GEOSCIENCE ASSESSMENT OF DECLINED PRODUCTION RATE AND RECOVERY FROM A RESERVOIR IN "ANDA" FIELD, ONSHORE SOUTHWESTERN NIGER DELTA.

Abstract

Declined production rates in wells producing from common reservoirs are enigmatic and generally viewed as phenomenal in some fields worldwide. The challenge posed by such discordant production trends forecloses the preponderance of totally and partially abandoned production, especially in aging fields. This study assesses possible factors associated with varying well production trends from a common reservoir in a field in the onshore westerrn Niger Delta, by integrating multi-geoscience parameters including formation evaluation, 3D quantitative seismic analyses, paleoenvironmental diagnoses, paleobathymetric studies and reservoir petrophysics to unravel the complexity of the reservoir. Composite well logs were collected from five wells selected for the study. Gamma ray and SP logs were combined to delineate the depositional environment of "Heri sand" based on Schlumberger (1985) log motif classification. The results were applied and found useful to develop optimum recovery production plan for the study field. It has been revealed from this study that declined production performances of Heri sand reservoir is attributed to the deposition of the reservoir in three distinct paleoenvironments under different bathymetric settings within a coeval period. These factors constitute strong influences on the petrophysics of the reservoir which invariably influences' the production performance of the reservoir. Having realized the cause of declined rate of reservoir in the Anda field, the reservoir can be revitalized by well injection and fracturing

Keyword: geoscience assessment, declined production rate, reservoir, Anda field, onshore southwestern niger delta.

Introduction

Conventional oil accumulates through long geological processes in underground formations known as reservoirs. Typical reservoirs consist of porous rocks, such as sandstone or carbonates, where petroleum resides in the tiny void spaces between the rock grains. An oilfield may consist of one or several reservoirs reachable from the surface by drilling. Non-renewable fossil fuels provide about 81% of the global primary energy supply and remains the single largest primary fuel, satisfying 33% of the world's energy needs in 2009 (IEA,2011) [1]. Given the high reliance on oil, particularly within the transportation sector, it is evident that policy makers and the public need reliable forecasts of future oil supply.

The annual reduction in the rate of production from a single field or a group of fields, after a peak in production is termed decline rate. Detailed empirical analyses of decline rates have been produced for well over 50 years and most studies tend to agree on the typical decline rates for different categories of fields, despite some differences in details (Höök M , et al, 2009,). [2,3]. The likely explanations of the reported drop rates, on the other hand, are being contested. Many say that underinvestment is the primary cause of the observed decrease rates, while others argue that the reason is simply physical constraints to production rates.

According to Cambridge Energy Research Associates (CERA) and IHS Inc., the average global decline rate for producing oil fields is 4.5 percent per year, lower than the 8 percent per year mentioned in other research. The CERA-IHS study was based on the production characteristics of 811 oil fields, which account for roughly two-thirds of current global production and half of total estimated proven and probable reserves. Annual field decline rates are not increasing with time, according to Peter M. Jackson, CERA oil industry activity director and report author. This finding "provides the basis for more confidence about the future availability of oil. Decline rates are a function of reservoir physics and investment strategies. There is a general historical trend toward lower decline rates in recent years, which may be due to better reservoir management practices and the impact of new technology

Inefficient results of secondary recovery measures in heterogeneous reservoirs may be due to lack of in-depth knowledge of the depositional environment and petrophysics of the reservoirs . Discordant production volumes of crude oil from wells draining a specific reservoir is a function of variable intra-depositional environments, petrophysics and post diagenetic changes within the reservoir(Nyberg, 2015). Heri sand reservoir is a four –way closure structure and basically a water driven reservoir in "Anda" field. The field assumed production in year 2001 with over 15 wells producing from the main reservoir "Heri sand".

Production irregularities observed in the field from inception are interpreted in relation to multi-geoscience parameters like Formation evaluation studies, biostratigraphic data, special core analysis, seismic data, sediment logical studies and petrographic studies. (**Nwokocha et al, 2016,** Busch, 1975). Integrated studies show that "Heri sand" reservoir were deposited in three distinct paleoenvironments (distributary channel, barrier bar and mouth bar) under inner, middle and outer neritic paleobathymetric conditions.

The production profile of an oilfield is often shown in figure 1 below. Significant variations, on the other hand, can be caused by development history, technological or oil price changes, accidents, political decisions, sabotage, and other causes. Some fields have short plateau periods, more akin to a single peak, whilst others (especially huge fields) may maintain very consistent production.

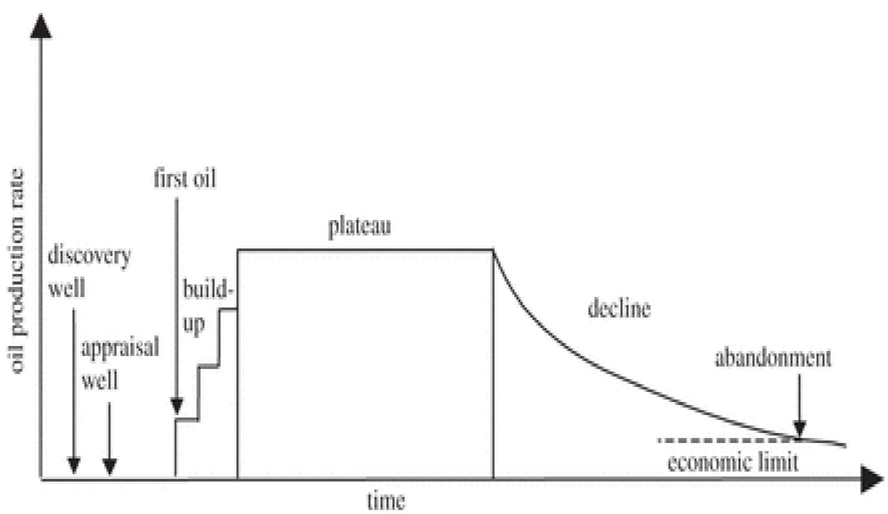

Figure 1. Idealized production behaviour of an oilfield. Source: Höök *et al.* [2].

