Ndip et al., J Geol Geophys 2018, 7:2
DOI: 10.4172/2381-8719.1000331

Journal of Geology & Geophysics

Research Article Open Access

Seismic Stratigraphic and Petrophysical Characterization of Reservoirs of the Agbada Formation in the Vicinity of 'Well M', Offshore Eastern Niger Delta Basin, Nigeria

Edwin Ayuk Ndip[1-4*], Agyingyi CM [3,4], Nton ME[2] and Oladunjoye MA[2]

[1]*Institute for life and Earth Sciences (including Health and Agriculture), Pan African University, Ibadan, Nigeria*
[2]*Department of Geology, University of Ibadan, Nigeria*
[3]*Petroleum Geosciences Research Group, University of Buea, Cameroon*
[4]*Department of Geology, University of Buea, Cameroon*

Abstract

Two dimensional seismic and composite well logs from well M in the eastern offshore Niger delta basin were used to carry out a seismic stratigraphic and petrophysical characterization of reservoirs of the Agbada Formation. Three seismic sequences have been delineated within a time window of 600 ms-2200 ms showing depositional environments that have prograded from the delta platform in seismic sequence one (S1) down to the wave dominated prodelta /slope in seismic sequences three (S3). Five seismic facies (F1, F2, F3, F4, and F5) have been mapped within the study area with F2, the hydrocarbon habitat, consisting of deltaic distributary channel fills. The deposits of F2 were formed during aggradation to progradation of the delta and are considered to be High stand system tracts (HST) reservoirs. Twenty reservoirs zones (A-T) were identified with porosity ranging from 0.192 to 0.423 and permeability from 5.078 to 12,397.895 md, indicating very good porosity and permeability as a result of the low shale volume (0.031-0.148). The values for the bulk volume water are constant or nearly constant throughout the reservoirs and the reservoirs are said to be at irreducible water saturation implying the reservoir can produce water free hydrocarbon hence they are very good hydrocarbon reservoirs. The reservoirs qualities of well M are good and some of the reservoirs are petroliferous. Therefore, Well M could serve as a control well in hydrocarbon exploration in the offshore depobelt.

Keywords: Seismic sequence; Seismic facies; High stand system tract; Petroliferous; Niger delta basin

Introduction

The Niger Delta clastic wedge contains the 12th largest known accumulation of recoverable hydrocarbons, with reserves exceeding 34 billion barrels of oil and 93 trillion cubic feet of gas [1]. Niger Delta province is one of the most prolific basins in Africa typified by six depobelt, notably offshore, coastal and central swamps, Northern Delta, Greater Ughelli swamp [2]. This has led to an extensive study of the Niger Delta depocenters after a long while of non-productive search in the Cretaceous sediments of the Benue Trough [2,3].The Niger Delta clastic wedge spans a 300,000 km^2 area in Nigeria and the Gulf of Guinea offshore [4], with a sediment volume of 500,000 km^3 [5] and a sediment thickness of over 10 km in the basin depocenters [6].

The delta can be divided into sub-environments that have distinctive characteristics and facies. These deposits have been divided into three large- scale lithostratigraphic units: (1) the basal Paleocene to recent pro-delta facies of the Akata formation, (2) Eocene to recent, paralic facies of the Agbada formation, and (3) Oligocene-recent, fluvial facies of the Benin formation [7-9]. These Formations become progressively younger farther into the basin, recording the long-term progradation of depositional environments of the Niger delta onto the Atlantic Ocean passive margin. Stratigraphy of Niger delta is complicated by the syndepositional collapse of the clastic wedge as shale of the Akata Formation mobilized under the load of prograding deltaic Agbada and fluvial Benin Formation deposits. A series of large-scale, basin ward-dipping listric normal fault formed as underlying shale diapired upward. Blocks down dropped across these faults filled with growth strata, changed local depositional slopes, and complicated sediment transport path into the basin. Studies on the lithofacies and morphology of the sub aerial and marine parts of the delta have been carried out by Pugh [10], Hill and Webb [11], Allen [12-15] and Oomkens [16]. While work on the constructive and destructive delta building episodes are well documented in Weber and Daukoru [17], Agagu [18] and Whiteman [9]. Evamy [7] studied the hydrocarbon habitat in the basin. Larue and Legarre [19] characterized the Meren E-01 reservoir in the study area. These authors all indicated that the Agbada Formation is the main hydrocarbon habitat in the basin.

It has been observed over the years that hydrocarbon exploration and exploitation attention has been on structural traps [20]. At present most of the identified structural closures on the shelf and upper slope have been drilled and the search for hydrocarbon is becoming increasingly more difficult and expensive [21]. Combined geophysical well logs and seismic stratigraphy approach will no doubt be an effective exploration tool to delineate lithology, lithofacies, sequences and depositional environment, hydrocarbon reservoirs. The main objective of this study was to carry out a seismic stratigraphic analysis of the Agbada Formation in the vicinity of well M and to characterize reservoir units in it. In order to delineate seismic sequences and seismic facies and establish petroliferous system tracts within the seismic sequences, identify the lithology sequences in the well and evaluate the petrophysical properties of the reservoir units.

***Corresponding author:** Edwin Ayuk Ndip, Institute for life and Earth Sciences (including Health and Agriculture), Pan African University, Ibadan, Nigeria, Tel: +237 2 33 32 27 60; E-mail: ndipedwin70@gmail.com

Received January 27, 2017; **Accepted** March 04, 2018; **Published** March 12, 2018

Citation: Ndip EA, Agyingyi CM, Nton ME, Oladunjoye MA (2018) Seismic Stratigraphic and Petrophysical Characterization of Reservoirs of the Agbada Formation in the Vicinity of 'Well M', Offshore Eastern Niger Delta Basin, Nigeria. J Geol Geophys 7: 331. doi: 10.4172/2381-8719.1000331

Citation: Ndip EA, Agyingyi CM, Nton ME, Oladunjoye MA (2018) Seismic Stratigraphic and Petrophysical Characterization of Reservoirs of the Agbada Formation in the Vicinity of 'Well M', Offshore Eastern Niger Delta Basin, Nigeria. J Geol Geophys 7: 331. doi: 10.4172/2381-8719.1000331

Location of Study Area

Well M is located in the Eastern offshore Niger delta Basin, where sequences of thick clastic material of the Agbada Formation were deposited in the deltaic fluvio-marine environment. The precise location of well M is classified (Figure 1).

