Electro-sequence analysis and natural resources potential of a transitional environment in central swamp depobelt, Niger delta, Nigeria

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Abstract

Sequence stratigraphy and Electrosequence of the Don-Field Central Swamp depobelt of the Niger Delta Basin, was carried out using well logs, biostratigraphic and core data. The aim of this study is to re-characterise and revalidate the reservoirs within the study area and provide an optimum framework for predicting reservoir character, development and reservoir quality distribution. Detailed petrophysical evaluation reveals proficient hydrocarbon reservoir units with variable parameters (i.e. porosity, permeability and shale volume) that can accommodate productive hydrocarbon reserve. Core data analyses revealed heavy minerals like pyrites and glauconites that can be of economic interest. The gamma wireline signatures of the wells show reservoir units that are predominantly blocky in shape indicative of fluvial channels. Fluvial channels are typically associated with coastal and/or marginal marine environments. More so, the aforementioned observations were validated using palaeoenvironmental interpretation of strata penetrated by Well-1, Well-2, and Well-3 via the sidewall core analyses. Sequence stratigraphic surfaces such as maximum flooding surfaces (MFS) and sequence boundary (SB) were observed to show good correlation with palynological and foraminiferal zones. The stacking patterns (i.e. progradation, retrogradation and aggradation) encountered gave acumen into systems tracts (i.e. lowstand system tract (LST), transgressive system tract (TST) and highstand system tract (HST) interpretation. These system tracts constitute a depositional sequence set of middle—late Miocene age bounded chronologically by MFS of 9.5 Ma, 12.8 Ma, 15.0 Ma, 15.9 Ma and SB of 12.1 Ma, 13.1 Ma, 15.5 Ma, 15.9 Ma. The SB and MFS were delineated based on Shell Petroleum Development Company (SPDC) biozonation scheme: F-zone and P-zone were within P820-P680 and F9500-F9600/F9700 as contained in the biofacies interpreted data of index fossils (*Globorotalia foshi* S.I; *Globorotalia praefohsi*; *Globorotalia peripheroacuta*; *Orbulina* spp; *Praeorbulina sicana*; *Paragloborotalia mayeri*; *Neogloboquadrina acostaensis*) which corresponded to the alphanumeric code N8–N16 planktonic foraminiferal zones of Blow.

Keywords Depositional system · Biostratigraphic markers · Electrosequence · Formation evaluation · Niger delta

Introduction

Over the years, the global demand for oil and gas products has continued to increase and this situation has intensified exploration activities in search for new hydrocarbon reserves. Based on the aforementioned reasons, the Niger Delta Basin has been extensively studied to unravel subtle stratigraphic and structural traps (Knox and Omatsola 1987; Weber and Daukoru 1975; Evamy et al. 1978; Ejedawe 1981; Urang et al. 2020). In order to meet the increased global demand for oil and gas, different geological, geophysical and geochemical approaches have been employed in hydrocarbon exploration and exploitation. However, these

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methods tend to be complex, expensive, and pose enormous challenge during formation evaluation and decision-making (Ladipo 1992; Stacher 1995). Concurrently, it is important to take into account the risks associated with the environment, economy and technology uncertainties during oil and gas exploration. Formation evaluation provides maximum framework for reservoir assessment geared towards successful exploration, development and exploitation of commercially viable hydrocarbon reservoirs. The sedimentological and stratigraphic facets of Africa's leading oil province have been opened-up in recent time by the works of Reijer (2011) and Mode et al. (2015) based on the pioneer researches of Short and Stauble (1967), Weber (1971), Knox and Omatsola (1987), Ladipo (1992), Stacher (1995) and Durand (1995). Previous research works on sedimentological, biostratigraphic and sequence-stratigraphic styles clarified the collective influence of eustatic cyclicity and local tectonics (Ladipo 1992; Stacher 1995; Reijers et al. 1997; Owoyemi and Willis 2006; Magbagbeola and Willis 2007; Anyiam et al., 2019). Thus, the genetic sequence of depositional belt is marked at the top by the maximum flooding surface and at the base by a transgressive surface. Galloway (1989a, b), based on reports of Frazier (1974) proposed that maximum flooding surfaces rather than sub-aerial unconformities be used as sequence boundaries. Thus, strata bounded by maximum flooding surfaces within transgressive shales are more readily identifiable in the Niger Delta. Individual sea-level cycles are reflected in the Niger Delta in various sedimentary sequences (Haq et al. 1988). Interferences of these cycles with different periods resulted in the formation of sequence sets that are chronostratigraphically confined and sedimentologically characterised. The aim of this study is to reflect, revalidate and establish a cost effective way by which sequence sets can provide optimum framework for predicting reservoir character and quality distribution in the central swamp depobelt, Niger Delta-Nigeria.

Location and geology of the study area

The study area is part of the Cenozoic oil prolific Niger Delta Basin according to Merki (1972). The area “Don-field” is located in the Central Swamp Depobelt of the Niger Delta within Oil Mining Lease-12 (OML-12) block with an area of about 91,803.278 square feet. It is located between Longitudes $7^{\circ}0.22^{\circ}\text{E}$ — $7^{\circ}0.32^{\circ}\text{E}$ and Latitudes $4^{\circ}0.81^{\circ}\text{N}$ — $4^{\circ}0.85^{\circ}\text{N}$ (Fig. 1).

The Niger Delta is a terrigenous epicratonic embayment which lies at the edge of the Africa continental crust (Weber and Daukoru 1975; Evamy et al. 1978; Ejedawe 1981). The sedimentary basin is composed of five depositional units known as depobelts that are considered as separate entities based on the diversity in stratigraphic, structural framework

and hydrocarbon distribution (Hospers 1965; Stoneley 1966; Burke et al. 1972; Doust 1987; Knox and Omatsola 1989). These depobelts are: (i) the Northern Delta of Late Eocene—Middle Miocene, (ii) Greater Ughelli of Oligocene-Early Miocene, (iii) Central Swamp of Middle–Late Miocene, (iv) Coastal Swamp of Late Miocene-Pliocene and (v) Offshore of Middle- Late Pliocene (Weber 1971; Weber and Daukoru 1975; Doust and Omatsola 1990). The deltaic deposit are composed predominantly of regressive clastic successions mainly of sedimentary origin and this regressive packages consists of deltaic deposits that are defined by three main lithostratigraphic units, i.e. Akata, Agbada and Benin formations (Fig. 2). The marine shales of the Akata formation at the base consist mainly of overpressured marine shales that are about 19,685.04 feet thick. The Akata formation is overlain by the Agbada formation that is composed of paralic successions of interbedded sands and shales, about 13,123.36 feet thick in the central parts, but however, thins seawards and towards the delta margin. The non-marine alluvial continental deposits of the Benin formation is composed mainly of fluvial gravels and sands that thickens up to 6561.68 feet in the delta centre and thins towards the delta margin. The Niger Delta basin currently produces hydrocarbons mainly from rocks of Eocene-Pliocene age, (Weber and Daukoru 1975; Evamy et al. 1978; Ekweozor and Daukoru 1994; Ekweozor and Okoye 1980; Haack et al. 2000). However, due to the advancement in exploration technology, investigation in the basin is gradually shifting to the delta toe and flanks of the delta, where Cretaceous prospects are expected.

