# Impacts of Subtle Reservoir Stratigraphic Changes on Fluid Dynamics - Case Study of DD Reservoir

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## Abstract

DD is a matured reservoir in Field 'A' offshore Niger Delta with approximately 45% recovery. The reservoir pressure has only declined by 8% in part due to water injection which started at inception. The reservoir stratigraphy consists of two lower multi-Darcy regressive layers overlain by a highly heterogenous transgressive interval. Further reservoir development targeting the transgressive layer within such a reservoir can be challenging and requires good understanding of the impacts of reservoir stratigraphic changes. This paper discusses the impacts of subtle reservoir stratigraphic changes on fluid dynamics observed while planning a horizontal well, during the actual well drilling and after the well was brought online. Reservoir studies (constrained to core data) indicated significant lithologic variability within the reservoir, though this was initially underrepresented in the first pass Earth Model (EM) as revealed by a Simulation Model (SM) run. The EM assumed a uniform upward fluid flow resulting into flat fluid contacts notwithstanding the impact of peripheral water injection. Both SM and Saturation logs suggested non-uniform fluid contacts and preferential fluid flows along high perm streaks with shale/low perm layers serving as local barriers; the saturation logs show ~20ft of 'by-passed' oil zones below the interpreted Current Oil Water Contacts. The SM shows that the lateral section of the high-rate oil producer in the field is in an isolated oil pool within the bypassed zone beneath a 100% swept zone. These zones were marked by stratigraphic changes seen in static and dynamic models, which possibly influenced the observed fluid movements. Thus, the lateral section of the proposed Well-XH trajectory was further optimized to cut across many stratigraphic layers. MDT results from the actual Well-XH established a gas gradient below the GOC down to a localized shale streak, and an oil gradient up to the same streak – indicative that the small shale layer acts as a localized barrier to flow. Well-XH was successfully completed and put on production. However, the water cut significantly increased with less than a year of production – this was faster and higher than SM prediction. A careful review of this behavior in both EM and SM raised a suspicion that a high BSW-producing well that was shut in prior to that spike was channeling the water away from Well-XH. Developing the heterogenous transgressive layer within the DD reservoir revealed some controls of reservoir stratigraphic changes on fluid movements, which are the subject of this paper.

**Keyword:** *Stratigraphy, Heterogeneities, Bye-Pass, Viscous Fingering, Channeling, Waterflood, Sweep, Streaks, Permeability, Baffle, saturation logs, breakthrough, Watercut*

# INTRODUCTION

Reservoir studies (constrained to core data) indicated significant lithologic variability within DD reservoir, though this was initially underrepresented in the first pass Earth Model (EM) as revealed by a Simulation Model (SM) run. The EM assumed a uniform upward fluid flow resulting into flat fluid contacts notwithstanding the impact of peripheral water injection. Both SM and Saturation logs suggested non-uniform fluid contacts and preferential fluid flows along high perm streaks with shale/low perm layers serving as local barriers; the saturation logs show ~20ft of 'by-passed' oil zones below the interpreted Current Oil Water Contacts. The SM shows that the lateral section of the high-rate oil producer in the field is in an isolated oil pool within the bypassed zone beneath a 100% swept zone. These zones were marked by stratigraphic changes seen in static and dynamic models, which possibly influenced the observed fluid movements. Thus, the lateral section of the proposed Well-XH trajectory was further optimized to cut across many stratigraphic layers. MDT results from the actual Well-XH established a localized shale layer acting as a localized barrier to flow.

DD is a brown reservoir in Field 'A' offshore Niger Delta with approximately 45% recovery over its 24 years production history. The reservoir has produced nearly 40 MMBO with only about 8% pressure decline due mostly to 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 flows resulting in non-uniform fluid contacts, oil by-passed zones, water channeling, preferential oil sweeps and thus impact on well performances. These phenomena, principally caused by 'viscous fingering'; a condition whereby a displacing fluid in a reservoir bypasses the displaced fluid, creating uneven or fingered profile (Greenkorn et. el., 1988, Sarma, 1986, Zahra et. el., 2018, Kargozarfard et. el., 2019, and Schlumberger Oilfield Glossary). Sarma (1986) acknowledged reservoir heterogeneity and stability of the displacement process as two main causes of premature breakthrough of flooding fluid in an Enhanced Oil Recovery (EOR) process. Studies as early as Engleberts and Klinkenberg (1951) and more recently Collins (1976) and Zahra et. el. (2018) revealed that permeability, system geometry and displacement velocity of the displacing fluid, among others, are pertinent parameters to stability (viscous fingers) and viscous fingering in porous medium. Zahra et. al. (2018) established a critical flow rate above which, higher injection rate adversely affects oil displacement through fingering which results in ineffective sweeps. Developing the heterogenous transgressive layer within the DD reservoir revealed some controls of reservoir stratigraphic changes on fluid movements, which are the subject of this paper.

## 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 (

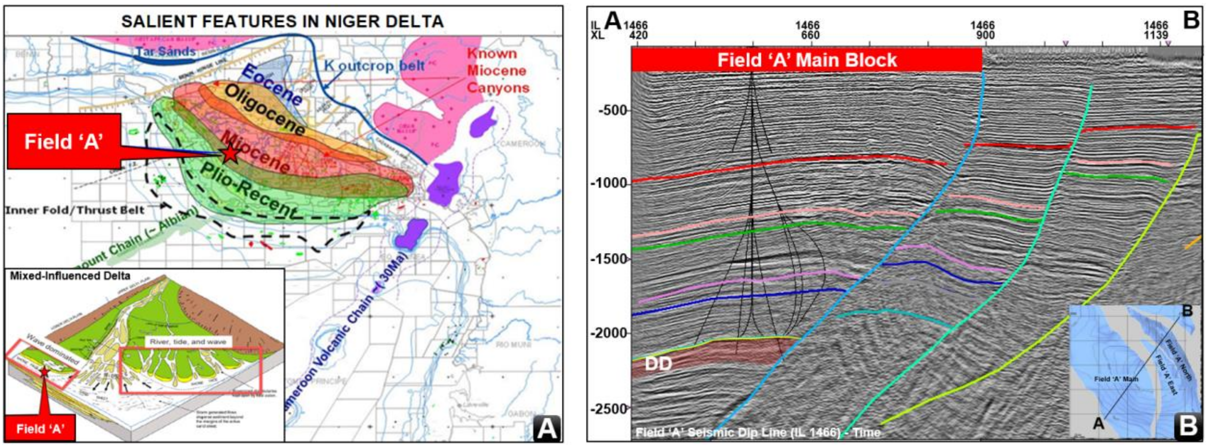



**Figure 1**).

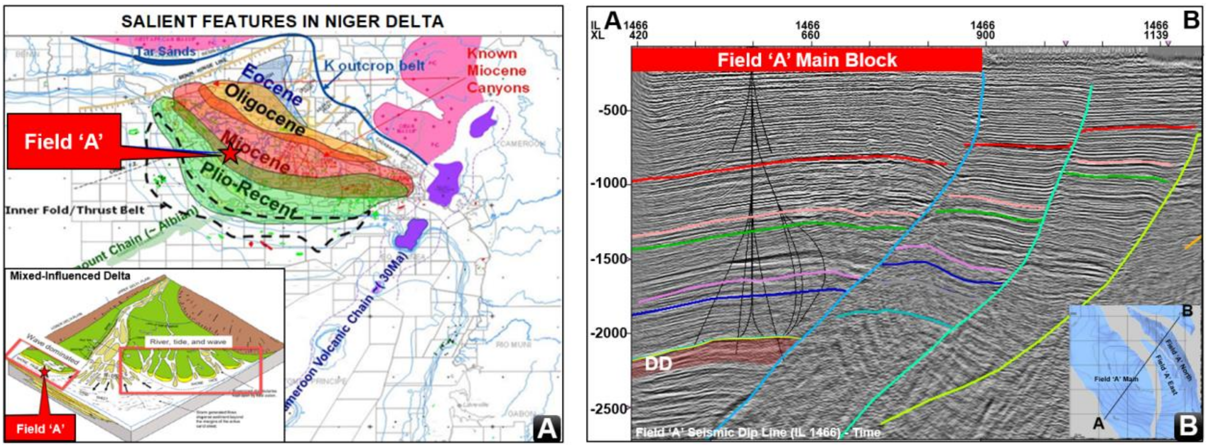





***Figure 1:*** *Location of DD reservoir in Niger Delta Depobelts (A) and within field structural setting (B).*

# 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 growth fault (Fault 1) and two smaller fault blocks defined by two other normal faults (Faults 2 and 3) converging behind Fault 1 (

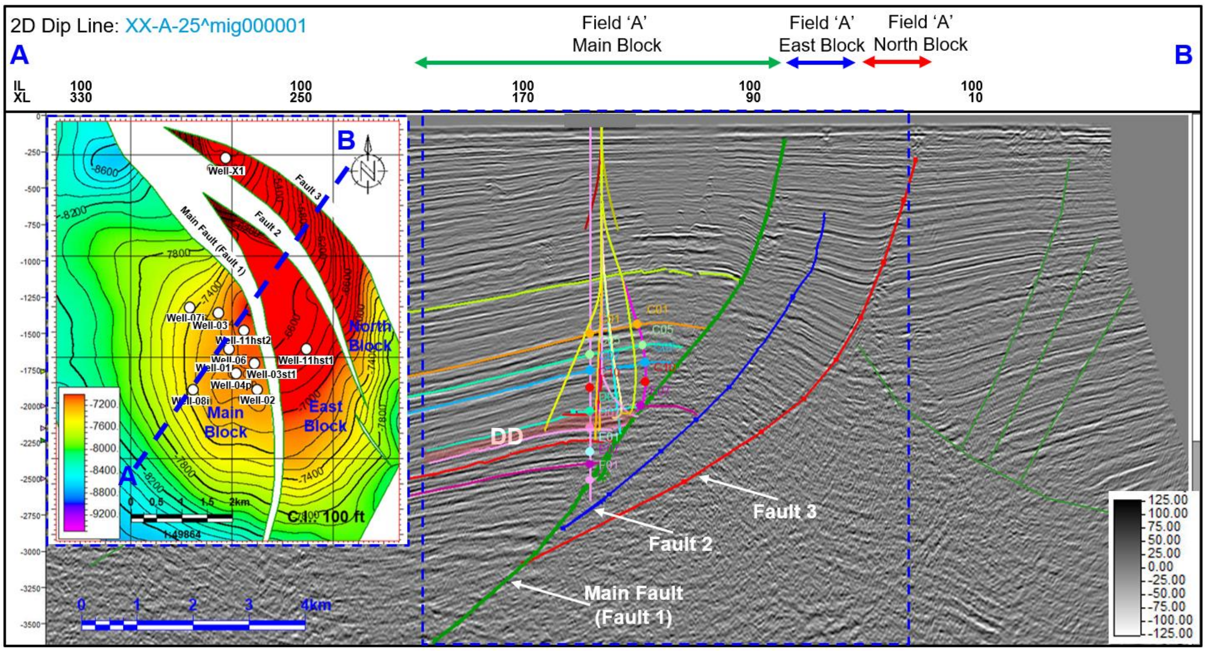



**Figure 2**). The main block contains 90% of the hydrocarbon in the field and can be described as a roll-over structure within the hanging wall of Fault 1.

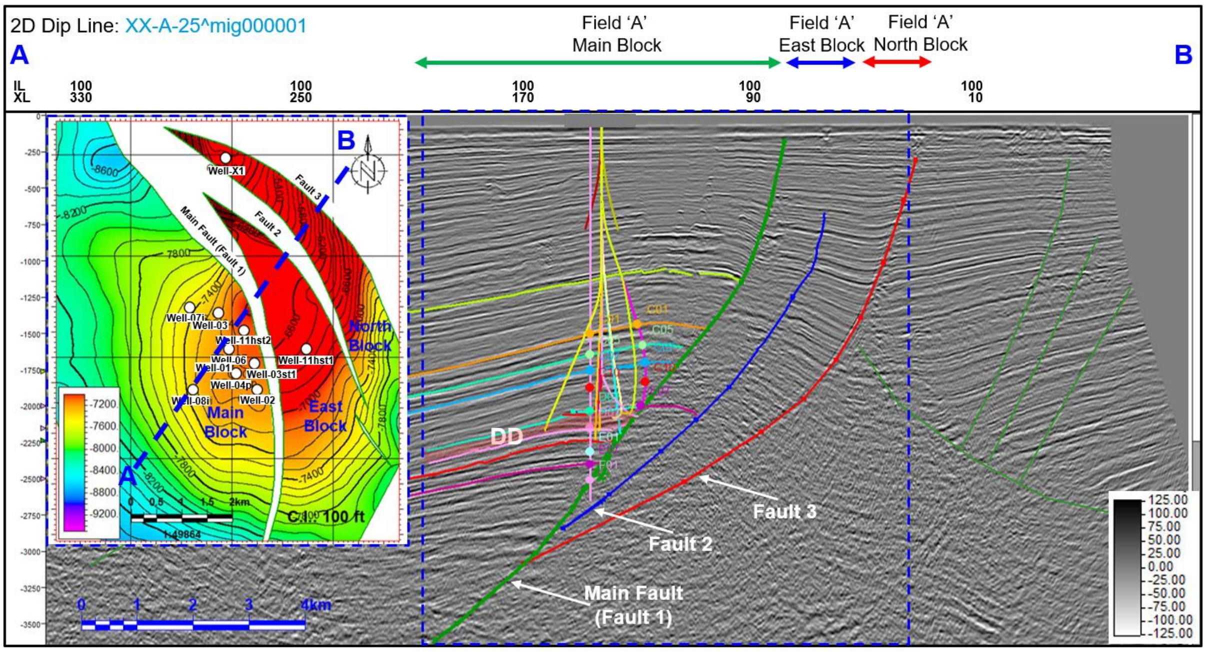



***Figure 2:** Seismic Dip Line showing Main, East and North Blocks within Field 'A' Structural Setting.*

The shallower reservoirs in the main block are mainly 4-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 is no discovery in the north block.

