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Characterization of reservoirs and depositional study of J-P Field, shallow offshore of Niger Delta Basin, Nigeria

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ABSTRACT

Well log data interpretation was carried out over J-P Field in the Niger Delta, Nigeria. This was done with a view to characterizing the reservoirs based on the estimation of petrophysical parameters and to assessing the environment of deposition in J-P Field. Seven reservoirs were mapped and correlated across the four drilled wells in J-P Field. Petrophysical parameters such as porosity, volume of shale, water saturation and hydrocarbon saturation were estimated. In addition, depositional environments of each reservoir in J-P Field were determined based on the gamma ray responses. This study reveals that the range of petrophysical parameters across the delineated reservoirs; for porosity varies from 19 to 21%, thickness varies from 24 to 122 m, volume of shale varies from 15 to 29%, water saturation varies from 22 to 60% and hydrocarbon saturation varies from 40 to 78%. The depositional environment was interpreted as comprised of prograding deltas, transgressive marine sands, fluvial channels and deltaic settings. It is concluded that J-P Field has a porosity range varying from good to very good in quality and high hydrocarbon saturation of oil. Furthermore, the study revealed that J-P Field falls within the marginal marine depositional environment.

Introduction

The significance of crude oil in the Nigerian economy cannot be underrated, as it controls 90% of the nation's export revenues. More than two thirds of the generated revenues within the country are dependent on petroleum products. In recent times, there have been challenges in the Exploration and Production (E & P) companies within the Niger Delta, such as an unbalanced record of hydrocarbon reserves from wells as a result of leaking faults or prevention of hydrocarbon by a seal from being accumulated within the traps [1, 2]. These challenges had led to high uncertainties in reservoir properties which had greatly affected the E & P of some fields in the Niger Delta [2]. Improper interpretation of reservoir's properties has led to poor performance of reservoir during hydrocarbon production. Also, the constraints involved in prospecting for

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oil and gas in the modern world today need to be traced back to the origin of deposition and formation of reservoirs. It is imperative to integrate some of the following: basic geological knowledge (such as depositional history), structural interpretation, log data and modeling of depositional environments as parts of the requirements for a successful reservoir characterization. Characterization of reservoirs and depositional study has been an unconventional method in prospecting for hydrocarbon [3]. This study emphasizes on the use of this method to utilize the events that had occurred millions of years ago to predict the effect of depostional environment on the physical parameters of reservoirs.

Reservoir characterization is a quantitative measure to understand the dynamics of a reservoir [1, 3]. It encompasses all techniques and methods that could improve the understanding of geological and petrophysical parameters that control the fluid flow. The depositional study is the analysis of the depressed environment where sediments have been deposited. The geographical location, physical and chemical parameters, as well as the parent rock in that zone would determine the sediment type that is deposited in such environment. Identification of depositional environment is based on the lithology of the area, sedimentary structures and fossils present. Depositional environment is categorized into continental (terrestrial), marginal-marine and marine environment [4, 5]. The continental environment includes fluvial, alluvial, river (braided, meandering), desert (aeolian), lacustrine and glacial environment [4]. The marginal-marine environment includes beach, barrier-island, lagoonal, deltaic, estuary and tidal-flat environments. The marine environment includes shallow marine and deep marine environments [4]. Evaluation of log motifs is one of the means to analyze the paleodepositional environment [5].

Petrophysical study and determination of the environment of deposition of hydrocarbons have become vital in the analysis of well data. Due to this reason, the use of geophysical well logs and petrophysical analysis were put in place for this study to evaluate the reservoir's properties and understand the sedimentological factors that govern hydrocarbon accumulation in a reservoir [6]. The prolificacy of oil reservoirs can be determined using the results of the petrophysical analysis [7]. A prolific reservoir must be porous, permeable, oil saturated and greatly thick. Therefore, it is necessary to map reservoir sands and rank them using the petrophysical parameters [8].

Niger Delta basin has been explored greatly for diversifying issues, ranging from reservoir characterization [7–11] to structural analysis [1, 2, 12, 13], but few previous works have reported depositional environment in the Niger-Delta [14, 15]. The depositional environment study enables sound prediction and description of reservoir quality including its distribution [16]. In addition, if deposition of environment is integrated with petrophysical studies, it gives more understanding about the sedimentological features that could influence the fluid flow within the trap [17–19]. Therefore, the aim of this study is to characterize the identified reservoirs and to determine the paleodepositional environment of J-P Field, which varied between latitude 4° 29′ 58.50″ to 4° 30′ 10.50″ north and longitude 5° 59′ 55.00″ to 6° 01′ 0.10″ east in a shallow offshore of Niger Delta Basin, Nigeria. The objectives include delineation of hydrocarbon reservoirs, evaluation of petrophysical parameters, characterization of observed reservoirs and establishment of a presumed environment of deposition.

