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Establishing Sand Body Continuity Using High Resolution Sequence Stratigraphic Analysis in Agbada Field, Niger Delta, Nigeria

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Abstract

This study developed a sequence stratigraphic framework for Agbada Field. Field wide correlation gives an insight into stratigraphic succession of the field which is the typical sand/shale alternation of the Agbada Formation. This correlation was integrated with biostratigraphic data. The major maximum flooding surface (MFS) is the 15.9 Ma, Chiloguembelina-3 which was interpreted in the thick shale interval above the D1.0 reservoir. The other undated maximum flooding surface (MFS) lies below the D4.0 sand. The sequence boundary lies at the base of D3.0 reservoir. There are three systems tracts interpreted in the intervals of interest; a basal highstand system tract (HST) above which we have a Sequence Boundary and overlain by a Lowstand System tract (LST) above which there is a transgressive surface which signalled the onset of the Transgressive System Tract (TST) that completed the end of the cycle. Parasequence correlations revealed the continuity of sand units which give an indication of the lateral continuity of sand bodies and the potential trapping and retention capabilities which would help in infill drilling plans to maximally exploit the reservoirs.

KEYWORDS: Agbada, Chiloguembelina, Systems tracts, Lateral continuity

1.0 Introduction

The Niger Delta is ranked among the major prolific deltaic hydrocarbon provinces in the world and is the most significant in the West African continental margin. Oil and gas in the Niger Delta are principally produced from sandstones and unconsolidated sands predominantly in the Agbada formation. The goal of oil and gas exploration is to identify and delineate structural and stratigraphic traps suitable for economically exploitable accumulations and delineate the extent of discoveries in field appraisals and development.

Sequence stratigraphy is a multidisciplinary approach to the study of genetically related facies within chronostratigraphically significant surfaces (Van Wagoner et al., 1990). It provides a potential unifying framework for interpreting much of rock records, and has considerable economic significance as it helps in identifying exploration prospects and predicting source rocks, seals and potential reservoir traps. Successful exploration and production strategies are becoming increasingly dependent on the proper application of sequence stratigraphic concepts. A regional analysis may require only defining the major sequences boundaries to reconstruct basin paleogeography. However, to more precisely delineate hydrocarbon fairways, additional details must be extracted from seismic data through integration of core, wireline log and biofacies data, and interpreting these data within a geological context. Levels of interpretation include delineating systems tracts within a sequence, recognizing the parasequences constituting a system tract and integrating available data into a predictive geological facies model. This study builds a sequence stratigraphic framework for the Agbada field in offshore Niger Delta.

This study is aim at define the sequence stratigraphic framework across the reservoirs of interest, define and identify the trend, continuity and quality of reservoir sand bodies. Carryout stratigraphic interpretation of the study area and identify key stratigraphic surfaces.

1.1 Location of Area of Study

The area of study, Agbada Field is located in the central swamp; Niger Delta It is located within OML 17. The field was discovered in 1960 and has a current production of 25Mbop/d (Figs. 1 and 2).