## DATA AND METHODOLOGY

**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 (

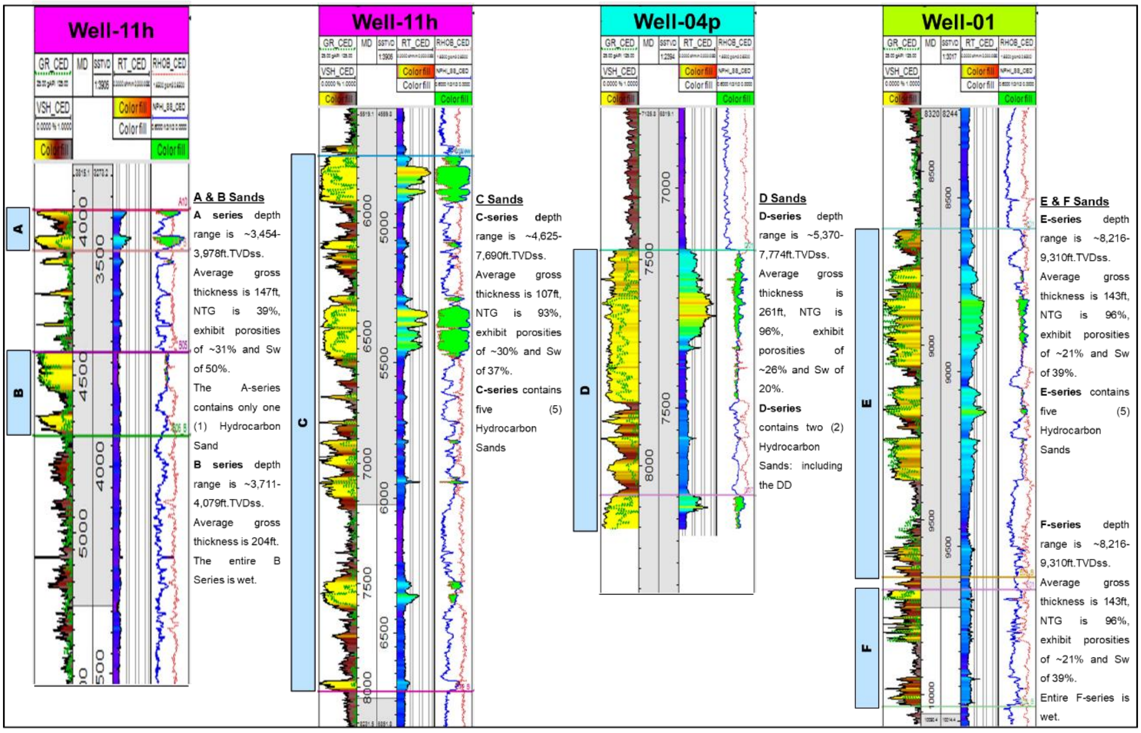



**Figure 3**).

An in-house biostratigraphic analysis of Well-02 carried out in 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),

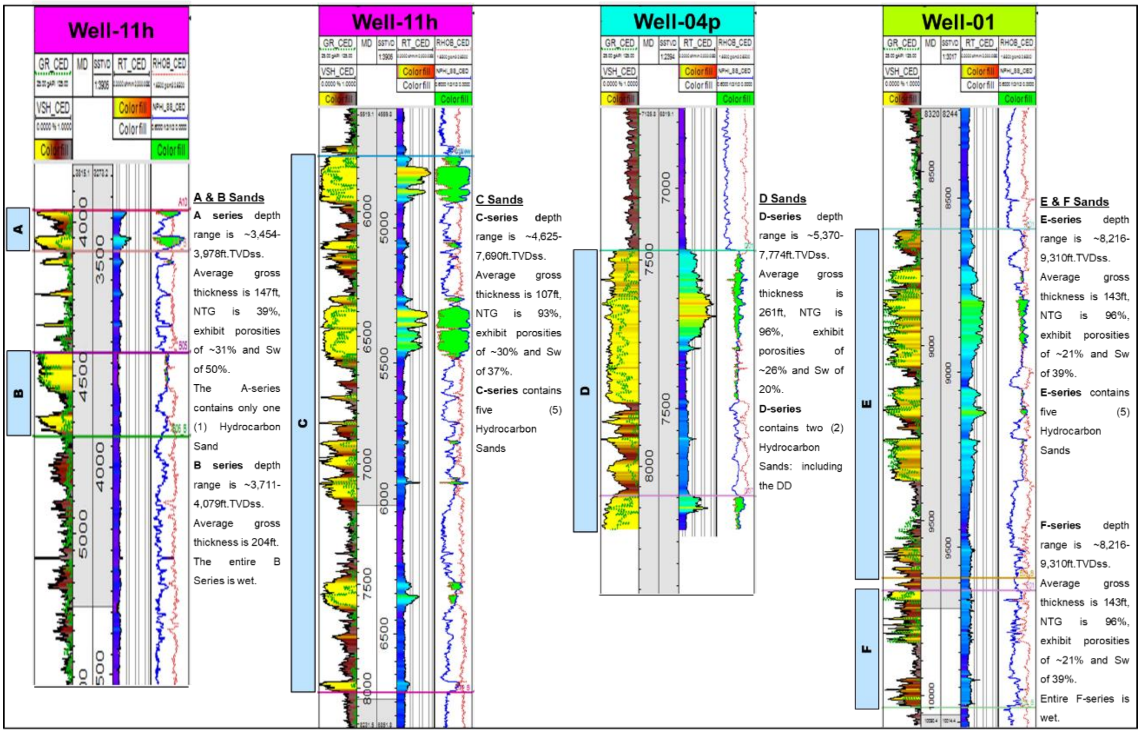



**Figure 3 and Figure 4**.

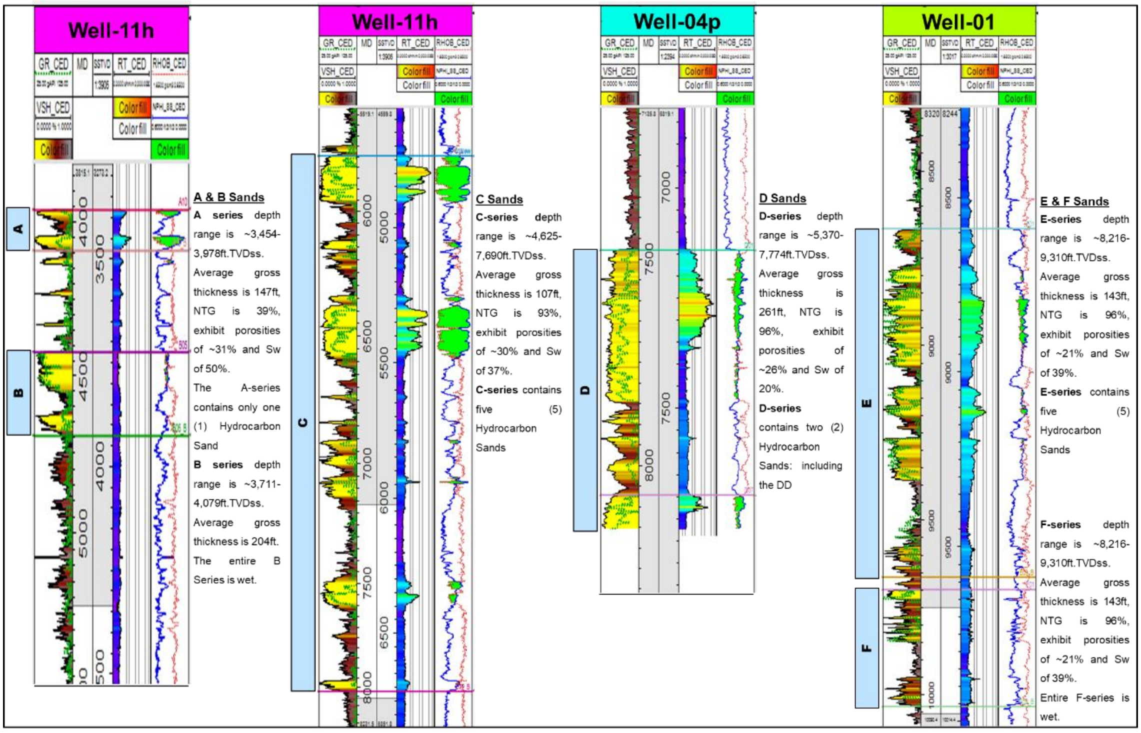



***Figure 3:** Field 'A' Composite Logs showing sand series within the field and descriptions.*

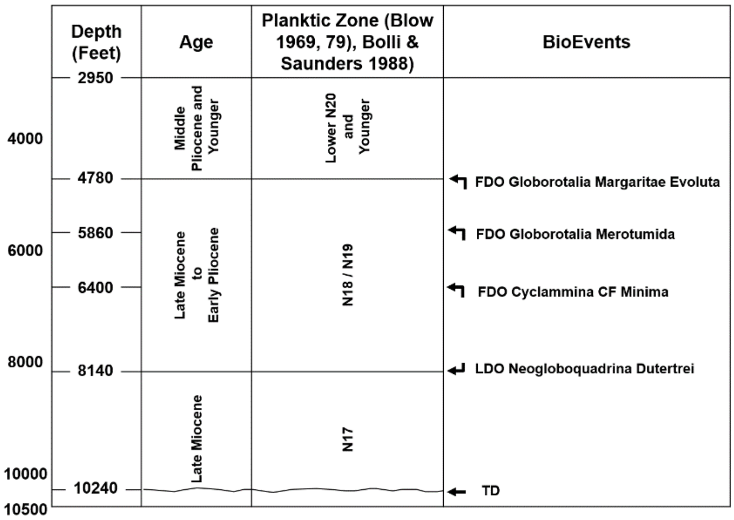


***Figure 4:*** *Foraminiferal Biozonation of Field 'A' from Well-02 (Blow, 1969/1979; and Bolli & Saunders,1988).*

Lithologic description of ditch-cuttings and wireline log motifs from an in-house Biostratigraphic, Paleoenvironmental and Sequence Stratigraphic Analysis of Well-01 carried out in 1997, 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) – **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 (CA, CB, CC, CD sands).

***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<br>• Sand-shale alternations<br>• Sand-shale ratio: - 25:75 | 2B | 2 | Agbada |
| 6879 - 5046 | • Progradational unit<br>• Sand-shale alternations<br>• Sand-shale ratio:- 24:76 | 2A | | |
| 10240 - 6879 | • Agradational unit<br>• Sand-shale alternations<br>• Sand-shale ratio:- 35:65 | 1 | 1 | |

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 according to Junaid, 2017 in Sedimentological Analysis and Core Description of Field A. 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 DD reservoir; these patterns can also be clearly seen in shallow sands like the CB.

## Reservoir Geology

DD 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. The reservoir consists of over 300 feet (ft) hydrocarbon column within a well-developed massive sand sub-divided into two lower multi-Darcy regressive layers overlain by a highly heterogenous transgressive interval. Most of the producers were completed in the middle more homogeneous layer. DD currently has two (2) active producers and one (1) active water injector, although one other injector is capable of injecting but shut in for reservoir management purpose.

DD 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 cumulative production of 39.44MMBO and 63.27 BCF of gas by year end 2020. The current reserves estimate is 12.21 MMSTBO and 8.56 BCF of gas.

**Reservoir Structure:** The DD 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 hanging wall of Fault 1 (

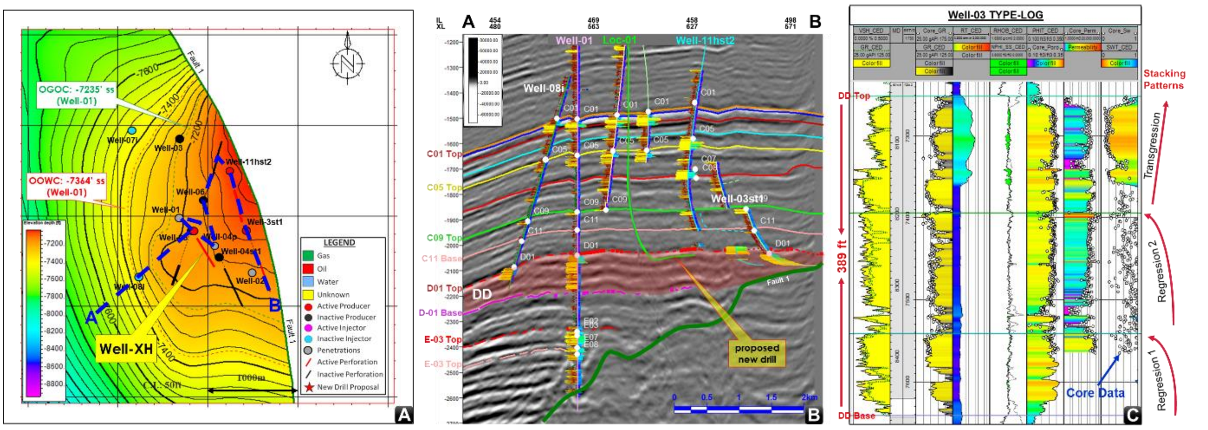



**Figure 5**). In addition to flat spots and clear Original Oil-Water-Contacts (OOWCs) in several wells, borehole velocities provided very good seismic-to-well tie and control points for depth stretching velocities.

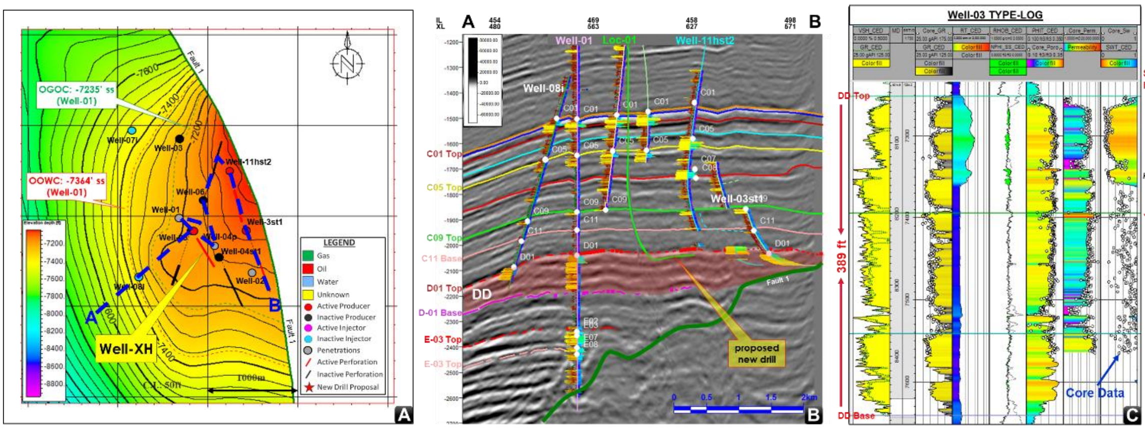


*Figure 5: DD Reservoir Structural Map (A), Seismic Section (B) and Typelog with key stratigraphic layers (C).*