Geology of the study area

Niger Delta is one of the world's hydrocarbon producing basins with its formation dated back to the Tertiary age [20]. It is situated in the southern part of Nigeria, which shares a border with the Atlantic Ocean (Fig. 1a). It is housed within the Gulf of Guinea and covers both the onshore and offshore of the Delta's province [21], which is bounded by latitude 4° 0′ to 7° 30′ north and longitude 3° 0′ to 9° 0′ east (Fig. 1a). J-P Field is one of the shallow offshore fields in the Niger Delta Basin. Four oil producing wells are drilled on J-P Field, which is bounded by latitude 4° 29′ 58.50″ to 4° 30′ 10.50″ north and longitude 5° 59′ 55.00″ to 6° 01′ 0.10″ east (Fig. 1b). The development of the Delta that now resulted in a total thickness of more than 10 km began during Eocene [8]. The major source-rock in this region is the upper Akata Formation, marine shales and minute contributions from the interbedded marine shale beneath Agbada Formation [1, 7]. The major target for oil in Niger Delta is the sandstone facies of the Agbada Formation [22]. However, turbidite sands of the upper Akata Formation is a potential target both in the offshore and probably deeper layers below the current producing onshore of Niger Delta [7].

Hydrocarbon analysis in the Niger Delta entails an understanding of the geologic formation of this basin. As documented by [23] and other earlier researchers that have explored the Niger Delta basin, the geology of this basin is same as that of the triple junction point, which evolved during the African-South American Continental plates' breakage. The deposition of sediments in the Niger Delta started in the Paleocene era of Akata Formation. The three major formations within the tertiary Niger Delta basin include Akata, Agbada and Benin Formations. These formations have presented the prograding depositional facies that are distinguished utmostly based on sand-shale ratios [1, 2, 8, 14, 24–26].

The Akata Formation composes of thick shales and turbidite sands. A very minute amount of silt and clay are present in this formation. It is majorly referred to as the source rock and the mobile formation that squeezed into shale diapirs, which is produced due to the over-pressured nature of this formation in anaerobic conditions. Its total thickness is about 7 km (Fig. SM1). The marine facies, which is known as Agbada Formation, is described by both fresh water and deep sea attributes. This formation houses the hydrocarbons, which is known as the key player in exploration and production settings. The major reservoirs in Niger Delta Basin are the sandstones of the heterolithic Agbada Formation. The thickness of this formation based on [24] varies from 3.7 to ≈ 4.0 km (Fig. SM1). The lithologies of this formation are of alternating sands, silts and shales. The Benin Formation, the youngest of all, is composed of continental flood plain sands and alluvial deposits. It has a formation thickness of about 2 km (Fig. SM1). The age of these three formations is Paleocene, Eocene and Oligocene in the ascending order of their evolvement (that is, Akata-Agbada-Benin) [24].

