Research Article

Identification of seismic attributes for hydrocarbon prospecting of Akos field, Niger Delta, Nigeria

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Abstract
In this study, we have extracted and analyzed four seismic attributes of Akos oil field to obtain more information about the structures, stratigraphy and hydrocarbon potential of the Akos field from available seismic and a suite of well logs data. Two lithology and reservoirs were delineated from the well logs. Two horizons and growth faults were identified in the seismic sections. For a comprehensive analysis of the structural and stratigraphic understanding of the reservoirs, four seismic attributes variance edge, sweetness, root mean square and relative acoustic impedance were applied to the seismic data. The Variance edge analysis was used to delineate the prominent and subtle faults in the area. The high sweetness regions in the seismic data indicate high amplitude which indicates the presence of hydrocarbon-bearing sand units. The root mean square amplitude analysis also indicates the presence of hydrocarbon in seismic data. The relative acoustic impedance analysis was used for delineating lithology variation in the seismic sections. The result of the seismic attribute analysis has shown that the Akos field has good hydrocarbon prospects.

Keywords Seismic attributes · Root mean square amplitude · Variance edge · Niger-Delta · Hydrocarbon prospects

1 Introduction

Seismic attributes analysis involves the procedure used to extract corresponding subsurface geological information from seismic sections [5–7, 20]. Seismic attributes are extensively being used in the oil industry to predict subsurface reservoir properties [9, 28, 32, 35] . Seismic attributes are used in most seismic exploration and reservoir study to correctly image the subsurface geological structures, correctly characterize the amplitudes of the seismic data and to obtain information on reservoir properties [26, 27, 38, 39]. Seismic attributes analysis also offers clues to lithology typing, estimation of layer porosity, fluid content, mitigation of stratigraphic and structural features, drilling risk, reservoir characterization, and better identification and definition of sweet spots.

Seismic attributes are quantities of geometric, kinematic, dynamic, or statistical features obtained from seismic data [11, 18, 24, 35]. The geometrical seismic attributes can enhance the visibility of the geometrical characteristics of seismic events and are sensitive to the lateral variation of azimuth, continuity, similarity, curvature, energy, and dip [3]. The geometrical attributes are used for structural and stratigraphic interpretations of seismic data. This study aims to determine the seismic attributes of the Akos field for the identification of potential hydrocarbon reservoirs and four seismic attributes: variance edge, sweetness, root mean square and relative acoustic impedance were applied to the seismic data.

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2 Geological background

The study area (Akos Field) is located in the onshore coastal swamp depositional belt in the eastern part of the Niger Delta (Fig. 1) and it lies on latitudes 4° 19′ 00″ N and 4° 50′ 00″ N and Longitudes 6° 02′ 30″ E and 7° 10′ 00″ E. The base map of the area showing the seismic lines and well locations are shown in Fig. 2.

The Niger-Delta is located in the southern part of Nigeria, West Africa in the Gulf of Guinea. It is a major hydrocarbon province in the world. It covers an approximate area of about 75,000 with an average thickness of about 12 km. It is made up of an overall regressive clastic sequence [12, 30]. The Niger Delta resulted from the separation of the African and South American plates starting in the Late Jurassic and continuing into the Cretaceous.

The Niger Delta has one identified petroleum system known as the Tertiary Niger Delta (Akata-Agbada) petroleum system [8, 12, 23, 30, 37]. Three lithostratigraphy (Akata, Agbada and Benin Formations) are present in the basin [13]. The Akata formation is the main source rock and it is made up of shale. The Agbada Formation, which is the main reservoir, lies on top of the Akata Formation and it is made up of alternation of sand and shale. The Benin Formation lies on top of the Agbada Formation and it made up of sand lithology. Most aquifers in the basin are found in the Benin Formation. The oil in geological structures in the basin may be trapped in dip closures or against a Synthetic or antithetic fault (Fig. 3).

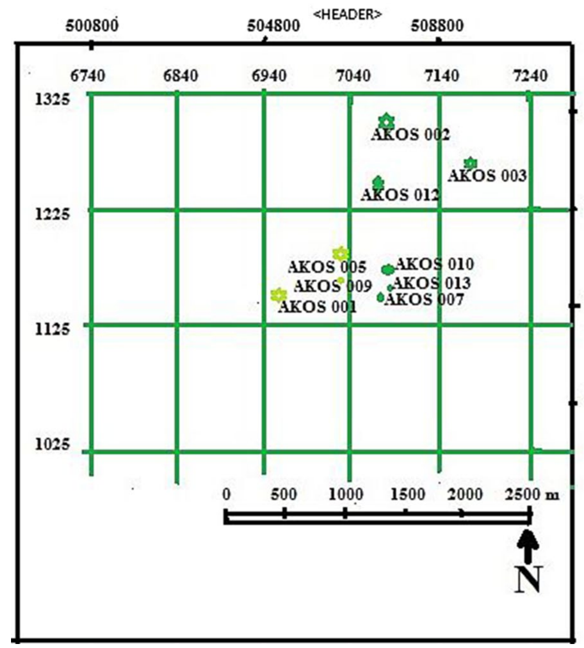

Fig. 2 Schematic Base map showing the study area

3 Materials and methods

The data provided for this research work are 3 D-seismic volume in SEG-Y format, composite well logs (ASCII), and check shot data: The logs include Gamma ray (GR), resistivity (LLD) and density (RHOB). The data were obtained from the Shell Petroleum Development Company of

