ZIBELINE INTERNATIONAL PUBLISHING

ISSN: 2521-0920 (Print)

ISSN: 2521-0602 (Online)

CODEN: MJGAAN

CrossMark

RESEARCH ARTICLE

PETROPHYSICAL EVALUATION OF RESERVOIRS FOR HYDROCARBON RESERVE ESTIMATION IN EASTERN CENTRAL SWAMP DEPOBELT, NIGER DELTA

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ARTICLE DETAILS

Article History:

Received 25 March 2020

Accepted 27 April 2020

Available online 18 May 2020

ABSTRACT

Petrophysical properties were evaluated in five wells in eastern Central Swamp Depobelt, Niger Delta using well logs. Analyses by Kingdom Suite software reveal that reservoirs' thicknesses ranged between 24.5ft in SNG in Afam 16 to 200.5ft in SNB in Obeakpu 005. Volume of shale varies within and across all the wells with values <30% of the total thicknesses. Relative permeability to water (K_{rw}) ranges from 0.00 to >1.00 across the wells. Reservoirs SNE and SNF in Afam 16 have average K_{rw} of 0.00 implying 100% water-free hydrocarbon production. SNC reservoir in Afam 15 and Afam 16 has average K_{rw} >1 implying 100% water production. The relative permeability to oil (K_{ro}) is very high in reservoirs with high hydrocarbon saturation. SNH in Korokoro 006 has average hydrocarbon saturation of 85.70% and K_{ro} of 0.89. SNB in Obeakpu 005 has average absolute permeability of 62,086.9mD. Reservoirs SNB, SNC and SND contain no producible hydrocarbon in Afam 15 but contain producible hydrocarbon in Afam 16, Korokoro 003 and Obeakpu 005 wells. Reservoirs SNE, SNF, SNG and SNH in Afam 15, Afam 16, Korokoro 003 and Korokoro 006 contain producible hydrocarbon with the exception of SNF in Korokoro 003. Afam 15 and Afam 16 are mainly gas-producing with estimated gas-in-place ranging from 72,630.27cu.ft/acre in SNB in Afam 15 to 1,534,667.86cu.ft/acre in SNH in Afam 16 while Korokoro 003, Korokoro 006 and Obeakpu 005 are mainly oil-producing with estimated oil-in-place ranging from 47,590.26bbl/acre in SNB in Korokoro 003 and 387,754.83bbl/acre in SNB in Obeakpu 005.

KEYWORDS

Petrophysical Properties, Reservoirs, Well Logs, Central Swamp Depobelt, Niger Delta.

1. INTRODUCTION

The evaluation of petrophysical properties of reservoirs is an important phase in converting information from raw log data into estimated quantities of oil, gas, and water in a formation. These estimated quantities are used to evaluate reservoirs and determine whether a well completion is necessary. Some of the essential petrophysical parameters needed to evaluate reservoirs include: porosity, permeability, lithology and reservoir thicknesses, formation resistivity factor, water saturation, hydrocarbon saturation, movable oil saturation, index of oil movability, bulk volume water and bulk volume oil (Schlumberger, 1989). This study is aimed at effectively and optimally delineating reservoirs necessary to accurately interpret hydrocarbon distribution in the sedimentary fill of eastern Central Swamp Depobelt, Niger Delta with the objectives of estimating reservoir thicknesses, volume of shale, effective porosity, water and hydrocarbon saturations, relative and absolute permeabilities and gas-in-place and oil-in-place of the different reservoirs in wells by petrophysical analyses.

Several researches have been conducted to evaluate reservoirs and estimate the hydrocarbon potential of different parts of the Niger Delta. Kalu et al., 2020 re-evaluated Emerald Field in the Niger Delta Basin, Nigeria using analyses of well logs, seismic facies, petrophysical and seismic attributes to produce 3D structural model of the Field as well as identify and estimate the petrophysical properties of the reservoirs in the

Field. Results show that 3 hydrocarbon-bearing reservoirs: Emy A, B and C were penetrated by the 4 wells studied. The results also reveal that reservoir porosity ranges from 10 to 29%, hydrocarbon saturation ranges from 0.75 to 0.84, water saturation ranges from 0.16 to 0.25, volume of shale ranges from 0.24 to 0.33 and net-to-gross ranges from 0.72 to 0.93. Five seismic facies were identified within the study area. Results also suggest that the environment of deposition at different locations within the Field are distributary channel fills, overbank and floodplain deposits, which depicts paralic zone. Two prospects (Emerald prospects A and B) and one lead were identified within the study area. The risk evaluation and estimated volume of hydrocarbon-in-place ranked Emerald prospect B as the highest.

