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3D seismic discontinuity attributes analyses for low – permeability reservoir sand fractures characterisation: an onshore example from Niger delta, Nigeria

J. O. Amigun and O. A. Akinleye-Martins

Department of Applied Geophysics, Federal University of Technology, Akure, Nigeria

ABSTRACT

In hydrocarbon exploration, fractures act as possible pathways for hydrocarbon flow especially in low-permeable siliciclastic reservoirs and carbonate reservoir layers. These fractures on typical seismic section are designatesub-seismic scale structures, occur below seismic resolution and thus difficult to detect on seismic section. This study aims to predict and characterise sub-seismic scale fractures within low-permeability siliciclastic reservoirs of Agbada Formation in "Kin" Field onshore Niger Delta basin by using discontinuity attributes i.e. similarity and curvature. The input seismic data of the study field was initially conditioned using the dip steering algorithm to improve the image quality of fractures in the data. Time-slices were extracted within the horizons of interest for seismic attribute analysis. Conventional log from porosity density was used to validate the interpreted fractures within the borehole environment. The attribute analyses result at time-slices 2024 ms, 2100 ms and 2197 ms show subtle features i.e. fractures with predominant trends NW – SE and NE – SW. A multi-attribute analysis was performed to optimise fractures prediction. Further results show relatively high fracture density at the western central and south eastern regions of the study area. Therefore, these regions could be inferred as potential hydrocarbon zones and locations for future wells placement.

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Fractures; similarity attribute; curvature attribute; dip steering algorithm; siliciclastic reservoirs; multi-attribute analysis

1. Introduction

In low permeable siliciclastic hydrocarbon reservoir rocks, natural fractures that are non-drilling induced fractures are increasingly becoming exploration and development targets due to their enhancement of the overall formation's permeability (Paitoon and Helmut. 2011), advent of horizontal drilling technology (Kuich 1989) and the industry ventures into more complex, deeper and unconventional reservoirs (Jaglan et al. 2015). Permeability is enhanced by fracture networks in low permeable siliciclastic reservoir and carbonate rock. They create conduits for hydrocarbon flow with resulting impact on productivity. During hydrocarbon recovery, fractures may also redirect the path of injected fluids thus limiting the fluids' usefulness in contacting, sweeping and displacing hydrocarbons (Aarre et al. 2012)

Fractures on the contrary can behave as fluid flow barriers and accordingly acting as seals, especially when filled with clay or shale (Laubach 2003). In line with Zellou et al. (1995), naturally fractured reservoirs represent a significant percentage of oil reservoirs throughout the world. However, reliable information on essential component of fracture's distinguishing attributes such as orientation (trend), geometry and pattern are sparse because few fractures intersect vertical well bores (Jaglan et al. 2015). According to Chopra and Marfurt (2007), fracture characterisation in effect, is the understanding of fracture patterns, so that suitable means can be devised for effectively draining out fractured reservoirs. A good understanding of the fracture network, i.e. fracture connectivity, orientation, and location definitely is the key point to fractured reservoir characterisation (Singh et al. 2008).

Sub-seismic scale structures, specifically fractures on standard seismic section often occurs below the seismic resolution and are thus hard to detect. The advancement in seismic attributes e.g. using dip steering and other related algorithms for computation of seismic attributes (Chopra and Marfurt 2007; Alai et al. 2014) and visualisation techniques (Tingdahl and de Rooij 2005; Jaglan et al. 2015) have made possible fracture identification and characterisation. The study area "Kin" Field is situated in the siliciclastic tight reservoirs of the Agbada Formation located onshore Niger Delta, Nigeria (Figure 1). A prior petrophysical study has indicated that this field is a major hydrocarbon potential target (see Table 1) with moderate porosity reservoirs (Akinleye-Martins 2016). These findings have brought forth the interest of employing in this paper the seismic discontinuity attributes of similarity and curvature which are edge sensitive tool (Chopra and Marfurt 2007; Odoh et al. 2014) that provide a clearer definition of the structural information contained in seismic datasets i.e. to identify and possibly characterise sub-seismic structures

CONTACT J. O. Amigun joamigun@futa.edu.ng Department of Applied Geophysics, Federal University of Technology, Akure, Nigeria

(a)

(b)

