Sand Thickness Distribution in Crestal (Growth) Faulted Systems Tracts Sediments in an Eastern Coastal Swamp Depobelt Oil Field, Niger Delta Basin, Nigeria

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ABSTRACT

Crestal (growth) faults lack fanning strata geometry that indicates general increase in sediment thickness towards fault boundary due to low growth but characterised by rollover deformation of strata toward the fault line in both the footwall and the hanging-wall. This study therefore aimed at maximising the potential of crestal faulted systems tracts deposits through the understanding of variability in its reservoir thickness distribution. Systems tracts including lowstand systems tract (LST), transgressive systems tract (TST) and highstand systems tract (HST) were determined from seismic data and wireline logs of five wells that penetrated stratigraphic units within a collapsed crest rollover anticline. Gross and net sand thicknesses and percentages of sands were calculated based on reservoirs top and bottom determined from gamma ray logs. Gross and net sand thickness values were contoured using rockworks 17 software. Gross sand thickness in LST, TST and HST ranged from 275 – 325ft, 225 – 275ft and 220 – 625ft respectively. Net sand thickness in LST, TST and HST ranged from 240 – 298ft, 120 – 195ft and 120 – 450ft respectively. Percentages of sands in LST, TST and HST ranged from 80 – 86%, 53 – 71% and 53.7 – 82% respectively. Sand thickness maps showed that LST sands thickened seaward, suggesting deltaic progradation, while TST thickened landward but toward regional sand supply paleo-direction. In HST, sands thickened towards the faults. Though all systems tracts are characterised by high sand thicknesses due to the increase in rate of sediment supply over time but it was only in HST that faults control the axis of sands deposition.

Keywords: Niger delta, depositional sequences, Stratigraphic boundaries, systems tracts, Sand thicknesses, sand percentagesa

INTRODUCTION

Reservoir sand thickness, whether gross or net is a necessary consideration in the exploration and exploitation of petroleum. Gross reservoir sand thickness which is the total interval of reservoir from the top to the bottom including tight rocks and shaly or silty components (Egbele *et al.,* 2005), varies with depositional systems in response to cycles of change in sediment supply or accommodation available for sediment accumulation and preservation. Therefore, depositional systems at the same stage of regional cycle of change in accommodation are linked in a systems tract, a component of a stratigraphic sequence. The regional change in accommodation is controlled by allogenic factors such as tectonic, climate and eustatic sea level change (Catuneau *et al.,* 2011). Consequently, gross sand thickness varies in different systems tracts and along structural/depositional dip (Posamentier and Vail, 1988; Oyanyan and Oti, 2015). Systems tracts and sequences are bounded by stratigraphic surfaces that indicates the position of sea floor as the shoreline shifts (either regression or transgression) in response to the cycles of changing accommodation and/ or sediment supply (Posamentier and Vail, 1988; Galloway, 1989; Catuneanu, 2006). The sequences, systems tracts and stratigraphic bounding surfaces are parameters or elements of sequence stratigraphy, that has become a veritable tool for the exploration of hydrocarbon traps; and for the correlation and the subseismic scale zonations of reservoirs across wells (Dolson *et al.,*1999).

Net reservoir sand thickness, which is the gross reservoir thickness minus the sum of thicknesses of intra-reservoir shales, also varies with different systems tracts and along structural or depositional dip. The distribution of intra-reservoir shales is controlled mainly by autogenic or autocyclic factors such as depositional environment energy flux, delta lobe switching, channel avulsion and

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lateral variability in the rate of local subsidence (Oyanyan and Oshinowo, 2020; Zecchin, 2005). The presence of intervening shales within reservoir results in heterogeneities, intra-sandbody compartmentalization and permeability anisotropy in hydrocarbon bearing reservoirs (Oyanyan and Oti, 2016a; Oyanyan and Ideozu, 2016). Therefore, understanding the distribution of sand thickness in systems tracts of an oil field is fundamental for the successful exploration and exploitation of hydrocarbon.

The reservoir potential of a sedimentary unit depends among others on thickness. Reservoir thickness mapping is part of the second stage of geometrical analysis of the stratigraphic components of a basin fill (Dolson *et al.,*1999). It gives fair understanding of the stratigraphic frameworks at sub-seismic scale that could help to address issues of reservoir geometry and hydrocarbon column height or net pay thickness variation in well development for optimum fluid flow. Reservoir thickness is an important parameter for hydrocarbon volumetric calculations.

Reservoir thickness trend reflects sediment deposition axis controlled by depositional dip, direction of sediment supply or growth fault. Where growth fault controls the axis of sediment deposition, sediments generally thickens toward growth fault boundary resulting in fanning strata geometry in seismic data (Doust and Omatsola (1989). Consequently, sand thickness trends are predictable and obvious no matter the systems tract. But in crestal faults, no fanning strata geometry resulting in the challenge of understanding variability in sand thickness distribution and predicting thickness trend. The maximization of potential of reservoirs of crestal faulted systems tracts requires the understanding of variability in its thickness distribution. Therefore, this paper is aimed at presenting this understanding by analysing the stratigraphic components of the studied oil field, correlating sandstone reservoirs across wells within stratigraphic framework, demonstrating the variability of sand thickness in the various systems tracts and determining the factors that control the sandstone thickness variability.

Study Area and Geologic Setting

The study area is located in the coastal swamp environment of Niger delta basin of Nigeria between latitude 4°28'30.62"N - 4°29'54.25"N and longitude 6°54'11.05" - 6°57'59.67"E (Fig. 1). It is about 55 Km from Port Harcourt, the capital city of Rivers State, Nigeria. Five oil wells have been drilled in the field so far. Four out of the five wells have been producing oil from five thick sandstone reservoirs.

The Niger delta basin is Tertiary in age. It is located in the Gulf of Guinea of West Africa or the southward end of the Benue Trough of Nigeria (Reijers, *et al.,* 1997; Tuttle *et al.,* 1999) (Fig. 1). It currently has onshore and offshore parts (Fig. 2). The onshore part can be described as epicratonic embayment which is a basin that lie on the continental crust but are partially opened to oceanic basin (Selly, 2000). At the southernmost end of the Benue trough, the Niger delta basin opened up into the Atlantic Ocean. The offshore part on the continental shelf environment, is a passive margin that has been subsiding due to the cooling of the underlying oceanic plate margin and the sediment loading of the continental crust (Doust and Omatsola, 1989). Therefore, the tectonic evolution of the Niger delta basin is connected to the tectonic evolution of the Benue Trough, an intracratonic rift basin that runs diagonally across Nigeria (Fitton 1980; Whiteman, 1982; Fig.1). Sediments deposition in the Niger delta basin began after Campanian-Maastrichtian sediments (also called proto-Niger Delta sediments) were deposited in southern Benue Trough (Akande *et al.,* 2011). Sediment deposition which began in the Eocene was controlled by both allocyclic and autocyclic processes (Reijers, 2011).