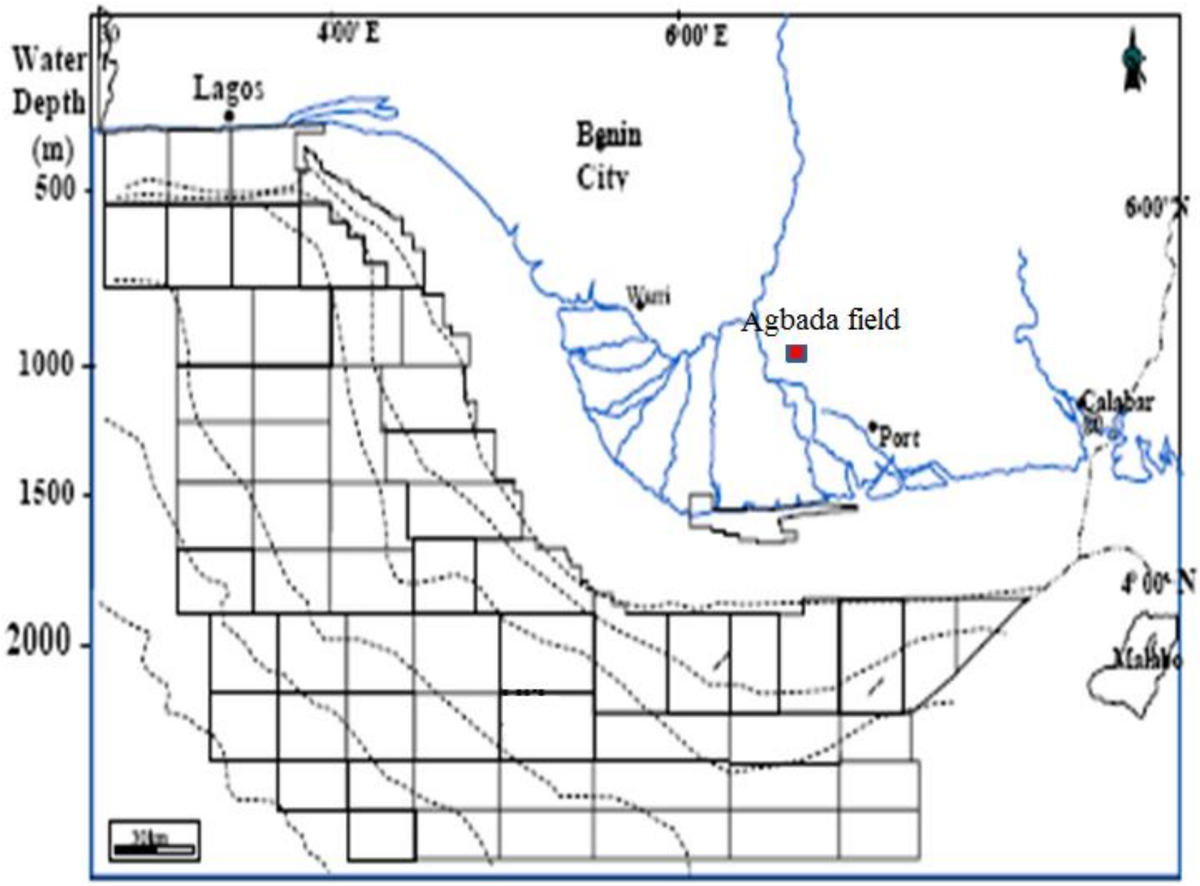

Fig. 1: Location of Agbada field

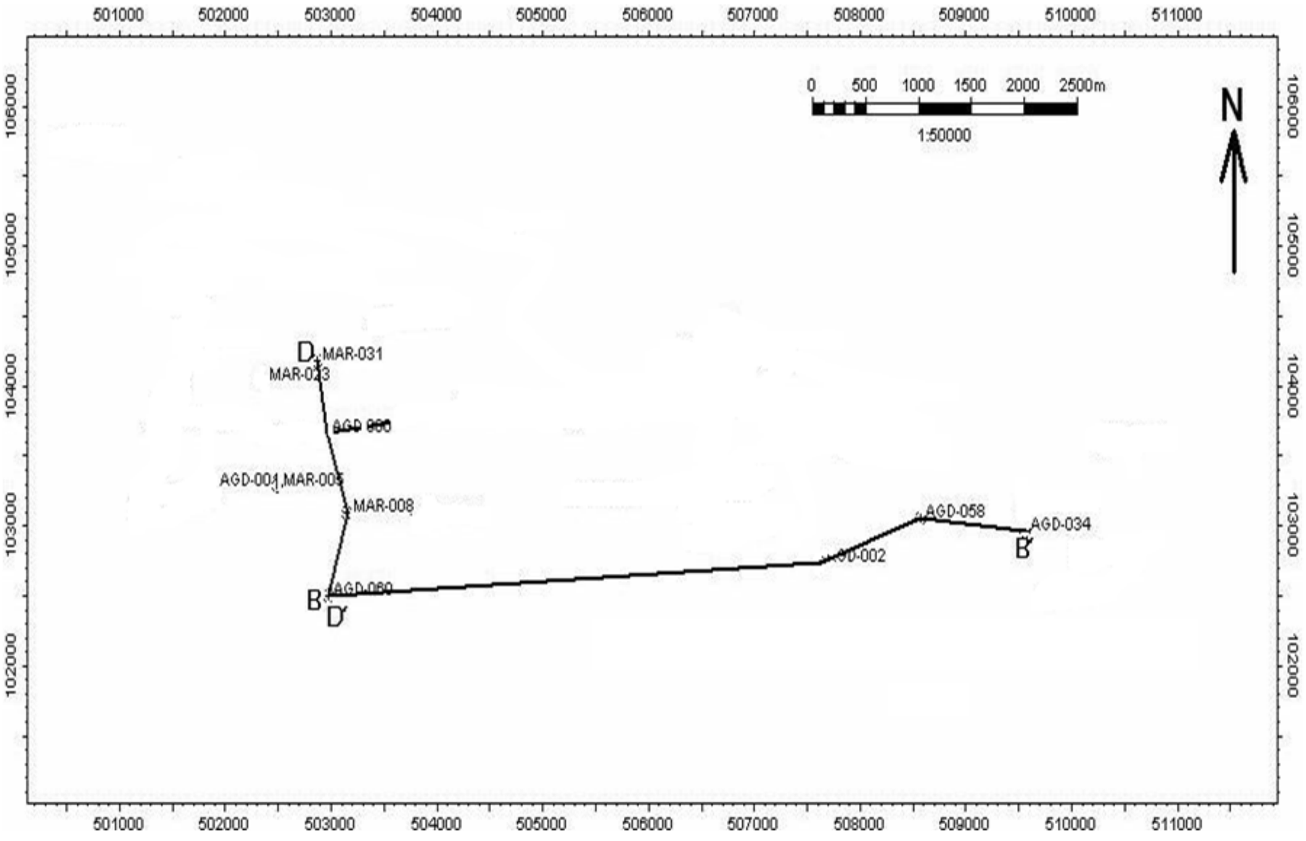

Figure 2: Basemap of well distribution in the study area

1.2. Regional Geology

The Niger Delta basin is located on the continental margin of the Gulf of Guinea in equatorial West Africa and lies between latitudes 4^{o} and 7^{o}N and longitudes 3^{o} and 9^{o} E (Whiteman, 1982). It ranks among the worlds' most prolific petroleum producing Tertiary deltas that together account for about 5% of the worlds' oil and gas reserves. It is one of the economically prominent sedimentary basins in West Africa and the largest in Africa. Detailed studies on tectonics, stratigraphy, depositional environment, petrophysics, sedimentology and hydrocarbon potential are well documented in the literature (Short and Stauble, 1967; Weber and Daukoro, 1975; Evamy et al., 1978; Knox and Omatsola, 1989; Doust and Omatsola, 1990; Nton and Adebambo, 2009; Nton and Adesina, 2009). The stratigraphy of the Cenozoic Niger delta is a direct product of the various depositional environments. Frankyl and Cordry (1967), Short and Stauble (1967), Avbovbo (1978) and Evamy et al (1978), provided the first information on the subsurface distribution of stratigraphic units in the Niger Delta. Subsequent studies include those of Doust and Omatsola (1990), Stacher (1995) and Haack et al (2000). Although the stratigraphy of the Niger Delta clastic wedge has been documented during oil exploration and production, most stratigraphic schemes remain proprietary to the major oil companies operating concessions in the Niger Delta basin. Three major lithostratigraphic units are defined in the subsurface of the Niger Delta, which are the Akata, Agbada and Benin Formations. They are Tertiary in age. There is decrease in age basinward, reflecting the overall regression of depositional environments within the Niger Delta clastic wedge. Stratigraphic equivalent units to these three formations are exposed in southern Nigeria. The formations reflect a gross coarsening-upward progradational clastic wedge (Short and Stauble, 1967), deposited in marine, deltaic, and fluvial environments (Weber and Daukoru, 1975).