Materials and methods

Formation evaluation, involves the estimation of lithological properties, reservoir potential and performance based on parameters such as porosity, permeability, grain size, degree of compaction, paleoenvironmental indices, amount of matrix and cement components. The aforementioned parameters were determined through analysis of wireline log suites, sidewall core samples and biostratigraphics data. The flow chart of the methodology is as presented in Fig. 3.

Extraction of petrophysical parameters from wireline logs

The well log data from Don-Field was made available for research by Shell Petroleum Development Company, Nigeria. An indispensable step in formation evaluation procedure is the estimation of amount of shale present in the prospective sandstone. (Ulasi et al. 2012; Urang et al. 2020). This aided the exact estimation of formation porosity and fluid content contained within the pay zone. Wireline logs were

Fig. 1 **a** Base map of the Don-field, central depobelt, Niger delta **b** Niger delta basin and its stage development. adapted from Short and Stauble, 1967 **c** Regional basins map of Nigeria showing Niger delta (Adapted from Corredor et.al., 2005)

used to ascertain depths of deposition, thickness of hydrocarbon productive intervals, specific reservoir parameters and to distinguish between fluids in the reservoir encountered using derivative models of Archie's Eqs. (1942) Suites of wireline logs ranging from gamma ray (GR), resistivity (LLD), sonic (DT), density (RHOB) and neutron (NPHI) logs were used in this study. This study considers the case of tertiary unconsolidated siliciclastic rocks where composition, pore geometry, interbedded thin shale layers, effect of invasion, pore fluid types and saturation levels, fluids distribution pattern, cracks and their orientation, grain packing, pore networks are possible sources of confidence in

quantitative reservoir parameter evaluation. Owing to the aforementioned effectiveness in petrophysical evaluation their significance can sway or converse depending upon the area, geology, compaction and depositional environment. Volume of shale (Vsh) is calculated and estimated through gamma ray index (IGR) from GR log to approximate clay contents in the reservoir rock using Larionov Eqs. (1969). The porosity of the reservoir interval is calculated and corrected by using density and neutron logs derivatives. The water saturation within reservoir pores was estimated from resistivity log using Archie's Eq. (1942) for clean sand intervals. The hydrocarbon saturation (Sh) (the percentage

Fig. 2 Stratigraphic column showing the three formations of the Niger Delta (Modified from Owoyemi 2004)

of pore volume in a formation occupied by hydrocarbons) was obtained by subtracting the value obtained for water saturation from 100%. The permeability, (K) (which is the ability of a rock to transmit fluid) was calculated by Wyllie and Rose (1950) log derived permeability equation. The ratio of water saturation to flushed zone water saturation gives the amount of hydrocarbons which have been moved by the invasion process. This ratio inferred as the moveable hydrocarbon index (MHI). Similarly, the work by Akaerue, et. al. (2018) in the same study area gave comprehensive mathematical derivatives and equations which were used in the current work to compute the petrophysical parameters. Gamma ray log was used to delineate different lithologies. The qualitative identification of reservoir zones was done using the log signatures from the studied packages. Strata with high GR, high neutron values, low resistivity and low density values indicated shale and was thus eliminated. Well log patterns of the sedimentary facies were then identified and interpreted through the gamma ray and resistivity log motifs in conjunction with biofacies interpretation, consequently providing information on rock properties and depositional environment as modelled by Busch (1975), Schlumberger (1985), Mode et al. (2015) and Anyiam, et al. (2019) (Fig. 4a, b).

Core data

Core data are usually generated during or after drilling operations, especially from exploration or production wells for the purpose of obtaining different information related to sub-surface geology (Keelan 1982). This provided information on the physical rock properties and facies analysis (lithology, porosity and fluid evaluation). The rock fabric and degree of compaction were considered as these affect porosity and permeability which are fundamental properties of the reservoir in determining quality and effectiveness. Shale volume was also estimated from the core analysis. Paleoenvironment of deposition of the rock and reservoir quality were determined to complement wireline log signatures. Total 65 core side-wall samples were taken in the interval of 4446 feet to 10,110 feet and analysed to measure uncertainty in petrophysical and rock physics parameters. Proper sedimentological analysis was carried out to ascertain the degree of heterogeneity in the sandstones as this could greatly affect quality.

Biostratigraphic reports

Biostratigraphic analysis of fossil material derived from core and cuttings delivers information on the age of sediments, the correlation surfaces between wells, and the depositional environment. The biostratigraphic data supplied by SPDC Nigeria Limited of Well-1 and Well-2 were used for the reservoir characterisation (Tables 1, 2, 3 and 4). A total of 105 composited samples from depth of 3340 to 9855 feet and 3700 to 10,640 feet, respectively, were processed and analysed for micropaleontological and palynological studies. Interpreted palynological (P) zone and Foraminifera (F) zone based on SPDC bio-zonation scheme were calibrated and depth matched with corresponding wireline logs. The population and diversity of the benthic and planktonic foraminifera integrated with the wireline motifs were used for the stratigraphic surfaces interpretation and ages assigned. (Fig. 4b, 5, 6).