The Niger delta basin has sediment thickness of about 12 km, covering a total area of about 140,000km^2 (Knox and

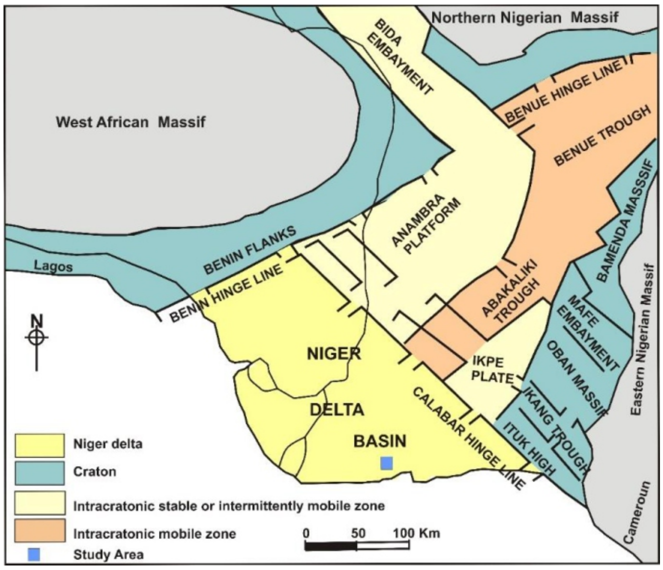

Figure 1: The Tectonic frame of Benue Trough and the location of the Niger delta basin with study area indicated (modified after Murat, 1972).

Omatsola, 1987). The total sediment thickness whose age ranged from Eocene to recent has been divided into three diachronous lithostratigraphic units, from bottom to top: Akata, Agbada and Benin Formations (Short and Stauble, 1967; Weber and Daukoru, 1975) (Fig. 2). The Akata

Formation is underlain by the basement complex and has a maximum thickness of 6500m, mainly consisting of over pressured marine shale with thin silt and sandy interbeds. Its age ranged from Paleocene to Recent. Overlying the Akaka Formation is the Agbada Formation. This shows a maximum thickness of 4000m and is characterized by paralic to fluvial-marine sands organized into coarsening-upward offlap cycles separated by shales. Its deposition began in the Eocene and continues into the Recent. The topmost Formation, the Benin Formation has a maximum thickness of 2000m and consists of continental fluvial sands/gravels and back swamp deposits. This formation comprises the latest Eocene to Recent continental deposits. The three formations occur within growth-fault bounded sedimentary units called the depobelts. Seven depobelts identified in the basin so far succeed each other in a southward direction (Doust and Omatsola, 1990; Stacher, 1995) (Fig. 3). The study area is located in the coastal swamp depobelt, which according to Reijers (2011) consists of two megasequences with five 3rd-order sequences belonging to the Agbada Formation, formed over 6.5 million years (from the Middle Miocene to the Late Miocene).

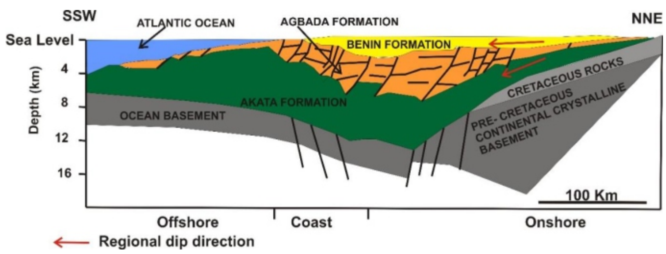

Figure 2: The stratigraphy of Niger delta Basin showing the different formations, structures and regional onshore structural dip direction (after Stacher, 1995).

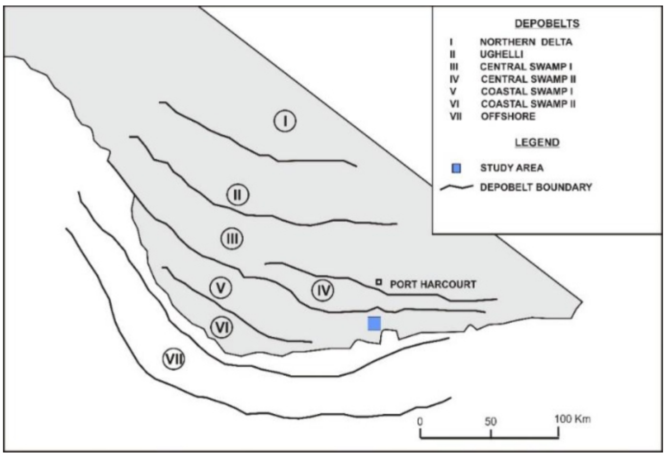

Figure 3: Geologic setting of Niger delta, showing the various depobelts and study area location (Modified after Knox and Omatsola, 1987).

DATA SET AND METHOD OF STUDY

The data set supplied by Shell Petroleum Development Company (SPDC) includes base map (Fig. 4), biofacies zones information, well-tied seismic data, structured contour map of a depth horizon and wireline logs suit consisting gamma ray, caliper, bulk density and neutron logs of five oil wells, all with sub-sea true vertical depth measurements (SSTVD). The biofacies zones data was used to determine the depobelt and the ages of rock strata penetrated by the well by interpreting it with the Niger delta sequence stratigraphic chart (Reijers, 2011; Oyanyan and Oti, 2016b). It has been discovered that the depobelt corresponds to coastal swamp facies with an overall Late Miocene age (10.6 – 10.35 Ma). These initial analyses were followed by the structural interpretation of seismic reflection data and the sequence stratigraphic analysis/correlation of the five wells.

The sequence stratigraphic interpretations are consistent with the nomenclatures of Catuneanu et al. (2011). Well log shapes were used to interpret depositional trend (aggradation, progradation and retrogradation), depositional environment and types of basal and top reservoir contacts or bounding surfaces (sharp or gradational) using the scheme of Cant (1992). The depositional trends, stratal stacking patterns and bounding surfaces were used to determine the sequence stratigraphic parameters- depositional sequences, parasequences and systems tracts. The absence of core samples for accurate lithofacies scheme resulted in suggestive interpretations for depositional processes and environments.

The gamma ray log tied to the seismic data was used along with seismic reflections amplitude, continuity and configurations to identify the sequence stratigraphic parameters and facies on the seismic dip section (Berryhill, 1986; Emery, D. and Myers, K., 1998). Reflection discontinuity or vertical displacement of parallel seismic refection was used to identify faults.

