NEW TECHNOLOGICAL DEVELOPMENTS AND METHODS FOR IMPROVING WELL PLACEMENT IN THE VINCENT FIELD, AUSTRALIA

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ABSTRACT

Advanced well placement technologies were utilized from the commencement of the development of the Vincent oil field located offshore, west of Australia. The first development well was drilled in June 2007. To date, there are a total of eight bi-lateral and five tri-lateral development wells with average horizontal well lengths in the reservoir exceeding 2000 m.

Geological and reservoir complexities contributed to a challenging drilling and geosteering environment, which often resulted in a number of undesired sidetracks to achieve the optimum well placement and meet pre-drill objectives. Drilling challenges included very fast penetration rates requiring immediate well placement decisions to be made, drilling windows of less than 3 m true vertical depth (TVD) in sections of wells and loss of directional control due to encountering faults and dipping stratigraphic surfaces.

Deep reading azimuthal resistivity logging-while-drilling measurements were used to position wells as high as possible to top structure and away from the oil-water contact. Interpretation of top structure from directional resistivity data is complicated by interference from dipping low resistivity intra-reservoir beds. Through detailed study of azimuthal resistivity responses from previous well campaigns and collaborative interpretation between the well placement and subsurface teams, the measurement signature between top structure and intra-reservoir surfaces was able to be distinguished.

Accurate, high density well surveys are critical when steering within a thin oil column. In a few earlier wells, low stationary survey sampling frequency of approximately every 30 m at the end of each drilling stand did not capture the true well trajectory and resulted in incorrect well positioning and inadvertent penetration of the gas-oil contact in one well. Subsequently, high density continuous surveys acquired while drilling were used as indicators for additional infill stationary surveys. Recently, a new processing method has been developed to integrate stationary surveys and continuous surveys in near real-time, improving wellbore placement accuracy and removing the requirement for time-consuming infill stationary surveys.

In addition to the above, to overcome the drilling challenges in the Vincent field, a new steering technology has been applied which is capable of greater dog-leg severity and has further aided well placement. This new rotary steerable system is a hybrid push- and point-the-bit technology and has potentially reduced the number of sidetracks required for optimal well placement.

INTRODUCTION

The Vincent oil field is located off north-western Australia. The reservoir is stratified and comprises a series of coarse- and fine-grained unconsolidated sandstone and siltstone interbeds with a regional dip of approximately 3° to the north-east (Fig. 1). The reservoir is overlain by thick overburden shale. The field is also intersected by extensive seismic and sub-seismic faults. A relatively thin 12 to 20 m oil column is supported by an underlying aquifer. A gas cap is present in the northern and central sections of the field. Wells were drilled over three development phases from 2007. The oil is accessed from a series of closely spaced horizontal multi-lateral wellbores with average lengths exceeding 2000 m through the reservoir section. Wellbore positioning was paramount to maximising reservoir production performance. An optimum standoff of a few metres from the gas-oil contact (GOC) was required for
wells drilled beneath the gas cap. Due to the presence of a strong aquifer drive, wells drilled away from the gas cap required precise placement of the wellbores approximately 2 m below top structure to maximise oil recovery (Smith and Gongora, 2012). The structural and stratigraphic complexities coupled with the well positioning requirements have given rise to a number of well placement challenges and trajectory control issues. Through three development phases of the field, these challenges have led to new innovations and solutions.

**Fig. 1** Cross section through the Vincent oil field showing dipping reservoir strata truncated at top structure and overlain by thick shale (Smith and Gongora, 2012).

**WELL PLACEMENT CHALLENGES**

Bed boundary mapping tools were employed in the second and third phases of the drilling campaign to delineate the top structure. The application of deep reading azimuthal resistivity technology provided real-time trajectory guidance to place wellbores between 1 and 3 m below top reservoir to access attic reserves and maximise standoff from the oil-water contact (OWC). The technology uses a combination of multi-frequencies (2 MHz, 400 kHz and 100 kHz) and multi-spacing (22 to 96 in.) technology to generate the directional shallow and deep phase shift and attenuation measurements that map the resistivity contrast between formation or fluid boundaries in real time while drilling (Omeragic et al, 2005). Due to the physics of induction resistivity measurements, the depth of investigation is greater in a resistive environment. As the resistivity contrast between reservoir and overburden increases, the tool’s distance-to-boundary sensitivity also increases. In the Vincent field, the resistivities of the oil-bearing reservoir range from 10 to over 100 ohm-m and allow the tool to map top structure as far as 4 m away from the tool.