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 (

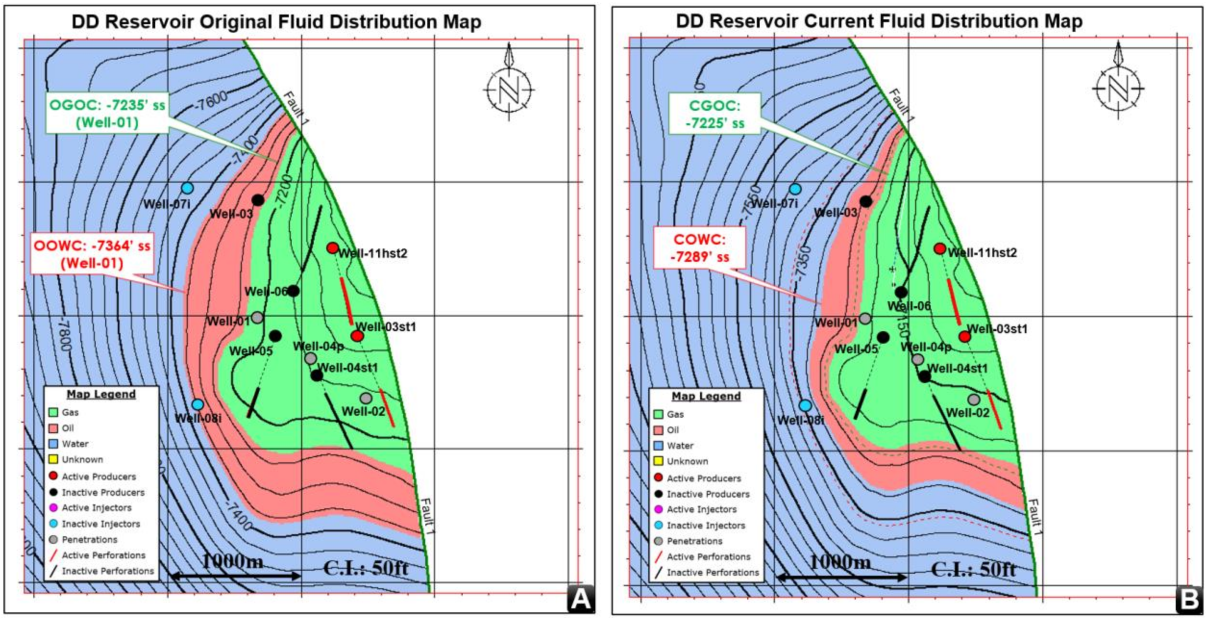



**Figure** **6** and

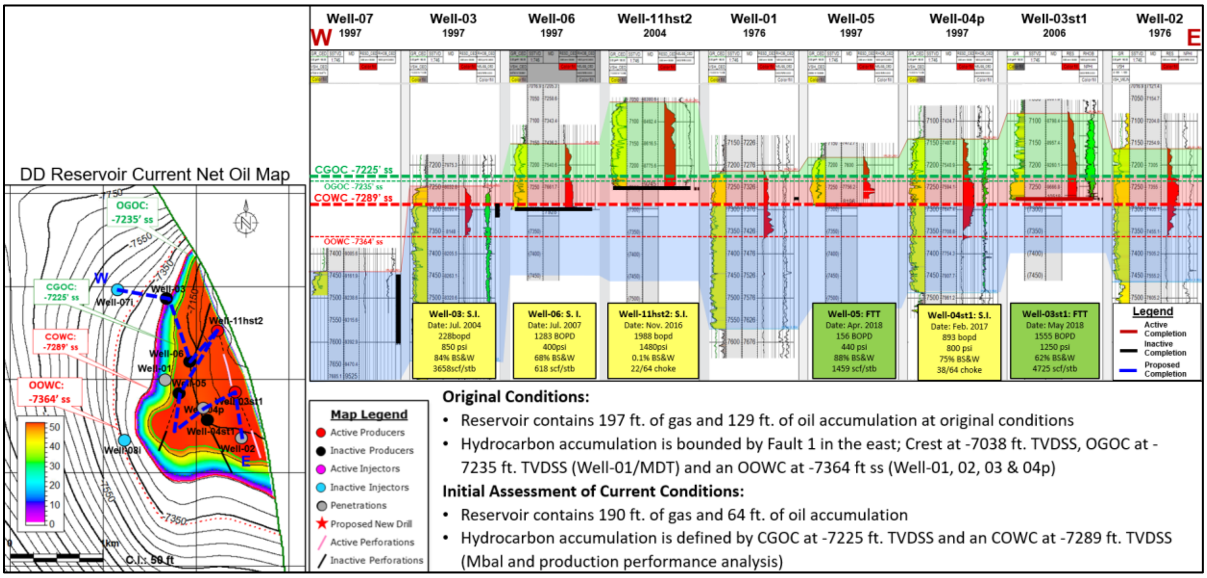



**Figure 7**).

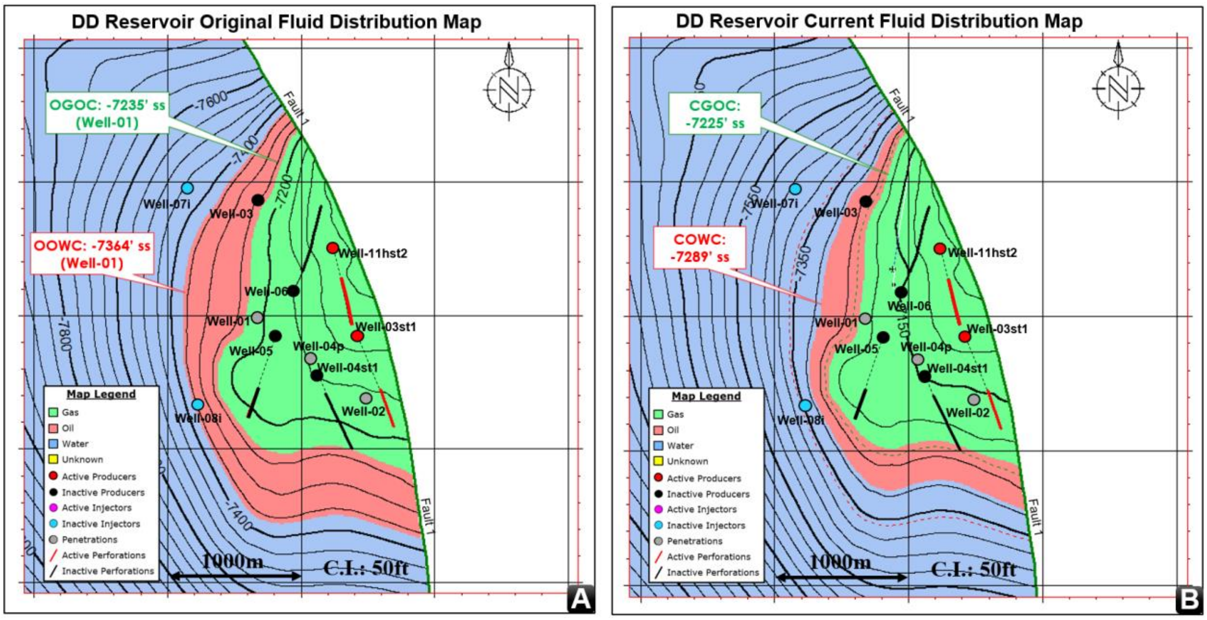



*Figure 6: DD reservoir fluid distribution maps at original state (A) and current state based on initial assessment (B).*

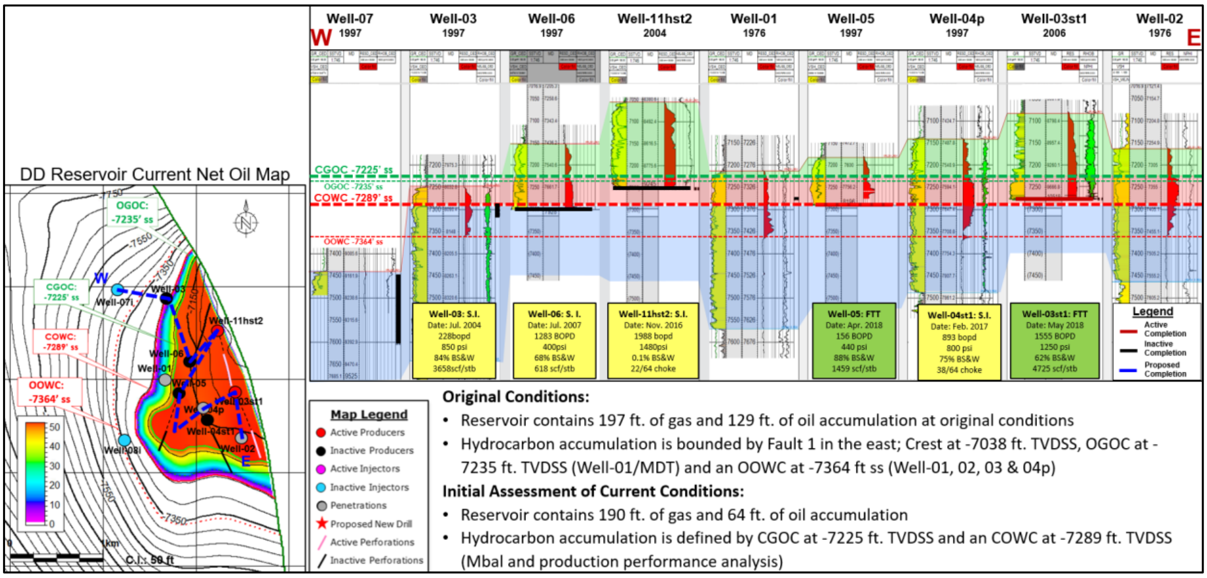
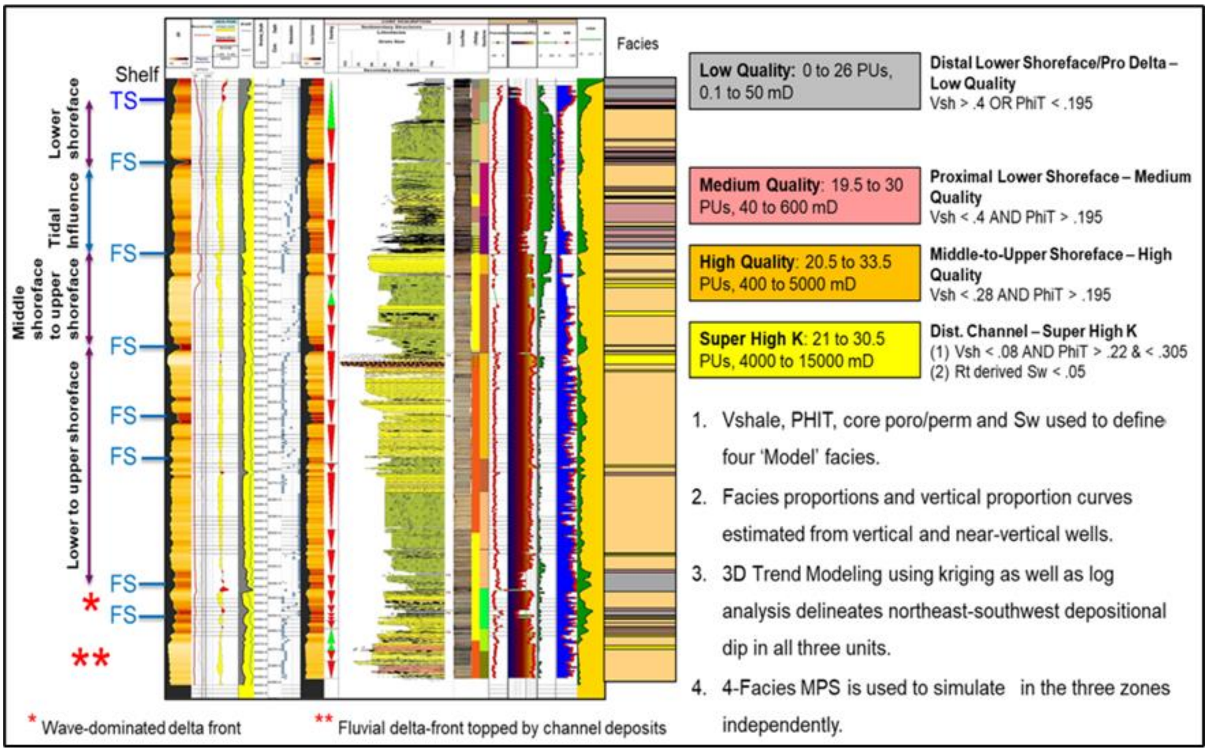



*Figure 7: Structural log section showing original and current (initial assessment) fluid distributions within DD reservoir and proposed well location.*