Reservoir sand components of systems tracts were differentiated from shale using gamma ray, bulk density and neutron logs (Dewan, 1983). The reservoir sands were labelled with capital alphabet letters starting from the bottommost/oldest to the shallowest/youngest. Gross reservoir thickness was determined by subtracting reservoir top depth values from the basal depth values. The net sand thickness was determined by subtracting the sum of intra-reservoir shale thicknesses from the gross sand thickness. The ratio of net sand thickness to gross sand thickness gave the net-to-gross sand ratio or multiplied by 100 to give the percentage of sand. Rockworks 17 software was used to contour the gross and net sand thickness values to produce the gross and net sand thickness distribution maps using easting, northings and thickness values as X, Y and Z values respectively.

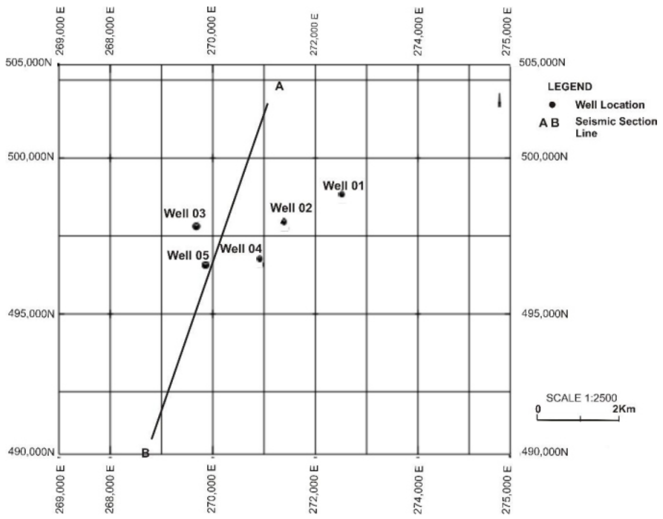

Figure 4: The base map showing seismic dip section line and number of wells and locations.

RESULTS AND INTERPRETATIONS

Structures and Seismic Data characteristics

The seismic data (Fig. 5) and structure contour map (Fig. 6) show that the studied oil field is a large collapsed crest rollover anticline, trending east-west. The five wells drilled so far in the field are all located on the east-west trending hinge zone of the rollover anticline. The field is bounded to the north by a major boundary growth fault, to the east by an antithetic fault and to the south by a synthetic growth fault.

The seismic section which is oriented parallel to the structural dip is characterized by parallel reflections and rollover anticlinal profiles, typical of Niger Delta Agbada Formation (Knox and Omatsola, 1987; Doust and Omatsola, 1989; Oyanyan and Oshinowo, 2020). The identified vertical displacement of seismic reflections trends/configurations is suggestive of faults. The listric or concave geometry of the fault line, the low or non-fanning geometry of strata towards the concave side of the fault line and the rollover deformation of strata toward the fault line in both the footwall and hanging wall indicate crestal faults (CF), based on the classifications of growth faults in the Niger delta basin by Doust and Omatsola (1989). The identified vertical displacement of seismic reflections by growth faults CF1 and CF2 show that the throw of the faults and subsidence decreased over time. According to Doust and Omatsola (1989) classifications, crestal faults are not characterised by obvious fanning geometry of reflections toward the concave side due to low growth (see Oyanyan and Oshinowo, 2020).

The faulted zone of interest is underlain by shale ridge characterised by chaotic seismic reflections (Fig. 5). The shale ridge is an evidence that the quick loading of under-compacted Akata Formation clay with deltaic sands of Agbada Formation triggers the development of the faults. The differential loading of the ductile shale and the listric geometry of the fault resulted in the formation of the rollover anticline that was collapsed by the combination of faults CF1 and CF2 (Doust and Omatsola, 1989).

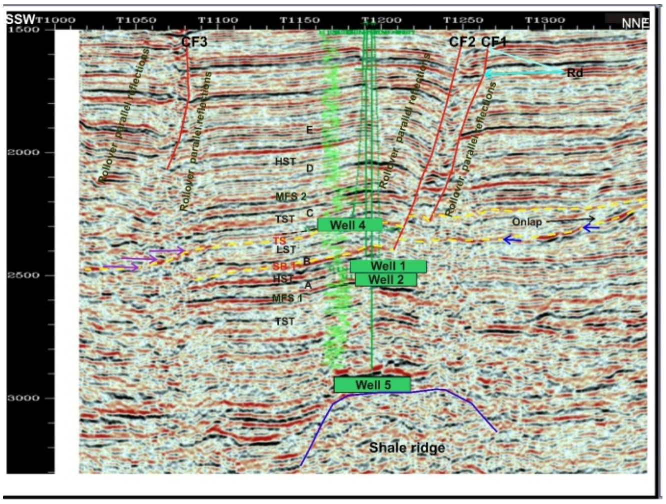

Figure 5: Well-tied seismic data showing sequence stratigraphic parameters, shale ridge, growth faults characterised by vertical reflections displacement (Rd) and listric geometry, and collapsed crest structure characterised by the rollover of parallel relections into anticlinal profiles on both sides of the crestal growth faults (CF). Abbreviations: SB = Sequence boundary, MFS = maximum flooding surface, TS = Transgressive surface, LST = Lowstand systems tract, TST = Transgressive systems tract, HST, = Highstand systems tract, Purple arrows = Marine onlap, black arrow = fluvial onlap; blue arrows = erosional truncation. The location of the seismic cross-section is shown in Figure 4.

Paleo-sedimentary processes, paleotopography and depositional environment can be interpreted from Seismic reflections configurations. Between 1600 and 2800ms two-way time (twt), the seismic data is characterised by medium to high amplitude and continuous parallel/subparallel reflections (Fig. 5), typical of parasequence, parasequence set and sequence boundaries in a prograding wedge over under-compacted clay in shoreface or marginal marine environment (Emery and Myers, 1998). Aside the zones of rollover of parallel reflections, rock strata reflections are either relatively flat or gently slanted southward indicating low paleo-slope gradient that may have enhanced the accumulations of sediments in shoreline and continental shelf depositional environments.

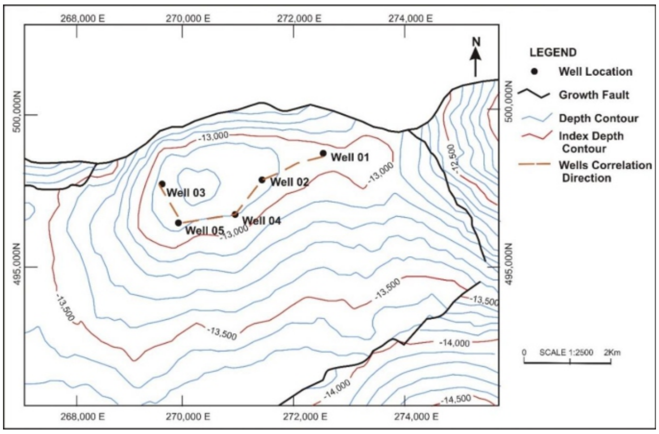

Figure 6: Depth structure map based on reservoir B top and TS seismic horizon (Fig. 5) depth data showing elevation variations, growth faults distributions and wells locations (by SPDC).

