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Research Paper

Amplitude Analysis for the Characterization of an Onshore Gas Field in the Greater Ughelli Depo-Belt of the Nigerian Delta

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ABSTRACT
A detailed interpretation of onshore 3D seismic data of a gas field in the Greater Ughelli depo-belt of the Nigerian Delta was carried out in this research work. Seismic data processing was actually targeted for the recovery of correct relative amplitudes and imaging. Calibration of seismic data to synthetic seismogram from the wells show that the hydrocarbon bearing reservoirs produced strong reflections or bright spots which terminate at the gas brine contacts at about 2230 ms and 2560 ms, due to fluid change and change of porosity resulting from differential pressure at depth, long term compaction and cementation of the reservoirs. This reflection has a consistent amplitude character (a trough) over the major part of the field covering an area of 25 x 17.5 km^2. The hydrocarbon column within the H1000 reservoir is about 340.13 ft, which is the greatest hydrocarbon column in this field. The hydrocarbon column within the H4000 reservoir is about 290.27 ft with about 10.34 m oil rim and it is next to the H1000. These reservoirs are massive channel sands with alternating shale packages. This field is one of the giants of natural gas accumulations in the Niger Delta. The study focused on the accurate calibration and identification of the seismic horizons, their amplitude variation along different lithological interfaces associated with the reservoir and their continuity of character. The study resulted in a better understanding of the seismic responses within the reservoirs, structural definition and fault resolution.
KEYWORDS*: Amplitude, Inversion, Lithology, Porosity*

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I. INTRODUCTION

The seismic amplitude is rich in information about subsurface formations and their fluid contents which is easily retrieved from the amplitudes of the seismic signals. Amplitude component analysis enables us to compute amplitude constituent components as a function of offset, by using amplitude variation with offset (AVO) approximations to extract amplitude constituent components in stacked sections. Amplitude constituent components analysis thus, helps predict seismic responses at angles where data are either not recorded or are of poor quality. analyze seismic data for possible hidden anomalies that could be associated with hydrocarbons. This is possible because reservoirs saturated with hydrocarbons usually have unique solid (reservoir) and fluid amplitude characteristics with which they respond to seismic energy and these unique rock and fluid properties discriminate them from their host. In onshore seismic acquisition and processing, we are often faced with the problem of near surface geology affecting the amplitudes deeper in the section. Correcting the affected amplitudes leads to a more accurate representation of lithologies' true AVO response [1] and [2].

One of the important steps in the seismic data conditioning is checking for consistency of amplitudes laterally. In onshore data, surface-related geology may affect both acquisition and processing workflows which in turn affect the subsequent analysis using seismic. We present a fast solution for addressing these near-surface effects in partial angle stack seismic using root-mean-square (rms) amplitude maps. The resulting seismic is suitable for use in any AVO analysis and Quantitative Interpretation (QI) workflows. It is believed that during acquisition a uniform source energy is input into the earth and any differences in amplitude recorded should be due to differences in geology. But this is not always true, although inversions often assume laterally consistent wavelets which is achieved through tactful and careful seismic data processing [2].

LOCATION AND GEOLOGY OF THE STUDY AREA

The location and geological setting of the field has been discussed in detail by [3] and [4].

II. MATERIALS AND METHOD

Prestack depth migrated 3D anisotropic seismic data with remarkable AVO (full and partial divided angle gathers) and well data acquired from five wells in this gas field from the Nigerian Delta were used for this study. Petrophysical evaluation was done on gamma ray log, density log, neutron log, sonic log, and resistivity log. Porosity, water saturation and shale volume were determined from the wireline logs. In the seismic data interpretation only two (2) reservoirs were used in this study because of their volume. Amplitude extraction, seismic decomposition and geobody capture were performed (Monier et al., 2021.

III. Results and Discussions

In the Nigerian Delta, experience backed up by many studies has established a clear relationship between hydrocarbons and amplitude anomalies. With the awareness that true seismic amplitudes are diagnostic of hydrocarbon anomalies, seismic amplitude interpretation is important for recognizing potential. Because hydrocarbons are found in three-dimensional enclosures, 3D seismic, is a significant breakthrough (Chopra and Herron, 2010). An interval within the seismic section is found which is laterally continuous, with uniform shale that lies above the zone of interest. This is our reference interval and the RMS map of this interval is our reference map. Given the assumption that interval is uniform, and the RMS map of a uniform interval should be free of amplitude patterns [5].

We must be cautious as it is likely that there are no completely uniform intervals, especially over the lateral distances of seismic surveys. So, the goal is to find an interval that is mostly uniform and carefully QC the results to make sure that the net gain is firmly in the positive. Prestack impedance inversion is much like AVO analysis, except that a wavelet is derived for each input angle [5]. Figure 1 is the panel displaying the well logs used in this study and horizons considered.

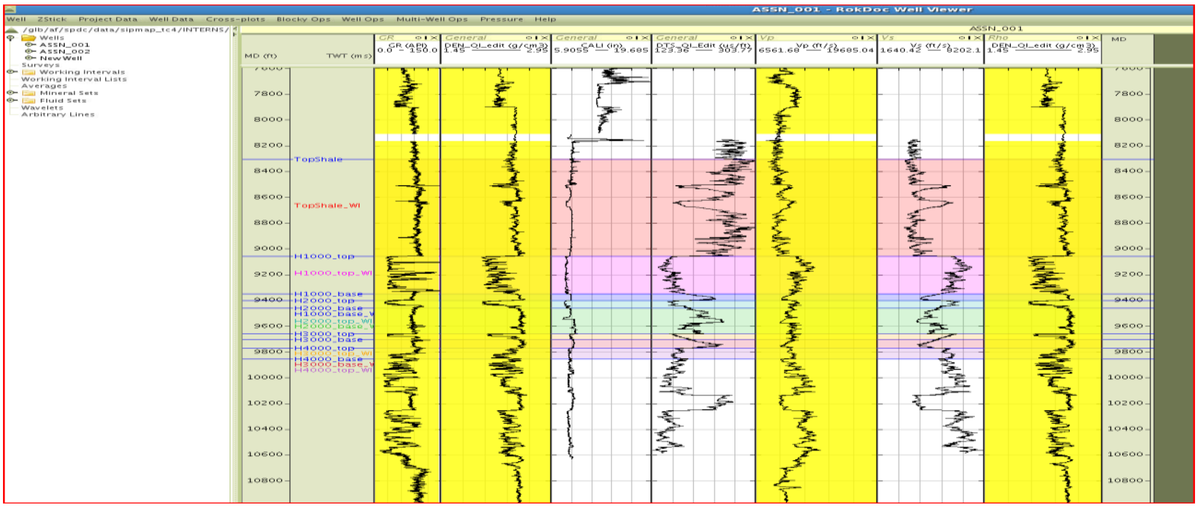

Figure 1. Well log panel showing the wireline logs used in this work and the target horizons being considered.

Density (rho) commonly varies with velocity so that its effects upon reflection coefficients is fairly satisfactorily taken into account by multiplying the reflection coefficient due to velocity contrast by a certain factor. However, departures from this rule exist as evidenced by scatter of observation points and may in some cases be significant (see figure 2). The V_p and rho domains could not effectively separate lithology because of high degree of overlap of both sand and shale clusters. Gamma ray space discriminated the lithologies as well as the P-velocity and porosity domains.