Geological Framework

The clastic wedge of the Niger Delta occurs along a failed arm of a triple junction system which was initially formed in the period of a breakup between the plates of South America and Africa, a process which occurred in the Late Jurassic [9,22]. Synrift sediments accumulated during the Cretaceous to Tertiary, with the oldest dated sediments of the Albian age. The thickest successions of synrift marine and marginal marine clastics and carbonates were deposited in a series of transgressive and regressive phases [2]. The synrift phase finished with basin inversion that occurred in the Late Cretaceous. Renewed subsidence occurred as the continents separated and the sea transgressed the Benue Trough. The Niger Delta clastic wedge prograded into the Gulf of Guinea at an increase rate that was so steady in order to respond to the evolution of these drainage areas and continued basement subsidence. Regression rates increase in the Eocene, with an increasing volume of sediments accumulated since the Oligocene. The movement of deep seated, over-pressured, ductile, marine shale of the Akata Formation within the basin produced normal faults in the basin. The shale tends to have deformed the clastic wedge of the Niger Delta [2]. Most of these faults are syndepositional and were produced during the progradation of the Delta. The examples of faulting styles in the Niger Delta are shown in Figure 2.

The clastic Niger Delta has three major lithostratigraphic units which include Akata, Agbada and Benin Formations (Figure 3); depositional environments range from marine, deltaic to fluvial environments [17,23].

Akata Formation is about 6400 m thick at the center of the clastic wedge; the lithologies include dark gray shale and silts, having streaks of sand which their origin could be from turbidite flow. The age of this Formation ranges from Paleocene to Recent. This Formation grades vertically into the Agbada Formation with abundant plant remains and micas in the transition zone [2].

Agbada Formation extends throughout Niger Delta clastic wedge and has a maximum thickness of about 3962 m. The lithologies of this Formation include alternating sands, silts and shales. Strata in this Formation are believed to have been produced in fluvial–deltaic environment. Agbada Formation ranges from Eocene to Pleistocene in age.

Benin Formation is the top of the clastic wedge Niger Delta. The top of this Formation consists of the recent subaerially exposed delta top surface. The shallow part of Benin Formation is made up of non-marine sands that were deposited in either upper coastal plain or alluvial depositional environments [2]. Benin Formation ranges from Oligocene to Recent in age [8].

Agbada Formation is the main reservoir in the Niger Delta clastic wedge. The ratio of gas to oil tends to increase toward the south within the depobelts in the Niger Delta. This is because of the complexity in the distribution of hydrocarbons in the basin [2].

The source rock in the Niger Delta consists of marine shale of Akata Formation. It could also consist of marine interbedded shales in the Agbada Formation as well as the underlying Cretaceous shale [2,7,24,25].

The primary seal rocks are the interbedded shale that occur in the Agbada Formation.

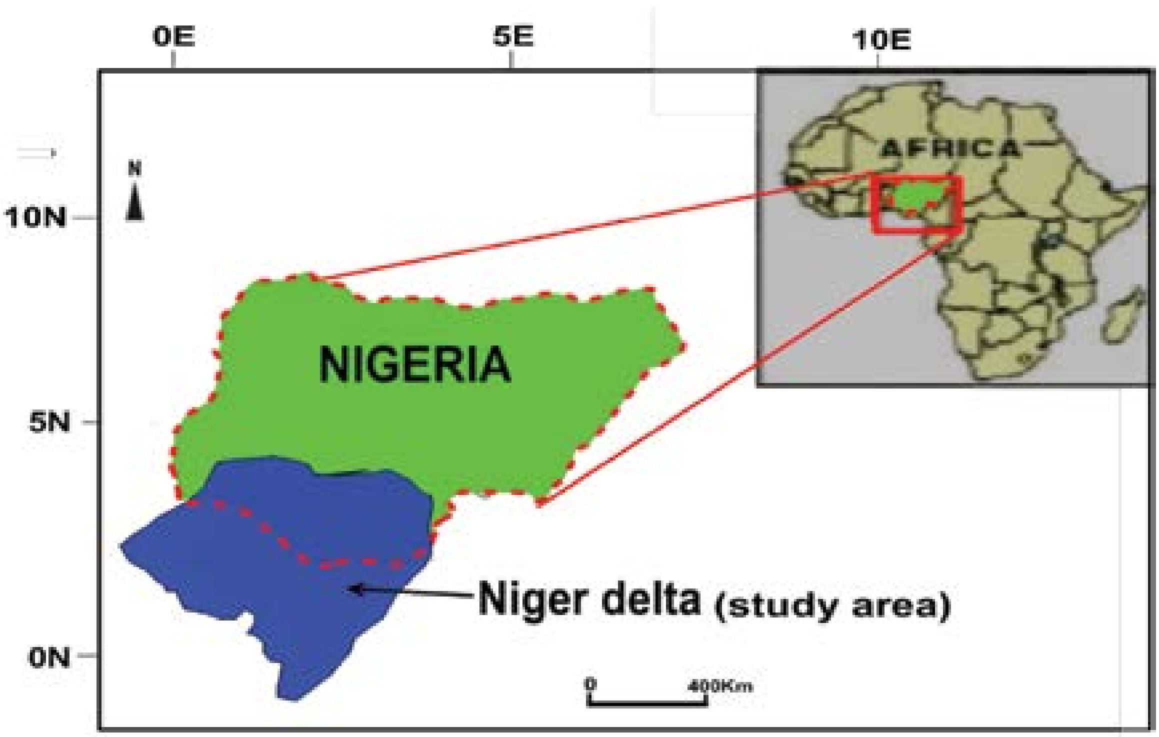

Figure 1: Location map of study area (modified after Corredor et al.).

