We are IntechOpen,
the world's leading publisher of
Open Access books
Built by scientists, for scientists

6,900
Open access books available

186,000
International authors and editors

200M
Downloads

Our authors are among the

154
Countries delivered to

TOP 1%
most cited scientists

12.2%
Contributors from top 500 universities

CLARIVATE ANALYTICS
BOOK CITATION INDEX
INDEXED

WEB OF SCIENCE™

Selection of our books indexed in the Book Citation Index
in Web of Science™ Core Collection (BKCI)

Interested in publishing with us?
Contact book.department@intechopen.com

Chapter

Geologic Characteristics and Production Response of the N5.2 Reservoir, Shallow Offshore Niger Delta, Nigeria

Prince Suka Momta

Abstract

Sedimentary facies and structural lineaments represent significant control factors on hydrocarbon flow behavior. These geological elements have been evaluated to understand possible cause(s) of rapid decline in pro¬duction. The N5.2 reservoir, located in shallow marine sandstones, offshore Niger Delta, has experienced decline in oil rate with a corresponding increase in water-cut within two years of beginning of production. The main objective of this study is the determination of reservoir architecture in order to individuate the possible cause(s) of rapid production decline. To this aim, several methods have been used, including the seismic attribute analysis, electrofacies analysis, well log and petrophysical correlations. The obtained results show that the N5.2 reservoir is a massive sandy unit, occurring within the paralic Agbada Formation of about 2133 m thick. A contour depth map of the reservoir shows the occurrence of a structural saddle associated with an elongated closure having two structural culminations. Further analysis using the root mean square (RMS) and anti-tracking seismic attributes has indicated a seismic facies parallel to the paleo-coastline direction and several faults and fractures. The high quality of the reservoir, fractures, poor management and water injection may have induced rapid fluid flow and consequently early watercut and decline in production.

Keywords: sedimentation, oil rate, watercut, porosity, permeability, reservoir

1. Introduction

Decline in oil production is common to mature oilfields where several wells have been drilled and exploited over a period of time. The volume of oil produced and the lifetime of a specific well or reservoir is a function of several variables, which could include the thickness of the oil column, sand-body architecture and geometry, quality of hydrocarbon, and several geologic uncertainties. It is expected that after many years of oil production from a reservoir there should be a time when the water oil ratio (WOR) should be significant. However, early decline in production for a reservoir with high potential is uncommon. The studied reservoir has experienced rapid decline in oil production with a corresponding rapid water breakthrough in just 2 years of the beginning of production.

Stratigraphic features and structural lineaments are geologic elements that will be examined to understand the architecture of the reservoir and the possible effects of lineaments on fluid flow. Fluvial and marine processes have influenced the deposition of sediments in the Niger Delta [1, 2]. Myriads of sub-environments exist within each mega environment either continental or marine. The stratigraphic imprint of these events at various scales can be identified and reconstructed from sedimentary rock bodies in both outcrops and cores [3, 4].

The structural elements that influence fluid flow include fractures, faults and folds, mapped in the subsurface of the Niger Delta [1, 5]. They are significant for the hydrocarbon entrapment and fluid mobility within the reservoir. Faults play an important role in the distribution of fluids in the subsurface and may act as baffles or conduits to flow [6]. In particular, this paper focuses on stratigraphic and structural features and their impact on the hydrocarbon production.

It has been established that facies architecture and reservoir condition influence the movement of fluids within the subsurface [4, 7–9]. However, a few studies have examined the control of geological factors in combination with production management strategy on flow behavior [7, 9, 10]. An integrated approach is adopted in this study to examine the relative impact of a combination of these uncertainties on fluid flow especially water, that can result in a rapid production decline. Rock types and fabrics are more significant than fluid properties in controlling the stratigraphic architecture of the reservoir. This is because, geologic characteristics such as facies properties and architecture, changes in depositional environments, etc., have more control on oil and gas recovery than production methods [11, 12]. In the Niger Delta, most of the sand-bodies hosting hydrocarbon occur as channels, shoreface, beach and barrier sand deposits [2, 13–15].

Studies on reservoir characterization of the Niger Delta have been carried out by several researchers. Osinowo et al. [16] described and characterized the Eni field, located offshore Niger Delta by integrating both seismic and wireline logs. Oyedele et al. [17] discussed structural lineaments and their impact on hydrocarbon accumulation in the EMI field, Niger Delta. The work of [18] focused on the impact of facies on reservoir quality and the application of 3D static model to characterize hydrocarbon potential of the KN field offshore, Niger Delta. The interplay of marine energy fluxes, the creation of accommodation space, sedimentation, facies architecture and hydrocarbon potentials of deep offshore areas have been explained in articles by [4, 19]. Reservoir characterization is essential at every stage in the lifetime of an oilfield for appropriate description of sand-body geometry and architecture [20–23].

This study aims at establishing facies characteristics, lateral continuity of sand bodies and the possible cause(s) of early water breakthrough that result in rapid decline in oil production of the N5.2 sand. This concept will have broad significance in the following areas: risk assessment and drilling optimization, understanding the geometries of sedimentary rocks and changes in their associated porosity and permeability [20].

2. Study area

The study area lies in the shallow offshore area of the Niger Delta, Nigeria (**Figure 1**). It is bounded in the north by Calabar Town, at a distance of about 3 km, and in the east by the Cameroon Volcanic Line about 30 km away. The field is circa 229 km^2, and the structure was described by [24], as an elongate, four-way dip closure in two culminations with a saddle between them. There are over 40 wells drilled in the field some of which include pilot holes, water injectors and horizontal production wells.
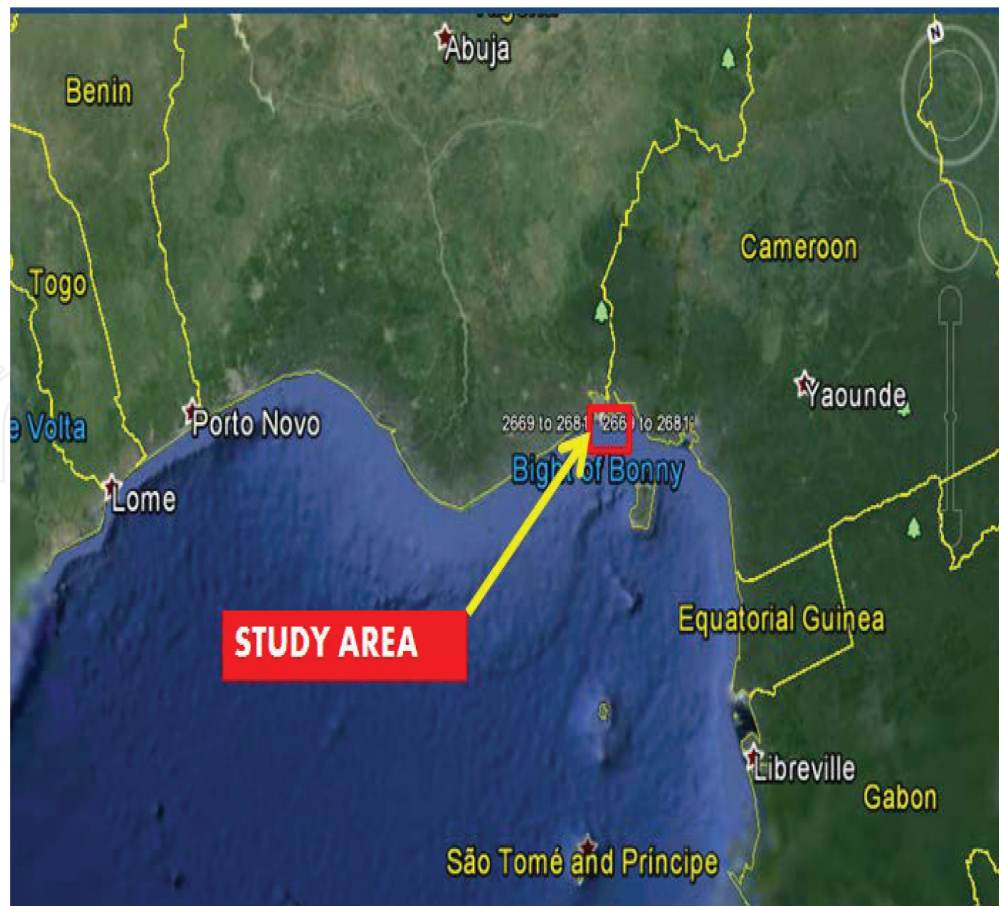
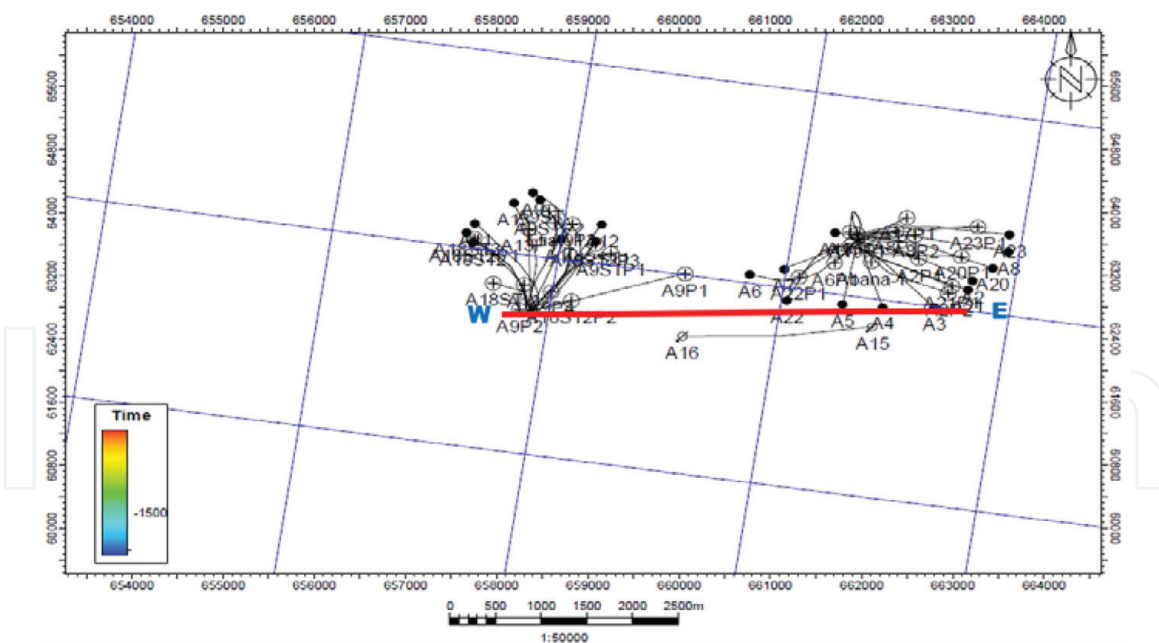**Figure 1.**
Map showing the study location.