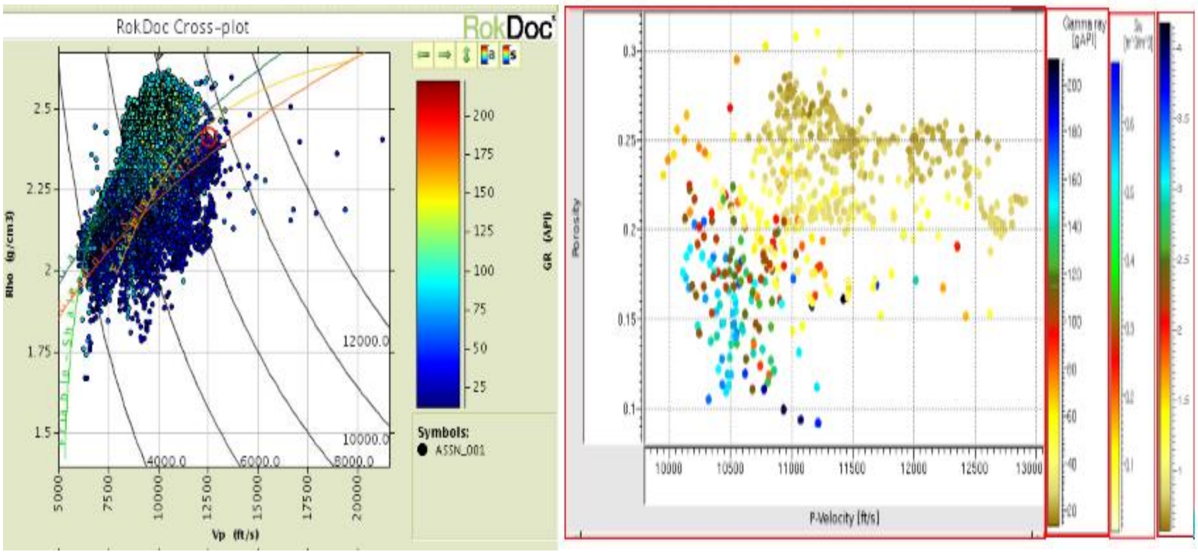

Figure 2. Crossplots of compressional velocity (V_p, P-velocity) versus density and porosity colour coded to gamma ray, water saturation and density values.

In Figure 3, both compressional velocity V_p and shear velocity V_s domains could separate the lithology according to their clusters. Also, the P-velocity is higher for the sands than for the shales and clustered according to their depths. In Figure 4, the V_p/V_s space separates the lithologies while P-sonic could not. However, the S-sonic and V_p/Vs space successfully the discriminated the two principal lithologies in the field.

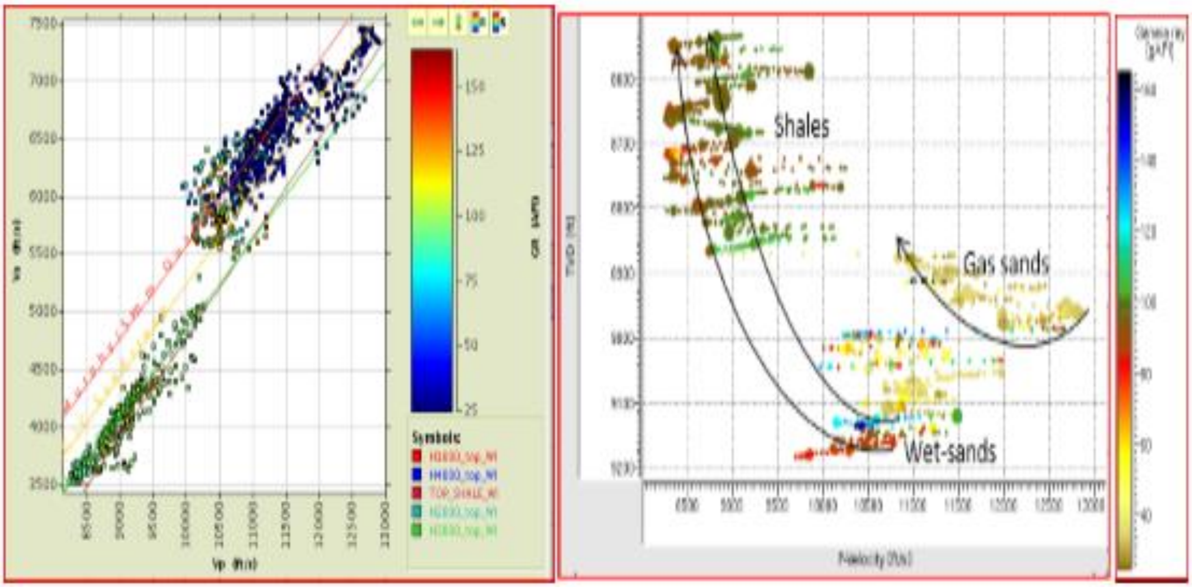

Figure 3. Crossplot of compressional velocity Vp versus Vs from the wells, colour coded to gamma ray.

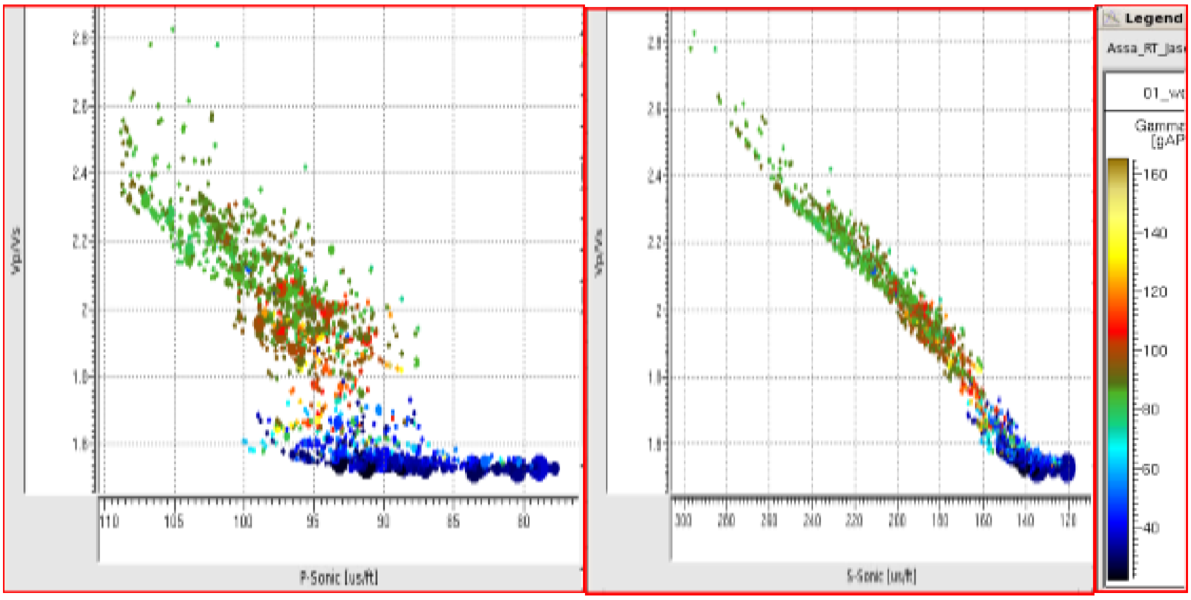

Figure 4. Crossplots of P-sonic and S-sonic against V_p/V_s colour coded to gamma ray values.