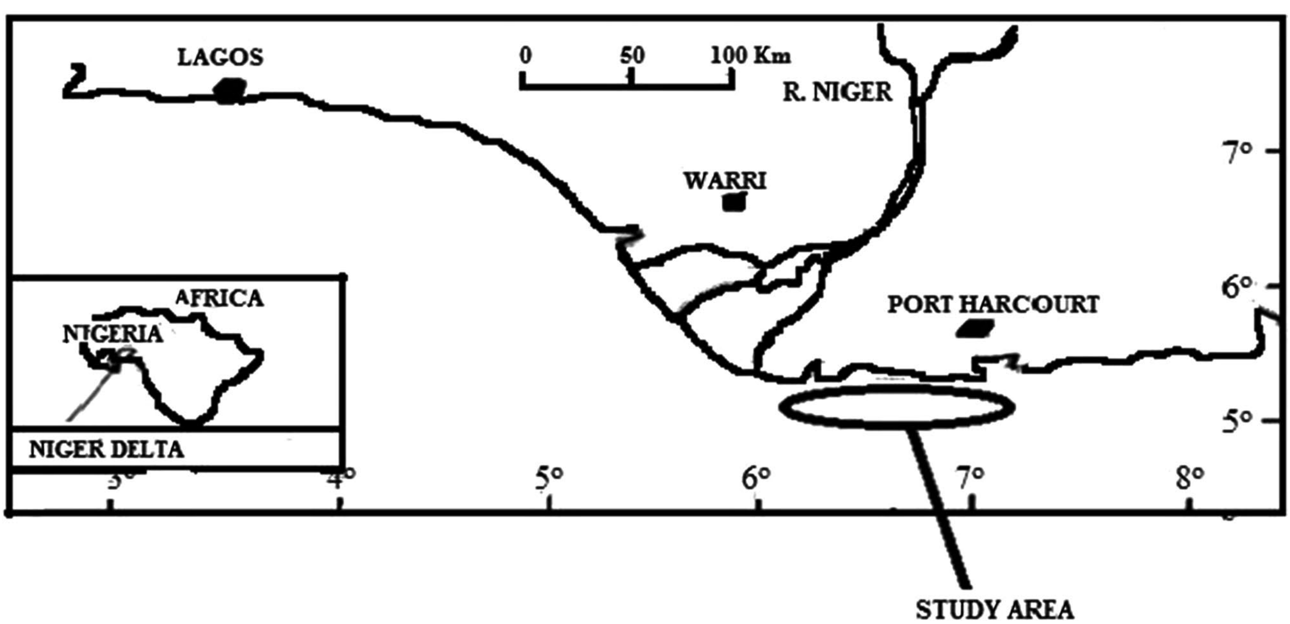

Fig. 1 Map Niger Delta showing the study area

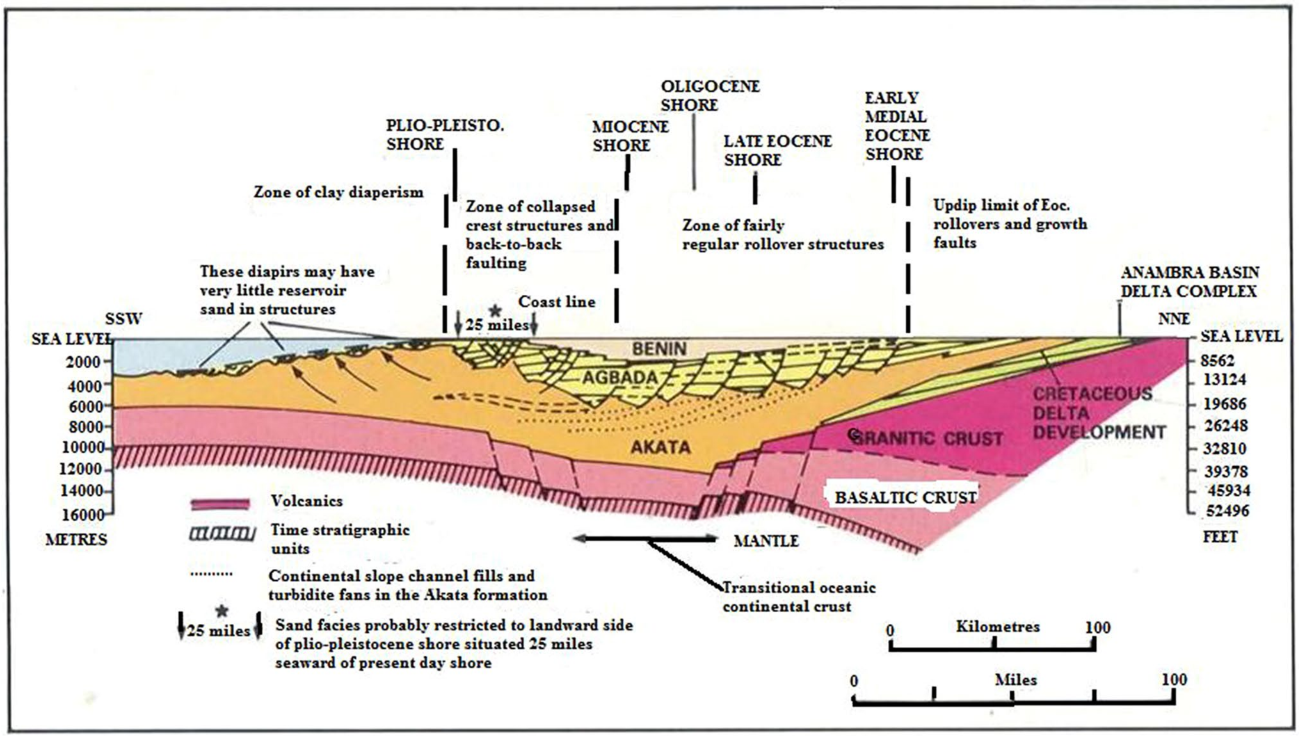

Fig. 3 Generalized dip section of the Niger Delta showing the structural provinces of the Delta. Adapted from [40]

Nigeria (SPDC) in line with the Department of Petroleum Resources (DPR) and the federal government's policy on education. Petrel® E&P software platform 2014 was used for the 3D seismic interpretation and attribute visualization, and well logs data analysis. Among the seismic attributes that have been used in the visualization of the geology of the subsurface are variance, root mean square amplitude, sweetness, and relative acoustic impedance. The seismic attribute analysis was applied to the seismic inline 6871. The procedure adopted for the research are; wells -to-seismic tie; seismic attribute analysis and prediction of reservoir properties from the seismic attributes.