A group of researchers identified reservoirs as well as hydrocarbon presence and determined petrophysical parameters using well and seismic data in TIM Field, south-western offshore Niger Delta (Nwaezeapu et al., 2019). Three horizons corresponding to selected sands tops (sands D, E and F) were mapped. Results of the analysis show an average porosity value of 0.23, water saturation value of 0.32 and an average net-to-gross value of 0.62. The total hydrocarbon proven reserves for mapped horizons (sand D, E, and F) were evaluated to be 39.04MMBO of oil, and 166.13BCF of gas for sand E. More so, Saadu and Nwankwo, 2018 evaluated the petrophysical parameters and hydrocarbon volume from seismic and well logs data within the Central Swamp Depobelt in the Niger Delta. Two reservoirs, GA and GB were delineated from the logs. Two horizons and

Quick Response Code

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Website:
www.myjgeosc.com

DOI:
[10.26480/mjg.02.2020.79.85](http://doi.org/10.26480/mjg.02.2020.79.85)

several faults were mapped from the seismic sections. The faults mapped are mainly synthetic and antithetic, characteristic of the Niger Delta. The average porosity and permeability estimated for reservoir GA are 20% and 1338mD respectively. Similarly, the estimated average porosity and permeability for reservoir GB are 21% and 1392mD respectively. The results show that the oil-bearing zones in the reservoirs are porous and highly permeable. There was no gas present in either of the reservoirs. The estimated initial hydrocarbon-in-place for reservoirs GA and GB are 57.84 MMSTB and 48.43 MMSTB respectively.

Alaminiokuma and Ofuyah, 2017 delineated porosity and permeability regimes in hydrocarbon-bearing reservoirs of Nembe Creek Field, Niger Delta by digitizing and correlating gamma ray, resistivity, and density logs from three wells: Nembe 01, Nembe 02 and Nembe 03 respectively. Results obtained from the analyses of these composite logs reveal eight potential hydrocarbon-bearing reservoirs. These reservoir sands were observed to have very good to excellent average porosities ranging from 29 to 45%. Permeability values were excellent within these reservoirs and range from 2200 to 5789mD. Hydrocarbon saturation was observed to be high in all the reservoir sands, ranging from 64 to 81% with corresponding water saturation from 19 to 36%. The regimes observed indicate that porosity and permeability increase with depth.

Another group of researchers evaluated petrophysical parameters, identified reservoirs and hydrocarbon presence in Greater Ughelli Depobelt of Niger Delta using 3D seismic and well data (Emina et al., 2016). Four hydrocarbon-bearing reservoirs within the depth range of 6743 to 9045ft, having volume of shale (V_{sh}) ranging from 15.32 to 29.06% were interpreted. The total porosity of the reservoirs ranges from 24.63 to 34.01%, while the effective porosity ranges from 17.26 to 31.71%, indicating that the reservoirs have very good porosities. The ratio of the net-to-gross thickness of the reservoirs ranges from 0.720 to 0.980 while the water saturation values range from 19.87 to 29.07%. From the water saturation deductions, the hydrocarbon saturation ranges from 70.93 to 78.86% of gas in the given reservoir.

Accordingly, this study which focuses on appraising hydrocarbon reservoirs based on petrophysical parameters is beneficial in delineating zones of overpressure, reservoirs geometries, estimating hydrocarbon reserves and in discriminating gas, oil and water bearing zones in the Niger Delta.

2. LOCATION AND BRIEF GEOLOGY OF THE STUDY AREA

2.1 Location of the Study Area

Figure 1: Map of the Niger Delta showing Depobelts and location of the study area - eastern Central Swamp Depobelt (Doust and Omatsola 1990).

