International Journal of Scientific & Engineering Research, Volume 10, Issue 12, December-2019
ISSN 2229-551

Reservoir Geological Study of Etema Field, SE Niger Delta, Nigeria.

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Abstract -This study was carried out to assess the quality of sand units and hydrocarbon potentials in Etema Field, South-Eastern Niger Delta, Nigeria. Data used for the study were principally a suite of wireline logs and seismic data from the field. The study involved wireline logs correlation of the sand units and, seismic interpretation of the Base Qua Iboe Shale unconformable surface and top of the most laterally continuous sand unit in the field. It also involved petrophysical evaluation of the various reservoir parameters, such as net and gross sand thickness, net-to-gross sand thickness ratio. Porosity, volume of shale, water saturation hence, hydrocarbon saturation and determination of oil in place.The studied interval consists of an alternation of sands and shale. The sand units identified were informally coded E1, E2, E3 E4 and E5 Across the field, the sands vary in shale content from 0.04 to 0.43, porosity from 0.19 to 0.35, water saturation from 0.01 to 0.93. However, net sand thickness ranges between 7 feet and 141 feet, gross sand thickness varies from 24 feet to 165 feet and net-to-gross sand thickness ratio lie between 0.20 and 0.99. The sand units are predominantly dip-oriented with feeder direction in the north east. Values for the Etema reservoir parameters compare favorably with published values of good quality reservoirs. Hydrocarbon entrapment in the area is by combination of structure and stratigraphy, but mainly stratigraphic with sands being truncated at the Base Qua Iboe unconformity. Hydrocarbon accumulation occurs in the Biafra as well as the flanking "Rubble Beds" while the Qua Iboe Shale act as cap rock and, or seal.

Keywords: *Reservoir, Base Qua Iboe Unconformity, subsea depths, isopach, hydrocarbon, Stock Tank Oil Initially in Place.*

1.0 INTRODUCTION

The Niger Delta is a large delta of the destructive type, having been formed under conditions of higher wave and tidal energy (Elliot, 1986, and Bhattacharya and Walker, 1992). The province is one of the world's largest deltas with an area extent of about 75,000 sq. km (Evamy et al, 1978) with the age range of Eocene to Recent (Short and Stauble, 1967).

The Niger Delta sedimentation is cyclic forming several depositional cycles (Asseez, 1974). The cycles comprise sediments of barrier bar, tidal channels, fluviomarine and fluviatile environments (Asseez, 1974). The structure and stratigraphy of the province has been influenced by rates of sedimentation and subsidence throughout its development (Asseez, 1974 and Evamy et al, 1978).

The delta (fig. 1), is by far the most important petroleum province in Nigeria (Schild, 1978). As a result, almost all hydrocarbon exploration and, or producing companies operating in Nigeria, have concessions in the delta. Mobil Producing Nigeria Unlimited is one of the operating oil companies in the delta and Etema Field (the study area), is one of its fields (fig. 2).

The sedimentology, stratigraphy and structure of the province have been reviewed by Short and Stauble (1967) and Asseez (1974). The basal sedimentary unit, the Akata Formation, is consist of plastic, low density, high pressure, shallow marine to deep marine shales (Schild, 1978). The transitional Agbada Formation is characterized by alternating deltaic (fluviiatile, coastal and fluviomarine) sand and shales and, grades into the overlying sandstones of the Benin Formation (Short and Stauble, 1967).

In general, the lithostratigraphy of the delta has been subdivided into the Akata Formation (oldest, at the bottom), overlain by Agbada Formation and Benin Formation (youngest). Weber and Daukoru (1975) in their study of the petroleum geology of the province, identified the deeply buried shales of the Akata Formation as the main source rocks in the delta, while the paralic sequence of the Agbada Formation provide the main hydrocarbon reservoirs. Similar conclusions had been reached in earlier studies by Short and Stauble (1967) and Reed (1969). However, Evamy et al. (1978), Ekweozor and Okoye (1980), Ekweozor and Daukoru (1984) and Nwachukwu and Chukwurah (1986)

International Journal of Scientific & Engineering Research, Volume 10, Issue 12, December-2019 ISSN 2229-551

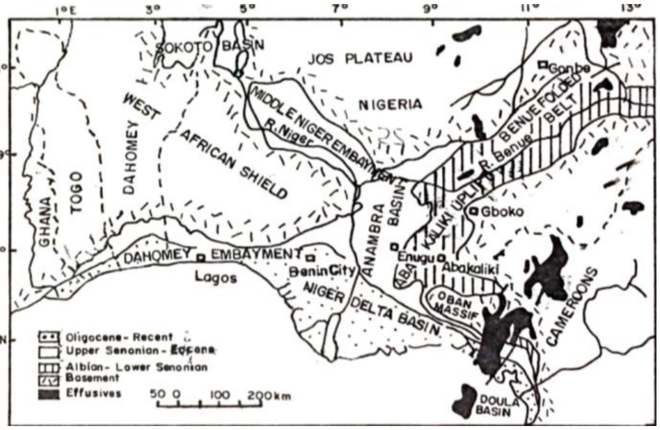

Figure 1. Geological map of Southeastern Nigeria showing Niger Delta Basin (After Asseez, 1974)

