shallow hazard study that showed soft formation 100 m below the sea bed. The “drilling ahead tool” (DAT) was placed in the 28” BHA inside the conductor casing to allow drilling ahead the next section without the need to pull out of the hole to change the BHA.

The drilling plan accounted for industry recommended practices to minimize conductor deviations from vertical and ensuring that the casing was jetted to program depth. (T.J. Akers, 2008). The following summary lists some of these:

1. 36in X-56 552.7 lb/ft conductor was used to provide enough bending resistance to support the BOP stack
2. The BHA weight below the drilling ahead tool (DAT) was kept below 2/3 the weight of the conductor to keep neutral point below the running tool.
3. Use of a mud motor to help removal of soils with bit rotation, ensure verticality control for the following section and improve ROP with higher mechanical power.
4. Bit space-out of 6” below the conductor shoe
5. Reciprocation of every joint.
6. The casing was allowed 3 hours of soaking time prior to releasing the DAT tool to drill ahead.
7. Seawater was used to drill this section with bentonite mud pills of 1.06g/cc.

There were no associated problems and the 30” conductor was set to the planned depth with a maximum deviation of 1deg of inclination.
The 28” hole was drilled with a conventional steerable motor assembly with a BHA configuration listed in the Table 1. In this section the “pump and dump” technique was used to prevent wellbore stability problems due to high collapse gradient. For this operation treated sea water was used with the addition of sodium carbonate to improve the bentonite performance. Weighted bentonitic mud (1.7g/cc) was prepared and stored beforehand to avoid any operation interruptions. The section was drilled to the total programmed depth without any sign of borehole instability or hole cleaning problems. The success of this operation credits the mud rheology employed and the practice of pumping viscous pills of 15m$^3$ every stand with high flow rates of (950 gpm) while drilling this section. The heavy pill of 1.38 g/cc was left in the open hole and the BHA was tripped out successfully.

17 ½” x 20” hole section – 16” Casing
A rotary steerable BHA with a hydraulic hole opener was used to drill the 17 ½” x 20” section. Prior to reaching the expected shoe depth, the seawater was substituted with 1.21 g/cc spud mud to drill this interval. A leak off test (LOT) was conducted using the Annular Pressure While Drilling tool (APWD) to accurately measure downhole pressures and for accurate LOT determination. The APWD tool measurement and extrapolated interpretation resulted in an equivalent mud weight of EMW of 1.36 gr/cm$^3$ and breakdown EMW of 1.38 gr/cm$^3$. An 80 to 20 oil to water ratio was used to approximate the well condition due to the influx of water while drilling necessitating the increasing of the mud weight to 1.33 g/cc. In this section, the drilling optimization engineers closely monitored the ECD, the drilling parameters, and ensured that the hydraulics were adequate for good hole cleaning. The mud weight required to prevent water influxes was approximating the value of the leak off pressure test and any pressure surges needed to be avoided from fracturing the formation. The flat rheology mud was critical during this section with a maximum ECD of 1.36 g/cc, just 3 points above the mud weight.

The total depth of the section was reached in 36 hours. Some tight spots were encountered that were reamed out during the short trips. After the acquisition of wireline logs, a wiper trip was made with a new BHA configuration for enlarging the rat hole from 17 ½” to 20”. Due to adverse weather conditions, the drilling operations were suspended leaving the drilled hole section in a static condition for several days. When operations resumed, another wiper trip was performed and the 16” casing was subsequently run and cemented to a planned depth with partial losses of 8.5 m$^3$.

14 ½” x 17 ½” hole section – 13 5/8” Casing
A rotary steerable BHA with a hydraulic hole opener was used to drill the 14 ½” x 17 ½” section. For the LOT, an additional 10 m of new formation was drilled. The initial slope change and fracture initiation pressures during the LOT were not observed. The fracture propagation and the initial shut-in pressure were also not observed. The maximum EMW before shutting down the pumps was estimated at 1.64 g/cc and 1.56 g/cc for the minimum stress Sh.