Sequence stratigraphic Parameters

Depositional Sequences, Systems tracts and Stratigraphic Surfaces

A sequence has been defined as a "cycle of change in accommodation or sediment supply defined by the recurrence of the same types of sequence stratigraphic surface through geologic time" (Catuneanu *et al.,* 2011; Catuneanu and Zecchin, 2013). That means, a depositional sequence represents cycle of change in accommodation creation and sediment supply, resulting in a relatively conformable succession of genetically related strata deposited during positive accommodation being bounded by subaerial unconformity or correlative conformity formed during negative accommodation.

In this study, parts of two depositional sequences (DS1 and 2) were identified in type well 3 (consisting most measured data) and correlated across other wells (Fig. 7). From the biofacies information of the field, the sequences are within the SPDC foraminiferal and pollen zones that ranged from P788 – P820 and F960 – F9620 respectively. In the Niger Delta Chronostratigraphic chart, the duration of cycles in which the sequences in the biozones were deposited ranged from 2.1 – 3Ma (Reijers, 2011). Therefore, based on the classifications of Vail *et al*. (1977; 1990) and Catuneanu (2006), these units are classified as third order sequences, separated by a sequence boundary (SB1) which, from the Niger Delta Cenozoic geological data table, was formed at 10.6Ma during relative sea level fall (Reijers, 2011). The lower sequence (DS1) was not fully penetrated, hence the basal boundary is not defined. The upper sequence (DS2) was fully penetrated by all wells but the well logs started below the sequence boundary representing the top of DS 2 sequence. But the components of a depositional sequence (systems tracts) were fully identified in DS 2. Thus, lowstand systems tract (LST), transgressive systems tract (TST) and highstand systems tracts (HST) were identified in the upper sequence (DS2), while only HST was identified in the lower sequence (Ds1).

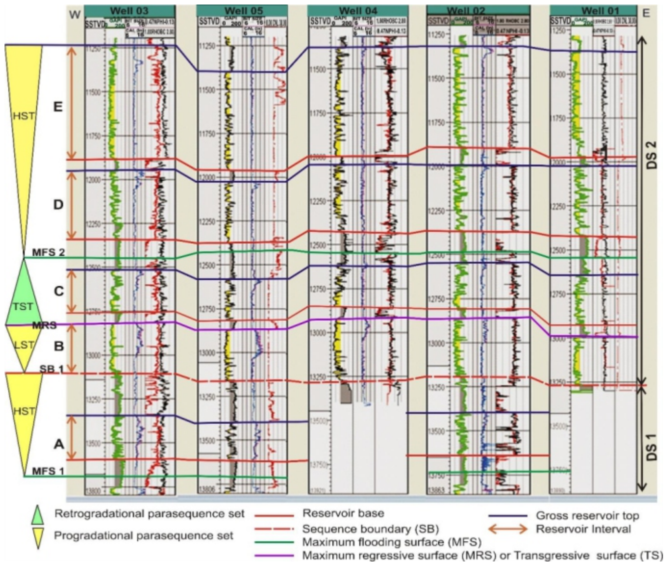

Figure 7: Framework of sequences, systems tracts, bounding surfaces and depositional trend. Column 2, 3 and 4 is gamma ray (in green), caliper (in blue), bulk density (in black)/neutron or compensated neutron (in red) logs respectively in wells 02, 03, 04 and 05. In well 01, there is no caliper log, resulting in gamma ray and bulk density/neutron logs in column 2 and 3 respectively.

Within the depositional sequences are stratigraphic surfaces that mark changes in stratal stacking patterns. They are surfaces that represent the paleo-seafloor at the beginning of the regression (highstand system tract) and at the beginning of the transgression (transgressive system tract). Maximum flooding surfaces (MFS) were identified in both DS 1 and 2. MFS is a stratigraphic surface that marks a change in stratal stacking patterns from transgression to highstand normal regression (Catuneanu et al., 2011). MFS 1 and 2 were identified in DS 1 and 2 respectively. The two MFSs were identified within condensed sections of about 150ft thick marine shales. The MFS surfaces are characterised by: 1) highest gamma ray values marking switch in depositional trend from retrogradation to progradation, and 2) surface of abrupt increase in neutron log values. From the Niger delta stratigraphic sheet (Reijers, 2011) and biofacies information, the MFS in DS 2 penetrated by all the wells was formed at 10.4Ma.

Unlike Maximum flooding surface, maximum regressive surface or initial transgressive surface is a stratigraphic surface that marks a change in stratal stacking patterns from lowstand normal regression to transgression (Nummedal et al.1993; Catuneanu *et al.,* 2011). It was identified only in DS 2. It also corresponds to the top of the LST reservoir sands (Fig. 7).

Stratigraphic surfaces (SB, MFS and TS) and systems tracts were also identified in the seismic dip section using the GR log of well 03 tied to it (Fig. 5). The stratigraphic surfaces are characterised by high amplitude and continuous reflections. The sequence boundary (SB) is a subaerial unconformity characterised, at the right side of the seismic section, by some seismic reflections termination (blue arrows) underlying it, indicating strata truncation by erosion. On top of the subaerial unconformity surface there are also some reflection terminations suggesting fluvial onlap and landward zone (Emery and Myers, 1998; Catuneanu, 2006). The transgressive surface (TS) merged with the unconformity surface confirming the right side of the seismic section as the up-dip or landward zone. On the left side of the seismic section, the TS is characterised on top by some reflections terminations (purple arrows) suggesting marine onlap, a transgressive healing phase deposit in the offshore zone (Catuneanu, 2006)

Systems Tracts and Sand Thickness Distribution

Lowstand Systems Tract (LST) and Reservoir Sand B Thickness Distribution

LST deposits indicate sediment accumulations after the onset of relative sea-level rise, during normal regression (Catuneanu *et al.,* 2011). It is formed when the rate of sediment supply exceeds the rate of accommodation creation. It is bounded at base and top by sequence boundary (sub-aerial unconformity) and maximum regressive surface respectively. It was identified as the basal systems tract in DS 2 with agradational base and coarsening-upward gamma ray log motif, signifying a progradational to aggradational succession set (Cant, 1992) (Fig. 7). Thus, the log traces indicate a coarsening upward sand-body which is well correlated across all the five wells.

