Egyptian Geophysical Society
EGS Journal, vol. 2, No.1, 153-164 (2004)

SEISMIC PETROPHYSICAL ANALYSIS OF THE MEANDERING FLUVIAL SANDSTONE RESERVOIRS OF THE MIDDLE FRIO FORMATION, STRATTON AND AGUA DULCE FIELDS, SOUTH TEXAS, USA.

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تحليل سيزمى بتروفزيائى لخزانات الحجر الرملى النهرية المتعرجة لمتكون فريو الأوسط، حقول وأجوا دولسى، جنوب تكساس، الولايات المتحدة الأمريكية

الخلاصــة: يعتبر التكامل بين بيانات الآبار مع السعة السيزمية طريقة فعالة لإيجاد الحدود الأفقية للسحنات لرسم نماذج معمارية محسنة للسحنات. ويعرض هذا البحث طريقة التي تربط المعاملات البتروفزيائية المحسوبة لبعض خزانات مختارة من متكون فريو الأوسط لمتوسط الجذر التربيعي للسعة السيزمية المحسوبة في مسافة ١٠ ملي ثانية. وتتضمن مجموعة المعاملات البتروفزيائية التي تم ربطها لمتوسط الجذر التربيعي للسعة السيزمية سمك الطبقة المنتجة، والحجم المسامي للهيدروكربونات والتشبع بالغاز وسمك الرمل الصافى والمسامية الفعالة وقد أثبتت النتائج أن أفضل خاصية للصخر التى يمكن استخلاصها من متوسط الجذر التربيعى للسعة السيزمية هى سمك الرمل الصافى (معامل الارتباط = ٠,٨٢) كما أن توقيع متوسط الجذر التربيعى للسعة السيزمية مقابل سمك الرمل الصافى وسمك الطبقة المنتجة والحجم المسامى للهيدروكربونات يظهر أن القيمة العالية لسمك الطبقة المنتجة والحجم المسامى للهيدروكربونات تتناسب مع القيم العالية لمتوسط الجذر التربيعى للسعة السيزمية. وهذا يظهر أن متوسط الجذر التربيعى للسعة السيزمية يمكن استخدامه لتحديد الحدود الأفقية للرواسب التى تملأ القنوات لمتكون فريو الأوسط فى حقول ستراتون وأجوا دولسى فى جنوب تكساس كما أن عدد طبقات الأجسام الرملية يتناسب أيضا مع متوسط الجذر التربيعى للسعة السيزمية والتى يمكن استخدامها فى التنبؤ بمواقع طبقات فريو الأوسط التى تشتمل على العديد من أجسام الرواسب التى تملأ القنوات المرصوصة رأسياً. ويمكن تطبيق نتائج هذه الدراسة على خزانات فريو الأوسط الأخرى فى حقول ستراتون– أجوا دولسى فى شاطىء خليج تكساس بالولايات المتحدة الأمريكية.

ABSTRACT: *The integration of well information with seismic amplitude is a powerful tool for locating lateral facies boundaries to construct improved facies architectural models. This paper addresses an approach that relates the petrophysical parameters calculated for selected middle Frio reservoirs to the RMS seismic amplitudes calculated in a 10ms window. The suite of petrophysical parameters related to the RMS seismic amplitude includes net pay thickness, hydrocarbon pore volume, gas saturation, net sand thickness, and effective porosity. The results indicate that the most reliable rock property that can be extracted from the RMS seismic amplitude is the net sand thickness (R^2 =0.82). Cross plotting RMS amplitude vs. net sand thickness, net pay thickness and hydrocarbon pore volume illustrates that higher values of net pay thickness and hydrocarbon pore volume are related to higher values of RMS seismic amplitudes. This implies that the RMS seismic amplitude can be used to delineate the lateral extent of the channel-fill deposits of the middle Frio Formation at Stratton and Agua Dulce fields in south Texas. The number of sandstone bodies was also related to RMS seismic amplitude and can be used to predict the location of the middle Frio horizons composed of several vertically stacked channel-fill sandstone bodies. The results of this study can be applied to the other middle Frio Formation reservoirs in the Stratton-Agua Dulce fields and in the Texas Gulf Coast.*

INTRODUCTION:

In the oil industry, seismic data is employed mainly for locating subsurface structural traps. In a field's development stage, the integration of core and well log information with seismic amplitude is a powerful tool to locate lateral facies boundaries such as point bars, crevasse splays and floodplain mudstones to construct improved facies architectural models. Analyzing amplitude variations appearing on attribute maps extracted from 3-D seismic cubes can result in geologically meaningful trends in the data and indicate, among other things, lithology and net sand thickness. The conversion of seismic data into meaningful petrophysical information, such as hydrocarbon pore volume and net pay thickness, of the reservoir is called seismic petrophysics, Crain (2003). Statistically robust correlation between log-and-core-derived petrophysical parameters and seismic attributes is ensured by good available well control. In interpreting the middle Frio Formation, all the seismic attributes in the SeisVision—GeoGraphix attribute library were tried to predict which attribute or combination of attributes best illuminates facies architectural elements such as meander-belts. As a result, RMS amplitudes calculated in a 10ms window found to be the best seismic attribute to illustrate middle Frio reservoir parameters. Seismic fluid and rock properties of the middle Frio sandstone reservoirs were studied (two papers in preparation) and used in the interpretation of the middle Frio RMS amplitude anomalies.

Stratton field is located in south Texas (Fig. 1). Production comes mainly from the Oligocene middle Frio Formation. The middle Frio Formation consists of vertically stacked reservoir sequences referred to as B- (shallower), C-, D-, E-, and F-series (deeper) of reservoirs (Fig. 2). This study focuses on the sandstone reservoirs of the deeper F-series, referred to as basal middle Frio.

Because of the thin-bed nature of the reservoir horizons in the basal middle Frio section at Stratton and Agua Dulce fields in south Texas, it is necessary to find a way to confirm that the target reservoir horizons (e.g. F11 and F39, Fig. 2) were accurately mapped from the seismic data. One way is to accurately tie seismic data to geologic data utilizing the available VSP display (Fig. 3). Another way is to correlate seismic amplitude with reservoir rock properties such as hydrocarbon pore volume. Hydrocarbon pore volume for gas reservoirs (net pay thickness x porosity x gas saturation) is a robust parameter related to seismic amplitude. Neff (1993) mentioned that amplitude and hydrocarbon pore volume have good correlation particularly for sands below tuning thickness and this kind of correlation has been used for thin sandstone pay prediction. Local sand geometries and some other petrophyscial parameters are among the factors that should be taken into consideration for successful predictions.

