Innovative Approach to Characterizing a Heavy Oil North Sea Reservoir drilled with OBM, using Multi-Depth of Investigation NMR, Dielectric Dispersion and Sonic Anisotropy

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Abstract

Heavy oil reserves are often found at relatively shallow depths in unconsolidated environments and are associated with significant drilling and logging challenges, especially bad hole condition and hole stability. In these heavy oil reservoirs, unknown or varying formation water salinity renders standard resistivity saturation analysis unreliable, and needs to be calibrated with Dean Stark core results, which are only available months after data acquisition. Accurate understanding of reservoir properties like oil saturation, viscosity, relative permeabilities and free water volume is essential for the efficient and economic development of heavy oil fields.

In this paper, we present an innovative approach to heavy oil characterization using novel multi-depth of investigation (nuclear) magnetic resonance (MR), dielectric permittivity and sonic shear dispersion principles.

This paper demonstrates how the MR reliably estimated heavy oil viscosity and also identified varying invasion profiles across the different hydrocarbon bearing sands in the reservoir, reflecting subtle changes in reservoir quality. The three independent radial measurements made by the MR tool allowed an estimate of the heavy oil mobility, by measuring the extent to which mud filtrate is able to move the reservoir fluids away from the wellbore.

We discuss how dielectric permittivity is used to provide formation water salinity (in the absence of a water leg) in the reservoir and also establish flushed zone resistivity in OBM. In addition, we demonstrate how this method directly provides irreducible water saturation along with heavy oil saturation without the need for resistivity data.

Finally we review how sonic shear dispersion and azimuthal data can reliably measure formation slowness in challenging unconsolidated sands and identify fractures generated during a leak-off test. We show how the horizontal stress estimation from advanced sonic processing can be used to reproduce data normally acquired only by such leak-off tests.

Introduction

The Kraken Field is located in the UK North Sea some 350km north-east of Aberdeen, Scotland and in water depths of 375ft. The field lies on the eastern margin of the East Shetland Platform on the flanks of the prolific North Viking Graben and East Shetland Basin light oil provinces (Appendix 1). Kraken and all other discoveries on the East Shetland Platform are characterized by relatively shallow, unconsolidated clastic reservoirs containing biodegraded heavy oils with, or without, associated gas caps (Jayasekera and Goodyear 1999). To date, none of the discoveries in this heavy oil province has entered production, although resources sizes are known to be large; Mariner Field, for example, is estimated to contain recoverable reserves of 400 million barrels oil equivalent (Berg et al., 2011).

Development of these potential resources has been challenged by subsurface and commercial factors relating to high oil viscosities (up to a reported 550cP in Bressay, Berg 2010) and the concomitant impact of adverse mobility ratios on sweep efficiency during primary water-flood (Jayasekera and Goodman, op cit.). However, under new operators and with improvements in technology and the market value of heavy oils, development plans are now well advanced for all the fields in this region.

The discovery of Kraken was made on 15th October 1985, when live oil was seen coming over the shakers in well 9/02-1 whilst drilling at a measured depth of 3919ft. Exploration well 9/02-1 was targeting potential Jurassic reservoirs in a fault-block trap, with secondary objectives in clastic sediments of Palaeocene age draped over the deeper structure. Although the primary objective proved
issues, the data collection program needed to address several "project proving" in concept: drilling, completion and data depositional porosities averaging 38% in wells drilled to date. Problems with the prior data set quickly moved to a phased development. Among other petroleum fluids and, in the success case, to allow the field uncertainties with regard to both the reservoir and the pressured, the reservoir sands are unconsolidated and retain range of 50-150ft seen in wells and estimated from seismic. Channels, forming pay sands of variable thickness, with a were deposited from mass-flows in submarine slope development planning. Studies suggest that the reservoirs allowing the project to move forward to fast-track the concept of a larger stratigraphic trapping geometry, thus the presence of further Heimdal reservoir units and proven sidetrack, 9/02b-5Z. The appraisal program has confirmed Nautical Petroleum plc and partners began in 2007 with step-of a much larger stratigraphic trap comprising multiple reservoirs (S. Jenkins, pers. comm.). An appraisal campaign by Nautical Petroleum plc and partners began in 2007 with step-out well 9/02b-2, culminating in 2011 with the drilling of well 9/02b-5 and with extended testing of horizontal sidetrack, 9/02b-5Z. The appraisal program has confirmed the presence of further Heimdal reservoir units and proven the concept of a larger stratigraphic trapping geometry, thus allowing the project to move forward to fast-track development planning. Studies suggest that the reservoirs were deposited from mass-flows in submarine slope channels, forming pay sands of variable thickness, with a range of 50-150ft seen in wells and estimated from seismic. Although at a depth of c.3850ft TVDs and, normally pressured, the reservoir sands are unconsolidated and retain depositional porosities averaging 38% in wells drilled to date.