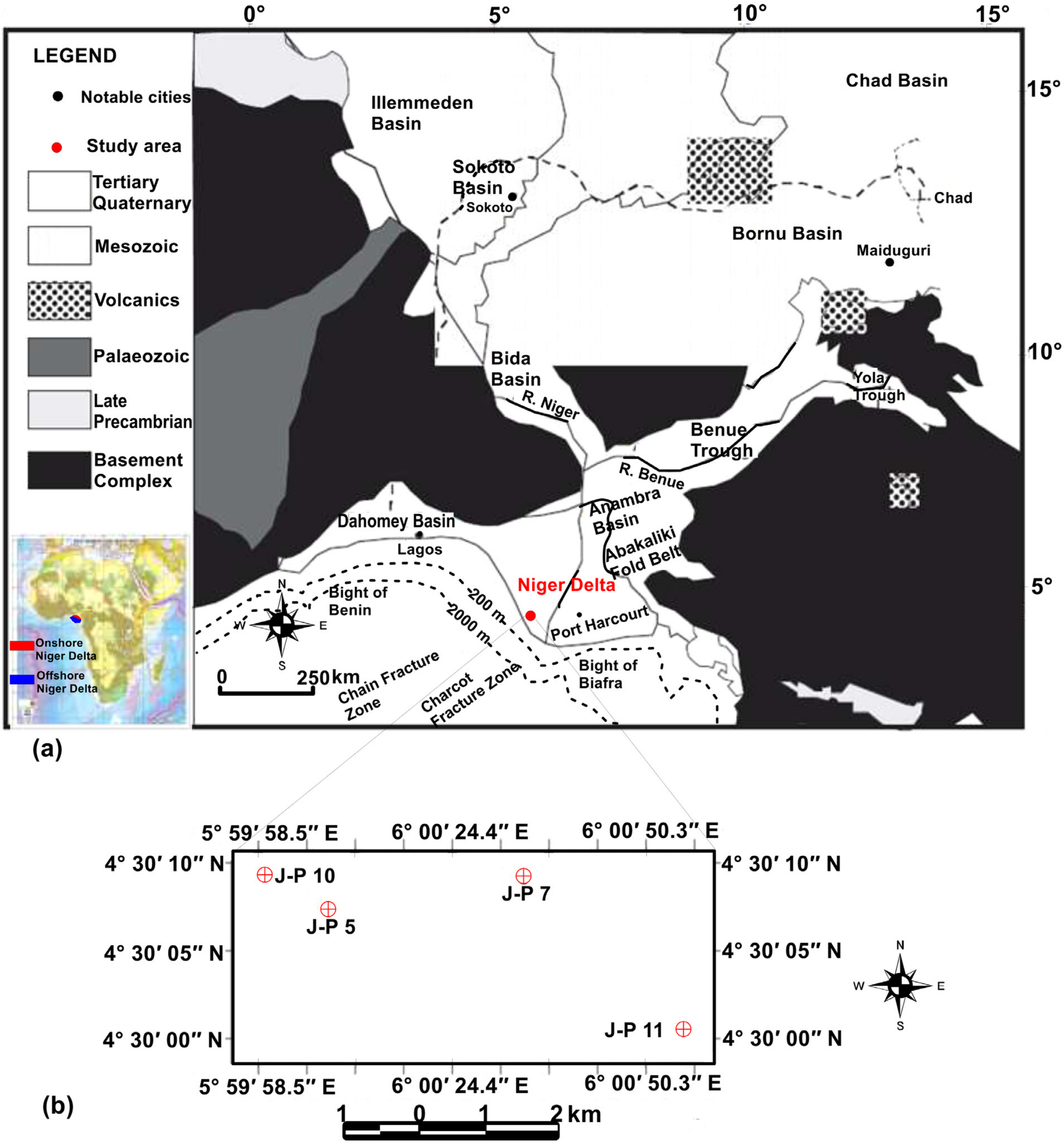

Fig. 1. (a) Geology of Nigeria showing the Niger Delta Province (modified from [21]), (b) Base map of J-P Field, Niger Delta.

Materials and methods

Four digital well log suites, which are composed of Gamma Ray (GR), resistivity, sonic and density logs are used for the study. The approach used in this study is based on the petrophysical evaluation of J-P Field, GR response to variations in grain size and the geological knowledge of the Niger Delta Basin, which was adopted from Adiela and Odiri [22] and Oyanyan et al. [25]. Gamma Ray log is a measurement of natural radioactivity of the formation. The log normally reflects the shale contents formation in a sedimentary formation. This is the radioactive concentration of elements in clay and shales. A low level of radioactive elements indicates a sandstone formation, unless radioactive contaminants such as volcanic ash or granite ash are present. Meanwhile, a high level of radioactive elements indicates a shale formation [1]. The total gamma ray level is recorded and plotted in API units which vary from 0 to 150 API.

The workflow for the study is presented in Fig. SM2. The well log data were loaded to Schlumberger Petrel software for data processing. Four wells (named J-P 5, 7, 10 and 11) as revealed in Fig. 1b were used for the study. Reservoirs (sandstones) were identified and correlated across the loaded wells. Petrophysical properties such as porosity (ϕ), water saturation (S_w), hydrocarbon saturation (S_h) and shale volume (V_{sh}) were determined to characterize each reservoir according to its ability to hold hydrocarbon. Depositional environments were identified based on the characteristics of shapes and variations on GR logs.

Interpretation procedures

For petrophysics, qualitative and quantitative interpretations are the two popular ways to interpret well log data and were adopted in this study [1].

Qualitative interpretation entails visual inspection of the shapes, patterns and signatures of the log. GR log is used to define the lithologic type. Hydrocarbon bearing zones could be determined using a resistivity log, while density and neutron logs are employed for mapping the fluid contact [1, 7, 8].

The quantitative interpretation of J-P Field is achieved by using the mathematical models for petrophysical properties to enable the characterization of the available reservoirs. Porosity is one of the petrophysical parameters that determine the amount of fluids that the pore spaces within a rock could hold. It could be categorized as total or effective. Total porosity determines the viability of all the interconnected and isolated pore spaces for fluid accumulation, while effective porosity only accounts for the interconnected pore spaces [27].

Density porosity (φ_{den}) can be determined using Eq. (1) as given by [27].

$$\varphi_{den} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \tag{1}$$

where ρ_{ma} is the matrix density, ρ_b or RHOB is the bulk density and ρ_f is the fluid density. In order to determine the φ_{den}, ρ_{ma} and ρ_f must be known. For estimation of total porosity (φ_t), ρ_{ma} is replaced as particle density, which is assumed as 2.65 gcm^{-3} for sandstone [27], while ρ_f for oil, water and gas are 0.87, 1.00 and 0.65 gcm^{-3}, respectively. However, φ_t can be determined by Eq. (2).

$$\varphi_t = \frac{(2.65 - \rho_b)}{(2.65 - 0.87)} \tag{2}$$

In Eq. (2), $\rho_f = 0.87$. This condition is valid if the two porosity (RHOB and neutron (PHIN)) curves for a hydrocarbon reservoir separate from each other and RHOB log value is less than PHIN log value, provided that the log matrix lithology is known [27].