The Akata Formation (Eocene – Recent) is a marine sedimentary succession that is laid in front of the advancing delta and ranges from 1,968ft to 19,680ft (600-6,000m) in thickness. It consists of mainly uniform under-compacted shales with lenses of sandstone of abnormally high pressure at the top (Avbovbo, 1978). The shales are rich in both planktonic and benthonic foraminifera and were deposited in shallow to deep marine environment (Short and Stauble, 1967). The Agbada Formation (Eocene-Recent) is characterized by paralic interbedded sandstone and shale with a thickness of over 3,049m. The top of Agbada Formation is defined as the first occurrence of shale with marine fauna that coincides with the base of the continental-transitional lithofacies (Adesida and Ehirim, 1988). The base is a significant sandstone body that coincides with the top of the Akata Formation (Short and Stauble, 1967). Some shales of the Agbada Formation were thought to be the source rocks, however; Ejedawe et al., (1984) deduced that the main source rocks of the Niger Delta are the shales of the Akata Formation. The Benin Formation is the youngest lithostratigraphic unit in the Niger Delta. It is Miocene – Recent in age with a minimum thickness of more than 6,000 ft (1,829m) and made up of continental sands and sandstones (>90%) with few shale intercalations. The sands and sandstones are coarse grained, sub-angular to well rounded and are very poorly sorted.

2.0. Materials and Methods

Data available for the study include 3D post stack seismic data and suite of wireline logs comprising of gamma ray, resistivity and neutron-density logs, Biofacies data (which include palaeobathymetry data, flora/pollen diversity, flora/pollen population, and pollen/flora zonation) for three wells, and check shot curve.

The gamma logs were used for lithology identification, field-wide correlation and sequence stratigraphic analysis. Sequence stratigraphic analysis of the studied intervals was done using pattern recognition of log signatures such as coarsening upward and fining upward patterns. Candidate maximum flooding surfaces, parasequence boundaries and sequence boundary were picked by integrating the gamma-ray log signatures along with the deep resistivity logs and marked neutron-density separation on the neutron and density logs (fig. 2). Parasequence boundaries were picked based on the contact of genetically related beds or bedsets bounded by marine flooding. Sediments that are genetically related obey Walther’s rule, a break in the law suggest the presence of a parasequence boundary. Parasequence sets stacking patterns were also used to interpret the system tracts in the intervals of interest. Cross-sections correlation drawn across some wells in the study area was constructed to reveal changes in lithofacies across the study area. Biofacies data were used for high resolution biostratigraphic studies. In this study, biostratigraphic data consisting of palaeobathymetry data, microfaunal abundance and diversity chart, aided in the delineation of the Maximum Flooding Surfaces, Sequence boundary and paleobathymetric interpretation. The ages of these key surfaces were also determined with the aid of the Niger Delta chronostratigraphic chart. Sequence stratigraphic framework was built for the study area by identifying and correlate regional bounding surfaces (maximum flooding surfaces and sequence boundaries). The markers help define the framework for the stacking patterns, system tracts definitions and base level cycles. Individual parasequences are defined largely based on the physical characteristics of gamma-ray logs and their relationships with the overlying and underlying parasequences. Gamma ray logs along with resistivity logs, neutron and density logs were used to identify the candidate sequence boundaries and maximum flooding surfaces. These candidate key surfaces were corroborated by high resolution biostratigraphic studies which was then used to build a chrono-biostratigraphic framework Well-to-seismic tie was achieved with the use of time-depth (T-Z) data which was used to create time-depth (t-z) curves. The equation of the line and the R^2 of almost all of the wells were close indicating similar average and interval velocity in those wells and little lateral velocity gradient variation. The polynomial equation of the mean line was used to generate the time equivalent on seismic at the well location of the reservoir tops and key stratigraphic surfaces. These were then used as starting points for seismic interpretation. In addition, the equation of the line was also used to convert these seismic time interpreted surfaces and faults to depth domain.