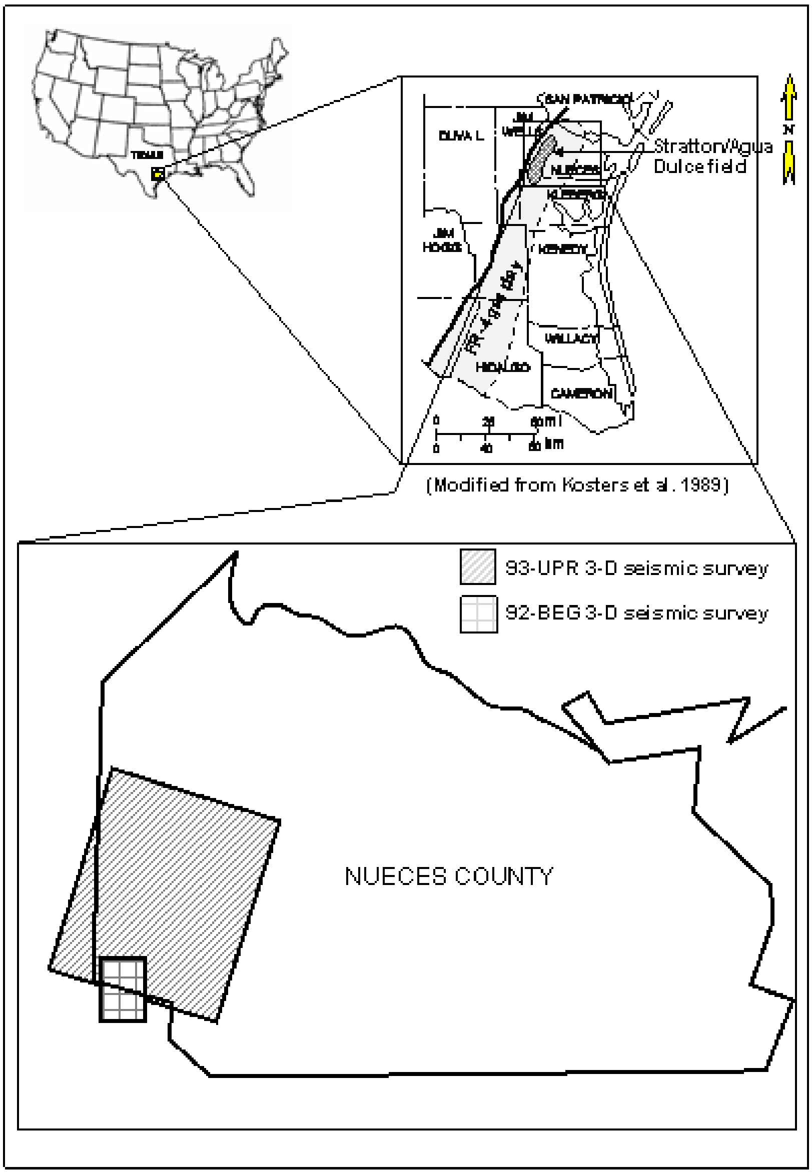

Fig. (1) Index map showing the location of Stratton and Agua Dulce fields in south Texas. Location of the two 3-D seismic surveys used in this study is also shown

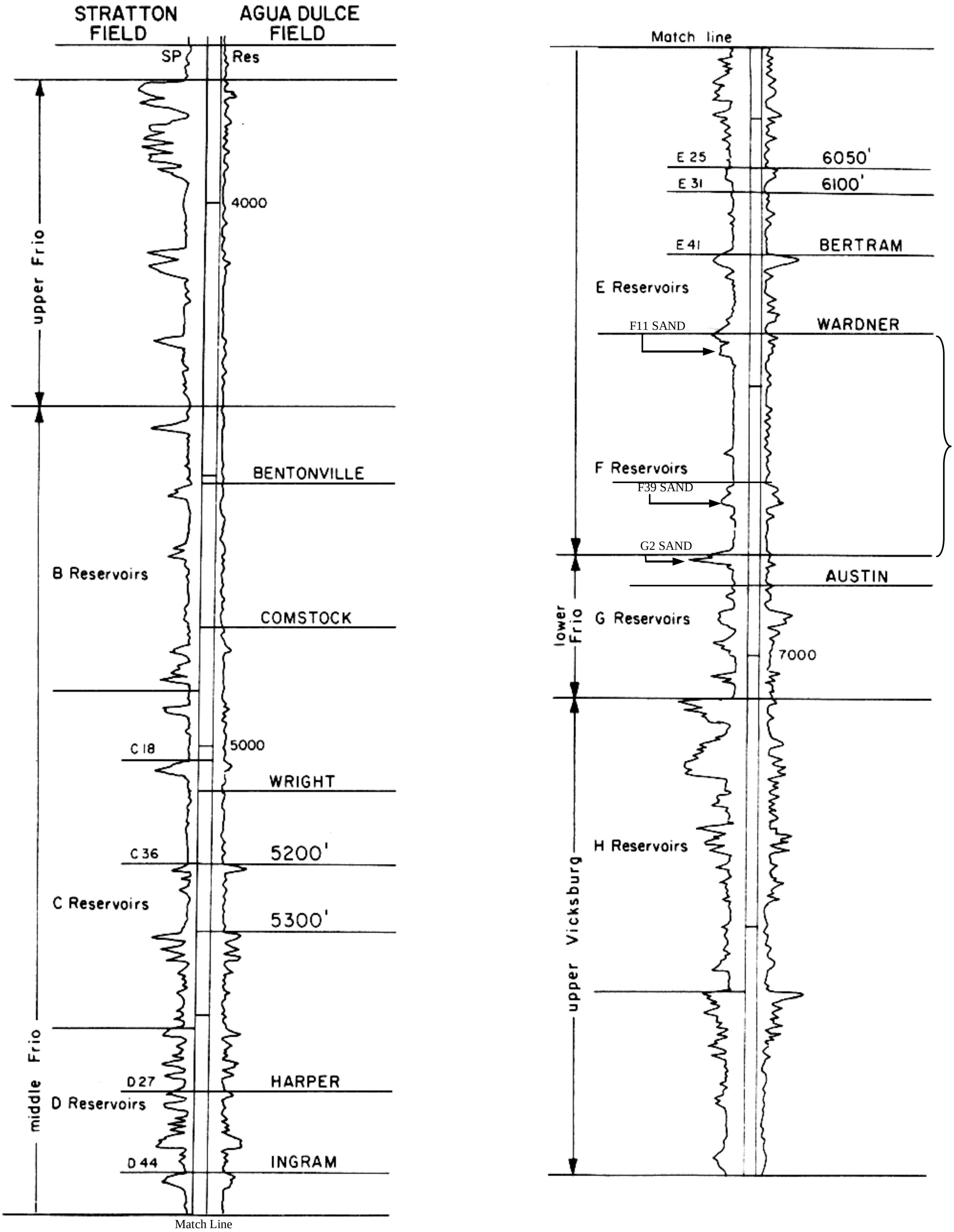

Fig. (2) Type log from the Union Production Company Driscoll No. 7A showing the Frio reservoir groups and nomenclature at Stratton (left) and Agua Dulce (right) fields (modified from Kerr, 1990).