Determination of effective porosity (φ_e) is as shown in Eq. (3).

$$\varphi_e = \varphi_t \times (1 - V_{sh}) \tag{3}$$

Evaluation of the amount of the hydrocarbons present in the reservoir is based on estimation of the volume of water present in the pore spaces. This requires the breakthrough of some form of “Archie Equation” [28] for the water saturation parameter S_w. When a hydrocarbon is present in the core, the nonconductive hydrocarbon reduces the cross-sectional area and blocks flow-paths in the rock; this effect increases the resistivity of the rock. In an oil-wet system resistivity will decrease at a great rate (with respect to brine saturation) than it does in a water-wet system [27].

Water saturation (S_w) is the ratio of the volume of water in the pore space to the total volume of the pore spaces in a rock. By using Archie's relationship as presented in Eq. (4), S_w could be determined.

$$S_w^n = \frac{R_w}{(\varphi^m \times R_t)} \tag{4}$$

where n and m are the saturation and cementation exponents, n varies from 1.8 to 4.0, while m varies from 1.7 to 3.0, but the default value for the two exponents is usually 2.0. R_w is the formation water resistivity and R_t is the true resistivity of the formation.

Hydrocarbon saturation (S_h) is the fraction of pore volume occupied by hydrocarbon. It can be estimated by Eq. (5)

$$S_h = 1 - -S_w \tag{5}$$

In order to compute the V_{sh}, the GR index (I_{GR}) needs to be determined as shown in Eq. (6).

$$I_{GR} = \frac{GR_{\log} - GR_{\min}}{GR_{\max} - GR_{\min}} \tag{6}$$

where GR_{log} is the GR reading of formation, GR_{min} is the minimum GR (i.e. sand) and GR_{max} is the maximum GR (i.e. shale).

$$V_{sh} = 0.83\left(2^{(3.7\times I_{GR})} - 1.0\right) \tag{7}$$

The yardsticks for characterization of the reservoirs in J-P Field were modified from [1, 8] and [29] as revealed in Table 1.

Table 1
Characterization of reservoirs based on ϕ and V_{sh} (modified from [1,8,29]).

Porosity (%)	Interpretation	Volume of shale (%)	Interpretation
0 – 5	Negligible	< 5	Clean sand
5 – 10	Poor	5 – 15	Slightly shaly sand
10 – 15	Fair	15 – 25	Shaly sand
15 – 20	Good	25 – 35	Very shaly
20 – 30	Very Good	> 35	Shale

The pattern of the curve as depicted by the GR log is a function of the grain size variations within a reservoir [30] as shown in figure SM3. This implies that the pattern of the GR curve indicates the degree of sand-to-shale content in a reservoir [31]. The three basic depositional environments are shown in figure SM3 are aggrading, prograding and retrograding environments. The general GR response to variations in grain size according to [32] was used for the identification of the character of curves for depositional study. The responses are categorized into five trends as highlighted in figure SM3. These trends are bell, funnel, cylindrical, symmetrical and irregular or serrated shape trends.

The bell-shaped pattern increases upwards in the GR values. It occurs in three environments [33–35] which include tidal or deep tidal channels, transgressive shelf sand and fluvial or deltaic channels. It can be smooth or serrated. It indicates a regular upward increase (from minimum to maximum point) in GR value, indicating an increase in clay content. This pattern could also be referred to as a dirtying-up shape trend.

The funnel shape pattern decreases upwardly in the GR values. It is characterized by a coarsening upward succession. According to Selley [33], three environments are identified for a coarsening upward succession, which includes regressive barrier bars, prograding submarine fans and prograding delta or crevasse splays. As published by Selley [33], the regressive barrier bars and prograding submarine fans are commonly deposited with glauconite, shell debris, carbonaceous detritus and mica. The prograding delta is differentiated from the crevasse splays based on the depositional scale. It is relatively large while the crevasse splay is thin. The prograding delta can also be referred to as a cleaning-up shape trend.

Cylindrical shape pattern depicts low gamma-ray value, sharp boundaries with no internal variation in its trend. Three general categories of environments can form cylindrical shaped trends [33]. These environments include tidal sand waves, grain flow fill and delta distributary channels. Tidal sand wave and grain flow fill are commonly associated with glauconite and shell debris [34–36]. It is also known as the boxcar shape trend.

Symmetrical shape pattern shows both prograding and retrograding depositional patterns. This signifies that it combines the pattern of both funnel and bell shapes. It has a gradual decrease and increases in GR values, it is known as a bow shaped trend.

The serrated shape pattern is of an aggrading depositional pattern. It depicts a high GR value with sharp boundaries. It has no internal changes. The pattern of its curve looks like saw teeth and is thus referred to as an irregular shape trend.