Results and discussion

Petrophysical analysis of Well-1 reservoirs

By applying a cutoff value of 70.1 API for the GR log, five reservoir units were delineated in Well-1 within the Agbada formation. The five reservoir units, i.e. A1 to A5 have thicknesses of 320, 160, 190, 52 and 25 feet, respectively (Table 5). The thickness of the individual net sand units ranged from 15 to 110 feet indicating that these reservoirs are not completely clean but contain some inter-fingerings of shale (a typical characteristic of paralic succession such as the Agbada formation). Average porosity values in the

Fig. 3 Work flow chart

reservoirs range from 16.07 to 21.51% suggesting, good to very good porosity reservoirs for the well (Rider 1986; Etu-efeotor 1997). The average volume of shale (Vsh) in reservoir A1 is 5.37% suggesting clean sand reservoir (Davies 2002). This means that the average volume of shale (Vsh) value in reservoir A1 may not affect its water saturation (Sw) significantly, unlike in other reservoirs (A2 to A5) where average volume of shale was more than 10 to 15% which is the permitted threshold according to Hilchie, (1978). Average resistivity and permeability values of 26.54 and 33.87 ohms-metre, and 131.08 and 1920.22 md, respectively, of reservoirs A5 and A3 suggested that these reservoir units contain hydrocarbon with excellent permeability. Reservoirs A1, A2 and A4 have average resistivity values of 1.5, 1.96 and 1.14 Ω m, respectively. This suggests that the fluid within

the reservoirs may be formation water. Also, these reservoirs have average water saturation percentage values of 79.41, 30.12 and 40.6%, respectively. Hence, suggesting high water saturation zones with little or no hydrocarbon.

Petrophysical analysis of Well-2 reservoirs

Well-2 is located at the eastern part of the 'Don Field'. A cutoff value of 69.0 API for the GR log was used to differentiate reservoirs from non-reservoirs. The reservoirs identified in Well-2 (B1 to B7), ranged in thickness from 30 feet in reservoirs B1 to 269 feet in B3 (Table 6). Reservoirs have very good to excellent average porosity values which ranges from 20.71% in reservoir B7 to 22.97% in reservoir B2. Reduction in average porosity values from reservoirs B1

Fig. 4 a Gamma ray and resistivity log shapes suggestive of depositional environment (Adapted from Aloa, et.al. 2013 b). Electrofacies in the wells across the study area. (Modified from Mode et. al. 2015)

to B7 is probably due to compaction resulting from overlying sedimentation. Average volumes of shale recorded are between 13.79 and 29.25%, suggesting that these reservoirs are not clean. Reservoirs B2, B4 and B5 show evidence of hydrocarbon saturation with average resistivity values of

28.80, 23.19 and 13.33 Ωm , respectively. Each of the reservoirs has average S_w of 13.38, 13.82 and 20.32% which was considered poor and implies that hydrocarbon saturations is good. Based on the negative crossing of the neutron and density logs by implication the hydrocarbon in reservoir B2

Table 1 Summary of Biozonation in well-1(Foraminifera) (SPDC 2010)

Top Depth	Bottom Depth (ft)	F.Zone (SPDC)	F-zone Blow (1969)	Reliability Gradient	Remarks
0	4000				No Data
4030	4200	F9600/F9700	N13/N14		Barren
4431	5106				Undiagnostic (practically barren)
5611	6900	F9500/F9600	N10/N12		Globorotalia foshi S.I
6927	9855	F9500	N10	1	Globorotalia praefohsi/Globorotalia peripheroacuta
	Microfaunal Marker				
	7662	F9540	N9	1	Globorotalia periphero/Orbulina spp.
	9120	F9520	N8	1	Orbulina spp./Praeorbulina sicana

Table 2 Summary Bio-zonation inwell-1 (Pollen) (SPDC 2010)

P Zone	Top	Bottom	Reliability	Remarks
	Depth	Depth (ft)	Gradient	
	0	3340		No data
P830	3342	3559	4	
	3560	3930		No data
P820	3935	4030	1	q.b. 292
P780	4104	4164	1	
P770	4431	4605	1	t. 440
P740	4720	7332	1	t.r. &b.r. 320
P720	7465	8798	3	b. 17
P680	9007	9790	2	

is gas, and the gas–water-contact (GWC) was delineated at about 5986 feet. Reservoirs B4 and B5 are probably hydrocarbon filled with little or no formation water. This probably explains the tracking together of density and neutron logs signatures. Reservoirs B1, B3, B6 and B7 are water saturated with little or no hydrocarbon based on the low

Table 4 Summary of Bio-zonation in well- 2 (Pollen) (SPDC 2010)

P Zone	Top	Bottom	Reliability	Remarks
	Depth	Depth (ft)	Gradient	
	0	4400		No data
P820	4490	4590		
	4610	5960		No data—Sandy
P740	5990			(high occ. of 320)
P720	6050	6710		

resistivity values observed. The average moveable hydrocarbon index (MHI) values of reservoirs 0.356, 0.426, 0.480 and 0.505 for the respective reservoirs, indicative of good fluid moveability.

Petrophysical analysis of Well-3 reservoirs

Well-3 is located in between Well-1 and Well-2 in the central part of the Don Field (Fig. 1a). The reservoir units' average thickness ranges between 113 feet in reservoir C7 and

Table 3 Summary of Bio-zonation in well – 2(Foraminifera) (SPDC 2010)

Top Depth	Bottom Depth (ft)	F.Zone (SPDC)	F-zone Blow 1969	Reliability Gradient	Remarks
0	3700				No Data
3795	4250				Undiagnostic
4310	4790	F9600/F9700	N13/N14		
4850	6170				Practically Barren
6290	7970	F9500	N10	3	Globorotalia praefohsi/Globorotalia peripheroacuta
8030	10,640	F9300	N7	4	Praeorbulina sicana/Catapsydrax dissimilis
	Microfaunal Markers				
	6350	F9540	N9	3	Globorotalia periphero/Orbulina spp
	7390	F9520	N8	3	Orbulina spp./Praeorbulina sicana

211 feet in reservoir C5, while the sand thickness of these reservoirs ranged from 37 to 205 feet (Table 7). Average porosity values of 19.90% to 27.05% suggest good to excellent porosity. The average Vsh in these reservoirs ranged from 13.60 to 28.54% indicating that the reservoirs may

Fig. 6 Biofacies interpretation of the study area. (Abbreviations: B=Barren; CD=Coastal Deltaic; PF=Proximal Fluvial Marine; SHIN=Shallow Marine-to-Inner Neritic; IN=Inner Neritic; IN-MN=Inner Neritic-Middle Neritic; MN=Middle Neritic; MN-ON=Middle Neritic-to-Outer Neritic. (SPDC, 2010)