As shown in **Fig. 1**, the presence of low-angled dipping intra-reservoir low resistivity beds, termed flooding surfaces, complicates the detection of top structure. The flooding surfaces have a slightly higher resistivity of 2 ohm-m compared to the overburden shale which has a resistivity of 1 ohm-m. Due to the very small difference in resistivities, the resultant inversion of the directional resistivity responses to an approaching flooding surface could be mistaken for overburden shale. Incorrect interpretation of the tool response could mean inadvertently placing the well below the flooding surface rather than below top structure.

Distinguishing tool response between the flooding surfaces and top structure initially proved challenging. **Fig. 2** shows an example of the wellbore intersecting a flooding surface at 2300 m measured depth (MD) and subsequently tracking under the overburden shale from 2490 m MD. The inversion result from the real-time well placement
software platform is a processed product of the azimuthal resistivity measurements and displays up to one boundary above and below the wellbore and the distances to these boundaries. The display has a resistivity colour scale with higher resistivities represented by lighter shades.

A boundary is observed below the wellbore between 2200 m and 2300 m MD with a distance to boundary of 1 to 2 m. The wellbore crosses the boundary at 2300 m MD and maps the boundary to 2490 m MD. This boundary was interpreted to be a flooding surface. Beyond 2490 m MD, the mapped low resistivity boundary overlying the wellbore was interpreted to be top structure. There is a very subtle change in resistivities (indicated by the darker shades) in the layer above the wellbore at 2490 m MD suggesting a change from flooding surface to top structure. Given the fast drilling rates which frequently exceeded 200 m/h in the Vincent field and tight drilling windows, quick and precise steering decisions were required. It was not possible to identify and distinguish top structure from flooding surfaces with confidence by relying on subtle changes in colour from the inversion result alone.

Consequently, a thorough review of directional resistivity curve responses was conducted using measurements from previously drilled wellbores. Through careful examination of the tool response characteristics between an approaching flooding surface and that of the overburden, distinct differences in the raw directional curves at multiple frequencies and depths of investigation were detected. Despite the two surfaces having similar resistivities, the differences in bed thicknesses also affected directional curve responses. The curve responses are described in detail below.

A simplified diagram of the inversion result together with the gamma-ray curve and directional attenuation curves SAD1 (100 kHz symmetrized attenuation) and SAD2 (2 MHz symmetrized attenuation) is shown in Fig. 3. SAD2 is a higher frequency, shallower reading attenuation curve compared to SAD1. A positive amplitude curve (directional curve plots on the positive side of the middle line) means that the wellbore is approaching the conductive surface from below. Likewise, if a directional curve has a negative polarity, the wellbore is approaching the conductive surface from above. The amplitude of the curves (distance away from the middle line) is an indication of the proximity of the conductive surface to the wellbore. The greater the amplitude, the nearer the conductive surface is to the wellbore. A zero polarity (a curve lying on the middle line) indicates that the sensor has not detected any conductive surfaces within its depth of investigation. The path along the wellbore is marked from A to E in Fig. 3. A description and explanation of the directional curve responses at each marker is provided below.

A. The shallower reading SAD2 curve has a negative amplitude and is responding to the conductive flooding surface within its depth of investigation approaching from below the borehole. The lower frequency, deeper reading
SAD1 curve displays a minimal response indicating that the thin (less than 1 m thick) flooding surface layer has had little effect on its measurement as its thickness is below the resolution of the SAD1 measurement.

B. The wellbore intersects and crosses the flooding surface. The directional curves show a change in polarity from negative to positive as the wellbore now tracks under the flooding surface. As at marker A, the SAD2 curve has a higher amplitude compared to SAD1 due to its ability to resolve thinner beds.

C. A slight drop in borehole inclination is caused by cutting across the flooding surface. The directional curves have moved towards the middle line indicating that the sensors are unable to detect any conductive layers within their respective depths of investigation. Based on the sensor readings, the borehole inclination was increased to identify and track top structure.

D. Both SAD1 and SAD2 curves display a strong positive response as top structure is approached. Unlike the response observed from the flooding surface, the SAD1 curve in this scenario has a strong amplitude response to the thick overburden shale.

E. The flooding surface has been eroded out. The directional curves are responding purely to the overburden shale. Although both curves continue to display a strong amplitude response, it is observed that the SAD1 amplitude is greater relative to SAD2.