Results and discussion

Sandstone and shale are the two lithologic units that were identified from the GR logs in J-P Field. The yellow section depicts sandstone while the black depicts shale. The GR cut-off for all wells in this study is within 0 and 150 API, where 0 to 70 API is for sandstone and 71 to 150 API is for shale. Seven (7) sandstone bodies (namely from top to bottom as: C-100, A-100, C-200, C-300, A-200, C-400 and C-500) were correlated across the four wells (J-P 5, 7, 10 and 11) used (Fig. 2). As discussed in Section 2, the seven delineated sandstone reservoirs are within Agbada Formation which was deposited in Eocene era. Agbada Formation serves as the main hydrocarbon reservoirs of the Niger Delta Basin. Reservoir C-500 is delineated at the base of Agbada Formation, which is in agreement with the work of Adagunodo et al. [1] who mapped the base of Jemir field at about 3863 m. The Akata formation was not penetrated by the wells in this current study due to disconformities in the interface between Akata and Agbada formations. The Agbada Formation extends throughout the Niger Delta clastic wedge which has a maximum thickness of approximately 4000 m [24]. Meanwhile, the deposition of the source rocks of the Akata Formation started in the Paleocene era (See Fig. SM1).

Petrophysical evaluation and reservoir characterization of J-P field

The petrophysical results of the four wells (J-P 5, J-P 7, J-P 10 and J-P 11) in J-P Field are shown in Table 2. The petrophysical results per each well as presented in Table 2 are in accordance to the well's arrangements on the correlation interface as shown in Fig. 2. Seven sandstone reservoirs were delineated from each well. Parameters such as reservoir's thickness, gross thickness, net thickness, volume of shale, total porosity, water saturation and hydrocarbon saturation which were estimated from the highlighted methods in Section 3 are presented in Table 2. In J-P 10, the total porosity, water saturation and hydrocarbon saturation of the delineated reservoirs varied from 19 to 22%, 25 to 71% and 29 to 75%, respectively. In J-P 5, the total porosity, water saturation and hydrocarbon saturation of the delineated reservoirs varied from 18 to 26%, 17 to 70% and 30 to 83%, respectively. In J-P 7, the total porosity, water saturation and hydrocarbon saturation of the delineated

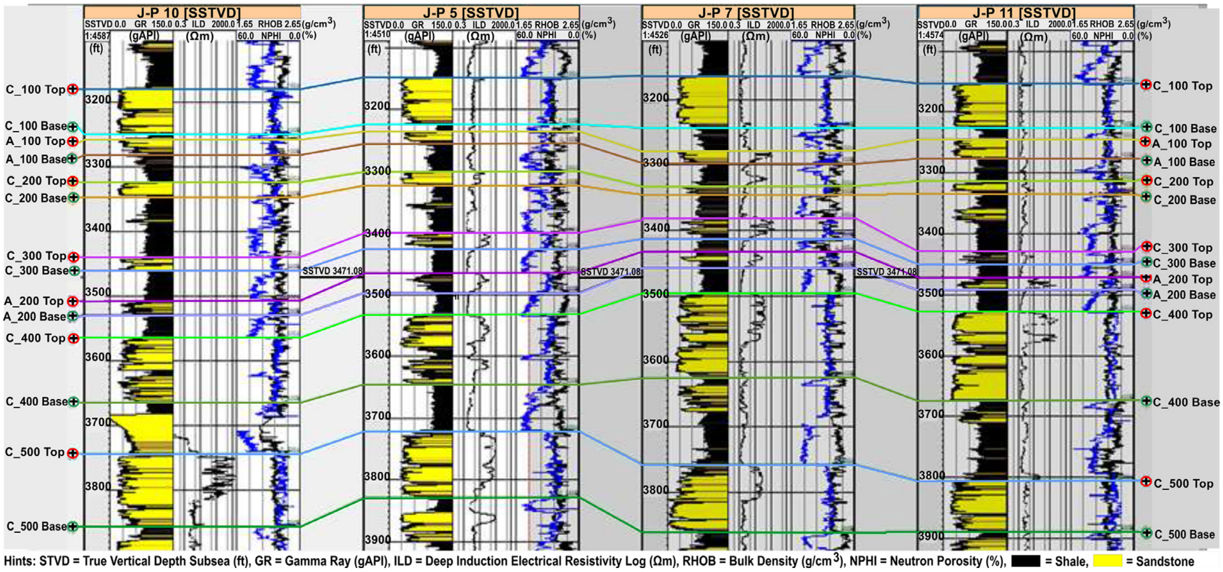

Fig. 2. Correlation of reservoir sands across wells J-P 10, J-P 5, J-P 7 and J-P 11 in J-P Field.

reservoirs varied from 16 to 21%, 29 to 54% and 46 to 71%, respectively. In J-P 11, the total porosity, water saturation and hydrocarbon saturation of the delineated reservoirs varied from 17 to 23%, 6 to 80% and 20 to 94%, respectively.