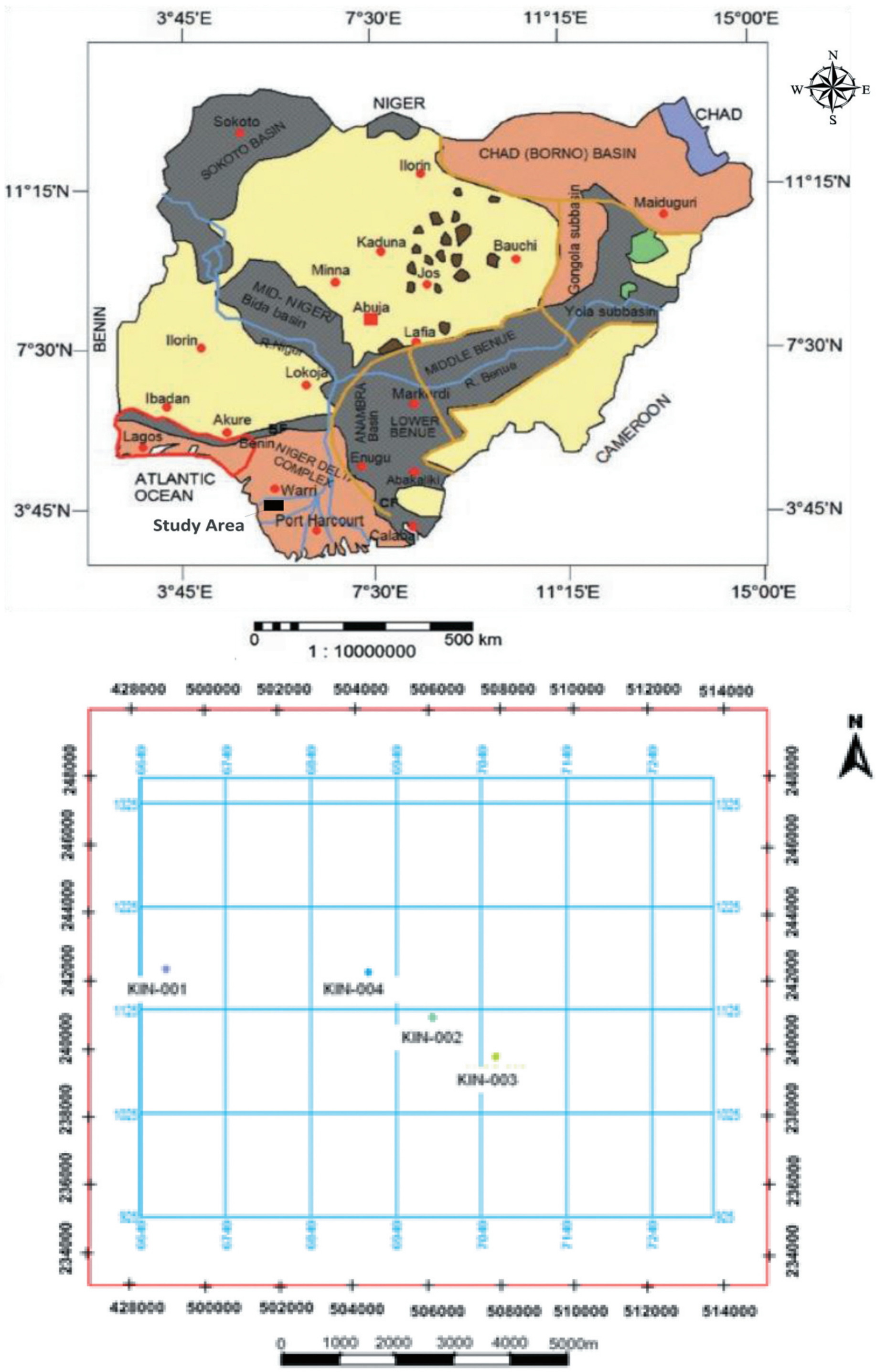

Figure 1. (a) Location map of the study field in Niger Delta basin, Nigeria, (b) Base map of the study field indicating the area covered by 3D seismic lines and drilled wells.

Table 1. Reservoir petrophysical parameters of some drilled wells in the study area. (Akinleye-Martins 2016).

	Reservoir Sand	Average Pay Thickness (m)	Porosity φ (%)	Permeability K (mD)	Water Saturation S_w (%)
Well Kin 1	Sand 1- Sand 4	54.49	24.4–32.7	604.8–920.6	33.2–69.9
Well Kin 2	Sand 1- Sand 4	45.03	21.3–30.8	674.8–1362.8	25.9–54.4
Well Kin 4	Sand 1- Sand 4	39.08	26.6–33.5	605.9–905.3	28.1–31.6

i.e. fracture networks/subtle faults likely to be controlling the field's reservoirs permeability.

2. Geology of the study area

The Niger Delta basin situated at the apex of the Gulf of Guinea on the West Coast of Africa is a prolific basin that is composed of regressive clastic sequence (Evamy et al. 1978; Damuth 1994; Reijers 2011). This basin started to develop in early Tertiary times when clastic river input increased (Doust and Omatsola 1990). It sediments thickness average 12 km, covering a total area of about140,000 km^2

Akata, Agbada and Benin Formations (Figure 2) are the three main lithostratigraphic units that underlay the Niger Delta. The top layer of the basin depositional sequence is the Benin Formation (Oligoecene to Recent) and it is a continental deposit of alluvial and upper coastal plain sands. Agbada Formation (Eocene to Recent) which underlies the Benin Formation is made up of coastal marine sequences of sand and shale, and regarded the main hydrocarbon-bearing unit (Short and Stauble 1967; Avbovbo 1978; Stacher 1995). This formation overlies the Akata Formation (Eocene to Recent), a basal marine shale unit considered to be the main source rock.

For the Niger Delta, its stratigraphy and structural pattern are constrained by the interplay between amount of sediment supply and subsidence (Evamy et al. 1978). The structural development of the delta since the Middle Eocene has been dominated by growth-faulting and associated rollover in the shelf portion. According to Weber (1987) growth faults are regarded the major migration conduit and principal factor controlling the hydrocarbon distribution pattern in the Niger Delta.

The study area which location is onshore Niger Delta, is recognised to lie within a zone where the physiographic setting is majorly controlled by extensional tectonic factors and the depositional regime