4 Delineation of reservoir

The available gamma-ray and resistivity logs from the oil wells in the field were used for lithologies and reservoirs delineation. The deflections of the gamma ray signature to the left (low values) indicate sandstone while the deflection to the right (high values) signifies shale. High resistivity values corresponding with sandstone zone is interpreted as a reservoir while low resistivity values represent shale or reservoir containing saltwater.

5 Generation of synthetic seismogram

Synthetic seismogram was generated from sonic and density logs for one of the wells in the field. Well to seismic tie of the hydrocarbon reservoir was carried out using checkshot data, which helps in studying how the seismic character would be expected to vary as the stratigraphy changes across the basin.

6 Fault interpretation

A fault is a break in the continuity of any geologic unit, which involved either a lateral or vertical movement of any part of the rock unit, caused by varying geologic processes. Faults can be delineated as abrupt termination of reflection events or displacement or distortion of reflection. Faults are identified on the dip sections, in the interpretation window or on the 3D window of the software.

7 Determination of root mean square (RMS) amplitude

The root mean square (RMS) amplitude was extracted from the seismic data as a surface attribute. Root mean square (RMS) amplitude is used to obtain a scaled estimate of seismic trace envelope. It is obtained in the software by sliding a tapered window of N samples as the square root of the sum of all the trace value x squared. The RMS attribute computation in Petrel software makes use of the inbuilt formula:

$$X_{rms} = \sqrt{\frac{1}{N}\sum_{n-1}^{N} w_n x_n^2} \quad (1)$$

where X_{rms} = root mean square amplitude, w_n = window values, N = number of samples in the window, x = trace value.

8 Variance (edge detection) method

In the Petrel software, the variance attribute uses an algorithm that computes the local variance of the seismic data through a multi-trace window with user-defined size. The local variance is computed from horizontal sub-slices for each voxel. A vertical window was used for smoothing the computed variance and the observed amplitude normalized. The variance attribute measures the horizontal continuity of the amplitude that is the amplitude difference of the individual traces from their mean value within a gliding CMP window.

9 Determination of relative acoustic impedance

The acoustic impedance inversion transforms the seismic data into an acoustic impedance model. The acoustic impedance of a media is given as

$$I = \rho V \quad (2)$$

where V = velocity, I = acoustic impedance, ρ = density.

To measure acoustic impedance, it is necessary to use seismic inversion. It was assumed that the input seismic data has been processed to reduced noise and multiples, and also contains zero phase and large bandwidth. The seismic trace represents a band-limited reflective series;

$$f(t) = \frac{1}{2}\frac{\Delta \rho v}{\rho v} \quad (3)$$

where f(t) = seismic trace.

The integration of the seismic trace will provide a band-limited estimate of the natural log of the acoustic impedance. Since the integration of band-limited, the impedance will not have absolute magnitude values and consequently is only relative. Relative acoustic impedance is an estimated inversion computed by the integration of seismic trace accompany by a high cut Butterworth zero-phase filter. It is a simplified inversion and has been generated as an asynchronous attribute in the software. It enhances acoustic impedance contrast boundaries. According to Taner [36], the relative acoustic impedance (RAI) can be computed by integrating the real part of the seismic trace.

$$ln(\rho v) = 2\int_{t=0}^{t=T} f(T)dt \quad (4)$$

Where f(T) = real part of seismic trace.

A Butterworth filter is then applied to remove long-wavelength trends that originated from the integration process [31].

$$BL(f) = \frac{1}{1 + \left(f/f_H\right)^{2N}} \quad (5)$$

where BL(f) = band –limited signal in frequency; f_H = frequency cutoff value of 10 Hz, (N = filter order of 3.

It is used for delineating sequence boundaries, unconformity surfaces, and discontinuities. The acoustic impedance may be related to the formation porosity and the presence of fluid in a hydrocarbon reservoir.

10 Determination of sweetness

Sweetness involves the implementation of envelopes and instantaneous frequency that are combined. Mathematically, it is expressed as

$$s(t) = \frac{a(t)}{\sqrt{f_a(t)}} \quad (6)$$

where s(t) = Sweetness, $a(t)$ = Envelope, $f_a(t)$ = instantaneous frequency.

Sweetness is used for the identification of features where the total energy signatures change in the seismic data.

