Values of Surveillance, Production Data and Subsurface Modeling in Horizontal Well Planning and Execution in an Offshore Niger Delta Reservoir

Mohammed Bilyaminu, Enekhai Oshobugie, Oyie Ekeng, Emeka Anyanwu, Eric Tuitjer, Ibeh Chijioke, Nnaemeka Nwamara and Okoro Innocent
Chevron Nigeria Limited

ABSTRACT

D01 is a mature reservoir offshore Niger Delta with approximately 45% recovery from seven producers (three are still active, one of which is Loc-04, a horizontal well drilled to accelerate production/reserve growth). Reservoir pressure has only declined by 8% partly due to water injection which commenced at inception. The stratigraphy consists of an upper highly heterogenous transgressive and two lower multi-Darcy regressive layers. Successful placement of a horizontal well in a high permeability, re-saturated and heterogeneous, waterflood reservoir like the D01 can be challenging and requires careful integration of all subsurface data. This paper discusses the values derived from such an exercise. Initial assessment grossly underestimated the impact of stratigraphic heterogeneities as later seen in saturation logs, earth and simulation models. The assessment overestimated the oil column by assuming uniform fluid contacts from production data with no gas cap expansion. Saturation logs showed a smaller oil column and placed the column partly into the original gas zone contrary to prior assessment. However, active completions in other parts of the reservoir are deeper than the Current Oil-Water-Contact (COWC) seen in the saturation logs. These suggested non-uniform fluid contacts and a receding gas cap. Contacts tracking in two post-production wells using a simulation model confirmed these findings. The saturation logs also show ~20ft of 'by-passed' oil zones below the interpreted COWCs. These zones were marked by stratigraphic changes seen in static and dynamic models, which possibly influenced the observed fluid movements. Thus, the proposed Loc-04 well trajectory was relocated, and its lateral section further optimized. Loc-04 well pressure test results confirmed a receding Gas-Oil-Contact (GOC) with re-saturation of the gas zone. The results also indicated that a small shale layer acts as a localized barrier to flow. Loc-04 well was successfully drilled and is on course to meet its expected recovery. In reservoirs with similar oil properties and re-saturation history, Nuclear Magnetic Resonance (NMR) survey should not be expected to resolve GOC uncertainty - rely on pressure measurements instead. Subtle stratigraphic contrasts in water flooded reservoirs can influence fluid movements. Utilized wells near proposed new drills for acquisition of saturation logs. Used near bit multi-azimuthal resistivity tool to geo-steer the lateral well section through the heterogenous reservoir portion.

Key Words:

INTRODUCTION

D01 is a matured reservoir located in Field 'A' offshore Niger Delta with approximately 38 Million Stock Tank Barrels of Oil (MMSTBO) recovery over its 23 years production history from seven producers, three of which are still active. It consists of over 300 feet (ft) hydrocarbon column in a three-way fault assisted trap downthrown of a listric fault. The reservoir stratigraphy is made up of a well-developed massive sand sub-divided into a highly heterogenous transgressive upper layer and two lower multi-Darcy regressive layers. Most of the producers were completed in the more homogeneous layer which contains the highest volumes. The reservoir has recovered nearly 45% with only about 8% pressure decline. Pressure support comes from a combination of basal and edge water drive, and water injection which commenced shortly after inception of production in 1997. A total of 80.2 Million Barrels of Water (MMBW) have been injected till date with a cumulative Voidage Replacement Ratio (VRR) of 0.77. Recent reservoir studies and well results revealed stratigraphic controls on fluid flow resulting in non-uniform fluid contacts; oil re-saturation of gas zone; and economically viable development opportunities within the reservoir.

Placing a horizontal well in such a high permeability, re-saturated and heterogeneous, waterflood reservoir with high recovery was quite delicate and required careful

We thank Chevron Nigeria Limited (CNL) management and our partner National Petroleum Investment Management Services (NAPIMS) for permission to publish this work. We also thank our colleagues whose technical inputs were extensively used in the assessment of the opportunity as well as planning, drilling and completing the well.

integration of all subsurface data (such as production, wireline and saturation logs as well as earth and simulation models); values derived from this exercise are discussed below.

Regional Geologic Setting

The field is located offshore western Niger Delta within the miocene extensional tectonic setting which is characterized by the typical Niger Delta-style major listric growth faults. Sediments are majorly deposited in a mixed-influenced setting in a wave dominated delta (Figure 1).

FIELD GEOLOGY

Field Structural Setting

The field is a simple extensional structure comprising the main block characterized by rollover anticlines set up by a large structure building listric growth fault (Fault 1) and two smaller fault blocks defined by two other major extensional faults converging behind Fault 1 (Figure 2). The main and the east blocks have proven hydrocarbons; the main block contains 90% of the hydrocarbon in the field and can be described as a roll-over structure within the hanging wall of the main structure building fault.

The shallower reservoirs in the main block are mainly 4-

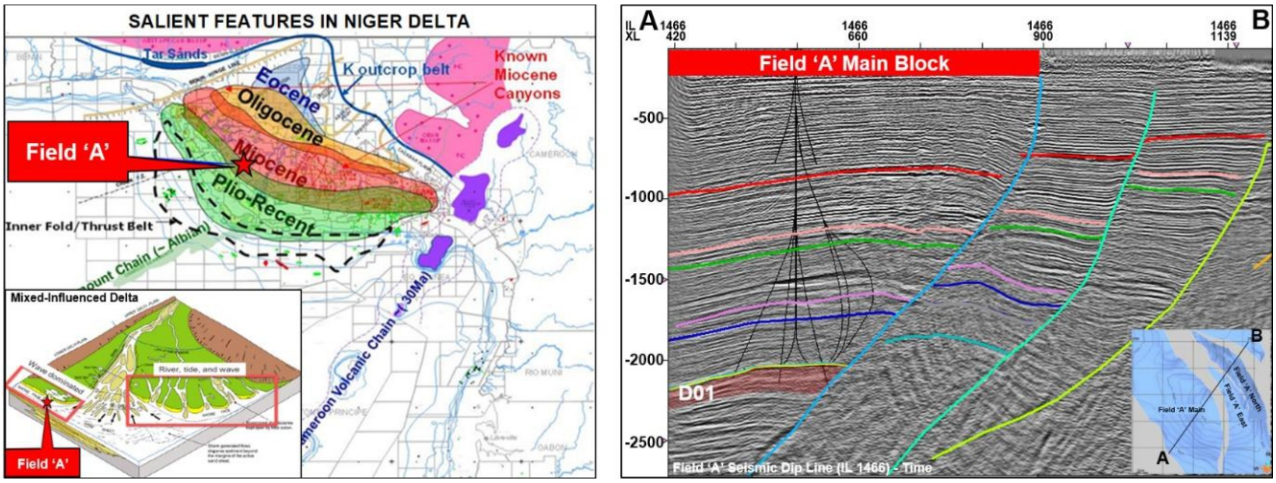


Figure 1: Location of D01 reservoir in Niger Delta Depobelts (Left) and within field structural setting (right).