Wells 9/02b-5 and 5Z, the subject of this paper, were “project proving” in concept: drilling, completion and data collection programs were designed to address outstanding uncertainties with regard to both the reservoir and the petroleum fluids and, in the success case, to allow the field quickly to move to a phased development. Amongst other issues, the data collection program needed to address several problems with the prior data set

1. The limited number of high-quality wireline data sets used to construct rock physics models which are critical to the field-wide mapping of pay sands.
2. Poor quality log data from wells drilled with water-based muds, due to formation washouts at reservoir level and in surrounding shales, which result in reduced confidence in reservoir property mapping and in the resultant hydrocarbon volumes.
3. Uncertainty in the salinity of the aquifer due to absence of a water-leg in any Heimdal reservoirs in Kraken wells to date.
4. A lack of core data to calibrate log-derived reservoir properties, including porosity and water saturation.
5. Insufficient data to reliably model the strength of the Heimdal reservoirs or their seals, resulting in uncertainty in the ability to drill and complete and produce long horizontal wells, as required for an economic development.
6. Uncertainty in the absolute in situ oil viscosity in the 9/02-1 core area, and no information on whether there is any vertical variation of viscosity within the oil column.

Data acquisition and job planning

Well 9/02b-5 was drilled to TD of 4793ft with maximum deviation of 43deg in oil - base mud (OBM) system. Basic LWD data was acquired in both the 12.25” and 8.5” sections. A comprehensive wireline acquisition program in the 8.5” section consisting of traditional triple combo – Platform Express (density, neutron and resistivity), natural spectral gamma ray (HNGS) and elemental capture spectroscopy was carried out. Other services include multi-depth of investigation NMR (MR Scanner), Dielectric Scanner, 3D sonic imaging (Sonic Scanner), pressureExpress, micro resistivity imaging and borehole seismic. Well 9/02b-5Z was horizontal and no wireline data was acquired.

The Platform Express tool provides triple combo measurements that are environmentally corrected. Photoelectric factor is also measured but the presence of barite in the OBM system makes it useful only for qualitative purposes. Resistivity data from the multi-coil array induction tool suffered from apparent bedding dip effect and had to be corrected for.

Elemental Capture Spectroscopy (ECS) and HNGS measurements in combination provide robust lithology analysis. Reliable clay volume estimates, matrix parameters and mineralogy identification from the ECS greatly reduce uncertainties in porosity computation.

The MR Scanner tool was primarily run for oil viscosity estimation, lithology independent porosity measurement and heavy oil movability analysis using the 3 independent depths of investigation (DOI). Data was acquired in high resolution mode while running in hole. The main log was carried out across the reservoir section in saturation profile mode at 1.5”, 2.7” and 4” DOI for fluid typing. A repeat pass was done with a special heavy oil saturation profile sequence which is customized for better sensitivity to very fast decaying heavy oil signals.
The objectives of running the Dielectric Scanner tool were to obtain resistivity independent hydrocarbon saturation and flushed zone water salinity. Flush zone resistivity (RXO) in OBM from the dielectric measurement was also required to ascertain if there was any movable water in the reservoir. The presence of free water will have significant impact on how the field will be developed. This service was run in combination with the PEX - ECS toolstring.

The Sonic Scanner tool was run in combination with the Dual OBMI for basic petrophysics, advanced geomechanics and completion applications. Sonic acquisition was in “standard mode” where all acoustic modes required for subsequent advanced processing / interpretation were simultaneously recorded. Two power positioning devices (PPC) were used to ensure proper sonic scanner tool centralization.

The PressureExpress tool was used for fast and efficient reservoir pressure measurement as heavy oil samples were not required.