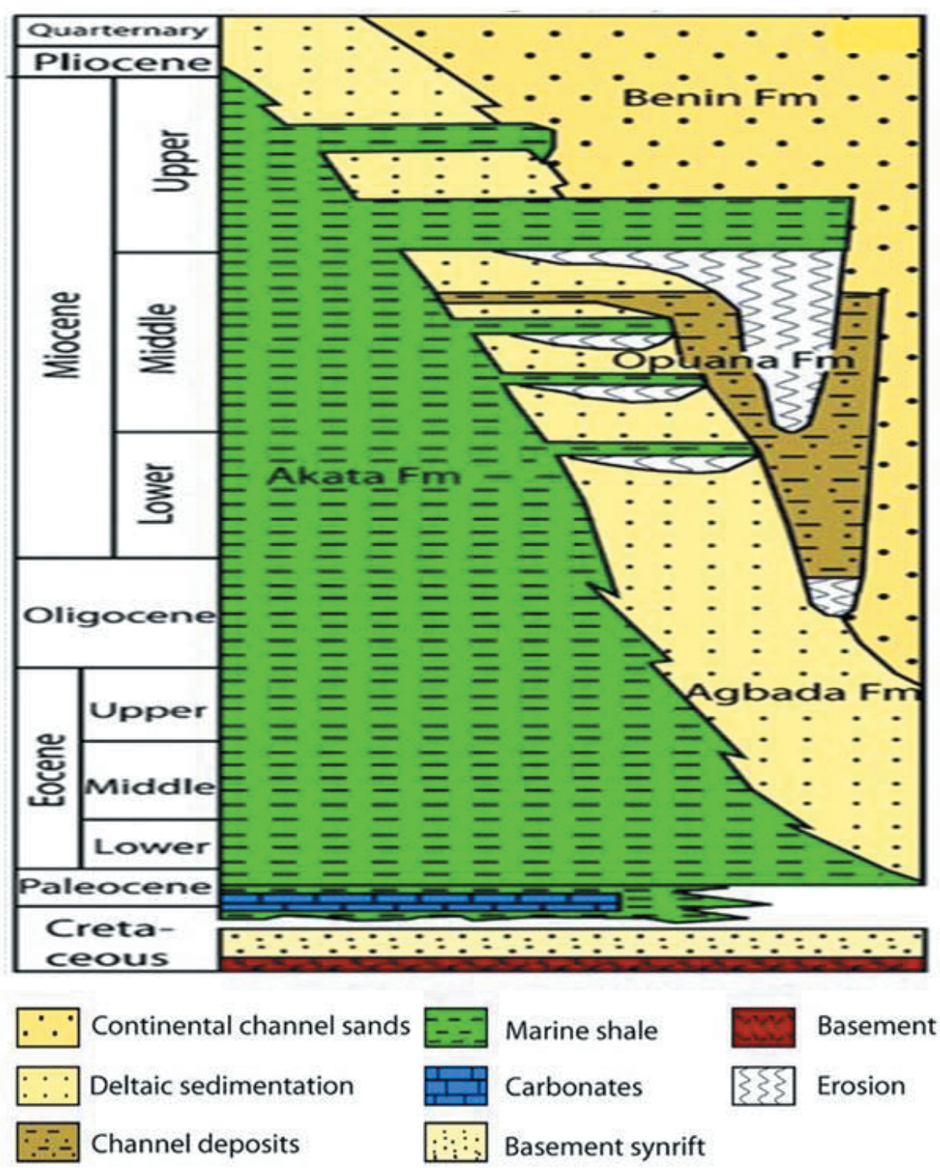

Figure 2. Generalising stratigraphy column indicating formations of the Niger Delta (modified from Doust and Omatsola 1990).

being controlled by structural growth i.e. mud diapirs and growth faults (Knox and And Omatsola 1989). Hence, this area may have experience multi-stage tectonic movement resulting in its Agbada Formation forming many unconformities accompanied with a large number of faults and fracture networks. According to Singhal and Gupta (2010), fractures.

created by structural movement are linked to a local tectonic event, and they form networks with specific spatial relationships to folds and faults.

The stacked pay sand reservoirs (Sand1 – Sand 4) of Agbada Formation at depth 2440–3210 m shown in Figure 3 are the main hydrocarbon producers in the "Kin" Field (Akinleye-Martins 2016). Individual sand reservoir units are relatively thick (6 to 146 m) and sandwiched between shale layers. The main hydrocarbon producers Sand 1 to Sand 4 are represented by relatively high resistivity and low gamma ray log values when compared with overlying or underlying shale.

3. Background

3.1. General characteristics of fractured reservoir

In carbonate and low permeable siliciclastic rocks, owing to their low matrix porosity and low permeability, fractures have become the effective storage spaces in their reservoirs. Consequently, the answer to a high and stable production well in these natures of rock is to drill the zone where fractures are highly developed (Wang et al. 2005, 2010; Han et al. 2006; Pang et al. 2010).

Fractures within a reservoir are either opened, closed or water/hydrocarbon filled (Laubach 2003; Paitoon and Helmut. 2011). Fractured reservoir could be explained as a reservoir in which naturally occurring fractures either have, or are predicted to have, a significant effect on reservoir fluid flow either in the form of increased reservoir permeability and/or reserves or increased permeability anisotropy (Alfred. 2000). Supported evidence have

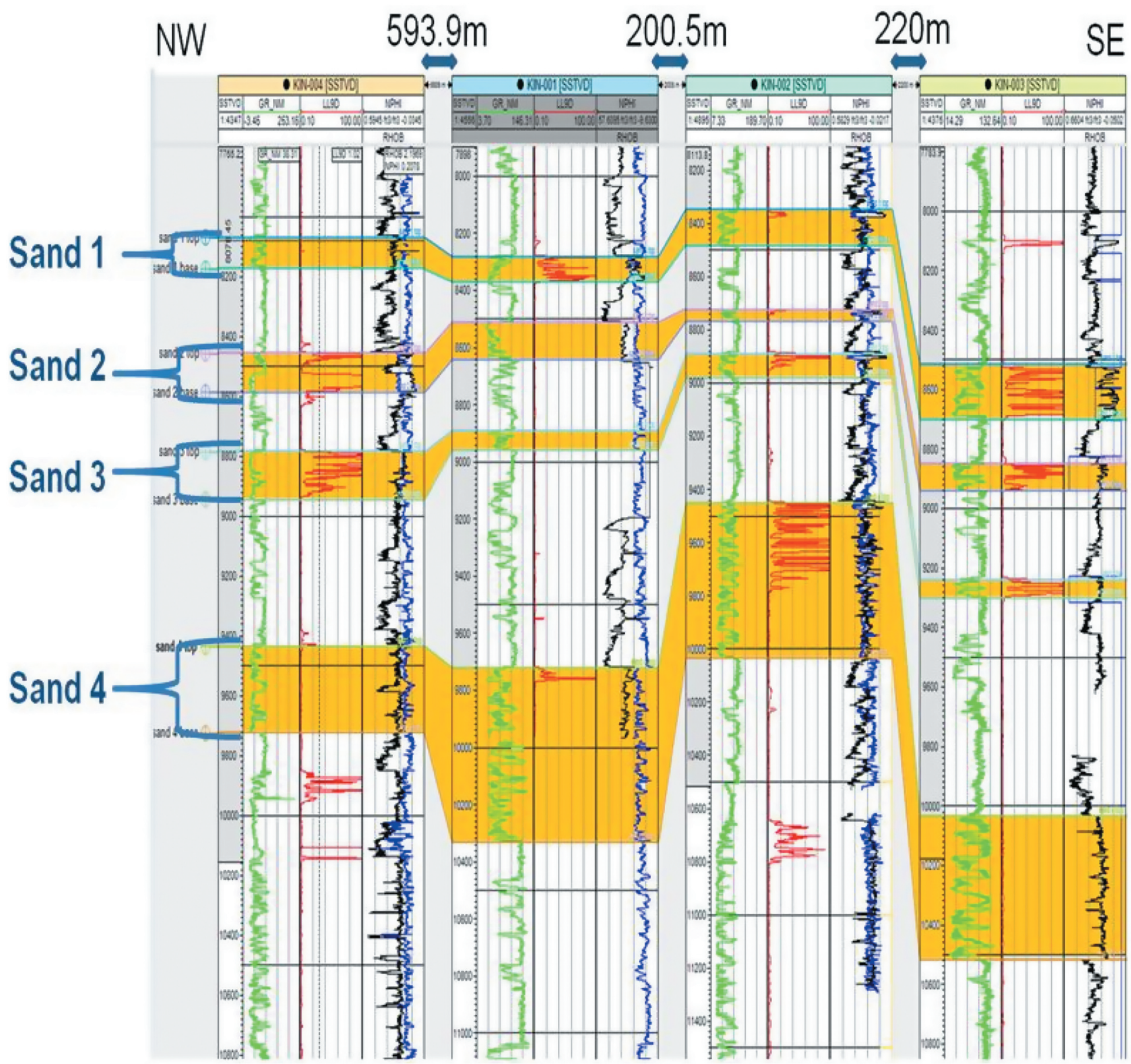

Figure 3. Well correlation panel for wells KIN; 004, 001, 002 and 003 showing sands 1–4, the main hydrocarbon reservoirs within Agbada Formation in the study field (Akinleye-Martins 2016) .

shown that fractures formed by structural movement have significant control on the petrophysical properties of the reservoir (Liu et al. 2011). These fractures not only offer the storage space, but also connect pores, thus improving the permeability of reservoir.