Citation: Ndip EA, Agyingyi CM, Nton ME, Oladunjoye MA (2018) Seismic Stratigraphic and Petrophysical Characterization of Reservoirs of the Agbada Formation in the Vicinity of 'Well M', Offshore Eastern Niger Delta Basin, Nigeria. J Geol Geophys 7: 331. doi: 10.4172/2381-8719.1000331

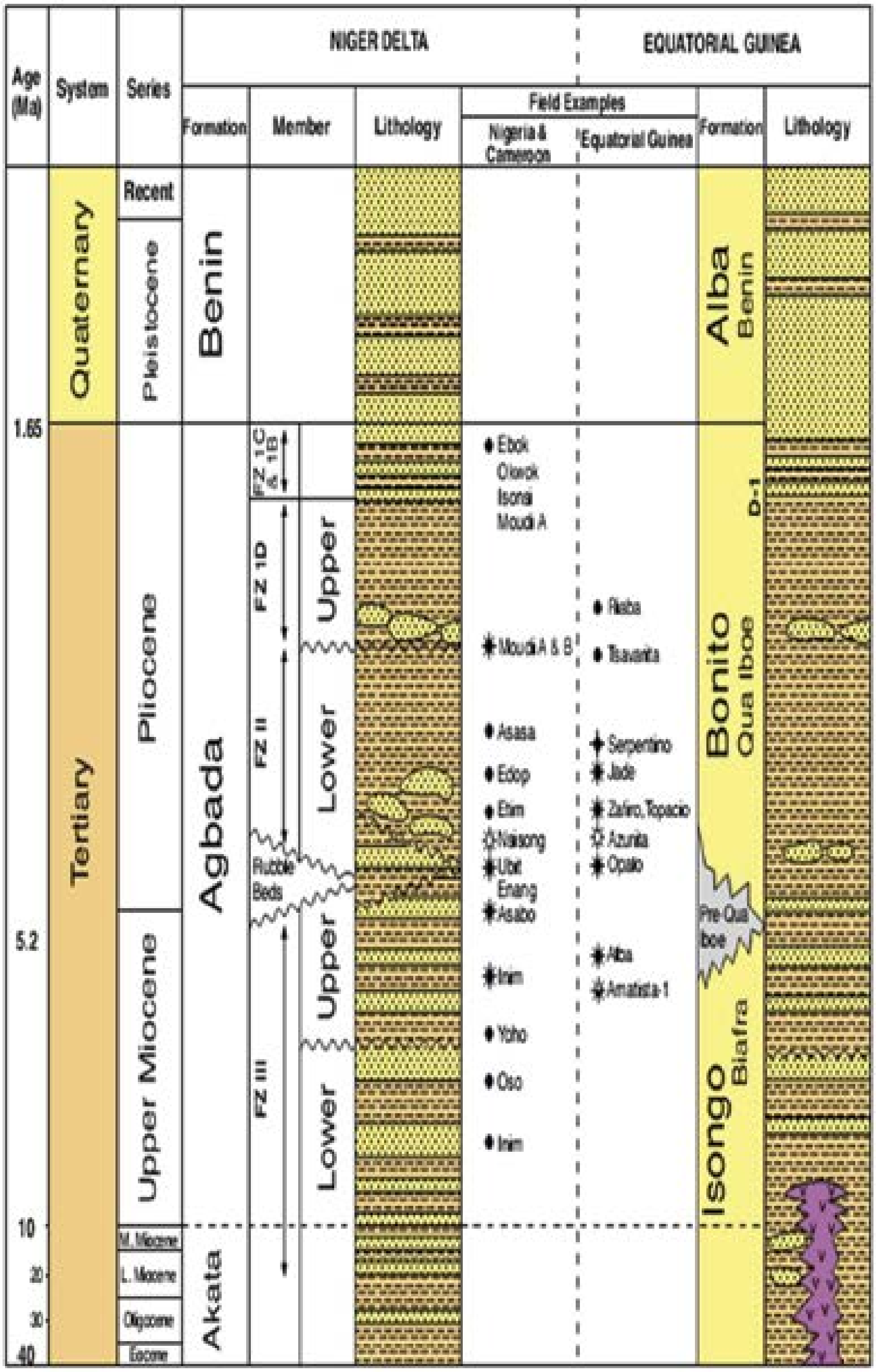

Figure 2: Stratigraphy of the Niger Delta Basin (Doust and Omatsola).

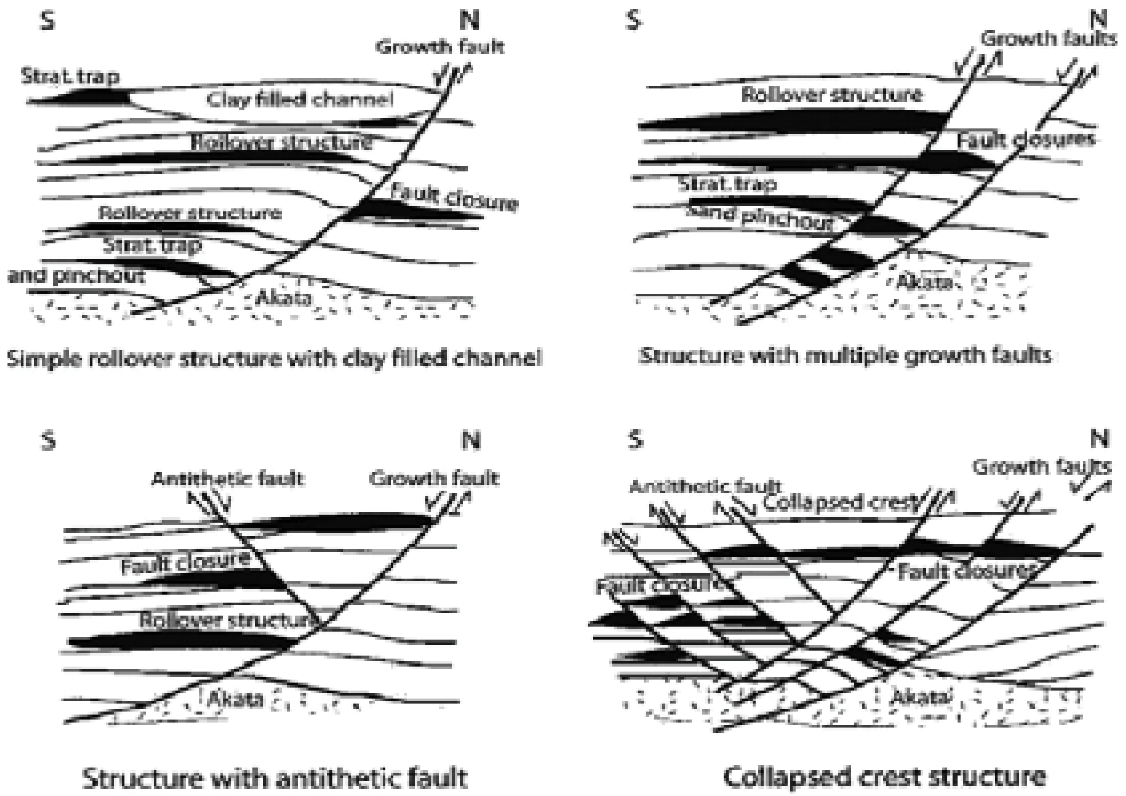

Figure 3: Niger delta oil field structures and associated traps (Stacher).