2 Location and Geology of the study area

"Anda" field is located in the southwestern Coastal Swamp depobelt of the Tertiary Niger Delta petroleum basin in Nigeria (Fig.2). The Tertiary section of the Niger Delta is divided into three Formations representing prograding deposition facies that are distinguished mostly on the basis of sand shale ratios estimated from

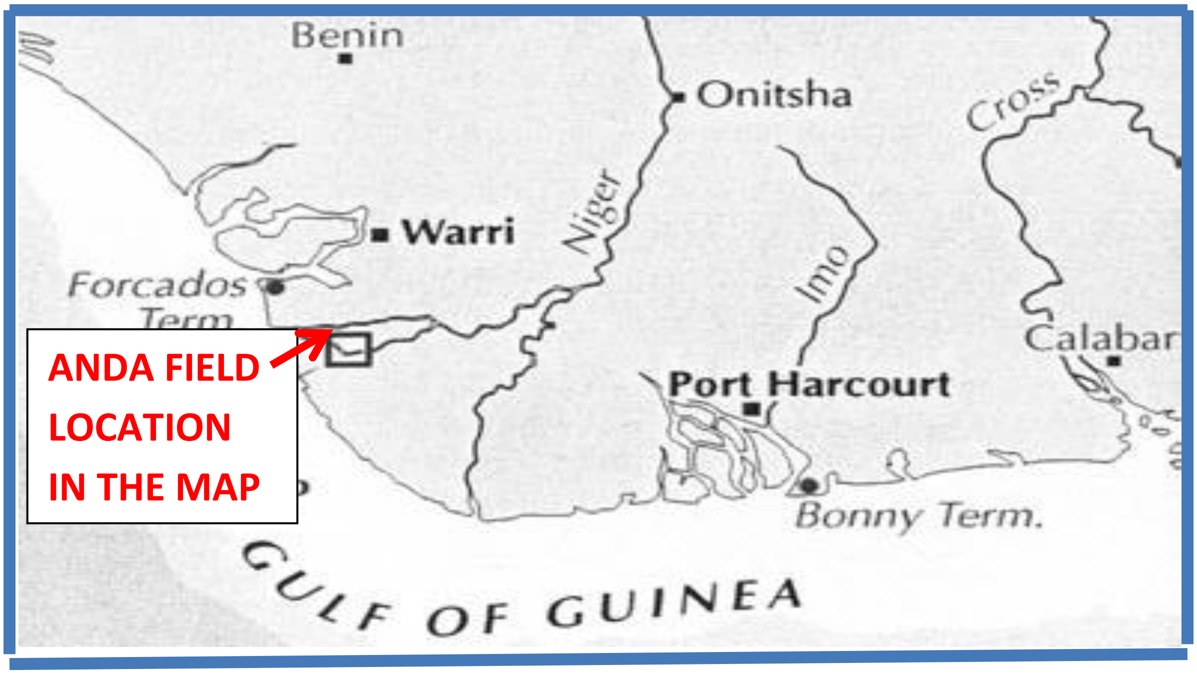

Figure 2: Location map of Niger Delta showing "Anda" field.

subsurface well logs. Reijers et al. (1996) categorized the vertical section of the Tertiary Niger Delta into three lithistratigraphic subdivisions: an upper delta top facies, a middle delta front lithofacies and a lower pro-delta lithofacies. The type of sections of these Formations is described in Short and Stauble (1967) to correspond with the Benin Formation (Oligocene-Recent), Agbada Formation (Eocene-Recent) and Akata Formation (Paleocene-Recent) respectively.

In brief, the tertiary section of the Niger Delta is divided into three Formations representing prograding deposition facies that are distinguished mostly on the basis of sand shale ratios estimated from subsurface well logs. Reijers et al. (1996) categorized the vertical section of the Tertiary Niger Delta into three lithistratigraphic subdivisions: an upper delta top facies, a middle delta front lithofacies and a lower pro-delta lithofacies. The type of sections of these Formations is described in Short and Stauble (1967) to correspond with the Benin Formation (Oligocene-Recent), Agbada Formation (Eocene-Recent) and Akata Formation (Paleocene-Recent) respectively. These three major lithostratigraphic units (figure 2) in the subsurface are defined by (Weber & Daukoru, 1975) to reflect a gross upward coarsening and fluvial environments in the basin.

Akata Formation

The Akata formation consists of clays and shales with minor sand intercalated sediments deposited in prodelta environment. This formation, beginning in the Paleocene and through the recent, was formed when terrestrial organic matter and clays were transported to deep areas characterized by low energy conditions and oxygen deficiency (Lauferts, 1998). The Akata Formation is overlain by Agbada Formation and constitutes the potential hydrocarbon source rock and reservoir rock in deep water. Doust and Omatsola, (1990) estimated the thickness of Akata Formation to be up to 7,000 meters thick and its mature marine shales to be the source rock of hydrocarbon in the Niger Delta.

Agbada Formation

The Agbada Formation (Eocene – recent) overlies the Akata Formation and consists of paralic siliclastics over 3,700 meters thick (Ehirim & Chikezie, 2017). This Formation is divided into an upper unit which consists of sandstone – shale alternations with the former predominating over the latter and a lower unit in which the shales predominate. The deposition of this Formation began in the Eocene and continues in the recent. It occurs throughout the Niger Delta clastic wedge with lithologies that are largely of alternating sands, silts, shales with progressive upward changes in grain size and bed thickness. Lauferts (1998) interpreted the strata of Agbada Formation to have been formed in fluvial-deltaic environments. The sandy part constitutes the main hydrocarbon reservoirs and the shales form seals in the delta oil fields (Ejedawe, 1981; Evamy et al., 1978; Doust & Omatsola, 1990).