Fig. 5 Niger delta chronostrat chart of Shell Petroleum Development Company (SPDC, 2010)

BIOFACIES INTERPRETATION									
	sn	DEPTH	S. TYPE	ENVIRON.	F. DIVERSITY	F. POPLN	P. DIVERSITY	P. POPLN	F. ZONE
9	1	4030	2	ON-BA	7	40	1	2	F3600/F3700
10	2	4050	3	ON-BA	6	120	1	8	
11	3	4104	2	MN	6	14	0	0	
12	4	4125	3	MN-ON	6	62	1	6	
13	5	4164	2	IN	2	2	1	1	
14	6	4200	3	ON-BA	9	73	0	0	UNDIAGNOSTIC
15	7	4431	2	B	0	0	0	0	
16	8	4557	2	IN	3	3	1	1	
17	9	4575	3	IN	2	6	0	0	
18	10	4720	2	B	0	0	0	0	
19	11	4860	2	IN	2	16	0	0	
20	12	4928	2	B	0	0	0	0	
21	13	5100	3	B	0	0	0	0	
22	14	5106	2	SHJN	1	1	0	0	
23	15	5611	2	IN	5	19	0	0	F3500/F3600
24	16	5640	3	IN	3	24	1	8	
25	17	5856	2	IN-MN	5	5	0	0	
26	18	5976	2	IN	3	4	1	1	
27	19	6000	3	B	0	0	0	0	
28	20	6060	3	B	0	0	0	0	
29	21	6118	2	IN-MN	5	40	1	3	
30	22	6120	3	IN	4	24	0	0	
31	23	6150	3	IN	2	6	0	0	
32	24	6180	3	CD	1	4	0	0	
33	25	6240	3	B	0	0	0	0	
34	26	6300	3	B	0	0	0	0	
35	27	6312	2	IN-MN	6	11	1	1	
36	28	6330	3	IN	2	16	0	0	
37	29	6360	3	B	0	0	0	0	
38	30	6370	2	B	0	0	0	0	
39	31	6420	3	IN-MN	4	66	1	18	
40	32	6480	3	MN-ON	8	144	1	8	
41	33	6540	3	MN-ON	6	96	0	0	
42	34	6600	3	MN-ON	5	88	2	16	
43	35	6660	3	B	0	0	0	0	
44	36	6720	3	MN-ON	6	52	0	0	
45	37	6780	3	MN	5	32	0	0	
46	38	6840	3	B	0	0	0	0	
47	39	6900	3	SHJN	1	32	0	0	F3500. RG 1 Top Cassigerinella 1
48	40	6927	2	ON-BA	24	253	6	38	
49	41	6945	3	B	0	0	0	0	
50	42	6960	3	SHJN	1	4	1	4	
51	43	7020	3	MN	4	72	1	8	
52	44	7080	3	MN	5	40	1	4	
53	45	7140	3	MN-ON	6	128	1	4	
54	46	7200	3	MN	3	48	0	0	
55	47	7260	3	MN	5	32	0	0	
56	48	7282	2	ON-BA	23	81	5	9	
57	49	7320	3	ON-BA	10	87	2	19	F3500. RG 1 Top Cassigerinella 1
58	50	7332	2	BA	43	7100	11	2629	
59	51	7350	3	ON-BA	20	554	4	163	
60	52	7380	3	ON-BA	25	1130	4	196	
61	53	7465	2	ON-BA	29	132	4	10	
62	54	7500	3	ON-BA	19	474	3	60	
63	55	7532	2	BA	43	10066	16	1762	
64	56	7620	3	BA	42	3614	14	746	
65	57	7662	2	BA	26	495	7	39	
66	58	7740	3	BA	40	13928	12	1672	Marker F3540 rg 1 Boliv 25/ Uvigerina 5
67	59	7764	2	BA	35	17722	12	2219	
68	60	7842	2	ON-BA	13	479	0	0	
69	61	7860	3	BA	37	5066	10	1040	Globorotalia peripheroa/ Orbulina spp.
70	62	7890	3	BA	41	5139	10	867	
71	63	7946	2	ON-BA	17	109	3	8	
72	64	7980	3	ON-BA	37	1792	3	312	
73	65	8055	2	MN	7	31	2	1	
74	66	8088	2	MN	7	560	1	1	
75	67	8100	3	BA	37	2134	11	264	
76	68	8200	2	BA	31	565	13	142	
77	69	8220	3	BA	32	3720	10	384	
78	70	8340	3	BA	45	3092	12	364	
79	71	8350	2	BA	31	3636	7	557	Orbulina spp./ Praeorbulina sicana
80	72	8372	2	MN	7	131	1	1	
81	73	8415	3	BA	35	2410	5	210	
82	74	8457	2	BA	10	1876	1	86	
83	75	8460	3	BA	39	5464	8	512	
84	76	8550	2	PF	2	7	0	0	
85	77	8558	2	BA	34	1295	14	280	
86	78	8580	3	BA	43	1936	13	260	
87	79	8598	2	IN	4	7	1	2	
88	80	8610	2	MN	9	55	2	8	
89	81	8617	2	ON-BA	23	214	3	23	F3520 RG 1 Chiloguembelina
90	82	8634	2	ON-BA	28	2211	5	202	
91	83	8655	3	ON-BA	37	2528	6	244	
92	84	8730	2	MN	9	39	0	0	
93	85	8740	2	MN	8	19	0	0	
94	86	8758	2	ON-BA	22	138	3	11	
95	87	8778	2	MN	14	97	3	66	
96	88	8787	2	IN	3	52	0	0	
97	89	8798	2	ON-BA	23	129	4	54	
98	90	8835	3	ON-BA	32	1044	5	140	F3500 RG 2
99	91	9007	2	MN-ON	15	108	3	14	
100	92	9120	2	MN-ON	17	70	5	31	
101	93	9165	3	BA	43	3124	12	968	
102	94	9180	3	BA	39	4072	8	1180	
103	95	9265	3	BA	27	1894	7	512	
104	96	9354	2	ON-BA	17	494	3	253	
105	97	9390	3	BA	38	4368	8	1184	
106	98	9420	2	CD	1	40	0	0	
107	99	9440	2	MN-ON	13	56	3	8	F3500 RG 2
108	100	9570	2	MN	8	15	1	2	
109	101	9642	2	ON-BA	10	342	2	101	
110	102	9630	3	ON-BA	28	804	6	132	
111	103	9790	2	MN-ON	12	44	4	8	
112	104	9825	3	ON-BA	25	236	3	36	
113	105	9855	3	ON-BA	31	946	9	186	