**Discussion of results**

**MR Scanner:**
The MR Scanner makes simultaneous independent measurements at multiple depths of investigation ranging from 1 – 4” away from the borehole. Figure 1 gives a quick overview of the tool design showing two high resolution antennas and a main antenna. Continuous diffusivity, D and relaxation times (T1 and T2) measurements at multiple DOI enable us to make a radial profile of saturation distribution. Inferences can then be made on mud filtrate invasion profile, hence reservoir oil movability and possible formation damage.

The identification of fluids and derivation of petrophysical answers is based on 3D inversion of D, T1 and T2 information. This complex data is then presented in an understandable 2D format (D-T1 or D-T2) as shown in Figure 2.

Heavy oils have fast decay rates and normally relax within the bound fluid region of T2/T1 distribution. Fortunately here, the volume of capillary bound water is quite small and where present overlays the heavy oil signal, so did not affect the viscosity analysis as the combined T2 peak is still representative of the heavy oil. 3D interpretation of the data in Appendix 2 shows the radial variation of fluids saturation from Shell 1 to Shell 8. As one moves away from the borehole, the volume of mud filtrate (light green) decreases and the oil volume (dark green) increases. This information is very significant to Nautical Petroleum as this confirms that though the oil is heavy, it is easily moveable. A similar comparison across the 4 different reservoir sands shows varying invasion profile which can be attributed to subtle changes in formation properties and/or differences in length of time the respective sand bodies were exposed to the mud system.

Shell 1 being the shallowest DOI (1.5”) was significantly influenced by mud filtrate invasion so oil viscosity analysis using T2 correlation was based on deep reading Shells 4 and 8 from both passes. Estimated viscosity from MR Scanner was in the range of 127 – 148cP. Laboratory result indicated oil viscosity of 161cP which was generally in good agreement with the NMR estimate.
Presented in Appendix 3-4 are diffusion maps (D-T2) across some sand intervals in the reservoir. The absence of free water signals on the maps confirms the reservoir is actually at irreducible water saturation. This information is critical to how the field will be developed.

**Dielectric Scanner:**

The Dielectric Scanner tool uses electromagnetic propagation to make continuous dielectric dispersion measurements (variation of dielectric properties – permittivity and conductivity with frequency). Formation dielectric properties are measured at 4 frequencies using transmitter – receiver arrays as shown in Figure 3, enabling radial profiling of the reservoir away from the borehole. Permittivity and conductivity measurements made with the dielectric scanner tool are then interpreted using petrophysical models. One primary output is water filled porosity which when combined with other sources of total porosity provide direct hydrocarbon saturation that is independent of resistivity and water salinity. Other outputs include formation water salinity, flushed zone resistivity (Rxo) both in WBM and OBM and textural effects (archie’s m parameter and CEC in shale sands).

![Figure 3 - Dielectric Scanner Tool configuration and dielectric dispersion measurement](image)

The processed dielectric scanner interpretation result is shown in Appendix 5.

Very good quality results were obtained in spite of the challenging OBM environment (high mud resistivity) where most of the signals from the dielectric tool propagate in the well bore instead of the formation.

Comparison of the water filled porosity from the dielectric scanner with total porosity provides a direct measurement of the heavy oil saturation. Track 4 shows the excellent agreement between Dean Stark core saturations (blue dots) and dielectric scanner oil saturation.

Flushed zone resistivity derived from dielectric (RXD_ADT) compares very well with AIT resistivity measurements. The overlay of RXD_ADT, AM10 and AM90 in track 6 confirms MR Scanner interpretation that the reservoir is actually at irreducible water saturation.

Textural information could also be extracted in this case as good dispersion was obtained from the 3 highest operating frequencies (F1, F2 and F3). Archie’s m parameter estimation (ranging from 1.78 – 1.98) in track 3, indicates there is no significant variation in the textural properties of the reservoir sands. Also note how core measured m parameter matches reasonably well with dielectric estimate at around X250ft.

Track 2 shows formation water salinity from the dielectric scanner ranging between 35 and 40 ppk. Micro-Rw cell analysis in the laboratory on water samples spun from cores at around X250ft indicated a salinity value of around 47ppk.

**Sonic Scanner**

The Sonic Scanner tool makes full sonic waveform measurement with dipole/monopole transmitters and azimuthal receivers that are placed at multiple axial positions. This enables the radial measurement of both near and far field slownesses (compressional, two shear in planes parallel to the borehole axis and Stoneley). The unique smooth body design of the sonic tool permits 3D modeling of rock properties as tool response in the wellbore can be reliably accounted for. This technological advancement now allows the extraction of shear in 3D that more accurately describes rock behavior compared to a conventional 2D measurement.