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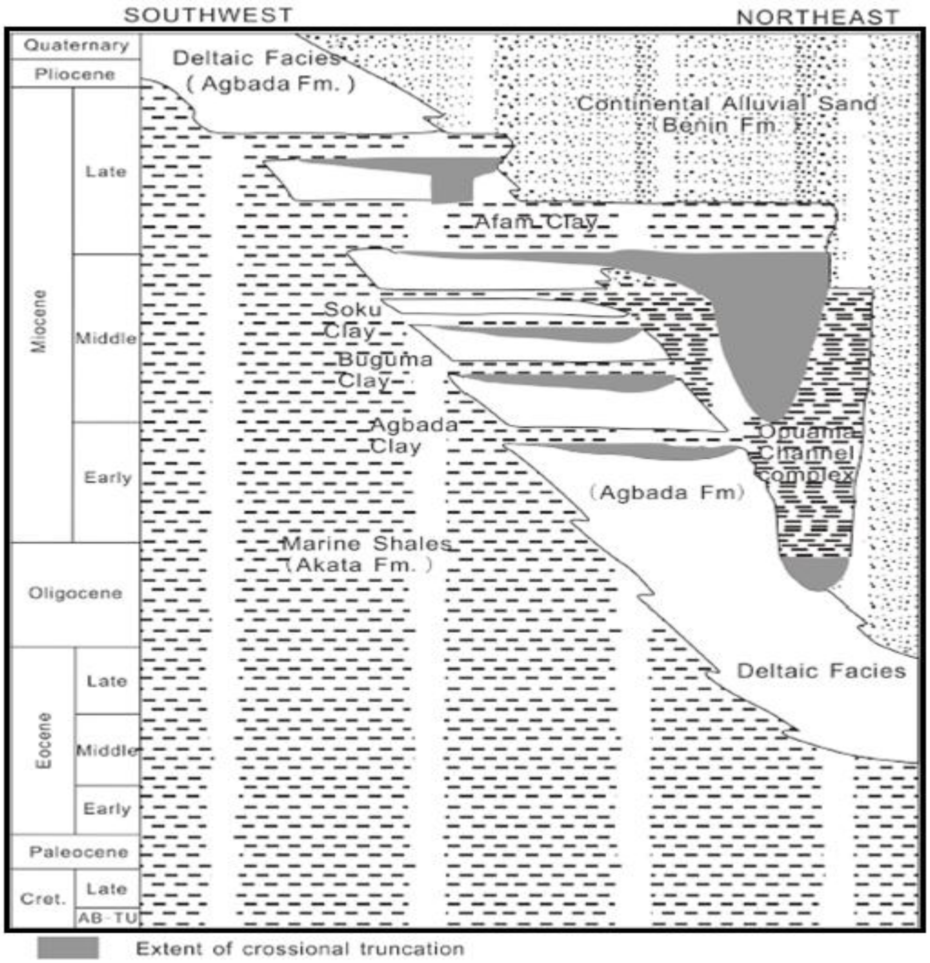

Figure 3: Lithostratigraphic column showing Niger Delta Formations (modified from Doust & Omatsola, 1990)

These three major lithostratigraphic units (figure 3) in the subsurface are defined by (Weber & Daukoru, 1975) to reflect a gross upward coarsening and fluvial environments in the basin. The study location covers an area of about 52 km² in onshore Niger Delta. “Heri sand” reservoir varies from 25-350m in thickness.

Several data sets were harnessed from the operator of the field. Some data sets were collected during drilling operations while some data sets were generated from the primary data measured from the field. Sets of data utilized during the study are enumerated below.

Table 1. Crude oil production data of 5 wells producing from Heri sand reservoir in Anda field

WELLS	Daily production (barrels/day)
Well 1	3,013

Well 2	2,020
WELL 3	1,010
WELL 4	1,009
WELL 5	2,019

Composite well logs collected from five wells were selected for the study. Gamma ray and SP logs were combined to delineate the depositional environment of “Heri sand” based on Schlumberger (1985), log motif classification (Figure 4). Relevant sections of the 3-D Seismic data of “Anda” field were superimposed with well logs to determine reservoir continuity in the field (Figures 4 and 5).

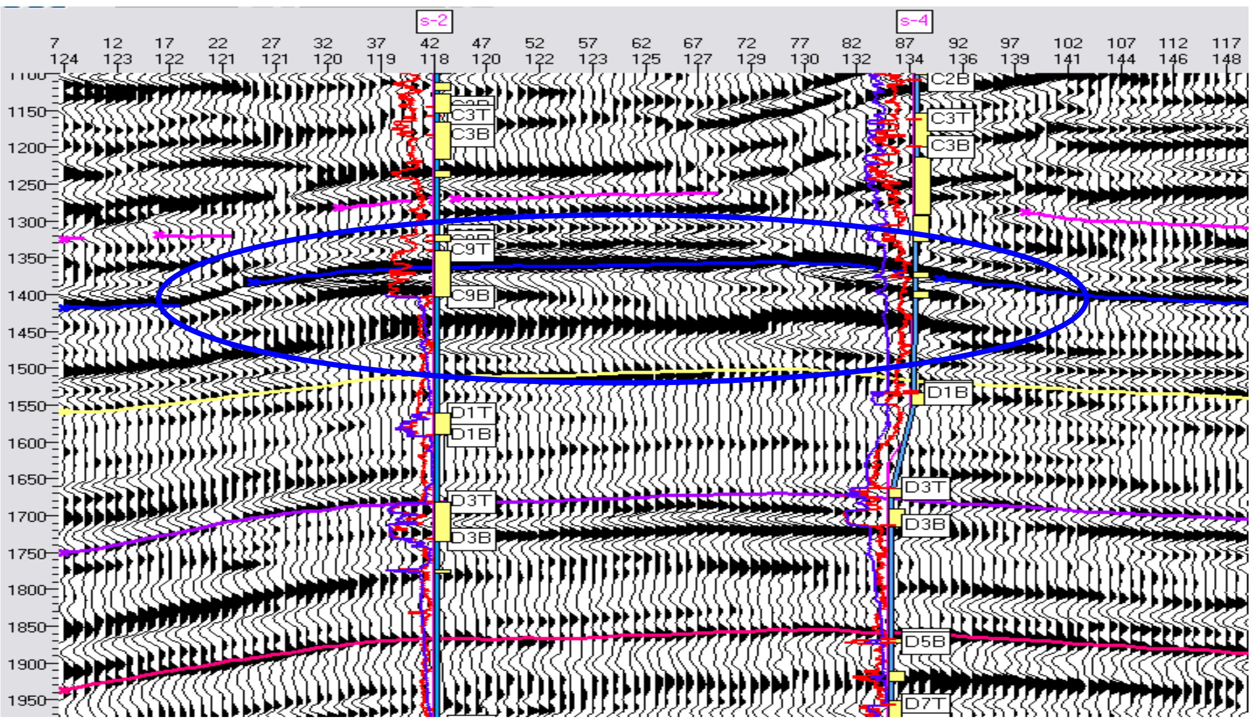

Fig. 4 Superimposition of seismic section on suite of well logs penetrated by the reservoir in the field