In another manner, fractures may harm productivity by creating seepages in the reservoir (thief zones), causing reservoir flow instability during enhanced oil recovery efforts and or redirecting the path of injected fluids, thus limiting the fluid's ability in contacting and displacing hydrocarbon. (Aarre et al. 2012)

3.2. Use of seismic attributes for fractured reservoir characterisation

On seismic section, faults and fractures are normally mapped as discontinuous reflection patterns that generally appear as linear, sub-linear or curvilinear features (Jaglan et al. 2015). The calculation and display of seismic attributes rank very high among the geophysical processing methods used for fault and fracture detection (Bahorich and Farmer 1995; Chopra and Marfurt 2009). Seismic attributes are important tool for reservoir prediction, and afterwards the coherence cube development, they acted key role in detecting subtle faults and fractures (Bahorich and Farmer 1995; Chen et al. 2005; Alai et al. 2014). Seismic attributes permit the extraction of physical properties and lithology, including fluid information which is hidden in the seismic data.

On edge-sensitive attributes such as similarity and curvature attributes, subtle geologic features i.e. below the resolution of the seismic data such as fractures and minor faults can be more clearly identified and their structural detail including trends revealed.

(i) *Similarity or Coherence attribute*: 3-D seismic data are generally binned into a regular grid, therefore coherence or similarity is obtained by calculating seismic trace similarity in both in-line and cross-line directions of the grid (Bahorich and Farmer 1995). Localise regions of seismic traces cut by a fault or fractured surface normally have a different seismic character than the corresponding regions of neighbouring traces. Calculation of coherence or similarity for each grid point along a time slice results in lineaments of low coherence along faults/fractured surfaces (i.e. the coherence is lower when the traces are less similar).

(ii) *Curvature attribute*: In a general sense, curvature is a measure of how deformed a surface is at a particular point. And as such is mainly analysed using the lineament concept (Hobbs 1904). It can be defined in simple mathematics as a second – order derivative of the curve (Chopra and Marfurt 2007). Faults and fractures as geologic structures often exhibit curvature i.e. representing flexures, folds, faults kinks, fractures etc. (Roberts 2001; Santosh et al. 2013). Curvature will be large for a curve that is "bent more" and it value will be zero for a straight line. There is large variety of curvature attributes (Roberts 2001), but those used for fracture detection in this study are the minimum curvature and maximum curvature. The one curve from infinite number of normal curvatures, which defines the largest absolute curvature of the surface, is referred to as maximum curvature. The maximum curvature attribute primarily amplifies anticlines and up-throw side of faults while minimum curvature attribute mainly magnifies synclines and downthrown side of faults. Curvature attributes are very effective at delineating fracture and subtle fault geometries (Jaglan et al. 2015b).

The similarity and curvature attributes are often grouped as geometrical attributes because they mostly help in defining the geometrical nature of seismic reflections.

4. Methodology

The "Kin" Field area is studied as an example for the characteristics of fractured reservoirs of onshore Niger Delta basin, aided with integrated analyses of seismic, geology and conventional well log data. 3D seismic data over the "Kin" Field was optimally conditioned using the dip steering algorithm in OpendTect™ software to improve the data quality by increasing the signal-to-noise ratio. The steering cube volume was calculated in a Fast Fourier Transformation (FFT) domain in order to make easy the extraction of seismic dip and azimuth information (Jaglan et al. 2015). According to Rijks and Jauffred (1991), dip magnitude and dip azimuth are able to illuminate subtle faults having a displacement significantly less than the size of a seismic wavelet.

For instance, similarity and curvature attributes were extracted from the conditioned seismic data (steering cube volume). The dip-steered attributes have an advantage over the non-steered attributes of depicting more geological pictures of the subsurface than artefacts. Subtle geologic features, mainly fractures and minor faults, were detected and mapped on the extracted dip-steered attributes at time-slice 2024 ms, 2100 ms and 2197 ms, specifically prior to and after a multi-attribute analysis. These specified time-slices correspond to reservoir tops H1, H2 and H3 shown on the seismic section inline 6985 of the study area (Figure 4). Although a number of faults can be observed on the vertical seismic section, but the real objective of this study is to map fractures and subtle faults. Rose diagram was also plotted to reveal the predominant orientation of the mapped fractures. A summary of the workflow used is shown in Figure 5.

5. Results and discussion

5.1. Data conditioning

The conventionally processed seismic data over the study area were discovered to be far less than perfect for seismic interpretation of sub-seismic scale faults and fractures. Consequently, data conditioning techniques which comprise dip extraction and frequency filtering were applied to improve the “Kin” Field seismic data and extract exact information from fracture attributes (Tingdahl and de Rooij 2005; Chopra and Marfurt 2007).

The algorithm of the dip extraction (dip-steering) conditioning technique used, allows the establishment and engagement of “steering cubes” which contain at every sample position the local dip and azimuth of seismic events (Jaglan et al. 2015).

Figure 6a is a time-slice from “Kin” Field at 2024 ms equivalent to the time surface map of Horizon H1. This map indicated some prominent faults shown on the vertical seismic section in Figure 4, though on it is also hints of subtle faults and fractures that do not appear as clearly. Equivalent similarity and curvature attribute maps of the time surface map of horizon H1 are displayed in Figures 6(b,c) respectively. These attribute maps clearly show sharper definition of the subtle faults and fractures thus describes the superiority of conditioned data over conventional seismic data (time surface) in terms of faults and fractures illumination.

5.2. Fracture analysis

Seismic attributes employed for fracture detection are usually the types which can delineate the vertical and lateral discontinuity of seismic traces (Pico et al. 2012). Figure 7(a) shows the result of similarity attribute on time-slice 2100 ms. This is a coherency attribute that is highly sensitive to discontinuity in the seismic data (Santosh et al. 2013). This attribute is generated by specifying intensity; therefore, the lowest intensity values correlated to fracture e.g. the dark colour lineaments pointed to by the blue block arrows in Figure 7(a). Considering the distribution of the arrows, the mapped features e.g. the fractures are concentrated largely at the western and eastern central of the study area.