**Reservoir Stratigraphy**: DD 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 (



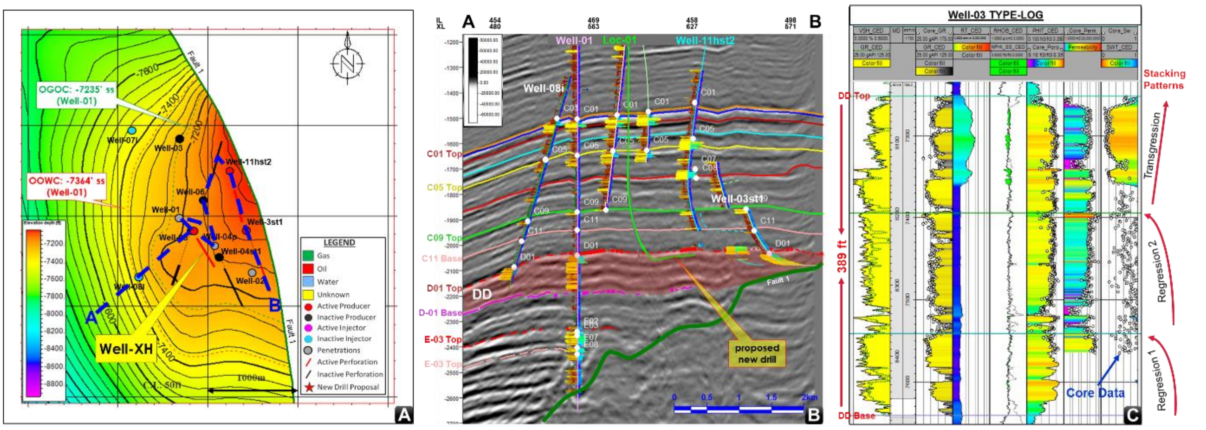



**Figure 5B and C,**

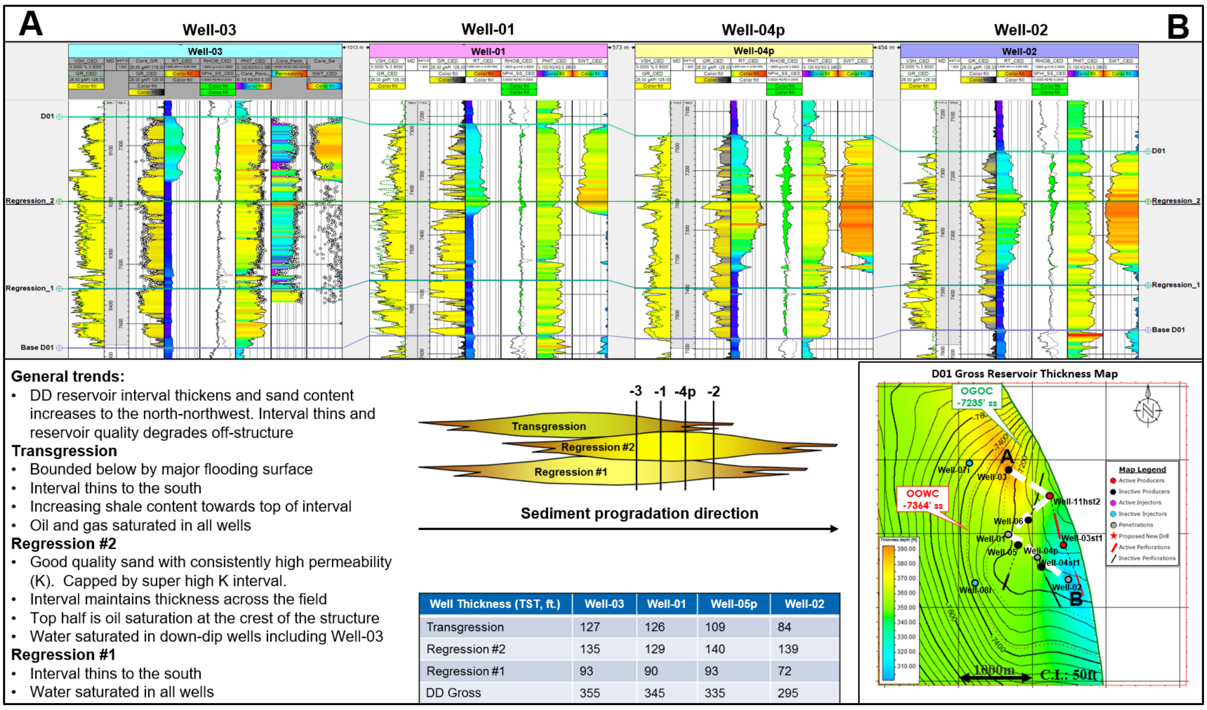
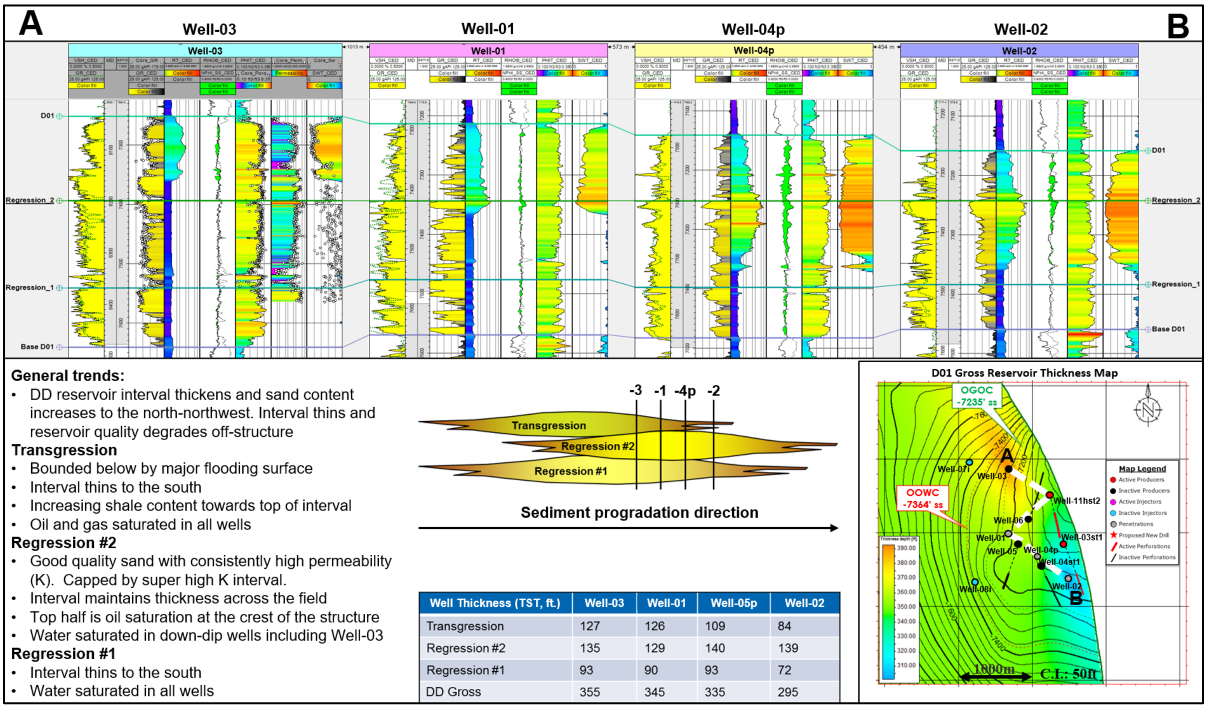



**Figure 10, Figure 9 and**




| 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 |
| DD Gross | 355 | 345 | 335 | 295 |

**Figure 10**).

*Figure 8: Lithofacies and Depofacies interpretation from Well-03 Core Data for the DD Reservoir (from Sedimentological Analysis and Core Description of Field A by Junaid, 2017).*

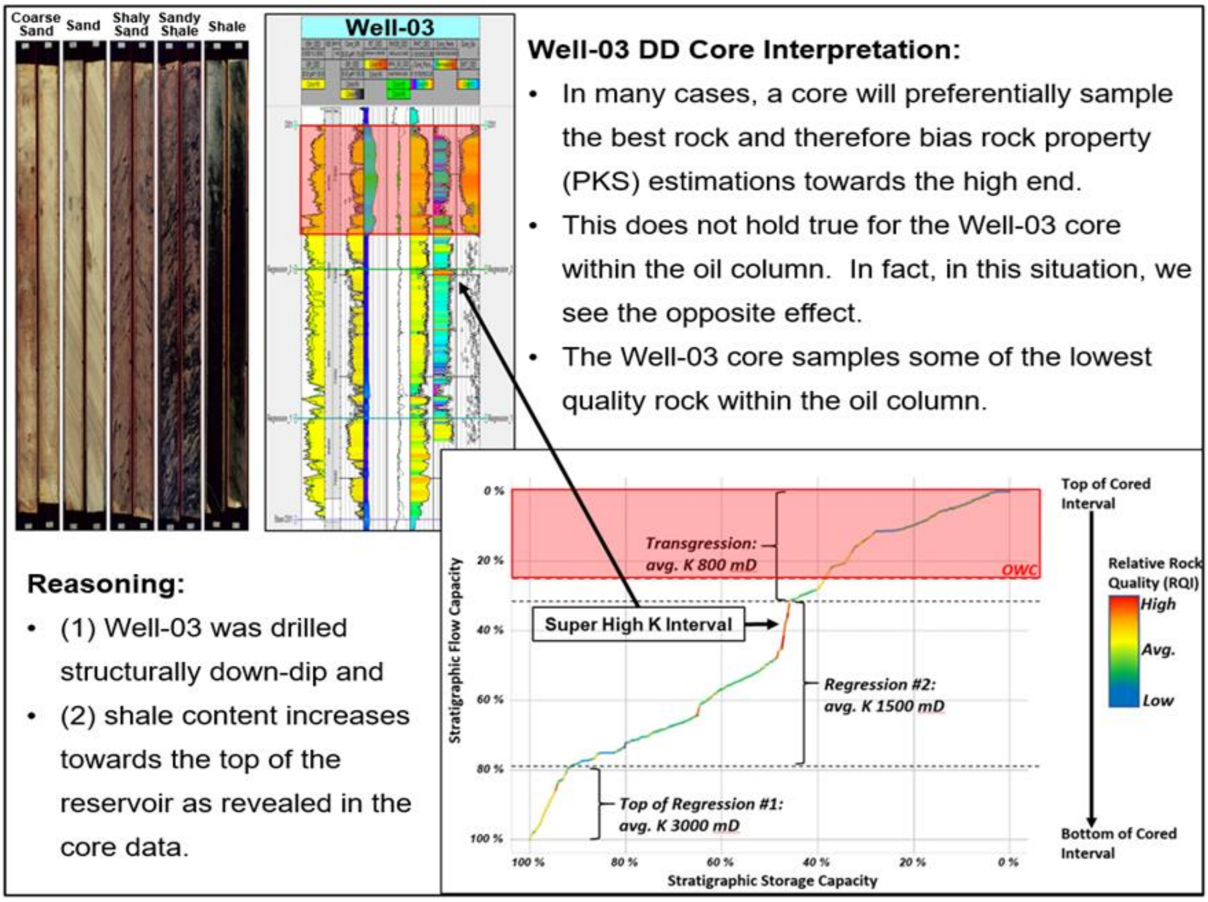
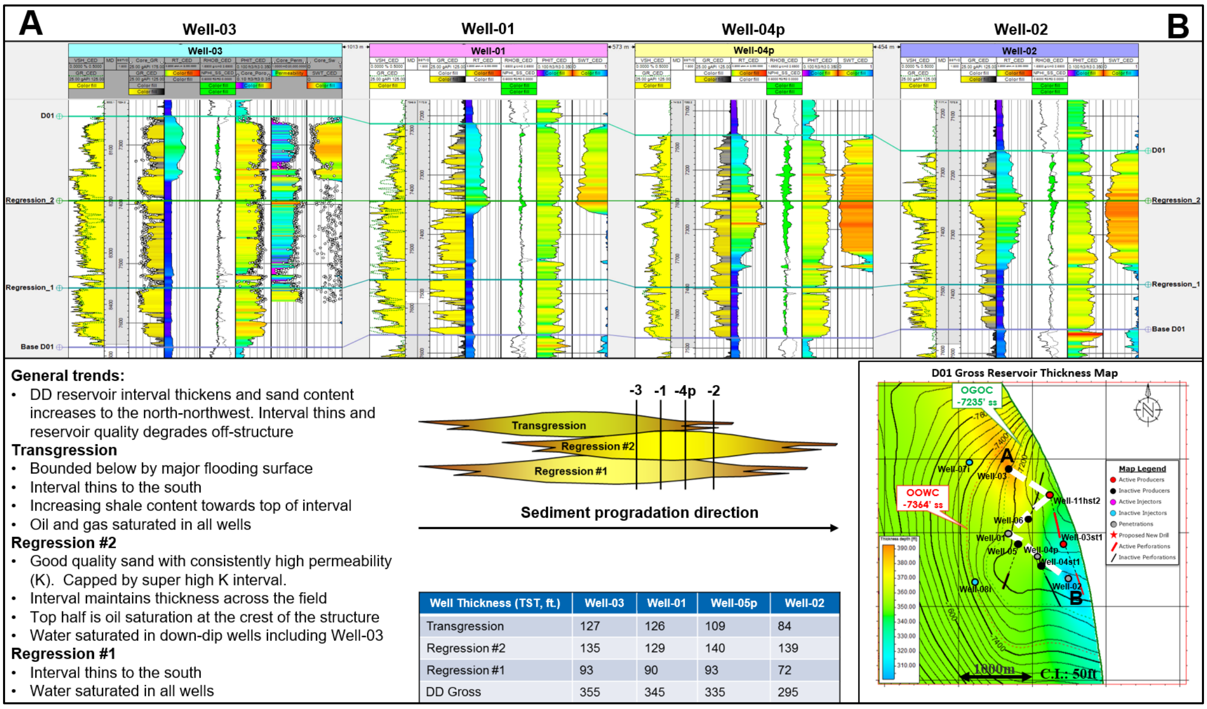



*Figure 9: Core Data from Well-03 in the DD reservoir and range of Permeabilities.*




| 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 |
| DD Gross | 355 | 345 | 335 | 295 |

***Figure 10:*** *Stratigraphic section describing the stratigraphic layers and trends within the DD reservoir.*

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 8** and **Figure 9**).

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.

## RESULTS AND DISCUSIONS

### Stratigraphic Footprints on Fluid Dynamics

During the preliminary development opportunity evaluation of the DD reservoir, an assessment of the remaining oil volume and how it is distributed within the reservoir was carried out mainly based on Material Balance (MBal) analysis and well logs. This assessment presumed a stabilized system with uniform (flat) 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),