Well 1

Well 2

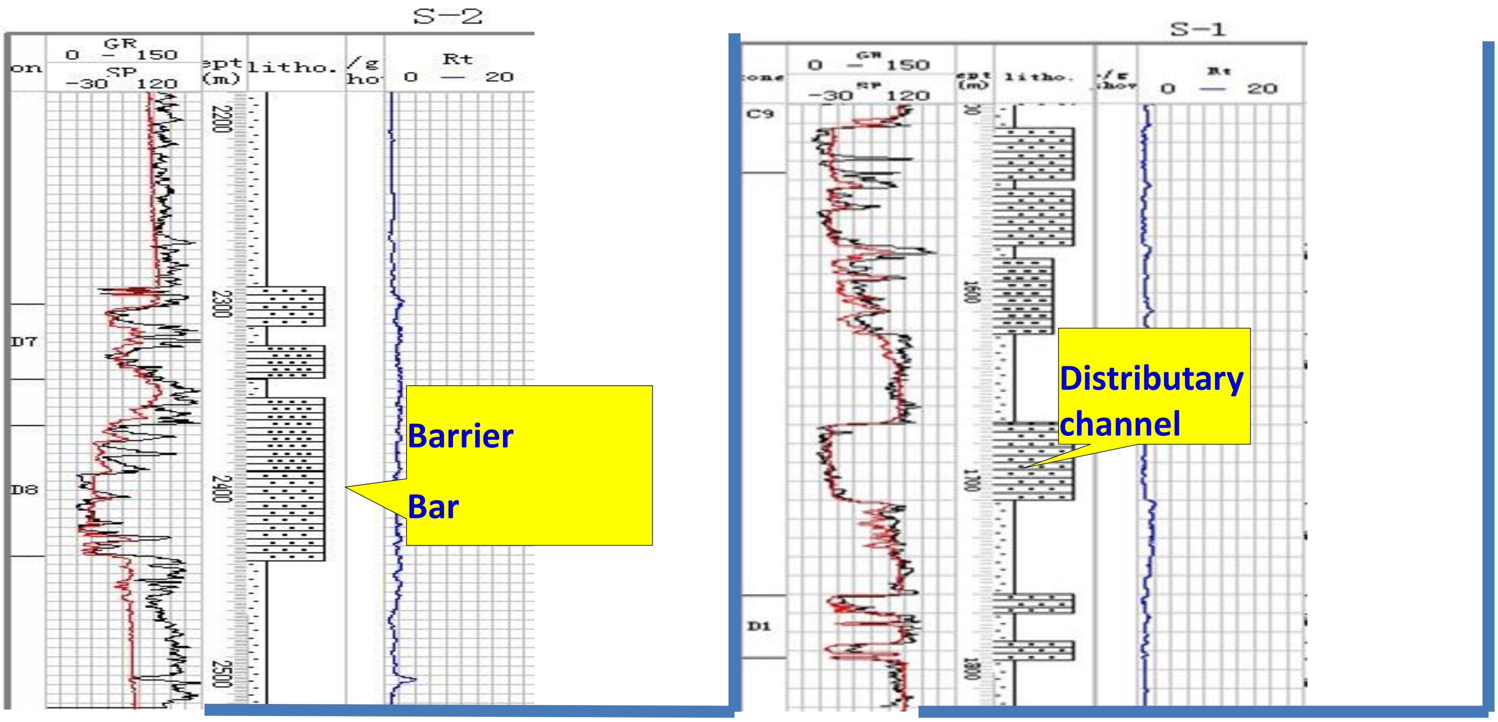

Fig. 5. Gamma ray log signature of Heri sand in selected wells

Fig. 6. Gamma ray log signature of Heri sand in well 3

Result and Discussions.

A total of 118 ditch cutting samples were studied for lithologic description analyses. For all the wells selected, samples were taken at 10ft (3.03m) intervals. Petrographic studies of the samples were carried out using hand lens and binocular microscope (Max .X40). Detailed lithologic descriptions of the reservoir penetrated in five well locations are given below.

Table 2 .Ditch cutting samples from Heri sand reservoir across 5 wells

Selected wells	**Well 1**	**Well 2**	**Well 3**	**Well 4**	**Well 5**
Reservoir interval(ft)	6120-6300	6925-7075	6350-6600	6700-7000	6500-6800
Reservoir thickness(ft)	180	150	250	300	300
No. of core samples	18	15	25	30	30
Sample intervals(ft)	10	10	10	10	10

In well 1 , Sandstones: Light grey to white, translucent to transparent, unconsolidated to very poorly consolidated, fine grained to subrounded, well sorted quartz grains. It exhibits argillaceous matrix, koalinitic cement, good porosity with oil show and oil odour. In well 2, Sandstones: Grey to white translucent, unconsolidated to very poorly consolidated, fine grained, subrounded, well sorted quartz, translucent argillaceous matrix, koalonite cement with good porosity. In well 2,Sandstones: Off-white to white, translucent to transparent, unconsolidated to very poorly consolidated poorly sorted, very fine to fine grained, subrounded to rounded, moderately well sorted, minor argillaceous matrix, occurrence of koalinite cement, good porosity. In well 3, Sandstones: Dirty white, translucent to transparent, unconsolidated to poorly consolidated, medium grained, subrounded, moderately well sorted quartz, minor argillaceous matrix, occurrence of koalinite cement with good porosity values. In well 5 ,Sandstones: Transparent to translucent, unconsolidated to very poorly consolidated, fine grained, subrounded, well sorted, quartz, koalinitic cement, and good porosity with oil stains.

Also thin section studies of the photomicrographs of the reservoir were carried out using binocular microscope (magnification X40). Photomicrographs of several thin section slides were analysed and studied (Fig. 7). Three distinct petrographic groupings were observed in the study and their representative photomicrograph slides are shown below in figures 7, 8 and 9.