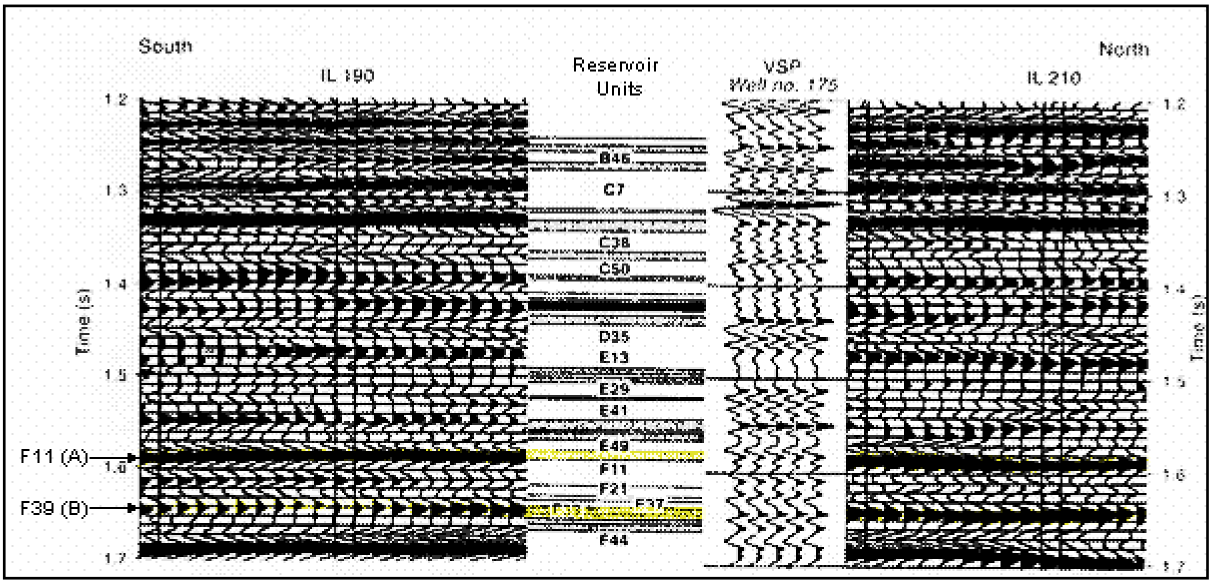

Fig. (3) VSP display of Wardner 175 well (Modified from Hardage, et al., 1996). The horizons of Interest: F11 and F39, are located at ~1.58 s and ~1.65 s, respectively. The peaks A, B (black-filled to the right) are top of reservoir units.

Another consideration is that some of the middle Frio sandstone reservoirs are thin and separated by about 2-10 ft of mudstones. In this type of stratigraphy, a given thin bed can be positioned anywhere in the seismic reflection wavelet. The basal middle Frio interval is made up of concentrated and dispersed fluvial sandstone reservoirs; and amplitude trends and changes in interval velocity may be related to lithology, porosity, gas saturation, bedding geometries and net-sand thickness. One way to interpret the amplitude anomaly is to cross plot it with other attributes so that geological meaning can be extracted from it. Cross plotting amplitude versus net pay thickness and hydrocarbon pore volume is commonplace. Petrophysical analysis is necessary to obtain these parameters. This paper addresses an approach which relates the calculated petrophysical parameters to the measured seismic amplitude and emphasizes that different ideas must be employed to extract as much geological information as possible from seismic data to lower exploration and production risk.

PETROPHYSICAL PROPERTIES

Within the study area, 171 wells penetrated the interval of study. Of these 171 wells, logs from 36 wells were usable for quantitative well log analysis. The other 135 wells were either unavailable in digital format, failed to provide the necessary curves, or lie outside the area covered by the two 3-D seismic surveys. Only 20 usable wells are located in the area covered by the UPR 3-D seismic survey and 20 wells in the BEG 3-D seismic survey area, with 4 wells located in the overlap area between the two seismic surveys (Fig. 1).

Petrophysical evaluation was performed for the 36 wells having complete sets of well logs (gamma ray (GR), neutron (NPHI), density (RHOB), and resistivity (SN, ILM, ILD)). Out of these 36 wells 31 wells were drilled into the hanging wall rollover anticline and the other 5 wells were drilled in the footwall side of the Agua Dulce growth fault (Fig. 4). The petrophysical analyses were performed using the Dual Water Model for shaly sandstones to obtain reliable values. The evaluation was made using GeoGraphix –Prizm Software. The average petrophysical parameters (PhiE, Vshl, Sg, net pay thickness, and hydrocarbon pore volume) are calculated for the basal middle Frio sandstone reservoirs. Shale volume was calculated using a gamma ray indicator. Neutron porosity was corrected for matrix and shale volume to obtain the effective porosity. The obtained effective porosities for the F11 horizon are similar to the core-measured porosities for the same interval in the cored well Wardner 184. Net pay was determined petrophysically, using cutoff parameters of 10% PhiE, 50% Vshl, and 60% Sw. This means that each interval increment (1 ft) with PhiE < 10% and Vshl > 50% and Sw > 60% will not be considered as net pay and vice versa.

Two post-stack final-time-migration 3-D seismic surveys (Fig. 1) were used to achieve the goals of this study: (1) The first, the 93UPR-AGUADULCEQ 3-D data set, was obtained from the Anadarko Petroleum Corporation based in Houston, Texas. It is proprietary data acquired in 1993 by Union Pacific Resources Company. It will be abbreviated to UPR survey. (2) The second is the BEG 3-D seismic data set acquired in 1992 by the Bureau of Economic Geology (BEG) at the