Table 5 Summary of Petrophysical results for Well-1

Reservoir Unit	Interval (ft)	Net Sand (ft)	Average Porosity (%)	Average K (md)	Average Vsh (%)	Average MHI	Average Sw (%)	Average Resistivity (Ω m)	Fluid Type
A1	6960–7280	313	21.51	152.98	5.37	0.37	79.41	1.5	Water
A2	7350–7510	110	21.12	273.24	18.63	0.26	30.12	1.96	Water
A3	8360–8550	117	21.11	1920.22	19.73	0.18	20.66	33.87	Oil
A4	8800–8852	39	18.92	22.76	13.29	0.34	40.6	1.14	Water
A5	9535–9560	15	16.07	131.08	28.96	0.43	43.50	26.54	Oil

Table 6 Summary of Petrophysical Results for Well-2

Reservoir unit	Interval (ft)	Net sand (ft)	Average Porosity (%)	Average K (md)	Average Vsh (%)	Average MHI	Average Sw (%)	Average Resistivity (Ω m)	Fluid type
B1	5883–5931	30	23.39	1379.20	27.96	0.356	27.60	4.72	Water
	5961–5985	35	22.97	772	13.79	0.571	13.38	28.80	Gas
B2	5986–6050	52	26.98	1325.91	11.83	0.297	22.09	6.59	Water
B3	6086–6370	269	22.44	68.034	13.58	0.426	34.56	3.78	Water
B4	6425–6469	42	23.75	209.272	14.41	0.201	13.82	23.19	Oil
B5	6490–6531	41	24.36	161.03	15.96	0.273	20.32	13.33	Oil
B6	6552–6624	64	21.69	48.596	16.67	0.480	40.07	2.48	Water
B7	6740–6800	30	20.71	43.794	29.25	0.505	43.28	3.23	Water

Table 7 Summary of the Petrophysical Results for Well-3

Reservoir unit	Interval (ft)	Net sand count (ft)	Average Porosity (%)	Average K (md)	Average Vsh (%)	Average MHI	Average Sw (%)	Average Resistivity (Ω m)	Fluid type
C1	8201–8256	53	27.05	54.10	18.79	0.077	27.05	1.10	Water
C2	8279–8395	65	25.92	115.14	27.45	0.031	25.92	3.39	Water
C3	8474–8576	97	26.14	114.514	13.60	0.032	26.14	3.04	Water
C4	8750–8834	72	24.09	354.948	21.30	0.012	24.09	67.81	Oil
C5	9045–9256	205	23.88	555.327	15.12	0.009	23.88	201.58	Oil
C6	9308–9371	40	24.60	82.04	28.54	0.034	24.60	2.91	Water
C7	9485–9598	37	19.90	62.12	27.82	0.047	19.90	5.25	Water

Table 8 Summary of sand master report Along Hole Depth for Well-2

Form Code	Top Depth(ft)	Base Depth(ft)	Net Gas	Net Oil	Highest Oil	GDT	OUT	ODT	HCWC	WUT	Ave Por
D											
30,000	5962	6056	17	10					5992		30
D											
40,000	6086	6338		13	6090	5979	5982			6106	29
D											
50,000	6408	6470		52	6418			6106			27
D											
60,000	6488	6534		33	6494				6522		27
E											
70,000	7810	7884							7844		28

Table 9 Summary of sand master report Along Hole Depth for Well-3

Form Code	Top Depth(ft)	Base Depth(ft)	Net Gas	Net Oil	Highest Oil	GDT	OUT	ODT	HCWC	GUT	Ave Por
E											
7000	8739	8839	85							8754	22
E											
7500	8930	8962		18			8934	8952			21
E											
8000	9045	9258	212						9728		24
U											
3000	9713	9819		12							21

Fig. 7 Well logs showing the depths of GUT, GDT, OUT, ODT, WCWC and WUT

not contain clay types that could adversely affect quality in appreciable amounts. This is also reflected in the good to excellent average permeability values that ranged from 354.948 md in reservoir C4 to 555.327 md in reservoir C5. The reservoirs have good average porosity values that vary between 19.90% in reservoir C7 and 27.05% in reservoir C1. Reservoirs C4 and C5 have high resistivity values of 67.81 and 201.58 Ω m, respectively. Water saturation within these reservoirs (i.e. between 24.09% and 23.88%) suggests

hydrocarbon saturation of 85.1% and 86.12%, respectively. Reservoirs C1, C2, C3, C6 and C7 are water-bearing reservoir based on their low average resistivity values of 1.10, 3.39, 3.04, 2.91 and 5.25 Ω m, respectively. Also their high average S_w value range of 19.90 and 27.05%, suggests high water saturation with little or no hydrocarbon. The average moveable hydrocarbon index (MHI) values range from 0.009 to 0.012 indicating good fluid moveability. This is also

Fig. 8 Correlation between Well logs and Core data of well-3

confirmed by the reservoir permeability, where values as high as 354.948 and 555.327 md were observed.

Depth of hydrocarbon occurrence

The depths where hydrocarbons occur in a reservoir, especially at the contact zones are marked by increase in resistivity values. Result analysis shows that the depth of

hydrocarbon occurrence varies from well to well due to variations in thickness of the overlying sediments, and possibly faulting (Anyiam et. al. 2019). The sand master report of well-2 and well-3 used in the determination of hydrocarbon depth of occurrence shows the fluid contacts within the reservoir, such as, hydrocarbon water contact (HCWC), gas down to (GDT), gas up to (GUT), oil up to (OUT), oil down to (ODT), water up to (WUT) and oil water contact (OWC)

Fig. 9 Electrosequence stratigraphic Interpretation of the Well logs showing the positions of MFS, SB (erosional) with different Systems Tracts

(Tables 8 and 9). In well-2, the depth of 5982 feet marks OUT indicating the depth of hydrocarbon occurrence, while in well-3, the GUT and OUT at depths of 8754 and 8934 feet, respectively, show the zones of hydrocarbon accumulation (Fig. 7).