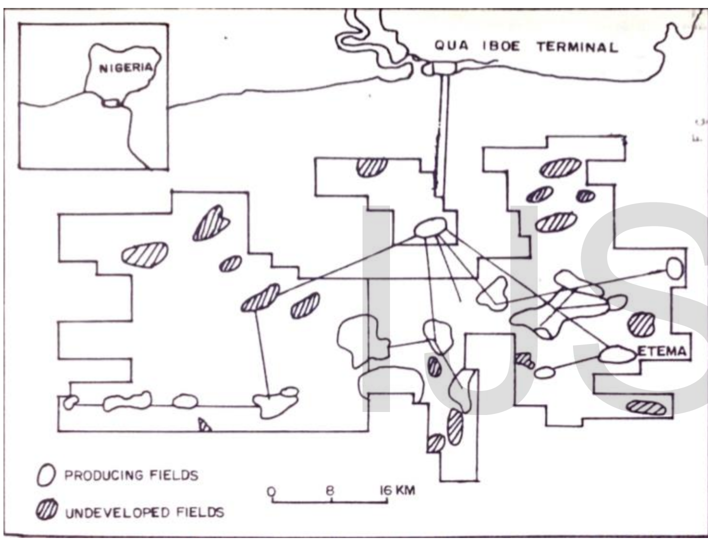

Figure 2. Map of Mobil acreage showing location of Etema Field

have pointed out the joint contribution of shales of the Akata Formation and the interbebedded shales of Agbada Formation in the generation of hydrocarbons in the Niger Delta. Lambert-Aikhionbare et al. (1992) based on the integrated geological and geochemical analysis of source rocks in the Niger Delta, concluded that the interbedded shales of the paralic Agbada Formation are the major source rocks in the province.

Orife and Avbovbo (1981), described several important stratigraphic and, unconformity traps in both the western and southern parts of the Niger Delta. Burke and Dewey (1974) and Merki (1972) examined the tectonic evolution of the Niger Delta highlighting growth faults and associated rollover anticlines as the major structures controlling hydrocarbon accumulation in the province.

In the southeastern part of the delta where Etema Field (the study area) is located, only two of the three formations in the delta are penetrated by the wells in the field. They are the Benin and Agbada Formations.The Agbada Formation is differentiated into four local members: the D-1, Qua Iboe Shale, "Rubble Beds" and Biafra Members (figure 3). For purposes of this study, the Benin Formation and, the D-1 and Qua Iboe Shale Members of Agbada Formation are not considered in detail. This is because, they are not within the reservoir interval for the study. The "Biafra Member" is subdivided into the Upper Biafra, Middle Biafra and Lower Biafra. The Biafra Member consists of an alternating sequence of marine sands and shales which subcrop against the top Biafra unconformity in the Upper Biafra section. Older beds subcrop southwards, whereas progressively younger beds subcrop northwards in the field. The Upper Biafra as well as the "Rubble Beds" Members makeup the reservoir intervals in Etema Field hence, are the main exploration in the southeastern Niger Delta. The Etema reservoir interval is Lower Pliocene in age (Ecco Consult, 1991). This section has a considerable thickness and consists of several sand units of varying thickness, porosity and fluid saturation (Harry et al, 2017; 2018). Usually, the first reservoir occurring below the Qua Iboe Member is called Base Qua Iboe (BQI), whether it is the Rubble Beds, Upper or Middle or Lower Biafra (Schild, 1978).

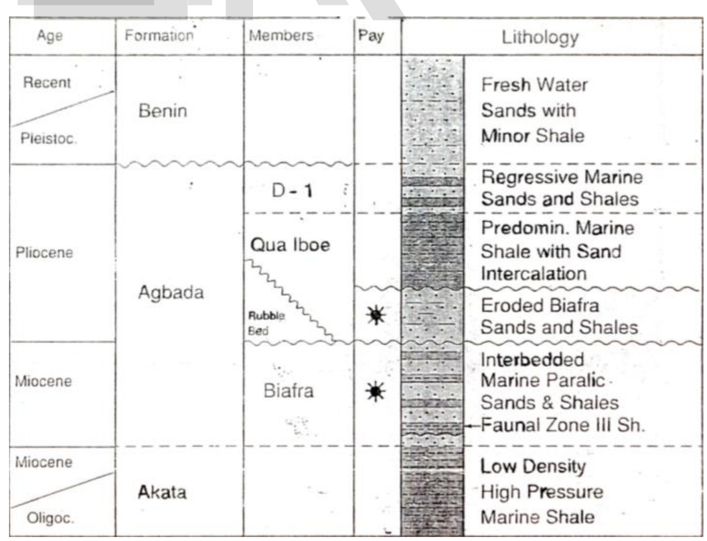

Figure 3. Stratigraphic column of Niger Delta

1.1 Study Location

The Niger Delta is located at the southern end of Nigeria, bordering the Atlantic Ocean and extending from about latitude $4^0 35'$N to $5^0 45'$N and longitude 3^0 $42'$E to $9^0 10'$E (fig. 1). The

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Etema Field is situated on latitude $5^0 18'$N to $5^0 19'$N and longitude $8^0 15'$E to $8^0 16'$E in the south eastern offshore block of the Niger Delta (fig. 1). The field covers an areal extent of about 20.88sq. km and lies in water depth ranging from 101 and 121 feet. There are two platforms (platforms A and B) and a total of sixteen wells in the field (fig. 4).

1.2 Objective of Study

The study is aimed at assessing the quality of the sand units in the field based on the evaluation of their reservoir parameters. The study also looks at the hydrocarbon accumulation of the area based on the stratigraphic and structural styles of the reservoirs in the area. The study covers all the six wells in the A-platform area of the field and two stand-alone wells in the field. The wells are coded Etema 2, Etema 3, Etema 4A, Etema 5A, Etema 6A, Etema 7A, Etema 7A RD and Etema 8A. The depth interval for the study is from Base Qua Iboe depth to the total drilled depth for all the wells.