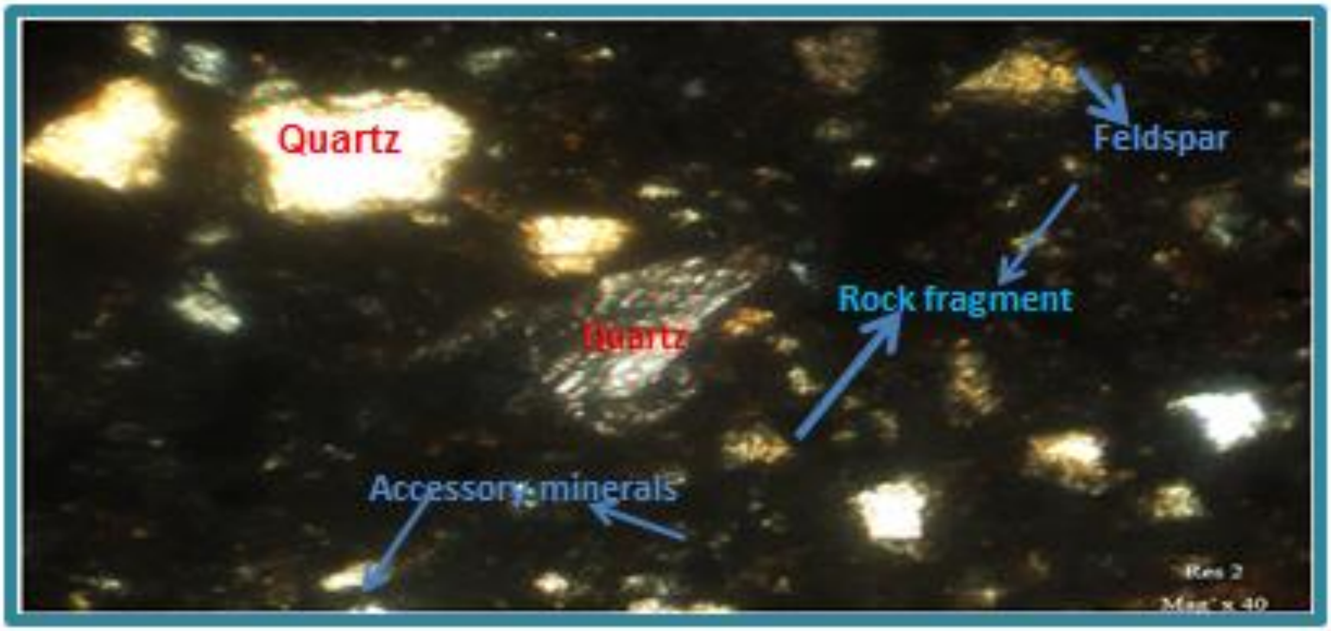

Fig. 7. Photomicrograph of the reservoir sands in the distributary channel depositional environment.

Fig. 8. Photomicrograph of the reservoir sands in the Mouth bar depositional environment

Fig. 9. Photomicrograph of the reservoir sands in the Barrier bar depositional environment

Cored reservoir samples from the selected wells were used in laboratory studies for petrophysical data (permeability and porosity) deductions after being subjected to special core analysis (Table 1). Five samples which were selected for core properties determination are shown in Table 3.

At a nominal pressure of 200psig (pounds per square inch) and a net sleeve confining pressure of 400psig (pounds per square inch) the absolute brine permeability was measured.

The conventional absolute gas permeability, helium porosity and grain density measurements were undertaken at the end of the study of special core analyses.. Conventional measurements taken at the end of the study gave the values of gas permeabilities and plug porosities as shown in Table 3.

Table 3 Permeability and porosity values measured from special core analysis

Wells	Porosity(%)	Permeability(mD)
1	32.2	899
2	28.8	359
3	16.8	299
4	17.9	309

5	29.0	360

Microfloral and faunal data were analyzed from the ditch cutting samples preserved from the selected wells. Marker specie recovered from the analyses were useful in well to well correlation of the reservoir as well as chronostatigraphic age determination. Benthonic foraminifera were very useful bathymetric and paleoenvironmental inferences of the reservoir at various locations in the field. Paleodepositional environments were deduced from these data integration. Well to well correlation of the reservoir using gamma ray, SP, Resistivity log and index microfossils are given in figure 10 below.

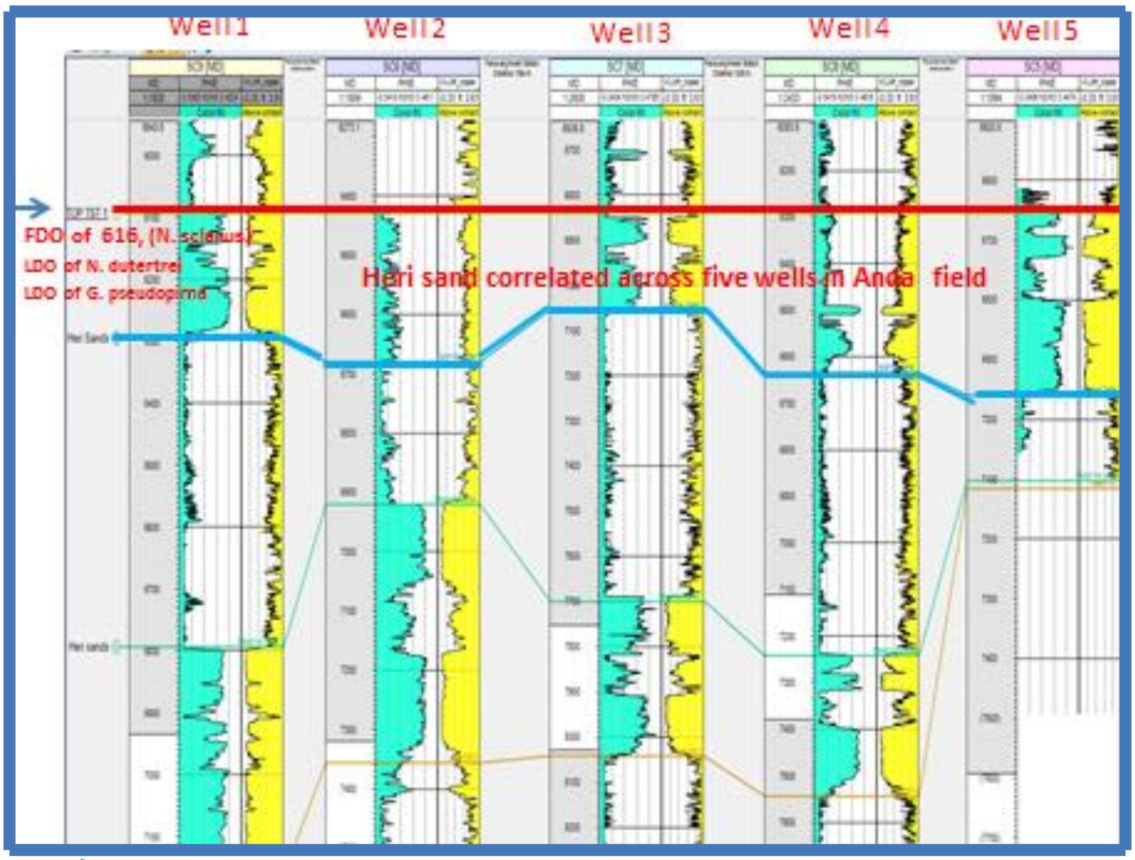

Fig. 10. Correlation of the reservoir across selected wells using well logs and biostratigraphic data.