Furthermore, the NTG which defines the productivity of each reservoir for hydrocarbon exploitation was determined. In order to determine the level of interconnected pores that supports the fluid flow in each reservoir, the effective porosity of each reservoir was also estimated. The NTG and $Ø_e$ for the reservoirs in J-P 10 varied from 0.69 to 0.90 and 14 to 20%. The NTG and $Ø_e$ for the reservoirs in J-P 5 varied from 0.20 to 0.87 and 12 to 18%. The NTG and $Ø_e$ for the reservoirs in J-P 7 varied from 0.76 to 0.82 and 13 to 17%. The NTG and $Ø_e$ for the reservoirs in J-P 11 varied from 0.74 to 0.88 and 13 to 20%. In the ranking of porosity values as presented by Bayowa et al. [8], 0 to 5%, 5 to 10%, 10 to 15%, 15 to 20%, 20 to 30% and > 30% porosity values are ranked as negligible, poor, fair, good, very good and excellent qualities for reservoirs. In this study, the effective porosity of all the reservoirs in J-P Field varied from 12 to 20% which corresponds to a fair and good reservoir quality, which is in agreement with the work of Bayowa et al. [8] who evaluated the petrophysical properties of reservoirs in "BAO" Field, Niger Delta.

The average petrophysical results of the seven reservoirs that were delineated and correlated in J-P Field were characterized according to their capability for hydrocarbon accumulation as indicated in Table 3. Reservoir C-100 has an average thickness of 76 m across the four wells (Table 3), with an average total porosity of 21%. The NTG and the effective porosity of C-100 are 0.85 and 19%, respectively. The values for the effective porosity and total porosity in C-100 are between good and a very good reservoir quality as described by Bayowa et al. [8]. This shows that the pore spaces in C-100 are sufficient enough to hold an appreciable amount of hydrocarbon. It has a high ratio of water saturation (52%) than hydrocarbon saturation (48%) of oil. The volume of shale is 15% indicating that it contains more clean sand than shaly sand.

Reservoir A-100 has an average thickness of 24 m across the four wells (Table 3), with an average total porosity of 19%. The NTG and the effective porosity of A-100 are 0.64 and 15%, respectively. The values for the effective porosity and total porosity in A-100 are within the range of a good reservoir quality. This shows that the pore spaces in C-100 are sufficient enough to hold hydrocarbon moderately. It has a lesser ratio of water saturation (40%) than hydrocarbon saturation (60%) of oil. The volume of shale is 25% implying that it is a shaly sand unit.

Reservoir C-200 has an average thickness of 25 m across the four wells, with an average porosity of 21% (Table 3). The NTG and the effective porosity of C-200 are 0.72 and 16%, respectively. The values for the effective porosity and total porosity in C-200 are within the range of a good reservoir quality. This shows that the pore spaces in C-200 are sufficient enough to hold hydrocarbon moderately. It has a high ratio of water saturation (58%) than hydrocarbon saturation (42%) of oil. The volume of shale is 28%, which implies that it is a shaly sand unit.

Reservoir C-300 has an average thickness of 25 m across the four wells with an average porosity of 20%. The NTG and the effective porosity of C-300 are 0.71 and 14%, respectively. The values for the effective porosity and total porosity in C-300 are within the range of a fair and a good reservoir quality. This shows that the pore spaces in C-300 are fairly good to hold hydrocarbon. It has a hydrocarbon saturation (53%) of oil and water saturation of 47% (Table 3). The volume of shale is 29%, which represents a shaly sand unit.

Reservoir A-200 has an average thickness of 25 m across the four wells with an average porosity of 20%. The NTG and the effective porosity of A-200 are 0.73 and 14%, respectively. The values for the effective porosity and total porosity in A-200 are within the range of a fair and a good reservoir quality. This shows that the pore spaces in A-200 are fairly good

Table 2
Petrophysical parameters of J-P Field.

Reservoir	Depth(Top-Bottom) (m)	Gross thickness (m)	Net thickness (m)	V_{sh} (%)	NTG (Frac.)	$Ø_t$ (%)	$Ø_e$ (%)	S_w (%)	S_h (%)
J-P 10									
C-100	3178–3250	72	61.9	14	0.86	22	20	53	47
A-100	3258–3282	24	19.0	21	0.79	20	17	35	65
C-200	3324–3348	24	16.6	31	0.69	19	14	45	55
C-300	3442–3462	20	14.0	30	0.70	21	15	25	75
A-200	3508–3530	22	15.8	28	0.72	19	14	71	29
C-400	3565–3664	99	80.2	18	0.81	20	17	35	65
C-500	3743–3856	113	101.7	10	0.90	21	19	30	70
J-P 5									
C-100	3147–3224	77	64.7	16	0.84	21	18	45	55
A-100	3235–3256	21	4.2	33	0.20	20	14	47	53
C-200	3299–3322	23	15.4	33	0.67	26	18	70	30
C-300	3399–3426	27	17.6	35	0.65	18	12	30	70
A-200	3464–3494	30	19.8	34	0.66	19	12	66	34
C-400	3531–3645	114	90.1	21	0.79	20	16	34	66
C-500	3722–3828	106	92.2	13	0.87	19	17	17	83
J-P 7									
C-100	3164–3244	80	64.8	19	0.81	19	16	54	46
A-100	3278–3297	19	14.6	23	0.77	17	13	48	52
C-200	3315–3346	31	24.2	22	0.78	21	17	40	60
C-300	3383–3412	29	22.0	24	0.76	21	16	53	47
A-200	3432–3457	25	19.5	22	0.78	20	16	32	68
C-400	3494–3624	130	106.6	18	0.82	20	16	29	71
C-500	3757–3861	104	81.1	21	0.78	16	13	36	64
J-P 11									
C-100	3153–3226	73	64.2	12	0.88	23	20	55	45
A-100	3244–3277	33	26.1	21	0.79	21	17	31	69
C-200	3312–3334	22	16.3	26	0.74	17	13	76	24
C-300	3428–3451	23	17.0	26	0.74	19	14	80	20
A-200	3471–3493	22	16.5	25	0.75	20	15	71	29
C-400	3528–3674	146	128.5	12	0.88	21	19	49	51
C-500	3791–3888	97	82.5	15	0.85	22	19	6	94