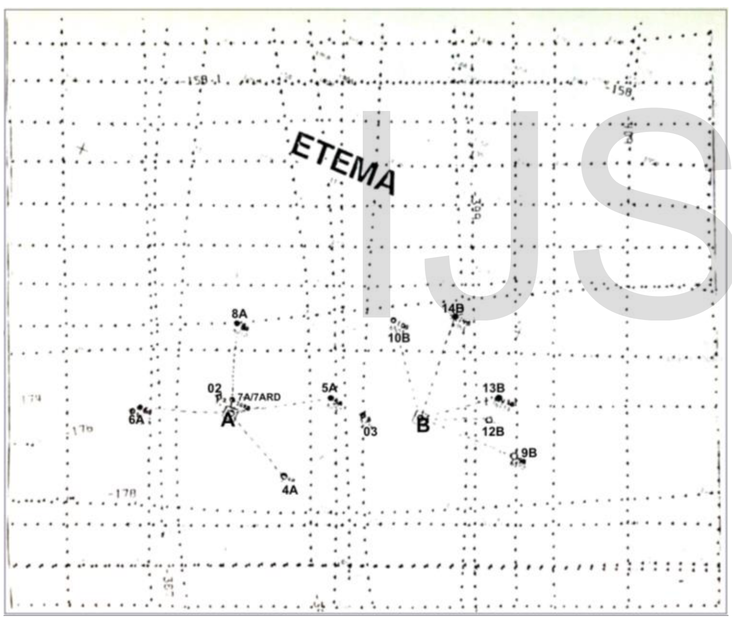

Figure 4. A section of Etema Field basemap showing location of wells

2.0 Materials and Methods

The data available for the study included but not limited to the following; composite logs of all the eight wells in the study area; porosity logs (sonic, density and neutron logs) of all the wells in the study area; seismic base map of the field; checkshot survey data for wells Etema 3, Etema 6A, Etema 7A and Etema 8A and 36-fold 2-D migrated seismic lines covering the entire study area. The governing parameters for the study included porosity, water saturation hence, hydrocarbon saturation, net-to-gross sand thickness ratio and, structural and stratigraphic features (faults and unconformities).

The study was carried out using wireline log correlation of the sand units in the study area, seismic mapping of Base Qua Iboe unconformity surface and top of the most laterally continuous sand (sand E4) in the study area, and production of structure maps of the two surfaces to ascertain the structural dispositioning of the wells in the area. The approach was complimented by determination of fluid content in the reservoirs, mapping the distribution of the various reservoir parameters such as net sands, gross sands, net-to-gross sand thickness ratio, quantitative determination of volume of shale, porosity and computation of water saturation hence, hydrocarbon saturation and, computation of stock tank oil initially in place. Correlation of the sand units was done using gamma ray, resistivity and conductivity logs as key logs and where necessary, density, sonic and neutron logs were incorporated.

Volume of shale (V_{sh}), was determined using the equation:

$$V_{sh} = 0.083[2^{(3.7*I_{GR})} - 1]$$

Where,
I_{GR} is gamma ray index and obtained from the formula:

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

Where,
GR_{log} = gamma ray reading of formation;
GR_{min} = minimum gamma ray for clean sands or carbonates
GR_{max} = maximum gamma ray reading for shale

Porosity was determined from the porosity logs (density, sonic and neutron logs). In each case of the porosity determination, correction for shale effect was done since most of the sand units contained significant amount of shale. Data for porosity determination was derived from porosity logs and applied in the appropriate formula as shown below:

Density porosity corrected for shale effect ($\emptyset_{Den}$) was derived from the formula:

$$\emptyset_{Den} = \left[\frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}\right] - V_{sh}\left[\frac{\rho_{ma} - \rho_{sh}}{\rho_{ma} - \rho_f}\right]$$

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where,
ρ_{ma} = matrix density of formation;
ρ_b = bulk density of formation;
ρ_{sh} = density of adjacent shale;
ρ_f = density of drilling fluid;
V_{sh} = volume of shale;

Values of ρ_{ma} and ρ_f used in the study were 2.65g/cc and 1.1g/cc respectively

Sonic porosity corrected for shale effect $(\emptyset_{sonic})$ was derived from the formula:

$$\emptyset_{sonic} = \frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}} * \frac{100}{\Delta t_{sh}} - V_{sh}\left[\frac{\Delta t_{sh} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}}\right]$$

Where,
Δt_{log} = interval transit time of formation

Δt_{ma} = interval transit time of formation matrix

Δt_f = interval transit time of drilling fluid

Δt_{sh} = interval transit time of adjacent shale

V_{sh} = volume of shale

Values of Δt_{ma} and Δt_f used in the study were 55.5 μ_{sec}/ft and 185 μ_{sec}/ft respectively

Neutron porosity was determined directly from neutron log.

Determination of fluid content was done using a suite of resistivity and porosity logs.

Water saturation hence, hydrocarbon saturation was computed using the formula:

$$S_w = \frac{-\frac{Vsh}{Rsh} + \sqrt{\left[\frac{Vsh}{Rsh}\right]^2 + \frac{\emptyset^2}{0.2 * R_w * R_t * (1 - V_{sh})}}}{\frac{\emptyset^2}{0.4 * R_w * (1 - V_{sh})}}$$

(after Schlumberger, 1975)

Where,

$S_{hc} = (1 - S_w)$

Where,

R_w = formation water resistivity at formation temperature

R_t = true formation resistivity at formation temperature

ϕ = average porosity corrected for volume of shale

R_{sh} = resistivity of adjacent shale

S_w = water saturation in uninvaded zone

S_{hc} = hydrocarbon saturation

Stock Tank Oil Initially In Place (STOIIP) was computed using the equation:

STOIIP = 7758*A*h* n/g*ϕ* (1-Sw).

Where:

STOIIP = Hydrocarbon (Gas/oil) initially in Place acre-feet
A = Areal extent of the accumulation acre
H = Average Net Pay for the reservoir zone (feet)
Φ = Average Effective Porosity (fraction)
n/g = Average net-to-gross (fraction)
Sw = Average Water Saturation (fraction)
7758 is the constant that converts the volume from acre-feet to stock tank barrels

3.0 Results and Discussion

Sand unit E1 in the study area occurs between subsea depths of 5581 feet (well 3) and 5646 feet (well 8A) (table 1). The sand unit is separated from the Base Qua Iboe unconformity at irregular

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intervals by shale unit of about 15 to 20 feet thick. The log pattern shows a stable low gamma ray value in between high gamma rays values suggesting fluvial environment of a probably braided stream systems of Klein (1984), Busch and Link (1985) and Rider (1990) (figure 6).