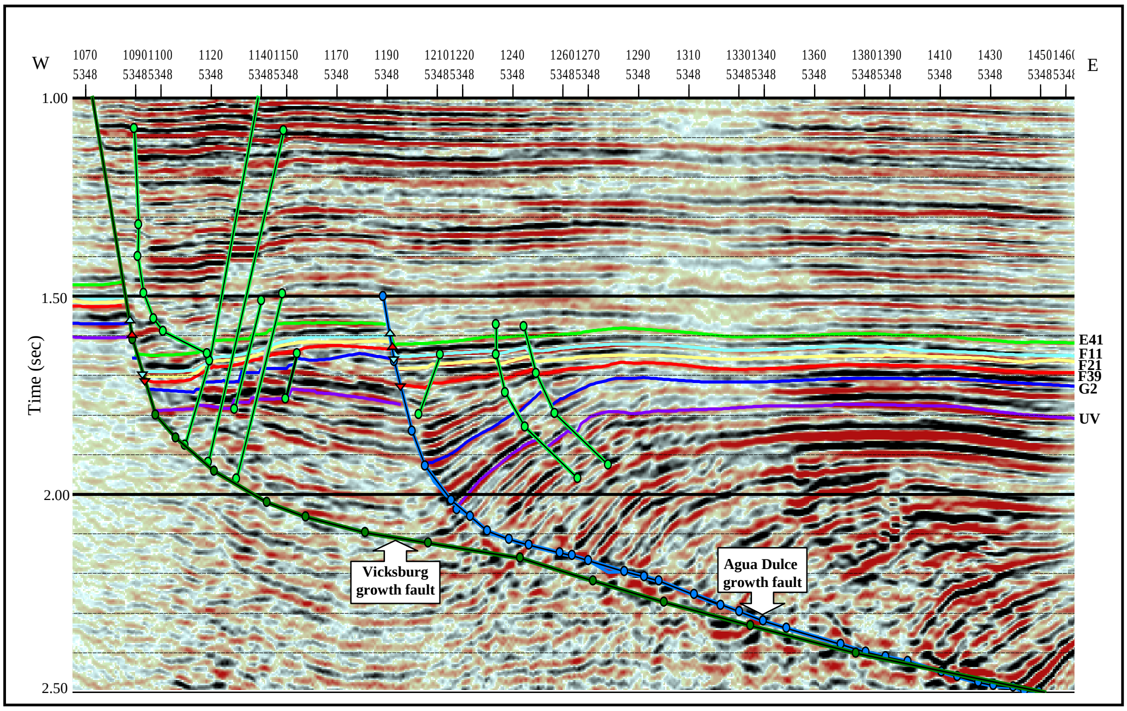

Fig. (4) Regional seismic section from the UPR 3-D seismic volume showing variations in the structural framework of the Frio and the Vicksburg reservoirs in the Stratton field area, south Texas. It also shows that major and subsidiary growth faults affecting the basal middle Frio interval (F11-G2) and younger sediments. G2= top lower Frio; UV= upper Vicksburg.

University of Texas at Austin. Two square miles carved out of this data set is public domain. Acquisition geometry and frequency content differ from the UPR 3-D data set. It will be abbreviated to BEG survey. Both 3-D seismic volumes can be used to relate measured seismic amplitude to calculated reservoir rock properties which in turn used to interpret the fluvial facies architecture of the basal middle Frio Formation.

Properties relationships are determined by the calculation of the rock petrophysical properties at well locations, then these properties are correlated with RMS seismic amplitudes measured for the reservoir units of interest (F11and F39) within the target interval.

1. Amplitude vs. Net Pay Thickness and Hydrocarbon Pore Volume

As mentioned earlier, the purpose of the petrophysical analysis in this study is to relate robust petrophysical parameters such as hydrocarbon pore volume to seismic amplitude.

Fig. 5 is a crossplot of hydrocarbon pore volume (right scale) and net pay thickness (left scale) versus the RMS amplitudes computed for the hanging wall F11 reservoir unit in the BEG area. It shows a positive linear correlation between RMS amplitude and net pay/ hydrocarbon pore volume (R^2 (Net pay) = 0.7213 and R^2 (HCPVol) = 0.7989). The higher values of net pay thickness and hydrocarbon pore volume are related to higher values of RMS seismic amplitudes. Wells with thick, channel-fill sandstone facies have high RMS amplitude values such as well Wardner 200. Wells composed of thin, dirty channel-fill and splay facies, such as Wardner 197 correlate with low RMS amplitude values from seismic data.

As shown in Fig. 5, the scatter of the data points around the trend lines indicates that the correlation between RMS seismic amplitude and net pay thickness/ hydrocarbon pore volume is higher at low-intermediate RMS amplitude values (500-12000 amplitude units) than at high RMS amplitude values (12000-18500 amplitude units). This implies that the ability to predict the net pay thickness and hydrocarbon pore volume of the middle Frio reservoir horizons from RMS seismic amplitude is higher at low-intermediate RMS amplitude range than at higher RMS amplitude range.

The crossplot (Fig. 6) between RMS amplitude, net pay thickness and hydrocarbon pore volume in the UPR area (hanging wall side, Figs. 4 and 12A) shows that the RMS amplitude increases linearly with increasing net pay thickness and hydrocarbon pore volume. For example, the F11 horizon in well Wardner 178 consists of concentrated channel-fill sandstones located in high amplitude area; while in well Wardner 194, the F11 horizon is composed of thin channel-fill facies and located in low amplitude area.

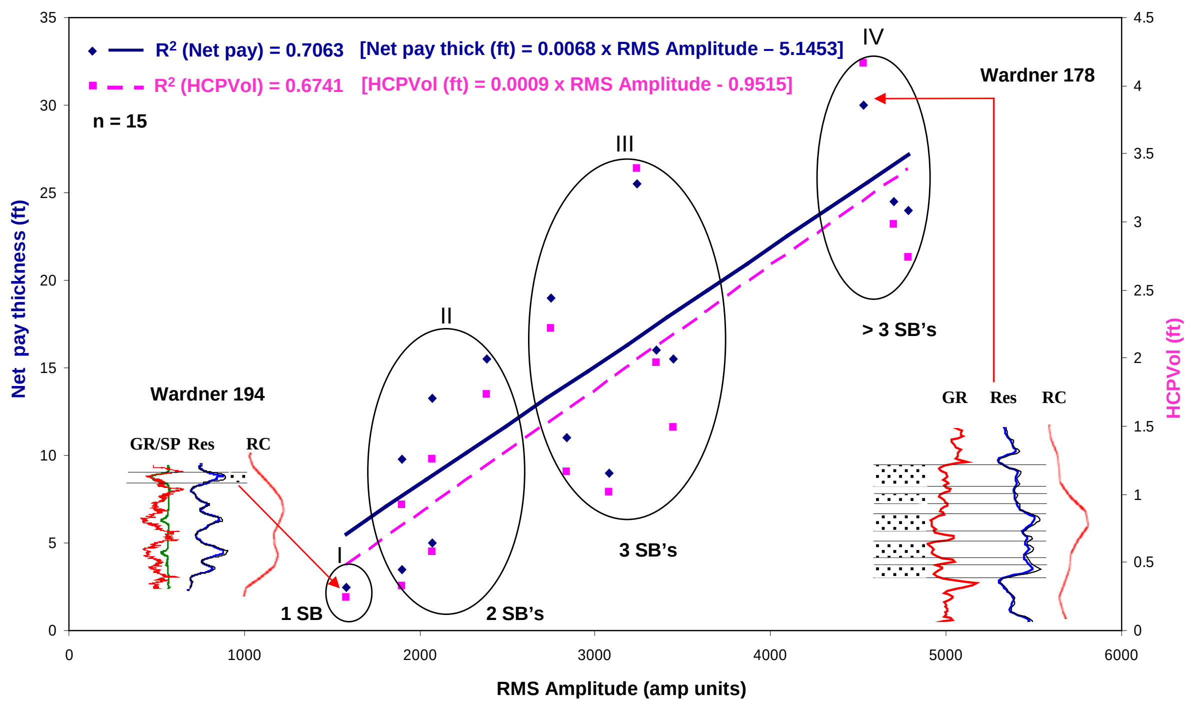

Fig. (5) Crossplot of RMS amplitude vs. net pay thickness and hydrocarbon pore volume (HCPVol) for the F11 interval in the BEG area. Notice that high amplitudes correspond to a thick layer composed of multiple sand bodies (SB's) and vice versa. The data points can be separated into four facies groups.