3. Reservoir stratigraphic architecture, facies and well log analysis

The field covered a distance of more than 7 km from the east to the west. The lithologic well correlation indicated that most of the sand-bodies (N5.2 and others) are laterally extensive across the oilfield (**Figures 2** and **3b**). A key stratigraphic marker used to constrain the correlation is the Qua Iboe Shale (QIS) (**Figure 3a**). Gamma ray trends forms the basis for delimiting reservoir tops and bases (**Figure 3a** and **b**).

The N5.2 sand is a high quality reservoir characterized by sand with some silt and shale fractions in almost negligible proportions. It is laterally extensive and cuts across the field covering a distance of more than 7 km, and well developed towards the eastern flank. It displays a layer-cake architecture with gross thickness between 33.82 and 105.13 m. The N5 reservoir displays stacked highstand parase-quence set and occurred in six sub-units in wells located in the eastern part of the field (**Figure 3a** and **b**).

3.1 Environment of deposition

The well log (gamma ray log) and drill-cutting samples are the major lithologic tools used to identify lithofacies in the field. Ditch cutting sample description (**Table 1**) [15] indicates that the N5.2 sand contains some glauconite pellets show-ing sedimentation within a marine environment. The depositional environments inferred using electrofacies and the presence of glauconite within the sample inter-val are; beach, barrier bar, shoreface and regressive bars [15]. The overall gamma ray trend shows an upward coarsening sequence.
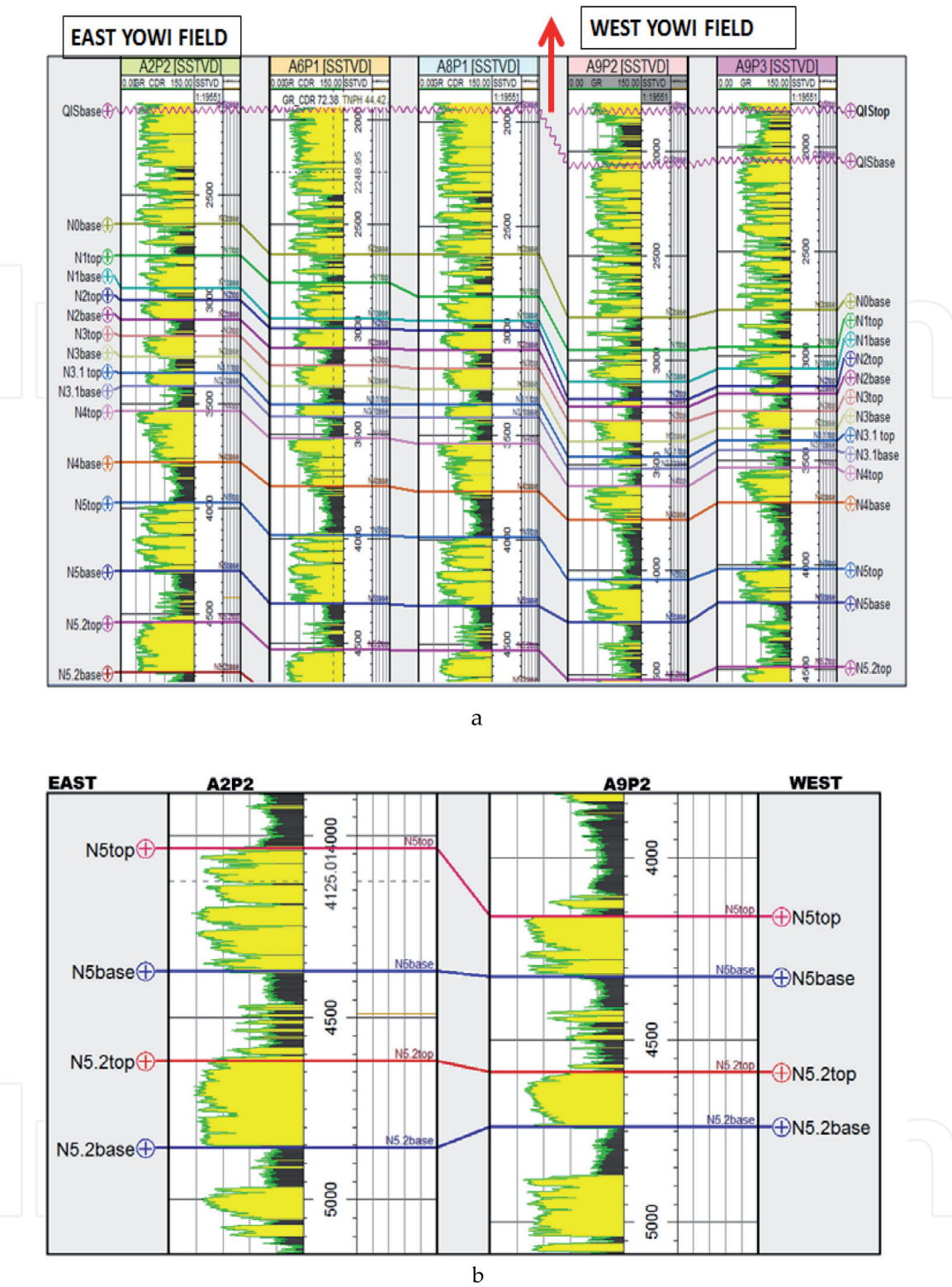
Figure 2.
Seismic base map showing well locations and line of section.

The log expression for the N5.2 sand exhibits blocky/cylindrical motif (**Figure 4**). It has a sharp base with a gradational top, about 70.08 m thick, excellent reservoir quality, good lateral continuity and displaying a layer-cake reservoir architecture deposited probably as barrier bar or a channel sitting on a beach-barrier system (**Figure 4**). There are particles of glauconite in the ditch cutting sample indicating that the sediments were deposited within the marine environment.

3.2 Architecture and reservoir characteristics of the N5.2 sand

3.2.1 Architecture of the N5.2 reservoir

The root-mean-square amplitude, a seismic attribute generated over the seismic volume at different timeslices is more diagnostic in facies identification. Generally, the RMS amplitude is an expression of the square root of the average of the squares of the amplitude within certain window of the analysis, and it is related to the energy within the seismic trace. The root-mean-square (RMS) are useful in differentiating between lithology types. For instance, values of the trace with high amplitudes may indicate a highly porous lithology such as porous sand, which are potential high quality hydrocarbon reservoirs. It can also serve as a direct hydrocarbon indicator. Three different color bands are used to indicate amplitude values: yellow indicates the highest amplitude (100 RMS value); light brown to red (50–68 RMS values), and the light green to blue colors represent the least to medium amplitude points (0–18, and 20–30 RMS) (**Figure 5**). The N5.2 sand falls within the Beach-Barrier-shoreface (BBS) RMS trend that aligned parallel to paleo-coastline direction (**Figure 5**) indicating a shallow marine depositional architecture. Depth structure map also indicated similar trend showing a four-way dip closure having two culminations and depositional axis parallel to the major structure-building fault (**Figure 6**).