Drilling resumed and the O/W ratio continued to be monitored, influx of water was determined and corresponding contingency measures of increasing the mud weight resulted with the mud weight gradually increased from 1.37 g/cc to the final mud weight of 1.44 g/cm$^3$. While drilling this section, the downhole MWD (measurement while drilling) tool displayed indications of “Stick and Slip” and high torque conditions were also seen on the surface indicators. It was
determined that these were originating from the adverse weather conditions that included large wave heights. This required the rig to activate its heave compensator to minimize the vertical movement due to high sea state which resolved the problems.

This section also encountered a couple of conditions requiring well control actions. One occurred at the target depth while circulating bottoms up that resulted in a 3.9 bbl mud pit gain and controlled mud weight of 1.49 g/cc. Another event occurred during a short trip to the shoe with a pit gain of 1.28 bbl and 6300 ppm of gas, controlled with mud of 1.59g/cc. During the tripping of the 13 5/8in casing, 109 m³ of fluid losses were recorded.

12 ¼” x 14 ¾” - 9 5/8” Casing

A rotary steerable BHA with a hydraulic hole opener was used to drill the 12 ¼” x 14 ¾” section. The LOT was performed with a 1.59 g/cc mud weight and pressures were recorded with a downhole APWD tool with a resulting EMW leak off test of 1.74 g/cc. The wellbore was vertically drilled using the rotary steerable tool from the 13 5/8” casing shoe to kick off point located 67m below the shoe. The well was deviated to the programmed azimuth and inclination achieving the required DLS (dog leg severity) of 3.03deg/30m. The remaining long tangent section was drilled to the total depth with a mud weight of 1.67 g/cc without experiencing any hole stability issues. The mud logging information with continuous mud property tracking identified sandy intervals filled with water that affected the oil to water ratio (67/33) that required raising the mud weight to control the water influx. An additional dedicated trip was implemented for the hole enlargement of the pilot hole with a 14 ¾” Rhino reamer .The 9 5/8” casing running operation experienced partial mud losses of 5 m³ and additional 13 m³ of partial losses while pumping/cementing.

8 ½” – Open Hole section

The directional drilling of the 8 ½” hole was conducted with a 1.69 g/cc mud weight. Due to loss circulation problems in the previous sections from induced hydraulic fracturing, an extended leak off test – ELOT was conducted 13m below the 9 5/8” casing. The large volume of fluid pumped and shut in analysis was used to determine the fracture closure pressure. The results included: closure pressure EMW of 1.86g/cm³, total volume pumped of 10.7 bbls with 2 bbls injected to the formation. (See Figure 7)

Drilling continued increasing mud weight to 1.73 g/cc to account for small changes in the oil to water ratio. Drilling continued through the clay stone interbedded with limestone while maintaining the hole inclination at 25.4°. The calcium carbonate addition was increased to 60 kg/m³ in the mud system to prevent mud losses. Drilling continued in the Lower Eocene formation and the mud weight was increased to 1.77g/cc before tripping out of the hole. The well was suspended and cements plugs to abandon were placed.
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<th>OUT (m)</th>
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<td>1533.5</td>
<td>Tricone Bit 28” + Motor F. 9 1/2” (C/st 27 3/4”, BH=0) + Valve C.P. 9 1/2” + Stab 9 1/2” x 28” + ARC-9” (LWD) + TELESCOPE 9” (MWD) + SonicVISION 9” (LWD) + Stab 9 1/2” x 28” + DC Monel 9 1/2” + 2 DC 9 1/2” + combination 7 5/8” Reg-P x 6 5/8” Reg-C + 2DC 8” + 2 Drill Ahead Tool.</td>
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<td>PDC Bit 17 1/2” + Power Drive 17 1/2” + Comb. 7 5/8” Reg (P) x 6 5/8” Reg (C) + stab 17 3/8” + LWD/APWD (ARC) 8” + TeleScope (MWD) 8” + sonicVISION 8” + seismicVISION 8” + Stab 8 x 17 1/2” + 1 DC 8” + Stab 8 x 17 1/2” + Hole opener Rhino Reamer 20” c/VCP + 1 DC 8” + Stab 8 x 17 1/2” + 4 DC 8” (4 joints) + Jar 8” + 1 DC 8” + Combination 6 5/8” Reg P x 5” XH C + 3 DC 6 1/2” + 3 Ling. TP HW 5” + 60 DP 5” S-135, 25.6 lb/ft</td>
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<td>PDC Bit 14 1/2” + Power Drive 14 1/2” + Stab 14 3/8” + ARC-8 (LWD / APWD) + TeleScope 8” (MWD) + SonicVISION 8” + SeismicVISION 8” + stab 14 1/2” + 1 D.C. Monel 8” + stab 14 1/2” + Hole opener RhinoReamer 17 1/2” c/VCP, (Tob 2x8) + 1 Drill Collar 8” + stab 8” x 14 1/2” + 2 Drill Collars 8” + Jar 8” + 1 Drill Collar 8” + Comb. 6 5/8” Reg P x 5” XH C + 3 Drill Collars 6 1/2” + 9 HWDP 5”</td>
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Table 1. BHA designs used in Kabilil-1