For accurate interpretation of the features in Figure 7(a), an opacity control feature was further applied. Its outcomes as shown in Figure 7(b) indicates contamination, possibly by acquisition footprint that is highlighted by orange-coloured ellipse on the attribute map. According to Chopra and Marfurt (2009), this footprint is artefact that does not make any geologic sense. Figure 7(ce) described outcome of the application of curvature attribute in this study.

Figure 7(c) represents the minimum curvature attribute, defines as the absolute lowest curvature of the surface. The plane in which it is calculated is orthogonal to the plane of the maximum curvature

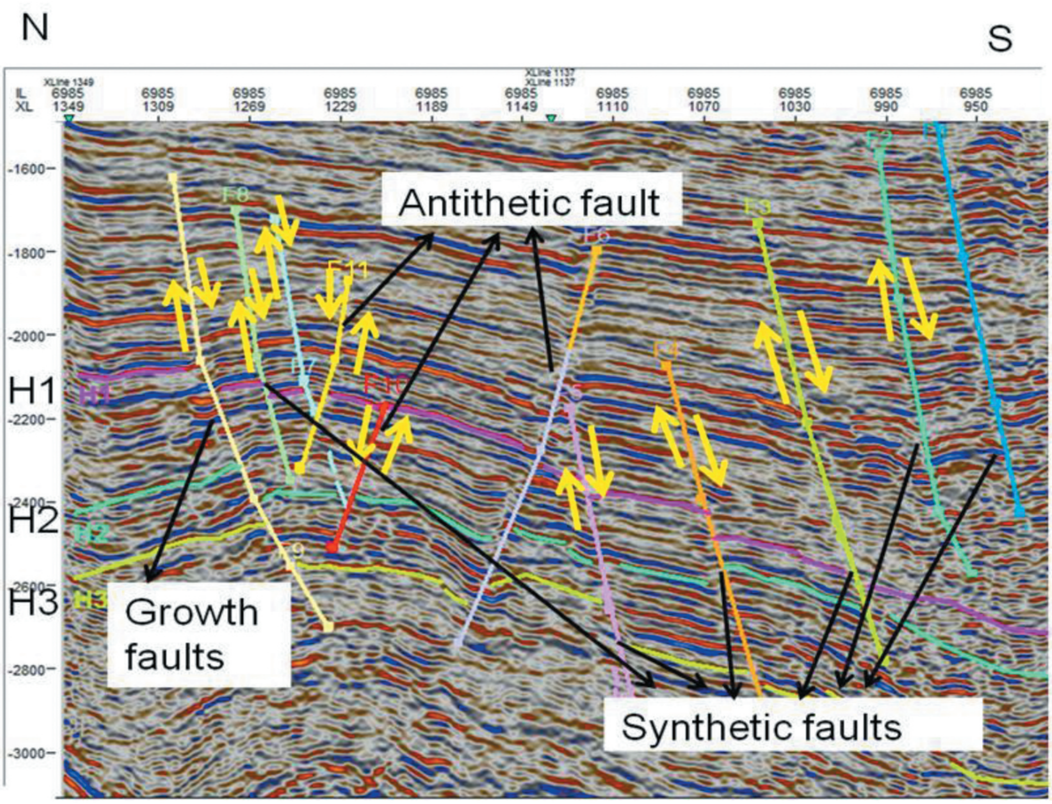

Figure 4. Interpreted seismic section (Inline 6985) from “Kin” Field showing the three mapped horizons H1, H2 and H3 considered for fracture analysis.

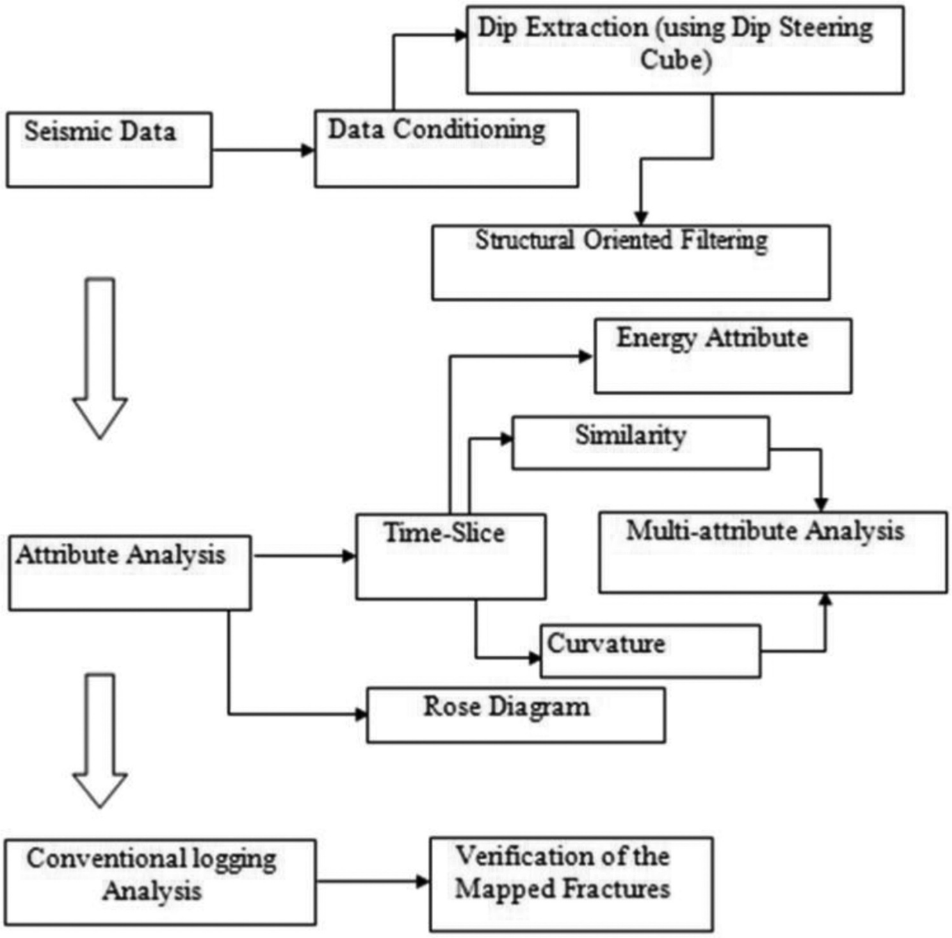

Figure 5. The work flow used for prediction and mapping of fractured reservoirs.

(Jaglan et al. 2015) and will general highlight synclinal and bowl features. The calculated minimum curvature attribute map in Figure 7(c) does not display much detailed geologic features and not as clearer and interpretable as the maximum curvature in Figure 7(d).