Lithologic and petrographic studies of Heri sand distinctly identify three major sub- lithofacies units in the reservoir. The summary of petrographic studies given in modal analyses result in figure 10 divides the reservoir into three subunits as interpreted below.

Unit A: This sub-unit displays a blocky shaped gamma ray log pattern diagnostic of a channel sand depositional environment. Modal analyses of major minerals display quartz- 65%, feldspar -5 % and rock fragment-30%.

Unit B subunit is diagnostic of a funnel shaped gamma ray log pattern exhibiting a coarsening upward sequence. In some cases it displays a Christmas tree shaped log pattern of Vail, 1988 depicting a mouth bar depositional environment (Sclumberger, 1982). Modal analyses of major minerals display quartz- 15%, feldspar -45 % and rock fragment-35%.

Unit C reservoir sub-lithofacies display gamma ray log pattern characterized by saw-toothed profile with crescentic shape pattern suggestive of barrier bar depositional environment (Busch 1975). Modal analyses of major minerals display quartz- 40%, feldspar -25 % and rock fragment-35%.

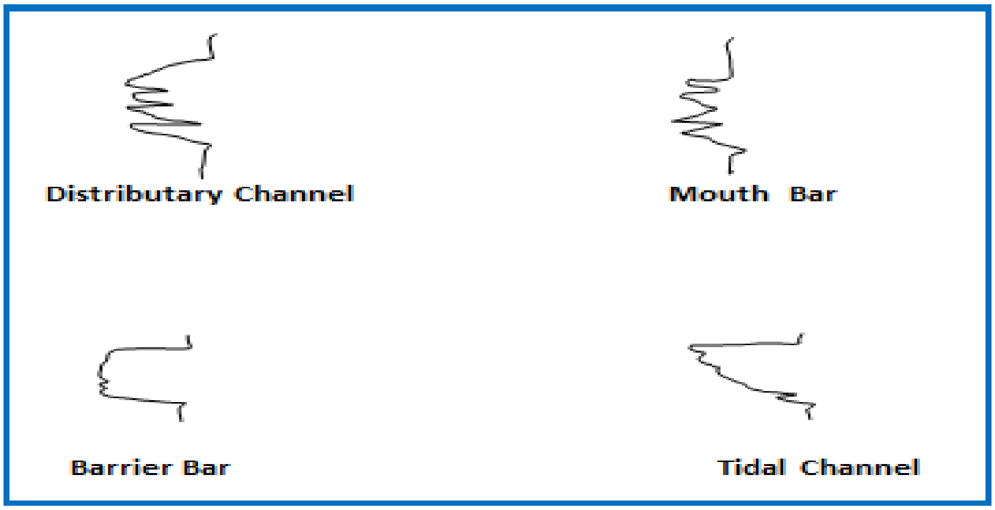

Fig. 11. Recognition of depositional environments using gamma logs from deltaic reservoirs (After, Sclumberger, 1985).

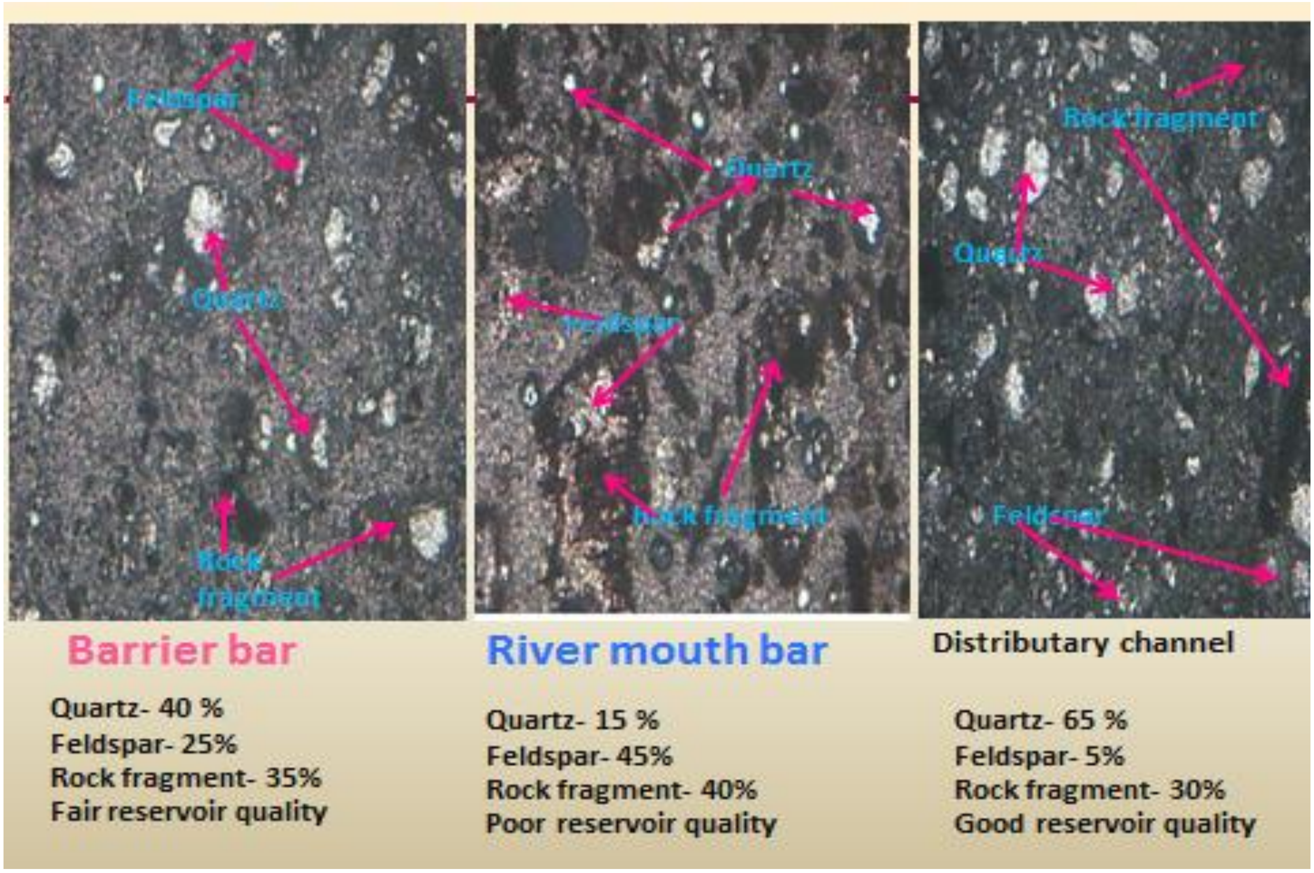

Fig 12. Photo micrograph of the representative units of depositional environments of the reservoir.