The gross and net sand thicknesses vary from 107 feet (well 8A) to 165 feet (well 3) and, 94 feet (well 8A) to 141 feet (well 3) respectively (table 2). Net-to-gross sand thickness ratio ranges from 0.80 (well 5A) to 0.88 (well 8A) (table 2). Average volume of shale in the sand unit varies between 0.15 (well 5A) and 0.22 (well 8A) (table 3) while average porosity values for the sand range from 0.23 (well3) to 0.27 (well 5A) (table 4).

However, water and hydrocarbon saturations vary respectively from 0.12 (well 3) to 0.28 (well 5A) and 0.72 (well 5A) to 0.88 (well 3) (table 5). The isopach map of the sand unit E4 (most laterally continuous sand unit in the study area), trends in a dip orientation with feeder direction in the northeast (figure 5). This sand unit constitutes the "Rubble Beds" depositional megasequence in the area.

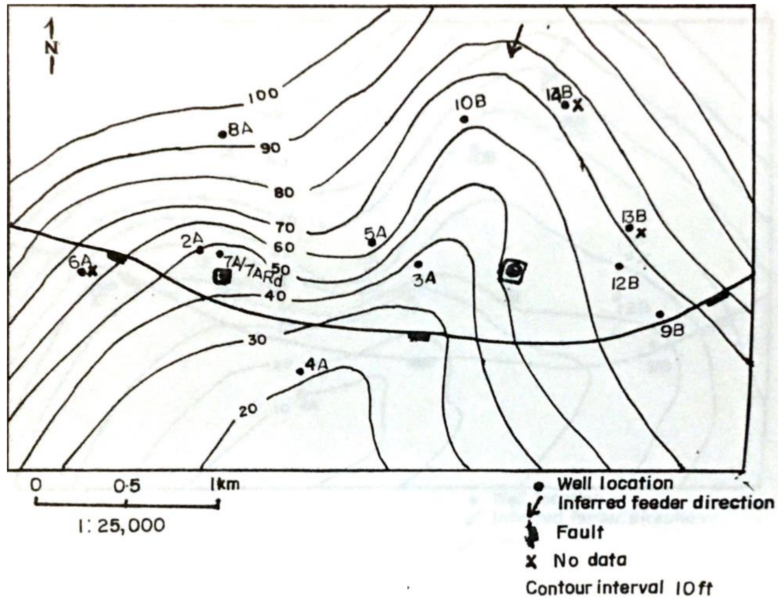

Figure 5. Sand E4 gross isopach map

Net-to-gross sand thickness ratio ranges from 0.78 (well 7A RD) to 0.87 (well 8A) (table 2). Average volume of shale in the sand unit varies between 0.09 (well 7A RD) and 0.19 (well 8A) (table 3) while average porosity values for the sand range from 0.28 (well 7A RD) to 0.31 (well 8A) (table 4). Water saturation varies from 0.08 (well 8A) to 0.21 (well 5A) and hydrocarbon saturation ranges from 0.79 (well 5A) to 0.92 (well 8A) (table 5). This sand unit trends in a dip orientation with feeder direction in the northeast (figure 6).

Table 1: Top and base of sand units in Etema Field

Sand Units		Wells							
		2	3	4A	5A	6A	7A	7ARD	8A
E1	Top (ft-ss)	NA	5581	NA	5587	NA	NA	NA	5646
	Base (ft-ss)	NA	5746	NA	5715	NA	NA	NA	5753
E2	Top (ft-ss)	NA	NA	NA	5792	NA	NA	5342	5753
	Base (ft-ss)	NA	NA	NA	5836	NA	NA	5402	5809
E3	Top (ft-ss)	NA	NA	NA	5836	NA	5391	5402	5809
	Base (ft-ss)	NA	NA	NA	5914	NA	5426	5456	5873
E4	Top (ft-ss)	5601	5851	5574	6137	NA	5562	5605	6044
	Base (ft-ss)	5651	5891	5598	6205	NA	5610	5640	6136
E5	Top (ft-ss)	5651	NA	5598	6205	5487	5610	5640	NA
	Base (ft-ss)	5724	NA	5652	6235	5547	5686	5716	NA

Sand unit E2 in the study area occurs between subsea depths of 5342 feet (well 7A RD) and 5792 feet (well 5A) (table 1). The sand package is separated by shale units of about 10 to 15 feet thick at irregular intervals from the sand unit above. The log pattern shows a branching and recombining configuration distinctive of anastomosing stream deposits (Klein, 1984), (figure 6). The net and gross sand thicknesses range from 38 feet (well 5A) to 49 feet (well 8A) and, 44 feet (well 5A) to 60 feet (well 7A RD) respectively (table 2).

Table 2: Gross sand thickness, net sand thickness and net-to-gross sand thickness ratio in Etema Field.

Sand Units		Wells							
		2	3	4A	5A	6A	7A	7ARD	8A
E1	Net	NA	161	NA	102	NA	NA	NA	94
	Gross	NA	165	NA	128	NA	NA	NA	107
	Net/ Gross	NA	0.98	NA	0.80	NA	NA	NA	0.88
E2	Net	NA	NA	NA	38	NA	NA	47	48
	Gross	NA	NA	NA	44	NA	NA	60	56
	Net/ Gross	NA	NA	NA	0.86	NA	NA	0.78	0.88
E3	Net	NA	NA	NA	16	NA	7	19	32
	Gross	NA	NA	NA	78	NA	35	54	64
	Net/ Gross	NA	NA	NA	0.21	NA	0.20	0.35	0.50
E4	Net	44	22	13	67	NA	47	33	91
	Gross	50	40	24	68	NA	48	35	92
	Net/ Gross	0.88	0.55	0.54	0.99	NA	0.98	0.94	0.99
E5	Net	24	NA	22	12	33	30	36	NA
	Gross	73	NA	54	30	60	76	76	NA
	Net/ Gross	0.3288	NA	0.41	0.40	0.55	0.39	0.47	NA