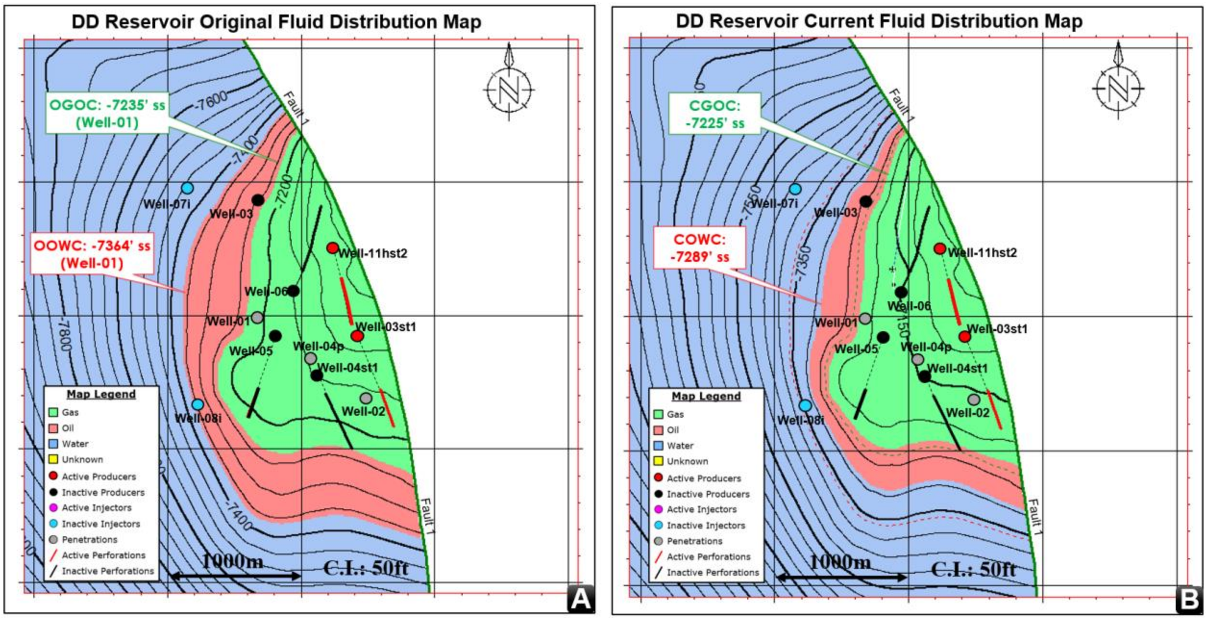



**Figure** **6**B and

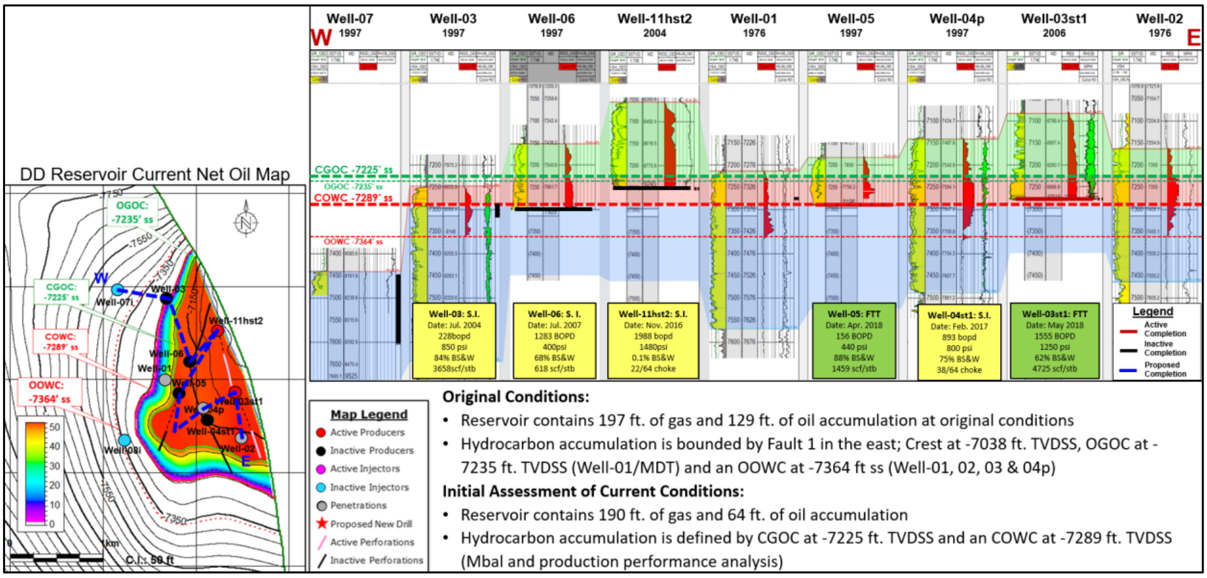



**Figure 7**.

A more detailed reservoir study integrating more 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 produce preferential fluid flow. These lithologic variabilities include several thin shale streaks mostly localized and a couple of high permeability layers of varied thicknesses both localized and widely spread often spanning the entire reservoir extent (

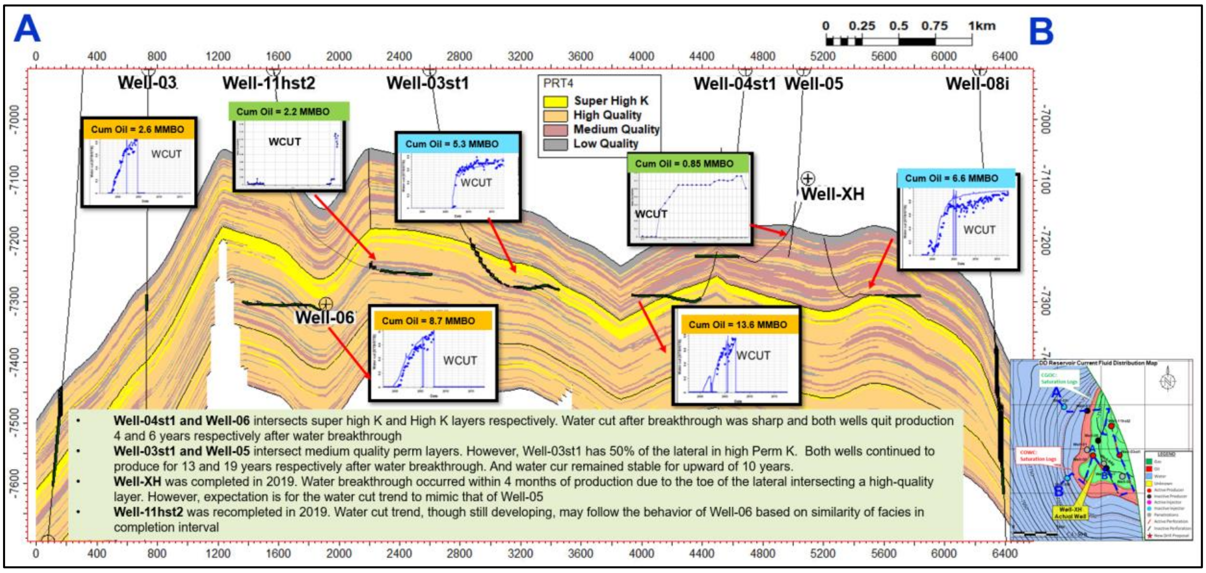



**Figure 11**).

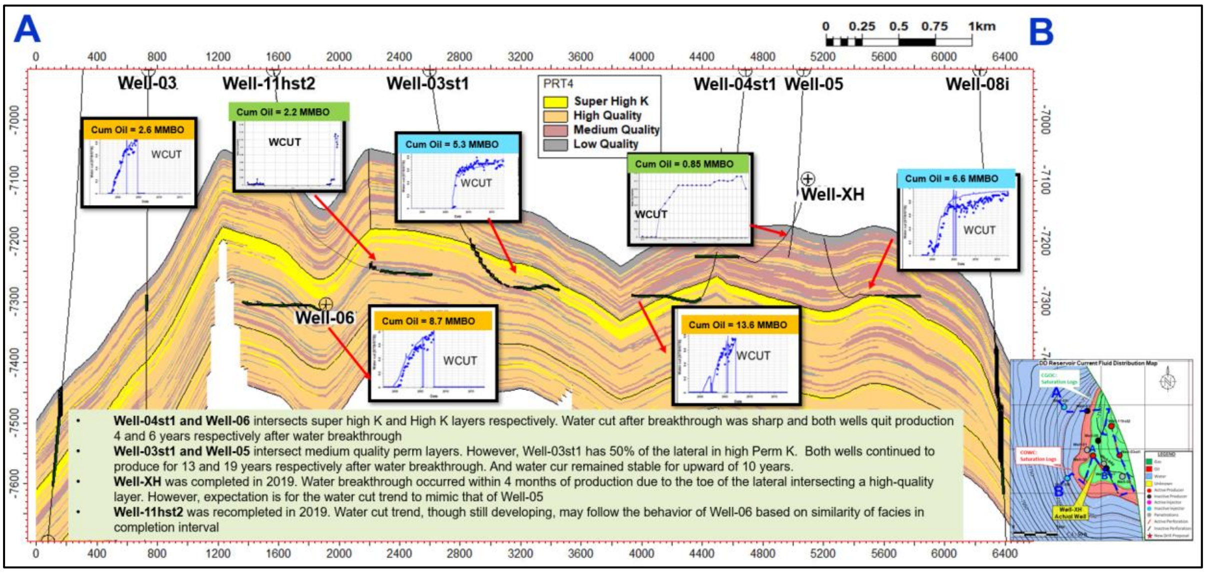



***Figure 11:*** *A section through earth model (facie properties) showing; lithologic variabilities (thin shale streaks and high permeability layers that influence fluid movement, and watercut trends in producers.*

A 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 northwestern area, a receding gas cap and a re-saturation of part of the gas zone with oil (

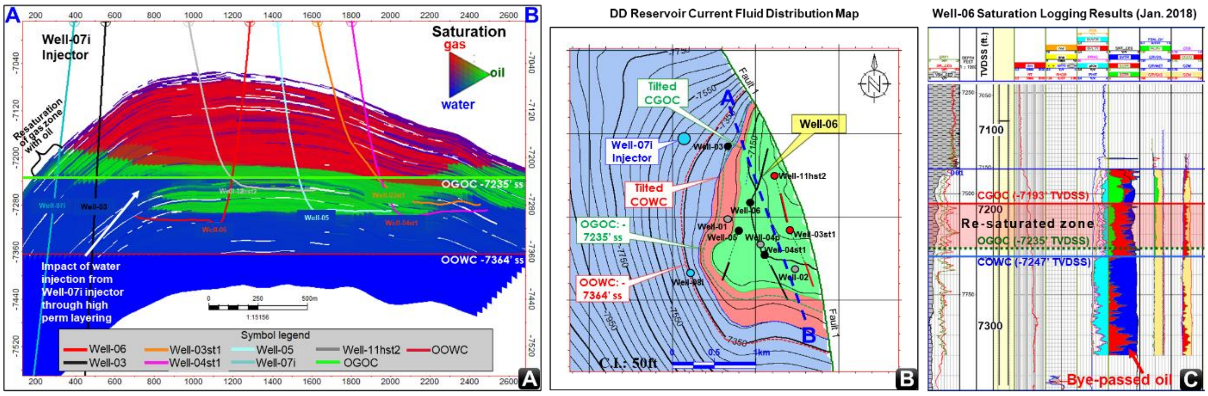



**Figure 12A**). As expected, the water from the injectors is seen to sweep preferentially through relatively high permeability layers, controlled by the shale baffles, to give rise to water fingered profile and uneven fluid contacts (

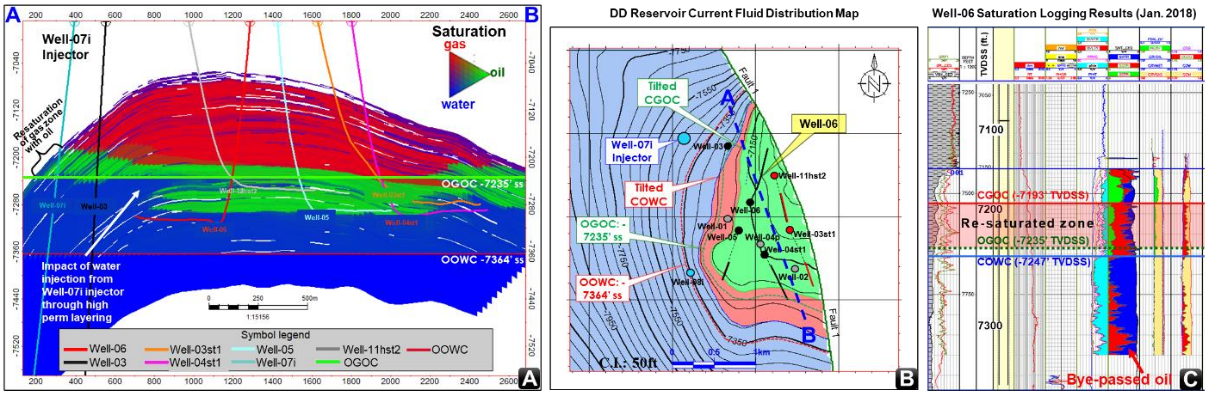



**Figure 12A and B**) with the resultant effects of an inefficient oil and water encroachment that led to bypassed zones (

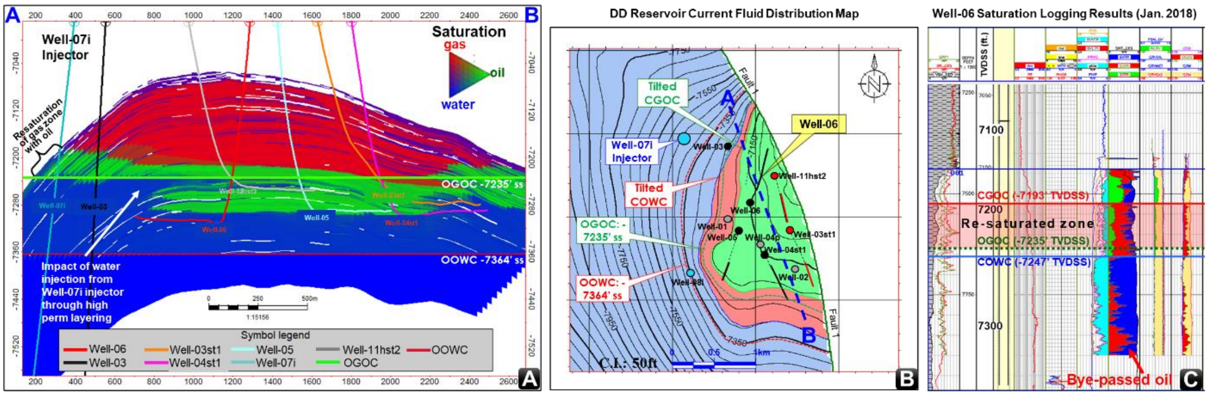



**Figure 12C** and

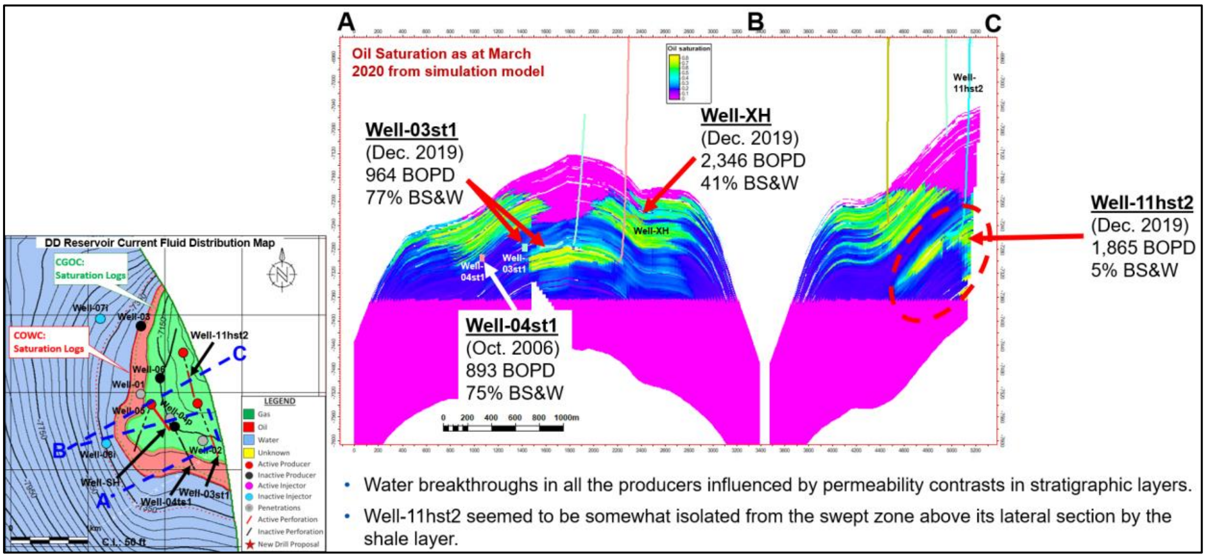



**Figure** 13) and an early breakthrough of water in some producers (Well-04h and Well-06h took 67 and 41 months respectively to break water) irrespective of the vertical and spatial location of the completions (