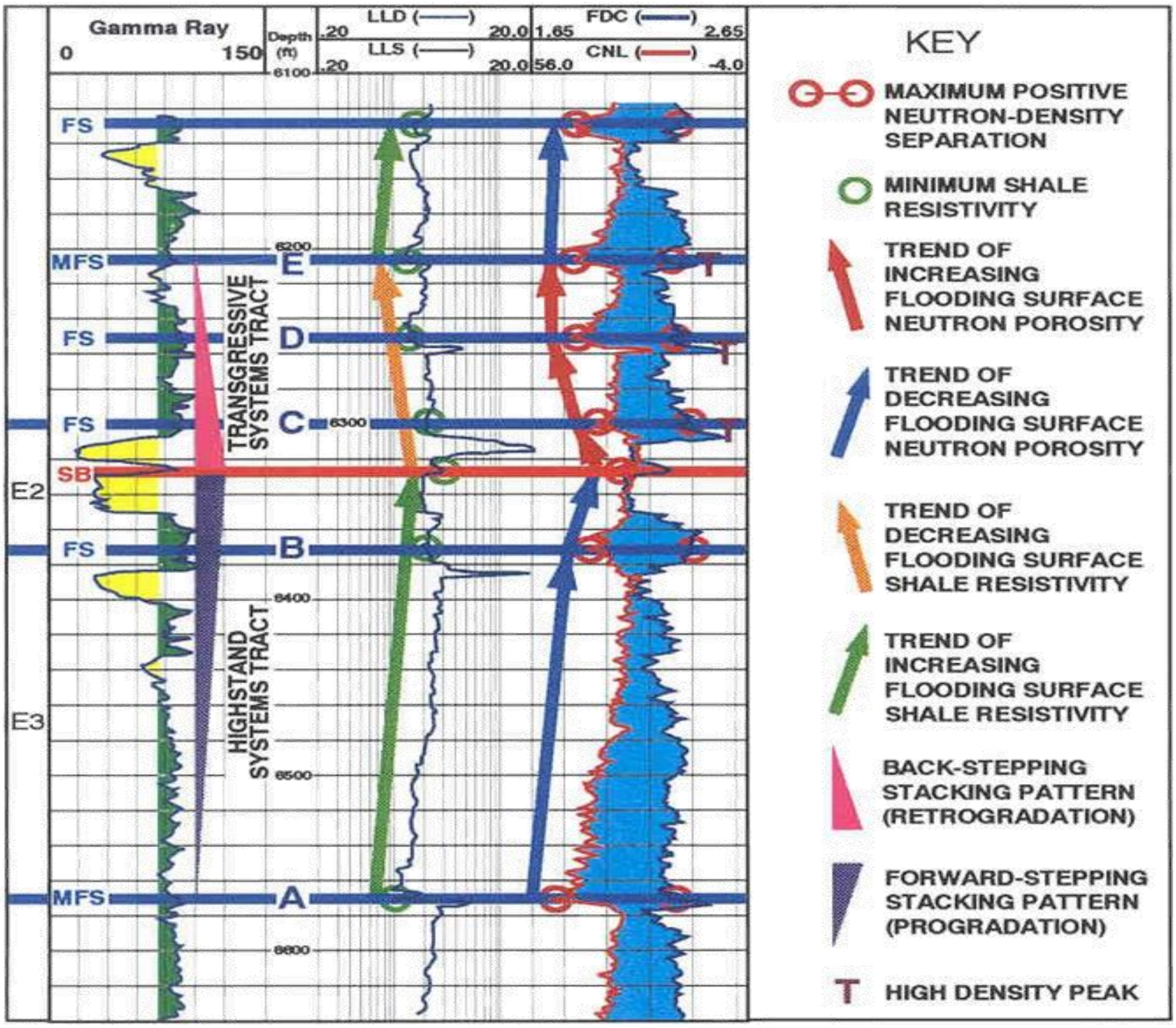

Figure 3: Recognition of MFS and SB from well logs. MFS is the maximum flooding surface, FS is the flooding surfaces, SB is the sequence boundary

3.0. Results and Discussion

3.1. Key Sequence Sratigraphic Surfaces

Two maximum flooding surfaces and a sequence boundary which were corroborated by high resolution biostratigraphic were delineated in this studies, this was then used to build a chrono-biostratigraphic framework (Fig. 4)

3.2. Maximum Flooding Surfaces

Two maximum flooding surfaces were delineated. The first one which lies within the thick shale sequence above the D1.0 sand is Chiloguembelina 3 regional marker (15.9my). This was used as a datum for sequence stratigraphic correlations. The other maximum flooding surface is an undated marker within a thick shale sequence sitting directly below the D4.0 sand; the faunal peaks and paleobathymetric depths which range from neritic to bathyal helped in the identification of these surfaces, and these constitute the major bounding surfaces in line with Galloway stratigraphic sequence model. The reservoirs of interest are penetrated by the P680 pollen zone and the F9300/F9500 and F9500 forams zones. In Wells AGD-001, and AGD-060, the D4.0 reservoir is within the F9300/F9500 zone while in Well AGD-002, it is within the F9500 zone indicating that Well AGD-002 penetrated the zones at shallower depths. This is further confirmed from the palaeobathymetric data which shows that while MFSs in Wells AGD-001, and AGD-060 are from the middle neritic to bathyal range (fig. 3), the MFSs in Well AGD-002 is within the inner neritic region. The recognition of these maximum flooding surfaces was further aided by the wireline log data where there is high gamma ray, low resistivity and high neutron and density separation.

3.3. Sequence Boundaries

In line with the typical sequence stratigraphic model, a sequence boundary was inferred in between the two maximum flooding surfaces. The sequence boundaries picked from the logs is that surface that the separates two different stacking patterns of parasequence sets, observed by abrupt change in gamma ray values. A coarsening upwards trend (progradation) to a fining upwards trend (retrogradation) on the gamma ray curve represents the time of maximum basinward shift of the shoreline within the relative sea level cycle, and defines the position of the sequence boundary (Emery and Meyers., 1998).

Taylor and Lovell (1995); Van Wagoner et al., (1990) described the general criteria for the recognition of sequence boundaries to include Evidence of erosional truncation along the sequence boundary, basinward shift in facies and environments across the sequence boundary, changes in the parasequence stacking patterns in shallow shelf settings from progradational parasequences below to the sequence boundary to retrogradational parasequences above.

From the GR log, in Well AGD-002, the GR signature at the sequence boundary shows a sharp basal upward fining contact with the underlying facies which could be interpreted as either tidal or fluvial channel sands. In the more distal Wells 01 and 60, the GR curve expression is "blocky" indicating either valley fill or basin floor fan deposits. The sequence boundary was also marked by a lull in faunal abundance and diversity and paleobathymetric depths ranging from the inner to middle neritic. On well logs, they are characterized by low gamma ray values, relatively high sand density and a minimal separated of the neutron and density logs.

3.3. Transgressive Surface

The transgressive surface is defined as the flooding surface separating the progradational or aggradational lowstand system tracts from the retrogradational transgressive system tracts (Van Wagoner *et al.*, 1987). This surface does not necessarily separate distinct facies and may lie within the basal fluvial deposits. This surface is also referred to as the first major marine flooding surface. However this is just a facies contact and has limited chronostratigraphic significance since it cannot be correlated regionally and is commonly seen as an estuarine-fluvial contact (Allen and Posamentier., 1993).

From all three wells under observation, a transgressive surface likely occurs at the base of the D2.0 sand. In Well AGD 001 and 002, a coarsening upward succession which is likely the prograding wedge of a lowstand system tract is overlain by a fining upward succession likely of a transgressive system tract. If this interpretation is correct, then the surface bounding them is a transgressive surface. This can also be confirmed the faunal abundance and peaks as in the case of a maximum flooding surface. This surface marks the start of the transgressive system tract.