![Figure 4- Sonic Scanner – Complete acoustic characterization of sound propagation around the borehole](image)

Raw waveform data from the thirteen receiver arrays of the Sonic Scanner tool was first processed for basic formation slownesses. Dispersion analysis of the two dipole flexural measurements allowed the true formation shear slowness to be picked in the low frequency range. Inputs for geomechanical and advanced petrophysical analysis were obtained by further processing the data for shear anisotropy and radial profiling.
Sonic Scanner and applications for drilling geomechanics

The importance of geomechanics in field development planning is well understood in the oil industry. Because most of the heavy oil reservoirs occur in relatively shallow and weak sands, understanding the risks to develop these becomes even more important. Directions of stable horizontal wells, available mud weight windows to avoid borehole collapse and mud losses, and time dependent shale instability will control the reach of ERD wells. As a part of this study, a full geomechanical analysis was undertaken to assess these risks. One of the 3 wells used for geomechanical modeling included advanced acoustic measurements using Sonic Scanner. Three shears and compressional measurements were made at multiple azimuths and several depths of investigation, allowing complete acoustic characterization of the formation (Ref 1).

The acoustic velocities depend on intrinsic properties like matrix and fluid, and extrinsic properties like stresses. The complete acoustic characterization of the formation allows the user to discriminate the effect of these two, and invert the acoustic measurement for minimum and maximum horizontal stresses (Ref 4). These are then used to calibrate the geomechanical modeling and estimate the drilling mud weight windows and risks. The stress inversion works well for porous clean sands where the effect of horizontal stress imbalance creates a stress crossover signature on the frequency dispersion curves as shown in Figure 5.

The clean Heimdal sands of Kraken field were found suitable for this methodology. Minimum and maximum horizontal stresses and stress direction were extracted in well 9/02b-4. To confirm the stress estimation from Sonic Scanner a full Extended Leakoff test (XLOT or ELOT) was conducted in well 9/02b-5. The minimum horizontal stress obtained from the XLOT was found to be very close to the range estimated from Sonic Scanner in 9/02b-4.

The objective of geomechanical analysis was to determine the mud weight windows needed for drilling horizontal well 9/02b-5z and associated drilling risks. Standard workflow was adopted for constructing the mechanical earth model, which was then used for the wellbore stability analysis. In the absence of core data the dynamic mechanical properties were constructed using log data (sonic and density) and then converted into static properties using known correlations based on regional data base. There was considerable uncertainty in the horizontal stress estimations due to lack of calibration data. Only one FIT and one LOT were available in offset wells and those were also from depths above the reservoir where the horizontal section was planned. Hence it was decided to investigate the use of Sonic Scanner data for stress estimations.

Figure 5:- Horizontal stress imbalance causes a split in shear waves, with fast shear polarized in the direction of maximum stress and slow one polarized in the direction of minimum stress. The direction of maximum stress is estimated from the direction of fast shear. The split also causes a crossover of fast and slow flexural on the dispersion analysis. This happens a few inches into the formation. In a vertical well the full radial profile measured with Sonic Scanner allows for the inversion of stresses under such conditions.

Stress estimation from sonic scanner.

Stress induced crossover was observed in the shallower Dornoch and the main Heimdal sands in well 9/02b-4. Due to stress concentration at the wellbore wall, shear slowness near the wellbore increases when compared to far field. This appears as alteration on the radial profiles of fast and slow shear. Figure 6. The radial profile at a selected depth in the Heimdal sands is shown in Figure 7. In this altered zone, shear slowness near the wellbore increased by up to 8% when compared to the far field. However in the immediate vicinity of the wellbore, plastic and non linear behavior tends to dominate. For stress inversion these plastic and non-linear sections need to be excluded. This is done by limiting the acceptable increase of shear velocities. For Heimdal sands two cases were tested; in the first case any increase of more than 3% in shear velocity was considered as non-linear and plastic, in the second case this limit was set to 2%. These limits are based on core testing. The minimum horizontal stress was found to be in the range of 0.73-0.75 psi/ft for Dornoch and 0.72-0.74 psi/ft for Heimdal sand. The maximum horizontal stress was found to be 1.04 -1.07 times minimum stress. The results are shown in Table 1. Although the uncertainty in stress was small, due to the risks involved, it was decided to confirm the estimated horizontal stress by a special extended leak off test in the pilot hole (9/02b-5) before drilling the horizontal side track.
Figure 6: Stress concentration due to excavating a borehole appears as alteration on the shear radial profile, where the shear velocities near the borehole are slower than the far field.