3.2.2 Reservoir characteristics of the N5.2 sand

Well log attributes show that the N5.2 reservoir is a massive, clean and thick (about 70.08 m thick) barrier/shoreface shallow marine sandstone with excellent reservoir quality. Pixel-based facies modeling using sequential indicator simulation

a

b

Figure 3.
(a) Well correlation of key reservoirs in the field and (b) well correlation of N5.2 reservoir across the field.

Reservoir	Sample description
(N5.2 reservoir) Well A2P2	Sandstone: medium to dark brown, oil saturated, clear, translucent, friable to loose quartz grains, very fine-fine grains, and predominantly very fine, sub-rounded to rounded, very well sorted, excellent porosity and permeability, contains mica with traces of glauconite, traces of carbonaceous speckles. Oil shows: medium brown oil stain, intense bright yellow fluorescence, instant blooming milky white cut fluorescence, light brown residue. Very strong hydrocarbon odor

Table 1.
Ditch cutting description of the N5.2 reservoir [15].

(SIS) algorithm for stochastic distribution of properties shows three distinct lithofacies (sand, siltstone and shale) in the reservoir across the field (**Figure** 7). These facies were defined based on log signatures, volume of shale cut-off, and
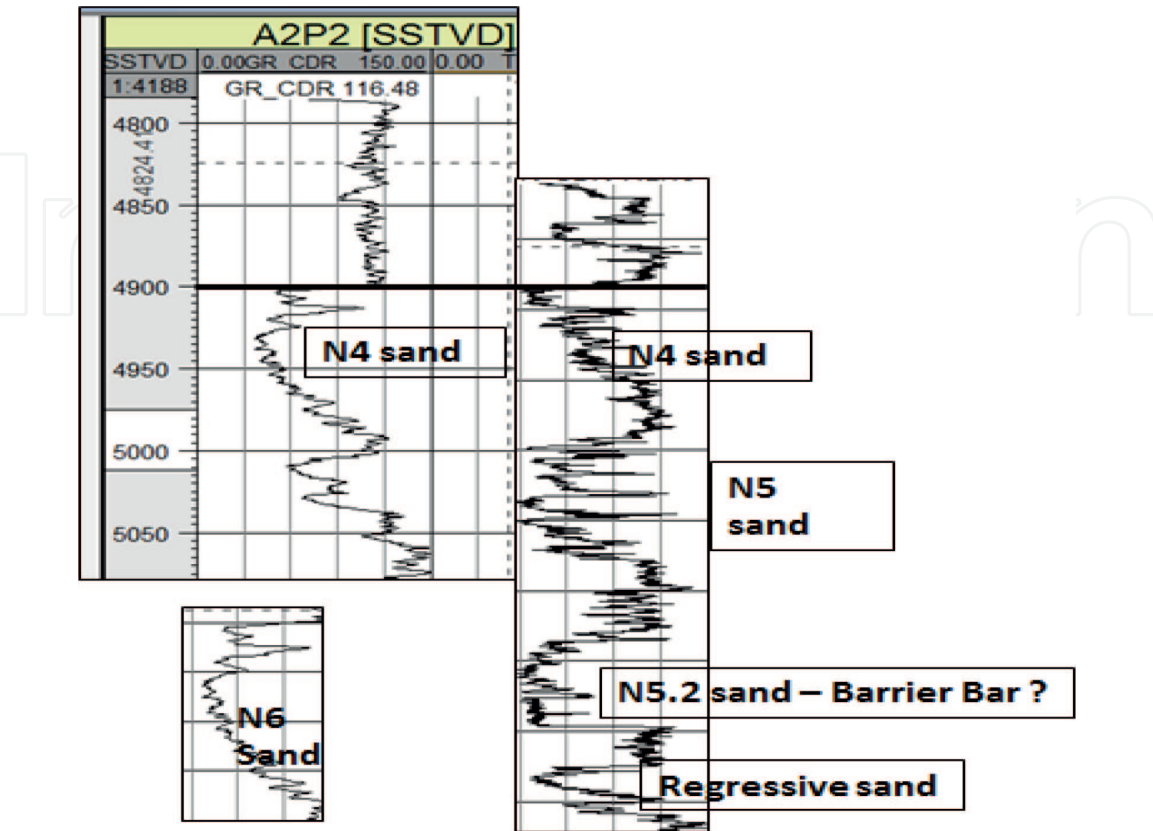
Figure 4.
Gamma ray log motifs showing inferred depositional environments of the reservoirs.
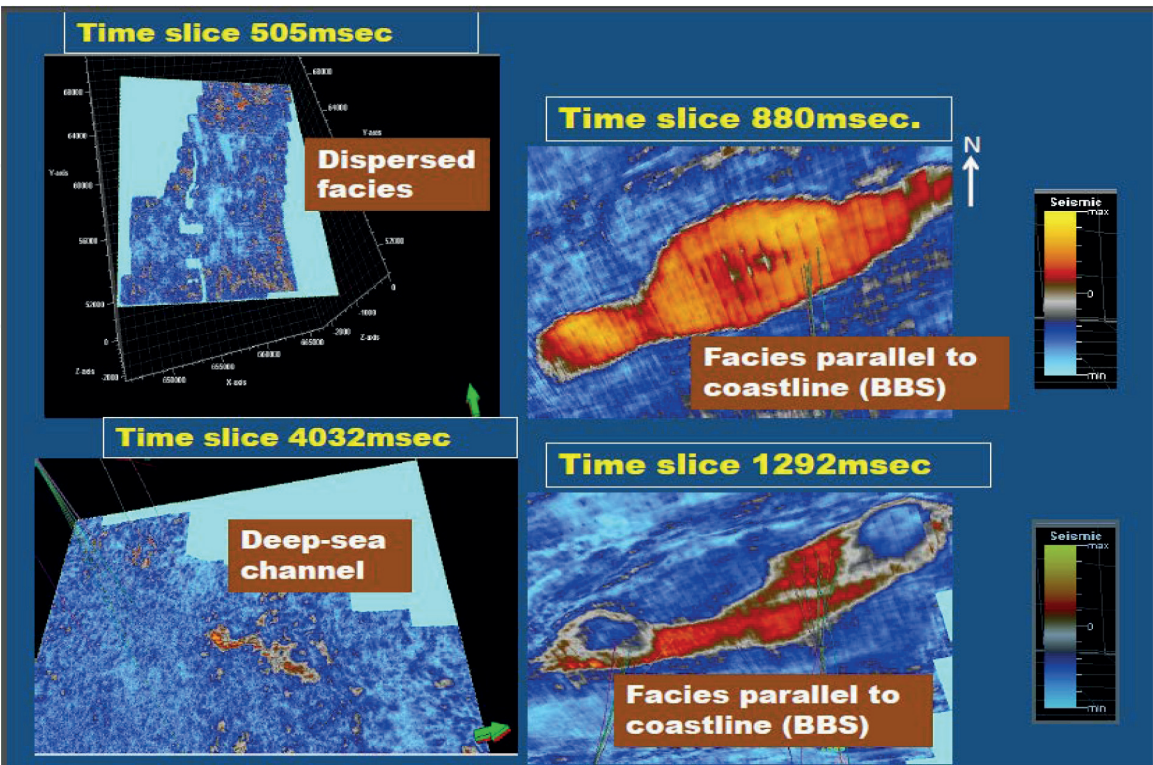
Figure 5.
RMS amplitude showing facies trends and architecture. Hint: BBS indicates beach, barrier and shoreface architecture. The N5.2 sand falls within the BBS category.

net-to-gross (NTG) calculations. The volume of shale (VSH), net-to-gross ratio (NTG) and total porosity (PHIT) from petrophysical evaluation were populated into the 3D grid facies model (**Figures 7** and **8**). Sand is the dominant lithofacies in

Figure 6.
Depth structure map for N5.2 reservoir in two structural culminations and a saddle.