Gross and net sand thicknesses and percentage of sand of the LST sandbody labelled "B" in Figures 5 and 7 ranged from 275 – 325ft, 240 – 298ft and 80 – 86% respectively (Table 1), while mean gross and mean net sand thicknesses and mean percentage of sand were 307ft, 257ft and 83.2% respectively (Table 2). Both gross and net sand thicknesses maps show southward or seaward thickening of sands in one direction and thinning of sands along strike from well 4 as the locus point (Figs. 8 and 9). They suggest progradation and aggradation in normal regressive setting characterized by sand thickening toward the point a river carrying sediments enters a bigger body of water or sea (Catuneau *et al.,* 2011). This type of sedimentation results in shoreline shifting seaward, and elevation/thickness increasing seaward. The action of waves, rip and longshore currents can re- distribute the sediments around the river mouth (delta), but during fairweather, the shoaling and breaking waves have the potential to move more sediment landward than seaward, hence keeping the sand within the beach and shoreface area (Catuneau, 2006). Therefore, the gross and net sand thickness are highest in well 4, suggesting that the locus of lobe deposition was likely around the location of well 4. Also, down-dip or southward thickening of sands and thinning of sands along strike indicate sand thickness higher in wells located in the direction of fluvial sediment supply, but decreased laterally towards other wells that are far from the direction of the river mouth. Furthermore, it suggests shallow-marine LST deltaic reservoirs connected landward with a topset of amalgamated fluvial channels.

Seaward thickening of sands is typical of LST in marginal/shallow marine siliciclastic system (Catuneau et al., 2011; Zecchin and Catuneanu, 2015). In lowstand stage, the rates of base-level rise increase over time, until normal regression changes to transgression. Consequently, accommodation increase at the shoreline over time, with increasingly more sediment required to fill it. This scenario results in normal regressive deltaic deposits become thicker with time and in an offshore direction (Catuneau. 2006). This is why the gross and net sand thicknesses gradually increase from well 2 to well 4 locations towards offshore direction, though both are probably located within the sand fairway or the direction of fluvial sediment supply.

Table 1 shows that wells 1, 3 and 5, have higher percentage of sand when compared to that of wells 2 and 4 that recorded higher gross and net sand thicknesses. This can be attributed to the winnowing action of waves in shoreface or deltaic depositional environment. The more sediment deposits are lateral distant from the direction of fluvial supply, the more the detrital clay components are winnowed-off by wave action and longshore current. It suggests the dominance of wave in the paleo-environment.

Generally, reservoir B has the highest percentage of sands

(Tables 1 and 2). This could be attributed to the high sediment supply and energy flux during lowstand. It also substantiates the fact that lowstand systems tract is defined by high sediment supply in low accommodation setting. This proved beyond reasonable doubt that LST is actually a product of normal regression, where shoreline regression is caused by the rate of sediment supply being greater than the rate of accommodation creation.

Table 1: Shows Reservoir Gross and Net Thicknesses Measured in Feet and Percentages of Sands.

Res.	Well 1			Well 2			Well 3			Well 4			Well 5		
	Gross	Net	%	Gross	Net	%	Gross	Net	%	Gross	Net	%	Gross	Net	%
A	NA	NA	NA	270	145	53.7	250	180	72	NA	NA		220	120	55
B	285	240	84	325	260	80	275	240	87	362.5	298	82	287.5	248	86
C	275	195	71	250	175	70	225	130	58	225	120	53	250	165	66
D	400	280	70	375	260	69	400	290	73	325	223	69	350	255	64
E	550	450	82	550	415	75	587	437	74	625	450	72	550	385	70

Res. = Reservoirs

Table 2: Mean gross and net reservoir thicknesses and percentages of sand in systems tracts.

Reservoirs	Mean gross sand thickness (Ft)	Mean net sand thickness (Ft)	Mean % of sand	Systems Tracts
A	246	148.33	60.23	HST
B	307	257	83.8	LST
C	245	157	63.67	TST
D	370	261.6	69	HST
E	572.4	427.4	74.6	HST

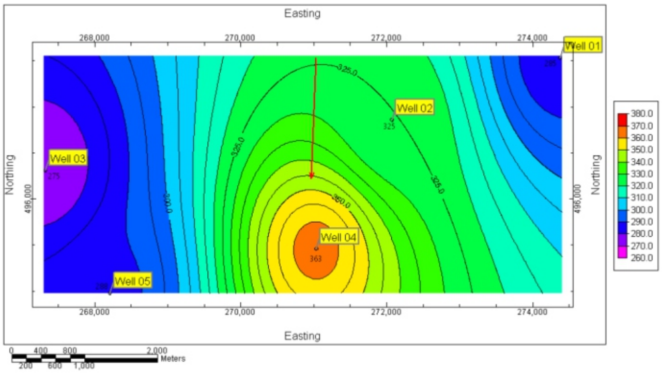

Figure 8: Reservoir sand B gross thickness distribution. It indicates LST normal regressive setting characterized by gross sand thickness increasing basinward but decreasing along strike from the locus of lobe deposition possibly in response to sediment dispersing waves and longshore current. The red arrow shows the seaward or depositional dip direction (see Figs. 2 and 6).

Transgressive Systems Tract (TST) and Reservoir Sand C Thickness Distribution

TST deposits are accumulated from the onset of transgression until the time of maximum transgression of the coast marked by the maximum flooding surface (Catuneanu *et al.,* 2011). It is formed when the rate of

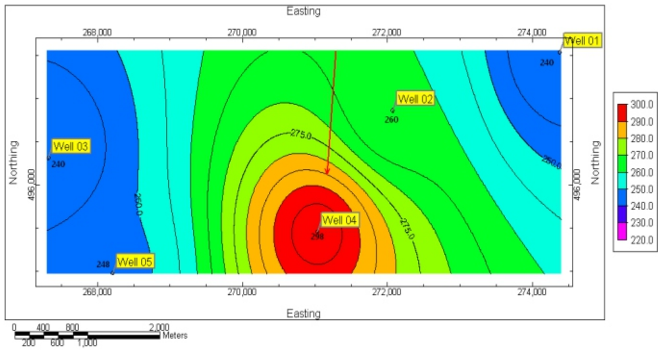

Figure 9: Reservoir sand B Net thickness distribution. It correspond with gross sand thickess and also indicates LST normal regressive setting characterised by net sand thickness increasing downdip or more basinward, but decreasing along strike from the locus of lobe deposition possibly in response to sediment dispersing waves and longshore current. The red arrow shows the seawrd or depositional dip direction (NNE –SSW).

accommodation creation, by sea-level rise or subsidence, exceeds the rate of sediment supply at the coastline (Aschoff *et al.,* 2018). In this study, TST was only identified in DS 2, overlying LST (Fig. 7). It is bounded at base and top by maximum regressive surface and maximum flooding surface (MFS2) or final transgressive surface respectively. The log profile of TST in well 01 in the east is blocky but internally serrated. According to Cant (1992), a similar blocky but internally serrated profile may be suggestive of fluvial aggradation with tidal influence. But in wells 02, 03, 04, and 05, the general log profiles are characterised by three high frequency funnel-shaped log motifs with upward decrease in thicknesses forming a general bell shape or retrogradational log trend, which sometimes suggestive of back-stepping bayhead deltas or barrier islands in transgressive coastline setting (Muto and Steel, 1992; Aschoff *et al.,* 2018). The log profiles are quite similar to that of back-stepping bayhead delta and estuary in Catuneanu (P. 136, 2006), where they are seen to also correlate with fluvial meandering log profiles in a TST. Bayhead delta is formed in wave-dominated coastline and when the transgression of the open shoreline is faster than the transgression of the river that supplies sand to the basin (Catuneanu, 2006; Nichols, 2009). Therefore, the gradual internal change in the log profile from East to West suggests the increase and decrease of influence of wave and of tide towards the west respectively. It is similar to that described by Oyanyan and Oshinowo (2020). It also suggests that sands in well 01 are mostly fluvial sands trapped by marine transgression in shallow marine environment, while in other wells may be combinations of fluvial sands and sands provided by processes of wave erosion in the upper shoreface during transgression and transported landward during fairweather

(Catuneau 2006). This is also why a Systems tract is defined as the linkage of contemporaneous depositional systems.