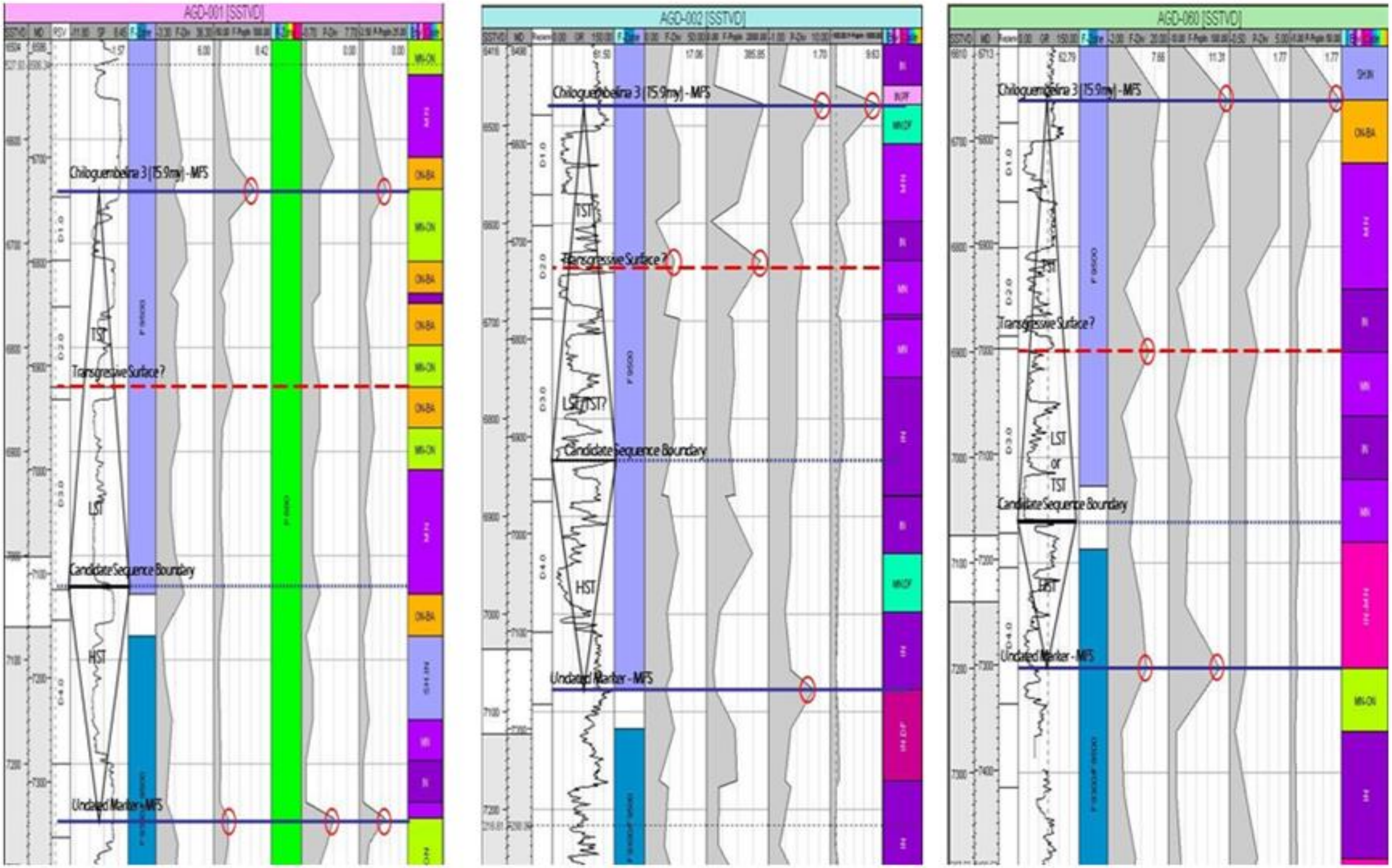

Figure 4: Biostratigraphic framework constructed from Wells AGD-001, 002, 060

3.4. Parasequence sets

3.4.1. D4.0 interval: progradational parasequence set

The d4.0 sand interval consists of three to four symmetrical parasequences that comprises the overall progradational parasequence set. (figs. 5 and 6). This interpretation is based on the gamma ray signature in most of the wells indicated by an overall coarsening upward succession in almost all the wells used in this study. In general, each successive parasequence gets thinner than the previous parasequence. Strike and dip oriented cross-sections show a decrease in sand thickness and an increase in shale content basinward within each parasequence and in the entire d4.0 interval. In the absence of core, the contact between the progradational parasequences of the d4.0 interval and the overlying aggradational parasequences can be inferred to be erosional giving rise to a sequence. This inference is based mainly on stacking patterns from well logs.

3.4.2. D3.0 Interval: Aggradational Parasequence Sets

The D3.0 interval overlying the D4.0 interval consists of two to three parasequences with the number of parasequences increasing in the basinward direction that comprises the overall aggradational parasequence set. In some wells, the basal or middle parasequences reflects a fining upward parasequences succession that could be interpreted as incised valley fills. From the cross-sections, it can also be observed from the relatively same position of facies contact when hung on a datum that the D3.0 is an aggradational parasequence set. The reservoir quality remains more or less the same in proximal and distal wells though the parasequence boundaries are more pronounced in the more basinward wells (Figs. 5 and6).

3.4.3. D2.0 and D1.0: Retrogradational Parasequence Sets

The shallower D1.0 and D2.0 interval consists of two and three parasequences respectively and together depicts an overall retrogradational parasequence set consisting of that reflect a fining upward succession on the gamma ray curve. This succession referred to as “backstepping” and is evident as deeper water facies overlie shallower water facies. Logs through these successions suggest they have sharp bases that are overlain by sandy intervals that gradually deepen upwards into shallow marine shale.