Figure 7.
Facies model showing lithofacies characteristics of N5.2 sand [25].
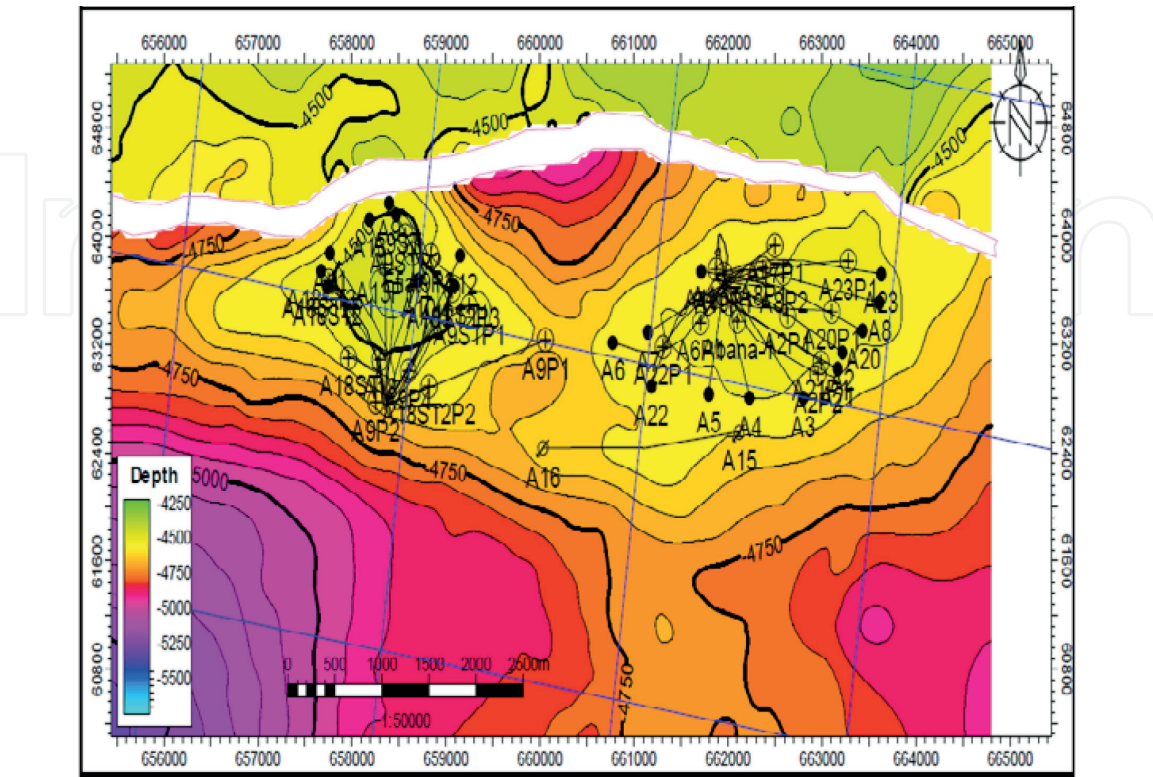
the reservoir (**Figure 5**) with over 83% NTG and negligible volume of shale (VSH) (**Figure 7**). This implies that the reservoir flow mechanism will be influenced by the properties of the sand facies.
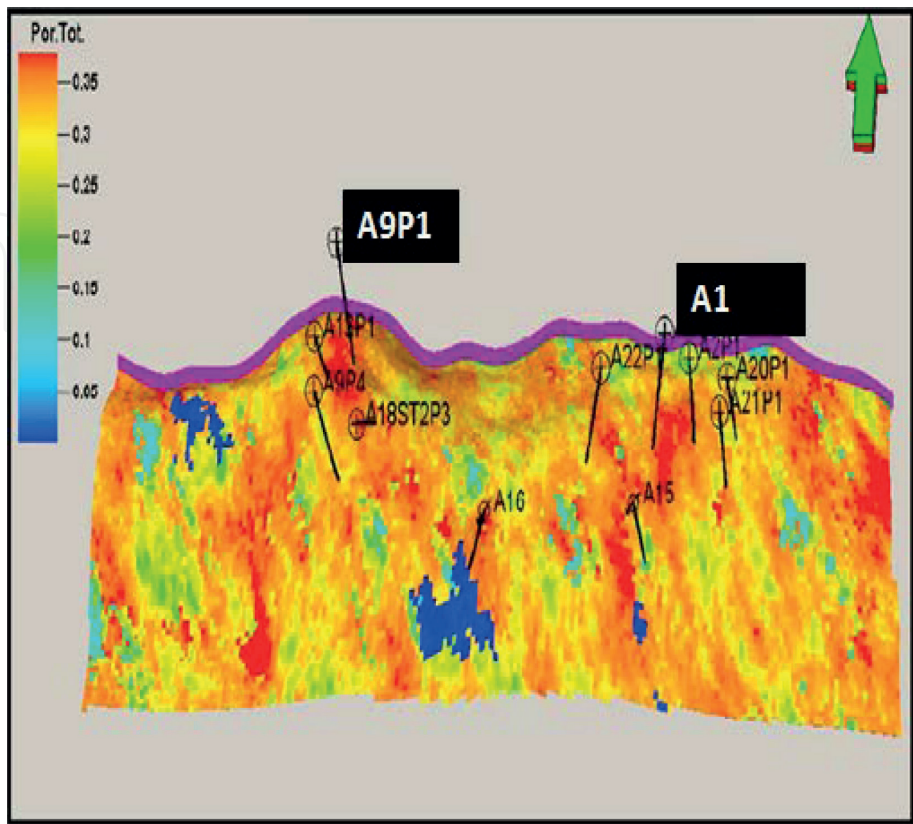
Figure 8.
Porosity model for N5.2 sand.
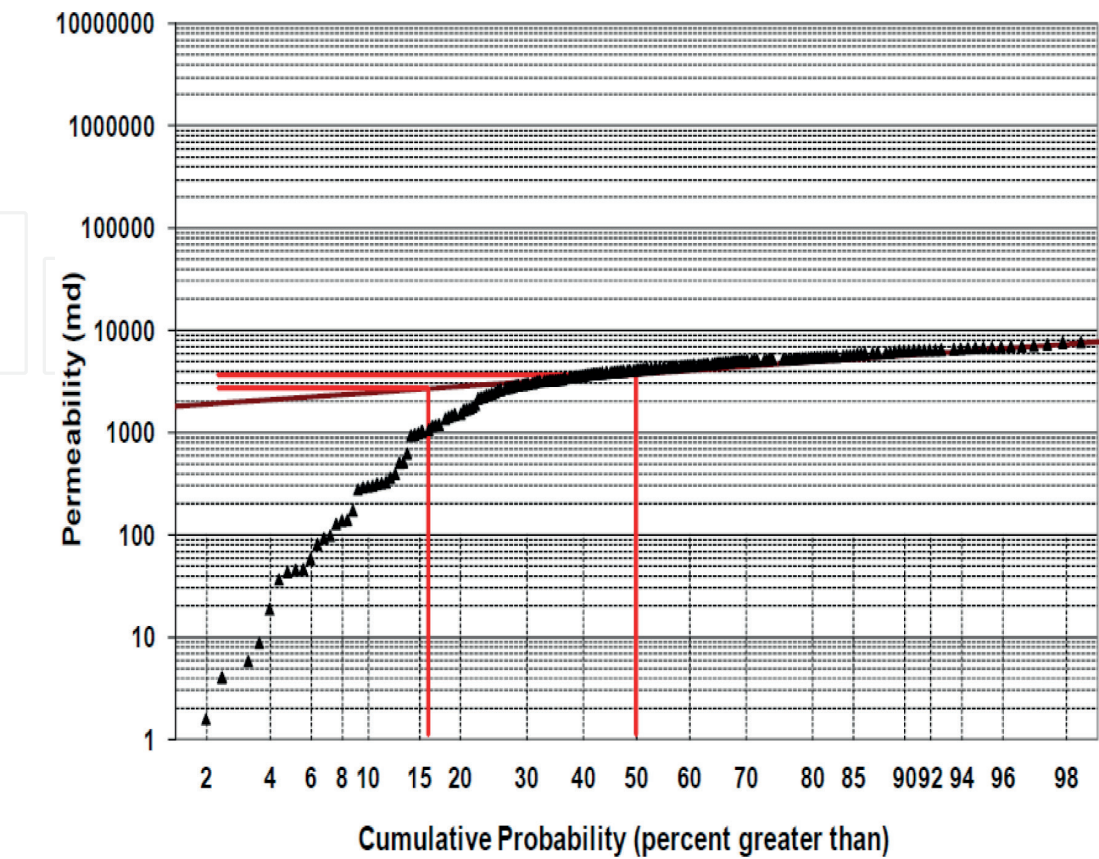
Figure 9.
Dykstra-Parson plot for heterogeneity test (N5.2 VDP = 0.3).