Data Availability

The study was initiated with the collection of data. The data consist of electronic copy of seismic section and a suit of well logs from well M in the eastern offshore Niger delta basin. The well log suit consists of gamma ray (GR), spontaneous potential (SP), resistivity (ILD, ILM), porosity (density and neutron) and photoelectric logs.

Methodology

The seismic section were used for seismic stratigraphic analysis while the wire line logs were used in evaluating petrophysical properties and Interpretation was done using commercial Petrel software which is an interactive software to estimate all the parameters needed for seismic stratigraphy and petrophysical characterisation of reservoirs. Petrophysical evaluation was concerned with the rock proportion that determines the quality, quantity and recoverability of hydrocarbon in a reservoir. Since the potential and performance of a reservoir depends on the porosity, permeability and fluid saturation. The relationships among these properties are used to identify and evaluate reservoirs. Hence the following properties were evaluated: shale volume, porosity, permeability, hydrocarbon and water saturation, bulk water volume and net pay. The various logs were used to evaluate the above properties although not without the help of others.

Shale volume (V_{sh})

The Gamma Ray index (I_{GR}) was used to determine the amount of shale that is present in each of the reservoir Formations. Since GR readings increase with increase in shale content. The volume of shale is very important to note because it is used to evaluate other petrophysical parameters like reservoir net thickness, irreducible water saturation (S_{wirr}), effective porosity and thus the permeability. The gamma ray index (I_{GR}) was determined from the equation 1 below:

$$I_{GR} = \frac{GR_{\log} - GR_{\min}}{GR\max - GR_{\min}} \quad (1)$$

Where, GR_{log} = GR reading of Formation

GR_{min} = minimum GR reading (clean sand or carbonates)

GR_{max} = maximum GR (shale base line value)

The volume of shale was then determined using the Lavrionov [26] equation 2

$$V_{sh} = 0.083(2^{3.71GR}\_1.0) \quad (2)$$

For Tertiary rocks, since reservoir of the Agbada Formation are of Tertiary age.

Porosity (Ø)

Porosity which is a measure of reservoir storage capacity is defined as the ratio of the void volume to that of the total rock volume and filled with fluids. Porosity is a relative measurement and commonly expressed in decimal/fractional units or else as percentage. The porosity logs used are Neutron and Density. From the Neutron and Density logs the porosity (Ø) of each of the reservoirs units was determined using the equation 3 below:

$$\varnothing = (\varnothing_{ND} + \varnothing_{D}) \quad (3)$$

Where, $\varnothing_N$= Neutron porosity obtained from Neutron log.

$\varnothing_D$= Density porosity obtained from Density log.

Density porosity was derived from bulk density using the equation 4:

$$\varnothing_D = \frac{\delta_{ma} - \delta_b}{\delta_{ma} - \delta_{fl}} \quad (4)$$

δ_{ma}=matrix density, δ_{fl}=fluid density,δ_b=bulk density.The effective's porosity (Øe) for each reservoir zone was estimated using the equation 5 below:

$$\varnothing_e = \varnothing_D - V_{sh}\varnothing_{sh} \quad (5)$$

Where; $V_{sh} \times \varnothing_{sh}$ = shale bound water

Water saturation (S_w)

Water saturation (S_w) is the proportion of the pore space that is occupied by water. Saturation is a relative measurement and commonly expressed in decimal/fractional units or else as percentage. From porosity the formation resistivity factor (F) was calculated

$$F = a / \varnothing^m \quad (6)$$

Where, **a** is the tortuosity factor for sand given as 0.81, m is cementation factor given as 2.

The water saturation (S_w) of the reservoirs was then calculated using formation water resistivity (Rw)

Rw=Ro/F (7)

in the Archie (1942) equation

$$Sw = \sqrt{\frac{F \times Rw}{Rt}} \quad (8)$$

Where, Ro is resistivity of water bearing formation (ILD at water formation).

Rt is true formation resistivity (from ILD). Having determined S_w, hydrocarbon saturation (S_{HC}) was then calculated from the equation 9:

$$\mathbf{S_{HC}} = 1 - Sw \quad (9)$$

Permeability determination (K)

Permeability is the capacity of a reservoir rock to permit fluid to flow. It is a function of interconnected pore volume; therefore, a rock is permeable if it has an effective porosity. For the permeability (K) of the reservoir to be determined, the irreducible water saturation, (S_{wirr}) (that is the proportion of water adsorbed on a mineral surface or held within microspores by capillary action) must be known. S_{wirr} is given as

$$S_{wir} = \frac{c}{\Phi} \quad (10)$$

Where C= constant (for sandstone 0.02-0.10).

The Wyllie and Rose, (1950) equation below was used to determine the K.

$$K = 79 \times \frac{\varnothing^3}{S_{wirr}}, \text{(drygas)} \quad (11)$$

$$K = 250 \times \frac{\varnothing^3}{S_{wirr}}, (medium - gravityoils) \quad (12)$$

Bulk volume water (BVW)

The BVW in a reservoir is simply the product of the Water saturation (S_w) and the porosity (Φ) as given in equation 13.

$$BVW = S_w \Phi \quad (13)$$

It is important in that it indicates whether or not a reservoir is at $S_{wirr.}$ At $S_{wirr,}$ a reservoir produces Water –free hydrocarbons because all the formation water is held through surface tension or capillary pressure by the grains. A reservoir at S_{wirr} exhibit BVW values that are constant or nearly constant throughout [27]. This means that when BVW is calculated at different points through an interval, the values should be the same or very close to the same for an essentially water-free completion.