11 Results and discussion

11.1 Well logs and seismic interpretation

Based on the gamma ray logs, two lithologies were identified sand and shale. From the lithology log,

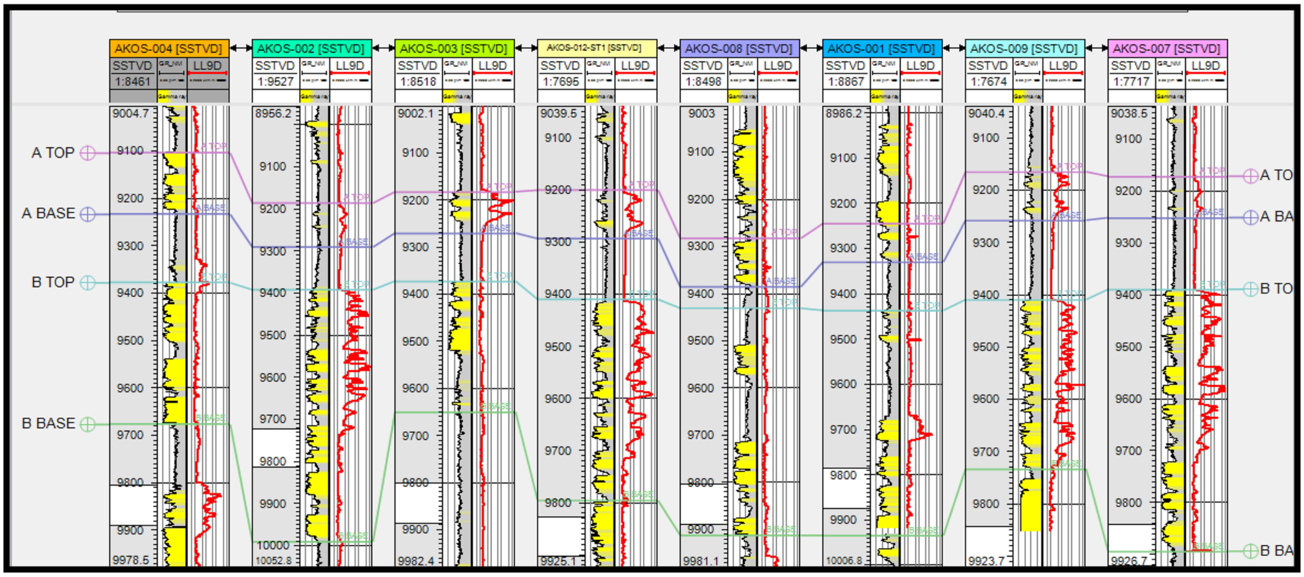

Fig. 4 Well log correlation panel of Akos field

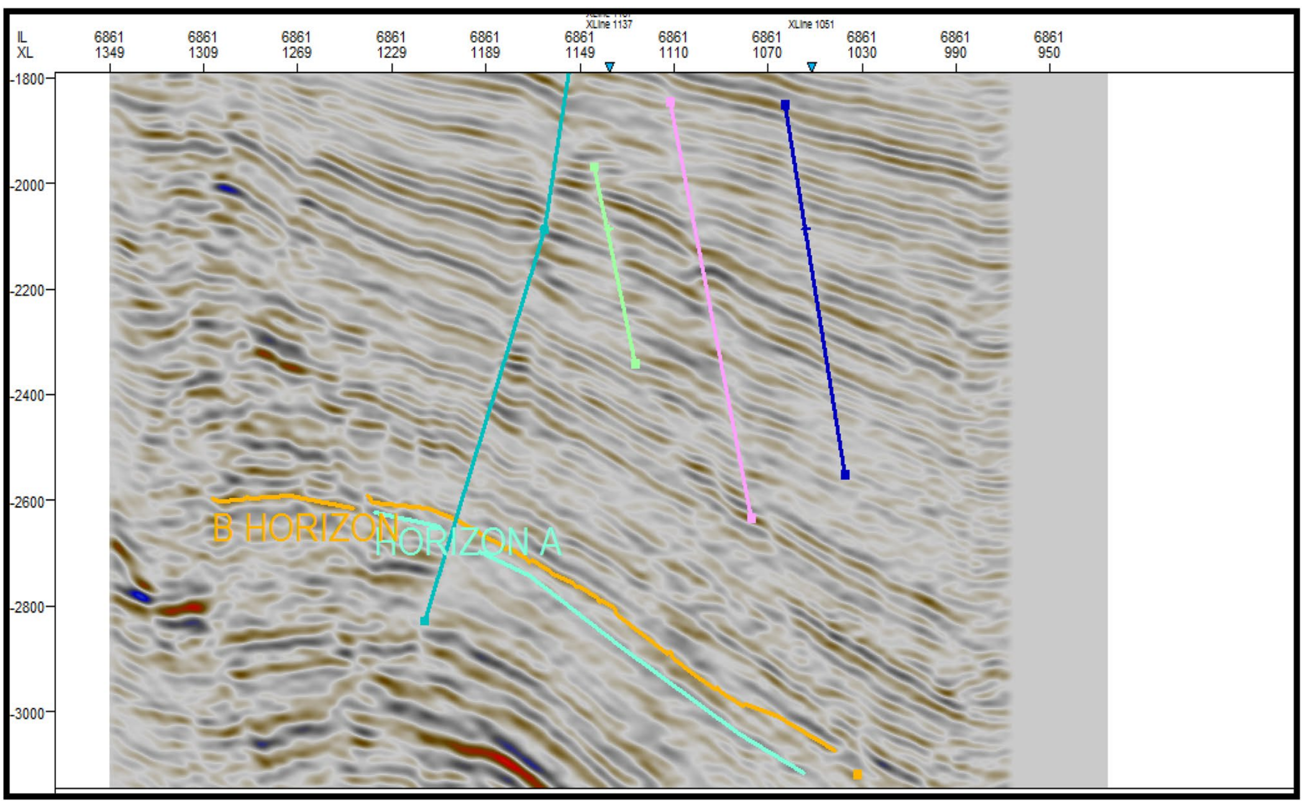

Fig. 5 Seismic section showing interpreted horizons and faults

the interval colored yellow is sand, while the interval colored grey is shale. Two reservoirs were observed and correlated across the oil wells in the field (Fig. 4). The interpreted horizons and faults in the seismic data are shown in Fig. 5. Two horizons A and B were delineated. Similarly, some of the interpreted faults in the area are also shown.