Figure 5 displays the crossplots of P-impedance versus S-impedance and porosity colour coded to gamma ray and water saturation. The S-impedance domain separated the lithologies according to their scatter/cluster while the P-impedance domain could not. Similarly, porosity space distinguished the sands from the shales and the sands have lower gamma ray and water saturation values than the shales [3] and [5].

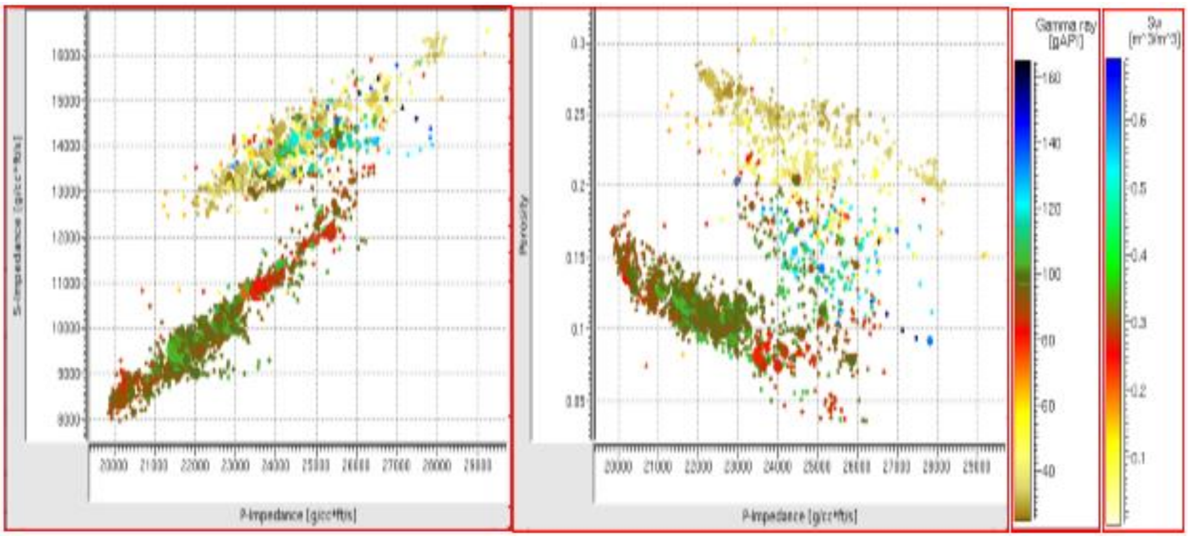

Figure 5. Crossplots of P-impedance versus S-impedance and P-impedance versus porosity colour coded to gamma ray and water saturation

Furthermore, Seismic attributes were extracted, analyzed and interpreted as key to understanding anomalies and their distribution pattern which gave rise to a more detailed channel morphology. Two main stacked reservoirs of similar depositional environments, trending northeast-northwest and south-southeast directions form the focus of this study. Prestack forward modeling of migrated seismic gathers provided the prediction of whether a given hypothesized rock property (cluster in a crossplot) can be separated from the background from surface amplitude measurements. In AVA_z, the interpreter first flattens the far offset stack of common azimuth migrated volumes onto a reference pick. Figure 6 displays the normal moveout (NMO) corrected gathers around a well location in the study area. These NMO corrected gathers were considered as amplitude components and were sorted to produce constant angle amplitude sections. These amplitude sections were quality controlled and investigated to reveal expressions that were not seen in full stack sections [1] and [5].

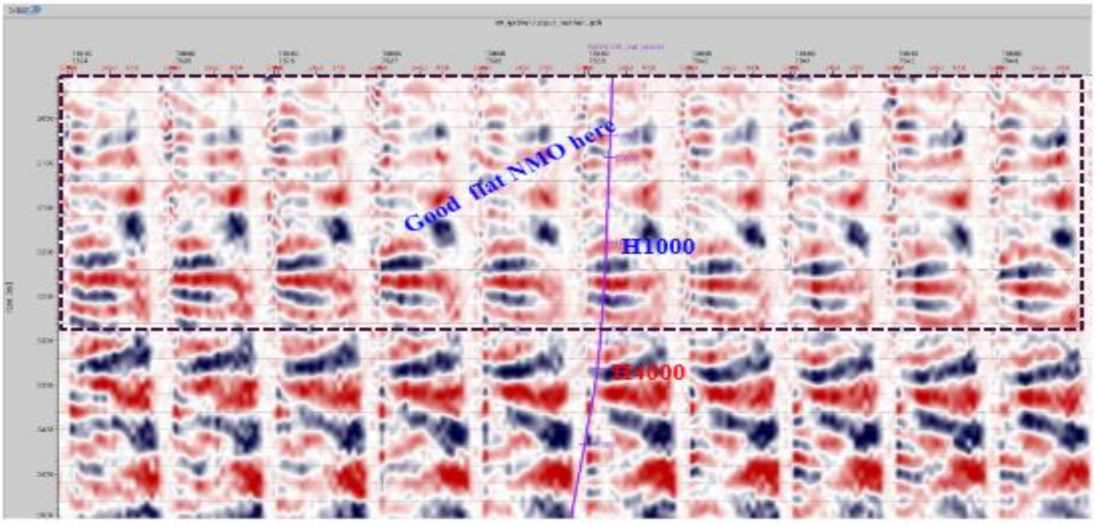

Figure 6. Normal moveout (NMO) corrected gathers around a well location ([3] and [6])

Phase, frequency and amplitude variation are the measurable parameters available for analysis, because they are the principal kinds of information available for extraction from seismic data. Understanding how seismic amplitudes change with reservoir lithology, porosity, and fluid product requires a deep understanding of the underlying rock physics. Usually, at the location of a drilled well, we have measurements that give us a good idea of the elastic and physical properties of the subsurface (velocity, density, lithology, porosity, confining stress, pore pressure, saturation, fracturing, etc.). Rock physics systematics provides a means to predict the seismic amplitude behaviour away from well control, in areas we may hypothesize to be favorable for additional hydrocarbon accumulation [7] and [8].

The concept of elastic impedance which is the result of inverting an angle limited stack. The study of amplitudes is also a powerful tool for reservoir delineation. Examination of prestack amplitude gathers often shows a variation with offset (and hence with incident angle). With the common use of relative amplitude processing for bright spot analysis, early theoretical work on amplitude changes with incident angle due to lithology changes could be put into practical use. The first use was to further the identification of gas sands in Tertiary basins which give rise to what we now call class III or II AVO anomalies [9].

Figure 7 shows near (0° - 10°), middle ($11^o – 20^o$) and far (21^o - 30°) constant angle gathers. The AVO is preserved in all the angle stacks and the angle stack are properly aligned in time. The amplitude in the gathers exhibits remarkable changes from angle to angle. The middle stack amplitudes are not clipped and does not appear too bright compared to the near and far stacks. At small angles, the top of the reservoir H100 (2180 ms) and H400 (2320 ms) does not look different from its surroundings. As the angle increases, the reservoir's amplitude stands out. At higher angles, the amplitude becomes strongly negative. Shear amplitudes would decrease as the shale content increases whereas there is significant compressional amplitude increase due the presence of gas cap. Amplitude decrease could also be attributed to directional permeability [10]. 3D seismic, with the help of modem interpretation techniques, now provides continuous amplitude maps of such high resolution that hydrocarbon sand reservoir delineation can often be interpreted in spectacular detail. In the Nigerian delta, experience backed up by many studies has established a clear relationship between hydrocarbon sand amplitude anomalies. Cementation could also be expected to reduce the variability within the rock units [11].