The study area is located within OML 11 in the eastern part of the Central Swamp Depobelt of the Tertiary Niger Delta (Figure 1). The Central Swamp Depobelt is one of the most prolific oil provinces in the whole of the Niger Delta as revealed by the sheer number of fields, sizes, reserves and production levels (Ozumba, 2018).

2.2 Brief Geology of the Study Area

In the conventional sections, collapsed crests grading into the K-type and faulted rollover structures characterize the study area. At depth, this trend is also characterized by mainly deep footwall closures with some hanging wall components in a limited sense (Ozumba, 2018). Sedimentation within the Central Swamp Depobelt was mainly wave-dominated and the activity of the Opuama Canyon has been initiated on the north-western flank of the Delta (Petters, 1984). The oldest sediments in the Central Swamp Depobelt are dated around the Latest Oligocene. Sedimentation in this area was mainly starved at this time as only shales of the Akata Formation were deposited (Corredor et al., 2005). Deposition of the paralic facies (Agbada Formation) probably took place from the earliest Miocene times onwards.

3. METHODOLOGY

3.1 Wells Location and Field Data

The petrophysical parameters are evaluated by digitizing, correlating and computing Gamma Ray, Spontaneous Potential, Resistivity, Neutron, Sonic and Density logs from Wells: Afam 15 & 16, Korokoro 003 & 006 and Obeakpu 005 using the Seismic Micro Technology (SMT, Kingdom Suite) software. Figure 2 is the base map showing the well locations in the study area.

Figure 2: Base map showing well locations in the study area

3.2 Delineation of Lithology and Hydrocarbon-bearing Zones

Gamma Ray (GR) and Spontaneous Potential (SP) logs were digitized to delineate the lithology penetrated by the Wells. A combination of GR log and induction resistivity logs were analyzed to delineate the hydrocarbon-bearing sands (Timur, 1968). Zones of possible oil accumulations are indicated by high resistivity values whereas water zones have low resistivity values. Figure 3 shows the lateral correlation of the reservoir sands across the Wells.

3.3 Determination of Gross/Net Thickness of the Reservoirs

The gross reservoir thickness, H is determined by picking the tops and bases of the reservoir sands across the Wells (Figure 3). Shale thickness, h_{shale} within the reservoir sands is obtained by defining shale and sand baselines respectively on the Gamma ray log.

3.4 Computation of Petrophysical Parameters in the Study Area

The computations of the petrophysical parameters using established empirical relations are done using equations (1) to (16) in Tables 1a and 1b below:

Table 1a: Equations for computing the petrophysical parameters in the study area

Parameters	PETROPHYSICAL PARAMETERS								
	Net Reservoir Sand Thickness (ft)	Gamma Ray Index, I_{GR}	Volume of Shale	Total Porosity, ϕ_T	Effective Porosity, ϕ_E	Formation Resistivity Factor, F	Water Saturation, S_w	Irreducible Water Saturation, S_{wirr}	Flush Zone Water Saturation, S_{xo}
Equations	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	$H = H_{shale}$ H = Gross Reservoir Sand Thickness	$I_{GR} = \frac{(GR_{log} - GR_{min})}{(GR_{max} - GR_{min})}$ (Dresser, 1979)	$V_{sh} = 0.083(23.7 * I_{GR} - 1)$ (Larionov, 1969)	$\phi_T = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$ (Dresser, 1979) $\rho_{ma} = 2.65 \text{ gcm}^{-3}$ for sandstone ρ_b = Bulk density; $\rho_f = 1.0 \text{ gcm}^{-3}$ for water and 0.87 gcm^{-3} for oil.	$\phi_{eff} = \phi_T - [\phi_{sh} * V_{sh}]$ (Dresser, 1979) ϕ_T = total porosity; ϕ_{sh} = log reading in a shale zone, V_{sh} = volume of shale	$F = \frac{a}{\phi^m}$ (Archie, 1942) a = Tortuosity taken as 0.62; m = cementation exponent taken as 2 for sands.	$S_w = \left(\frac{a R_w}{R_t \phi^m} \right)^{\frac{1}{n}}$ (Archie, 1942) R_w = Resistivity of the interstitial water; R_t = True resistivity of the Formation; n = saturation exponent taken as 2	$S_{wirr} = \sqrt{\frac{F}{2000}}$	$S_{xo} = \left[\frac{F R_{xo}}{R_{so}} \right]^{\frac{1}{n}}$ (Archie, 1942)