3.2.3 Test for heterogeneity and flow unit characterization of the N5.2 sand

Dykstra-Parson's coefficient is an expression that measures the degree of variation and heterogeneity of a reservoir [26]. The variation in the values of the core permeability reflects the degree of heterogeneity in the reservoir. Rock samples with zero permeability values (shales) were not used since it is a logarithmic plot. The Dykstra-Parson plot performed for the core samples from the well section is shown in **Figure 9**. The Dykstra-Parson's number for the core samples is 0.30—which indicates a homogenous reservoir. Higher values of Dykstra-Parson indicate more heterogeneity of which one is the maximum number.
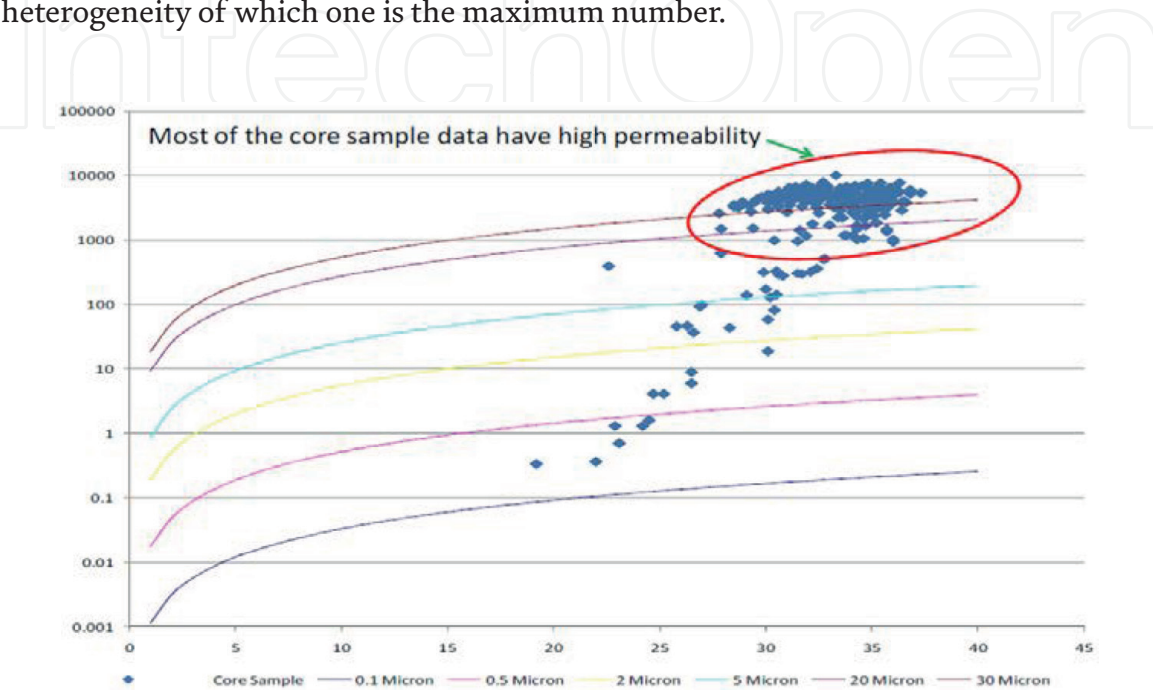
Figure 10.
Winland plot for the N5.2 sand.
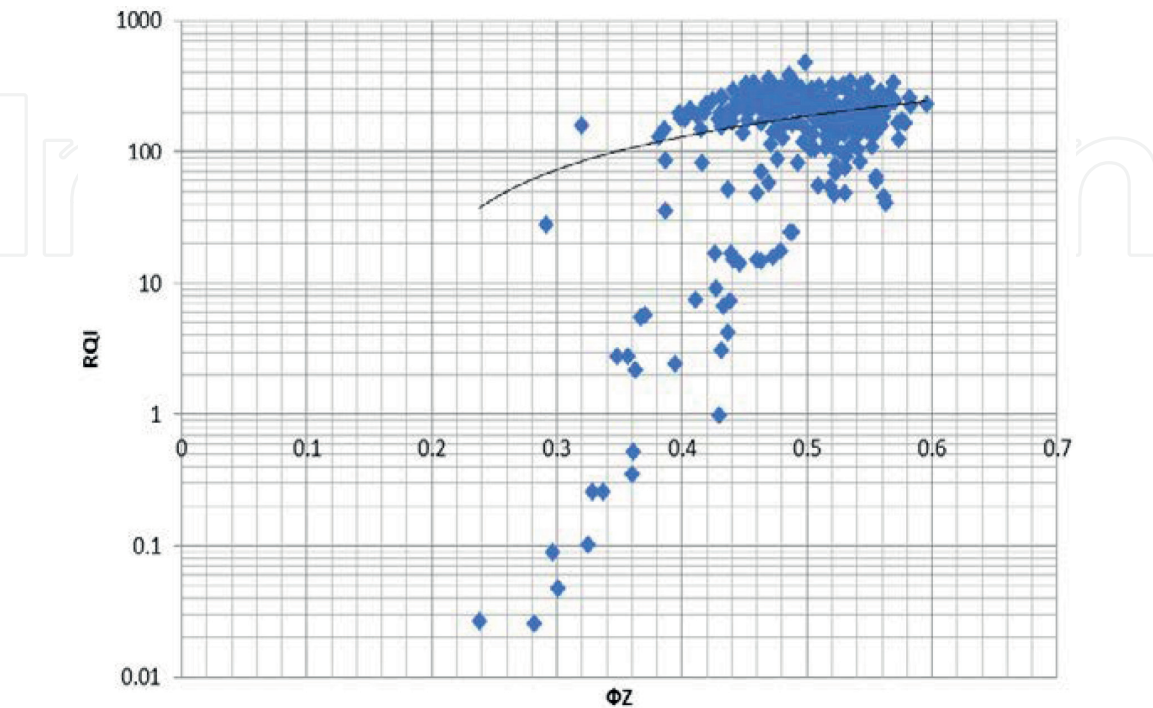
Figure 11.
RQI versus normalized porosity crossplot. Note that most of the samples have high quality index with RQI above 100. This is indicative of a high quality formation with high hydraulic potential.

The hydraulic capacity of the sand-body was well understood from plots generated from Winland and Rock Quality Index for flow zone characterization (**Figures 10** and **11**). Most of the samples plot within 1000 mD on Winland plot, showing a mega porous reservoir with a high quality index (**Figure 10**). Beside the presence of fractures that have created anisotropic condition in the homogenous geobody, excellent reservoir quality will enhance fluid flow in the reservoir [25]. Reservoir properties have major influence on reservoir fluids and the hydraulic behavior of the rock. It is important that these uncertainties are well understood because they are relevant to reservoir management decisions.

4. Possible causes of rapid production decline

4.1 Fracture network

Fractures are lineaments that occur in rocks which represent minor breaks in the natural order of the properties of the rock [27, 28]. They are evidences of the brittle failure of the rock due to lithostatic stresses initiated by tectonism and other geodynamic processes [29]. Network of fractures and faults have been identified in the area (**Figures 12**–**14**). They appear as short, disconnected and network of dark patches around the well area on seismic time slices [25, 28].

Several factors may be responsible for the development of these fractures. These could be due to changes in lithostatic pressure, geothermal stresses, hydraulic pressure and high drilling density in the field [25]. There is presently no infill drilling opportunity on the structure due to high drilling activity. The regional stress somewhat affects the orientation of the fractures as some are parallel to the axis of the growth faults, whereas some have multiple orientations especially around the well area (**Figures 12** and **13**). Non-uniform fracture distribution and heterogeneity in natural fractured reservoirs (NFR) make the development of water-cut asymmetrical and estimation of critical rate and breakthrough time will require fracture pattern modeling for proper understanding of fracture development around the producing wells. Consequently, tectonics, geothermal processes and human activity (drilling, well stimulation) could contribute to fracture generation. Fracture patterns and high vertical permeabilities created are also two important flow parameters that will allow for rapid non-uniform flow of water into the well. The N5.2 sand
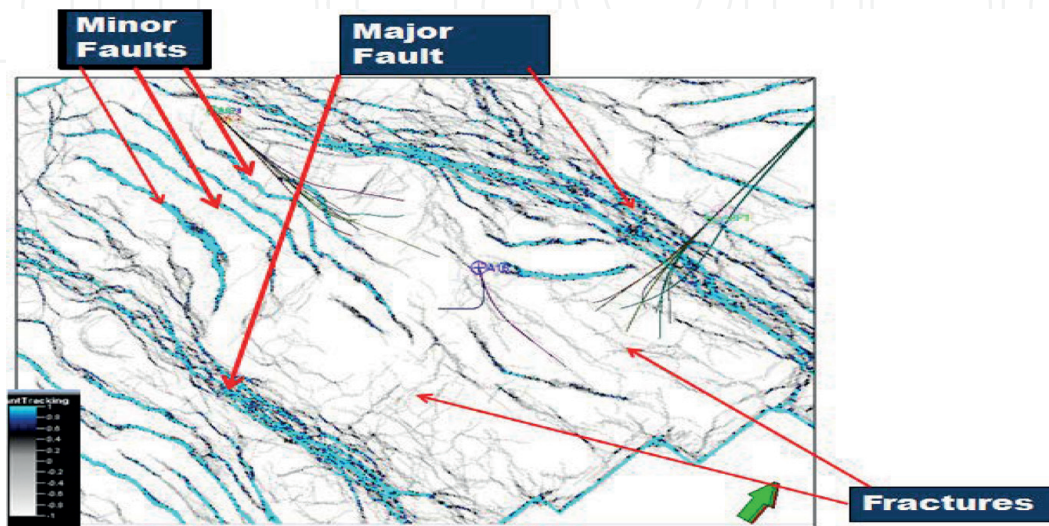

Figure 12.
Ant tracking at time-slice 1346.748 ms showing structural discontinuities.