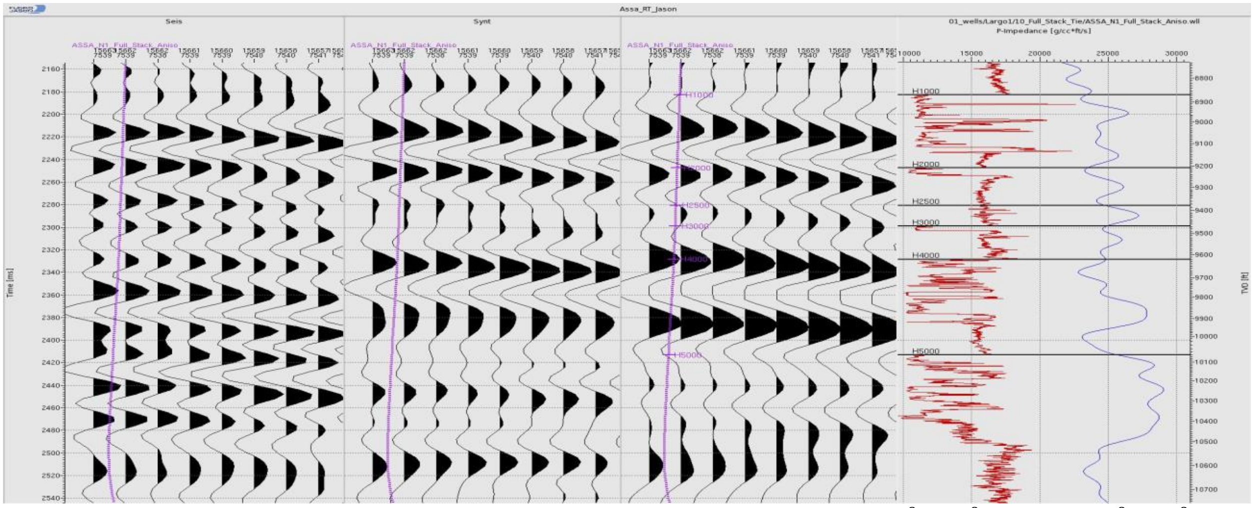

Figure 7. Amplitude variation with offset model from log data. Angle stacks near (0^o – 10^o), middle (11^o – 20^o) and far (21^o – 30^o) after [3] and [11].

The amplitude anomalies are a trough (at H1000) and a peak (at H4000) associated with sands and strong amplitudes are as a result of the presence of hydrocarbon which has been confirmed by drilled wells in the area. However, to link the seismic amplitudes to reservoir properties, we made sure the amplitudes are a true representation of lithology and/or impedance variations. This was because several factors in acquisition and processing could lead to erroneous amplitudes which might cause misleading representations of the true lithologies. The main targets in the gas field are the H1000 and H4000 in the Agbada formation. The constituents of the rocks have a complex heterogeneous mixture of clay, silicates and carbonates. Moderate to high amplitude areas on the attribute maps tie with gas sands while low amplitude section on the map correspond to brine sand and shales, which was proven by the results of the drilled wells in the field [1] and [4].
The synthetic seismogram was generated by wavelets (see Figure 8) which has closely the same phase and frequency spectrum as the processed seismic data. Moreover, each of the anomalies in amplitude represents some form of information about the reservoir in response to the passage of seismic energy. Typically, this shows amplitude response to reservoirs saturated with hydrocarbon. Amplitude, variation with offset (AVO) demonstrated that geologic formations containing hydrocarbons have their own amplitudes with which they respond to seismic excitations. These seismic responses are controlled by their lithology type, pore space, and fluid content [12]. In turn, this has provided supportive interpretation for strong amplitude anomalies observed at the tops of hydrocarbon-saturated reservoirs.

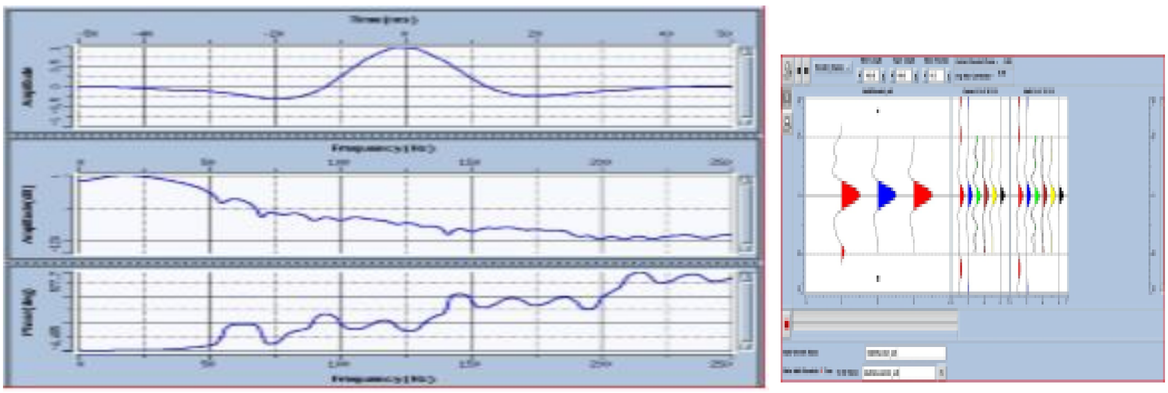

Figure 8. Amplitude, phase and spectra and the wavelets derived for the inversion.

The wavelets extracted from the three partial angle stacks show variations in peak amplitudes which show consistent peak amplitudes after necessary corrections.

In order to assess the features of seismic responses to geologic formations, amplitude sections are produced at various angles. Amplitude patterns are more pronounced in the near partial angle stack and near surface effects change with depth. The formation is laterally continuous, so most of the variations in amplitude are believed to be caused by near surface effects. In this oil and gas province, seismic interpretation is complicated by poor reservoir continuity and intense faulting [11]. The reservoirs in the main productive interval, sands deposited in a fluvio-deltaic environment, have limited lateral continuity and, as a result, the seismic character in this interval is variable.

The surface seismic data (see Figure 9) played an important role in characterizing the subsurface heterogeneity because it provided both lateral and vertical coverage and also a link to rock physics through AVO. A 2D seismic profile running through five (5) wells in the study area was taken through an amplitude preserved AVO processing flow. Data quality was reasonably good, and the usual noise problems in terms of ground roll and other wave modes were skillfully tackled using adaptive and iterative noise attenuation schemes. The surface elevation variation along the profile is about 45 m, and this is of the same order as the reservoirs depth variations of 100 – 250 ft. This elevation variation was a significant factor regarding the amplitude recovery and the stability of the AVO inversion at the reservoirs' levels. Care was exercised for amplitude recovery and super binning was part of the data conditioning for AVO inversion [10], 13 and [14].