Core data analysis

Representative core data from well-3 were gotten from the interval between 8770 and 9890 feet. Core description shows physical and chemical characteristics of the lithologic intervals Revil et al. 2002; Glover 2010). The analysis was based on the sidewall sample description (Fig. 8). The genetic facies identified were the lower shoreface, upper shoreface, marine shale, tidal channel and channel heterolithics according to Mode et al. (2015) (Fig. 4b). The depositional environments spans through incised canyons, channels, inner mid shelf, shelf margin, and slope margin. The reservoir units represent intervals that are rich in sandstones (89 to 98% of sand). Such intervals contain grey, silty, well sorted and loosely consolidated sands with presence of few heavy

minerals, pyrite, rare mica flakes and weathered glauconite (Fig. 8). The sorting and poorly consolidated natures of pore throats of sand grains in the reservoir units imply that these reservoir units have good fluid moveability. The result shows that reservoir intervals evaluated have good porosity and permeability qualities due to sphericity and good sorting of the grains. However, the presence of heavy minerals and clayey particles could reduce porosity and permeability qualities of rocks, because these particles could form pore throat blockages between sand grains thereby reducing pore radius and thus porosity and permeability. The core result shows the occurrence of different lithofacies at depths of 8824, 8830, 9256 and 9259 feet. At certain depths, there are non-reservoir intervals due to protrusion towards the south most position as observed in Well-1 (Fig).

Lithologic identification

Petrophysical and core analysis for depths between 8750 and 9750 feet shows that low gamma-ray log and high gamma-ray log values were recorded for the sand and shale units,

Fig. 10 Electrosequence stratigraphic correlation panel across “Don-wells” showing the system tract and SPDC-Zonation Scheme: PZone = Palynological Zone; F-Zone = Foraminifera Zone

respectively. Gamma-ray log values recorded between 8750 and 8840 feet, 9050 to 9256 feet, 9308 to 9371 feet and 9485 to 9595 feet indicate the presence of reservoir units (Fig. 8). These depth ranges also agrees with the core description for those depths, where very high sand percentages in

comparison to shale percentage were observed. The lithologic compositions within these intervals are mainly silts and well-sorted, loosely consolidated sands. On the other hand, between 8790 and 9050 feet, 9250 and 9357 feet and 9601 and 9763 feet, non-reservoir units were identified based on

Fig. 11 Electrosequence analysis across “Don-wells” showing the stacking patterns

the relatively high gamma ray log values that indicate high percentage (i.e. > 90%) composition of shale (Fig. 8).

Fluid type identification

The resistivity log and core description for depths between 8759 and 8840 feet and 9050 to 9256 feet show hydrocarbon reservoir units that have relatively high average resistivity values than adjacent water saturated reservoir units (Tables 5, 7 and 8). The sands were stained with carbonaceous films, especially at depths of 8824 and 9256 feet indicating the presence of hydrocarbon. Conversely, low

resistivity values together with the absence of carbonaceous films were noted in other reservoir units, thus, this depicts water saturated zones, especially at depths of 8828, 8833 and 9554 feet (Figs. 7 and 8). Water bearing intervals are outlined by low resistivity since resistivity increases when the formation water is replaced by oil while porosity remains constant. Also, density decreases when the water is replaced by oil in the formation with the same porosity, thus the hydrocarbon bearing intervals were not characterised at those points. (Archie, 1942).

Fig. 12 Zonal scheme/bio-zone marker species, and ages, (Modified from Blow 1969)

Presence of heavy minerals

High gamma-ray responses observed at some clean sandstone intervals were as a result of the presence of heavy minerals such as weathered glauconite, pyrite and mica flakes. For better clarity, the integration of core data with well logs enhanced the determination and differentiation of these radioactive reservoirs from shale. The presence of weathered glauconite, mica flakes and pyrite generally indicates a transitional environment, i.e. coastal/marginal marine environment (Porrenga 1967; Prince 2018). In the studied intervals, glauconite is rare to common, while pyrite, shell fragments, ferruginous materials and mica flakes are very

rare. Glauconite and pyrite are important accessory minerals used for environmental studies. Glauconite forms as an authigenic mineral during the early stage of diagenesis of marine sediment, and may also indicate slow rate of deposition (Smulikowski 1954; Hower 1961; McRae 1972; Odin and Matter 1981; Lewis and McConchie 1994; Amorosi 1995) and/or gap in deposition in a case of mature glauconitic mineral with mean potassium (K_2O) content of ~7% (Odin and Fullagar 1988). It is extremely susceptible to sub-aerial weathering and it is not known as a reworked second cycle detrital mineral (Selley 1997). The presence of glauconite in sand is an indication that the sand is of marine origin. This has also been reported by other researchers within the area from integrated evidences from sedimentology, stratigraphy, mineralogy and geochemical investigation (Lewis 1962; Adegoke et al. 1971 and 1976; Petters 1979 and 1982; Seiglie et al. 1982; Ojo 1996; Ozumba 1997; Fadiya 1998; Okosun and Liebaw 1999; Chafetz and Reid 2000; Goki et al. 2007 and Opeloye 2012). More so, pyrites within the shale units suggest reducing conditions. The combination of these accessory minerals with gamma-ray responses helped in sub-dividing the environment into regressive barrier bar, tidal sand wave, and tidal channels Mode et al. (2015). According to Prince (2018), these sub-environments suggest shoreface deposits in marginal marine settings (Fig. 4, 8 and 9).

Electrosequence analysis

Electrosequence involved the interpretation of gamma ray and resistivity log for diagnostic characteristics such as trends, shapes, and abrupt breaks, which are indicative of the depositional environment and energy of deposition (Serra and Sulpice, 1975). The analysis revealed facies ranging from Marine-Shale, Heterolithic channels, upper and lower shorefaces, Shaly-Sandstone and/to Sandstone Facies (Fig. 4b). The depositional systems of Shoreface, prodelta, distributary, tidal and fluvial systems were deduced from gamma ray log signatures. The Bell-shaped log patterns on gamma ray logs indicate a fining upward trends or an upward increase in gamma ray value (typical feature of fluvial channel deposits). The Funnel-shaped log patterns indicate a coarsening upward trend, clearly showed deltaic progradation. Cylindrical (blocky or boxcar) log motif are on thick uniformly graded coarse grained sandstone unit, probably deposits of braided channel, tidal channel deposits (Fig. 4b, 9 and 11).