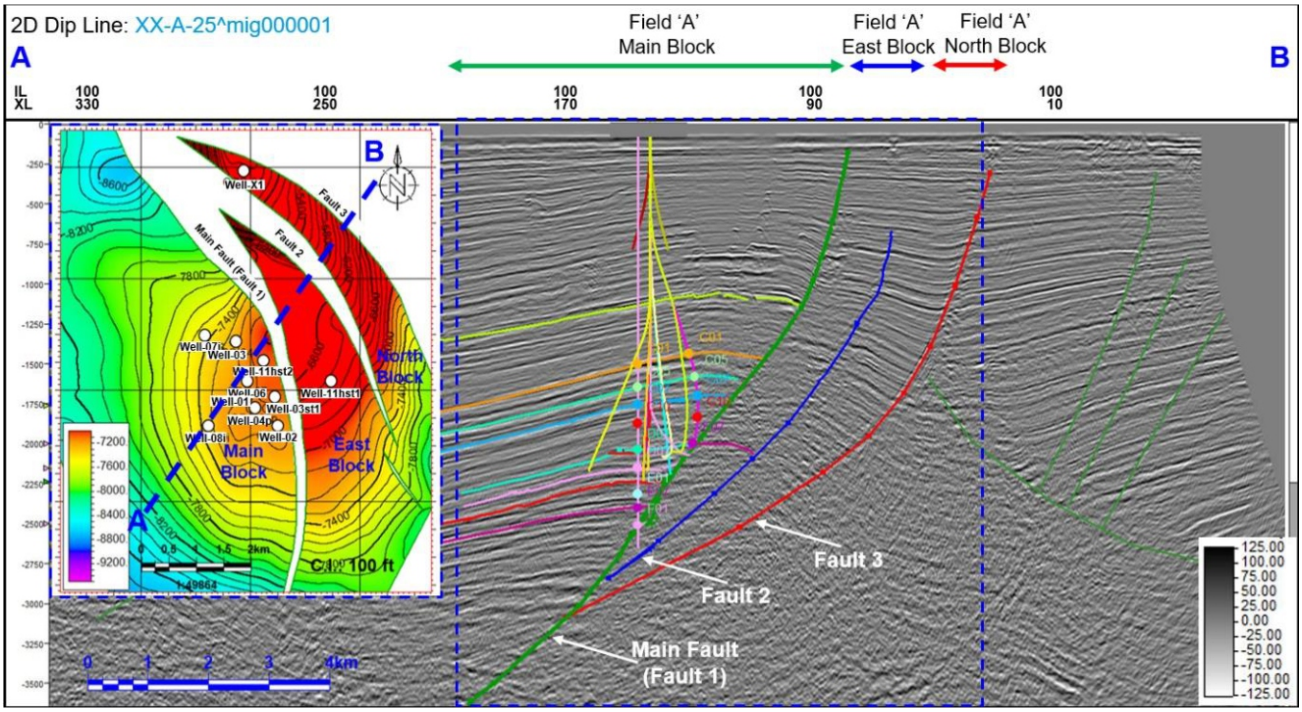


Figure 2: Seismic Dip Line showing Main, East and North Blocks within Field 'A' Structural Setting.

way dip hydrocarbon accumulations whereas the deeper sands are 3-way fault dependent structures. Oil and gas discovered in the east block were trapped within a structural wedge on the footwall of Fault 1 but there was no hydrocarbon discovery in the north block.

Field Depositional Setting and Stratigraphy

The field comprised thirteen (13) reservoirs distributed across five sand series. The shallowest sands (C-series) are within an approximate depth of 4,500 ft to 8,000 ft. True Vertical Depth Sub-Sea (TVDSS) and are mostly gas-bearing reservoirs. The D-sand series in which the subject reservoir is found, contains 78% of proven oil in place volume in the field and was encountered between 5,000 ft. to 8,000 ft. TVDSS approximate depth. The deepest hydrocarbon bearing sands are the E-sand series which are encountered at an approximal depth of 8,000 ft. to 9,500 ft. TVDSS and are mostly condensate bearing (Figure 3).

A Biostratigraphic analysis of Well-02 (1992) described the hydrocarbon bearing stratigraphic intervals in Field 'A' to be of Late Miocene to Middle Pliocene age as held by Martini (1971), Blow (1969/1979) and Bolli & Saunders (1988), see Figure 3 and Figure 4 .

From lithologic description of ditch-cuttings and wireline log motifs, A Biostratigraphic, Paleoenvironmental and Sequence Stratigraphic Analysis of Well-01 well (1997) indicated that Field 'A' stratigraphic intervals belong to the paralic Agbada Formation. Interpretation of paleoenvironments and other offset data during the analysis separated the stratigraphy into two (2) main lithofacies sequences which span three (3) lithofacies units within the Niger Delta Agbada formation consistent with classification of Evamy et al (1978), see Table 1 . Lithofacies sequence 2 has been subdivided into two lithofacies units based on the recognition of repetitive progradational up-ward-shoaling patterns within the sequence.

Hydrocarbon resources are concentrated in Lithofacies Unit 1 (D, E and F sand series) and Unit 2A (C01, C05, C09 and C10 sands).

Routine core analysis and geologic interpretation indicate an overall wave dominated setting with mostly Lower – Upper Shoreface sediments deposited in wave and storm-dominated shorelines (Junaid, 2017). Clear majority of the sediments are relatively clean sandstones (100 to >10,000md) that were deposited as part of a series of stacked, prograding deltaic shoreface successions. The core sampled three (3) thick successions (Lower regression, middle regression and an upper transgression) exhibiting coarsening upwards (regression) and fining upward (transgression) stacking patterns that are clearly seen in all the wells that penetrate the subject D01 reservoir; these patterns can also be clearly seen in shallow sands like the C05.

RESERVOIR GEOLOGY

Introduction

D01 is a saturated reservoir discovered in 1976 by Well-01. It has a total of twelve (12) well penetrations; seven of which have been completed and produced while two were completed as water injectors. This is the only developed and producing reservoir in the field.

D01 reservoir has a Stock Tank Oil Originally in Place (STOOIP) of 85.41 MMSTBO and Estimated Ultimate Recovery (EUR) of 51.65 MMSTBO. It also has an Original Solution Gas in Place (OSGIP) of 107.70 Billion Cubic Feet (BCF) and EUR of 70.82 BCF. Production started in October 1997 and has continued till date with

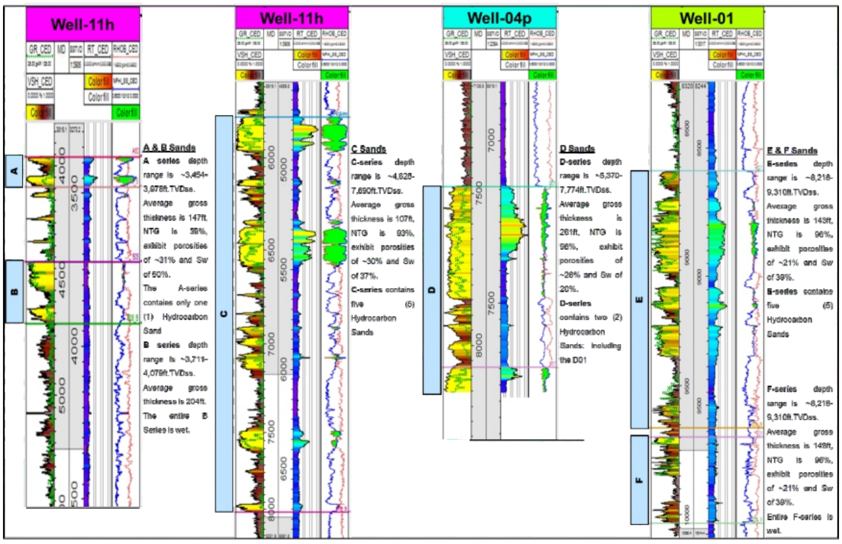


Figure 3: Field 'A' Composite Logs showing sand series within the field and descriptions.