The sandier facies of the D1.0 and D2.0 intervals have poorer reservoir quality compared to the underlying aggradational and progradational parasequence sets of the D3.0 and D4.0 intervals respectively. Overall, the sand intervals become thinner and shaly distally as shown in strike and dip sections (Figs. 5 and 6). The reservoir quality also follows this trend with more proximal wells penetrating better-developed sands of higher quality.

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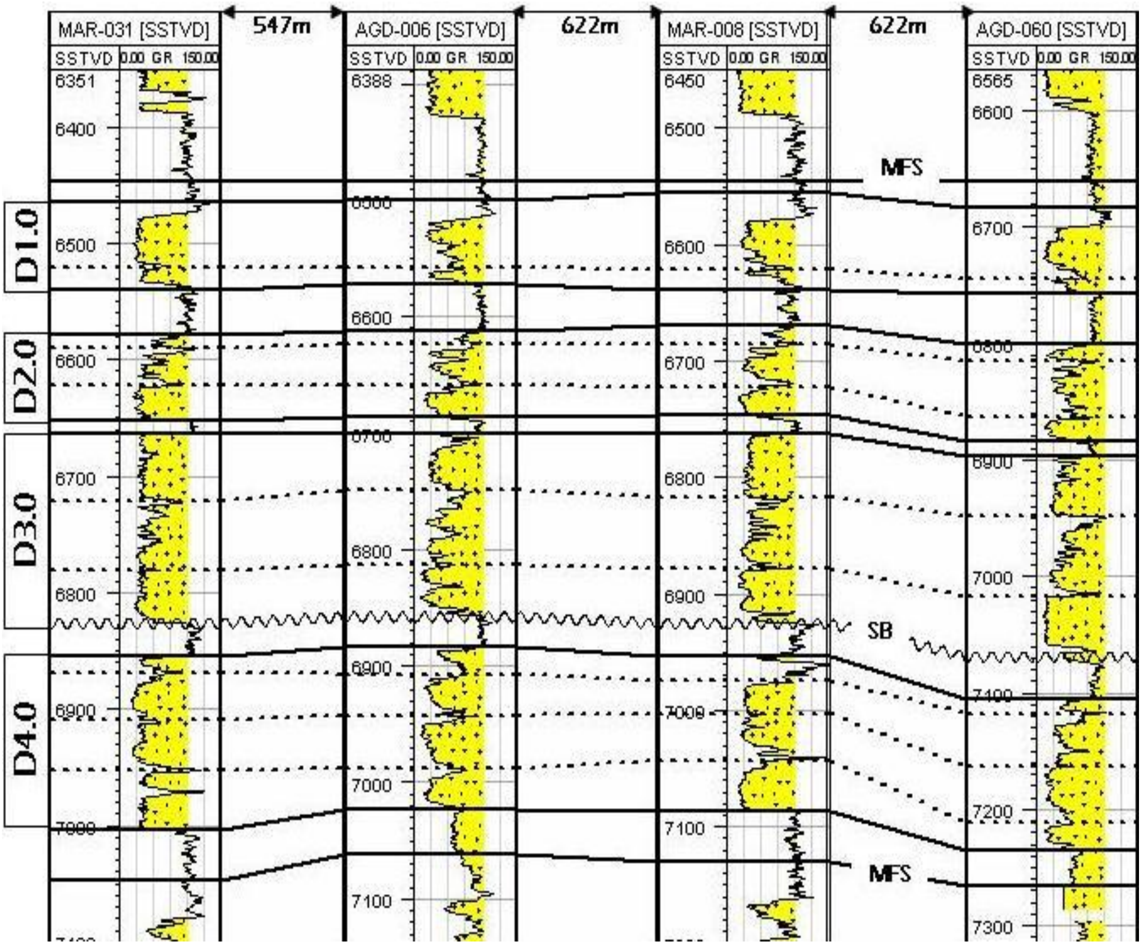

Figure 5: Dip-oriented cross-section (D-D') indicating the different parasequence sets. The correlation is hung on the MFS Chiloguembelina 3