Net pay zone

Net reservoirs thickness interval that contains movable hydrocarbons. The bases for cut –off criteria include; reservoir lithology (low V_{sh}), storage capacity for fluid (porosity), flow capacity (K).

Results and Interpretations

Seismic stratigraphic interpretation

Three seismic sequences (Figure 4) were mapped within a time window of 600-2200 ms. The sequences were mapped from discordant and /or concordant relationship of rock units at the sequences boundaries. These intervals were defined primarily on the basis of seismic reflection patterns and seismic facies. The sequence boundary (SB) is laterally extensive and conformable in stratigraphic order from the oldest (S1) to the youngest (S3). The Table 1 are below give the characteristics of seismic sequences.

The seismic facies are characterized by the following; TWTT/ms.

Facies 1 (F1) is parallel continuous and wavy reflection with low-high amplitude of low frequency. They indicate uniform sedimentation for an infill or a sequence on top of a subsiding substratum [28]. The parallel continuous and wavy geometry indicates rippled sand of subaqueous delta platform. The high amplitude reflection character points to the vertical alternation of contrasting lithology typically of the Agbada Formation that is alternating sand/shale while the low amplitude indicates similar lithology on both sides of the interface that is sand /silt sand which is a lithologic characteristics of reservoir of the Agbada formation [29].

Facies 2 (F2) is parallel, continuous and even, low-high amplitude with low frequency and is composed of channel deposits. The channel sand is interpreted to be stratigraphic trap and serve as the major reservoir in the area [30]. The channel is deltaic distributaries of a prograding delta. The parallel geometry indicates uniform sedimentation with cross bedded sands. The high -low amplitude indicates contrasting lithology of the Agbada Formation.

Facies 3 (F3) is sub parallel continuous reflection of low- high amplitude. The sub parallel geometry indicates a fairly uniform sedimentation condition [28]. The high continuity of the subparallel reflections in this facies is more diagnostic of delta front in the delta platform than delta plain. The amplitude varies vertically and laterally. The portion with high amplitude indicates constant delta sandstone/ prodelta shale lithologic contrast while the moderate amplitude suggests presence of less contrasting lithology [31].

Facies 4 (F4) is hummocky reflection configuration with low-high amplitude. It is characterized by short, curved and discontinuous reflection. It interpreted as the result of a cut and filled and contorted bedding [32]. The contorted bedding is the result of water escaping during burial. It is characterized by over-steeping of the sedimentary lamination of the prodelta.

Citation: Ndip EA, Agyingyi CM, Nton ME, Oladunjoye MA (2018) Seismic Stratigraphic and Petrophysical Characterization of Reservoirs of the Agbada Formation in the Vicinity of 'Well M', Offshore Eastern Niger Delta Basin, Nigeria. J Geol Geophys 7: 331. doi: 10.4172/2381-8719.1000331

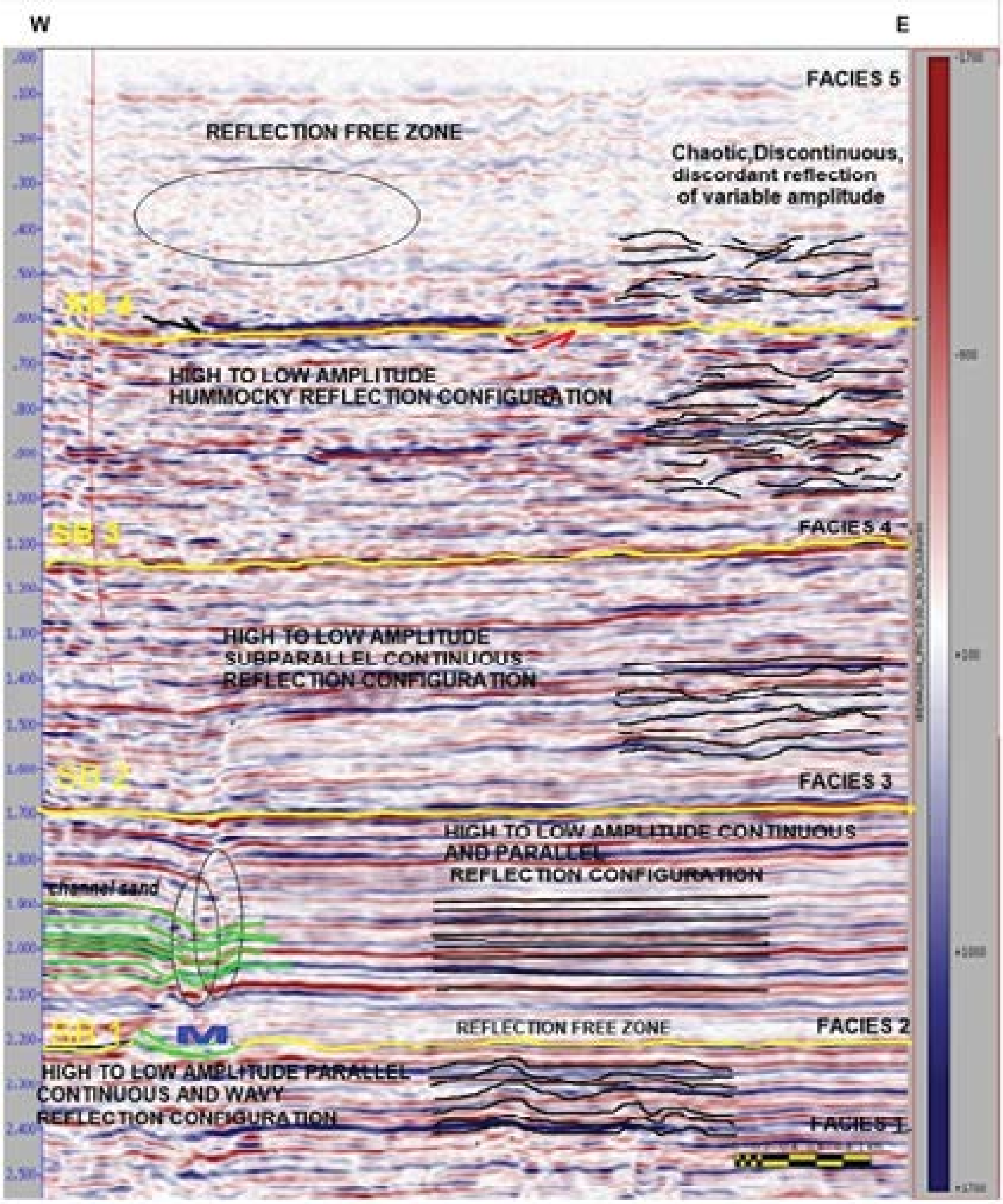

Figure 4: Variable density seismic display with interpreted seismic sequences (S1, S2, S3) with sequences boundary (SB1-SB4) and seismic facies (facies 1-facies 5).