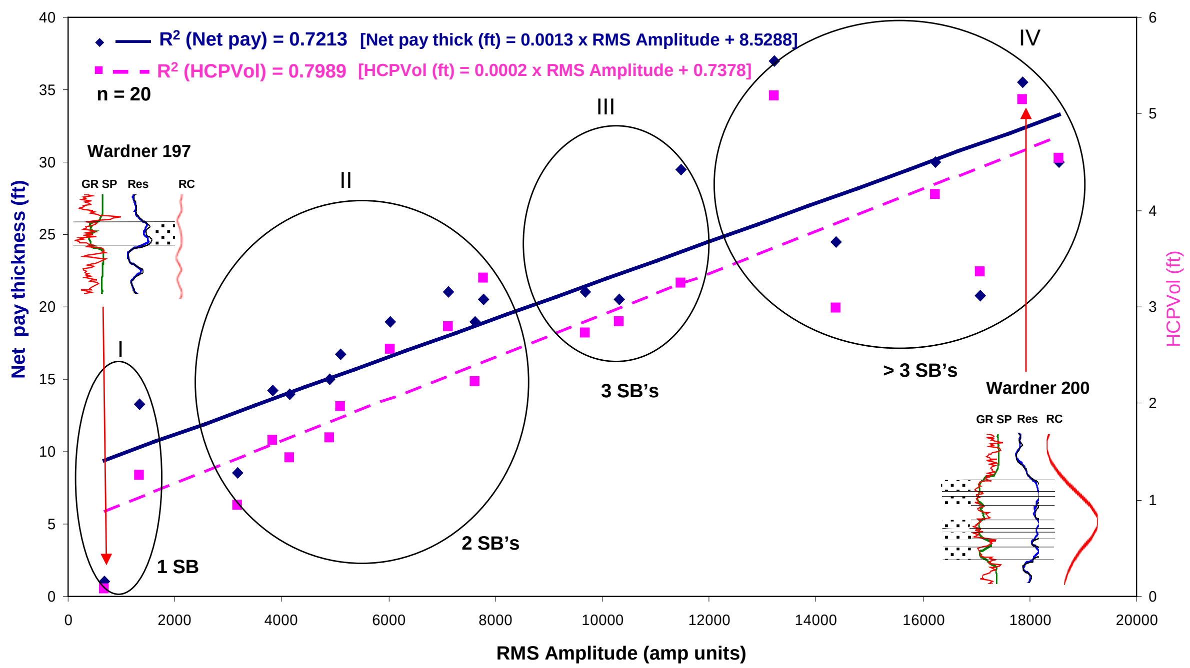

Fig. (6) Crossplot of RMS amplitude vs. net pay thickness and hydrocarbon pore volume (HCPVol) for the F11interval in the UPR area (hanging wall side). Notice that high amplitudes correspond to a thick layer composed of multiple sand bodies (SB's) and vice versa. The data points can be separated into four facies groups.

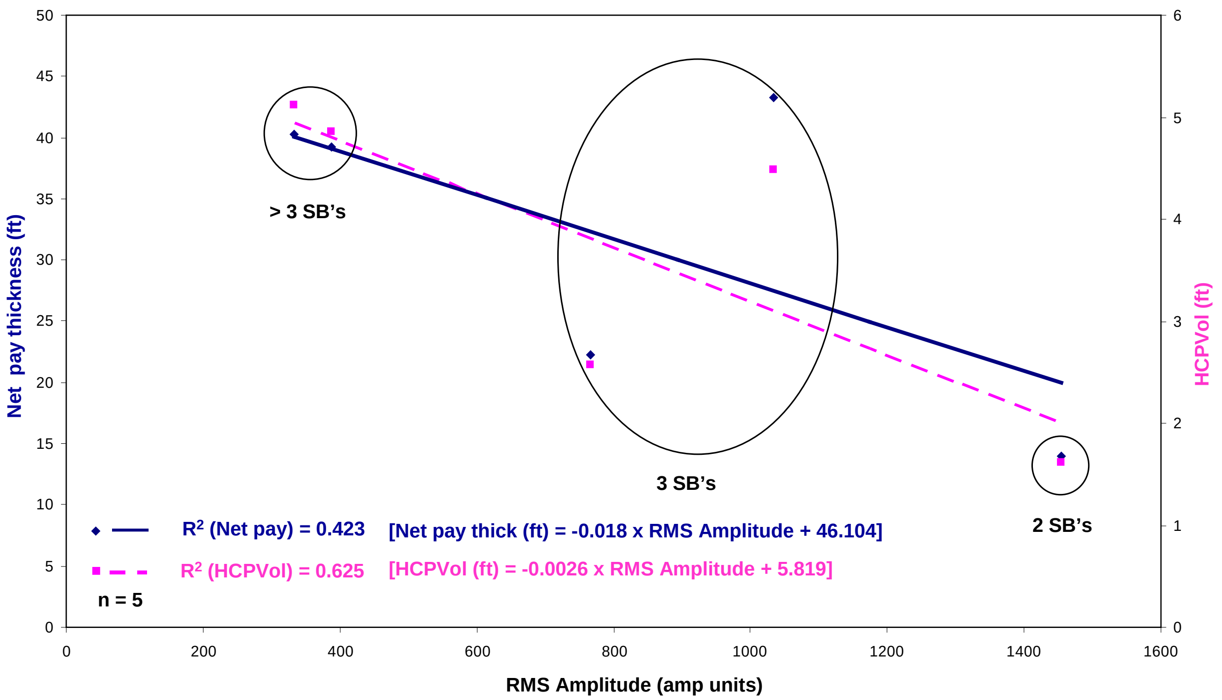

Fig. (7) Crossplot of RMS amplitude vs. net pay thickness and hydrocarbon pore volume (HCPVol) for the F11 interval in the UPR seismic survey area, footwall side. Data points can be separated into three groups based on the number of sand bodies (SB's).