International Journal of Scientific & Engineering Research, Volume 10, Issue 12, December-2019 ISSN 2229-551

Table 3: Volume of shale within the sand units in Etema Field

Sand Units	Wells								Average Vol of Shale
	2	3	4A	5A	6A	7A	7ARD	8A	
E1	NA	0.12	NA	0.15	NA	NA	NA	0.22	0.28
E2	NA	NA	NA	0.20	NA	NA	0.09	0.19	0.16
E3	NA	NA	NA	0.43	NA	0.28	0.38	0.22	0.32
E4	0.05	0.14	0.14	0.06	NA	0.04	0.09	0.08	0.09
E5	0.25	NA	0.34	0.15	0.10	0.19	0.22	NA	0.21

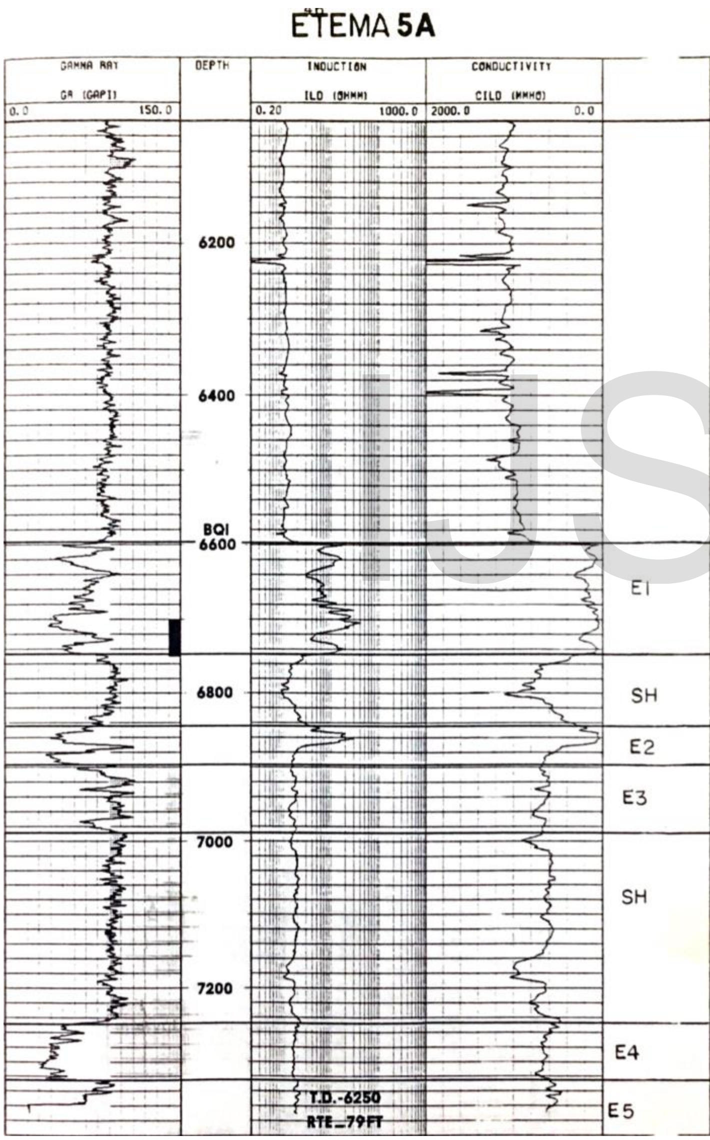

Figure 6. A section of well 5A showing study interval

Sand unit E3 in the study area occurs between subsea depths of 5391 feet (well 7A) and 5836 feet (well 5A) (table 1). The sand is separated from the sand unit above by shale units of about 18 to 28 feet thick at irregular intervals. The log pattern shows an irregular coarsening upwards sequence indicating an anastomosing stream deposits of Klein, (1984), (figure 6).
The net and gross sand thicknesses vary from 7 feet (well 7A) to 32 feet (well 8A) and, 35 feet (well 7A) to 78 feet (well 5A) respectively (table 2). Net-to-gross sand thickness ratio ranges from 0.20 (well 7A) to 0.50 (well 8A) (table 2). Average volume of shale in the sand unit varies between 0.22 (well 8A) and 0.43 (well 5A) (table 3) while average porosity values for the sand vary from 0.21 (well 7A) to 0.24 (well 8A) (table 4). Water saturation varies from 0.26 (well 7A RD) to 0.80 (well 5A) and hydrocarbon saturation ranges from 0.20 (well 5A) to 0.74 (well 7A RD) (table 5). The trend of the sand is dip oriented sand with its depositional azimuth in the northeast direction.

Sand unit E4 in the study area occurs between subsea depths of 5562 feet (well 7A) and 6137 feet (well 5A) (table 1). The log pattern is generally blocky suggesting slump deposits of Busch and Link, (1985), (figure 6). It indicates a high energy, deep marine deposits (Davies and Ethridge, 1975). The net and gross sand thicknesses vary from 13 feet (well 4A) to 91 feet (well 8A) and, 24 feet (well 4A) to 92 feet (well 8A) in that order (table 2). Net-to-gross sand thickness ratio ranges from 0.54 (well 4A) to 0.99 (well 8A) (table 2). Average volume of shale in the sand unit varies between 0.04 (well 7A) and 0.14 (wells 3 and 4A) (table 3) while average porosity values for the sand vary from 0.21 (well 3) to 0.35 (well 2) (table 4). Water saturation varies from 0.09 (well 7A) to 0.99 (well 8A) and hydrocarbon saturation ranges from 0.01 (well 8A) to 0.91 (well 7A) (table 5). The trend of the sand is dip oriented sand with its depositional azimuth in the northeast direction (figure 5).