Figure 7: Stress concentration at the borehole causes a crossover on the shear radial profile and dispersion curves.

Table 1: Minimum and maximum horizontal stress estimated from Sonic Scanner.

<table>
<thead>
<tr>
<th>Formation</th>
<th>Slowness Reduction %</th>
<th>Overburden</th>
<th>Core Pressure</th>
<th>Sphg_min psi</th>
<th>Sphg_max psi</th>
<th>Sphg_min psf</th>
<th>Sphg_max psf</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dunwich</td>
<td>2</td>
<td>2792</td>
<td>1544</td>
<td>2403.9</td>
<td>2657</td>
<td>0.39</td>
<td>1.60</td>
</tr>
<tr>
<td>Heimdal</td>
<td>2</td>
<td>3071.4</td>
<td>1741</td>
<td>2694</td>
<td>2658</td>
<td>0.22</td>
<td>1.67</td>
</tr>
</tbody>
</table>

Extended Leakoff test in the pilot hole 9/02b-5

The test was conducted through running a special packer and setting it in Heimdal sands, isolating 200 ft of Heimdal sands and some overlying and inter-bedded shales. Due to the very high reservoir permeability, and to limit the time spent on the test, it was decided to conduct the test at a higher than normal rate. The down hole pressure was measured through an annular pressure sensor of the LWD tool. The test was repeated three times and on all occasions, a similar minimum stress result from decline analysis was measured. The minimum stress measured from XLOT was 0.74 psi/ft which was equal to the upper limit estimated earlier from Sonic Scanner. The results confirmed the theory of stress inversion from Sonic Scanner in clean porous sands, like Heimdal.

Figure 8: First cycle of XLOT test is shown. Breakdown of 15.1 ppg and minimum stress of 14.26 ppg was measured which was same as estimated from Sonic Scanner in well 9/02b-4. Pumping stopped momentarily after breakdown, but was then continued for the stipulated time and then stopped. The pressure decline afterwards was analyzed to estimate the time of closure of fracture which was taken as minimum horizontal stress. Two more cycles were done after this, and the results were same as the first test.

Location of hydraulic fracture created during XLOT.

It was imperative to confirm that the XLOT indeed created the fracture in sands, and not in shales. A full logging suite was run after the XLOT. The image logs could not identify the fracture created by XLOT due to its less than optimum borehole coverage and resistivity contrast in OBM. However the anisotropy processing of post-frac Sonic Scanner identified intrinsic anisotropy in Heimdal sands which was interpreted to be the fracture created during XLOT. This
confirmed that the closure stress measured during the XLOT was indeed representative of the sands.

\[ \text{Figure 9: Parallel dipole dispersion curves observed across Heimdal sands indicates presence of intrinsic anisotropy (fractures).} \]

The results of the pilot hole 9/02b-5 were used to update the wellbore stability model and generate new mud weight windows for the planned horizontal side track 9/02b-5Z. During drilling the horizontal section, the drilling performance and hole stability was monitored in real-time by a geomechanics engineer. This ensured that all the lessons learnt during pre-drill modeling and the pilot hole were effectively translated into real-time decisions, ensuring a successful completion of the well.

**Conclusion**

This write up successfully demonstrated how the combination of multi-depth of investigation NMR, dielectric dispersion and 3D acoustic image along with other conventional measurements was used to provide Nautical Petroleum with pertinent information required to address the numerous issues and uncertainties associated with the earlier sets of data and development of the Kraken heavy oil field. Some key answers provided include:-

- Direct hydrocarbon saturation which is independent of resistivity and formation water salinity ($R_w$).
- Oil viscosity and movability
- Formation water salinity (in the absence of a water leg) and Archie’s $m$ parameter
- Principal horizontal stresses and near wellbore formation alteration.

By integrating induction resistivity data, 3D NMR interpretation and flushed zone resistivity from dielectric, it was established that the Heimdal sands in Kraken field are at irreducible water saturation.

Continuous in-situ viscosity estimation confirmed there is no vertical variation in the oil column.