Seismic sequences	Boundary		Amplitude	Reflection pattern	Environment of deposition
S1	Base	concordant	High	Parallel continuous and even	Delta platform
	Top	concordant	Low		
S2	Base	concordant	Low	Sub parallel with fair continuity	Delta platform
	top	concordant	High		
S3	Base	concordant	high	hummocky	Delta slope

Table 1: Characteristic of seismic sequences.

Facies 5 (F5) is chaotic seismic facies unit, discontinuous discordant reflection of variable amplitude due to the presence of deformed over pressured shale resulting from improper dewatering during rapid burial of the sediments [29]. The facies consists of reflection free zones where the acoustic impedance contrasts are weak. This interpreted to be a rather homogenous gross lithology [28]. It can be thick shale of the Akata formation.

System tracts

Seismic well- tie (Figure 5) was carried out and reveal that out of the four sequences boundary identified base on seismic facies characteristics two actually tie with the well log with SB1 being a maximum flooding surface (MFS) and SB2 a sub aerial conformity (or just SB). Therefore,

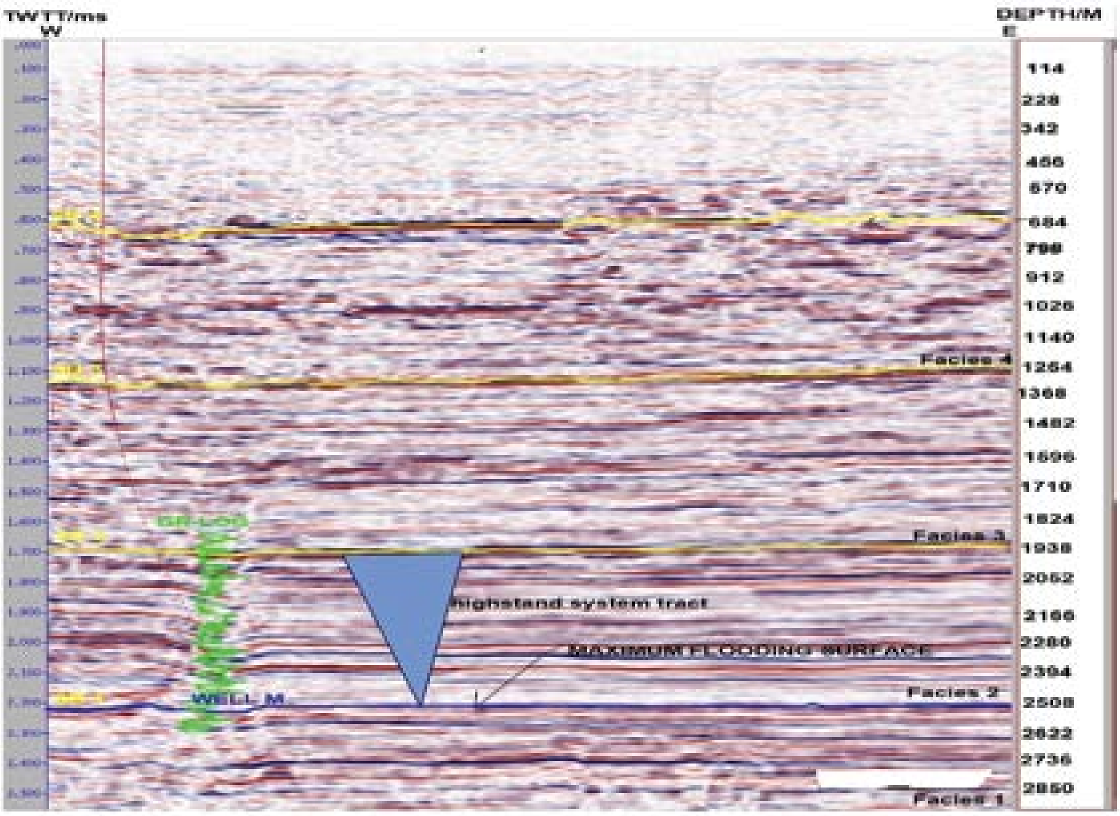

Figure 5: Seismic well tie with sequences boundary and maximum flooding surface illustrating high stand system tract.

zones	Depth (m)	Vsb (v/v)	Ø (v/v)	Øe (v/v)	Sw (Y/v)	Suc(v/v)	K (md)	BV\V	Net pay	Fluid type
A	1948-1950	0.048	0.281	0.198	0.794	0.206	2094.782	0.165	2	Gas
B	1960-1967	0.05	0.192	0.127	0.713	0.287	1565.259	0.128	7	Gas
C	1968-1971	0.043	0.423	0.098	0.693	0.307	2938.939	0.295	3	Gas
D	1973-1990	0.1	0.244	0.11 1	0.561	0.438	359.513	0.132	17	Gas
E	1993-2000	0.106	0.27	0.229	0.47	0.53	192.052	0.127	7	Gas
F	2016-2018	0.148	0.285	0.233	0.803	0.197	12,397.90	0.229	2	Gas
H	2035-2045	0.037	0.233	0.214	0.562	0.474	13.702	0.121	10	Gas
I	2050-2065	0.051	0.238	0.199	0.576	0.424	20.444	0.154	15	Gas
J	2080-2087	0.043	0.247	0.192	0.323	0.677	61.414	0.045	7	Gas
K	2093-2103	0.045	0.255	0.245	0.258	0.742	133.4	0.067	10	Gas
L	2110-2122	0.067	0.239	0.23	0.284	0.7 16	204. 163	0.074	12	Gas
M	2133-2138	0.113	0.229	0.180	0.379	0..621	5.078	0.087	5	Gas
N	2140-2150	0.087	0.235	0.21	0.365	0.634	9.111	0.161	10	Gas
O	2163-2167	0.019	0.221	0.215	0.73	0.27	45.201	0.161	4	Gas
P	2177-2183	0.074	0.239	0.216	0.529	0.471	15.9 17	0.157	6	Gas
Q	2198-2202	0.061	0.236	0.177	0.654	0.346	14.628	0.171	4	Gas
R	2208-2220	0.099	0.222	0.211	0.707	0.293	213.36	0.141	12	Gas
S	2237-2245	0.08	0.224	0.208	0.732	0.268	3739.007	0.164	8	Gas
T	2177-2183	0.031	0.224	0.213	0.774	0.226	95.377	0.167	10	Gas