Table 1b: Equations for computing the petrophysical parameters in the study area (continued)

Parameters	PETROPHYSICAL PROPERTIES						
	Permeability (K)	Relative Permeability to Oil (K_{ro})	Relative Permeability to Water (K_{rw})	Hydrocarbon Saturation (S_h)	Residual Hydrocarbon Saturation (S_{hr})	Oil-in-Place (OIP) (bbl/acre)	Gas-in-Place (GIP) (cu.ft/acre)
Equations	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	$K = \left[\frac{250 * \phi^3}{S_{wirr}} \right]^2$ (Wyllie and Rose, 1950)	$K_{ro} = \frac{(1 - S_w)^{2.1}}{(1 - S_{wirr})^2}$	$K_{rw} = \left[\frac{(S_w - S_{wirr})^2}{(1 - S_{wirr})} \right]$	$S_h = (100 - S_w)\%$	$S_{hr} = 1 - \sqrt{\frac{F R_{so}}{R_w}}$	$OIP = 77580 \phi A h (1 - S_w)$ ϕ = Porosity (%) A = Area drained in acres H = thickness (ft) S_w = Water Saturation (%)	$GIP = 43560 \phi A h (1 - S_w)$ ϕ = Porosity (%) A = Area drained in acres H = thickness (ft) S_w = Water Saturation (%)

Figure 3: Lateral correlation of the reservoir sands across the wells

4. RESULTS

4.1 Hydrocarbon Reservoir Sands

Seven prospective reservoir sands: SNB, SNC, SND, SNE, SNF, SNG and SNH were identified in the wells. These reservoir sands are continuous in the wells except in AFAM 15 where SNF, SNG and SNH and in OBEAKPU 005 where SND, SNE, SNF, SNG and SNH are not penetrated by these wells.

4.2 Average Petrophysical Parameters for the Reservoir Sands in the Wells

Tables 2a and 2b and Figures 4 to 10 respectively show the computations and plots of the average petrophysical parameters obtained for the reservoir sands in the wells.

Table 2a: The average petrophysical parameters of the reservoirs in the study area

Well	SAND	RESERVOIR SAND THICKNESS (ft)	V _{sh} (%)	φ _e (%)	F	R _t (Ω-m)	R _o (Ω-m)	S _w (%)	S _h (%)	S _{wirr} (%)
Afam-15	SNB	117	4.84	28.84	10.21	1.73	1.12	93.02	6.98	7.08
	SNC	85	8.51	23.23	18.88	4.32	1.99	88.71	11.29	9.24
	SND	93.5	4.06	24.83	14.75	1.62	1.51	94.13	5.87	8.39
	SNE	64	7.50	23.63	16.20	91.37	1.62	21.80	78.20	8.83
Afam-16	SNB	122	12.53	28.20	11.90	6.55	0.87	67.20	32.80	7.29
	SNC	71	15.48	24.97	24.11	70.83	1.70	37.67	62.33	9.35
	SND	90	5.61	26.22	18.73	49.55	1.28	45.95	54.05	8.25
	SNE	58	7.64	27.21	12.58	119.80	0.84	12.89	87.11	7.71
	SNF	123.5	10.93	23.66	15.53	100.90	1.00	12.70	87.30	8.70
	SNG	24.5	21.63	19.26	30.77	15.86	1.89	37.76	62.24	11.61
	SNH	168	6.37	23.92	18.74	145.03	1.13	10.20	89.80	8.96
Korokoro-003	SNB	156.5	3.39	36.01	6.29	4.02	0.45	56.71	43.29	5.60
	SNC	54	9.18	33.73	7.62	34.08	0.53	16.77	83.23	6.11
	SND	159	7.79	31.35	8.42	5.11	0.56	48.88	51.12	6.46
	SNE	77.5	5.79	30.53	8.80	62.73	0.58	16.26	83.74	6.62
	SNF	111	7.27	21.67	17.79	2.76	1.12	63.59	36.41	9.38
	SNG	52.5	21.43	21.94	18.48	53.20	1.15	20.05	79.90	9.45
	SNH	98.5	14.29	24.01	15.39	92.81	0.94	20.27	79.73	8.61
Korokoro-006	SNE	73	11.07	29.73	9.41	9.64	0.57	29.50	70.50	6.83
	SNF	106	12.90	34.08	7.16	2.48	0.42	41.16	58.84	5.96
	SNG	55.5	26.94	26.60	30.90	16.94	1.08	28.45	71.55	9.50
	SNH	102	8.39	23.46	17.41	99.55	0.99	14.30	85.70	8.99
Obeaku-005	SNB	200.5	14.59	30.68	19.15	58.02	0.59	26.33	73.67	8.21
	SNC	50	24.14	25.67	16.65	33.07	0.50	30.95	69.05	8.64