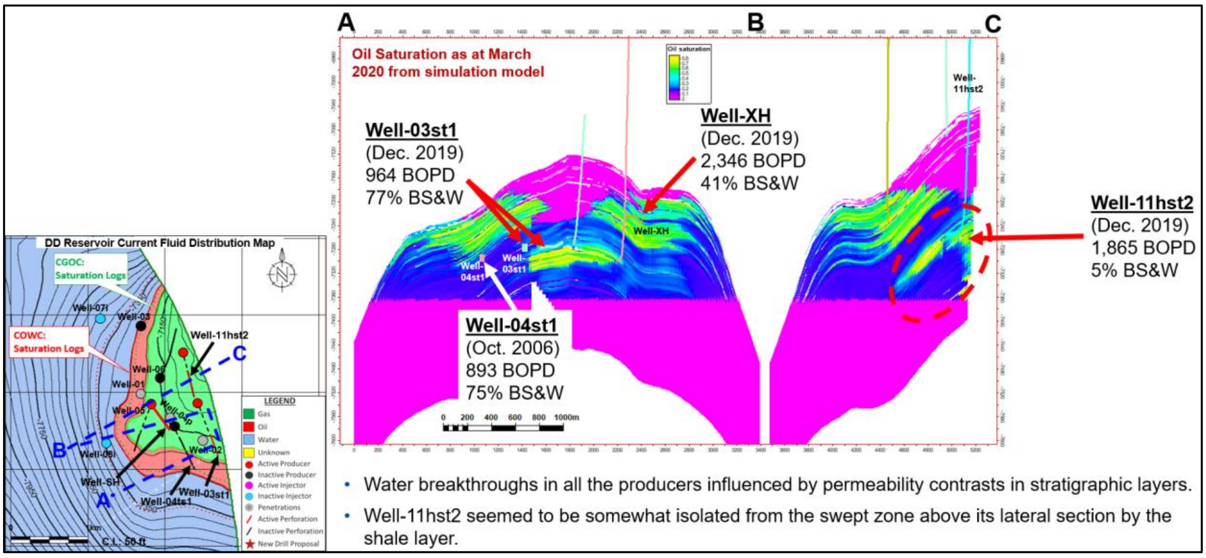



**Figure** 13).

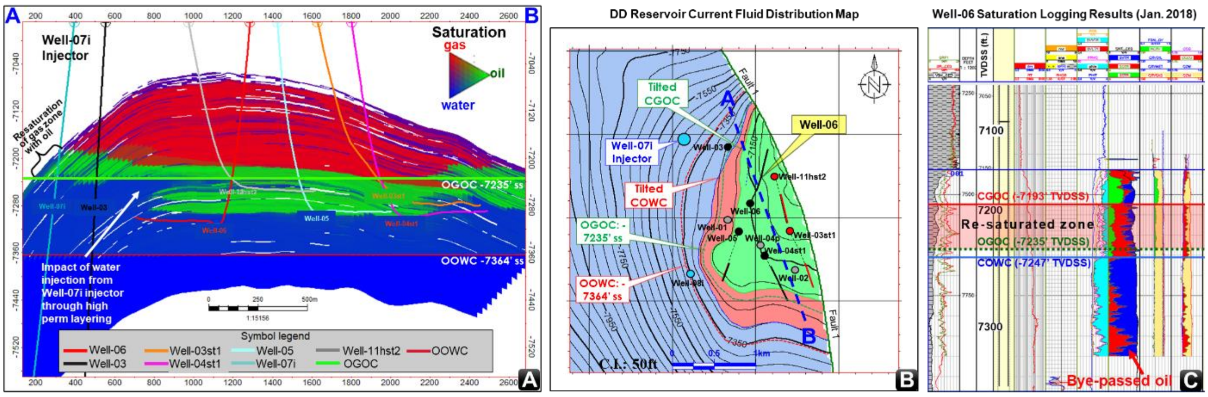



*Figure 12: Cross section through DD reservoir simulation model at end of history showing impact of water injection on fluid flow (A), inset map showing sloping contacts and location of proposed wells (B), and Well-06 Saturation log showing oil-bypassed zone, re-saturated zone painted red and current contacts (C).*

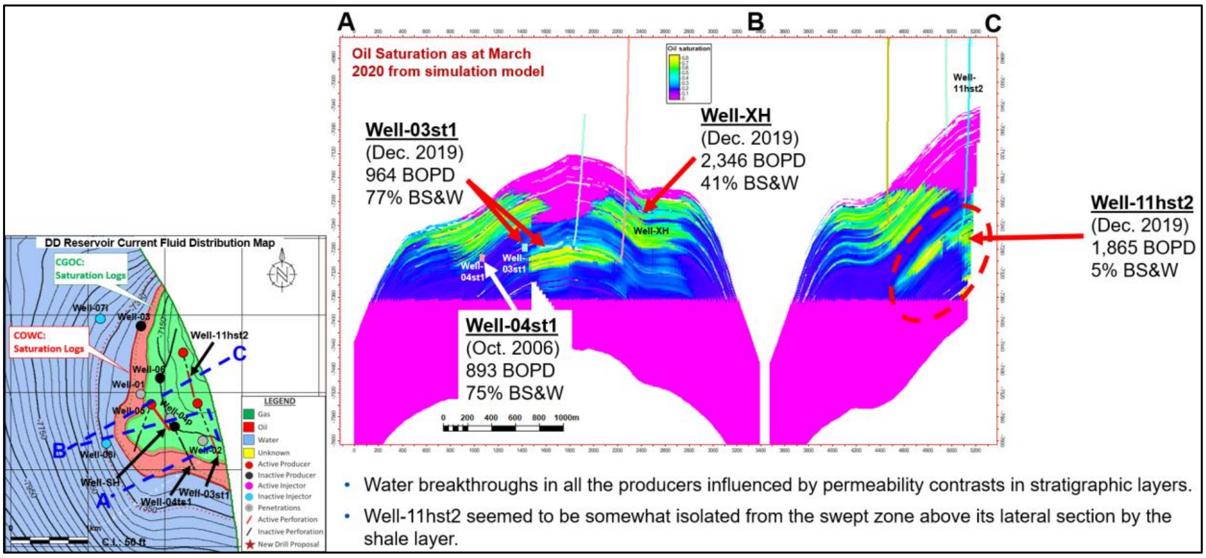



*Figure 13: Section through simulation model (end of history) showing oil bypassed zones beneath 100% swept intervals and water fingering within the DD reservoir. Take note of well performances relative to placements of respective completions.*

A Saturation log acquired in the northern portion of DD reservoir proximal to the dominant water injector showed that, the expected current contacts have moved up shallower in the reservoir. The oil column in that area is now within the zone originally occupied by gas (

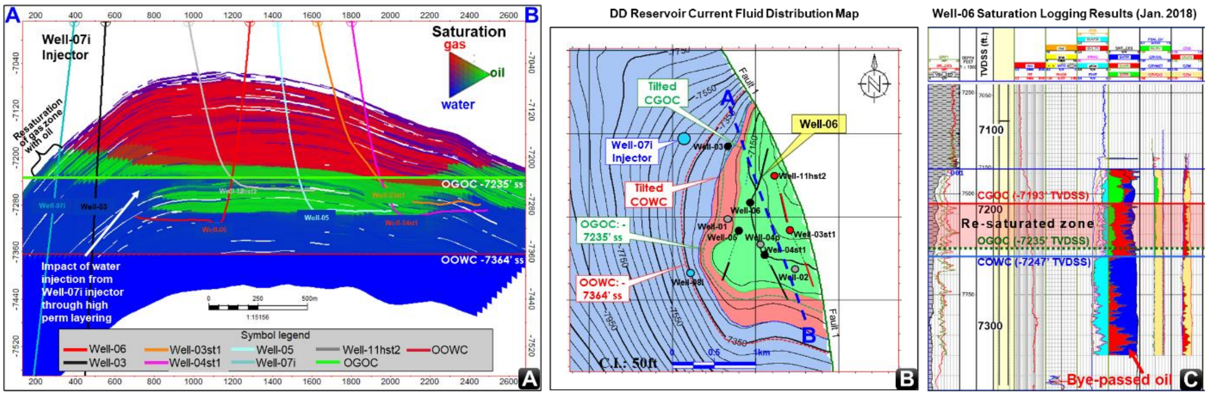
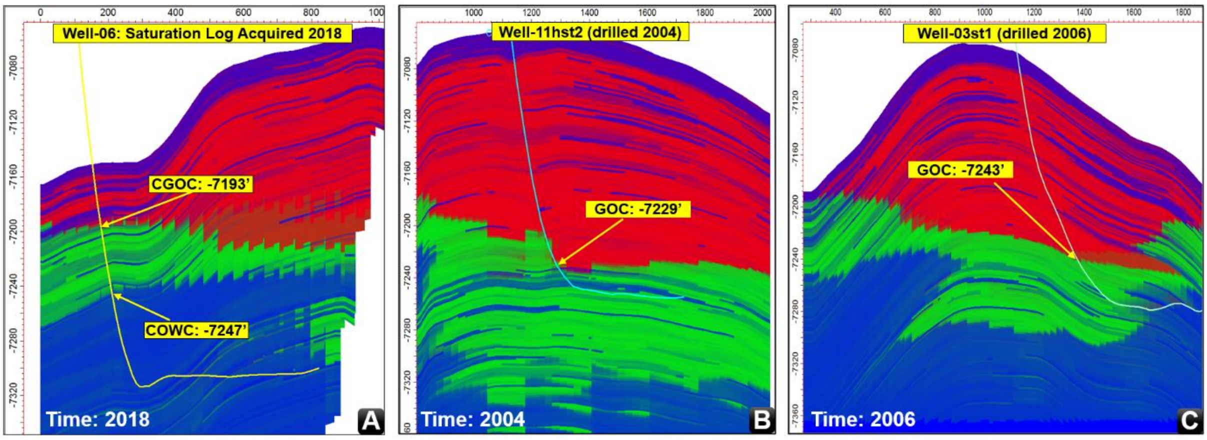



**Figure 12**). However, active completions in other parts of the reservoir are deeper than the COWC seen in the saturation log. These confirmed non-uniform fluid contacts and a receding gas cap seen in the simulation model. A validation exercise was carried out on the simulation model to test how well 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 (-7229 ft. TVDSS) and Well-03st1 drilled in 2006 (-7243 ft. TVDSS), **Figure 14**.




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

| D | 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 14:*** *DD Simulation model Cross Section along well paths showing fluid contact tracking over time in post-production wells; Well-06 (A), Well-11hst2 (B), and Well-03st1 (C). The table (D) compares the contacts logged by the wells with those tracked from the simulation model.*

Tectonic tilting and hydrodynamic sloping contacts are not uncommon (Dickey, 1988 and Estrada, 2000). Consequently, a sloping contact approach was adopted in evaluating the remaining in-place volumes; the oil column increasing in thickness from the north to the southeast.

A second saturation log was acquired in the southern area from Well-04hst1 (September 2018) to ensure spatial understanding of the current hydrocarbon column thickness. The results are largely comparable with those from the first (

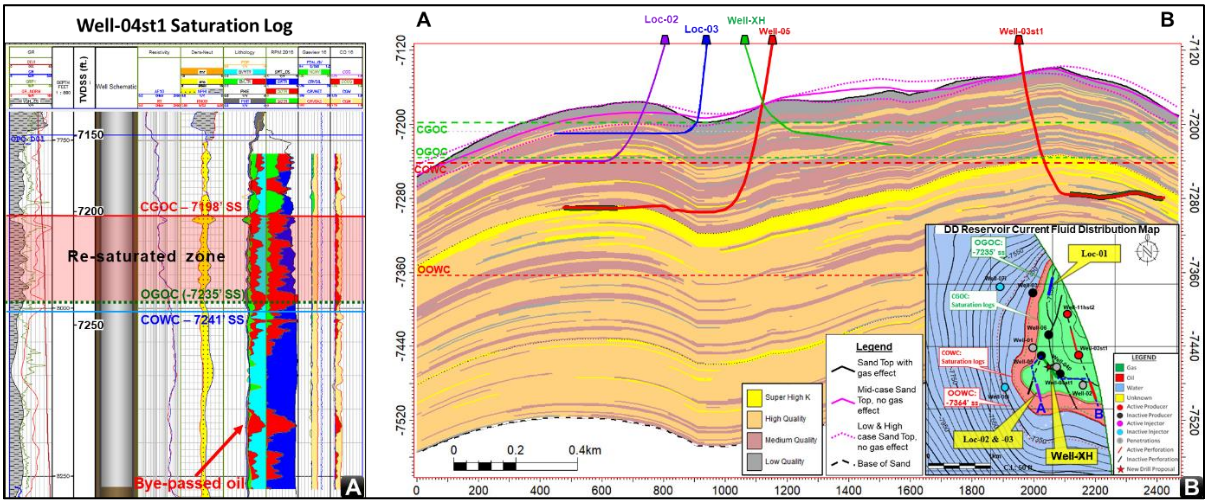



**Figure 15A**). Both saturation logs show about 20 ft. of 'by-passed' oil zones below the interpreted COWCs from first saturation log in Well-06. The simulation model shows that the lateral section of the high-rate oil producer in the field is in an isolated oil pool within the bypassed zone beneath a 100% swept zone (

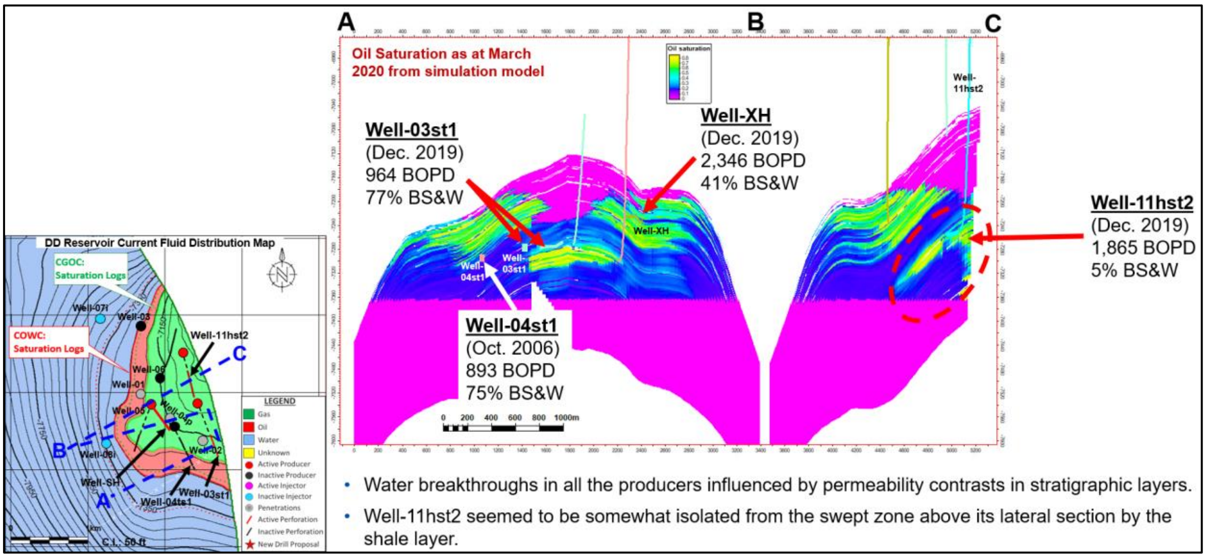



Figure 13). These zones were marked by stratigraphic changes seen in static and dynamic models, which influenced the observed fluid movements. Thus, the lateral section of the proposed Well-XH trajectory was further optimized to cut across many stratigraphic layers (