Table 2: Summary result of average petrophysical parameter in the various reservoirs zones in well M.

well M was drilled in a High stand system tract (HST) that is found in a time window of 1620-2280 ms with an average thickness of 752.4 m.

The HST is interpreted to consist of an aggradational to progradational set of parasequences that overlies the MFS with distributary channel- fill reservoir sand. The reservoir has a very good lateral continuity along the strike of the basin as interpreted from the seismic characteristic of parallel continuous and even low-high amplitude. The sand/mud ratio and the reservoir connectivity tend to increase and improve upward as the decreasing rates of base-normal regression.

Petrophysical results

Table 2 is a summary result of average petrophysical parameter in the various reservoirs zones in well M. The average reservoir porosity (0.423-0.192) deceases with depth indicating that the reservoir quality is good [33]. This is because of the low shale volume in the various reservoirs zones. The low shale volume in the reservoirs zones can be attributed to the minimal cementation and compaction caused by the overburden pressure from the overlying rocks. The average permeability (12,397.895-5.078 md) in the reservoirs zones decrease with depth because of the overburden pressure, as reservoir zones at deeper depth are affected more. The water saturation is inversely proportional to the hydrocarbon saturation with the water saturation decreasing with depth because of increasing temperatures while the hydrocarbon saturation increases.

Discussion

The seismic stratigraphic analysis have reveal three seismic sequences (S1, S2 and S3) mapped within a time window of 600 ms-2200 ms with characteristic low-high amplitude, parallel continuous and wavy to sub parallel continuous reflection configuration deduced to be delta platform while hummocky reflection is delta slope [32]. The termination pattern of the boundary between S1 and S2, is concordant both the upper and lower boundary while S3 is bounded by concordant lower boundary and toplap upper boundary. The characteristic of these seismic sequences (S1, S2 and S3) is typically of the Niger delta basin [29,31].

Five seismic facies (F1-F5) were identified using the characteristic of amplitude, frequency, and continuity and reflection configuration. Their internal geometry ranges from parallel continuous and wavy, sub parallel continuous, hummocky and chaotic reflections configuration. These geometries can be due to variation in sedimentation rates, subsidence and/or burial effect, syndepositional differential tectonic movement [7,22] Seismic Facies 2 (F2) is the hydrocarbon habitat and is continuous parallel of low-high amplitude with low frequency and. It consists of channel sand deposit of deltaic distributaries of prograding delta. The channel is a stratigraphic trap and constitutes the main reservoir of well M [30]. These deposits were formed during aggradations to progradation of the delta and are Highstand system tract (HST) reservoir [7]. The channel sand of HST tends to confirmed with what Kulke [4] describe as reservoir units of the Agbada formation.

The lithologic sequences of well M consist of sandstones beds alternating with shale which indicates the Agbada Formation of Short and Stauble [8]. The average shale volumes in the reservoirs zones are low (0.031-0.148) and are similar to works of Anyiam [34]. The low shale volume is responsible for the very good porosity and permeability of the reservoirs zones in well M. The reservoir zones are completely saturated with gas and the reservoir sand are described as gas bearing sand by Adaeze [35].

Natural gas is derived from Type III kerogen which formed from terrestrial material, with origin from fibrous and woody plant fragment and structure less colloidal humic matter [36] and the Agbada formation is made up of paralic sediment that is mixed continental and brackish water and marine deposits, the Type III kerogen might be the source of this high occurrence of gas. The average water saturation in the reservoir ranges from 0.258-0.803 while the average hydrocarbon saturation ranges from 0.197-0.742. The water saturation is inversely proportional to the hydrocarbon saturation. The low water saturation might be due to the source rocks (shale) since they have been subjected to maturation temperatures (>175˚C) for a considerable length of time for gas generation [37].

The nearly constant bulk volume water value in the reservoirs implies the reservoir is at irreducible water saturation and can produce water free hydrocarbon under reservoir pressure [24]. The net pay (2-17 m) and the high hydrocarbon saturation make these reservoirs good for exploitation.

Conclusion

Seismic Stratigraphy analysis revealed three seismic sequences (S1, S2 and S3). The depositional environment has prograded from delta platform (delta front) down to the wave dominated prodelta /slope. Seismic facies analysis also reveals that there is a vertical alternation of contrasting lithology (sand/shale) in the seismic sequences. Five seismic facies (F1-F5) were identified based on the amplitude, frequency, continuity, and reflection configuration. Facies 2 (F2) reveal channels sand deposits of deltaic distributaries of prograding delta. These deposits were form during aggradation to progradation of the delta and are HST reservoirs.

Petrophysical evaluation reveals the reservoir quality, quantity and recoverability of hydrocarbon in each of the reservoir zones within well M. From the petrophysical results the reservoirs have average porosity of 0.192 -0.423 and average permeability of 5.078-12,397.895 md because of the low shale volume and are consider as suitable reservoirs. The high hydrocarbon saturation from 0.197-0.742 combined with the net pay thickness of the reservoirs make these reservoirs suitable for hydrocarbon exploitation. Seismic stratigraphic and petrophysical characterisation have shown that the reservoirs qualities of well M are petroliferous. The results of this research will serves as an exploration guide in the Niger delta basin and further petroleum exploration in the area with channel fills as target.