Special core analyses studies for petrophysical data of the reservoir display different values for porosity and permeability plotted across the reservoir. Porosity values ranges from 25-35 % while permeability values ranges from 338-889mD. There is a general trend in the petrophysical data profile declining from north to south of the field. Petrophysical data (permeability and porosity values) results when correlated with the paleodepositional environment data deduced from the study as shown in figure 12 provides basis for correlation between the depositional environment and the petrophysics of the reservoir(see Table 4).

Table 4. Correlation of the petrophysical data with the depositional environment in the field

Reservoir Core Properties Summary

Petrophysical Data (Average)	DEPOSITIONAL ENVIRONMENT		
	Distrlbutary Channel	Barrier Bar	River Mouth Bar
Permeability (mD)	899	354	306
Porosity(%)	31.2	28.9	17.4
Grain Density(g/cc)	2.63	2.65	2.69

Total core length recovered per well: 19-24ft
No of samples measured for permeability/porosity per well: 20
Total no of samples measured for grain density per well: 25

Biostratigraphic studies of the microfossils recovered from the reservoir shades more light on the reservoir paleobathymetry, chronostratigraphic age and the energy of the depositional regimes during periods of the deposition. Further deductions into the paleobathymetry of the reservoir depositional environments were also inferred from the planktonic –benthonic ratio of foraminifera, arenaceous –calcareous ratio and relative abundances of mangrove pollen and spores. as shown in table 5 below.

Correlation of the biostratigraphic data with paleodepositional environment and bathymetric results derived from this study is summarized in table 6 and 7 below.

Table 5 Summary table correlating log derived depositional environment and bathymetric result.

Wells no.	Depsnl Envi.	Log. Motif.	Depth range(ft)	Bathymetry
Well 1	Distributary channel	Cylinder shaped	6120-6300	Inner neritic
Well 2	Barrier bar	Serrate funnel	6925-7725	Middle neritic
Well 3	River mouth bar	Funnel shaped	6350-6600	Outer neritic
Well 4	River mouth bar	Funnel shaped	6700-7100	Outer neritic
Well 5	Barrier bar	Serrate funnel	6500-6800	Middle neritic

Table 6. summary table correlating depositional environment, biostratigraphic data and bathymetric data in the study

Wel No	Fossil frag.	Foram Div	Bent. Pop	Plank Pop	P/B Rato	Bathym etry	Depsnl Envi	Paly debrs	Paly div.	Mang. paly	Acc. minl
1	High	High	Mod.	High	> 1	Inner neritic	Dist. Chan.	high	Hig h	Low	Pyrite,
2	Mod.	High	High	Mod.	1	Middle neritic	Barrier bar	Low	Low	Low	pyrite
3	Low	Low	High	Low	< 1	Outer neritic	Mouth bar	Low	Low	High	Glauc.
4	Low	Low	High	Low	< 1	Outer neritic	Mouth bar	Nil	Low	Mod.	Glauc.
5	High	Mod.	High	Low	1	Middle neritic	Barrier bar	High	Hig h	High	

Deductions from this study show that Heri sand was deposited in a coeval period within late Miocene epoch under three distinct depositional environment (distributary channel, barrier bar and mouth bar) in differing bathymetric regimes ranging from inner neritic, middle neritic and outer neritic setting.

It is noted that similar depositional environments and bathymetric regimes in the field yield close volumes of crude oil in their daily production profile as shown in Table 7 below. Most productive zones in the reservoir were deposited under the distributary channel under inner neritic regimes with crude volumes of about 3013 barrels of oil per day. This constitutes the best quality reservoir in the field. Barrier bar environments constitute relatively a fair reservoir quality, producing about 2020 barrels of crude oil per day and mostly deposited under middle neritic paleobathymetric setting.

Mouth bar environment constitutes the poorest quality reservoir in the field with daily production rate of about 1010 barrels of oil per day. Petrographic analyses show preponderance of feldspar minerals indicating immaturity of barrier bar sediments in the field.

Table 7 correlation of the production profile and depositional environments in Heri sand reservoir

WELLS	Daily production (barrel/day)	Depositional Environment
Well 1	3013	Distributary channel
Well 2	2020	Barrier bar
well 3	1010	Mouth bar
well 4	1009	Mouth bar
well 5	2019	Barrier bar

Based on the findings of this study it can be seen that Heri sand reservoir can be mapped and compartmentalized for ease of development and placement of viable wells for optimum recovery. Compartmentalization from the 3D seismic time slice map of reservoir is shown below in figure 13.