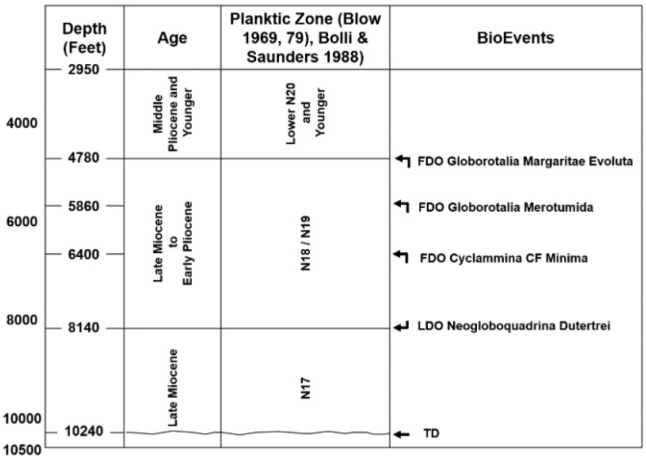


Figure 4: Foraminiferal Biozonation of Field 'A' from Well-02 (Blow, 1969/1979; and Bolli & Saunders, 1988).

Table 1: Field 'A' Lithostratigraphic Sub-divisions from analysis of Well-01 (Evamy et al (1978).

Depth Interval (feet)	Characteristics	Lithofacies Unit	Lithofacies Sequence	Formation
5046 – 2950	Progradational unit Sand-shale alternations Sand-shale ratio: - 25:75	2B	2	Agbada
6879 - 5046	Progradational unit Sand-shale alternations Sand-shale ratio:- 24:76	2A		
10240 - 6879	• Agradational unit • Sand-shale alternations • Sand-shale ratio:- 35:65	1	1	

cumulative production of 38.18 Million Barrels of Oil (MMBO) and 61.19 BCF of gas by year end 2019. The current reserves estimate is 13.47 MMSTBO and 10.64 BCF of gas.

Reservoir Structure

The D01 structure is a rollover anticline formed by the main growth fault (Fault 1). The structure strikes NW-SE and hydrocarbons are trapped within a 3-way dip closure on the downthrown side of Fault 1 ( ). In addition to flat spots and clear Original Oil-Water-Contacts (OOWCs) in several wells, borehole velocities provided very good seismic-to-well tie and control points for depth stretching velocities.

The twelve (12) well penetrations in the D01 top structure generally provide enough well control for the structural crest. However, there is significant depth uncertainty in the southern portion of the reservoir where there is no well penetration. A review of the seismic data shows a velocity push down effect in the southern area directly below the shallower gas-filled C01 to C05 sands – this resulted in a structural nose and a depression in that region (Figure 6). The D01 time structure map compares reasonably well with the depth-converted equivalent (Figure 6, Maps A & B), indicating that the structural nose is inherent in the seismic data and not caused by the velocity volume used in depth conversion. Therefore, the push down noted on the seismic which created the structural nose in that region of the reservoir can only be caused by slower velocities within the thick gas columns above the reservoir.

The hydrocarbon column is defined by an Original Gas-Oil-Contact (OGOC) from pressure data at -7235 ft. subsea and an OOWC from well logs at -7364 ft. TVDSS (Figure 10 and Figure 11).

Reservoir Stratigraphy

D01 reservoir log motif shows three distinct stacking patterns across the entire reservoir; a lower Regression 1, a middle Regression 2 and an upper Transgression. The interpretation of core, log signatures and seismic data for the reservoir show that clear majority of the sediments were deposited in wave and storm-dominated shoreface environments as part of a series of stacked, prograding deltaic successions (Figure 5, Figure 8 and Figure 9).

The sand units are dominantly coarsening upwards, clean and well developed with very good permeabilities averaging between 800 to 3000 millidarcies (mD). A super high permeable layer of about 15000 mD runs across the entire reservoir (Figure 7 and Figure 8).

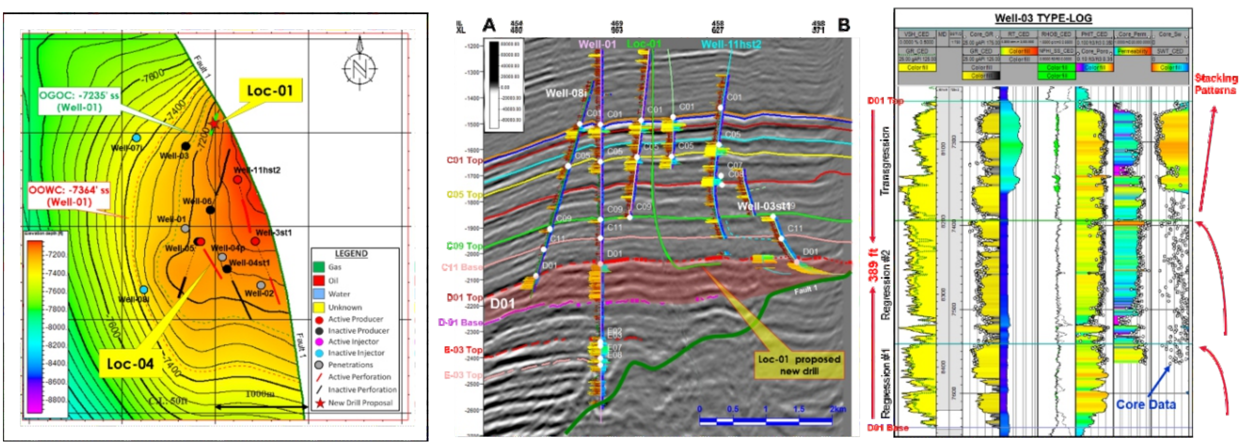


Figure 5: D01 Reservoir Structural Map (left), Seismic Section (middle) and Typelog with key stratigraphic layers (right).