V_{sh}-Volume of Shale; φ_e-Effective Porosity Corrected for Shale; F-Formation Factor; R_t-True Resistivity; R_o-Formation Resistivity at 100% Water Saturation; S_w-Water Saturation, S_h-Hydrocarbon Saturation; S_{wirr}-Irreducible Water Saturation

Table 2b: The average petrophysical parameters of the reservoirs in the study area(contd.)

Well	SAND	K(mD)	K _{ro}	K _{rw}	S _{xo} (%)	S _{hr} (%)	RESERVE ESTIMATE
GIP(cu.ft/acre)							
Afam-15	SNB	9530.79	0.04	0.92	98.09	1.91	72,630.27
	SNC	2536.49	0.11	1.54	95.89	4.11	140,436.68
	SND	3883.68	0.02	0.95	98.55	1.45	-
	SNE	2909.43	0.74	0.02	70.78	29.22	533,192.34
GIP(cu.ft/acre)							
Afam-16	SNB	405.00	0.40	0.44	90.34	9.66	293,792.15
	SNC	5669.52	0.65	1.19	74.40	25.60	573,878.19
	SND	4205.76	0.48	0.57	79.68	20.32	402,910.14
	SNE	7472.17	0.89	0.00	63.40	36.60	597,490.35
	SNF	2363.25	0.91	0.00	64.70	35.30	1,087,560.78
	SNG	1013.79	0.53	0.11	80.21	19.79	121,405.03
	SNH	2532.33	0.99	0.03	61.02	38.98	1,534,667.86
(OIP) (bbl/acre)							
Korokoro-003	SNB	47050.98	0.23	0.20	88.13	11.87	47,590.26
	SNC	90663.50	0.78	0.01	68.19	31.81	118,602.08
	SND	16655.69	0.32	0.13	85.41	14.59	86,972.45
	SNE	12973.64	0.81	0.01	67.10	32.90	149,342.64

	SNF	941.00	0.15	0.22	91.27	8.73	-
	SNG	1497.66	0.78	0.02	70.21	29.79	75,310.12
	SNH	2588.92	0.77	0.02	69.22	30.78	141,232.15
(OIP) (bbl/acre)							
Korokoro-006	SNE	11161.31	0.57	0.03	77.36	22.64	121,281.49
	SNF	34366.80	0.37	0.05	83.69	16.31	162,635.01
	SNG	14437.86	0.63	0.06	75.18	24.82	84,097.09
	SNH	2343.64	0.89	0.01	65.38	34.62	230,133.87
(OIP) (bbl/acre)							
Obeaku-005	SNB	62086.92	0.74	0.20	68.92	31.08	387,754.83
	SNC	10645.45	0.64	0.12	72.98	27.02	72,953.98

K-Permeability; K_{ro} -Relative Permeability to Oil; K_{rw} -Relative Permeability to Water; S_{xo} -Flush Zone Water Saturation, S_{hr} -Residual Hydrocarbon Saturation, mD-Milli Darcy, OIP-Oil-in-place, GIP- Gas-in-place.