On the maximum curvature attribute map (Figure 7(d)), the lineaments i.e. displayed in reddish-yellow and blue depicts subtle geologic features. It was difficult to interpret some of the lineaments because they have low reflections hence, colour contrast was employed (Figure 7(e)) to improve the interpretation of the curvature attribute map. Presented in Figure 7(e) are fractures and flexures that were easily seen i.e. pointed to by the red block arrows. Compared with the similarity attribute map (Figure 7(a)), these features are observed to also concentrate primarily at the western and eastern central of the study area.

The yellow-coloured ellipse in Figure 7(e) highlight acquisition footprint at the south eastern area, thus correlating the similarity attributes map in Figure 7(b). A multi-attribute analysis that integrates similarity and curvature attributes was performed to optimise the fractures prediction.

The multi-attribute map in Figure 7(f) at 2100 ms was able to display information on each geometric attribute i.e. similarity and curvature simultaneously in one-time slice. The multi-attribute analysis improves the visualisation of subtle features by revealing with clear definition of the connectivity of fracture networks.

Aside from the subtle features that are thinly faults and fractures, stratigraphic features were also captured in the curvature attribute slice (Somasundaram et al. 2017). Figure 8 calls attentions to a suspected channel (i.e. highlighted by the black eclipse and the red box) the discontinuities caused by the channel were well-defined because the levees of the channel are a form of flexure which is easily detected by curvature attribute (Chopra and Marfurt 2009). The direction of flow of the ancient channel as highlighted within the black eclipse, trends NE – SW.

The rose diagrams in Figure 9(ac) were generated by extracting from the multi-attribute time-slice 2024 ms, 2100 ms and 2197 ms, respectively, the orientation of identified lineaments corresponding to subtle faults and fractures and their density (Wells 2000). It was observed that their general trends are in the NE – SW and NW – SE directions. According to

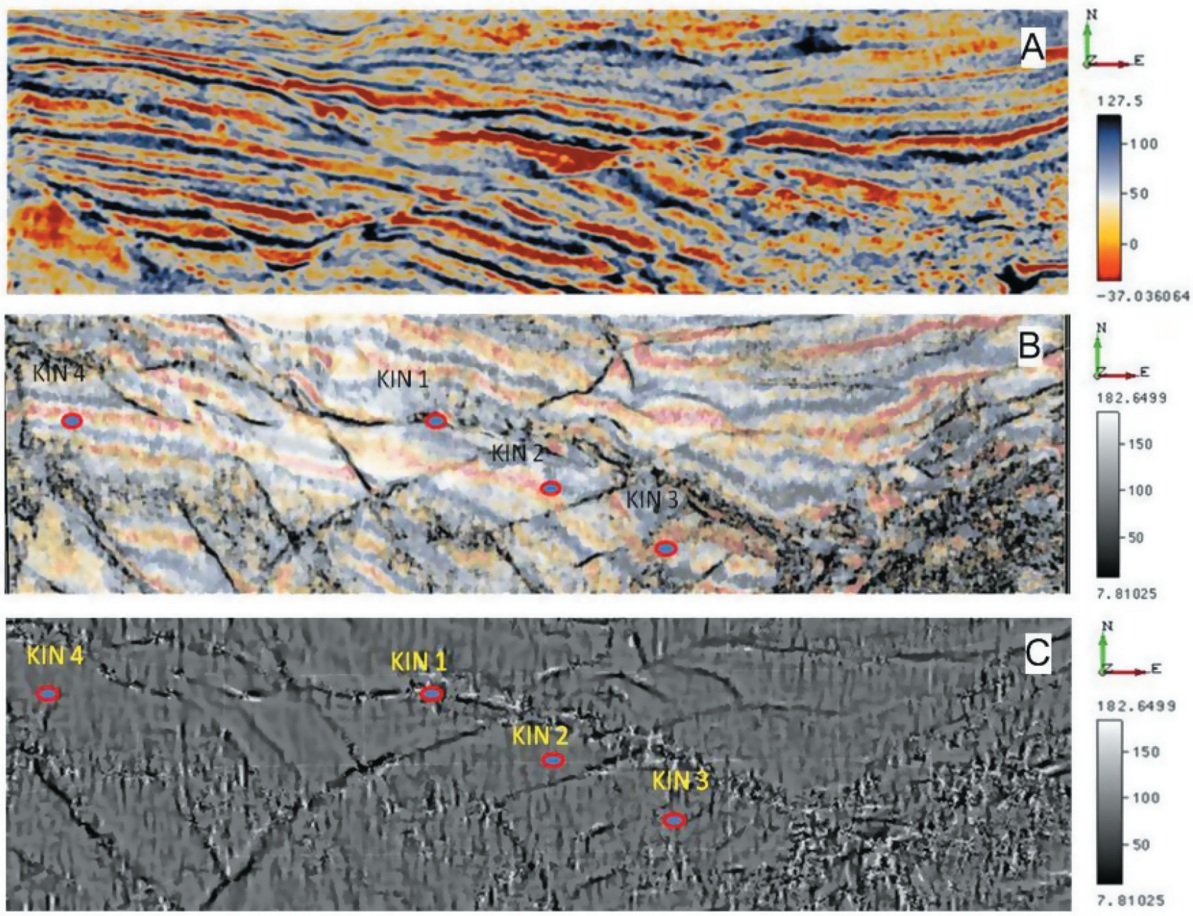

Figure 6. (a) Horizon time surface map at 2024 ms from "Kin" Field (b) Equivalent similarity attribute map (c) Equivalent curvature attribute map indicating well locations.

Aarre et al. (2012), optimal well placement requires factoring the predominant trend of natural fractures into the selection of wellbore orientation.

In an attempt to predict locations for potential hydrocarbon prospect within the study area, the energy attribute (i.e. for characterising high amplitude zones depicting high acoustic property indicative of hydrocarbon) was calculated and extracted over the specified time slice.

The energy attribute map at time slice 2197 ms in Figure 10 shows bright spots highlighted by the yellow ellipses at the south-western (SW) region of the map. The bright spots correlated with the positions of identified fracture networks on the attribute maps in Figure 7 and another bright spot is located within the channel seen on the curvature attribute map in Figure 8.

Conventional logging method comprising density log was employed to validate the fractures and subtle faults interpreted on the seismic attribute maps. In Figure 3, well Kin1 at depth 8314.69 ft (2534.32 m) was observed to coincide with a fracture zone equivalent to time slice at 2024 ms on the seismic attribute maps of Figure 6. At this depth interval, the porosity density log (i.e. black log signature on the third panel along the track of well Kin1) in Figure 3 display relatively high value. Also, this matched favourably with the result of the petrophysical analysis at this interval that indicates increased porosity and permeability (Akinleye-Martins 2016). Hence, this validation though qualitative provides further confidence that areas proximal to subtle faults and fractures are linked with enhanced permeability, and consequently better reservoir quality.