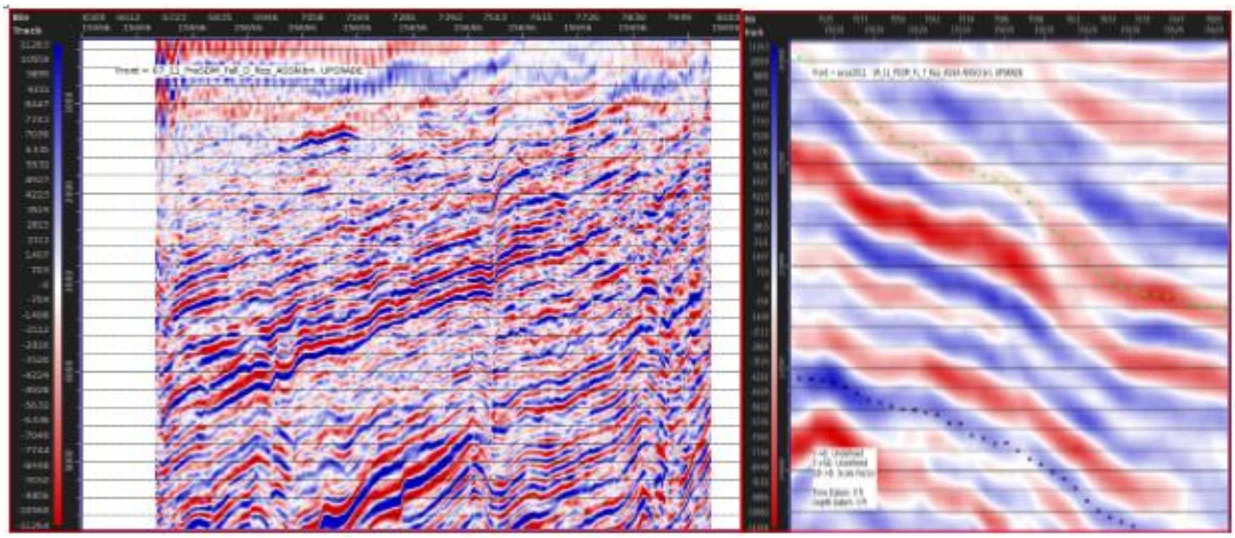

Figure 9. Full prestack depth migrated seismic section of channels showing laterally more uniform amplitude after necessary corrections, horizons are in dotted lines.

An arbitrary line using modern data in a fast track preststack migration volume connects some amplitude anomalies in the area of study (Figure 9). All data in this paper have been processed so that peaks represent increases in acoustic impedance and troughs indicate decreases in acoustic impedance. Some of these anomalies occur at similar depths or stratigraphic levels near the base of the Formation, but others are at a higher level. We can see high amplitudes, and for the largest amplitude anomalies, we can see amplitude and time delay effects on the underlying reflections. Figure 10 shows the P-impedance and S-impedance display from well data. Note the very weak P-impedance inability to separate the sands from their encasing shales while there exists a strong separation of the sands from their encasing shales from the S-impedance. There is insufficient P-wave velocity and density contrast between the sandstone and the encasing shale to cause significant reflectivity contrast on the compressional wave data. The contrast in shear rigidity modulus between the reservoir sandstone and the surrounding shale (sediments) causes a strong seismic expression on the shear wave data. The reservoir sandstone is transparent to P-waves, but it is recognizable on S-wave data [10] and [11].

However, we could cluster alternative seismic measurements (attributes) to better risk a given prospect or characterize a reservoir. For example, a target that is structurally high, has four-way closure, and has a class III AVO anomaly is an excellent prospect in most Tertiary basins. Seismic attribute analysis enhances seismic interpretation by revealing additional insights in seismic reflection data and reducing uncertainties through accurate mapping of channel features and pattern recognition [14].

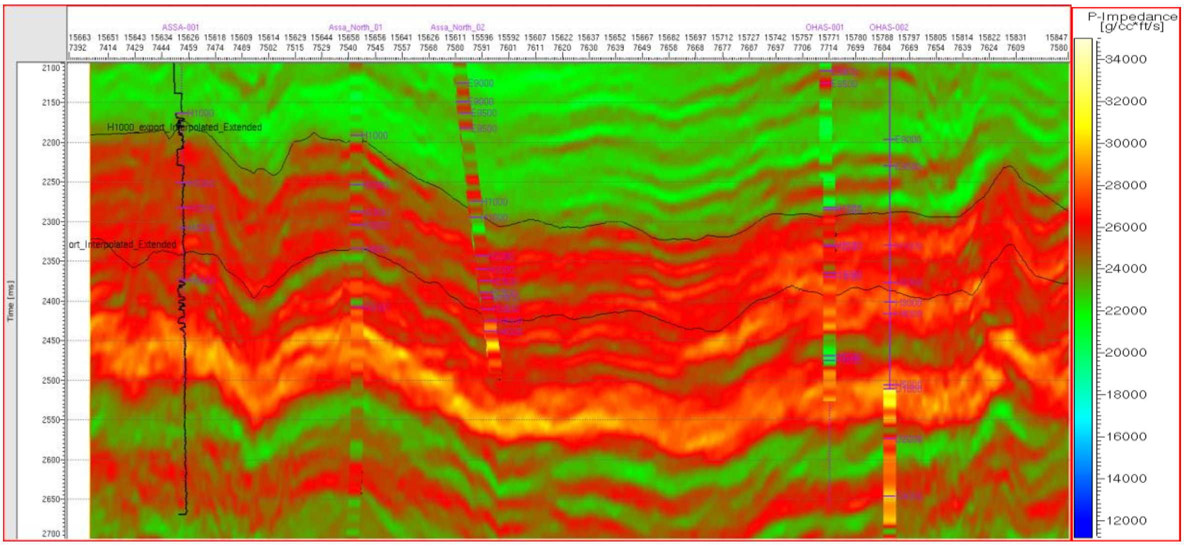

Figure 10(a). Inverted P-impedance volume overlain with well tops marker, p-impedance log and inverted P-impedance from the wells colour coded to P-impedance values