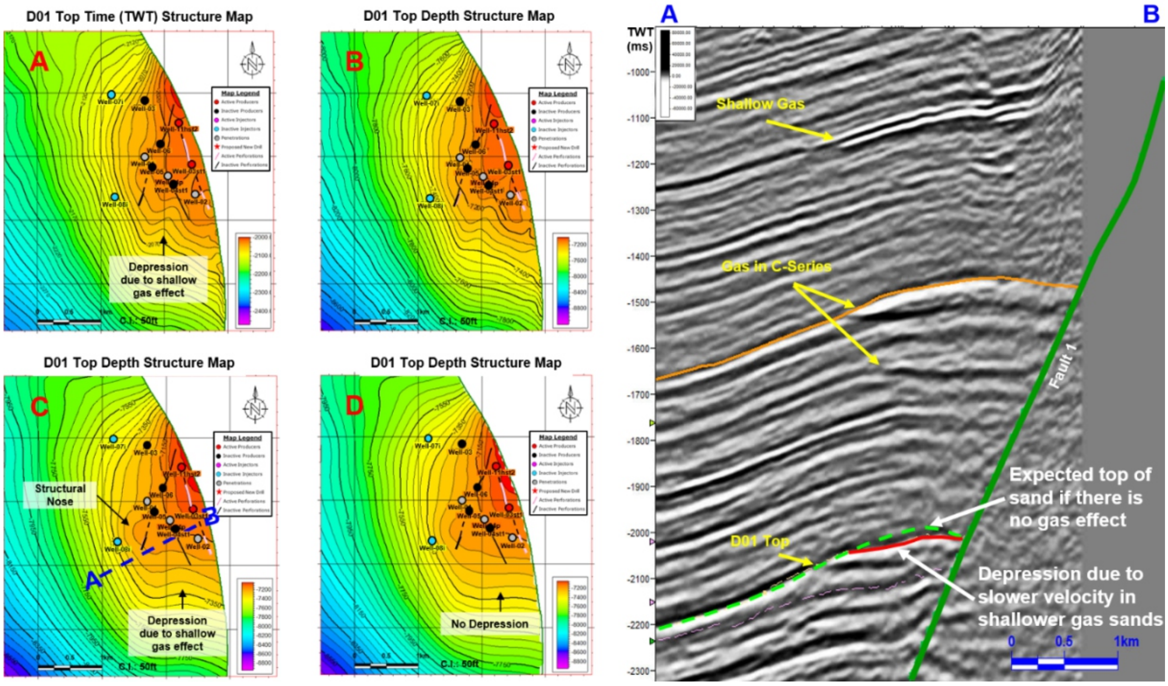


Figure 6: D01 top reservoir maps and 3D Seismic Section showing the impact of shallower gas reservoirs on top structure maps ('A' is two-way-time (TWT) structure map; 'B' is a depth structure map not constrained to well; 'C' is a depth structure map constrained to wells; 'D' is a depth structure map without gas effect.

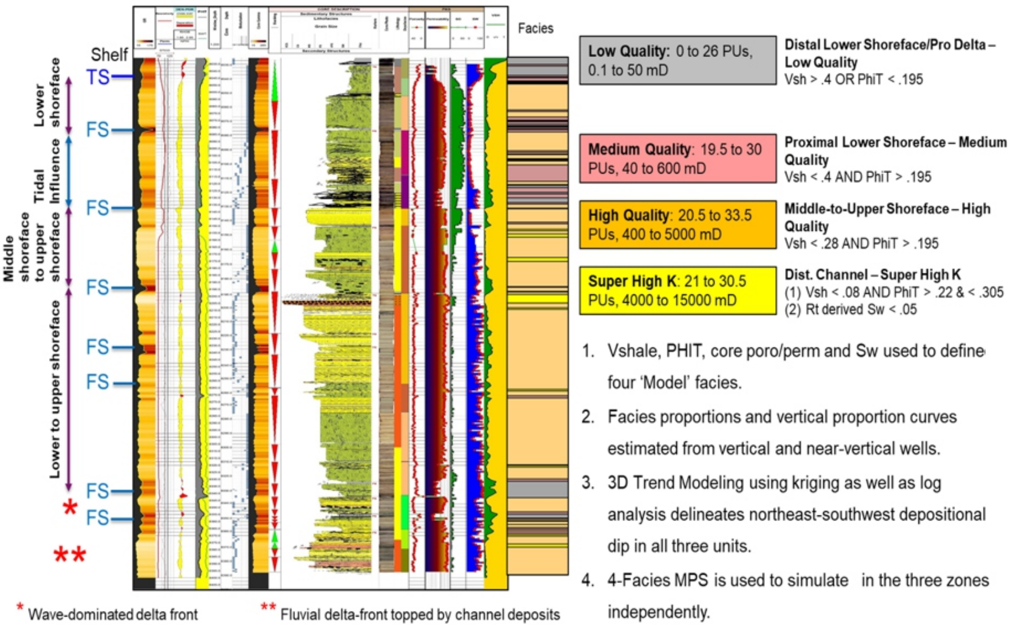


Figure 7: Lithofacies and Depofacies interpretation from Well-03 Core Data for the D01 Reservoir (Junaid, 2017).

Reservoir thickness and quality increase to the north-northwest and degrade off-structure. The average reservoir properties are; gross thickness of 320 ft., porosity of 0.26, Net-to-Gross (NTG) of 0.96, and water saturation (Sw) of 0.22 (Figure 9).

Initial Reservoir Evaluation

During the preliminary development opportunity evaluation of the D01 reservoir, an assessment of the current fluid contacts and remaining oil volume was carried out mainly based on Material Balance (MBal) analysis and well logs.

This assessment resulted in 30.70 MMSTBO of estimated Current Oil in Place (COIP) volume within a sixty-four feet (64 ft.) remaining oil column which was defined by a Current Gas-Oil-Contact (CGOC) at -7225 ft. TVDSS and a Current Oil-Water-Contact (COWC) at -7289 ft. TVDSS; predicting a regression of the OGOC by 3 ft. and COWC by 76 ft. (Figure 10 and Figure 11). The assessment presumed a stabilized system with uniform fluid contacts due to stoppage of water injection five years prior and a minimal withdrawal of about 1,000 barrels of oil per day (bopd).

As a result, a horizontal sidetrack (Loc-01), was proposed to be drilled in the northwestern flank of the reservoir where there is no active producer (Figure 10). The well was proposed to be landed attic of all active producers within the homogenous upper regressive stratigraphic unit.

Further Assessment and Reservoir Evaluation

A more detailed reservoir study integrating all available data was carried out to include; re-interpretation of core data acquired in the reservoir, re-processing of wireline log data, re-characterization, building of new earth and simulation models. The earth model highlighted stratigraphic heterogeneities that could impact fluid flow. The simulation model (completed in February 2018) indicated some influence of water injection on fluid movement from the dominant water injector (Well-07i injected 80% of cumulative volumes); this resulted into tilted fluid contacts in the north western area, a receding gas cap and a re-saturation of part of the gas zone with oil (Figure 12).

A Saturation log acquired in proximity to the proposed Loc-01 well showed a smaller than expected COIP of 27.78 MMSTBO and a 54 ft. of oil column, 42 ft. of which was distributed in the zone originally occupied by gas. However, active completions in other parts of the reservoir are deeper than the COWC seen in the saturation log. These suggested non-uniform fluid contacts and a receding gas cap. A validation exercise was carried out on the simulation model to test how well it predicted fluid contacts logged through the production life of the reservoir. The model closely matched the GOC logged by Well-11hst2 drilled in 2004 (-7229ft. TVDSS) and Well-03st1 drilled in 2006 (-7243 ft. TVDSS), see Figure 13.