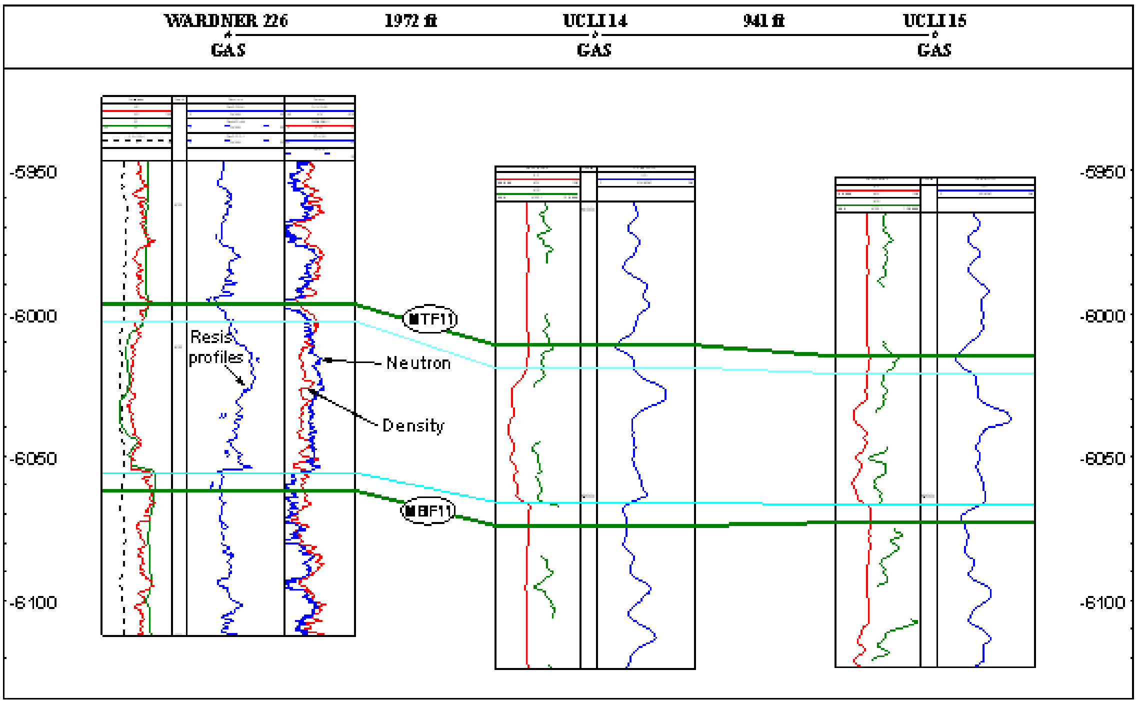

Fig. (8) Well log structural cross section connecting wells located in the F11 footwall low-amplitude area. Crossover between neutron and density log profiles in well Wardner 226 indicates the presence of gas. Location of the cross section is shown in Fig. 12A.

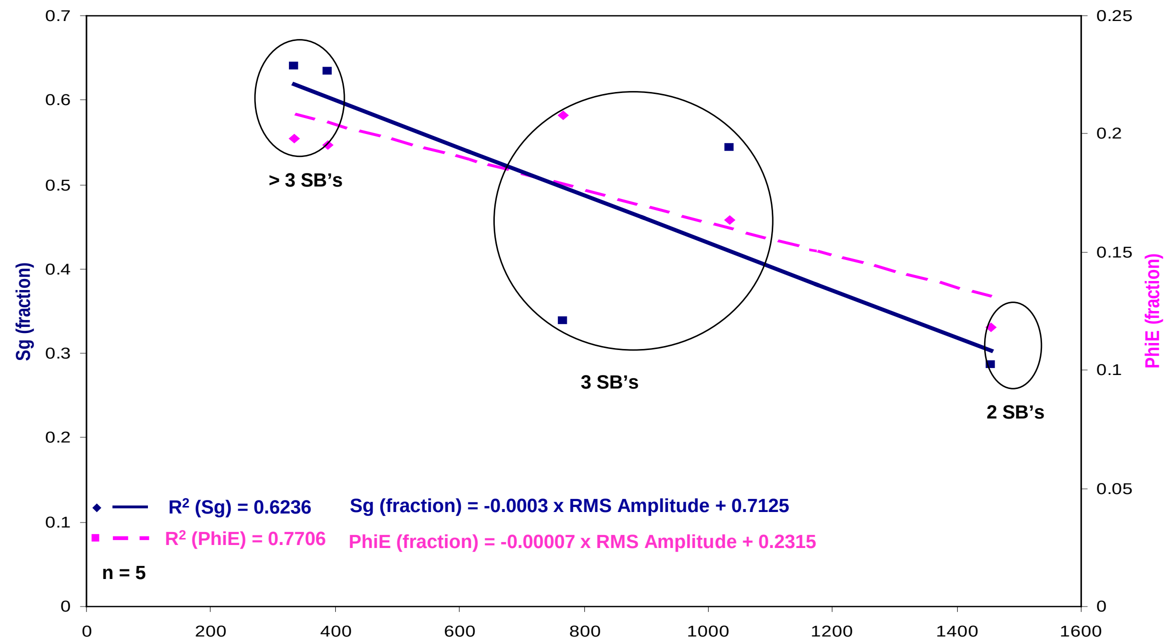

Fig. (9) Crossplot of RMS amplitude vs. effective porosity and gas saturation for the F11 interval in the UPR seismic survey area, footwall side. Data points can be separated into three groups based on the number of sand bodies (SB's).

Correlations of the RMS amplitude-to-net pay thickness/ hydrocarbon pore volume confirm that the seismic amplitude can be used to delineate the lateral extent of the channel-fill deposits of the F11 depositional unit in the study area; i.e. it can be used to delineate the spatial locations of the basal middle Frio architectural elements.

In contrast to the hanging wall side in the UPR area, inverse relationships (correlation coefficients of R^2 (Net pay) = 0.423) and R^2 (HCPVol) = 0.6249) exist between RMS amplitude and net pay thickness/ hydrocarbon pore volume (Fig. 7) for wells present in the footwall side of the Agua Dulce fault. This inverse relationship may be due to variation in the percentage of gas saturation on both sides of the Agua Dulce fault. The well log cross section (Fig. 8) connects wells located in the footwall low- amplitude areas (location of the cross section is shown in Fig. 12A). Most of the wells in the footwall low-amplitude area show gas cap over water leg in the F11 reservoir interval. The presence of gas is indicated by the crossover of neutron and density curves and by variable resistivity values measured for the F11 reservoir interval in the Wardner 226 well (Fig. 8). The other two wells included in the cross section show resistivity log patterns for the F11 interval similar to that of the Wardner 226 well. Thus, it can be concluded that footwall low (dim) amplitudes are associated with partially gas saturated sandstones. Cross plotting of RMS amplitudes versus gas saturation and effective porosity (Fig. 9) for the F11 interval in the footwall side indicates that increased effective porosity is associated with increased gas saturation possibly leading to dim amplitudes.

The F11 footwall low-amplitude anomaly at the F11 level may be due to velocity variations or interference effects, which result in dim amplitude. Lowering of velocity in the footwall side may be due to: high gas saturation, high percentage of soft clay minerals, and structural position of these deposits. The footwall block of the Agua Dulce fault is highly deformed by synthetic and antithetic faults (Fig. 4), which result in high fracturing of the middle Frio reservoirs. This kind of fracturing may lower the seismic wave velocities, which, in turn, cause low reflectivity.

In general, for the F11 interval good correlations exist between the RMS amplitude and the rock properties such as net pay thickness and hydrocarbon pore volume. Lower correlation coefficients may be a result of the tuning effects that occur between F11 and surrounding layers or some other factors.

2. Amplitude vs. Number of Sandstone Bodies

Another way to relate the computed RMS amplitudes to rock properties is to correlate them with the number of sand bodies (SB's) comprising the interval of interest at well locations. Based on the number of SB's, the data points plotted on Figs. 5 and 6 for the F11 interval can be separated into four groups. Group I consists of one SB and is represented by low amplitude; group II is made up of two SB's and is represented by low-to-medium amplitude range; group III consists of three SB's and is represented by high amplitude values;

and group IV consists of more than three SB's and is represented by the highest amplitude anomaly.