Table 4: Porosity and average porosity within the sand units in Etema Field

Wells/Sand Units	2	3	4A	5A	6A	7A	7ARD	8A	Sand Average f
E1	NA	0.23	NA	0.27	NA	NA	NA	0.27	0.24
E2	NA	NA	NA	0.28	NA	NA	0.28	0.31	0.29
E3	NA	NA	NA	0.22	NA	0.21	0.21	0.24	0.29
E4	0.35	0.21	0.22	0.27	NA	0.34	0.31	NA	0.28
E5	0.23	NA	0.26	0.19	0.28	0.27	0.20	NA	0.24

Sand unit E5 in the study area occurs between subsea depths of 5487 feet (well 6A) and 6205 feet (well 5A) (table 1). The sand package is separated from the one above by shale intercalations of about 42 feet thick at near-regular intervals. The log pattern depicts a generally fining upward profile indicating a meandering stream point-bar deposits of Klein, (1984) and Busch and Link, (1985), (figure 6).
The gross and net sand thicknesses vary from 30 feet (well 5A) to 76 feet (wells 7A and 7A RD) and, 12 feet (well 5A) to 36 feet (well 7A RD) in that order (table 2).

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Net-to-gross sand thickness ratio ranges from 0.33 (well 2) to 0.54 (well 6A) (table 2). Average volume of shale in the sand unit varies between 0.10 (well 6A) and 0.34 (well 4) (table 3) while average porosity values for the sand vary from 0.19 (well 5A) to 0.23 (well 2) (table 4). Water saturation varies from 0.16 (well 7A) to 0.99 (well 5A) and hydrocarbon saturation ranges from 0.01 (well 5A) to 0.84 (well 7A) (table 5). The trend of the sand is dip oriented sand with its depositional azimuth in the northeast direction.Well 5A was picked as the reference well for this study in that all the sand units identified in the study area were penetrated by the well (figure 6).All of sand units E2, E3, E4 and E5 belong to Biafra depositional megasequence in Etema Field.

Reservoir quality as well as petroleum accumulation capabilities of any reservoir are critical aspects of reservoir geology and, are strongly dependent on a number of geological parameters (Alpay, 1972, Poston et al, 1983, and Haldorsen and Damsleth, 1993). These parameters include: permeability, porosity, water and hydrocarbon saturations, lithologic characteristics (sorting, packing and shape), structural and stratigraphic styles.

Table 5: Water and hydrocarbon saturations within the sand units in Etema Field

Sand Units		Wells								Average saturation
		2	3	4A	5A	6A	7A	7ARD	8A	
E1	S_w	NA	0.12	NA	0.28	NA	NA	NA	0.23	0.21
	S_{hc}	NA	0.88	NA	0.72	NA	NA	NA	0.77	0.79
E2	S_w	NA	NA	NA	0.21	NA	NA	0.13	0.07	0.14
	S_{hc}	NA	NA	NA	0.79	NA	NA	0.87	0.93	0.86
E3	S_w	NA	NA	NA	0.80	NA	0.48	0.26	0.47	0.50
	S_{hc}	NA	NA	NA	0.20	NA	0.52	0.74	0.53	0.50
E4	S_w	0.15	0.85	0.23	0.93	NA	0.09	0.12	0.99	0.48
	S_{hc}	0.85	0.15	0.77	0.07	NA	0.91	0.88	0.01	0.52
E5	S_w	0.34	NA	0.29	0.99	0.31	0.16	0.28	NA	0.39
	S_{hc}	0.66	NA	0.71	0.01	0.69	0.84	0.72	NA	0.61

Etema Field assumes a structural configuration similar to an inverted heart at the Base Qua Iboe unconformity (fig. 7). The structure could be said to have been generated by movement of underlying shale mass which became diapiric in the southern part of the field. The field is restricted by faults to the southeast, stratigraphy to the south and by dip closure to the north (figure 7 – BQI depth map). Inspite of the fact that only a few of the several faults interpreted affected the field directly, it is not impossible that there could be other seismically unresolved minor faults over the field. This is probably a limitation to the 2-D seismic resolution. The major stratigraphic feature in the field is the unconformity at the Base Qua Iboe Shale Member. The unconformity surface offers a very good acoustic impedance contrast between the underlying and overlying strata, hence, a very good map-able horizon (Cox, 1996). All the five sand units identified in Etema Field, truncate at one point or the other at this unconformable surface.

Petrophysical analysis provided information for evaluation of the major reservoir parameters. A key parameter – porosity (percentage of space not occupied by rock matrix) was evaluated in detail and effective porosity (ratio of interconnected pore spaces to the total bulk volume of the rock), measured. A rough field appraisal using this approach to qualify reservoir sands is given as follows:

0 – 5% negligible
5 – 10% poor
10 – 15% fair
15 – 20% good
20 – 25% very good
25 and above excellent (North, 1985).

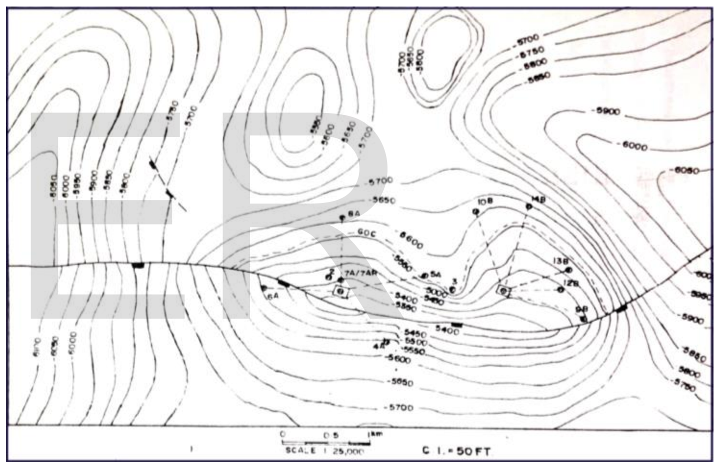

Figure 7. Base Qua Iboe Unconformity depth structure map

The petrophysical studies of the reservoirs in Etema Field have shown that the sands contain significant amount of shale. Shale content in reservoirs has strong effects on their petrophysical and production characteristics (Lambert-Aikhionbare and Shaw, 1982). As a result, volume of shale was computed and used to quantify other reservoir parameters in this study. This approach gives a near accurate value for the reservoir parameters (Asquith and Gibson, 1987).