Sequence stratigraphic interpretation

The sequence stratigraphy analysis provided an opportunity to understand lithofacies, stacking patterns, depositional

Fig. 13 Phases of delta evolution and some of their characteristics. (Adapted from Reijer 2011)

sequences and systems tracts distribution across the study area. The erosional sequence boundaries (SB) as observed are characterised by sizeable sand unit defined in well log by abrupt and sharp bases of thick low gamma ray value intervals usually separating coarsening-upwards intervals from fining upwards intervals (Fig. 10 and 11). The maximum flooding surfaces (MFSs) are characterised by thick and extensive shale units defined by thick high gamma ray value intervals that separate overall fining-upward interval from coarsening-upwards intervals, and high abundances and diversity of microfossils (Fig. 10 and 11). These stratal surfaces were delineated using floral and faunal abundance

and diversity combined with palynological and foraminiferal zones encountered. Consequently, the stratigraphy of Niger Delta sections has conventionally been based on biochronological interpretations of fossil spores and foraminifers. Palynological and foraminiferal biozones have proved to be reliable tools for large-scale correlations between Hydrocarbon wells (Reijers, 2011). Following the planktonic foraminiferal zonal scheme of Blow (1969) as amended by Kenneth and Srinivasan (1983) (Fig. 12). The biostratigraphic framework and alphanumeric codes based on biostratigraphic zonation customised by the Shell Petroleum Development Company of Nigeria (SPDC) (Fig. 5 and 6)

Table 10 Nature of 3rd-order composite sequences and their parasequence sets in the Niger Delta (Reijer 2011)

Sequence MAIN SHALE Secondary shale	Time span (ma)	Cycle (ma)	Higher order duration (ma)	Depobelt
Sequence BOLIVINA-46	5.00–0.00	5.00 (~)	0.83 (-)	Offshore
Sequence UVIGERINA-8	9.50–5.00	4.50 (~)	1.50 (~)	Offshore/central swamp
Sequence 09 DODO SHALE	11.50–9.50	2.00 (-)	1.00 (-)	Coastal/central swamp
Sequence 08 CASSIDULINA	12.80–11.50	1.30 (-)	1.30 (~)	Central/coastal swamp
Sequence 07 CHILOGEMBELINA-3	15.90–12.80	3.10 (-)	1.55 (+)	Central/coastal swamp
Sequence 06 OGARA SHALE	19.40–15.90	3.50 (-)	1.75 (+)	Central swamp/ughelli
Sequence 05 ALABAMINA-1	26.20–19.40	6.80 (+)	1.36 (~)	Ughelli
Sequence 04 UVIGERINELLA-5	31.30–26.20	5.10 (~)	2.55 (+)	Ughelli/northern delta
Sequence 03 OROGHO	35.90–31.90	4.60 (~)	1.53 (+)	Northern delta
Sequence 02 UVIGERINELLA-8	38.00–35.90	2.10 (-)	1.05 (-)	Northern delta
Sequence 01 EPONIDES-11	54.60–38.00	16.60 (+)	1.51 (+)	Northern delta

(~): within 10% of average total duration

(+): more than average duration

(-): less than average duration

established planktonic foraminifera representation of middle Miocene zones N8 – N16 (Blow, 1969) and F9500-F9600/F9700 (Shell zonation) in the study area (Tables 1–4). The Shell biozonation was published by Evamy et al. (1978). This zonation allows correlation across all facies types from continental to marine. These biozones are based on index planktonic and benthonic foraminifers recognised from transgressive marine shales (Petters, 1982). The regionally consistent marine marker shales, as well as some of the more local shales (Fig. 13 and Table 10), have usually been named after one of the marker species and are coded systematically (Fig. 5, 6 and 14).

The generated paleobathymetric map shows generally that sediments were deposited within neritic through bathyal environments, aligning with the progradational pattern of deposition of the Niger Delta (Fig. 15) (Emery and Myers, 1996; Kendall, 2003). Three MFS were mapped and dated paleontologically; 9.5 Ma (3980 feet), 12.8 Ma (5850 feet) and 15.0 Ma (7662 feet) recognised as maximum shale peaks in Well-1, while MFS 15.9 Ma (9120 feet) was recognised in Well-2. Also, three SB were mapped and dated; 12.1 Ma (4800 feet), 13.1 Ma (6250 feet) and 15.5 Ma (8450 feet) in well-1 and 15.9 Ma (9120 feet) in Well-2 (Fig. 10, 11

and Tables 1–4). The aforementioned ages indicate Langhian–Serivillian stage of Middle–late Miocene on the global geochronological scheme of Harland et al. (1990) (Fig. 14). Relative thickness of the systems tracts shows changes in rate of sedimentation caused by variations in local conditions like tectonics, effects of gravity, eustatic sea level changes and availability of accommodation space (Haq et al. 1988). Three systems tracts, namely the highstand systems tract (HST), the lowstand systems tract (LST) and the transgressive systems tract (TST) are all represented in Well-1, but in Well-2, only the highstand system tract (HST) and transgressive system tract (TST) were delineated. Sequence stratigraphic correlation across Well-1 and Well-2 shows thickening of sediment package from northeast to southwest (Figs. 9 and 10). This reveals the evidence of structural influence on stratigraphy which have been attributed to syn-sedimentary and gravity tectonics within the Niger Delta basin. The evolution of the Niger Delta basin is controlled by pre- and syn- sedimentary tectonic activities described by Evamy et al. (1978), Ejedawe et al. (1984), Knox and Omatola (1989), Stacher (1995). Mode et al. (2015) agree that the occurrence of the identified sequence stratigraphic surfaces at different depths along dip and strike directions in the

Fig. 14 Chronostratigraphic data sheet (west and east halves combined) of the Niger Delta. (Doust and Omatsola 1990)

wells shows evidence of faulting within the field. Hence, the sediments are thinner in the up-dip (northeast) section and thicken down-dip (southwest) with a corresponding decrease in net-to-gross values (Fig. 10). This thickening of sediment package down-dip could be attributed to the high rate of subsidence and deposition that is influenced by structures on stratigraphy (Evamy et al. 1978). Also, flattening at various MFS reveals a shift of depositional centres from the north to the south. The depositional sequences recognised were made up of genetic units of LST, TST and HST. The sands

of LST and HST constitute the reservoir packages, whereas the shales of the TST in which most of the MFS were delineated serves as seal/cap rocks for the reservoir units. The alternation of reservoir units of the LST and HST, and the seal units of the TST offer good stratigraphic configurations for entrapment, hence, was the target for hydrocarbon exploration (Dim 2017). Sequence stratigraphic analysis was not carried out in Well-3 due to non-availability of sequence stratigraphic data for the well. The summary of the identified

Fig. 15 The paleobathymetric map showing the depositional environments across the study area

systems tracts for the Wells in the study area is as shown (Table 11 and Figs. 9 and 10).