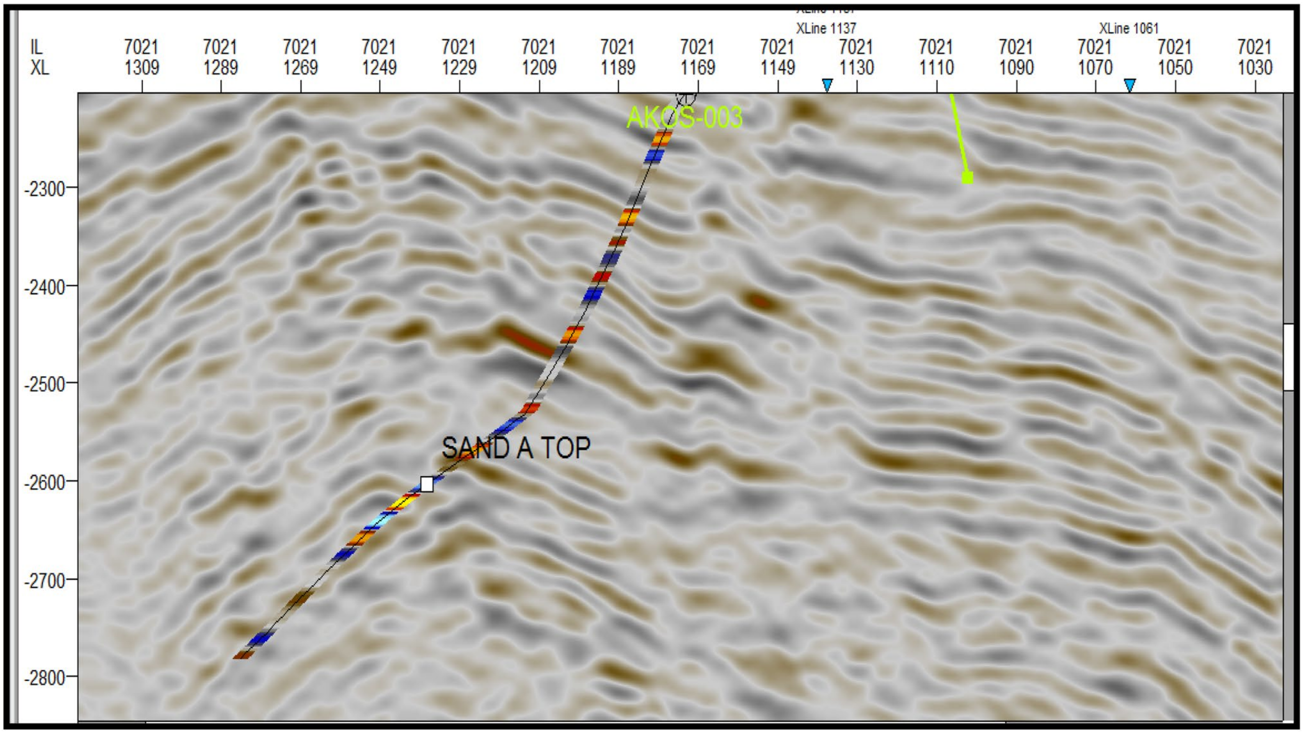

Fig. 6 Well-to-seismic Tie on Inline 7021

11.2 Well to seismic tie

The result of the well to seismic tie for the field is shown in Fig. 6. The well to seismic tie was used to delineate the position of the observed reservoirs in the well logs in the seismic data.

11.2.1 Seismic attributes

A series of seismic volume attributes such as variance edge, sweetness, relative acoustic impedance, and Rms amplitude were generated in Schlumberger's Petrel® software interface to investigate potential structural and stratigraphic controls within the study area. Figure 7 shows the computed variance attributes of the seismic section. The variance values range from 0.0 to 1.0. Values of variance equal to 1 represent discontinuities while a continuous seismic event is represented by the value of 0. The high values are denoted with red to yellow colorations.

Figure 8 represents the sweetness values of the seismic data. The sweetness value ranges from 0 (blue) to 22,500 (yellow). High sweetness values may be attributed to both high amplitude and low frequency while low sweetness value is as a result of low amplitude and high frequency in the seismic volume.

The relative acoustic impedance generated in the study area is shown in Fig. 9. Base on the map, the yellow and red colors represent the highest relative impedance while the lowest relative impedance is represented by the blue color.

The result of the RMS amplitude analysis is shown in Fig. 10. The RMS amplitude values range from 0 (blue) to 12,000 (red). The red yellowish color represents hydrocarbon sands. Some of these hydrocarbon sands were not detected in the original seismic section. The observed changes may be due to changes in lithology or fluid content.