Rocks are said to be of good reservoir quality if the porosity is greater than 0.15 and volume of shale less than 0.45 (Beaumont and Foster, 1986; Asquith and Gibson, 1987). Reservoir rocks are said to be of pay quality if water saturation is less than 0.45 (Beaumont and Foster, 1986). The values obtained for the various reservoir parameters in the study area compare favourably and, are far higher than those values for good

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quality reservoirs of Beaumont and Foster, (1986), and Asquith and Gibson, (1987).

The gamma ray logs used in the study, created some uncertainties in accurately computing volume of shale which was used in correcting for shale effects in other reservoir parameters. This is due to the fact that the sand units in some wells are characterized by higher gamma ray readings. It is most probably that there are some radioactive elements in the sands. Some of it may be tool error or due to materials in the well bore. The end result is the introduction of some potentially significant errors in the computation of volume of shale and other reservoir parameters.

The well sections along strike and dip directions in the study area (figures 8 and 9), show lateral discontinuity of some of the sand units in the field. They are either faulted out, eroded or pinched out. Pinch outs and faults however, accounted principally for the lateral discontinuity of the sand units. The sand terminations provide good exploratory targets in the area.

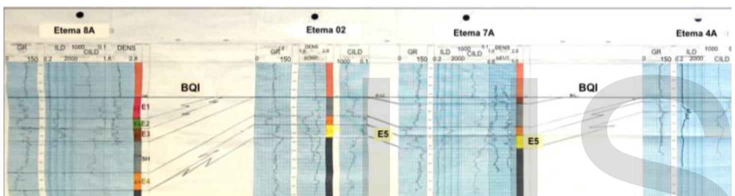

Figure 8. Well section along dip in Etema Field

The structural disposition of the wells along the strike and dip directions are shown in figures 10 and 11. Along the dip direction, a basin within a basin structure created by a convex downward fault, is interpreted. Subsidence occasioned by sedimentation succeeded the faulting gradually with the sediments building upwards from the base. As a consequence of erosion and probably minor faults beyond the resolution of the 2-D seismic, some of the sand units in wells 2, 4A and 7A have been cut off at the Base Qua Iboe unconformity.

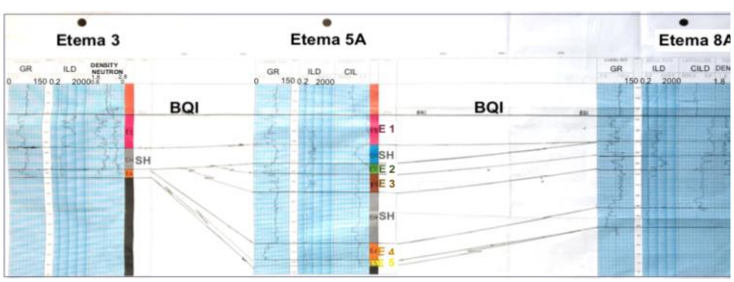

Figure 9. Well section along dip in Etema Field

Hydrocarbon entrapment in the study is by combination of structure and stratigraphy. Stratigraphy seems to have played a dominant role, with the sands being truncated at the Base Qua Iboe and Top Biafra unconformities. The Top Biafra unconformable surface was however not mapped primarily because it is limited to the southeast and central parts of the field, hence, not laterally continuous enough. Sand E4, the most laterally continuous sand unit in the field was mapped and top depth structure map of the sand produced (figure 12).

Hydrocarbon accumulation occurs in the Biafra as well as the flanking "Rubble Beds while the Qua Iboe Shale acts as cap rock/seal for the reservoirs. Shale smear along fault plane in the area could possibly lead to entrapment. Besides a possible entrapment by shale smearing, trapping is also possible when a reservoir is juxtaposed against a shale body across a fault (Knot, 1993).

Lateral fluid communication is believed to occur where "Rubble Beds" feed oil into Biafra sands and, or where there is sand-to-sand juxtaposition across fault (Knutson and Ragnhild, 1991). There is however no vertical fluid communication since the sand units are vertically isolated.

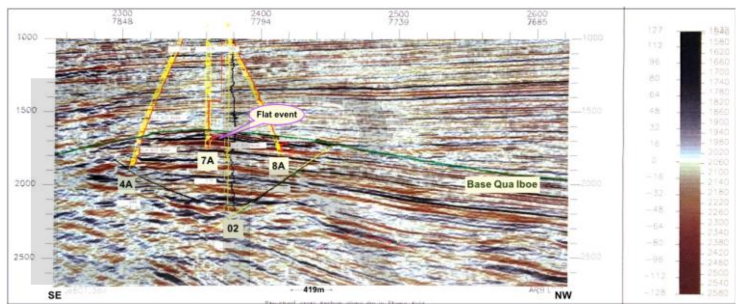

Figure 10. Arbitrary seismic section (SE – NW) along dip in Etema Field

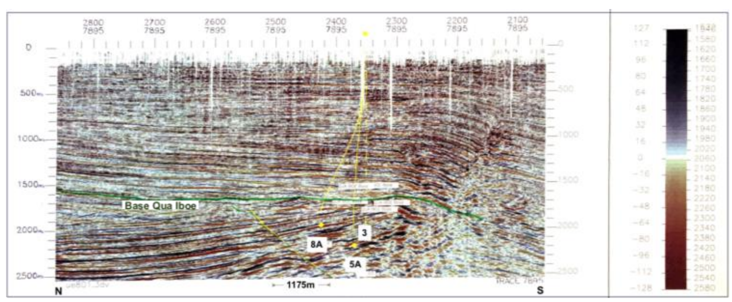

Figure 11. Seismic Trace 7895 along well 5A in Etema Field

Hydrocarbon accumulation occurs in the Biafra as well as the flanking "Rubble Beds while the Qua Iboe Shale acts as cap rock/seal for the reservoirs. Shale smear along fault plane in the area could possibly lead to entrapment. Besides a possible entrapment by shale smearing, trapping is also possible when a