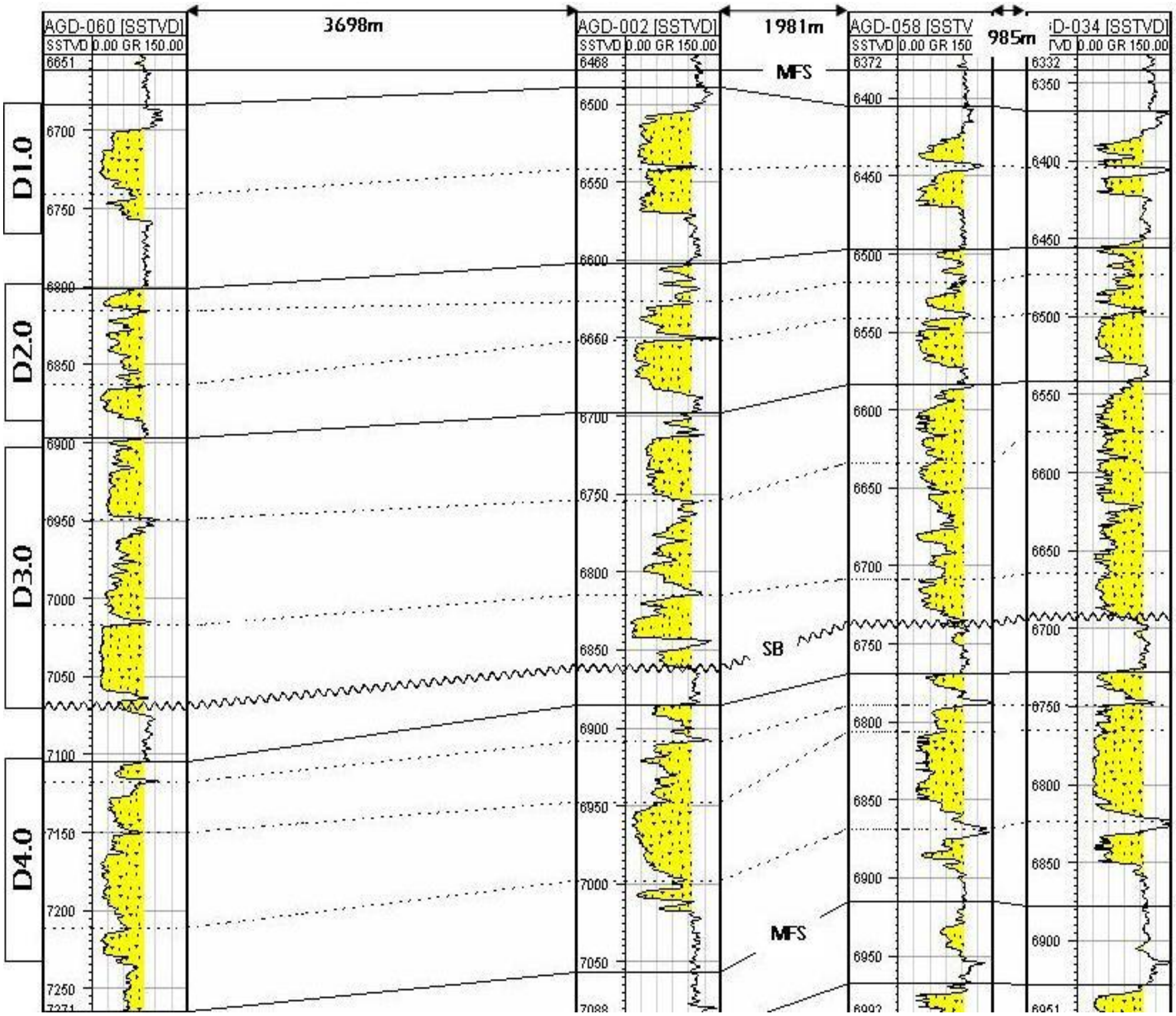

Figure 6: Strike-oriented cross-section (B-B') indicating the different parasequence sets. The correlation is hung on the MFS Chiloguembelina 3

3.5. Sequence stratigraphic interpretation

A sequence stratigraphic interpretation is attempted for the d1.0 to d4.0 reservoir interval. The galloway (1989) genetic stratigraphic sequence model is adopted because it is easier to pick and correlate maximum flooding surface as the important boundaries on well logs and at outcrop. The inferred interpretation is one of a highstand system tract (hst) in the d4.0 sand bounded below by an undated maximum flooding surface and capped above by a sequence boundary and followed by a probable lowstand system tract (lst) capped by a transgressive surface before being finally overlain by a transgressive system tract (tst) which is bounded above by the regional chiloguembelina 3 marker (15.9my)

3.6. Implications for Reservoir Quality

The sequence stratigraphic interpretation has highlighted the control of base level changes on reservoir rock distribution and quality. The system tracts are associated with hydrocarbon source, reservoir and seal rocks which vary between the different system tracts. The best quality sands are found in the highstand D4.0 interval deposited during relative base level rise. The sediments form a progradational parasequence set that display upward trends of parasequence thinning and increase in percentage of sand within parasequences. This is followed by the prograding wedge sands of the lowstand maximum flooding surface to end the cycle. (fig. 7)

D3.0 interval deposited during times of relatively equal sediment deposition and creation of accommodation spaces. The sediments form an aggradational parasequence set that displays a fairly equal parasequence thickness but with some occurrence of upward parasequence thinning in some wells due to interbedded shales. There is a decrease in bedset thickness and relative sand content from proximal to distal areas. The transgressive systems tract deposits comprising the D1.0 and D2.0 intervals as expected have relatively poorer reservoir quality and forms the seals of reservoirs with reasonable shale thickness.