Figure 4: Reservoir sand thicknesses

Figure 5: Volume of shale in the reservoir sands

Figure 6: Porosity of the reservoir sands

Figure 7: Water and hydrocarbon saturations

Figure 8: Relative permeabilities to oil and water

Figure 9: Absolute permeability of the reservoir sands

Figure 10: Reserve estimate in the reservoir sands

5. DISCUSSION

5.1 Afam 15

Four reservoir sands SNB, SNC, SND and SNE are delineated in this well with SNB having the highest thickness of 117 ft and SNE the lowest thickness of 64ft. SNB, SNC, SND and SNE contain average volume of shale ranging from 4.06 to 8.51%. Effective porosity in these reservoirs are almost entirely uniform ranging from 23.23 to 28.84%. Water saturation is observed to be high in SNB, SNC and SND ranging from 88.71 to 94.13% with SNE having the lowest value of 21.80%. Conversely, hydrocarbon saturation was highest in SNE with a value of 78.20% and low in SNB, SNC and SND ranging from 5.87 to 11.29% indicating that low hydrocarbon saturation implies high water saturation and vice versa. Reservoirs SNB, SNC and SND contain essentially water while SNE contains some amount of hydrocarbon with water (Wyllie and Rose, 1950). The relative permeability to water, K_{rw} is highest in SNC with a value of 1.54 and high in SNB and SND with values of 0.92 and 0.95 respectively. SNE has the lowest value of 0.02. This is not the case with K_{ro} for which SNE has the highest value of 0.74 while SNB and SND have the lowest values of 0.02 and 0.04 respectively. SNC has a low K_{ro} value of 0.11. Very low values of relative permeability to oil implies that little or no hydrocarbon will be produced in such reservoirs.

More water than hydrocarbon will be produced from reservoirs SNB, SNC and SND because of their very high relative permeability to water while more hydrocarbon than water will be produced in reservoir sand SNE due to its low K_{rw} . SNB has the highest absolute permeability of 9530.79mD while SNC, SND and SNE have permeabilities of 2536.49mD, 3883.68mD and 2909.43mD respectively. This implies that hydrocarbon will flow easily in SNB than in SNC, SND and SNE. The estimated Gas-in-place are 72,630.27cu.ft/acre in SNB, 140,436.68cu.ft/acre in SNC and 533,192.34cu.ft/acre in SNE. This is mainly a gas-producing well.

5.2 Afam 16

Seven reservoir sands SNB, SNC, SND, SNE, SNF, SNG and SNH are delineated in this well with SNH having the highest thickness of 168ft and SNG the lowest thickness of 24.5ft. The volume of shale is highest in the deep section with a value of 21.63% in SNG and lowest in the middle section with values ranging from 5.61 to 10.93% in SND, SNE and SNF. Average effective porosity in these reservoirs are almost entirely uniform in the shallow section ranging from 23.66 to 28.20% except in SNG in the deep section with a low value of 19.26%. Water saturation is observed to be high in SNB with a value of 67.20% and low in SNE, SNF and SNH with values ranging between 10.20 and 12.89%. Conversely, hydrocarbon saturation is high in SNE, SNF and SNH with values of 87.11, 87.30 and 89.0% respectively and low in SNB with a value of 32.80%. Reservoir SNB contains essentially water, SNC, SND and SNG have hydrocarbon saturation >50% and so contain significant hydrocarbon with some water while the SNE, SNF and SNH contain mainly hydrocarbon. The relative permeability to water, K_{rw} is highest in SNC with a value of 1.19. SNH has a low value of 0.03 while SNE and SNF have 0.00 K_{rw} values indicating zones from which water-free production is expected (Asquith and Gibson, 1982).

On the other hand, K_{ro} is high in SNE, SNF and SNH with values of 0.89, 0.91 and 0.99 respectively while SNB, SNC, SND and SNG have low values of 0.40, 0.65, 0.48 and 0.53 respectively. More water than hydrocarbon will be produced from reservoirs SNB, SNC, SND and SNG because of their high K_{rw} while more hydrocarbon than water will be produced in reservoir SNE, SNF and SNH due to its high K_{ro} . SNE has the highest absolute permeability of 7472.17mD while SNB has the lowest absolute permeability of 405.00mD. Absolute permeability is fairly good in SNC, SND, SNF, SNG and SNH. This implies that hydrocarbon will flow easily in SNE than in SNB and others. SNF and SNH have the highest estimated GIP of 1,087,560.78 and 1,534,667.86cu.ft/acre respectively while SNG has the lowest GIP of 121,405.03cu.ft/acre. SNB, SNC, SND and SNE have GIP values ranging from 293,792.15 to 597,490.35cu.ft/acre. This is mainly a gas-producing well.