Tectonic tilting and hydrodynamic sloping contacts are not uncommon (Dickey, 1988 and Estrada, 2000). Consequently, a sloping contact approach was adapted with thickening of the oil column away from the north (where Loc-01 is located) to the south east – this led to the re-location of the proposed well to the southern flank (see Loc-02 in Figure 12) with no change in the landing depth.

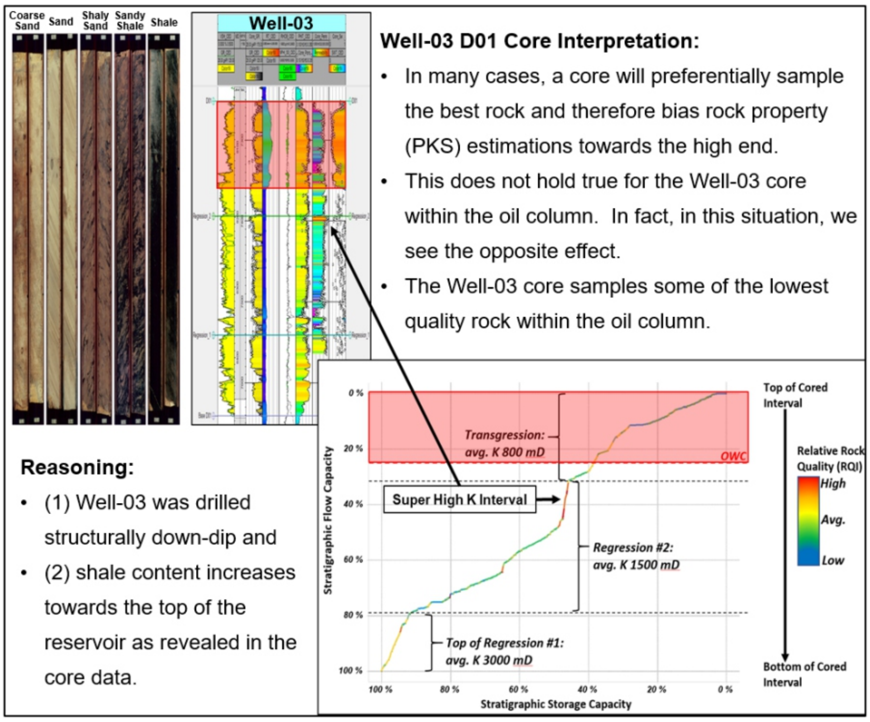
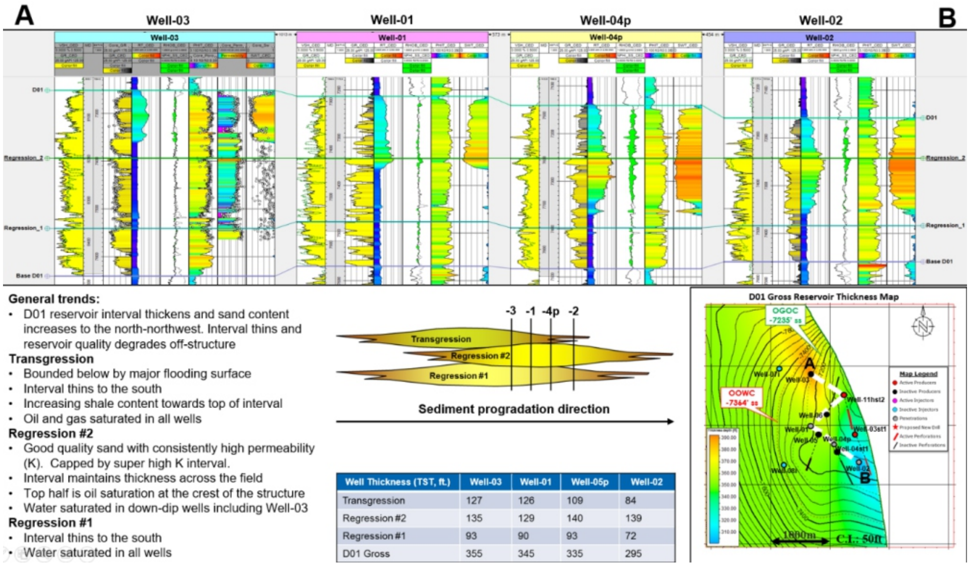


Figure 8: Core Data from Well-03 in the D01 reservoir range of Permeabilities.

A second saturation log was acquired in the southern area from Well-04hst1 (September 2018) close to the proposed Loc-02 in order to ensure spatial understanding of the current hydrocarbon column thickness. The results are largely comparable with those from the first saturation log but with a smaller (43 ft.) oil column, 37 ft. of which was distributed into the zone originally occupied by gas (Figure 14 , see log on the left). The contact logged by this



Well Thickness (TST, ft.)	Well-03	Well-01	Well-05p	Well-02
Transgression	127	126	109	84
Regression #2	135	129	140	139
Regression #1	93	90	93	72
D01 Gross	355	345	335	295

Figure 9: Stratigraphic section describing the stratigraphic layers and trends within the D01 reservoir.

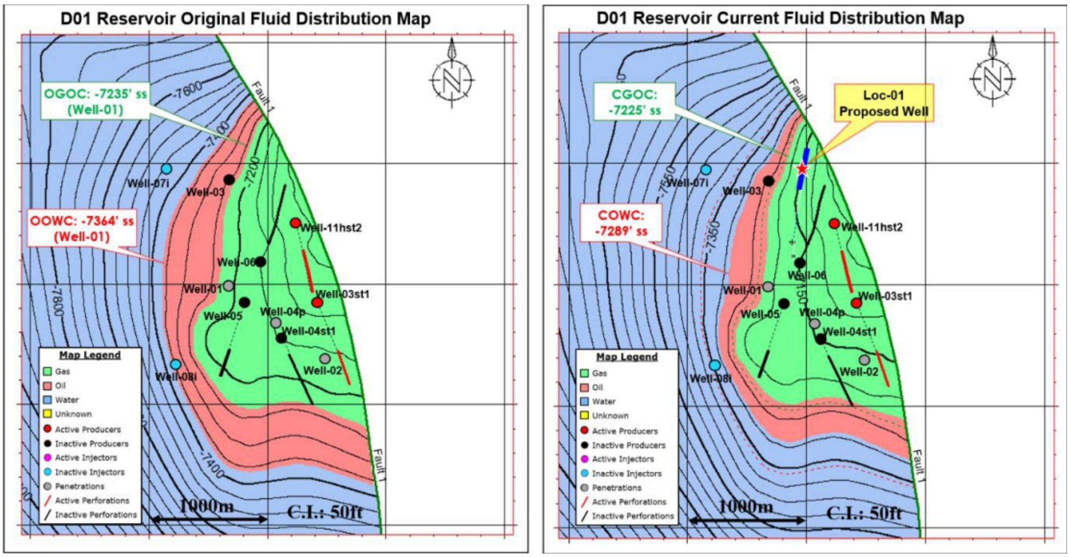


Figure 10: D01 reservoir fluid distribution maps at original state (left) and current state based on initial assessment (right).