Figure 7. a) Standard LOT 13 5/8” casing shoe b) Extended LOT 9 5/8” casing shoe. Both tests were recorded with APWD. With this deep-water operation, the ELOT provided more accurate fracture pressure detection, thereby mitigating loss circulation problems.
Logging While Drilling

Seismic Vision While Drilling (SVWD) - Real-time VSP

In an effort to mitigate some of the challenges and uncertainties identified in the pre-drill planning of this sub-salt well, the seismic while drilling service was implemented to acquire depth-velocity information in real time. A real time look-ahead-of-bit check shot and VSP was acquired in the interval between 1500 m to 2200 m, (16” casing) and a salt proximity survey was conducted in the 13 5/8” casing section. The results obtained in the feasibility study confirmed that seismic while drilling can be a valuable tool for resolving drilling uncertainties. Different source positions were tested with several azimuths to identify the best position in which to confine the ray path to a 2D plane (to constrain the inversion) to guarantee that the energy will transmit through the salt and arrive at the sensors. Based on the results obtained through this exercise, it was determined that the optimal source was at 2700 m with an azimuth of 270 degrees (Figure 8a).

Figure 8. a) Salt proximity results (red dots) vs. model interpretation. Salt flank from interpretation vs. salt proximity. b) Interpreted salt was moved to adjust with salt proximity results. The table shows the distances between salt flank and well position for each recorded station. c) Surface seismic section showing the match with the real-time VSP and the drill bit position. d) Defining the fault position for setting the 16-in. casing before drilling the sediments with upward dips.

Before recommending the seismic-while-drilling technology to resolve the uncertainties of drilling this complex well, it was necessary to perform a feasibility study. This study consisted of simulated data acquisition with the information available and building a 3D model with geological information such as: interpreted horizons, velocity from surface seismic, density values, and the well deviation. The study was performed for two different applications: 1) salt
detection below the drill bit and 2) determine salt proximity to the well trajectory. Full technical descriptions of these models can be found in Sanchez, A et al. (2010).

**Check shot and VSP Look ahead of the Bit: 16” section:** The proposed seismic-while-drilling technology was implemented for drilling the interval between 1500 m to 2200 m that corresponds to the 16” casing section. Real-time checks shot analysis (time-to-depth relationships) were conducted to update the drill bit position on the seismic map. Transmitting the first five levels in real time made it possible to initiate the VSP processing and look ahead to obtain a corridor stack below the drill bit. The VSP data below the drill bit showed homogenous reflections and not the strong amplitude expected for salt presence, identifying a sequence of clastic sediments (not very strong amplitude changes) instead the salt body. The drilling continued and the next challenge was to set the 16” casing at the right position just below the expected fault plane. The real-time check shot made it possible to accurately map the drill bit position on the seismic section and with the measured velocities it was possible to estimate the distance from the current drill bit position to the fault plane (Figure 8c). When the drilling resumed, the fault zone was estimated to be located at 2080 m and the sequence of sediments dipping upward was estimated to be at 2140 m. This information was shared with the drilling engineers and was used to decide when to stop drilling for the 16” casing and to avoid encountering drilling problems crossing the mapped fault plane on the seismic section (Figure 8d). The mud weight was another consideration because it had reached its maximum allowable weight and did not leave any room for increasing mud weight contingency if the formations below the faults were of subsequent higher or abnormal pressure.