As shown, the responses from the azimuthal resistivity measurements are affected not only by the resistivity contrast between adjacent layers but also by the ability of the different frequencies to resolve varying bed thicknesses. The flooding surface was observed to cause greater amplitude responses in the higher frequency measurements with minimal response from the lower frequency, deeper reading directional curves. As the tool approaches the overburden shale, amplitude responses are observed from both low and high frequency directional measurements, with the lower frequency measurements having a greater amplitude response relative to the higher frequency measurements. The signature of the responses from the different frequencies and depths of investigation was utilized to distinguish between the thin flooding surface and the thick overburden shale and allowed the geosteering team to correctly identify and steer relative to top structure.

**Fig. 3** Simplified diagram of the inversion canvas with shallow and deep resistivity attenuation curve responses. Shallow and deep reading curves respond differently to the flooding surface and the overburden shale.
POSITIONAL ERROR DUE TO LOW SURVEY SAMPLING FREQUENCY

Stationary surveys were acquired every 30 m after drilling a stand of pipe but often masked the true tortuosity of the well path and failed to describe the actual course of the drilled well. A combination of mud motors and rotary steerable systems (RSS) was used in the first two phases of field development. With structural and stratigraphic changes affecting trajectory control, frequent steering adjustments were required to stay within the desired target borehole position. Though a 30 m survey sampling interval is standard industry practice, studies have shown that the computed wellbore position using 30 m survey intervals and a minimum curvature interpolation method (which assumes no appreciable changes in the curvature between surveys) can lead to an unacceptable cumulative wellbore position error (Stockhausen and Lesso, 2003). RSS can produce a compounding micro-dogleg effect, resulting in an overall build or drop between stationary surveys which can go uncaptured. The error is often more significant when using mud motors as the slide and rotate sequences of mud motor drilling causes alternating sequences of high and low doglegs which often go undetected in a survey spacing of 30 m.

Fig. 4 is an example of how the use of standard survey spacing of 30 m in the first phase of development resulted in significant TVD positional error in a well drilled with a mud motor. The GOC was intersected four times over a drilled length of just over 300 m. The stationary surveys indicated that the borehole not only intersected the apparent gas cap 6 m deeper than the expected GOC, but that the contact was also tilted. From the geological understanding gained from previous offset well results, it was very unlikely that the well drilled into a separate fault compartment with a tilted GOC that was 6 m deeper than the expected field contact. The accuracy of the stationary surveys was instead brought into question and the analysis resulted in a decision to deepen the well to locate the OWC to provide an additional control point. As with the GOC, the apparent OWC was also encountered 6 m deeper than expected. The unlikely coincidence of both GOC and OWC being deeper by a consistent 6 m convinced the well placement team that the cause of the discrepancy was due to survey error.

Continuous directional and inclination measurements from the measurement-while-drilling (MWD) tool were also taken in all three development phases. Continuous surveys are considered less accurate than stationary surveys as the bottom hole assembly (BHA) is not stationary and therefore not representative of hole angle while the BHA is attempting to achieve high dogleg severity (DLS) or subjected to high compressional loads and drag. Although less accurate, continuous surveys are more descriptive of the true well form because of the high sampling frequency of 1 to 3 m (depending on rates of penetration and signal strength) which has the ability to capture the micro-doglegs and tortuosity of the well path.

Post-run analysis of the well example shown in Fig. 4 compared the well path defined by the 30-m interval stationary survey data with that defined by the real-time continuous survey data. This comparison revealed a significant discrepancy in TVD position of the wellbore between the stationary and continuous surveys. The well path defined by the real-time continuous survey was 6 m shallower compared to the stationary survey, placing the fluid contacts back in the pre-drill expected TVD position. The true nature of the wellbore tortuosity was revealed in the high-density continuous real-time surveys (Fig. 5). Due to the pattern of alternating slide-and-rotate drilling sequences employed in the well, oriented or slide drilling was applied during the first half of each stand to increase the inclination, followed by rotary drilling in the latter half of the stand. The continuous inclination data showed a consistent pattern of an increase in inclination when the BHA was building angle in slide mode and a natural decrease in inclination when the BHA was in rotary mode as a result of drilling through soft formation. As stationary surveys were sampled at the end of a stand, the surveys only recorded the inclination at the end of each rotary drilling sequence and failed to capture the inclination from the slide sections. The cumulative error resulted in the interpolated stationary surveys being 6 m deeper compared to the actual well position.
Fig. 4 Well showing a discrepancy in TVD position between stationary and continuous surveys. The low survey sampling frequency of the stationary survey resulted in a 6 m TVD error and the incorrect interpretation of the GOC.