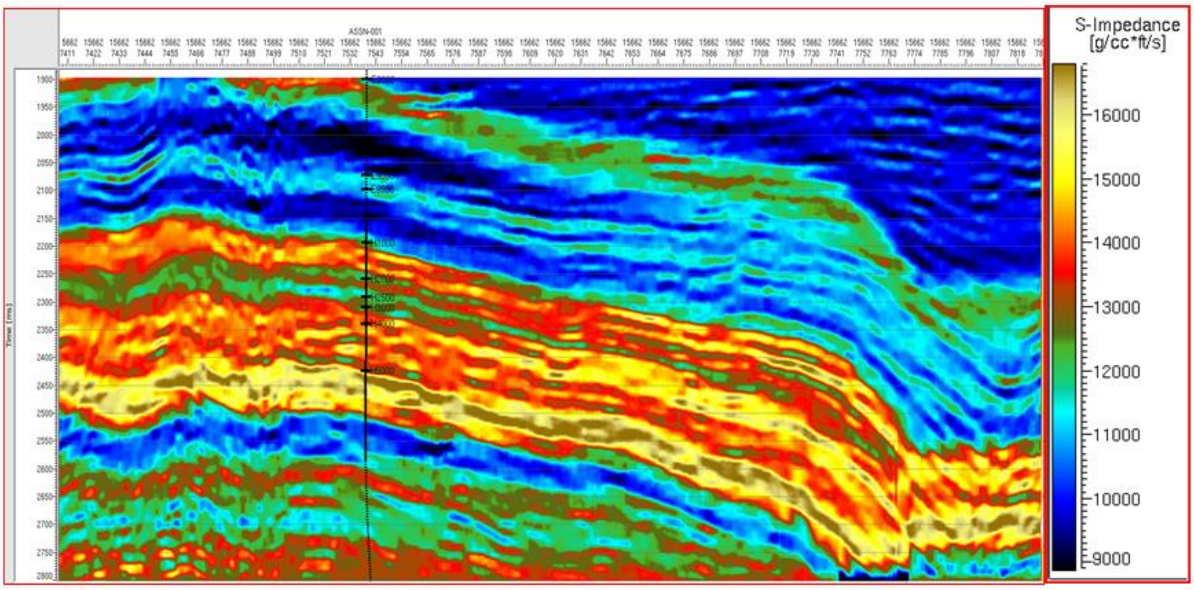

Figure 10 (b). Inverted S-impedance volume overlain with well tops colour coded to S-impedance values

Comparing results from different attributes help to successfully define sand reservoirs. Grid from the two interpreted horizons were used in the seismic attribute analysis to make root-mean-square (rms) amplitude maps. Thus, the rms amplitudes of the angle stacks over a defined time window within the reservoir formations or horizons (i.e. between top and base of each channel) were computed. This was done by referencing the calculation window of 200 ms above and below the interpreted seismic horizons. The size of window was varied, depending on the thickness of the zone over which the anomalies were seen on the seismic data [4] and [14].

We focused on the two seismic interpreted horizons and carefully produced amplitude maps for each angle stack at the reservoir intervals with carefully created time windows between and around them. Amplitude corrections were done because of surface geology, acquisition and processing imprints, while at the same time preserving geological features such as faults, salt dome, sedimentary beds, carbonate beds etc. after amplitude corrections. The amplitude map was balanced [1], [14] and [5]. This research work is based on the assumption that as the composition of a facies unit changes laterally, the phase, frequency and amplitude variation show up in the reflected seismic signal. A common example is the lateral change from sands to shales being experienced in the Niger Delta.

The 3D seismic, with the help of modem interpretation techniques, now provides continuous amplitude maps of such high resolution that hydrocarbons and reservoir delineation can often be interpreted in spectacular detail. Figures 11a&b show the amplitude attribute maps produced from the seismic gathers at near, mid and far angle stacks. The attributes were used to produce these amplitude sections at constant angles to screen the data for amplitude anomalies that could be good indicators of hydrocarbons. high amplitude values are associated with channel cut by northwest and southeast trending faults. Amplitude anomalies were along northwest and southeast regional faults and cut by secondary faults, as such amplitude anomalies are bound by both set of faults. These discontinuities are further confirmed to be faults by the displacement of the fluvial channels sands on the amplitude maps and the high amplitude channels oh the amplitude maps are cut by the discontinuities. Throughout the area of study, amplitude anomalies are scattered within the horizons of interest along the faults, channels and in the unfaulted zones. Intervals of broad amplitude are more promising for hydrocarbon exploitation compared to narrow anomalies [15].

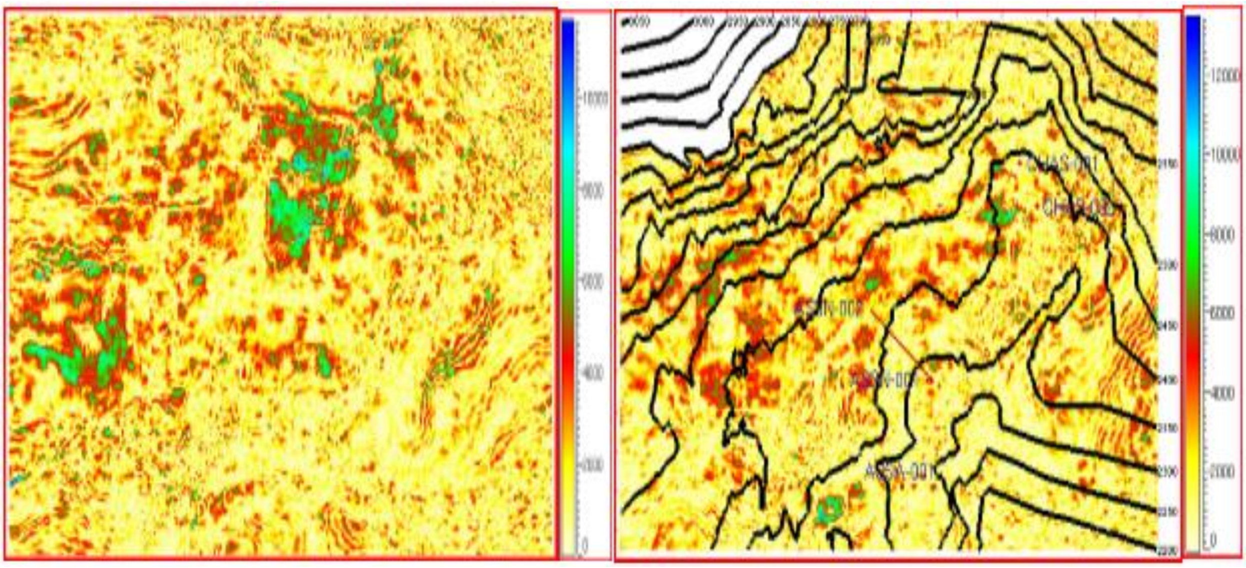

Figure 11. Root-mean-square amplitude horizon maps of near angle stacks of H1 and H4 over 2000 – 2700 ms time window

High values are indicative of the presence of hydrocarbons. In the upper part of the map, a clear anomaly, conformable with structural contours, outlines an accumulation in a well-defined fault block. Similarly, amplitude anomalies are present in other fault blocks in the middle and lower parts of the map. Most notably, the amplitudes show a clear communication between these fault blocks. Correlation of the reservoir sands amplitude maps of the seismic events with well log data provided significant insight into the reservoir character. Compressional amplitude increase refers to areas of increased productivity, additional hydrocarbon potential and distribution of youngest sandstones in the area [10] and [11]. The amplitude map in Figure 11(a) is from the same field but from a deeper reservoir level than the level illustrated in Figure 11(b). High values (green) are indicative of the presence of hydrocarbons. In the upper part of the map, a clear anomaly conformable with structural contours, outline sand accumulation in a well-defined fault block. Similarly, amplitude anomalies are present in other fault blocks in the middle and lower parts of the map. Most notably, the amplitudes show a clear communication between these fault blocks.