6. Conclusion

At "Kin" Field onshore Niger Delta, the application of similarity and curvature attributes has helped to delineate the presence, concentration, and trends of fractures and subtle faults within its low-permeability siliciclastic reservoirs. The fractures and subtle faults delineated are fine-scale structural features that are well below seismic resolution; otherwise, difficult to detect on seismic section. The mapped fractures show a predominant NW – SE and NE – SW trends and

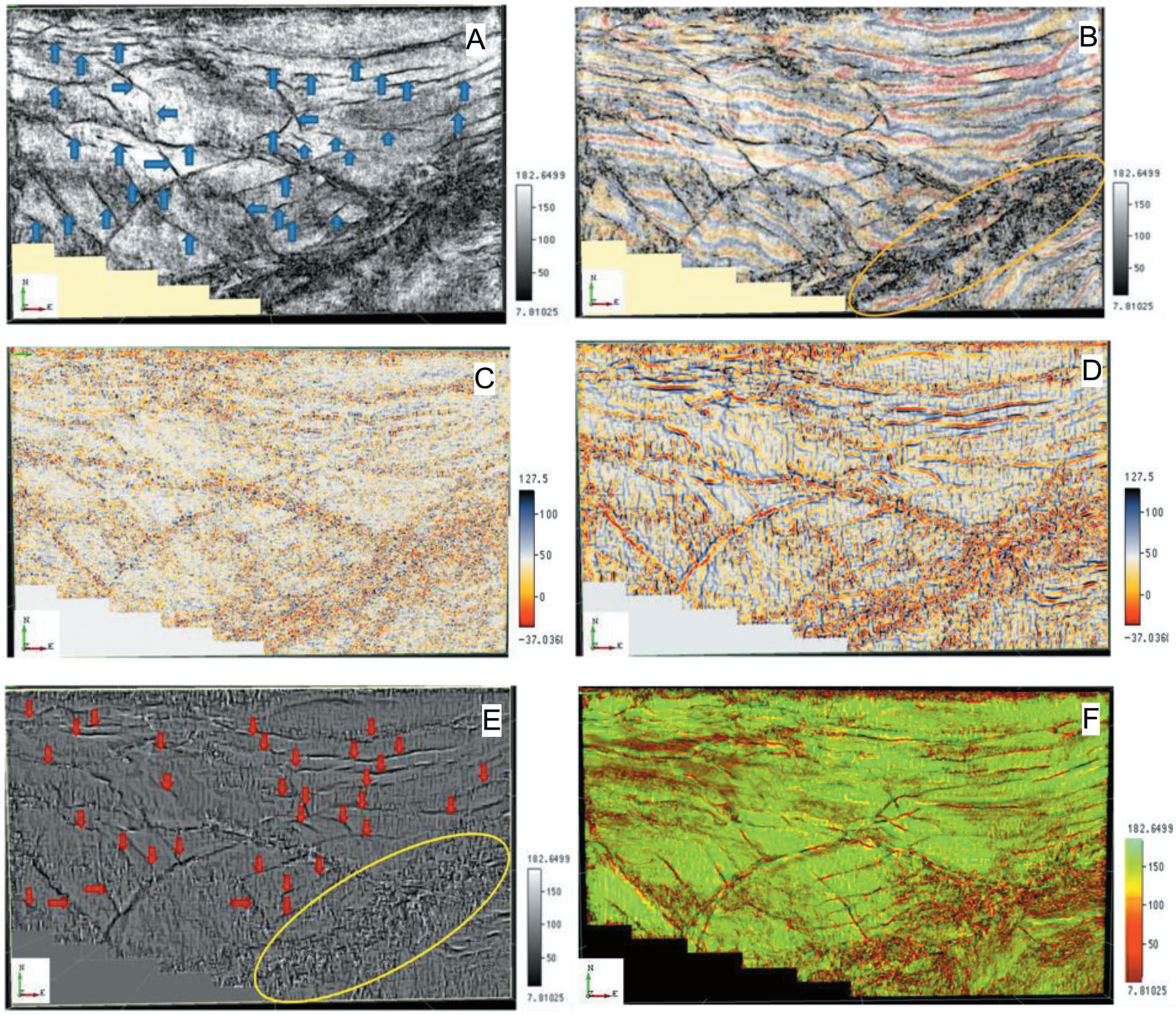

Figure 7. Discontinuity attributes extraction at time slice 2100 ms (a) similarity attribute map (b) output of opacity control feature on Figure 7a(c) minimum curvature attribute map (d) maximum curvature attribute map (e) output of colour contrast application on Figure 7(d) (7 f) multi-attribute analysis map.

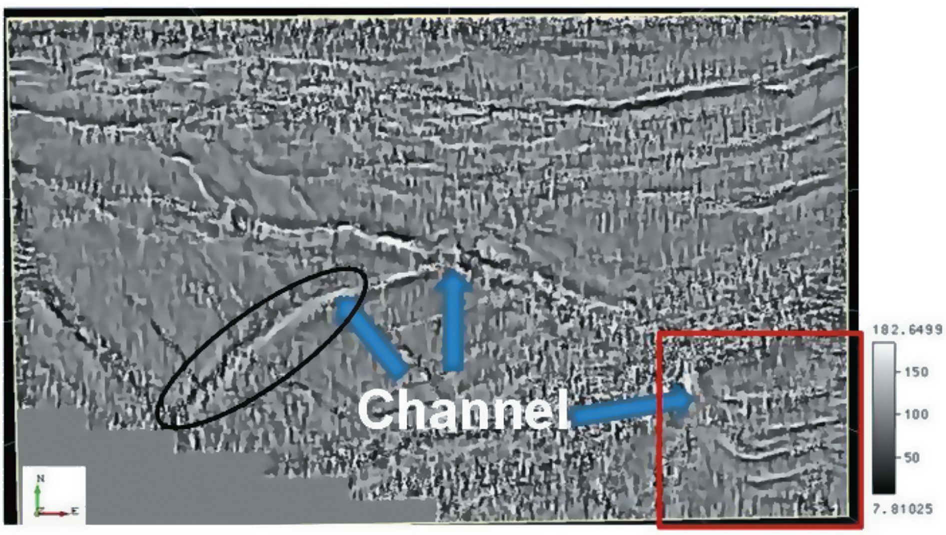

Figure 8. Curvature attribute time-slice at 2197 ms showing channel.