Fig. 5 Comparison of stationary and continuous survey inclination data. True well trajectory is better described using high density continuous surveys.
SOLUTIONS TO IMPROVING SURVEY ACCURACY

After the discrepancy between stationary and continuous surveys was identified and validated, both stationary and continuous surveys were simultaneously monitored in real time during the drilling of subsequent wells. Continuous direction and inclination measurements (CDNI) were transmitted to surface every 1 to 3 m of drilling depending on the penetration rate and telemetry settings. Data noise in the real-time telemetry transmission was sometimes present in the continuous survey data and after removal of the noise, the data was of sufficient quality for use in calculations to generate wellbore position. An error model for continuous survey data has to date not yet been developed.

Infill stationary surveys were acquired when the TVD positional differences between stationary and continuous surveys exceeded a predefined value of 1 m. Infill surveys were successful in achieving greater positional accuracy and capturing the micro-doglegs in the wellbore. However, a dedicated resource was required to process and monitor the two surveys and focus was often taken away from strategic well placement and planning to check and ensure the validity of the surveys. Infill surveys also added to rig time and operating costs.

In the third development phase, a high definition surveying (HDS) method was developed that combined stationary and continuous survey data to yield high definition wellbore surveys at 3-m intervals. This proprietary software first performs a multi-station correction to match the continuous survey data to GMAG corrected stationary surveys. GMAG is an algorithm used for correcting survey azimuth to compensate for drill string magnetic interference.

As part of the HDS method, a quality check of the processed continuous data is performed by comparing the data against the stationary surveys for consistency. The processed continuous surveys are then interpolated every 3 m to produce a high definition survey that has been tied to the stationary surveys. The HDS service includes a BHA sag correction to correct for the misalignment of the directional sensor with the borehole direction due to BHA deformation in the vertical plane caused by gravitational forces and borehole curvature (Studer and Macresy, 2006).

High definition surveys were processed and regular well position updates were provided while drilling. HDS eliminated the requirement for infill stationary surveys and provided a more accurate description of the wellbore position. The accuracy of the high definition surveys was tested on previous Vincent wells like the well example in Fig. 4. Application of the HDS method as shown in Fig. 6 would have resulted in a more accurate placement of the wellbore and the penetration of the GOC could have been avoided.

![Fig. 6 Comparison of stationary, continuous and HDS processed surveys. Application of HDS method results in an improved description of the well position.](image-url)
TRAJECTORY CONTROL ISSUES

Loss of trajectory control was frequently encountered when drilling into very unconsolidated stratigraphy, especially if the stratigraphy was dipping in the direction of drilling. Upon intersection of a highly unconsolidated intra-reservoir bed, there was a tendency for the BHA to drop from near horizontal to an inclination of 87° along the bedding plane. Often, control of the BHA could not be regained, resulting in the inevitable penetration of the OWC. Loss of trajectory control also occurred at fault zones whereby sudden drops or builds and azimuthal changes were encountered. Loss of control necessitated costly sidetracks. Fig. 7 is an example of the trajectory control issues encountered in a phase 1 well where three sidetracks were attempted to overcome drop zones, and the total length of the well was shortened because of the steering difficulties.

![Fig. 7](image)

**Fig. 7** Phase 1 well demonstrates the drilling difficulties in the Vincent field. Loss of trajectory control is the result of intersecting unconsolidated beds and faults.

NEW TECHNOLOGIES APPLIED TO OVERCOME LOSS OF TRAJECTORY CONTROL IN A CHALLENGING GEOLOGICAL ENVIRONMENT

The use of a steerable system mud motor was successful in overcoming most inclination drops by steering aggressively upwards and forcing the BHA out of the dropping tendency. The bent housing in a steerable system mud motor allows drilling to proceed in the direction the drill bit is pointing when the BHA is in the slide drilling mode. Depending on the bent housing angle, very high doglegs can be achieved in the slide mode. For example, a bent housing angle of 1.5° can deliver 8°/30 m of curvature in competent sand (Lesso et al., 2001). The bend angle is set at the surface and cannot be changed once the tool is down hole. In rotary drilling mode, the curve rate is much less than in slide mode. Directional drillers apply a sequence of alternating slide and rotary modes to achieve the required well path. In the Vincent development, the use of 1.5° bend in the mud motor was successful in arresting drops and regaining trajectory control. However, drilling with a mud motor could only achieve maximum borehole lengths of up to approximately 3500 m in the Vincent field as high tortuosities from slide sections and increasing hole drag with depth affected the ability to drill the well to total depth. Beyond 3500 m, the point-the-bit RSS was used in the first and second phases of development.