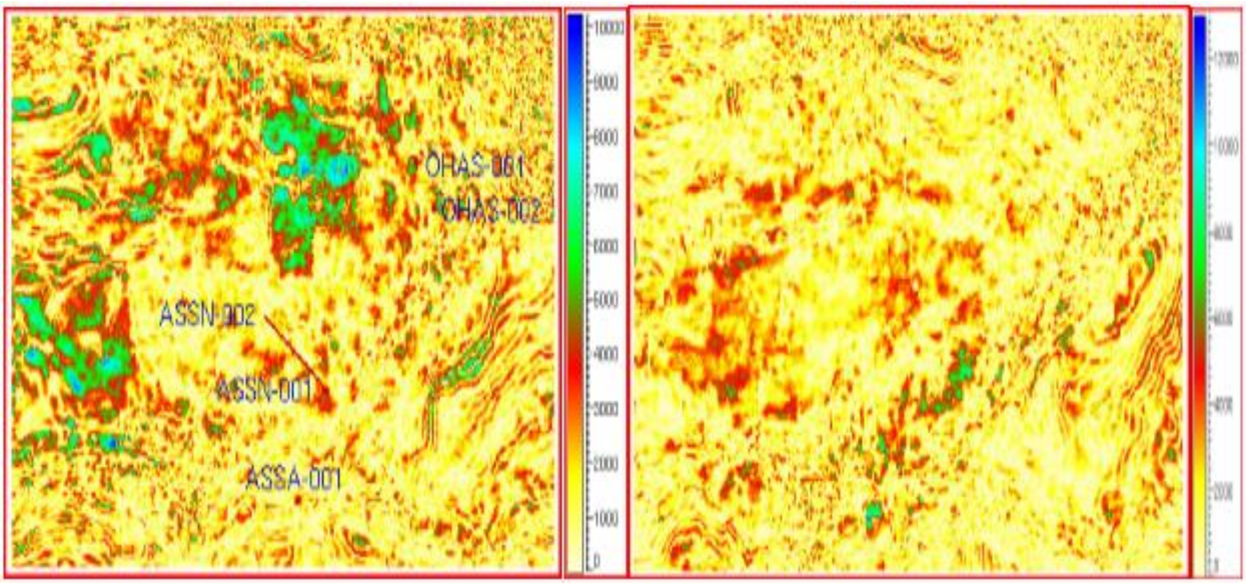

Figure 11(b). Root-mean-square amplitude horizon maps of middle angle stacks of H1 and H4 over 2000 – 2700 ms time window

The rms amplitude maps displayed for different angle stacks show anomalous (green) features with values higher than their surroundings. Figure 11(b) also, shows amplitude map displaying drilled wells in the study area. Through the rms amplitude extractions, channels have been defined and delineated. Interpretation of the stacked channelized shoreface sands through these seismic attributes helped in understanding shale filled and sand filled channels. Generally, the high amplitudes are found in area where gas sands exist. Very high amplitude spots are associated with solution gas caps, which are known to be present in these areas because of the relatively high gas oil ratio (GOR) in the fluids produced in nearby wells. Somewhat higher amplitudes are also observed in some parts of the field but in a structural position deeper. Additional modeling of the seismic response depending on different porefills showed that these amplitudes are not related to reservoir porefill. The amplitude displays show a distinct channel feature, Integration of the well data with the amplitude displays confirmed this interpretation. Well 2 on the edge of the channel, well 6 outside the channel in a proximal overbank area, and wells 4 and 5 in the crevasses play found progressively thinner sands [11]

Geobody capture, spectral decomposition, frequency analyses were conducted and showed that thin beds and subseismic features/beds. Another seismic attribute employed here is spectral decomposition of the seismic data originally in time or depth domain to different frequency cubes using discrete fast Fourier transform for imaging and mapping temporal bed thickness and geologic discontinuities over the 3D seismic data. Application of this signal analysis technique on the 3D seismic data successfully delineate stratigraphic and structural settings [5]. Three different frequency cubes were extracted from the prestack depth migrated seismic cube. Frequency analysis showed that the dominant frequency distribution of the angle stacks 2000 ms – 2700 ms is about 25 Hz – 30 Hz (see Figure 12). [1], suggested that if the intercept and gradient are known, reflection coefficient components contributing to fully or partially stacked traces can be derived at any angle within the interval of the validity of the approximation [13] and [16].

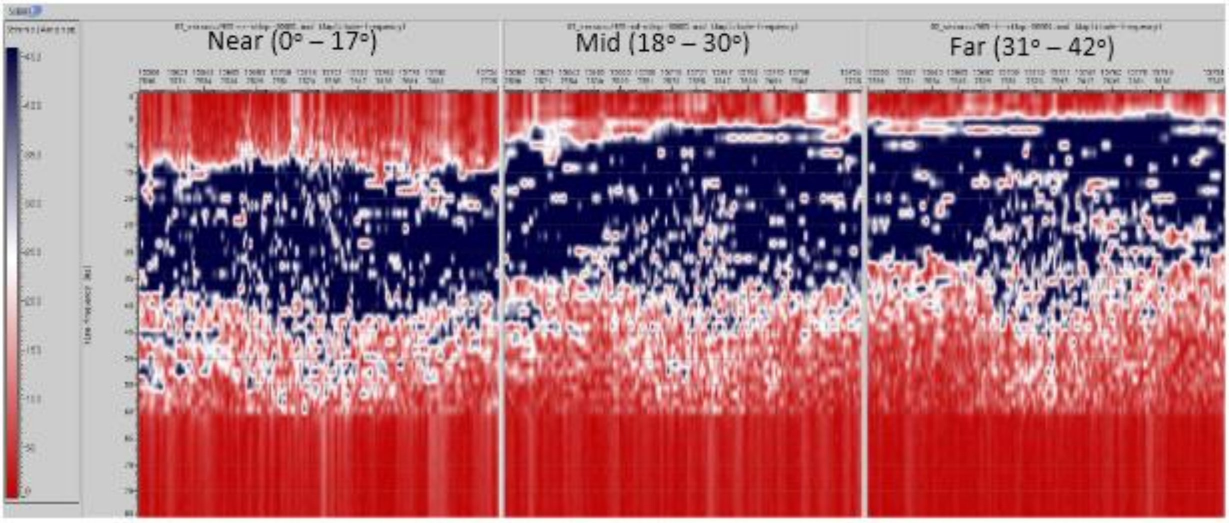

Figure 12. Amplitude and frequency distributing of the partial angle stacks (near (0^o – 17^o), mid (18^o – 30^o) and far stacks (31^o – 42^o), 2,000 ms – 2,700 ms window [12].

The channel fill tuning frequency is higher than the overall dominant frequency in H1000 and lesser than the overall dominant frequency in H4000. Spectral decomposition was done by applying discrete Fast Fourier transform around the grids of the two interpreted seismic horizons and transforming the amplitude or phase data into the frequency domain. The purpose was to analyze different frequencies of the seismic volume and examine each frequency band volume. The low frequency range (0 – 10 Hz) in the seismic data (in red) are missing in the near stack, mid frequency range (11 – 25 Hz) in deep blue, which also represent the core of the channel and high frequency range in the seismic data (26 - 42 Hz). The frequencies go down from near to far as expected. The colour blend enables visualizing the thickest sand sections and better quality sections of the channels resulting to white colour, where the three frequency ranges are present. This is the brightest continuous anomaly. This approach better delineate channel architecture and connectivity in more detail, supported by the rms amplitude maps [16] and [17].