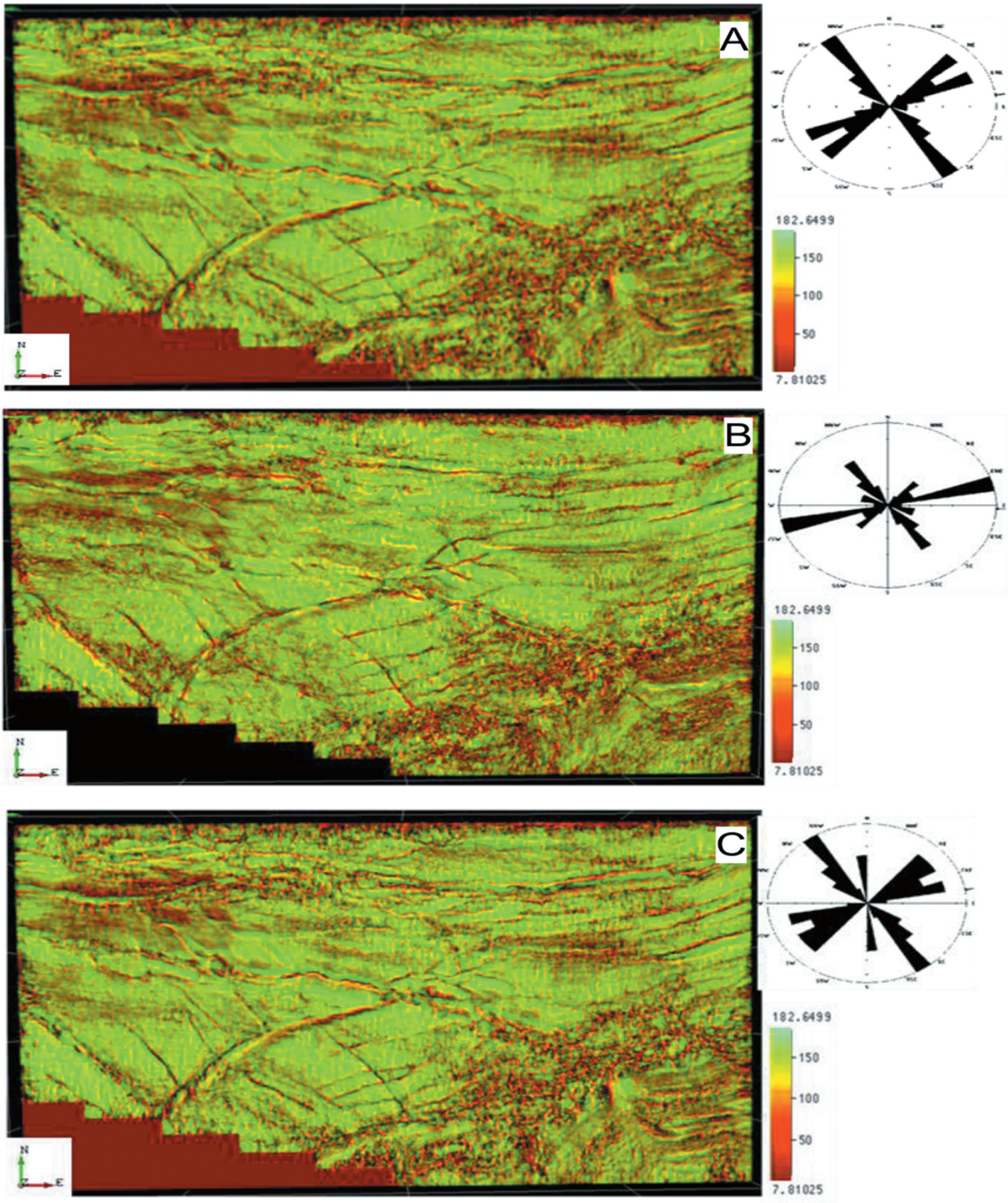

Figure 9. Lineaments on multi-attribute time slice (a) 2024 ms (b) 2100 ms (c) 2197 ms interpreted as black line segments and transformed into rose diagrams shown in the inset.

their detections were validated with the analysis and interpretation result of conventional porosity density log. The integrated analysis of the discontinuity attributes show lineament concentration (i.e. high fracture density) primarily at the western central and southeastern regions of the study area, hence these areas are marked potential hydrocarbon zone and location for future wells placement. From the assertions above, this study have established that apart from the principle structural trapping mechanism i.e. rollover anticlines and growth faults associated with the Niger Delta, fractures and subtle faults are

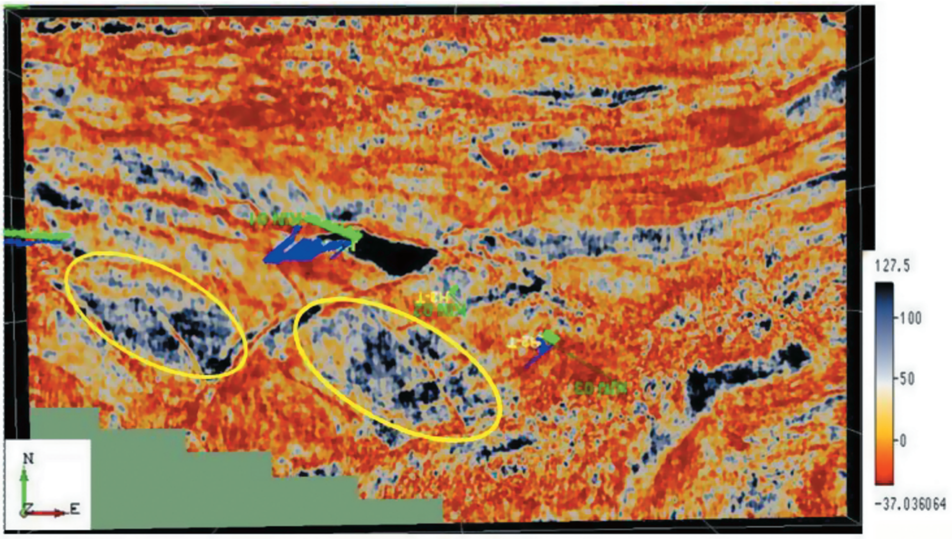

Figure 10. Energy attribute time slice at 2197 ms indicating bright spots correlating with mapped high fracture density zones.

somewhat responsible for substantial hydrocarbon accumulation in the low permeable siliciclastic reservoir rocks of the basin.

Disclosure statement

No potential conflict of interest was reported by the authors.

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