The Sonic Scanner was able to provide robust principal stress data which was later confirmed by XLOT.

Extensive geomechanics work driven by Sonic Scanner interpretation ensured the successful planning and drilling of the 1500ft lateral section.

**Acknowledgement**

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**Nomenclature**

- AIT = Array Induction Tool
- AM 10 = Formation dip corrected 10' resistivity
- AM 90 = Formation dip corrected 90' resistivity
- ADT = Dielectric Scanner
- CEC = Cation Exchange Capacity
- ECS = Elemental Capture Spectroscopy tool
- ELOT = Extended leak off test
- ERD = Extended reach drilling
- FIT = Formation integrity test
- HNGS = Hostile Environment Natural Gamma Ray Spectroscopy Sonde
- LOT = Leak off test
- $m$ = Archie’s cementation exponent
- NMR = Nuclear Magnetic Resonance
- PEX = Platform Express
- OBMI = Oil Base Mud Imager
- OBM = Oil - base mud
- $R_w$ = Formation water salinity
- $Rxo$ = Flushed zone resistivity
- WBM = Water - base mud
- XLOT = Extended leak off test
- XPT = PressureExpress Tool

**References**

4. Sinha, B., Ouellet, A., Berard, T., Estimation of principal horizontal stresses using radial profiles of shear slowness utilizing sonic data from a CO2 storage site in a saline formation in Germany; *SPWLA 51st Annual Logging Symposium, June 2010*.


Appendices

Appendix 1: UK North Sea location of the Kraken field.
Appendix 2:- MR Scanner Saturation Profile pass (using 3 DOI) composite log. 100ms T2 cutoff was used to distinguish heavy oil from mud filtrate. Total volume of heavy oil displayed includes the capillary bound water.

Track 1:- Gamma ray (Gr, green), caliper (HCAL) and bit size (BS)
Track 2:- Resistivity (AT 10, AT20, AT30, AT50, AT60 and AT90). Separation in AIT curves is due to bedding dip effect.
Track 3:- Density (RHOZ) and porosity (TNPH)
Track 4:- Saturation analysis from shell 1 - mud filtrate (light green), heavy oil + capillary bound water (dark green) and clay bound fluid (orange)
Track 5:- Saturation analysis from shell 4 - mud filtrate (light green), heavy oil + capillary bound water (dark green) and clay bound fluid (orange)
Track 6:- Saturation analysis from shell 8 - mud filtrate (light green), heavy oil + capillary bound water (dark green) and clay bound fluid (orange)

Notice the radial fluid saturation profiles away from the borehole in tracks 4 – 6 from shell 1 to 8 and across the respective sand bodies. This is indicative of the movability of the heavy oil. Deeper depths of investigation (shells 4 and 8) were used for viscosity analysis as they were least influenced by mud filtrate.
Appendix 3: D – T2 Diffusion maps of Heimdal sand stone unit III leaf 1 (top sand interval).
100ms T2 cutoff was used to distinguish mud filtrate from heavy oil and capillary bound water.

Appendix 4: D – T2 Diffusion maps of Heimdal sand stone unit III leaf 2 (middle sand interval)
100ms T2 cutoff was used to distinguish mud filtrate from heavy oil and capillary bound water.

In both appendices 3 and 4, clear OBM mud filtrate signals (bright red spots) are seen on the shallowest shell and absent in shells 4 and 8. Notice the heavy oil signals (cyan) between 10 and 100ms. The absence of free water on all 3 shells suggests the reservoir is at irreducible saturation.
Appendix 5:- Dielectric Scanner interpretation results.

Track 1: Dielectric Scanner Caliper and bit size
Track 2: Dielectric Scanner formation water salinity (FSXD_ADT)
Track 3: Dielectric Scanner m parameter (MN_ADT) and core m parameter.
Track 4: Dielectric Scanner water saturation (SWXD_ADT) and Dean Stark core saturation. Notice the good match between dielectric and dean stark results.
Track 5: Lithology track
Track 6: Dip corrected 10in AIT resistivity (AM10), Dip corrected 90” AIT resistivity (AM90) and ADT flushed zone resistivity (RXD_ADT). Overlay of dip corrected resistivity curves with dielectric flushed zone resistivity suggests the absence of mobile water.
Track 7: Dielectric Scanner water filled porosity (PWXD_ADT) and total porosity derived from ELAN interpretation