Predicting sand distribution and reservoir presence is one key task and uncertainty in exploration. Geobody extraction could help reduce this uncertainty through recognition and accurate mapping of channel features. Geobody capture facilitated detection of anomalies and delineation of stratigraphic and structural features. Here, reservoir zones were identified on the seismic section and separated from non-reservoir zones by applying different opacity filters on amplitudes before extraction [18]. Figure 13 displays the sand capture and Figure 14 is the inverted net-to-gross volume overlain with inverted net-to-gross logs from the wells together with the net-to-gross map of the field colour coded to volume of clay. The sand quality is quite good although the sand is not completely clean.

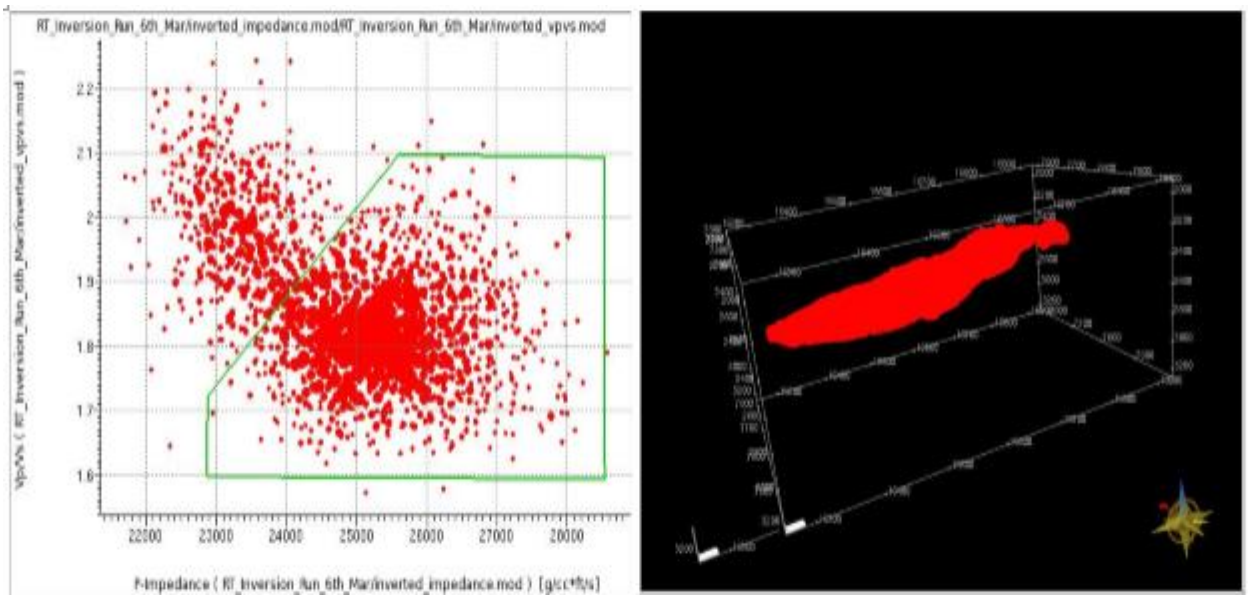

Figure 13. Geobody capture for the reservoir sands.

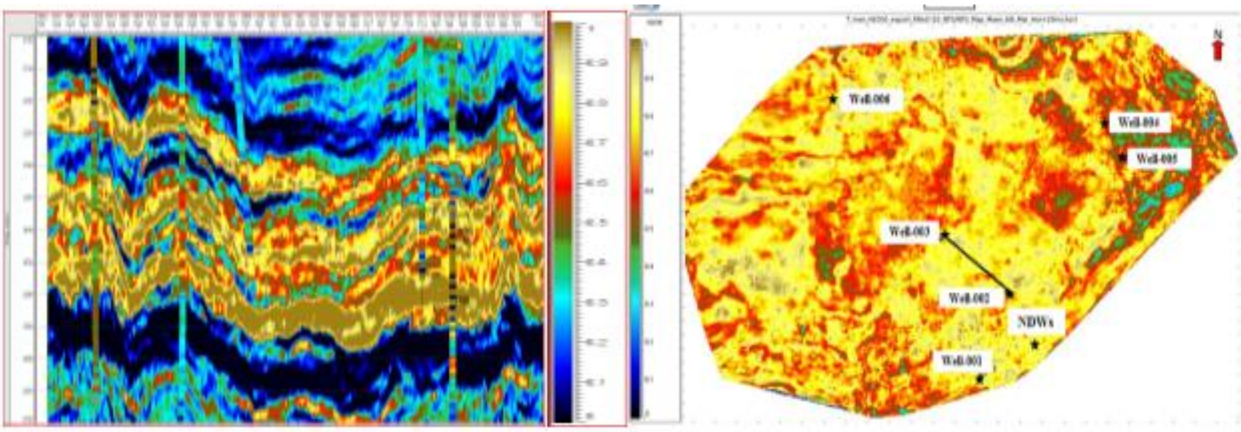

Figure 14. Net-to-gross volume and map of the study area colour coded to volume of clay

They showed as elongated bodies defining reservoir geometry and continuity and may represent channel depositional feature and geologically most plausible morphology of the channel. However, the geobody capture could not account for all the channel geometry due to the vertical resolution of the seismic where the geobody could not capture the subseismic and beds. It also failed to capture the presence of thin beds due to the absence of data to properly evaluate them. None theless, this research work has immensely highlighted the crucial role played by attribute analysis in defining subsurface targets [11] and [18].

IV. Conclusions

The 3D seismic data over the field has helped in imaging and visualizing the structure and leading to a better and robust understanding of the subsurface. Thus, the 3D seismic data and its spatial imaging of the subsurface is a reliable tool for stratigraphic interpretation. Integration seismic attributes, geobody extractions, frequency analysis through spectral decomposition, and inverted seismic sections have helped in the characterization the reservoir channels. Accurate calibration and identification of seismic horizons is very essential for detailed seismic interpretation resulting in clear definition of each seismic horizon and expression of any geologic interface. The study of amplitudes is also a powerful tool for reservoir delineation. This is illustrated by the investigation of a channel feature in the field. The combined study of amplitude and other attribute displays resulted in a detailed structural reassessment of this field. This had a marked impact on the appraisal and development strategy of the field. In particular, the drilling of two previously planned appraisal wells were cancelled, based on convincing structural evidence, and resulted in savings easily covering the cost of the 3D survey. As a result of the absence of a realistic reservoir model, it was not possible to plan development activities without severe risks. Therefore, it was necessary to re-evaluate the structural setting and reservoir quality on the basis of the available 3D seismic data. The amplitude displays show a distinct channel feature, the lower loop display clearly revealing the outline of the channel body. Integration of the well data with the amplitude displays confirmed this interpretation. The amplitude mapping on the discrete frequency volumes may help to map the reservoirs more effectively as compared to conventional seismic data. Spectral decomposition can be used to detect subtle faults. Northwest and southeast faults may help to compartmentalize the reservoir. Petrophysical evaluation and Geobody capture from rms, amplitude and spectral decomposition have enabled the description of two reservoirs in terms of their location, lithology, fluid content, lateral extent, continuity, and geometry, which formed the focus of the study. The frequency spectra helped to predict the distribution of the sands, detect the nature of the channels and detect faults. Amplitude analysis of AVO approximations and attributes to amplitude individual constituent components that form traces in stacked sections has enabled computation of amplitude sections at constant angles with additional information. We expect geology to vary greatly with depth, while remaining more constant laterally. There were limitations of data availability and vertical seismic resolution was calculated from the compressional sonic and average frequency spectrum.

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