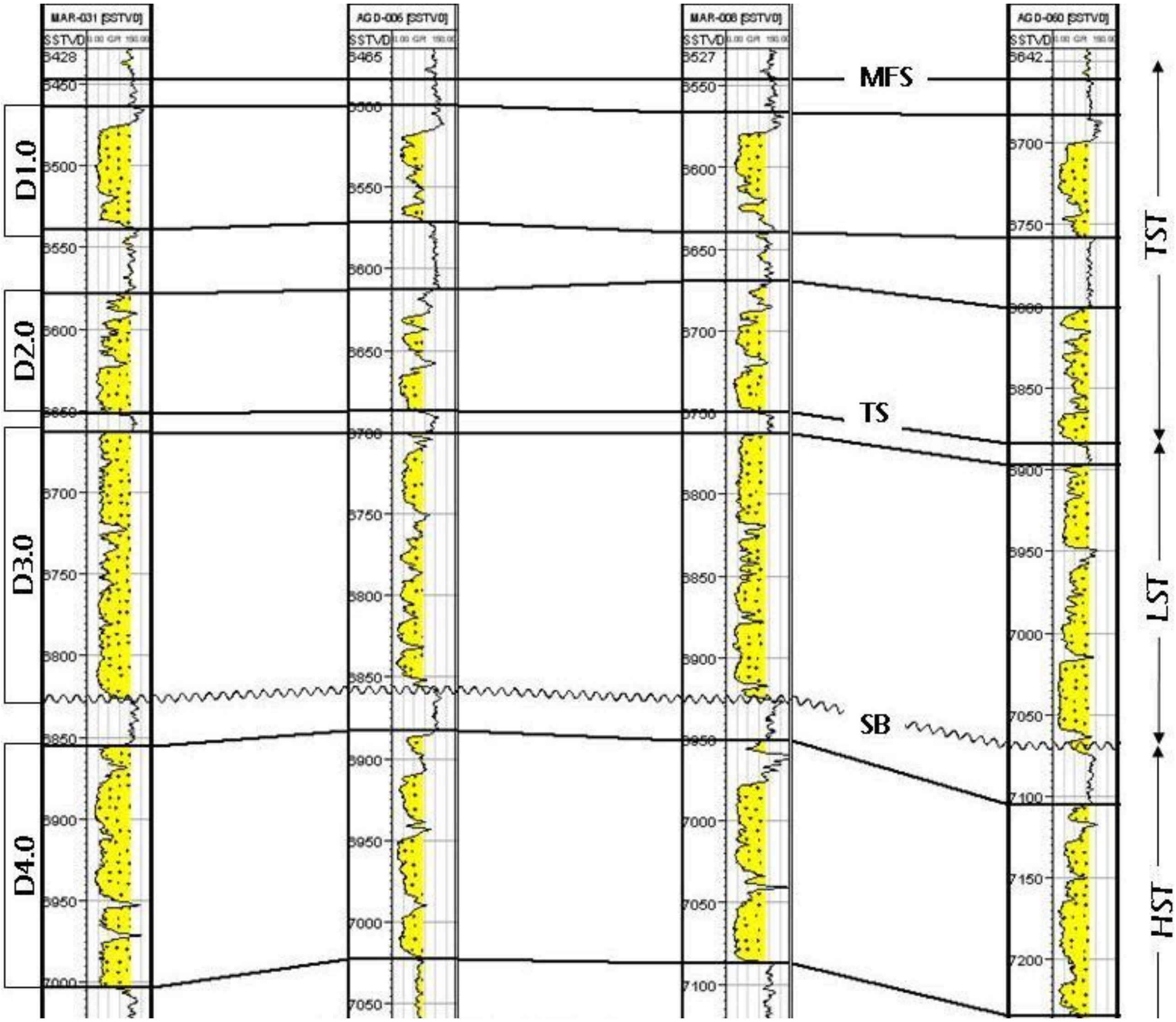

Figure 7: Cross-section (D-D') showing the sequence tracts. The interpretation was based on well logs and biostratigraphy data which were then correlated to other wells. Based on this interpretation, incised valleys or localized channels are predicted to have formed in the LST

3.7. Well-to-Seismic Match

Time depth data provided were imported into the Petrel to create a time-depth log which enabled the wells to be visualized in time domain, and when displayed along a seismic intersection produced well to seismic match with which was used to pick the right events in the seismic data. The regional events; the sequence boundary, maximum flooding surfaces, and mappable reservoir top were picked for interpretation (Fig. 8)

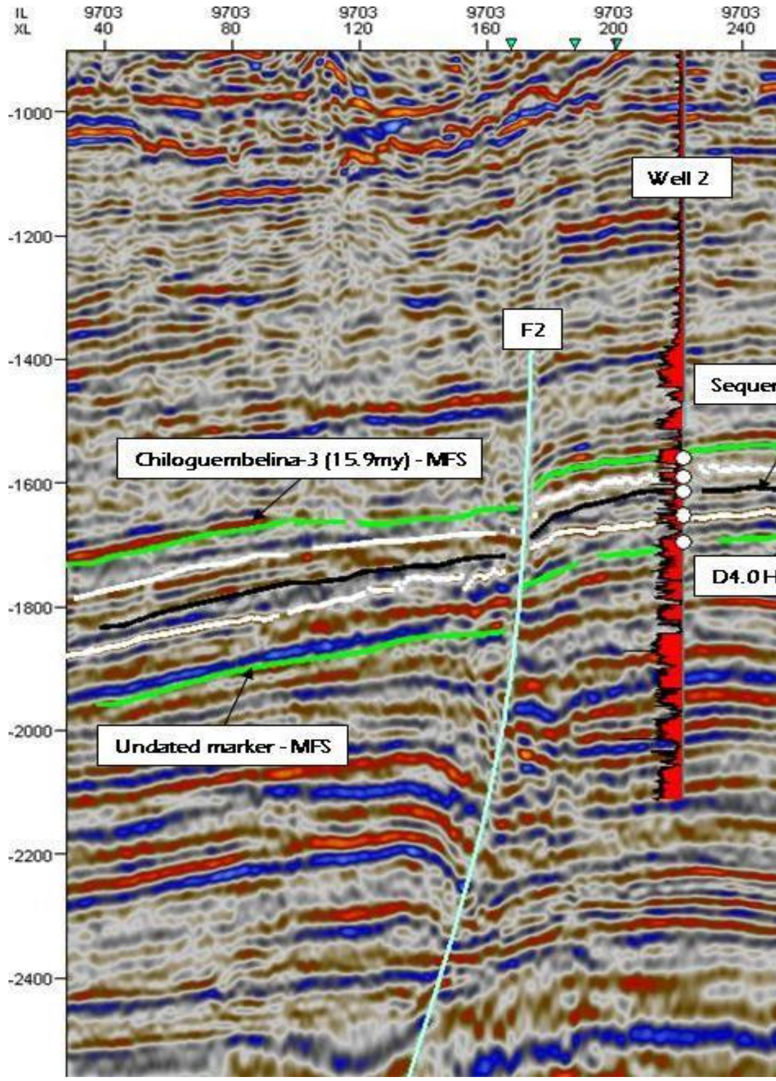

Figure 8: Well-to-seismic tie showing Well AGD-002 with GR curve used to tie to the seismic events and the interpretation of the faults and key horizons

4.0. Conclusion

The conclusions drawn from this study comprising sequence stratigraphy can be summarized as follows:

1. Field wide correlation was carried out with input from biostratigraphy to define the sand thickness trend. Distal sand bodies in the basinward direction are thinner and/or have more shale intercalations.
2. Two maximum flooding surfaces and one sequence boundary were interpreted in all the wells available for study and

mapped across the field. These 3rd order sequences were deposited in the shelfal shoreface environments with the possibility of incised valleys predicted by the presence of Lowstand system tract in the sequence stratigraphic framework.

3. Three parasequence sets were interpreted forming distinct stacking patterns. The D4.0 reservoir has progradational parasequence set followed by the aggradational parasequence set of the D3.0 reservoir and the retrogradational parasequence sets of the D1.0 and D2.0 reservoirs. However each parasequence has different parasequence stacking patterns depending on the local of the wells.
4. The genetic facies encountered in the depositional environment based on log signature are channel sands, shoreface sands, heterolithics and marine shale.

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