For example, in the BEG area, the well log cross section (Fig. 10) shows changes in the number of SB's of the F11 horizon consistent with the changes in the seismic amplitude (location of the cross section is shown in Fig. 12B). It was noticed that the highest amplitude anomaly correlated with thick channel-fill sandstone layer composed of several SB's (three or more SB's), such as in Wardner 185 and Wardner 211 wells. Intermediate amplitude values correspond to a layer composed of two channel-fill SB's such as the case of Wardner 79 well. Low amplitude anomaly corresponds to a layer composed of two thin crevasse splay SB's such as in the case of the Wardner 71 well. Thus, based on these findings, this study contributes to relating the number of SB's to RMS seismic amplitude; that is to say, RMS seismic attribute can be used to predict the location of the middle Frio horizons composed of several sandstone bodies.

3. Amplitude vs. Thickness

Net sandstone thickness and effective porosity are among the parameters that can be quantitatively characterized and used in the facies analysis of the basal middle Frio sequence. Sandstone thickness is measured from SP/GR and resistivity logs. Net sand thickness in each interval is defined as the sum of permeable sandstone(s) (SP deflection greater than 20% of maximum deflection). Cross plotting of RMS amplitude versus net sand thickness for the F11 reservoir interval in the BEG area (Fig. 11) shows a very good correlation (R^2 =0.824). This high correlation indicates that changes in the amplitudes are driven mainly by the net sand content of the F11 reservoir interval. It also shows that the F11 interval facies can be separated into four groups. In general, groups I and II are mainly thin, dirty channel-fill and crevasse splay sandstone facies. Groups III and IV are made up of thick, clean channel-fill sandstone deposits.

Another way to correlate seismic amplitude and net sand thickness of the horizons of interest is to overlay net sand isopachs over the RMS amplitude maps computed for the F11 and F39 intervals (Figs. 12 and 13). There is high correlation between the RMS amplitude and the net sand thickness for F11 and F39 in the BEG area (Figs. 12B and 13B), where high amplitude anomalies and thick isopachs indicate the location of channel-fill deposits. In the UPR area, in the hanging wall there is good correlation between net sand thickness and RMS amplitudes of the F11 and F39 intervals (Fig. 12A and 13A). On the footwall side (Figs. 12A and 13A), the F11 thick isopachs correspond to low amplitudes; this inverse relation is discussed earlier in section 1 of this paper. RMS amplitude maps (Figs. 12 and 13) of the F11 and F39 intervals illustrate meandering features shown by variable amplitude anomalies (related to reservoir thickness, porosity, and gas saturation). Using this kind of data integration, the location of the channel-belt systems of the basal middle Frio can be delineated.

In general, it should be noted that any mismatch between net sand thickness and the RMS amplitude anomaly in some areas may be due to the lack of well information at these specific locations.

4. Amplitude vs. Effective Porosity

The calculated effective porosities of the F11 sandstone facies in the BEG area range from 7% to 27 %. The relationship between seismic amplitude and effective porosity is illustrated in Fig. 14. There is a poor correlation (correlation coefficient of R^2 = 0.3556) between RMS amplitude and the effective porosity of the F11 interval in the BEG area. Grigsby and Kerr (1991) stated that the highly irregular distribution of calcite in the Frio Formation results in large variations in porosity. Chlorite and pyrite may also influence porosity of the middle Frio sandstone reservoirs (e.g. F11). Thus, the reduction in the effective porosity may result from the occurrence of the non-framework calcite cement and secondary minerals (clay minerals and iron oxides) in the basal middle Frio reservoirs.

One of the goals of this study is to calibrate seismic amplitude to rock properties. Based on this kind of calibration, what the amplitude anomalies represent can be predicted outside the areas of well control. With the results cited in the previous sections, this criterion can be generalized to interpret RMS amplitude anomalies computed for F11 and F39 intervals in the UPR and the BEG seismic surveys in the locations without well control. Wherever RMS amplitude is high, it indicates location of thick, channel-fill sandstone deposits; wherever is low, it indicates thin channel-fill and crevasse splays, levees, and floodplain mudstones. In this way the middle Frio channel-belt systems can be fully delineated.

Based on the information presented above, the RMS amplitudes (A_{rms}) computed for the horizons of interest are a function of five different parameters (P):

$$A_{rms} = f\,(P_1, P_2, P_3, P_4, P_5)$$

Table 1 shows these different parameters ranked in descending order from the highest correlation coefficient to the lowest. The information in this table indicates that the most reliable rock property that can be extracted from the RMS seismic amplitude is the net sand thickness.

Table 1. Ranking of the rock properties that can be predicted from RMS Amplitude.

R^2	Rank	Parameter
0.82	1	Net sand thickness, (P1)
0.75	2	Hydrocarbon pore volume, (P2)
0.71	3	Net pay thickness, (P3)
0.62	4	Gas saturation, (P4)
0.36	5	Effective porosity, (P5)