Hint: NTG means Net-to-gross.

Table 3
Mean petrophysical values of the delineated reservoirs.

Reservoir	Gross thickness (m)	Net thickness (m)	V_{sh} (%)	NTG (Frac.)	$Ø_t$ (%)	$Ø_e$ (%)	S_w (%)	S_h (%)
C-100	76	64	15	0.85	21	19	52	48
A-100	24	16	25	0.64	20	15	40	60
C-200	25	18	28	0.72	21	16	58	42
C-300	25	18	29	0.71	20	14	47	53
A-200	25	18	27	0.73	20	14	60	40
C-400	122	101	17	0.83	20	17	37	63
C-500	105	89	15	0.85	20	17	22	78
Mean	57	46	22	0.76	20	16	45	55

to hold hydrocarbon. It has a low hydrocarbon saturation ratio (40%) of oil in comparison with high water saturation of 60%. The volume of shale is 27% (Table 3), which means it is a shaly sand unit.

Reservoir C-400 has an average thickness of 122 m across the four wells (Table 3), with an average porosity of 20%. The NTG and the effective porosity of C-400 are 0.83 and 17%, respectively. The values for the effective porosity and total porosity in C-400 are within the range of a good reservoir quality. This shows that the pore spaces in C-400 are sufficient enough to hold hydrocarbon moderately. It has a high hydrocarbon saturation ratio (63%) of oil and water saturation of 37%. The volume of shale is 17%, showing that it contains more clean sand than shaly sand.

Reservoir C-500 has an average thickness of 105 m across the four wells, with an average porosity of 19%. The NTG and the effective porosity of C-500 are 0.85 and 17%, respectively. The values for the effective porosity and total porosity in C-500 are within the range of a good reservoir quality. This shows that the pore spaces in C-500 are sufficient enough to hold hydrocarbon moderately. It has a high hydrocarbon ratio (78%) of oil and water saturation of 22%. The volume of shale is 15% (Table 3), which reveals that it contains more clean sand than shaly sand.

It was observed in Table 3 that the volume of shale in A-100 > C-100, yet the hydrocarbon saturation of A-100 > C-100. Also, the volume of shale in C-100 is the same as that of C-500, yet the hydrocarbon saturation of C-500 > C-100. Reservoir A-100 in Table 3 accounts for the mean value of A-100 in J-P 10, J-P 5, J-P 7 and J-P 11, respectively. The same thing occurs in the estimation of other parameters, because the estimated parameter in Table 3 is the mean value of the

Table 4
Summary of Paleodepositional analysis of well logs in J-P field.

SAND UNIT	J-P 10	J-P 5	J-P 7	J-P 11
C-100	Cylindrical	Cylindrical	Cylindrical	Cylindrical
A-100	Funnel	Funnel	Funnel	Cylindrical
C-200	Cylindrical	Bell	Funnel	Funnel
C-300	Bell	Funnel	Funnel	Funnel
A-200	Funnel	Bell	Funnel	Bell
C-400	Bell	Bell	Cylindrical	Cylindrical
C-500	Cylindrical	Cylindrical	Bell	Cylindrical

entire reservoir in question in all the four wells. These variations are due to the responses of each reservoir from each well as shown in Table 2. The overall mean result of NTG (0.76) showed that the productive zones within the reservoirs are above average. The effective porosity and the total porosity are 16 and 20%. This shows that on average, the reservoirs in J-P Field are capable to hold hydrocarbon moderately [1, 8]. The overall mean results of volume of shale, water saturation and hydrocarbon saturation are 22%, 45% and 55%. These values further confirm that a tendency to produce high hydrocarbon ratio above average exist within the reservoirs in J-P Field.

Paleodepositional analysis of J-P wells

The paleodepositional environment study of the GR logs in J-P Field revealed that the log trends fall mostly into three categories of log motifs namely: funnel, cylindrical and bell shaped successions as shown in Table 4.