Lowstand systems tract (LST)

Sediments associated with lowstand systems tract in well-1 occur in incised valleys fill with coarse grained low-sinuosity channel or estuarine sandstone in response to sea level

rise or shale prone wedge with thin fine grained turbidites forms on the slope lowstand prograding wedges. These sediments were deposited when relative sea level was at or near the shelf margin and rising slowly, but were slow enough for sedimentation to take place with shelf edge deltaic process (Posamentier and Vail 1988). The lowstand prograding wedge interval in well-1 is characterised by funnel deltaic sand body that laterally prograded into proximal lagoon shales. The prograding lowstand wedge complex is identified only in well-1 at a depth range of 8350–8560 feet. This interval corresponds to channel fill environment with progradational parasequence set as shown. (Table 11 and Figs. 9, 10 and 11).

Transgressive systems tract (TST)

Transgressive systems tract develops as a result of increase in the rate of sea-level rise which has an overall deepening upward bathymetric signature. The rate of rise is at a maximum and sediment supply is more than the available space can accommodate. At this stage, the shelf is no longer in tune with the rising sea-level. Deltaic progradation ceases and sands are trapped up-dip in the estuaries (Scholle and Spearing 1998). Transgressive systems tract is observed in Well-1 (7750 to 78,340 feet and 9252 to 9760 feet) and Well-2 (6667–6700 feet) with maximum flooding surfaces (MFS 15 Ma, 15 Ma and 15.9 Ma) at the upper boundaries. The constant deepening interval above the lowstand tract in Well-1 at 8350 feet shows a proximal lagoon setting

Table 11 Summary of Identified systems tracts for well I

Surfaces	Depth (feet)	Remarks
SB (12.1 Ma)	4800	
LST		Consists of a progradational set of parasequences building out from the pre-existing continental slope characterised by shelf-edge deltas and shorelines
TST		Consists of a retrogradational set of parasequences displays an overall deepening-upward succession
HST		Aggradational to progradational parasequence set with upward coarsening signature of blocky trends illustrating a channel fill environment
MFS(12.8 Ma)	5850	
SB (13.1 Ma)	6250	
MFS (15 Ma)	7662	
TST		This system tract progressively deepens upward as successively younger parasequences step further landward. It shows constant high gamma ray values
TSE	7950	
LST		A prograding parasequence set with funnel(bow) stacking pattern, coarsening upwards showing a fill environment
SB (15.5 Ma)	8450	
HST		A prograding parasequence set that contains sets of condensed section with upward coarsening log spikes of a typical shoreface environment
MFS(15.9 Ma)	9120	
TST		An overall deepening upward sequence show by the consistent high gamma ray values that indicate irregular trends

that drowns the funnel lowstand wedge complexes (Kendall 2003). The proximal lagoon shales in Well-1 can serve as seal or cap rocks to the underlying channel fill reservoirs which contain hydrocarbon (Table 11 and Figs. 9, 10 and 11).

Highstand systems tract (HST)

This stage features a general decrease in sea level and it is characterised by initial aggradation of shales into intervals of shallowing-up facies. The rate of sea level rise is at a minimum and depositional rates exceed rate of sea level rise causing parasequences to build basinward in aggradational to progradational parasequence sets. Both fluvial and deltaic sands near the top of the unit prograde laterally into neritic shales. The highstand systems tract was identified in well-1 and 2, respectively, at 6900–7500 feet and 8340–8860 feet for well-1, and between 5960 and 6600 feet for well-2. This prograding highstand complex corresponds to the shallow marine depositional environment. The coarsening upward sequence with frequent deepening well log spikes gives rise to a good to excellent porosity value with occasional shale intercalations that tend to reduce porosity and permeability. Furthermore, the shore sand of the highstand systems tract have good reservoir properties as stated by Coleman and Prior (1980) and Anyiam et al. (2019) (Table 11 and Figs. 9, 10 and 11).

Conclusion

The electrosequence, reservoir character and natural resources potentials of the 'Don Field' Central Swamp Depobelt of the Niger Delta were comprehensively assessed and delineated. All reservoirs units in the wells encountered were classified as good reservoirs based on their viable Petrophysical properties delineated through wirelogs and core analysis. The biostratigraphic analysis reveals sequence stratigraphic surfaces marked by MFS 9.5 Ma, 12.8 Ma, 15.0 Ma, 15.9 and SB 12.1 Ma, 13.1 Ma, 15.5 Ma and 15.9 Ma of middle–late Miocene with bio-zones range of N8–N16 or F9500–F9600/F9700 corresponding with fossil index abundance of *Globorotalia foshi* S.I; *Globorotaliapraefohsi*; *Globorotalia peripheroacuta*; *Orbulina* spp; *Praeorbulina sicana*; *Paragloborotalia mayeri*; *Neogloborotalia acostaensis*. The electrofacies identified are lower shoreface, upper shoreface, marine shale, tidal channel, channel, and channel heterolithics. However, the presence of heavy minerals like pyrite and clay particles as noted in some of the reservoir may affect fluid moveability. The core and well log analysis divulges that sparse shale beds were also present, and the sandstone is composed of 89% quartz and about 11% clay and other minerals. The clay is a mixture

of illite (60%) and kaolinite (40%). High resistivity values recorded at intervals where sand particles are discoloured by carbonaceous films indicate possibly hydrocarbon zones. The maximum flooding surface mark regional seals and caps the major reservoir units across the various fields in the study area. The LST and HST sand units of the basin floor fans, channel, and shoreface are potential good hydrocarbon reservoirs, whereas the marine shale units of the TST, which is capped by MFS, also provides regional seals to the reservoir units.

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Declaration

Conflict of interests On behalf of all the co-authors (Mr Joseph Nnakuba, Mr Job Urang, Dr Ebong Dickson, Mr Joseph Eradiri and Dr Anthony Ugbaja), the corresponding author, Mr Emmanuel Akaerue, states that there is no conflict of interest.

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