5.3 Korokoro 003

Seven reservoir sands SNB, SNC, SND, SNE, SNF, SNG and SNH are delineated in this well with SNB and SND having the highest thicknesses of 156.5ft and 159ft respectively while SNC and SNG have the lowest thicknesses of 54.0ft and 52.5ft respectively. The volume of shale is highest in the deep section with a value of 21.43% in SNG and lowest in the shallow to middle sections with values ranging from 3.39 to 9.18% in SNB, SNC, SND, SNE and SNF. Average effective porosity is uniform in the shallow to middle sections ranging from 30.53 to 36.01% in SNB, SNC, SND and SNE and also uniform in the deep section ranging from 20.04 to 21.67% in SNF, SNG and SNH. This shows that porosity decreases with depth. Water saturation is observed to be high in SNB, SND, and SNF ranging from 48.88 to 53.59% and low in SNC, SNE, SNG and SNH with values ranging between 16.26 and 20.27%. Hydrocarbon saturation is high in SNC, SNE, SNG and SNH with values of 83.23, 83.74, 79.90 and 79.73% respectively and <50% in SNB and SNF but a little >50% in SND. Reservoirs SNC, SNE, SNG and SNH contain essentially hydrocarbon, SNB contains significant amount of water while SND contain some amount of water with hydrocarbon.

The relative permeability to water, K_{rw} is extremely low in SNC, SNE, SNG and SNH with values ranging from 0.01 to 0.02. SND has a low value of 0.13 while SNB and SNF have K_{rw} values of 0.20 and 0.22 respectively. SNC, SNE, SNG and SNH have high K_{ro} values ranging from 0.77 to 0.81 while SNB, SND and SNF have lower values of 0.23, 0.32 and 0.15 respectively. More hydrocarbon than water will be produced from reservoirs SNC, SNE, SNG and SNH because of the very high K_{ro} while more water than hydrocarbon will be produced in reservoirs SNB, SND and SNF due to low K_{ro} . SNC has the highest absolute permeability of 90663.50mD while SNF has the lowest absolute permeability of 941.00mD. The absolute permeability is fairly good in SNB, SND and SNE. This implies that hydrocarbon will flow easily in SNC than in SNF and others. SNC, SNE and SNH have the highest estimated Oil-in-place, OIP of 118,602.08, 149,342.64 and 141,232.15bbl/acre respectively while SNB has the lowest OIP of 47,590.26bbl/acre. SND and SNG have OIP values of 86,972.45 and 75,310.12bbl/acre respectively. This is also mainly an oil-producing well.

5.4 Korokoro 006

Four reservoir sands SNE, SNF, SNG and SNH are delineated in this well with SNF and SNH having the highest thicknesses of 106ft and 102ft respectively and SNG the lowest thickness of 55.5ft. SNB, SNC, and SND are not continuous in this well may be due to a period of break in deposition of sediments. These reservoir sands contain average volume of shale ranging from 8.39% in SNH to 26.94% in SNG. Effective porosity in these reservoirs are almost entirely uniform ranging from 23.46% in SNH to 34.08% in SNF. Water saturation is observed to be <50% in all the reservoirs. SNF has a value of 41.16%, SNE 29.50% and SNG 28.45%. SNH has the lowest value of 14.30%. Conversely, hydrocarbon saturation is observed to be >50% in all the reservoirs with SNH having the highest value of 85.70 %, SNE 70.50 %, SNF 58.84% and SNG 71.55%.

All the reservoirs essentially contain significant amount of hydrocarbon than water. The relative permeability to water, K_{rw} is extremely low in all four reservoirs ranging from 0.01 in SNH to 0.06 in SNG. Relative permeability to oil, K_{ro} is high SNE, SNG and SNH with values ranging from 0.57 to 0.89. SNF has a low K_{ro} value of 0.37. More hydrocarbon than water will be produced from reservoirs SNE, SNG and SNH because of their very high relative permeability to oil. SNF has the highest absolute permeability value of 34366.80mD while SNH has K values of 2343.64mD. SNE and SNG have fairly good K values of 11161.31mD and 14437.86mD respectively. This is an indication that hydrocarbon will flow easily in SNF than in SNH and others. The estimated oil-in-place, OIP are 121,281.49bbl/acre in SNE, 162,635.01bbl/acre in SNF, 84,097.09bbl/acre in SNG and 230,133.87bbl/acre in SNH. This is mainly an oil-producing well.