Funnel-shaped successions

The funnel shaped log motif occurred on A-100 (3235 to 3256 m depth with 21 m thickness) and C-300 (3399 to 3426 m depth with 27 m thickness) in J-P 5, A-100 (3278 to 3297 m depth with 19 m thickness), C-200 (3215 to 3346 m depth with 31 m thickness), A-200 (3432 to 3457 m depth with 25 m thickness) and C-300 (3383 to 3412 m depth with 29 m thickness) in J-P 7, A-100 (3258 to 3282 m depth with 24 m thickness) and A-200 (3508 to 3530 m depth with 22 m thickness) in J-P 10, C-200 (3212 to 3334 m depth with 22 m thickness), C-300 (3428 to 3451 m depth with 23 m thickness) in J-P 11, respectively (Table 4). It is dominant in C-200 at depth 3315 to 3346 m in J-P 7 (with a thickness of 31 m). The trend is usually interpreted to indicate deposition of cleaning upward sediment or an increase in the sand grain size of the turbidite bodies, as applied to a deep marine setting. The funnel shaped log motif in this study is in agreement with the works of Kalu and Co-authors [3, 22, 26] and [37] from Niger Delta. A notable difference between a crevasse splay and a prograding delta is the depositional thickness. At the range of 19–31 m, the funnel shaped log motifs tend to be prograding delta or prograding marine shelf [38] because the crevasse splay is relatively thin [36].

Cylindrical shaped successions

Cylindrical shaped log motif was observed on C-100 at 3147 to 3224 m depth with 77 m thickness, 3178 to 3250 m depth with 72 m thickness, 3164 to 3244 m depth with 80 m thickness and 3153 to 3226 m depth with 73 m thickness across the four wells. Also, the cylindrical shape was observed on C-500 (3722 to 3828 m depth with 106 m thickness) in J-P 5, C-400 (3494 to 3624 m depth with 130 m thickness) in J-P 7, C-200 (3324 to 3348 m depth with 24 m thickness) and C-500 (3743 to 3856 m depth with 113 m thickness) in J-P 10, C-100 (3153 to 3226 m depth with 73 m thickness), A-100 (3244 to 3277 m depth with 33 m thickness), C-400 (3528 to 3674 m depth with 146 m thickness) and C-500 (3791 to 3888 m depth with 97 m thickness) in J-P 11, respectively (Table 4). The thickness of the cylindrical gamma ray log shapes in the wells varied from 24 to 146 m. According to Emery and Myers [32], cylindrical trends with a greater range of thickness indicate turbidite sands. Considering only the log motifs, the environment of deposition could be that of a tidal sand wave, grain flow fill, or delta distributary channel. The cylindrical shaped log motif in this study is in agreement with the works of Kalu et al. [3] from Niger Delta.

Bell shaped successions

Bell shaped log motif was observed on C-200 (3299 to 3322 m depth with 23 m thickness), A-200 (3464 to 3494 m depth with 30 m thickness) and C-400 (3531 to 3645 m depth with 114 m thickness) in J-P 5, C-300 (3442 to 3462 m depth with 20 m thickness) and C-400 (3565 to 3664 m depth with 99 m thickness) in J-P 10, A-200 (3312 to 3334 m depth with 22 m thickness) in J-P 11, C-500 (3757 to 3861 m depth with 104 m thickness) in J-P 7, respectively (Table 4). The bell-shaped successions are usually indicative of transgressive sand, tidal channel or deep tidal channel and fluvial or deltaic channel. As reported by Nelson and James [39], tidal channels commonly contain glauconite and shell debris. Carbonaceous detritus is associated with fluvial or deltaic channels [33]. Although core samples and biostratigraphic data are not available to establish this, a thin bell shaped succession observed across the wells suggest that the sands were deposited in a transgressive marine setting [40], which is in agreements with the works of Kalu and Co-authors [3, 22, 26] and [37] from Niger Delta Basin. The reservoir sands in J-P Field are presumed to be deposited within marginal marine environments which include prograding delta or marine shelf, tidal sand wave, grain flow fill or a delta distributary channel and transgressive marine sands.

Conclusion

In this study, seven probable hydrocarbon bearing reservoirs (C-100, A-100, C-200, C-300, A-200, C-400 and C-500) of varying thicknesses were identified and they have been considered to be economically viable. The characterization of the reservoirs through a detailed estimation of petrophysical parameters showed that the reservoir quality is greatly influenced by good porosity due to the presence of sand bodies. The average water saturation for these reservoirs varied from 22 to 60%, while hydrocarbon saturation varied from 40 to 78%. The petrophysical parameters obtained in this study indicated that the wells in J-P Field have a high hydrocarbon saturation of oil. The three facies that were recognized from the depositional study are cylindrical-, funnel- and bell-shaped facies. It is concluded that the reservoir sands in J-P Field were deposited in marginal marine environments which is in agreement with the works of Adiela and Odiri [22], Oyanyan et al. [25] and Adeila and Jayeola [26].

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Declaration of Competing Interest

The authors declare no conflict of interest.

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Supplementary materials

Supplementary data associated with this article can be found, in the online version, at doi:10.1016/j.sciaf.2021.e01064.

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