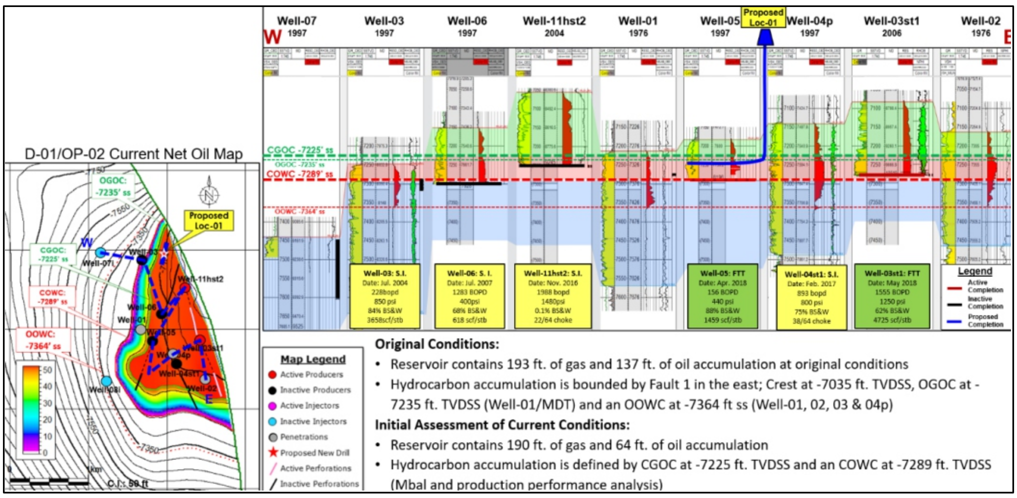


Figure 11: Structural log section showing original and current (initial assessment) fluid distributions within D01 reservoir and proposed well location.

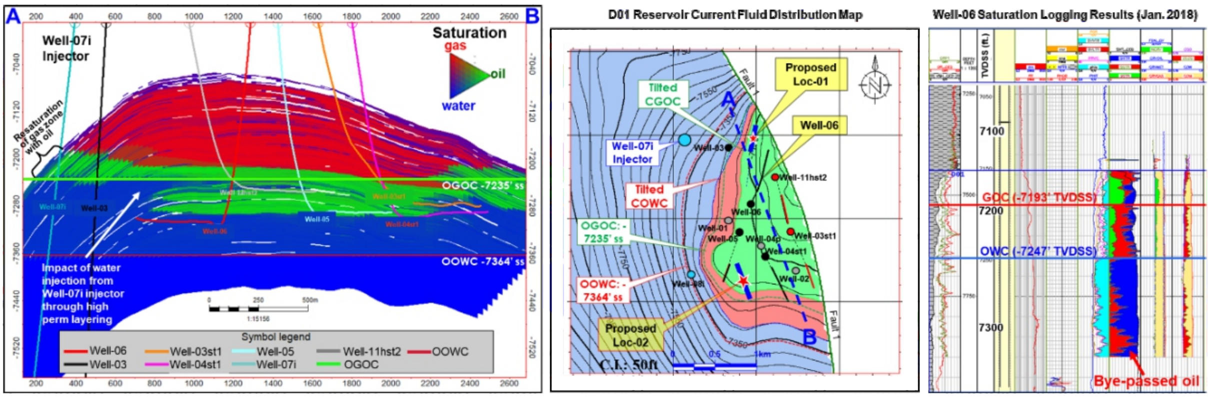


Figure 12: Cross section through D01 reservoir simulation model at end of history showing impact of water injection on fluid flow (left), inset map showing sloping contacts and location of proposed wells (middle), and Well-06 Saturation log (right).

saturation log puts the lateral of Loc-02 about 5 ft. above the logged COWC (Figure 14, see cross section on the right).

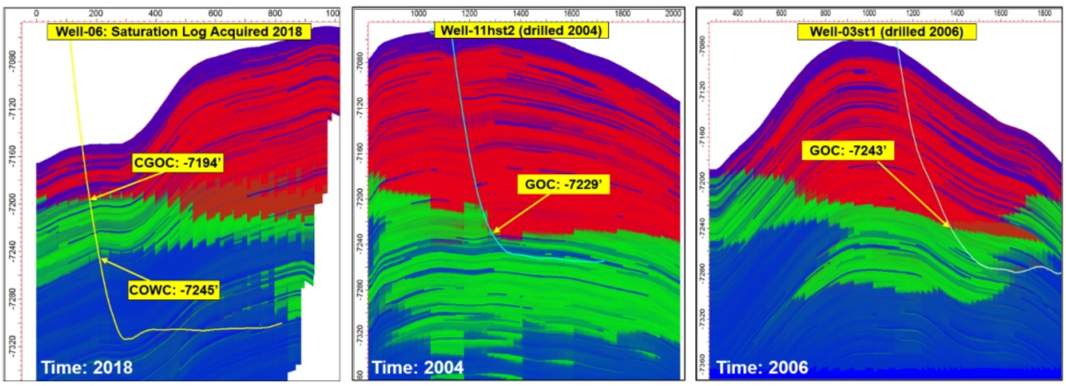
Both saturation logs show about 20 ft. of 'by-passed' oil zones below the interpreted COWCs. These zones were marked by stratigraphic changes seen in static and dynamic models, which possibly influenced the observed fluid movements.

Based on this, Loc-02 was further revised shallower (Loc-03, see cross section on Figure 14), but this resulted in lower oil recovery predicted by simulation model. In addition, there is high structural uncertainty in this area (which could impact the toe) due to the effect of slower velocities on the seismic data caused by shallow gas reservoirs discussed earlier (see Figure 6). Therefore, it became necessary to move the well towards existing well control and Consequently, Loc-04 was chosen as the final proposed well location in consideration of all the data. The lateral section was also planned to cut across the stratigraphic layers. Loc-04 is ~530 meters away from and ~48 feet above the shallowest active completion.

RESULTS

The actual well results indicated great consistency of the stratigraphy with the earth model. A 3 ft. shale layer was found acting as a localized barrier to flow ( ). The 3ft. shale buffer separates a gas zone above it from the oil zone below; revealing the gas limit to be 16 ft. deeper than the expected GOC defined by the saturation logs, this confirmed the impact of stratigraphy seen in the earth and simulation models.

Formation Pressure Gradients from Loc-04 confirmed the



Fluid Contacts from Saturation log (red Fonts) / Open hole logs vs. Simulation model estimates

	Well-06 (2018)		Well-11hst2 (2004)	Well-03st1 (2006)
Fluid Contacts	CGOC	COWC	GOC	GOC
Saturation log / Open hole log	-7193	-7247	-7228	-7243
2018 Simulation Model	-7194	-7245	-7229	-7243

Figure 13: D01 Simulation model Cross Section along well paths showing fluid contact tracking over time in post-production wells.