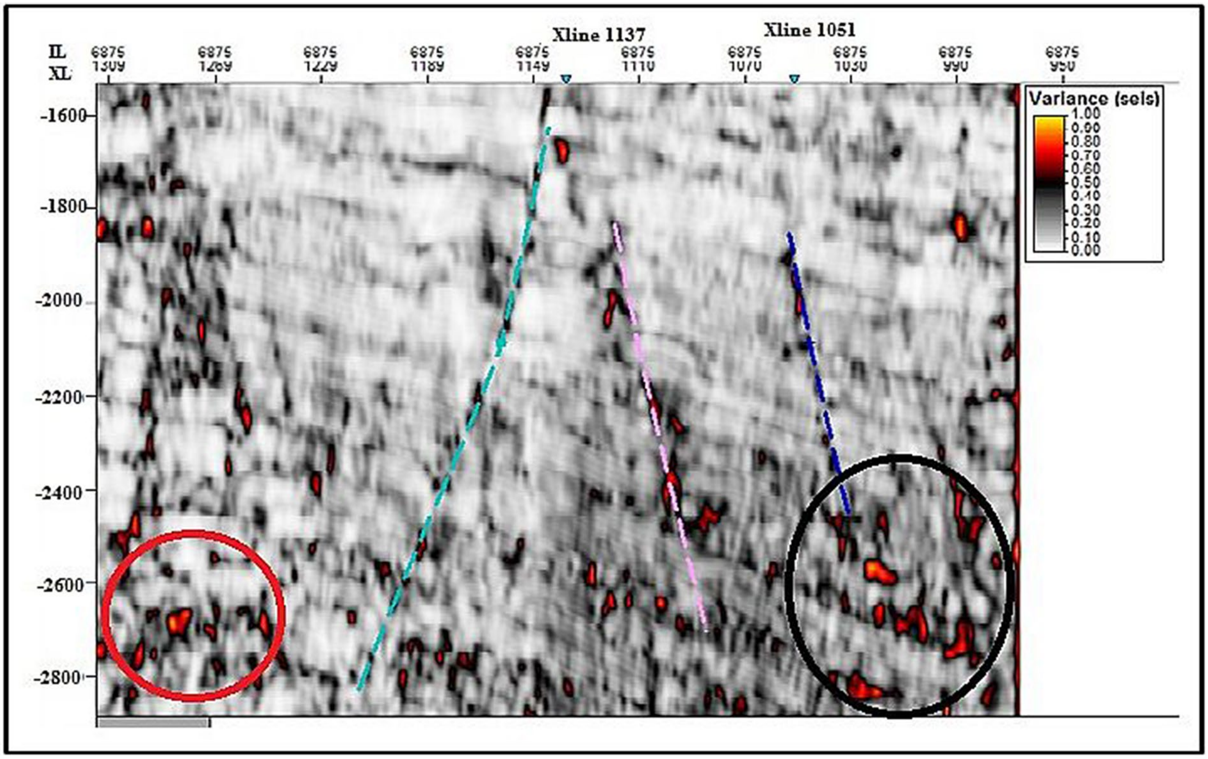

Fig. 7 Variance Edge inline 6875

Two main lithologies were delineated from the gamma ray logs. These lithologies are sand and shale. The alternation of the sand and shale is an indication that the log sections of the wells are within the Agbada Formation in the Niger Delta. Two reservoirs were delineated in the well and correlated across all the five wells. The structural interpretation of the seismic data shows that the studied area is dominated by synthetic faults. The tops of the reservoir observed in the well logs were correlated to the seismic sections as horizons A and B.

Concerning the variance map, the areas dotted with blue, green and pink colored lines signify values that correspond to the location of the discontinuity. The discontinuities may be interpreted as faults and boundaries as shown by the lines drawn on the variance attribute map [17]. The variance edge enhanced the faults or sedimentological bodies within the seismic data volume. Furthermore, several bright spots are also delineated (in black circle) which indicate high reflectivity sediments compare to their surroundings. These bright spots are an indication that a potential hydrocarbon trap might exist in the area. The variance attribute is edge imaging and detection techniques. It is used for imaging discontinuity related to faulting or stratigraphy in seismic data. Variance attribute is proven to help in imaging of channels, fault zones, fractures, unconformities and the major sequence boundaries [25]. The darkest regions in the seismic section, which make vertical strips, may be interpreted as faults or fractures. The zones with low variance values are due to similar seismic traces.

The high sweetness regions within the seismic data (circled in black) indicate high amplitude. They are interpreted as hydrocarbon-bearing sand units. Though the sweetness attribute is quite effective for channel detection and characterization of gas-charged bearing sand units, it is known to be less useful when the acoustic impedance contrast between shale and sand units are low and also less effective when both lithology units are high. In most cases, shale intervals are characterized by low amplitude (low acoustic impedance contrasts) and high frequency,