falls between time slice 1346–1479 ms on the seismic section, where these fractures have been mapped, indicating that the reservoir is affected by the fractures. Five (5) CT-scanned core plugs taken from this interval also revealed the presence of massive vertical fractures (**Figure 14**) [25]. The vertical fractures radiate from the center of the core plugs to the edge, running around the internal circumference of the core as concentric rings (**Figure 14**).
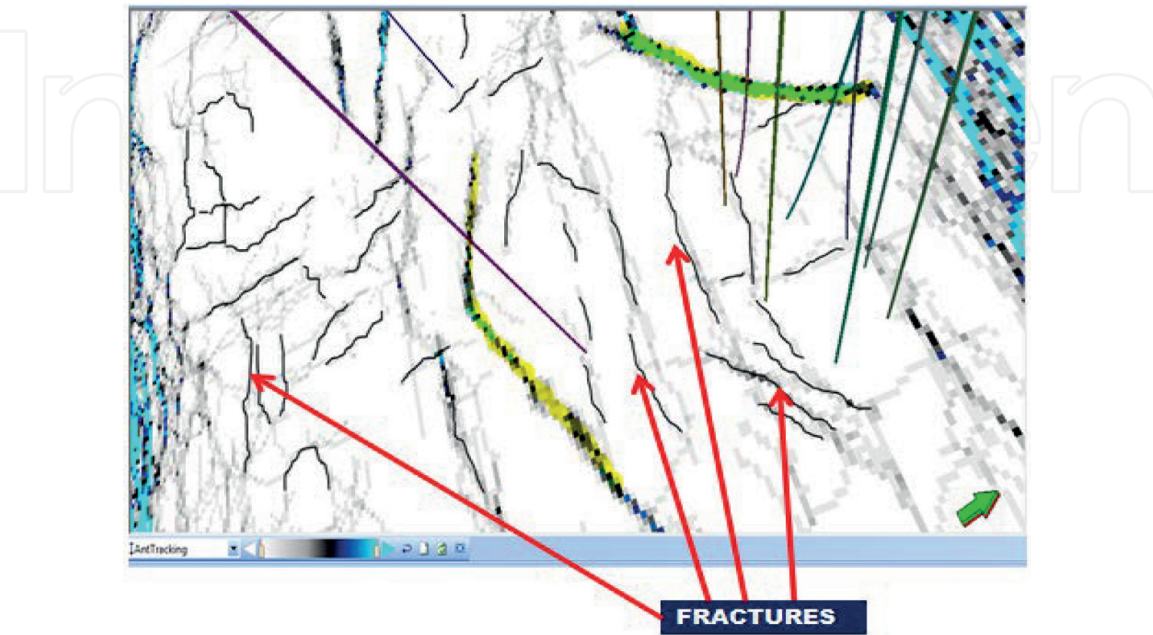

Figure 13.
Fractures highlighted to show orientations. Some of the fractures are aligned in the direction of the regional stress.
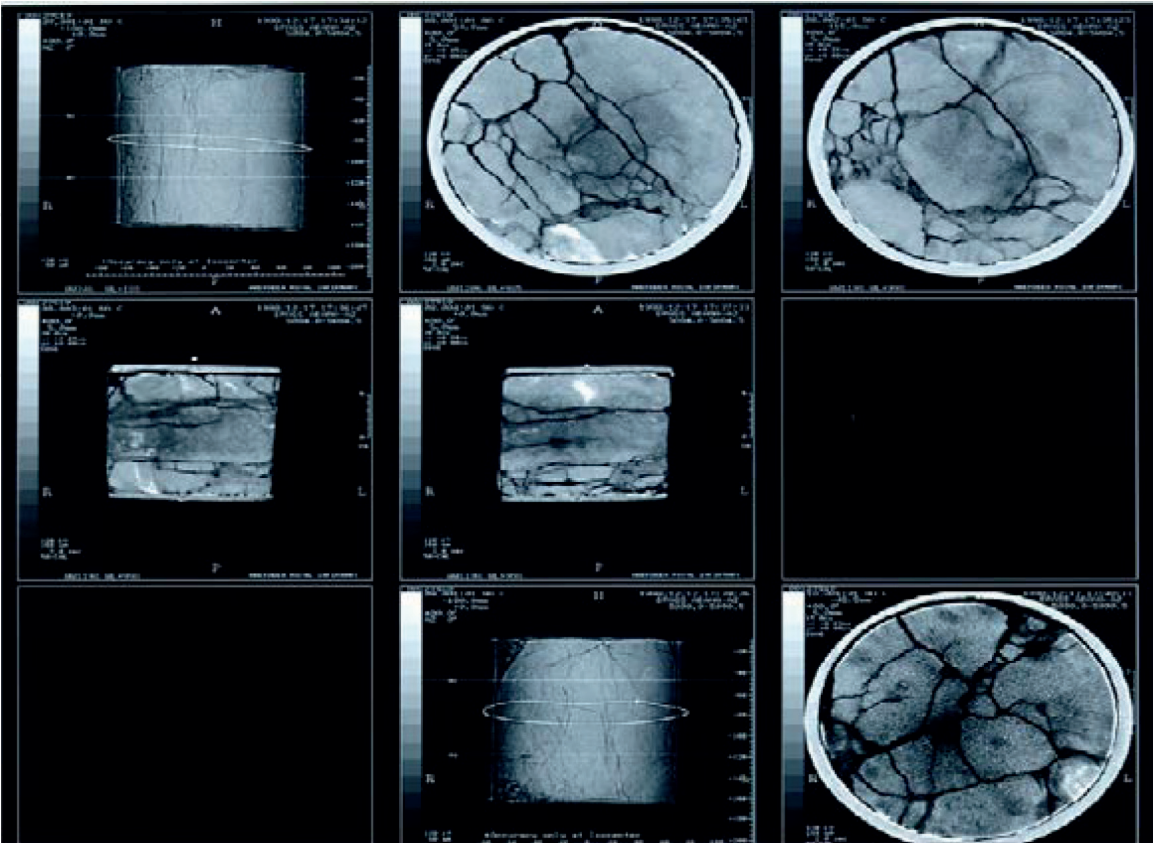
Figure 14.
Vertical fractures revealed in CT-scanned core sample p.

4.2 Production response

4.2.1 Effect of reservoir management on oil rate and basic sediment and water (BSW)

Production parameters considered include; Flowing Tubing Head Pressure (FTHP), Gas-Oil-Ratio (GOR), basic sediment and water (BSW) and choke size. The management of the choke has relative impact on oil rate and basic sediments and water (BSW). Practically, water production within the first 2 years of production was zero and peak production (over 4750 BOPD) was observed between the first 2 years (**Figures 15–17**).
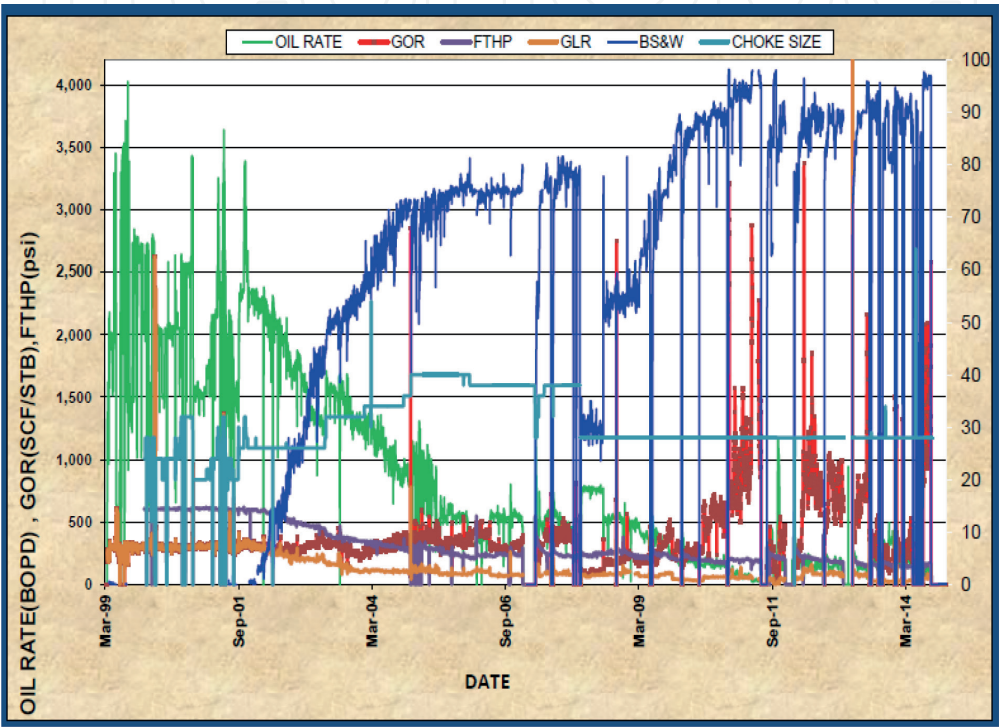
Figure 15.
The effect of choke management on oil rate and basic sediment and water for well A4.
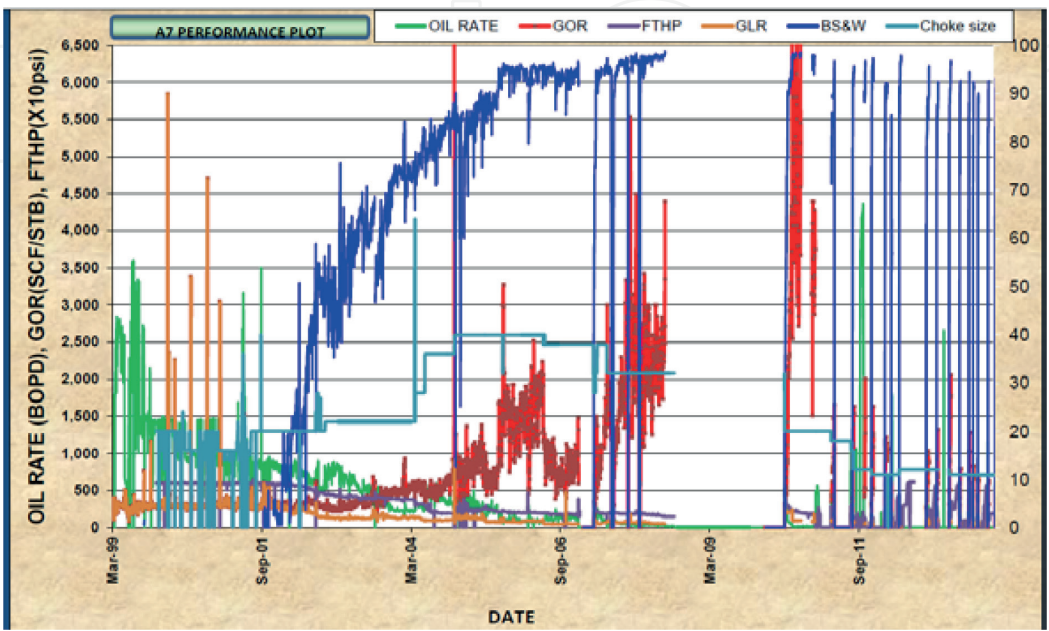
Figure 16.
The effect of choke management on oil rate and basic sediment and water for well A7.