References

1. Tuttle MLW, Charpentier RR, Brownfield ME (1999) The Niger delta petroleum system: Niger delta province, Nigeria, Cameroon, and Equatorial Guinea, Africa. USGS Open-file report 90-50.
2. Doust H, Omatsola E (1990) Niger Delta. Am Asso Petro Geol 48:239-248.
3. Doust H, Omatsola E (1989) Niger delta. Am Ass Petro Geol Memoir 48: 200-248.
4. Kulke H (1995) Regional petroleum geology of the World. Part II: Africa, America, Australia and Antarctica. Berlin, Gebrüder Borntraeger 142-172.
5. Hospers J (1965) Estimation of primary oil reserves. Am Ass Petro Geol 76: 400-422.
6. Kaplan AC, Lusser I, Norton J (1994) Classification and nomenclature systems for petroleum and petroleum reserves. Am Ass Petro Geol 60: 230-237.
7. Evamy BD, Haremboure J, Kamerling P, Knaap WA, Molloy FA, et al. (1978) Hydrocarbon habitat of Tertiary Niger Delta. Am Ass Petro Geol Bull 62: 270-298.
8. Short KC, Stauble AJ (1965) Outline of geology of Niger Delta. Am Ass Petro Geol Bull 51: 761-779.

9. Whiteman A (1982) Nigeria's: Its petroleum geology, resources and potentials. Vol 1 and 2 Pub. Graham and Trontman Ltd. 394.
10. Pugh JC (1954) Sand movement in relation to wind direction as exemplified on the Nigerian coastline. Res Notes Dept Geogr Univ Coll Ibadan 5: 1–14.
11. Hill MB, Webb JE (1958) The ecology of Lagos Lagoon II. The topography and physical features of Lagos Harbour and Lagos Lagoon. Philos Trans R Soc Bull 241: 310–333.
12. Allen JRL (1963) Sedimentation in the modern delta of the River Niger, West Africa. Deltaic and Shallow Marine Sediments. Amsterdam 26–36.
13. Allen JRL (1964) The Nigerian continental margin: bottom sediments, sub-marine morphology and geological evolution. Mar Geol 1: 289–338.
14. Allen JRL (1965) Late Quaternary Niger Delta and adjacent areas: Sedimentary environments and lithofacies. Bull Am Assoc Petrol Geol 49: 547–600.
15. Allen JRL (1970) Sediments of modern Niger Delta: A summary and reviews. Spec Publs Soc Econ Paleont Miner Tulsa 15: 138–141.
16. Oomkens E (1982) Lithofacies relations in the Niger Delta. Sedimentol 21: 195–222.
17. Weber KJ, Daukoru EM (1975) Petroleum geology of the Niger Delta. Proc of the Ninth World Petroleum Congress Vol 2, Geology: London, App Sci Publ 210-211.
18. Agagu OK (1978) Relationship of Niger Delta depositional patterns to hydrocarbon accumulation in the Ahia field Rivers States, Nigeria. J Min Geol 12: 64–75.
19. Larue DK, Legarre H (2004) Flow unit connectivity and reservoir characterization in wave dominated deltaic reservoir: Meren reservoir Nigeria. Am Ass Petro Geol Bull 88: 300–324.
20. Oyedele KF, Oladele S, Ogagrue DO, Bakare K (2012) Sequence stratigraphic approach to hydrocarbon exploration in Bobsaa field, onshore Niger Delta. J Petro & Gas Exp Res 2: 106-114.
21. Catuneanus O (2006) Principle of sequence stratigraphy. Elsevier science Ltd, Amsterdam 17-261.
22. Burke K (1972) Long shore drift, submarine canyons and submarine fans in development of Niger Delta. Am Asso Petro Geol Bull 56: 1975-1983.
23. Weber KJ (1986) Sedimentological aspect of oil fielding the Niger Delta. Geol. Minjbouw 50: 559-576.
24. Ekweozor CM, Okoye NV (1980) Petroleum source-bed evaluation of Tertiary Niger Delta. Am Ass Petro Geol Bul 64: 1241-1259.
25. Bustin RM (1988) Sedimentology and characteristics of dispersed organic matter in Tertiary Niger Delta: origin of source rocks in a deltaic environment. Am Ass Petro Geol Bul 72: 267-298.
26. Larionov VV (1969) Borehole Radiometry, National Electric Drag Racing Association, Moscow, Soviet Union.
27. Asquith G, Krygowski D (2004) Basic well log analysis. Am Asso Petro Geol Tulsa, USA 208.
28. Adeogba AA, Mc Hargue TR, Graham SA (2005) Transient fan architecture depositional controls from near-surface 3-D seismic data, Niger Delta continental slope. Am Ass Petro Geol Bull 89: 627-638.
29. Posamentier HW, Kolla V (2003) Processes and reservoir architecture of deepwater sinuous channels from the shelf edge to the basin floor, based on analyses of 3D seismic and side scan imagery. Presented at the 2003 Slope Conference, Liverpool, UK. Abstract volume, 67.
30. Stacher P (1995) Present understanding of the Niger Delta hydrocarbon habitat. 257-267.
31. Heinio, Davis RJ (2006) Seismic stratigraphy of the toe-slope region in deep water Niger Delta basin. Am Ass Petro Geol 86: 558-678.
32. Rincon DA, Arenas JE, Cuartas CH, Cardenas AL, Molinares CE, et al. (2007) Eocene-Pliocene planktonic foraminifera biostratigraphy from the continental margin of West Africa. Stratigraphy 4: 261-311.
33. Rider M (1986) The geological interpretation of well logs. Blackie Glasgow 175.
34. Anyiam OA, Mode AW, Ekwe AC (2010) Formation evaluation of an onshore appraisal well „KG-5", "Green Field", Niger Delta, Nigeria. Am J Sci & Indus Res 3-7.
35. Adaeze IU, Onyekuru SO, Iwuagwu CJ (2012) Petrophysical evaluation of uzek wells using well logs and core data, offshore depobelt, Niger Delta, Nigeria. Pelagia Research Library.
36. Tissot BP, Welte DH (1984) Petroleum formation and occurrence. Berlin, Springer-Verlag, 518.
37. Tissot BP, Welte DH (1978) Petroleum formation and occurrence. A New Approach to Oil and Gas Exploration. Springer-Verlag, Berlin Heidelberg, 530-538.