Gross and net sand thicknesses and percentage of sand of the TST sandbody labelled "C" ranged from 225 – 275ft, 120 – 195ft and 53 – 71% respectively (Fig. 7; Table 1), while mean gross and mean net sand thicknesses and mean percentage of sand were 245ft, 157ft and 63.67% respectively (Table 2). The Gross and net sand thicknesses maps shows increased in sand thickness towards north-east, with the highest value recorded in well 01 (Figs. 10 and 11). The percentage of sands decrease from 71% in well 01 in the northeast to 53% in well 04 in southwest, suggesting the north east as a possible input or source area for the sandstone. The maps show the effect of sea-level rise and direction of supply of sediment on sand thickness in TST deposits. The rise in base level accompanied by transgression leads to the erosion of the foreshore and upper shoreface, resulting in the thickness of sand increasing toward the direction of fluvial sediment supply. It therefore may suggest that sands were supplied from the north east and trapped in the fluvial system, resulting in sediment starvation of the shelf. Parts of the sediment eroded from the upper shoreface may have been transported landward to form backstepping bayhead delta or beaches (Catuneanu, 2006). It could also suggest decrease in shelf topographic gradient or trajectory of revinement surface from the north east to the south west, even as can be seen in the transgressive surface seismic horizon (Fig. 5). The landward movement of shoreline during marine transgression is relatively slower in area of high-gradient topography than in area of lower-gradient topography (Cattaneo and Steel, 2003). Consequently, sand thickens more in the direction of higher-gradient

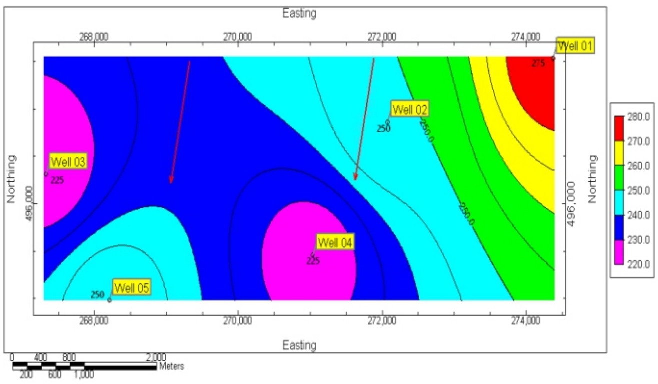

Figure 10: Reservoir C gross sand thickness distribution. It shows trapping of more sands towards the north-east during transgression and suggests the north east as a possible input area for the sandstone. The red arrows indicate depositional direction (NNE – SSW, see Figs. 2, 5 and 6).

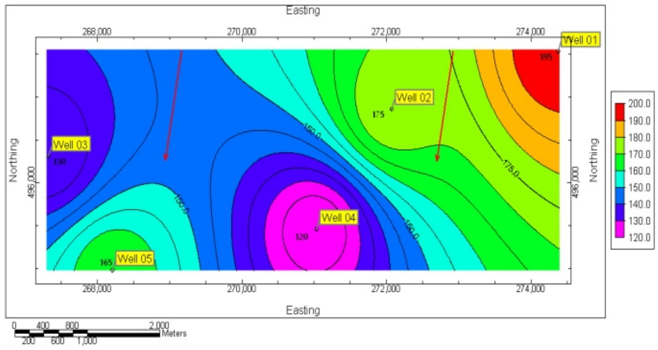

Figure 11: Reservoir C net sand thickness distribution. It corresponds with the gross sand thickness to also show the trapping of more sands towards the north-east during transgression and suggests southwestward deltaic progradation with the north east as a possible input area for the sandstone. The red arrows indicate depositional dip direction.

topography.

The percentages of sand show that the sand/mud ratio decreased southward or seaward, which is the structural dip direction (Figs. 2, 5 and 6), and away from the possible location of the river mouth as a result of decrease in the competency of the river and effect of the accelerating base level rise. Therefore, there is decrease in the amalgamation of channels fills in the aggrading fluvial system from the east, where well 01 is located, to down dip or southward and to the west of the field. Consequently, there are isolated sands as backstepping bayhead or beaches toward the west of the field.

Highstand Systems Tract (HST) and Reservoir Sands A, D and E Thicknesses Distributions

HST is a deposit of normal regression during late stage of relative sea level rise, when the rate of sediment accumulations exceeds the rate of accommodation creation due to decreased relative sea level rise (Catuneanu *et al.,* 2011). It is bounded at the base and top by a maximum flooding surface and a sequence boundary respectively. In this study, HST deposits were identified in DS 1 and 2 (Fig. 7). HST reservoir sands identified in DS1 is labelled "A", while the ones identified in DS2 are labelled "D" and "E". Reservoir sands D and E are parasequences separated by about 50ft flooding event marine shales in a progradational parasequence set. The trend of gamma ray log motif from the base of reservoir sand D to E shows an increasing progradational parasequence stacking pattern typical of HST (Posamentier and Vail, 1988). Based on the gamma ray log traces, the gradationally-based HST sands are aggradational – progradational successions typical of shoreface sands in a regressive shoreline setting (Cant, 1992; Zecchin and Catuneanu, 2013). In the seismic section (Fig. 5), the HST, unlike the TST and LST, are characterise by high amplitude parallel reflections typical of parasequence sets (Emery and Myers, 1998).

Gross and net sand thicknesses and the percentage of HST reservoir sand “A” penetrated by only three wells ranged from 220 – 270ft, 120 – 180ft and 53.7 – 72% respectively (Fig. 7; Table 1), while mean gross and mean net sand thicknesses and mean percentage of sand were 246ft, 148.33ft and 60.23 % respectively (Table 2). In contrast, gross and net sand thicknesses and percentage reservoir sand “D” penetrated by all wells ranged from 325 – 400ft, 223 – 290ft and 64 – 73% respectively, while mean gross and mean net sand thicknesses and mean percentage of sand were 370ft, 261.6ft and 69 % respectively. Similarly, gross and net sand thicknesses and percentage reservoir sand “E” penetrated by all wells ranged from 550 – 625ft, 385 – 450ft and 70 – 82% respectively, while mean gross and mean net sand thicknesses and mean percentage of sand were 572.4ft, 427.4ft and 74.6 % respectively.