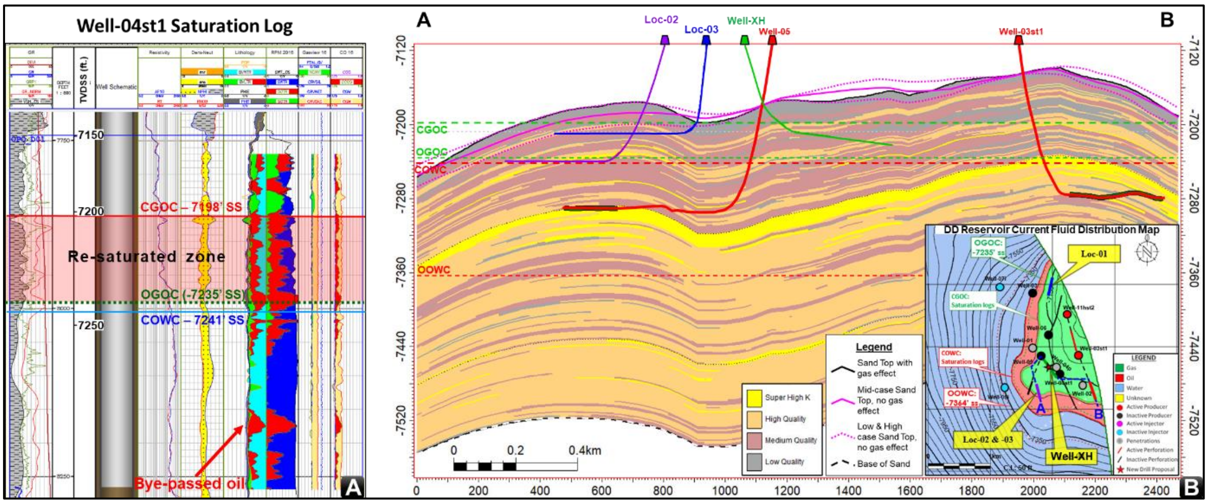



**Figure 15B**).

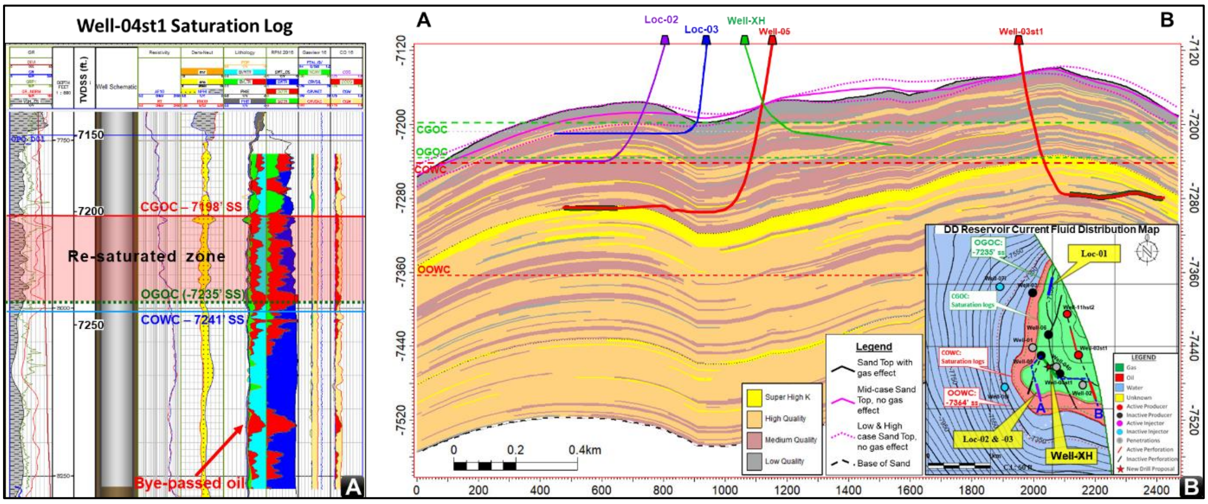



***Figure 15:*** *Well-04st1 Saturation log (A) showing oil-bypassed zone, re-saturated zone (painted red) and current contacts;*

*Cross Section through earth model facies showing reservoir heterogeneities and locations/placements of all proposed wells within the DD reservoir (B).*

Formation Pressure Gradients from the actual Well-XH established a gas gradient below the GOC down to a localized shale streak, and an oil gradient up to the same streak – indicative that the small shale layer acts as a localized barrier to flow (

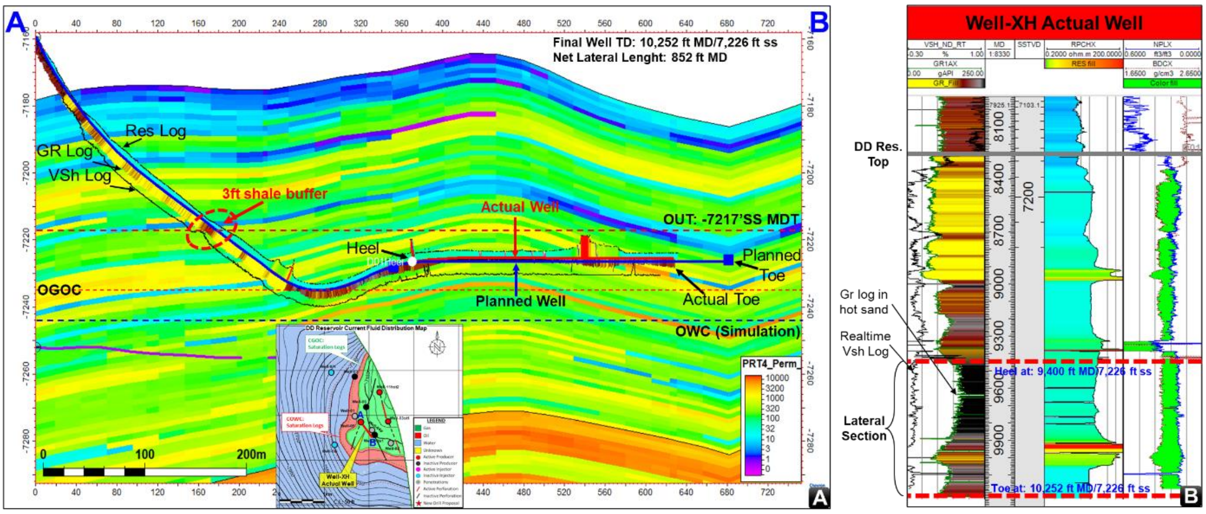



**Figure 16**). The 3ft. shale baffle separates a gas zone above it from the oil zone below; revealing the gas limit to be 16 ft. deeper than the expected GOC defined by the saturation logs, this further confirmed the impact of stratigraphy on fluid distribution seen in the earth and simulation models.

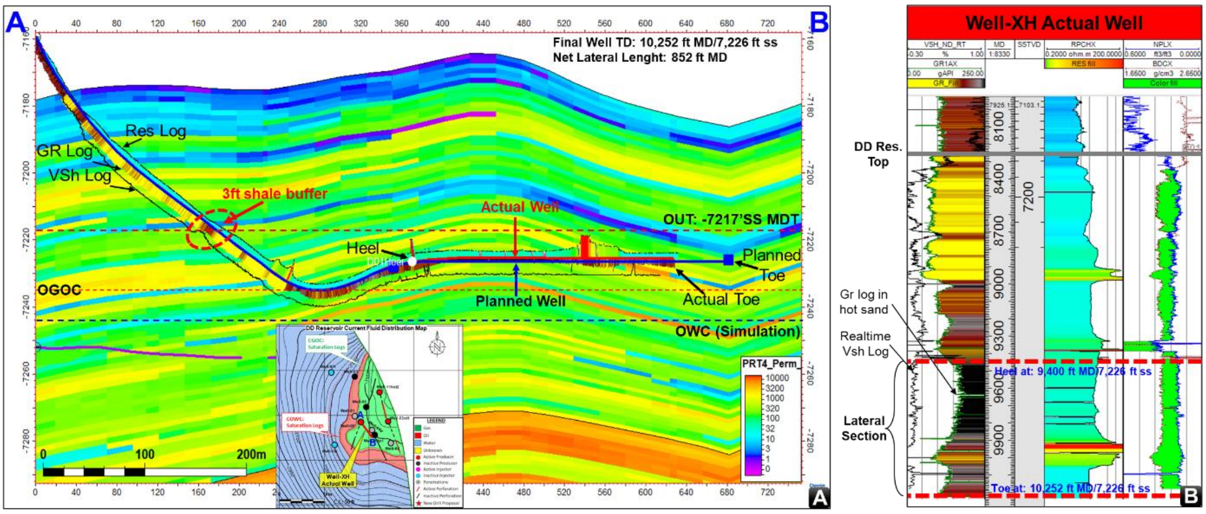



***Figure 16:*** *Permeability property (A) and Well-XH actual log (B) showing logged contacts, shale baffle and actual well path.*

Formation Pressure Gradients from Well-XH also confirmed the 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 (