**Salt proximity Survey - 13 5/8” section:** The suggested acquisition interval for the entire section was between 2200 m and 3400 m. A total of 18 levels/shots between 2175 m to 2658 m were acquired. To perform the inversion and compute the salt flank location, the 3D velocity model was constrained with the new information available. The salt velocity was assumed to be 4500 m/s from previous measurements of salt bodies; the water velocity used of 1500 m/s; and the velocity for the sediments above the salt dome were determined from the check shot survey acquired in the previous section using the seismic-while-drilling tool. The results obtained showed that the well was closer than expected to the salt dome with an approximate minimum distance of 200 m.(Figure 8b)

**Real-Time Logging While Drilling**

Logging While Drilling (LWD) tools were selected for initial formation evaluation and real-time pore pressure prediction using LWD resistivity and sonic data. Sonic was added to the logging suite to measure the formation velocity for seismic correlation with the seismic model.

**Real-Time Petrophysical Modeling.** In order to provide optimal decision making in real time, a formation evaluation logging suite was implemented in the 9 5/8” and 8 ½” open hole sections. Petrophysical information provided by the LWD tools was the basis for decisions on whether further data acquisition was required for each target zone. The coring schedule was amended when the zone was determined non-feasible. The azimuthal density neutron tool (ADN) and the EcoScope tool were included in the BHA3 and BHA5 (Figure 9) to acquire resistivity, porosity, lithology petrophysical information and for calibration of the geomechanics model. The density image was obtained from the measurements and the detailed images identified sand/shale
sequences, heterogeneous formations, structural dips and formation washouts. The ultrasonic and bulk density measurements were used to determine the hole diameters.

Figure 9. Example of the BHA3 and BH5 designed to obtain a complete suite of LWD measurements useful to provide formation evaluation and real-time geomechanics surveillance.

**Real Time Sonic Modeling.** Compressional transit time derived from LWD sonic was used to calculate the pore pressure profile based on the sonic log using the Eaton and Bower’s methods. Rock density information that was derived from ADN tool and the EcoScope®. The shear transit time was obtained from wireline dipolar sonic tool logs and empirical relationships were created for the well location in the pre-drill model. Four sources of sonic data were available in the pre-drill and real time phase, (Figure 10). The interval seismic velocity extracted from the pre stack velocity model, the interval velocity derived from the seismic while drilling tool, the LWD sonic velocity, and the wireline sonic velocity acquired by the Dipolar Sonic tool. This information and the LOT/ELOT pressure tests performed in the well allowed the geomechanics engineers to calibrate the MEM and calculate a complete well bore stability model that included a reliable collapse pressure (breakout). This was a good complement to the 3D modeling work that was performed in the pre-drill planning stage.
Figure 10.  a) Four distinct sources of interval/acoustic velocity were acquired in the pre-drill phase and real-time. b) Pore pressure profile calculated in the pre drill model (black curve) vs the final pore pressure (blue curve) estimated in real-time. Notice some discrepancies that were not reproduced in the initial model.

Conclusions

In summary, the Pemex Kabilil-1 well results demonstrated the ability to drill a challenging sub-salt well that faced many potential drilling problems. The application of new technologies, effective pre-drill modeling, workflows, and real time monitoring resulted in exceptional drilling performance. The lessons learned and the new team work achieved with this first subsalt Mexican well have improved working performance between the operator, rig contractor and the service companies. PEMEX has drilled 18 wells in deepwater and 4 wells in ultra deepwater where water depths are approaching 3000 m.

References

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