The gross and net sand thicknesses maps of reservoir D show that gross and net sand thicknesses as well as net to gross sand ratio or percentages of sand increased toward wells locations close to fault boundaries and generally thins southward which is the depositional and structural dip direction (Figs. 2, 12 and 13). Figure 12A shows that wells 01 and 03 are closer to fault boundary than the other wells in their north-east and west sides respectively. Hence, the thickness of sand increased toward their locations as indicated by the maps colour scale. They show that the axis of sand deposition was controlled by syn-depositional fault activity and substantiated the already established fact that thinning of sand in down-dip direction is typical of HST (Zecchin, 2005 and 2007; Catuneau *et al.,* 2011). Growth fault rollover of structures created a steep topographic gradient that slopes down toward the fault boundary (Figure 5). The steep topographic gradient moves sediment towards the fault boundary but also associated with erosion that over time decreased as the effect of growth fault subsidence also decreased.

Reservoir sand E is generally very thick across all the wells, but unlike in reservoir D, the gross and net sand thicknesses maps shows variability of sand thicknesses

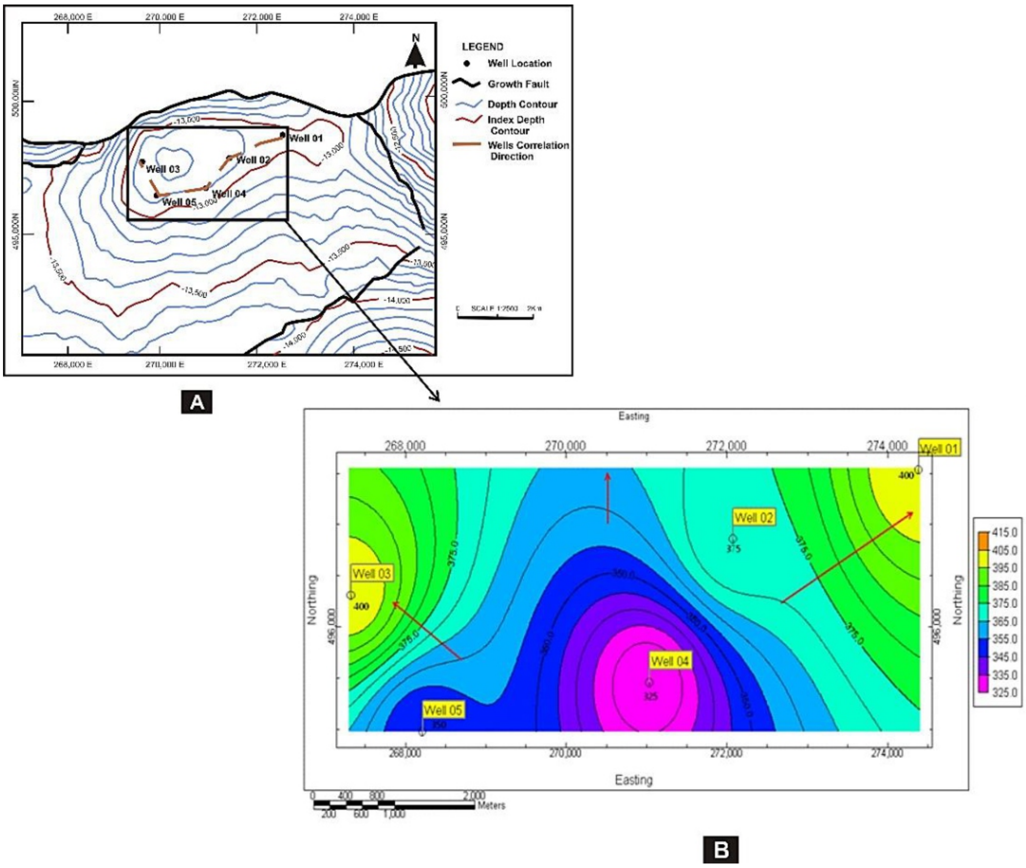

Figure 12: (A) Depth structure map indicating sand thickness contoured zone and growth faults boundaries. (B) Reservoir D gross sand thickness distribution. It shows thickening of sands toward the location of crestal faults. Wells 01 and 03 are closer to growth fault boundary than other wells. The red arrows indicate the direction to the locations of the nearest growth fault boundary.

along strike (east – west) (Figs. 14 and 15). This can be attributed to strike variability in sedimentation rate due to autocyclic shifting of sediment entry point into the basin, in rate of growth fault subsidence and in environment energy flux or sediment dispersing currents (Catuneanu, 2006; Oyanyan and Oti, 2015; Oyanyan and Oshinowo 2020b).

Generally, the percentage of a sand increased from reservoir A (the oldest sand unit) to reservoir E (the youngest sand unit) which indicates the sand/mud ratio increases in response to decelerating base-level rise and steady continuous increase in sediment supply.

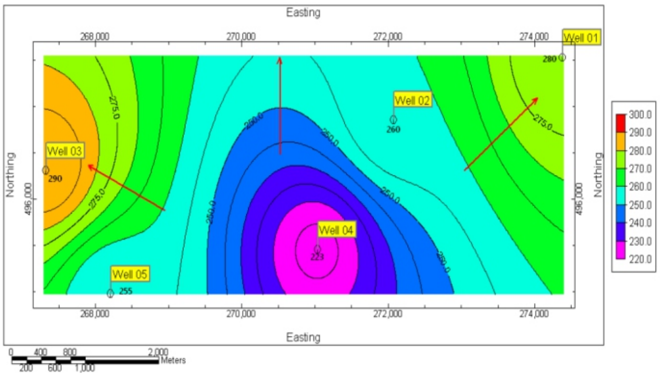

Figure 13: Reservoir D net sand thickness distribution. It correspond with the gross thickness map to show thickening of sands toward the location of crestal faults. The red arrows indicate the direction to the locations of the nearest growth fault boundary (see Figure 6).

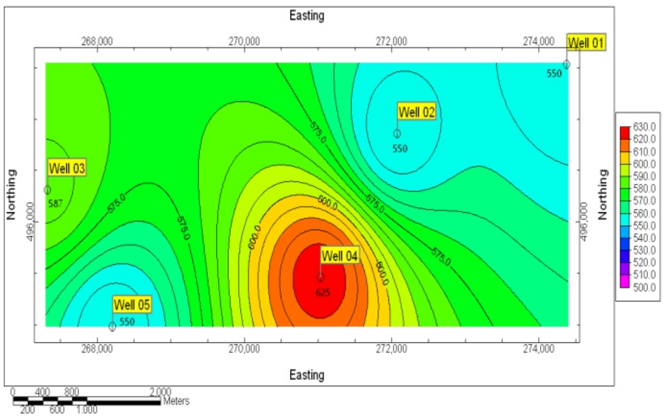

Figure 14: Reservoir E sand sand thickness distribution. It shows varied sand thickness along strike (east – west) though this sand is generally very thick.