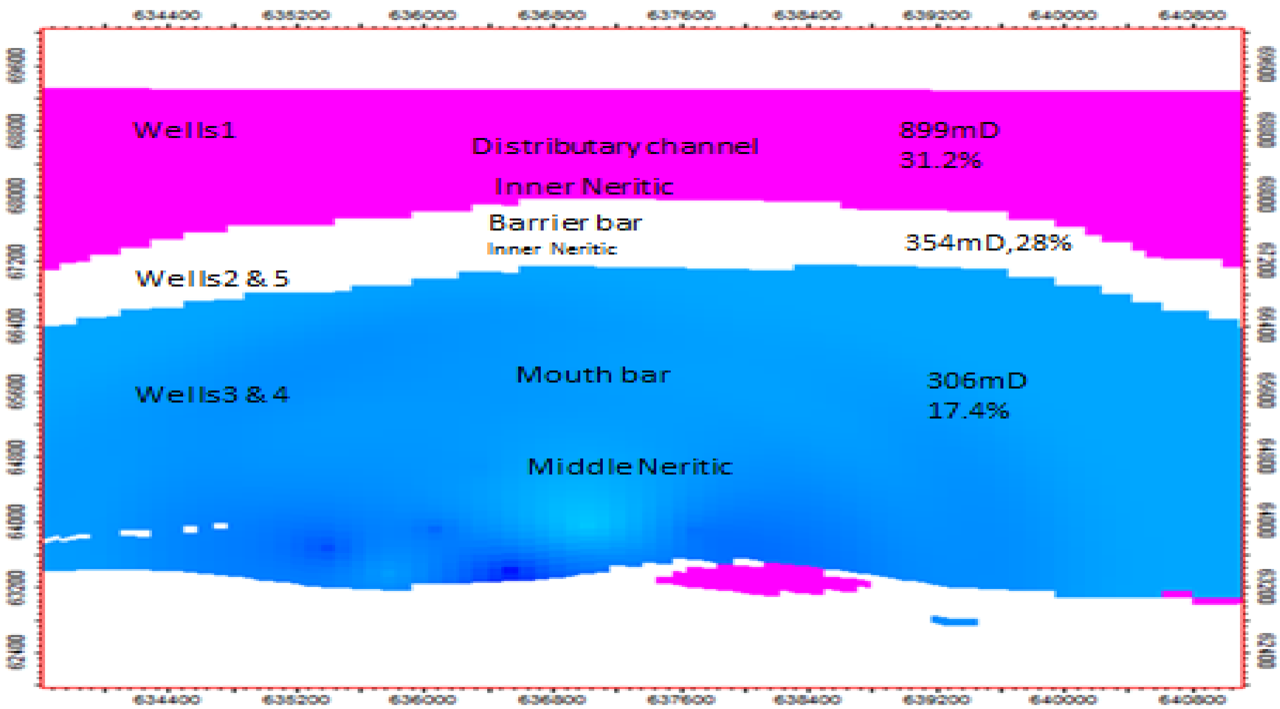

Fig. 13 Heri sand compartmentalization based on the study result.

5 Conclusion

Stemmed from the study, a sand body deposited under a coeval period can be formed under different types of bathymetric and paleoenvironmental conditions depending on the basin architecture. Reservoirs formed under such conditions can be termed "complex reservoirs" and requires integration of various geological disciplines to develop a proper exploration and development strategy in order to maximize hydrocarbon recovery from such reservoirs. Declined production performances of Heri sand reservoir is attributed to the deposition of the reservoir in three distinct paleoenvironments under different bathymetric settings within a coeval period. These factors constitute strong influences on the petrophysics of the reservoir which invariably influences' the production performance of the reservoir. Having realized the cause of declined rate of reservoir in the Anda field, the reservoir can be revitalized by well injection and fracturing.

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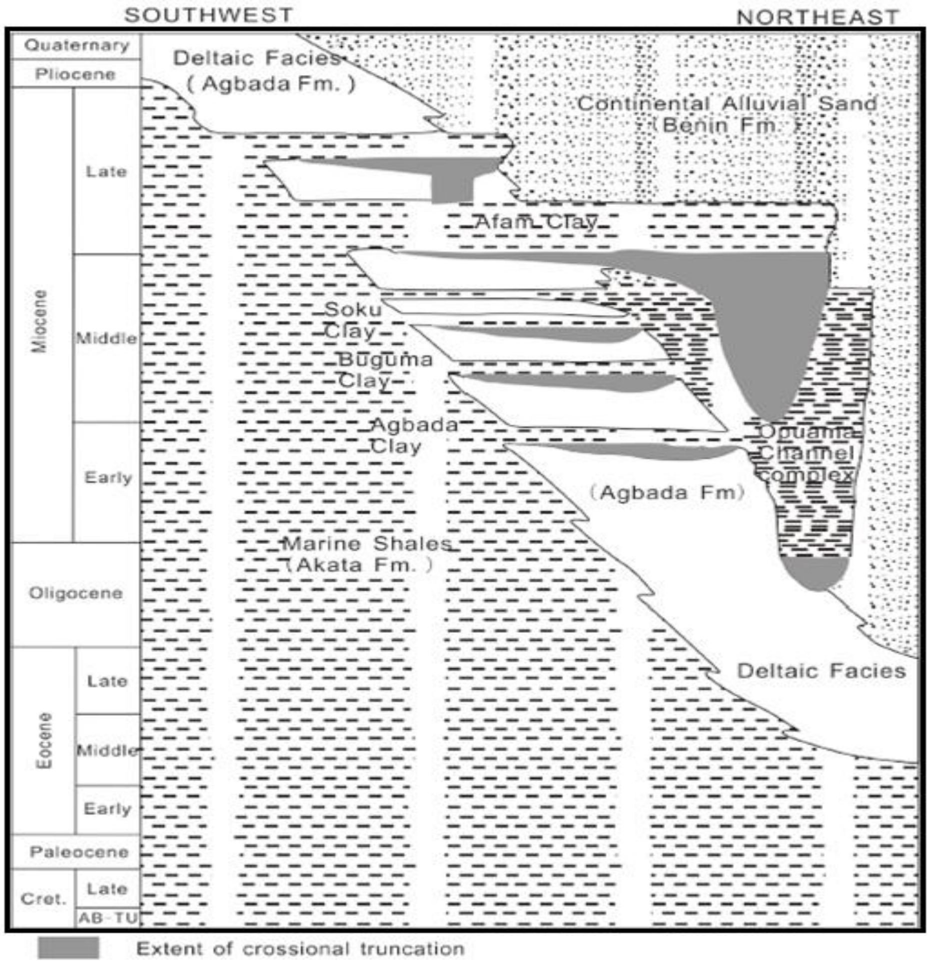

Figure: Lithostratigraphic column showing Niger Delta Formations (modified from Doust & Omatsola, 1990).

Akata Formation

The Akata formation consists of clays and shales with minor sand intercalated sediments deposited in prodelta environment. This formation, beginning in the Paleocene and through the recent, was formed when terrestrial organic matter and clays were transported to deep areas characterized by low energy conditions and oxygen deficiency (Lauferts, 1998). The Akata Formation is overlain by Agbada Formation and constitutes the potential hydrocarbon source rock and reservoir rock in deep water. Doust and Omatsola, (1990) estimated the thickness of Akata Formation to be up to 7,000 meters thick and its mature marine shales to be the source rock of hydrocarbon in the Niger Delta.

Agbada Formation

The Agbada Formation (Eocene – recent) overlies the Akata Formation and consists of paralic siliclastics over 3,700 meters thick (Ehirim & Chikezie, 2017). This Formation is divided into an upper unit which consists of sandstone – shale alternations with the former predominating over the latter and a lower unit in which the shales predominate. The deposition of this Formation began in the Eocene and continues in the recent. It occurs throughout the Niger Delta clastic wedge with lithologies that are largely of alternating sands, silts, shales with progressive upward changes in grain size and bed thickness. Lauferts (1998) interpreted the strata of Agbada Formation to have been formed in fluvial-deltaic environments. The sandy part constitutes the main hydrocarbon reservoirs and the shales form seals in the delta oil fields (Ejedawe, 1981; Evamy et al., 1978; Doust & Omatsola, 1990).

Benin Formation

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