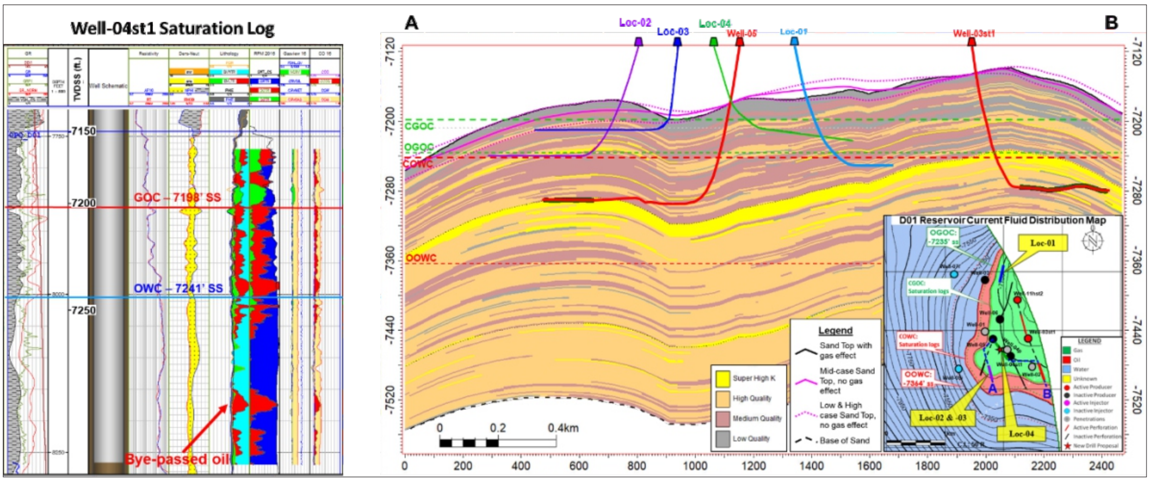


Figure 14: Well-04st1 Saturation log (left) and Cross Section through earth model facies showing reservoir heterogenities and locations/placements of all proposed wells within the D01 reservoir (right).

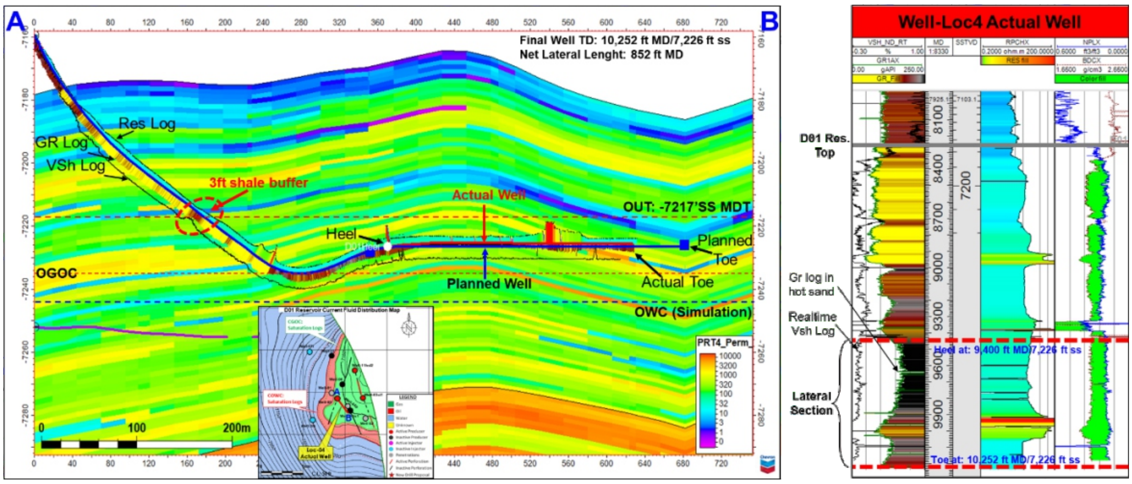


Figure 15: Permeability property (left) and Loc-04 actual log showing logged contacts, shale buffer and actual well path.

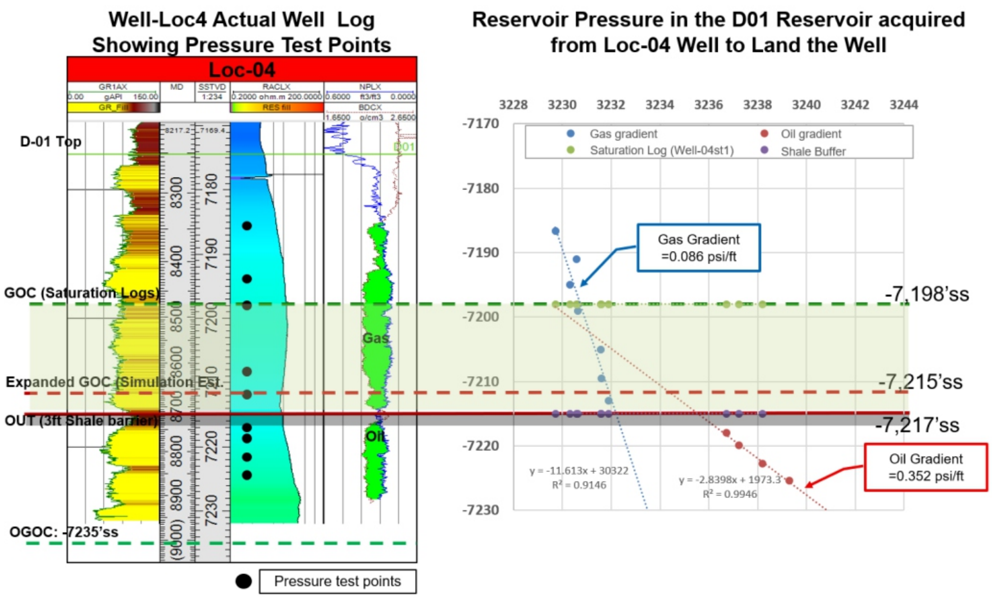


Figure 16: Identification of GOC using Pressure data and Correlation to Loc-04 well log (note the 3 ft. shale barrier).