There was high FTHP corresponding to periods of high oil rate (**Figures 15** and **18**) and choke size not exceeding 30 inches. Between September 2001 and March 2004, there was steady increase in choke from 33 to 60 (see **Figure 17**), with similar trend in the BSW. It is evident that the management of the reservoir also played a significant role on rapid fluid flow especially water.
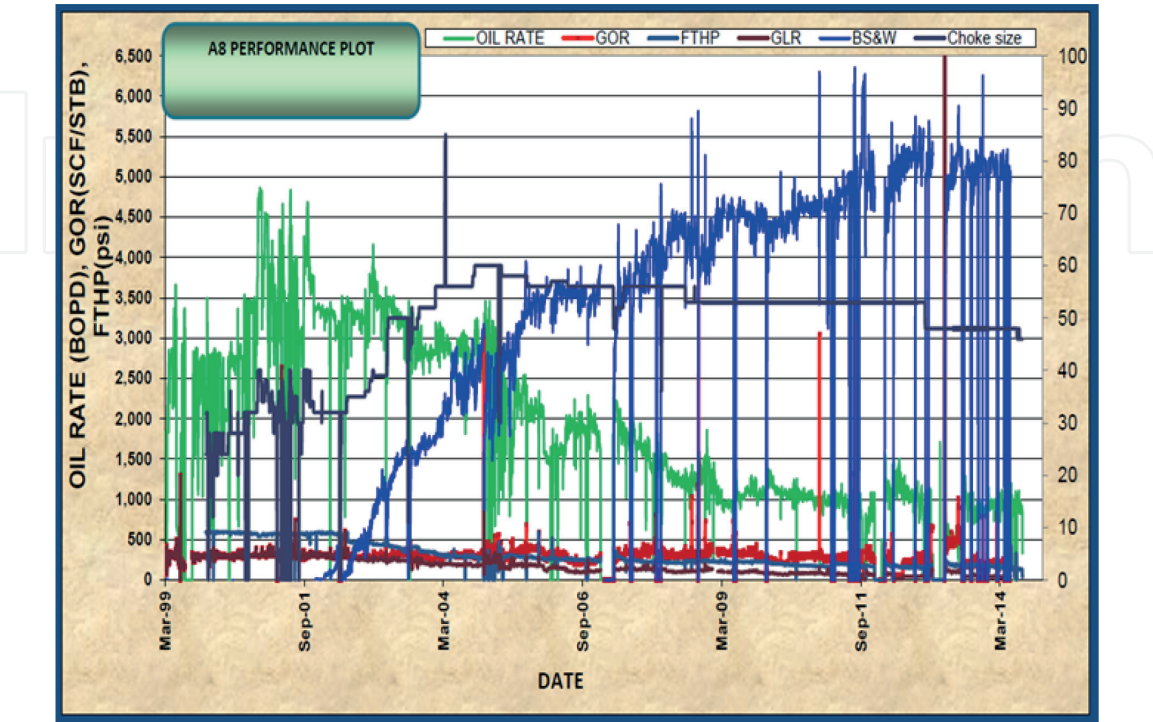
Figure 17.
The effect of choke management on oil rate and basic sediment and water for well A8.
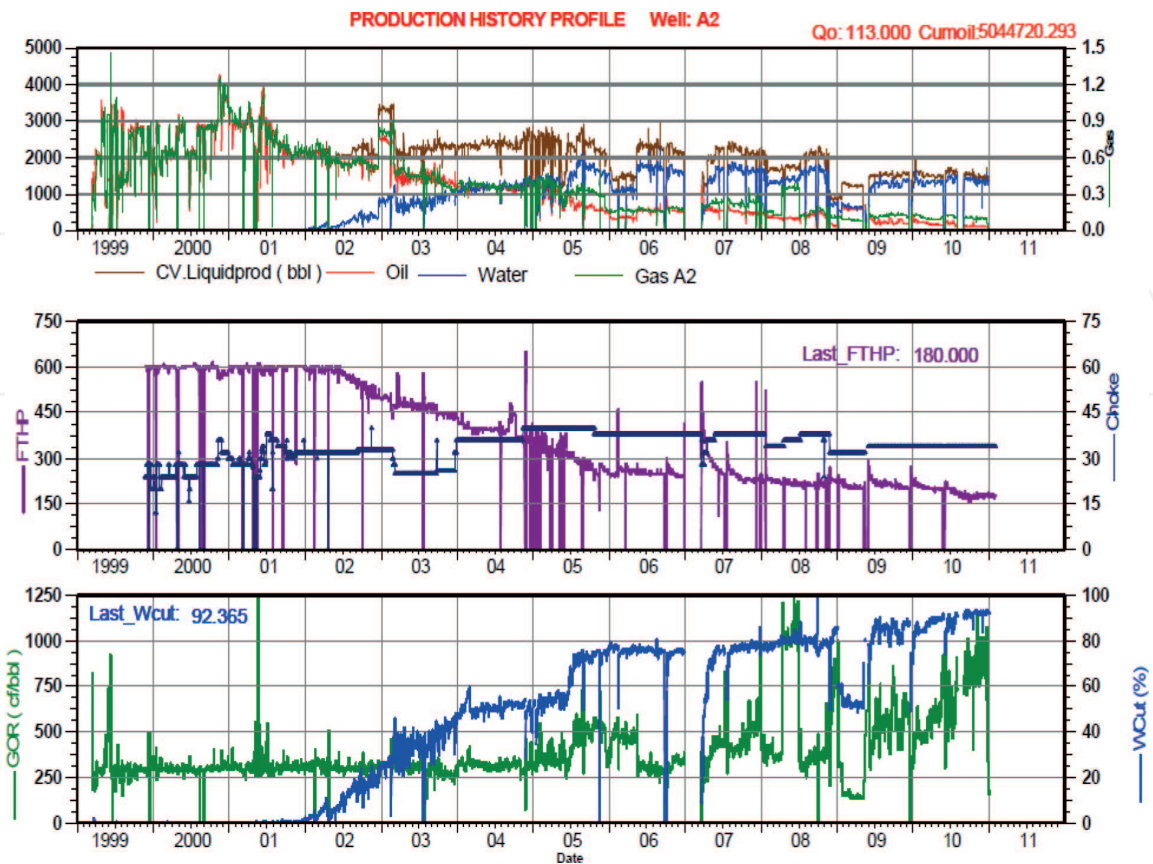
Figure 18.
Production history profile for well A2.

13

The continued water injection through the injector wells in the field could be another source of water production which has adverse effect on oil recovery especially for production wells proximal to the injectors.

The oil rate, Qo, as well as the liquid rate declined at the onset of water production in 2001 and afterwards liquid rate had remained constant at different choke sizes. The oil rate declined further as water cut increased (**Figures 15–18**). The total cumulative oil production as at January 2011 is about 67.18 MMSTB; this represents 43.91% recovery factor. However, there is still recoverable oil remaining in the reservoir, which can only be recovered if certain field operational conditions are considered.