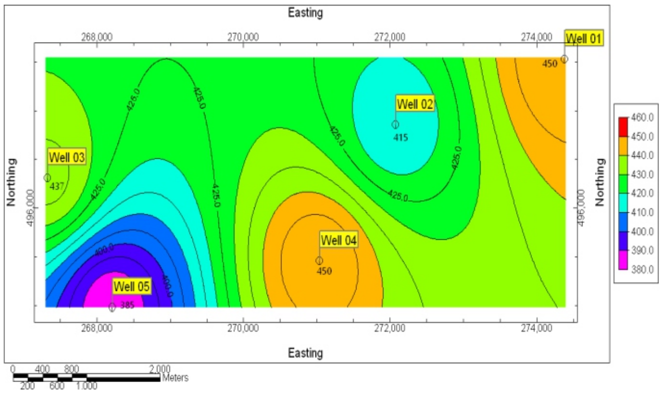

Figure 15: Reservoir E net sand thickness distribution. Just like the gross sand thickness map it also shows sand thickness variation along strike though not exactly correponding with the gross sand thickness in some well locations.

DISCUSSION

The development of stratigraphic sequences and different systems tracts in a basin depends on the amplitude and rate of eustatic change and on tectonics, which are major allogenic factors (Catuneanu and Zecchin, 2013; Zecchin and Catuneanu, 2013; Zecchin and Catuneanu, 2015). The eustatic change affects mainly the accommodation available for sediment deposition and preservation, while tectonics, which is either crustal subsidence or uplift determine change of accommodation and rate of sediment supply. According to Reijers (2011), depositional sequences and systems tracts of Coastal swamp depobelt of Niger delta were developed during steady increase in sediment supply that resulted in deltaic Progradation maintained at a steady rate of 13–17 km/Ma. The steady increase in sediment supply has been attributed to Neogene hinterland rising or uplift associated with the Cameroon volcanic activity (see Fitton, 1980; Cahen et al., 1984; Knox and Omatsola, 1987). Also, 3rd-order eustatic change was superimposed on the rising limbs of 2nd-order super-cycle suggesting constant availability of accommodation for sediment deposition and preservation (Reijers, 2011).

Gross and net sand thicknesses and percentages of sands distributions in the various systems tracts reflect rate of sediment supply, axis of sediment deposition, depositional sub-environment and energy flux. Generally, sand thickness and percentage of sand increased from the deepest reservoir to the shallowest, suggesting increase in rate of sediment supply and decrease in growth-fault subsidence over-time, typical of the Agbada Formation reservoir sands (Oyanyan and Oshinowo, 2020). The percentage of sands ranged from 53 to 86%, similar to ranges reported by Reijers (2011) for barrier complexes in coastal swamp depobelt. Even though TST reservoir sand C has the lowest mean gross and net sand thickness, it anomalously has percentage of sand close to or higher than that of some HST reservoir sands especially in wells 01 and 02, located in the north-eastern part of the study area (Tables 1 and 2; Figure 6). This could be attributed to steeply rising transgressive trajectories which according Aschoff *et al.* (2018), sequester sandy, thicker, better connected transgressive deposits than flatter transgressive trajectories. It was the LST topography that was possibly backfilled and preserved instead of broad flooded continental shelf where only thin and discontinuous sands are preserved during coastline transgression (*sensu* Aschoff *et al.,* 2018). Above all, the general high net to gross sand ratio or percentage of sand recorded in all the systems tracts further confirmed the high rate of sediment supply to Niger delta basin due to rising hinterland and the dominance of winnowing wave actions in the Late Miocene development of coastal swamp depobelt.

Sand thickness distributions within each systems tract shows that HST sands thickened towards growth-faults boundary, with a plan-view geometry that suggest an orientation along strike in coastal environment, whereas that of LST is more or less a localised sand-body similar to that of deltaic deposition in which thickness increasing towards delta lobe centre from where it decreases to other locations. According to Ejedawe (1981), Niger Delta sediments represent a coalesce of five delta lobes fed by four rivers. The LST sands could possibly be one of the delta lobes. The thickening of sands toward the growth-faults during HST suggest that growth-faults may have controlled the axis of sand deposition during the HST development, similar to that described by Reijers (2011) and Oyanyan and Oti (2015). The thickening of reservoir sands within the down-thrown block towards the growth fault boundary is very common in the Agbada Formation (Weber and Daukoru, 1975; Tuttle et al., 1999). Therefore, HST sand thickness varies according to lateral variations in growth fault subsidence.

The variability in sand thickness in the TST is quite different from that of HST and LST. Sediments are more reworked and dispersed by waves and longshore currents during marine transgression (Zecchin and Catuneanu, 2015). Consequently, TST sands thickened towards the area of low coastal energy flux and the direction of sediment regional supply, which is likely north-east. The TST sand thickness maps clearly showed that coastal swamp depobelt prograded from the northeast to the southwest, obliquely with respect to the current coastline; and sand fairway also northeast – southwest, in line with the findings by Reijers (2011).

CONCLUSIONS

The following conclusions can be drawn from this study:

1. Depositional sequences and systems tracts are clearly well developed in the studied area by cycles of changes in sediment supply and accommodation. All the systems tracts are characterised by high gross and net sand thicknesses and net to gross sand ratio or percentages of sand due to the increase in rate of sediment supply over time as a result of the Neogene hinterland tectonic uplift and high energy flux respectively. However, sand thickness still varied in the different systems tracts.

2. Lowstand systems tract (LST) sands thickened southward which correspond with the regional dip direction, while net-to-gross sand ratio or percentage of sand increases along strike from the direction of sand supply route possibly due to the winnowed-off of detrital clay by waves and longshore currents. They suggest progradation and aggradation in normal regressive setting. Therefore, variability in LST gross and net sand thickness in oil wells across the field mainly depended on the distance from sediment supply route while net to gross sand ratio depends on the winnowing action of waves.

3. TST sands thickened towards north east. Therefore, it suggests deltaic progradation in southwestward direction. Variations in sand thickness development was possibly controlled by variability in shelf topographic gradient or trajectory of revinement surface and by waves and tidal current actions.

4. In HST units, sands thickened towards the crestal faults and thinned seaward, suggesting sands depositional axis controlled by syn-depositional faulting. Variability in sand thicknesses along strike was also identified, suggesting lateral variability in syn-depositional fault subsidence and topographic gradient.

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