Rotary steerable systems were developed to overcome the problem of tortuosity caused by large changes in curve rates between slide and rotate sequences used by steerable systems mud motors. Push-the-bit systems divert part of the mud flow to push pads out against the formation, forcing the BHA in the required direction. A push-the-bit system requires a competent lithology to steer effectively and hence was not deemed suitable in Vincent because of the unconsolidated nature of the reservoir. Point-the-bit systems have the capability of changing the tilt of the bit in the direction of the desired curve while drilling. In the first and second phases of development, the point-the-bit RSS
used in Vincent did not have the same dogleg steering capability as a steerable system mud motor and was unable to force the BHA out of severe drops.

In the third phase of development, a more sophisticated RSS was developed with increased dogleg steering capability compared to the previous RSS. The hybrid RSS uses both push-the-bit and point-the-bit technologies. The system consists of internal pads that are energized by fluid diverted from the geostationary control unit valve (Fig. 8). Once energized, the internal pads push against the internal diameter of the steering sleeve stabilizer which moves the steering stabilizer. This creates a pivot point within the steering sleeve that allows the bit to point in the desired steering direction. The hybrid RSS differs from earlier RSS tools as it does not have any external moving pads which would push against the formation and control direction. The amount of bend or maximum DLS is limited by the strike rings and is preset when the tool is at surface. When the tool is downhole, the range of DLS from zero to the maximum setting is controlled by changing the steering ratio (i.e., the time that the tool spends in steering mode versus neutral mode). At a 100% steering setting, the maximum DLS is realized. The tool has been able to achieve doglegs of over 17°/30 m by using both point-the-bit and push-the-bit systems in conjunction. The ability of the tool to deliver high DLS on command makes it an ideal service for risk mitigation in highly faulted areas or in areas with high geological uncertainty. In the Vincent field, the hybrid RSS has been used to arrest drops and regain trajectory control. Wells were successfully drilled in a single run with smoother trajectories and fewer drops, and without the requirement for a trip for a mud motor or a sidetrack due to uncontrolled drops.

![Fig. 8 High dogleg capability from the hybrid point- and push-the-bit RSS.](image)

**CONCLUSION**

The success of any well placement operation relies on strong team work and communication between the subsurface and drilling teams and service providers. A commitment by the Vincent inter-disciplinary and inter-company well placement team to find solutions to address the well placement challenges through the use of advanced technologies or new methodologies has led to significant improvements in terms of improved well placement, minimizing drilling time and avoiding sidetracks. The new methods and technologies developed and applied in the Vincent campaign are applicable to other fields where well positional accuracy is critical to successful production performance.

A review of historical azimuthal deep reading directional resistivity data produced critical observations about the differences in responses of raw directional curves to flooding surfaces and overburden shales in the Vincent field. It is important to appreciate that despite the similar conductive properties of the two lithologies, the attenuation measurements at various frequencies responded differently to varying bed thicknesses. This understanding was key
to enabling the well placement team to correctly distinguish between flooding surfaces and overburden shales and effectively steer the well close to top structure.

The standard practice of taking 30-m spaced stationary surveys may often be inadequate in describing the true tortuosity of a well path and result in incorrect well positioning. The impact of low-frequency stationary surveys was demonstrated in a Vincent well in which inadequate survey density resulted in a 6-m TVD error and the inadvertent penetration of the GOC. The newly developed HDS method integrates continuous survey measurements with sag- and GMAG-corrected stationary surveys resulting in high density 3-m surveys that improve the positional accuracy of the borehole and more accurately describe the true well path.

Loss of trajectory control in unconsolidated formation was overcome by using steering assemblies with high DLS capability. Steerable system mud motors were able to generate high doglegs and overcome drops caused by the unconsolidated stratigraphy. However, insufficient torque prevented the use of mud motors beyond well lengths of 3500 m. Neither the point-the-bit and push-the-bit RSS technology was ideal and both had insufficient DLS capabilities in soft formations such as the Vincent reservoir to overcome uncontrolled inclination drops. The new hybrid point-the-bit and push-the-bit RSS technology was used in the third development phase and has the DLS capability to overcome inclination drops, enabling wells to be drilled in a single run without requirements for a sidetrack due to uncontrolled drops.

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