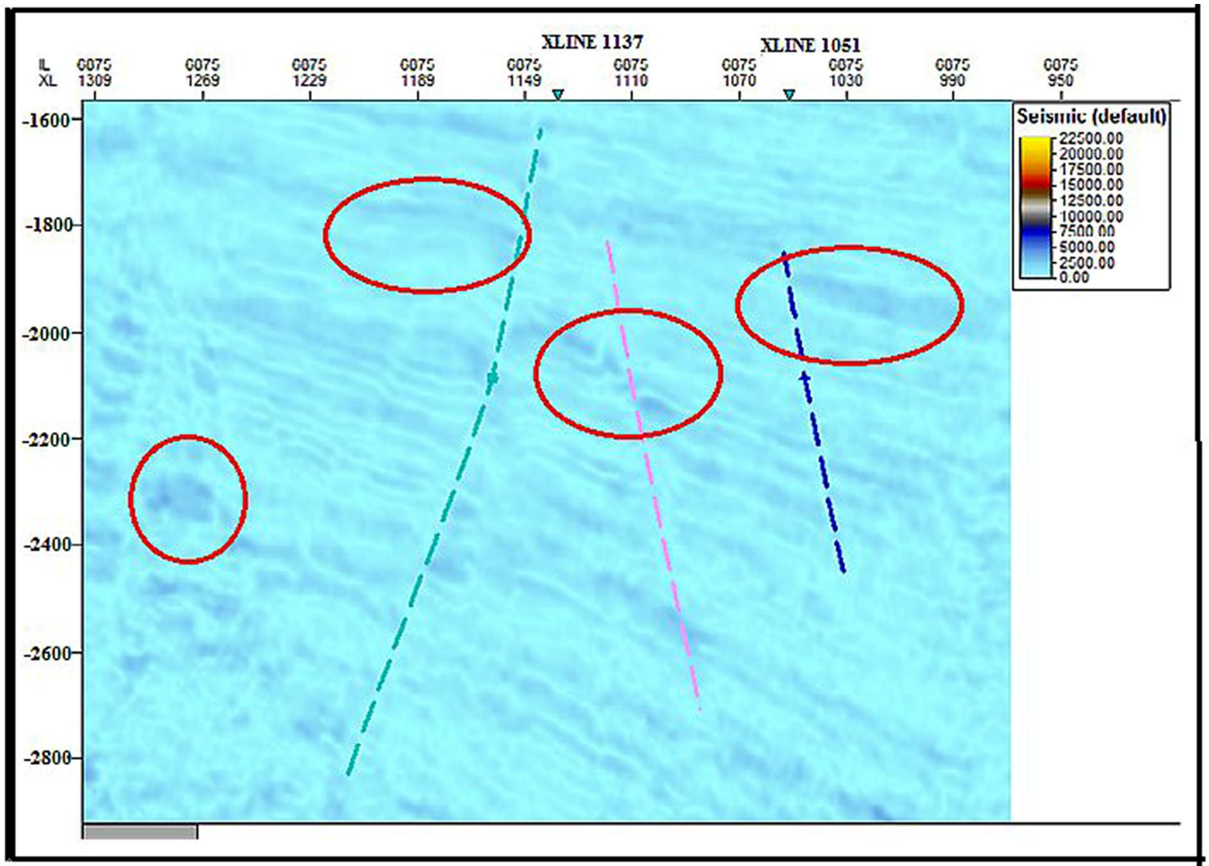

Fig. 8 Sweetness inline 6875

thereby indicating low sweetness. Sand intervals are characterized by high amplitude (high acoustic impedance contrast with the shales) and low frequencies, thus indicating high sweetness values. Sweetness is used for identifying sweet spots that are hydrocarbon prone. The high sweetness values in the seismic section are possible indications of oil and gas [15, 16, 29].

The relative acoustic impedance attribute represents apparent acoustic impedance or physical property contrasts. It is commonly used for lithology discrimination, thickness variation and sequences boundaries indicators associated with high contrasts in acoustic impedance values. It may also indicates unconformity surfaces, discontinuities, porosity and the presence of hydrocarbon in a reservoir [24]. The high relative acoustic impedance values are associated with shalier facies while lower values correspond to sand intervals [1, 33]. The high relative acoustic impedance may also be interpreted as sequences boundaries.

The RMS attribute is related to the variations in acoustic impedance. The higher the acoustic impedance values, the higher the RMS amplitude. The high values of RMS amplitudes may also be related to high porous sands, which are potential hydrocarbon reservoirs. RMS amplitude is similar to reflection strength and it is used in seismic exploration for delineating bright spots and amplitude anomalies [14, 21, 22]. The RMS amplitude is may be used for identifying coarser-grained facies, compaction related effects, and unconformities. The high values of RMS amplitudes circled in the map are interpreted as high porosity lithologies, such as porous sands. These high RMS amplitude segments are potential high quality hydrocarbon reservoirs.

The high amplitude (in black circles) in the seismic data conforms to the structures and confirm the presence of