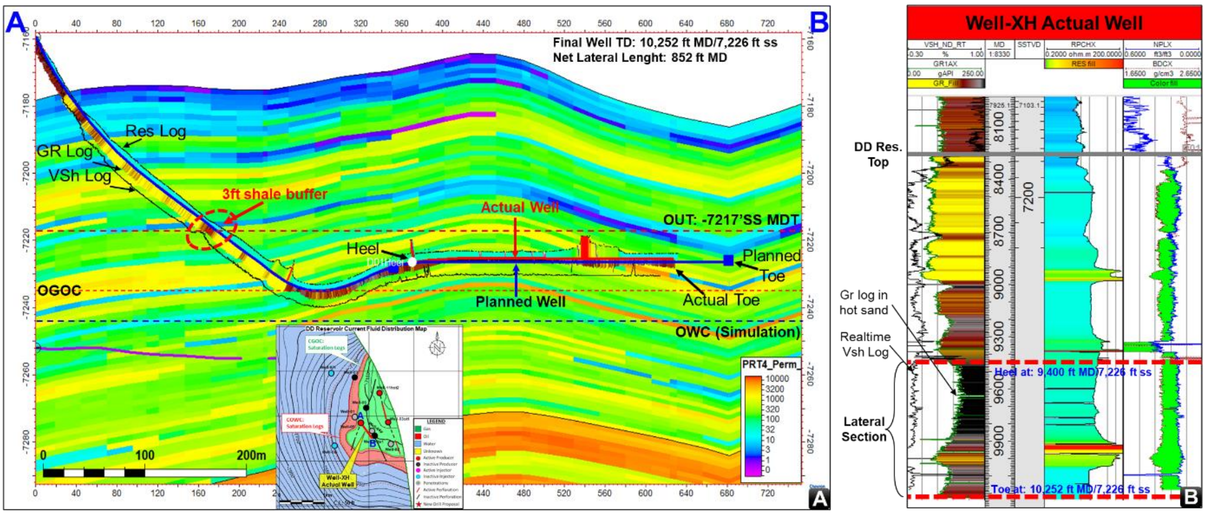



**Figure 16** and

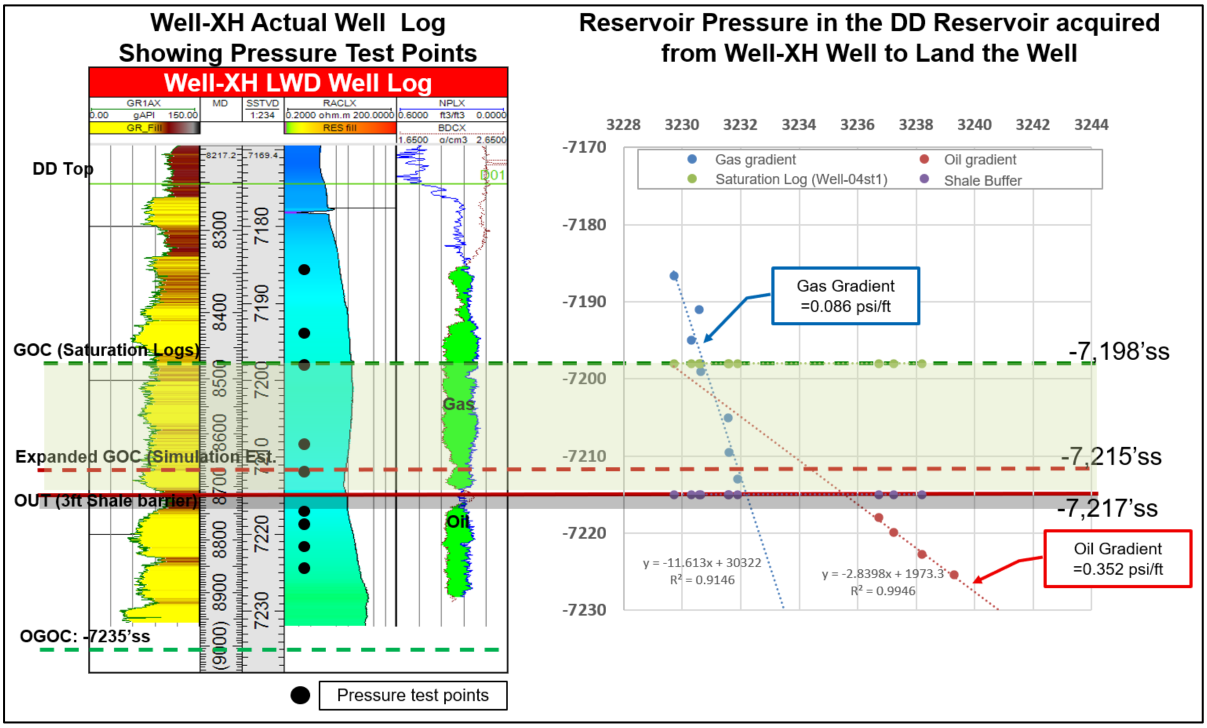



**Figure 17**).

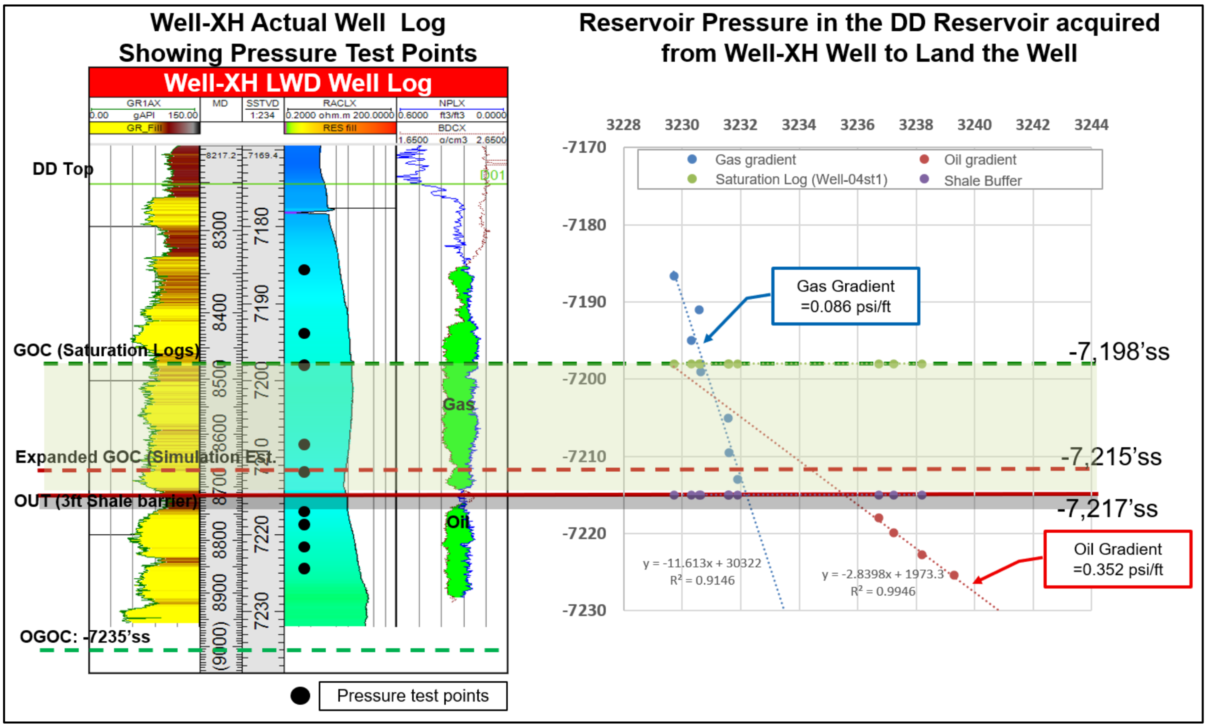



***Figure 17:*** *Formation pressure plots and Correlation to Well-XH well log showing 3 ft. shale barrier separating the gas from the column. Note the intersection of the oil and gas gradients.*

Well-XH was successfully completed and put on production. However, the water cut significantly increased with less than a year of production – this was faster and higher than SM prediction. This increased water production coupled with loss of water injection capability at the time contributed to a significant drop-in oil rate from about 1500 to about 370 BOPD. A closer look at this behavior in both EM and SM raised a suspicion that a high BSW-producing well (Well-03st1) that was shut in for OPEC curtailment prior to the spike had been channeling water away from Well-XH. Well-03st1 was completed downdip of Well-XH. However, this suspicion will be validated once Well-03st1 is put back on production as it could not sustain flow after the curtailment.

A careful observation of the water cut, and oil production profiles of the horizontal wells reveal how stratigraphy is influencing the production from the wells. From

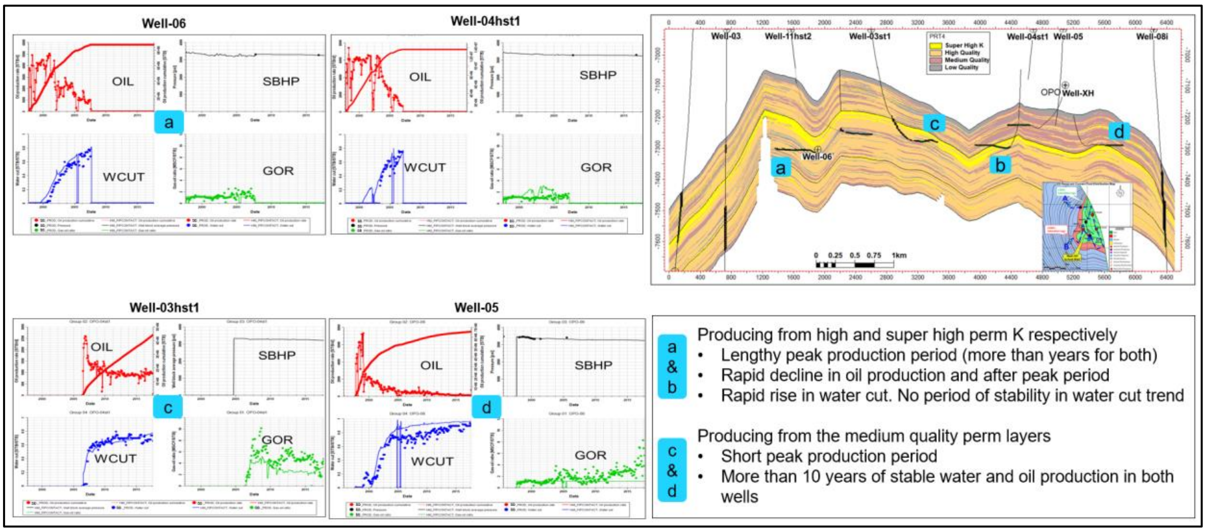


Figure 18, we can observe that wells completed with lateral sections in the high and super high permeability layers showed a lengthy peak oil production period but also a sharp rise in water cut. Wells with lateral sections predominantly in the medium permeability layers show a short peak period but a lengthy period of stable oil and water production, over ten (10) years. Well-XH which has a good portion of its lateral completed in the medium perm layer is beginning to exhibit similar trend as the latter. Thus, performance of earlier wells completed in specific stratigraphic units is providing insight into the performance of new wells completed in similar stratigraphic unit.

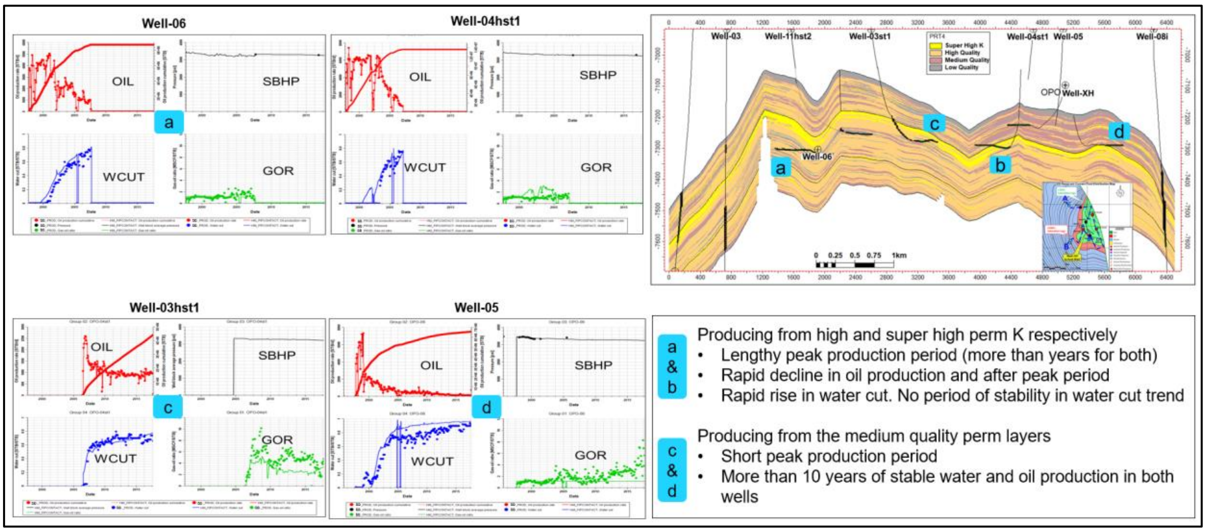



*Figure 18: Production performance plots of wells in DD reservoir showing stratigraphic influence on water cut and oil productions.*

Based on the above, the water injection rate has been reduced compared to historical records and the VRR is deliberately maintained between 0.5 and 0.7. This has resulted in oil production increase from Well-XH from 700 to over 1200 BOPD while Well-11hst2 has seen production increase from 1500 to about 2000 BOPD since the restart of water injection in March 2021 (**Figure 19**). More importantly a stability of water cut at about 60% was observed in Well-03hst, down from 70%. Perhaps the current water injection rate is now optimal (below the critical flow rate) as highlighted by Zahra et. al. (2018) to achieve more stability and minimize viscous fingering.

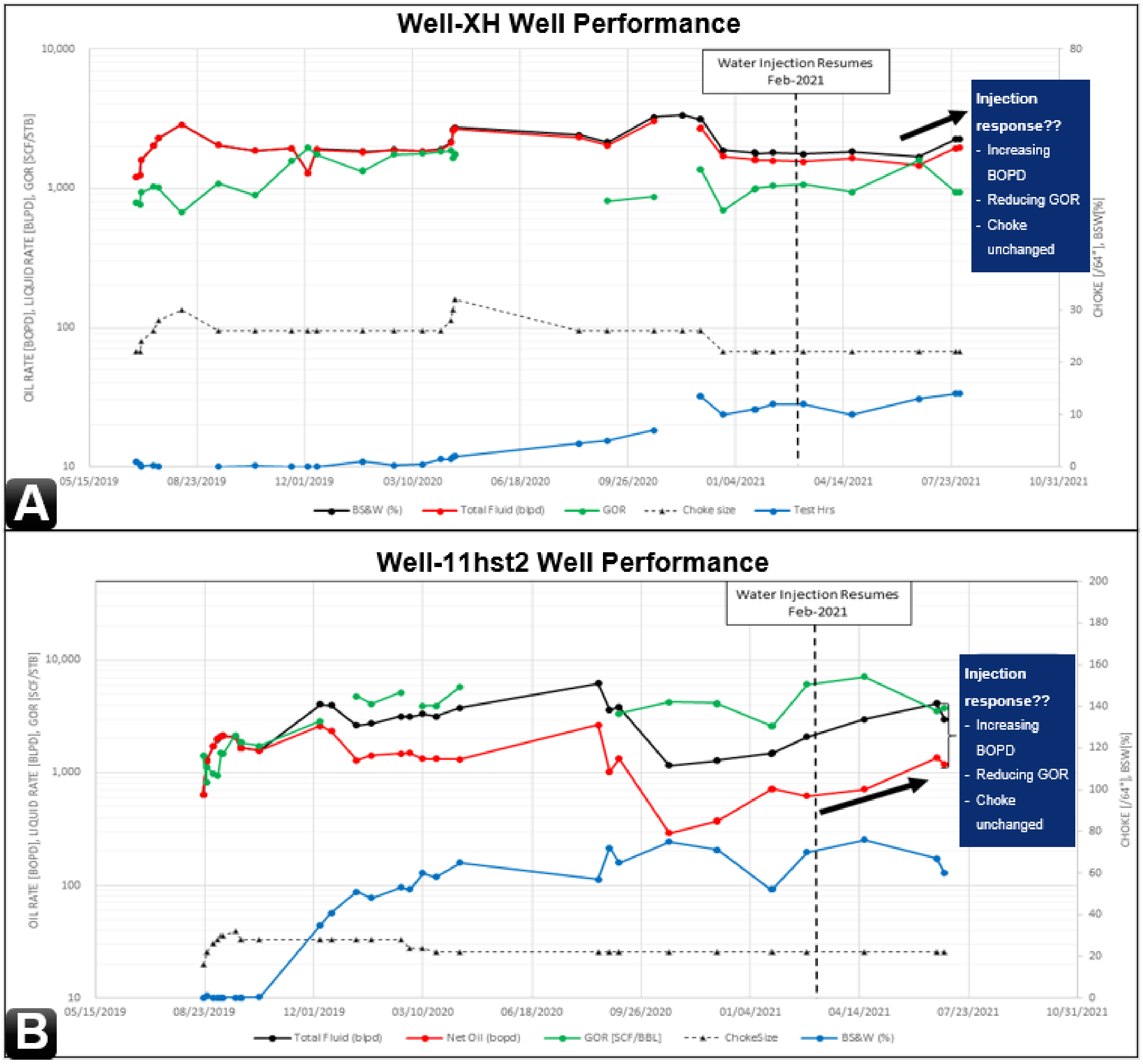



*Figure 19: Well-XH (A) and Well-11hst2 (B) production performance plots showing improved performance after reduction of injection rate.*

## SUMMARY AND CONCLUSION

Subtle and obvious reservoir stratigraphic heterogeneities seen in both wireline and core data were found to have influenced water flow and oil distribution within the DD reservoir. These influences were noticed in; Simulation model where water expectedly flows along high perm layers, small shales acting as barriers to flow, and preferential oil sweep; Saturation logs acquired in wells on the southern and northern regions of the reservoir show 100% swept zones in between high saturation oil intervals; Actual well results in Well-XH where gas column (extended deeper below the GOC) was isolated from the oil column by a 3ft thick shale layer; and high oil rate and a lower BS&W production performance of a well localized within a cell isolated by shales while other producers completed along high permeability super high ways have watered out.

In conclusion, subtle stratigraphic changes were found to significantly influence fluid flow and distribution of remaining oil within the DD reservoir; created bypassed oil zones (oil pools) which are isolated from swept zones above them; the observed tilted and fingered fluid contacts were the result of waterflooding influenced by stratigraphy; and water cut trends and oil production are seen to be strongly influenced by lithologic changes.

**Lessons Learned:** In waterflood reservoirs, understanding the stratigraphic architecture of the reservoir is key to setting injection targets and overall reservoir management system. It is also important to consider subtle stratigraphic contrasts in such reservoirs as they can influence fluid movements and create by-passed zones. Integration of the entire log suite (V-shale, Gamma ray, Neutron-Density, Resistivity, Porosity, Permeability, Core, Saturation logs etc.) as well as seismic data is key in properly capturing the reservoir internal architecture and plumbing. In hindsight, perhaps the high perm streak intersecting the lateral section of Well-XH towards the toe could have been blanked out while completing the new drill. Finally, extra attention to all available data is key to adequately capture reservoir heterogeneous in our day-to-day reservoir management.

## Acknowledgements

We thank Chevron Nigeria Limited (CNL) management and our partner Nigeria National Petroleum Corporation (NNPC) for permission to publish this work. We also thank our colleagues whose technical inputs were extensively used in this technical work.

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