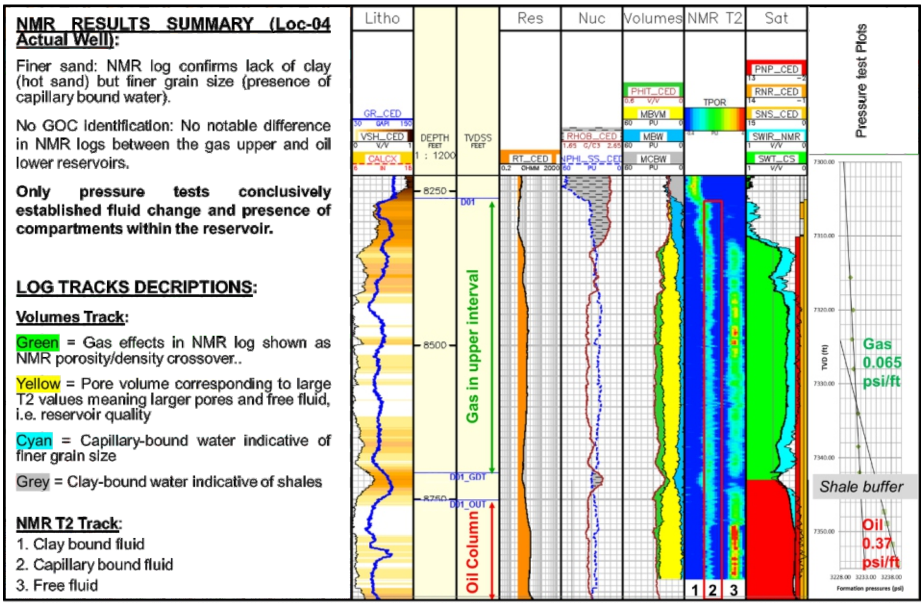


Figure 17: Fluid boundaries in Loc-04 well defined from LWD NMR and Pressure Data / Correlation of shale buffer to Fluid and Lithology.

receding GOC with re-saturation of the gas zone as assessed; the entire current proven oil column is within the original gas zone. It is defined by an HKO at -7217 ft. TVDSS and LKO at -7226 ft. TVDSS (Figure 15 and Figure 16).

Another challenge encountered was the difficulty in identifying the GOC in real-time during drilling, which was an anchor point for landing the well. Logging While Drilling (LWD) Nuclear Magnetic Resonance (NMR) is known to be very sensitive to gas and successfully used to characterize oil and gas reservoirs as described by Bittner et al (2006), Thorsen et al (2008) and Stanley et al (2017), therefore was relied upon to identify the GOC. A pre-job modeling performed using the oil API gravity (41^{o}) and 1000 Gas-Oil-Ratio (GOR) showed limited transverse magnetization time (T2) shift expected between oil and gas, but confirmed a significant porosity (pu) contrast at the GOC (4-5 pu deficit in 100% oil rim and up to 12 pu deficit in gas with 30/70% oil/gas mix). However, the tool could not define the gas-oil boundary due to the light API gravity of the oil worsened by the re-saturation effect. A back-up formation pressure tool was deployed to definitively identify the GOC and land the well (Figure 17).

Loc-04 well was successfully completed, brought on production at an Initial Production (IP) rate of 2000 bopd and is on course to meet the expected EUR.

CONCLUSION

The initial assessment of the development opportunity in the D01 reservoir overestimated the remaining oil column and volume, predicted negligible movement in the GOC over time and assumed flat fluid contacts since there was no water injection in the last few years with very minimal withdrawal. The assessment didn't envisage that GOC has significantly receded into the gas zone and substantial oil volume has re-saturated that zone. Reservoir heterogeneities were not seen to be a significant influence on the current distribution of fluid within the reservoir. Depth uncertainty was not considered a major concern except for the shallow gas effect. However, with the meticulous integration of all static and dynamic data, the true status of the current conditions within the reservoir was established. Consequently, the horizontal well was properly placed, successfully executed and put on production as seen in the actual well results.

Lessons Learned

Integration of saturation logs with production data enabled correct assessment of the development opportunity, placement of the horizontal well within the oil column and design of the lateral section for optimal performance.

When evaluating for further development opportunities, it is expedient to ascertain the actual current fluid conditions within matured water flooded reservoirs early in the assessment stage.

In such reservoirs with very little contrast between the oil and gas properties and re-saturation history, NMR alone might not be enough to resolve GOC uncertainty - incorporate formation pressure measurements also.

Subtle stratigraphic contrasts can influence fluid movements and create by-passed zones in water flooded reservoirs.

Best Practices

Wells near proposed new drills were utilized for acquisition of saturation logs.

Re-evaluated data using new methodologies/knowledge.

Near bit multi-azimuthal resistivity tool was used to geo-steer the lateral well section through the heterogenous reservoir portion.

Challenges

Inability to identify CGOC using NMR tool to land the well – this was resolved with formation pressure surveys Figure 16 and Figure 17). Radioactive sands encountered in Loc-04 Well appearing as low gamma ray on LWD logs was addressed in real-time using volume of shale calculation while drilling (Figure 15).

REFERENCES CITED

Junaid S. (2017): Sedimentological Analysis and Core Description of A, B, C, D, E, F, G, H and I Fields. Study Report number RFX4289825.

Biostratigraphic, Paleoenvironmental and Sequence Stratigraphic Analysis of Well-01. Global Energy Company Limited (1997), 4 – 30.

Biostratigraphic Analysis Report of Well-02. Report Number CH 9104. Goetrex Systems Ltd (1992), 21– 37.

Martini, E. (1971): Standard Tertiary and Quaternary Calcareous Cannoplankton zonation. In: Farinacci (Editor), Proceedings II Planktonic Conference, Roma (1970), 2:739-785.

Bolli, H. M. and Saunders, S. B. (1988): Oligocene to Holocene low latitude planktic foraminifera. In Bolli, H.M.: Saunders, J.B. and Perch-nielsen, K (Eds.), Plankton Stratigraphy. Cambridge University Press: 155 – 262.

Blow, W. H. (1969): Late Middle Eocene to Recent Planktic foraminiferal biostratigraphy. Proceeding first International Conference Planktonic Microfossils, Geneva (1967), 199-422.

Evamy, D. D.; Haremboure, J; Kamerling, P; Knaap W.A.; Molloy, F.A. and Rowlands, P.H. (1978): Hydrocarbon Habitat of Tertiary Niger Delta. American Association of Petroleum Explorationists Bulletin 62(1), 1-39.

Dickey, P. A.: ¨Discussion of Hydrodynamic Trapping in the Cretaceous Nahr Umr Lower Sand of the North Area, Offshore Qatar¨ Journal of Petroleum Technology (1988), 1075-1076.

Estrada, C. and Mantilla, C. Tilted oil water contact in the Cretaceous Caballos Formation, Puerto Colon Field, Putumayo Basin, Colombia. Paper SPE 59429. Presented at the Society of Petroleum Engineers Asia Pacific Conference, Yokohama, Japan, April 25–26, 2000.

Thorsen, A.K., Eiane T., Thern, H., Kroken, A., Iversen, M., Antonsen, F. Enhanced Net-to-Gross Understanding for Horizontal-Development Drilling in Complex Mature Reservoirs, Paper SPE 109274. Presented at the SPE Western Regional and Pacific Section AAPG Joint Meeting, Bakersfield, California, March 31–April 2, 2008.

Stanley, O., Ono, D., Victor, O., Charlie, T. Gas Identification in Thin Beds using LWD Measurements – West Africa Offshore Example. Paper SPE 189055-MS. Presented at the SPE Nigeria Annual International Conference and Exhibition, Lagos, Nigeria, July 31 –August 2, 2017.

Bittner, R., Komarek, F., Thern, H. F., Kruspe, Th., Kirkwood, A., Chemali, R. Magnetic Resonance While Drilling – A Quantum Leap in Everyday Petrophysics. Paper SPE 100336. Presented at the SPE Europec/EAGE Annual Conference and Exhibition, Vienna, Austria, June 12–15, 2006.