5. Conclusions

The conclusions drawn based on the results of this study are as stated below:

1. The key geological factors that aided fluid mobility especially vertical flow include: environments of deposition, rock properties, lateral continuity of reservoirs, limited and negligible shale barriers in the N5.2 sand, and network of fractures. Reservoir properties of N5.2 sand show that the facies is highly homogenous and exerts a greater impact on fluid flow across the reservoir. The results of anisotropy due to permeability within facies on oil production increases with vertical flow potential. Fracture networks created anisotropic condition in the reservoir resulting in dominant vertical flow created by vertical fracture permeability. The major drive mechanism in the field is water; vertical fracture permeability would have created a high mobility ratio resulting in both the injected and displacing fluid breaking through earlier at the producer sand.

2. A significant coning effect is observed where there is rapid increase in choke size. It increases breakthrough time and decreases oil rate.

3. Increase in vertical fracture permeability resulted to early breakthrough and reduces oil rate after breakthrough.

4. Geological conditions (fractures and excellent reservoir quality) and poor reservoir management accounted for high fluid movement as well as high watercut in the field.

5. Seismic time-slicing methodology remains the approach to display the various seismic attributes, and useful in: identification of facies, selecting the best drilling locations, and measuring the architecture of a reservoir.

6. Water coning effect is a significant reservoir phenomenon that occurs in aquifer-supported reservoirs and is aggravated in a fractured reservoir system.

7. A synergy of a comprehensive geological and engineering investigation is a must at every stage in field development. It will provide full information needed to understand the subsurface.

Conflict of interest

There is no conflict of interest in this research work.

Author details

Prince Suka Momta
Department of Petroleum Engineering and Development, Belemaoil Producing Limited, Nigeria

*Address all correspondence to: princemomta@yahoo.com

IntechOpen

References

[1] Reijers TJA. Stratigraphy and sedimentology of the Niger Delta. Geologos. 2011;**17**(3):133-162

[2] Amajor LC, Agbaire DW. Depositional history of the reservoir sandstones, Akpor and Apara oilfields, eastern Niger Delta, Nigeria. Journal of Petroleum Geology. 1989;**12**(4):453-464

[3] Kamola DL, Van Wagoner JC. Stratigraphy and Facies Architecture of Parasequences with Examples from the Spring Canyon Member, Blackhawk Formation, Utah, Sequence Stratigraphy of Foreland Basin Deposits; Outcrop and Subsurface Examples rom the Cretaceous of North America. Tulsa, OK, United States: American Association of Petroleum Geologists; 1995. pp. 27-54

[4] Zhang J-J, Wu S-H, Fan T-E, Fan H-J, Jiang L, Cheng C, et al. Research on the architecture of submarine-fan lobes in the Niger Delta Basin, offshore West Africa. Journal of Palaeogeography. 2016;**5**. DOI: 10.1016/j.jop.2016.05.005

[5] Doust H, Omatsola E. Niger Delta. In: Edwards JD, Santogrossi PA, editors. Divergent/Passive Margin Basins. Tulsa: American Association of Petroleum Geologists Memoir. Vol. 48. 1990. p. 239-248

[6] Lisle RJ. Detection of zones of abnormal strains in structures using Gaussian curvature analysis. The American Association of Petroleum Geologists Bulletin. 1994;**78**:1811-1819

[7] Tyler N, Ambrose WA. Facies architecture and production characteristics of strandplain reservoirs in the Frio Formation, Texas. In: Report of Investigation No. 146. Austin Texas: Bureau of Economic geology, University of Texas at Austin; 1985. p. 78713

[8] Rassi C, Hentz TF. Production prediction and reservoir characterization of systems tracts of fourth-order sequence in the Miocene offshore Louisiana (abs). American Association of Petroleum Geologists Annual Convention, Offshore program. 2003;**10**:A164

[9] Fitch PJR, Jackson MD, Hampson GJ, John CM. Interaction of Stratigraphic and Sedimentological Heterogeneities with Flow in Carbonate Ramp Reservoirs: Impact of Fluid Properties and Production Strategy. Lyell collection. EAGE/The Geological Society of London; 2014. Available from: http://pg.lyellcollection.org

[10] Tveranger J, Braathen A, Skar T, Skauge A. Centre for integrated petroleum research-research activities with emphasis on fluid flow in fault zones. Norwegian Journal of Geology. Tidsskrift. 2005;**85**:63-71

[11] Adeogba AA, McHargue TR, Graham SA. Transient fan architecture and depositional controls from near-surface 3D data, Niger Delta continental slope. American Association of Petroleum Geologists Bulletin. 2005;**89**(5):627-638

[12] Arochukwu E. Assessing the Impact of Reservoir Architecture on Secondary Recovery: A Case Study of "Century" Field, Niger Delta. NAPE Monthly Technical Meeting, Port Harcourt. 2014

[13] Weber KJ. Sedimentological aspects of oil fields in the Niger Delta. Geologie en Mijnbouw. 1971;**50**:559-576

[14] Momta PS, Omoboh JO, Odigi MI. Sedimentology and depositional environment of D2 sand in part of greater Ughelli Depobelt, onshore Niger Delta Nigeria. American Journal of Engineering and Applied

Sciences. 2015;**8**(4). DOI: 10.3844/ ajeassp.2015.556.566

[15] Momta PS, Odigi MI. Reconstruction of the depositional setting of tortonian sediments in the Yowi field, shallow offshore Niger Delta, using wireline logs. American Journal of Geosciences. 2016;**6**(1). DOI: 10.3844/ ajgsp.2016.24.35

[16] Osinowo OO, Ayorinde JO, Nwankwo C, Ekeng OM, Taiwo OB. Reservoir description and characterization of Eni field offshore Niger Delta, southern Nigeria. Journal of Petroleum Exploration and Production Technologies. 2017. DOI: 10.1007/s13202-017-0402-7

[17] Oyedele KF, Ogagarue DO, Mohammed DU. Integration of 3D seismic and well log data In the optimal reservoir characterisation of EMI field. Offshore Niger Delta oil province, Nigeria. American Journal of Scientific and Industrial Research. 2013. DOI: 10.5251/ajsir.2013.4.1.11.21

[18] Adeoti L, Onyekachi N, Olatinsu O, Fatoba J, Bello M. Static reservoir modeling using well log and 3-D seismic data in a KN field, offshore Niger Delta, Nigeria. International Journal of Geosciences. 2014;**2014**(5):93-106. Available from: http://www.scirp.org/ journal/ijg. DOI: 10.4236/ijg.2014.51011

[19] Prather BE. Controls on reservoir distribution, architecture and stratigraphic trapping in slope settings. Marine and Petroleum Geology. 2003;**20**:529-545

[20] Richards M, Bowman M. Submarine fans and related depositional systems II: Variability in reservoir architecture and wireline log character. Journal of Marine and Petroleum Geology. 1998;**15**:821-839

[21] Howell JA, Flint SS. Siliciclastics case study: The book cliffs. In: Coe A,

editor. The Sedimentary Record of Sea-Level Change. Cambridge, UK: Cambridge University Press; 2003. pp. 135-208

[22] Kirschbaum MA, Hettinge RD. Facies Analysis and Sequence Stratigraphic Framework of Upper Campanian Strata (Neslen and Mount Garfield Formations, Bluecastle Tongue of the Castlegate Sandstone, and Mancos Shale), Eastern BookCliffs, Colorado and Utah. U.S. Geological Survey Digital Data Series DDS-69-G. Denver, Colorado: Central Region; 2004. ISBN: 0-607-90854-5

[23] Slatt RM. Stratigraphic Reservoir Characterization, Handbook of Petroleum Exploration and Production. The Netherlands: Elsevier; 2006. pp. 8-30

[24] Wright IP, Malcolm FF, George ZJ. The Abana Field, Nigeria, from Discovery to Recovery: A Case Study. In: American Association of Petroleum Geologists Search and Discovery Article #90923@1999 International Conference and Exhibition. Birmingham, England; 1999

[25] Momta PS, Odigi MI. Impact of structural discontinuities on fluid flow and production behaviour: Case study of the Yowi field, offshore Niger Delta, Nigeria. Society of Petroleum Engineers. 2015. DOI: 10.2118/178260

[26] Dykstra H, Parsons RL. The Prediction of Oil Recovery by Waterflooding in Secondary Recovery of Oil in the United States. 2nd ed. Washington, DC: American Petroleum Institute. 1950. pp. 160-174

[27] Djebbar T, Donaldson EC. Petrophysics-Theory and Practice of Measuring Reservoir Rock and Fluid Transport Properties. Burlington: Gulf Professional Publishing is an imprint of Elsevier; 2004. pp. 488-548

[28] Momta PS, Odigi MI. Drilling deeper to access more hydrocarbon potentials in the Yowi Oilfield, Offshore, Niger Delta, Nigeria. In: SPE Nigeria Annual International Conference and Exhibition; 4-6 August; Lagos, Nigeria. Society of Petroleum Engineers; 2015. DOI: 10.2118/178261

[29] Djebbar T, Donaldson EC. Theory and Practice of Measuring Reservoir Rock and Fluid Transport Properties. USA: Gulf Professional Publishing, Elsevier; 2012. p. 950