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reservoir is juxtaposed against a shale body across a fault (Knot, 1993).
Lateral fluid communication is believed to occur where "Rubble Beds" feed oil into Biafra sands and, or where there is sand-to-sand juxtaposition across fault (Knutson and Ragnhild, 1991). There is however no vertical fluid communication since the sand units are vertically isolated. The Etema Field gas-oil-contact (GOC) at 5569 feet subsea depth and oil-water-contact at 5815 feet subsea depth, are derived from wells in the eastern and western parts of the field where distinct fluid contacts are observed. In the western part of the field, gas-oil-contact (GOC) is at 5569 feet subsea depth (well 7A) while Lowest Known Oil (LKO) is at 5814 feet subsea depth (Etema 5A). Highest Known Water (HKW) is at 5817 feet subsea depth (Etema 5A) and oil-water-contact (OWC) at 5815 feet subsea depth (well 12B). The distinct contacts translate to approximately to 1.655 seconds two-way-travel time for gas-oil-contact and 1.720 seconds two-way-travel time for oil-water-contact using checkshot survey data of wells in the filed especially the straight wells Etema 3 and 7A (table 6). These two-way-travel time values are in gas oil contact and oil water contact values associated with corresponding seismic flat events seen on seismic sections (fig. 10). Stock Tank Oil Initially In Place (STOIIP) for the most laterally continuous sand in the study area (Sand E4) is 720 barrels. This was evaluated based on dot counting method and Simpson's rule as applied to trapezoids. STOIIP was not calculated for the other sands because they were not continuous enough in the field for mapping.

Table 6: Check shot survey data for Wells 3, 6A, 7A and 8A

Etema 3		Etema 6A		Etema 7A		Etema 8A	
Two-way Travel Time (seconds)	Subsea Depth (feet)	Two-way Travel Time (seconds)	Subsea Depth (feet)	Two-way Travel Time (seconds)	Subsea Depth (feet)	Two-way Travel Time (seconds)	Subsea Depth (feet)
0.25	750	0.35	1000	0.28	800	0.24	700
0.35	1000	0.70	2147	0.35	1000	0.53	1583
0.42	1250	0.95	3050	0.51	1500	0.73	2245
0.51	1500	1.01	3250	0.67	2000	0.97	3100
0.59	1750	1.08	3500	0.81	2500	1.02	3250
0.67	2000	1.15	3750	0.96	3000	1.09	3500
0.74	2750	1.22	4000	1.03	3250	1.16	3750
0.82	3000	1.28	4250	1.10	3500	1.22	4000
0.89	3250	1.34	4500	1.17	3750	1.28	4250
0.96	3000	1.41	4750	1.24	4000	1.35	4500
1.02	3250	1.48	5000	1.31	4250	1.41	4750
1.10	3500	1.55	5250	1.37	4500	1.48	5000
1.17	3750	1.62	5500	1.44	4750	1.55	5250
1.24	4000	1.68	5750	1.51	5000	1.62	5500
1.30	4250	1.73	5950	1.57	5250	1.68	5750
1.37	4500			1.64	5500	1.74	6000
1.44	4750			1.69	5750	1.78	6200
1.51	5000			1.75	6000		
1.58	5250						
1.64	5500						
1.70	5750						
1.75	5950						

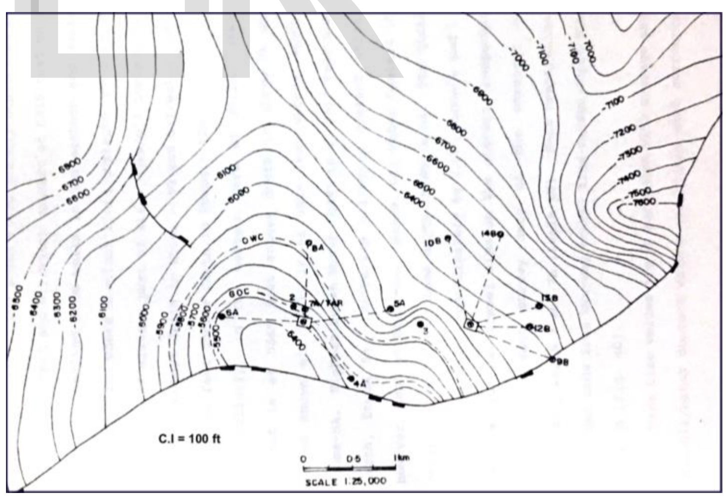

Figure 12. Top of sand E4 depth structure map

Summary and Conclusion

Five sand units were identified within the stratigraphic interval under investigation and studied in detail. The sand units were informally coded E1, E2, E3, E4 and E5. Log patterns of the sands in the area range from cylindrical or blocky to branching and recombining irregularly coarsening upward and generally fining upward profiles. The sand units are predominantly dip-oriented with feeder direction in the north east and, generally well developed in the field. Values for the Etema reservoir parameters compare favorably with published values of good quality reservoirs. Thus, the reservoir intervals in Etema Field are of good quality.

All the sand units in the field bear hydrocarbons except in well 5A where sands E3, E4 and E5 appear to be wet. It may probably be low resistivity reservoirs at those intervals.

Hydrocarbon entrapment in the area is by combination of structure and stratigraphy, but mainly stratigraphic with sands being truncated at the Base Qua Iboe unconformity. Hydrocarbon accumulation occurs in the Biafra as well as the flanking "Rubble Beds" while the Qua Iboe Shale act as cap rock and, or seal.

Deeper wells will be required for a complete assessment of the reservoir quality of the sands within the Biafra Member. Porosity logs if available for all the wells in the field, would enhance the results. 3-D seismic survey is recommended data for the area so that most of the stratigraphic and structural features that appear rather subtle on 2-D seismic data, should be more accurately interpreted.

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