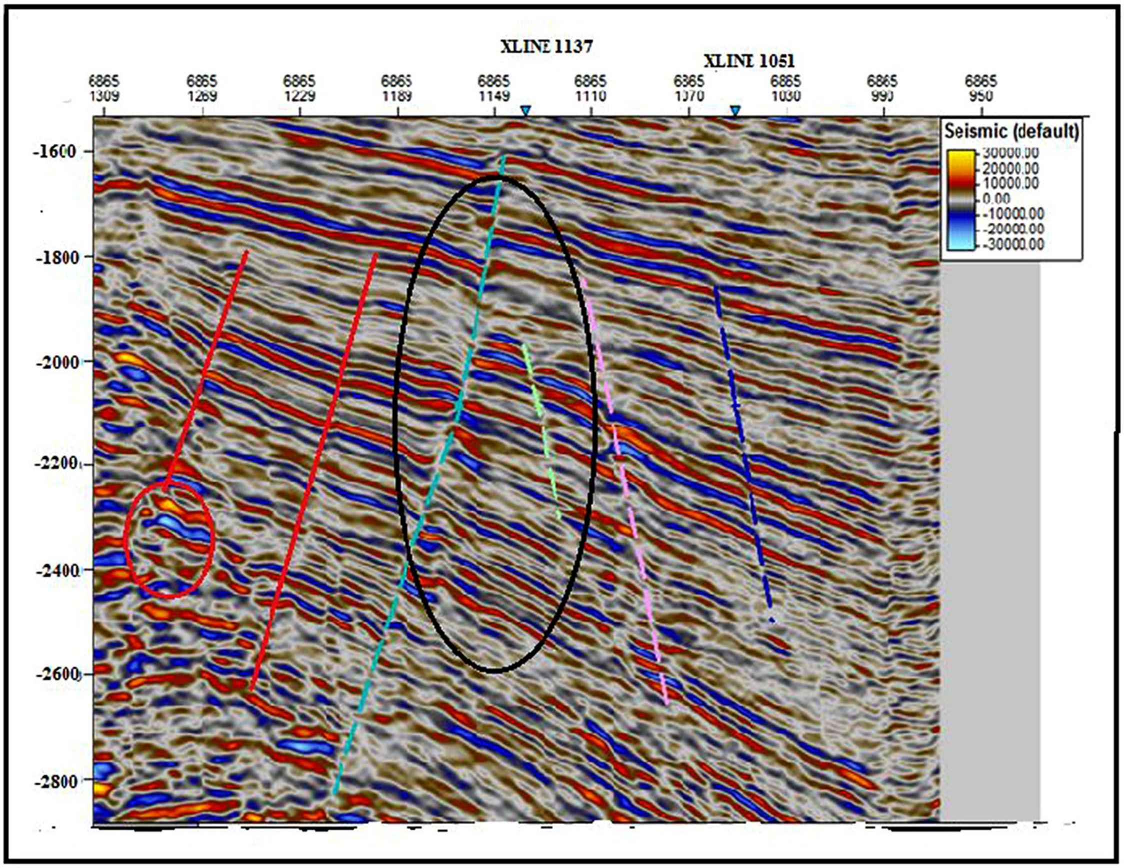

Fig. 9 Relative acoustic impedance inline 6865

hydrocarbon [4, 19]. The high amplitude ranges from gray to yellow/red coloration. Root mean square amplitude is used as a good indicator of the presence of hydrocarbon in seismic data [19]. The result of this research compares favorably with that obtained by other researchers [2, 10, 21, 34].

12 Conclusions

In this study, Petrel software has been used to generate and interpret seismic attributes and well logs. Two reservoirs and lithology were interpreted in the well logs respectively. The seismic attributes interpreted in include variance, relative acoustic impedance, root mean square amplitude and sweetness. The variance revealed the subtle structures and faults in the seismic section. The RMS amplitude, sweetness and relative acoustic impedance results highlighted the hydrocarbon zones. The seismic attribute analysis in this study has helped in increasing the understanding of the delineated reservoirs and geological structures in the study area towards a better delineation of hydrocarbon potential and improved reservoir characterization. Furthermore, it has been demonstrated that seismic attributes are complementary to the information derived through traditional methods of seismic interpretation. Extraction of seismic attributes can bring to fore new information and insights into stratigraphic and structural interpretations. Hydrocarbon exploration and development risks can be reduced greatly with the outcome of seismic attributes extraction and analysis.

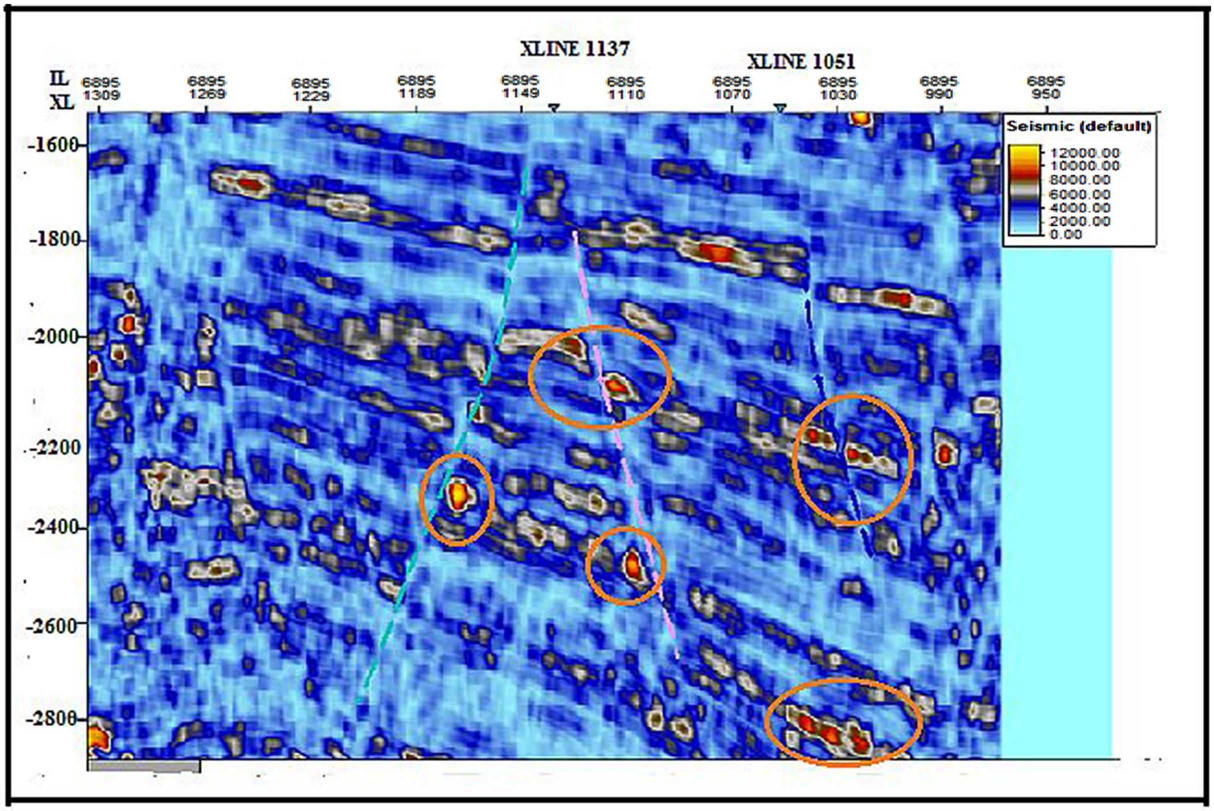

Fig. 10 RMS amplitude inline 6895

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Author's contributions This article was part of Enyenihi, Emmanuel Enifome MSc research work. Emujakporue, Godwin Omokenu supervised the work. Both prepared and approved the manuscript.

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Availability of data and materials The materials used for this research were obtained from Shell Petroleum Company Limited through the Department of Petroleum Resources, Nigeria. The dataset for the Akos Field can be obtained from Shell Petroleum Company Limited, Nigeria on request. Due to privacy, an individual has no right to give out the data without the consent of the SPDC, Nigeria.

Compliance with ethical standards

Complict of interests The authors Emujakporue, G. O and E. E. Enifome declare that they have no competing interests.

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