5.5 Obeakpu 005

Two reservoir sands SNB and SNC are delineated in this well with SNB having the highest thickness of 200.5ft and SNC the lowest thickness of

50ft. SNB contains average volume of shale value of 14.59% while SNC contain 24.14%. The average effective porosity in these reservoirs are 30.68% and 25.67% respectively. Water saturation, S_w is observed to be 26.33% in SNB and 30.95% in SNC while the hydrocarbon saturation, S_h is 73.67% in SNB and 69.05% in SNC. Both reservoirs contain essentially hydrocarbon with some water. The relative permeability to water, K_{rw} in SNB is 0.20 and 0.12 in SNC while the relative permeability to oil, K_{ro} is 0.74 in SNB and 0.64 in SNC. More hydrocarbon than water is expected to be produced from both reservoirs because of their very high relative permeability to oil. SNB has the highest absolute permeability value of 62086.92mD while SNC has K value of 10645.45mD. This implies that hydrocarbon will flow easily in SNB than in SNC. The estimated volume of oil-in-place in the reservoir sands are 387,754.83bbl/acre in SNB and 72,953.89bbl/acre in SNC.

6. CONCLUSION

Five wells (AFAM 15, AFAM 16, KOROKORO 003, KOROKORO 006 and OBEAKPU 005) were investigated and seven prospective reservoirs (SNB, SNC, SND, SNE, SNF, SNG and SNH) consisting of sand and shale in alternating sequence were delineated. All the identified reservoir sands are continuous except those not penetrated in shallow wells such as Afam 15 and Obeakpu 005. Reservoir thickness, volume of shale, effective porosity, relative and absolute permeabilities, hydrocarbon and water saturations and gas-in-place and oil-in-place were evaluated in order to determine the reservoirs' potential of this field.

Most of the reservoir sands in all the wells are observed to have significant thicknesses to accumulate hydrocarbon in exploitable quantities. Thicknesses ranging from 24.5ft in SNG reservoir in AFAM 16 up to 200.5ft in SNB reservoir in OBEAKPU 005 are measured. The volume of shale varies within and across all the wells with values <30% of the total thicknesses. This implies that there are more sands than shales in the reservoirs. Shaly-sand zones have higher effective porosity for intervals with low volume of shale while porosity within sandy-shale zones with high volume of shale are considerably reduced. Thus, the effect of shaliness in the sands is responsible for the reduction in the porosity because the zones with lowest porosity have the highest volume of shale.

Relative permeability to water (K_{rw}) in reservoirs ranges from 0.00 to >1.00 across the wells. Sand SNE and SNF in Afam 16 have average K_{rw} of 0.00 which implies that 100% water-free hydrocarbon production is expected. SNC in Afam 15 and Afam 16 has average K_{rw} >1 which implies that 100% water production is expected from this reservoir. The relative permeability to oil (K_{ro}) is very high in reservoirs with high hydrocarbon saturation. SNH in Korokoro 006 has an average hydrocarbon saturation of 85.70% and K_{ro} of 0.89. Absolute permeability is generally high across all the wells. SNB in Obeakpu 005 has average permeability value of 62,086.9mD. Reservoir sands SNB, SNC and SND contain no producible hydrocarbon in Afam 15 but contain producible hydrocarbon in Afam 16, Korokoro 003 and Obeakpu 005 wells. Reservoir sands SNE, SNF, SNG and SNH in Afam 15, Afam 16, Korokoro 003 and Korokoro 006 contain producible hydrocarbon with the exception of SNF in Korokoro 003.

7. RECOMMENDATION

Further research should be conducted with petrographic analysis of the reservoir sands using more wells, core and seismic data for detailed evaluation of type and distribution of shale since these affect reservoir qualities and reserve estimation. Future development of all the wells should be focused on deeper reservoirs with the exception of Obeakpu 005 which has producible hydrocarbon reservoirs within shallow depth interval.

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