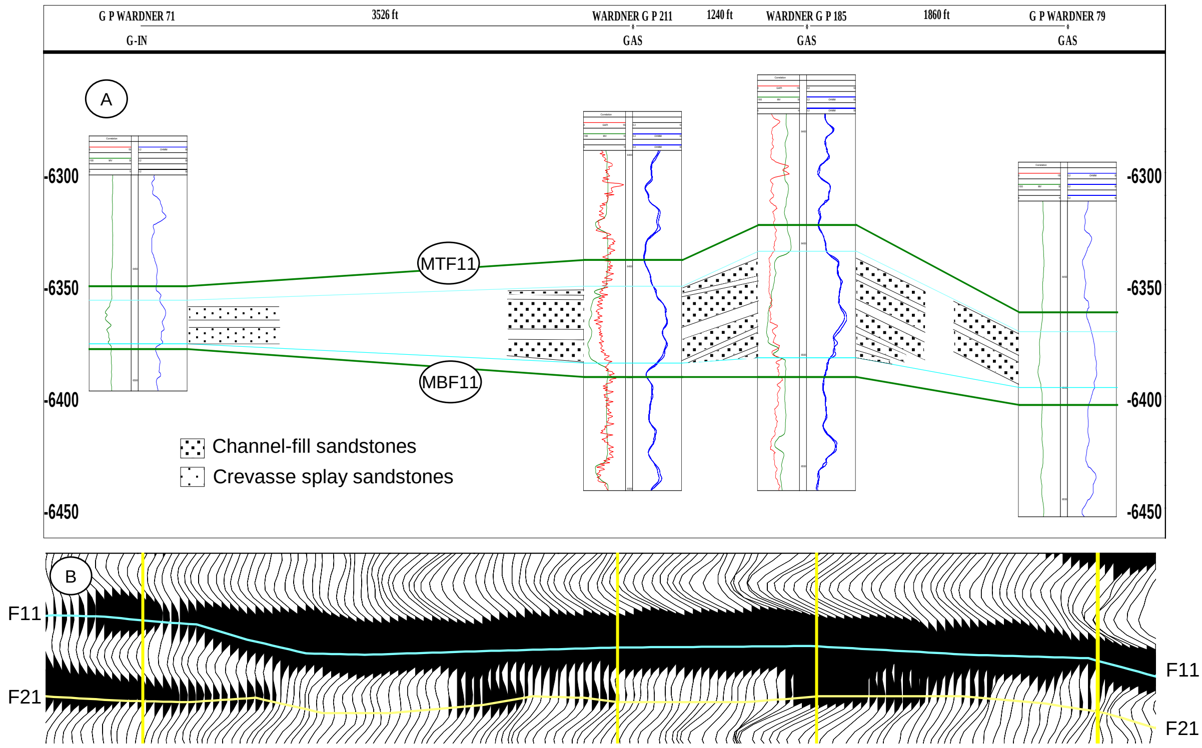

Figure 10. Well log structural cross section (A) and the coincident seismic section (B) showing the correlation between the number of sand bodies (SB's) comprising the F11interval and the seismic amplitude at the well locations. Location of the cross section is indicated on Fig. 12B.

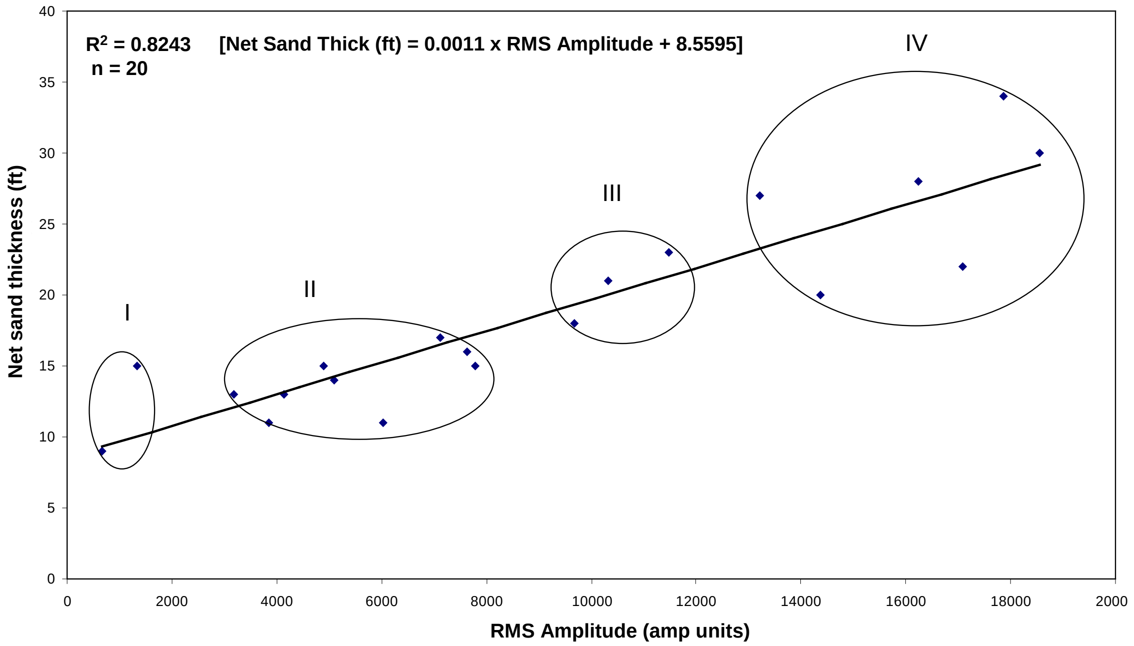

Fig. (11) Crossplot of RMS amplitude vs. net sand thickness of the F11 interval in the BEG area. The cluster of points can be separated into four facies groups based on their thickness.

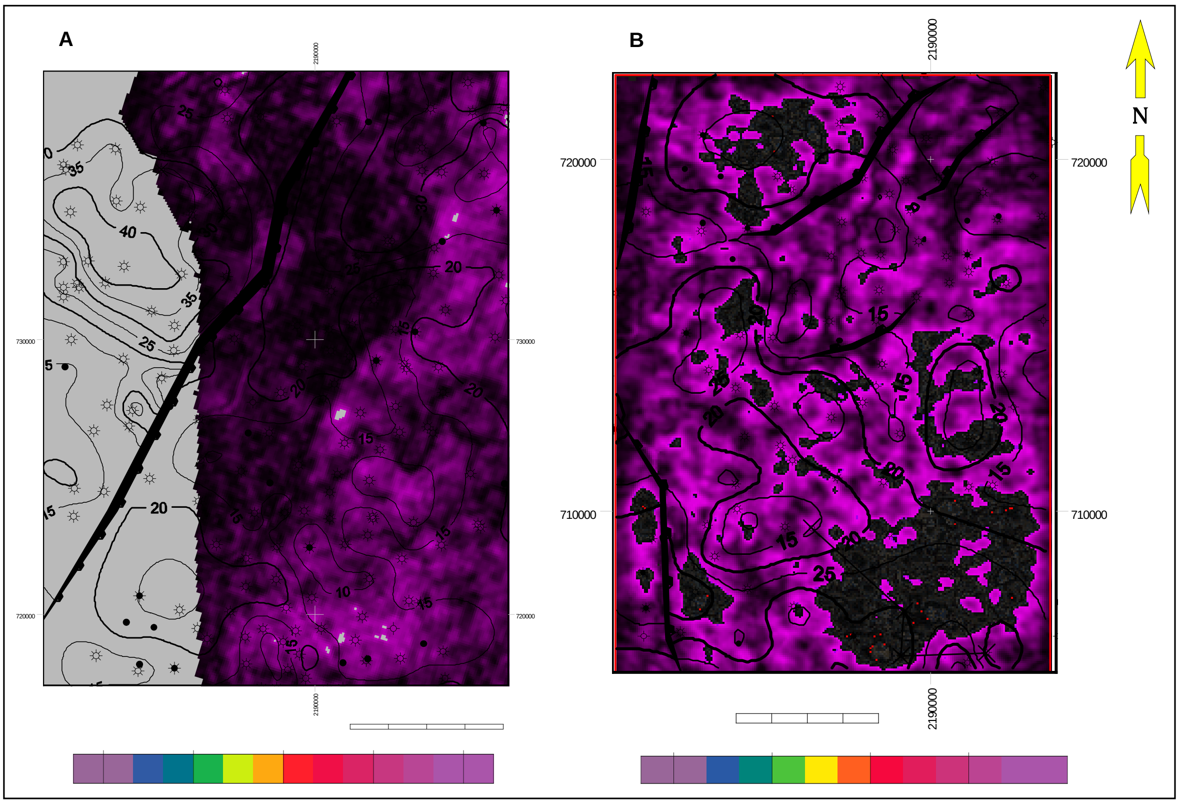

Fig. (12). Integration of net sand thickness and RMS amplitudes for the F11 interval in the UPR (A) and BEG (B) 3-D seismic survey areas, Stratton field, south Texas. C.I.= 5 ft.

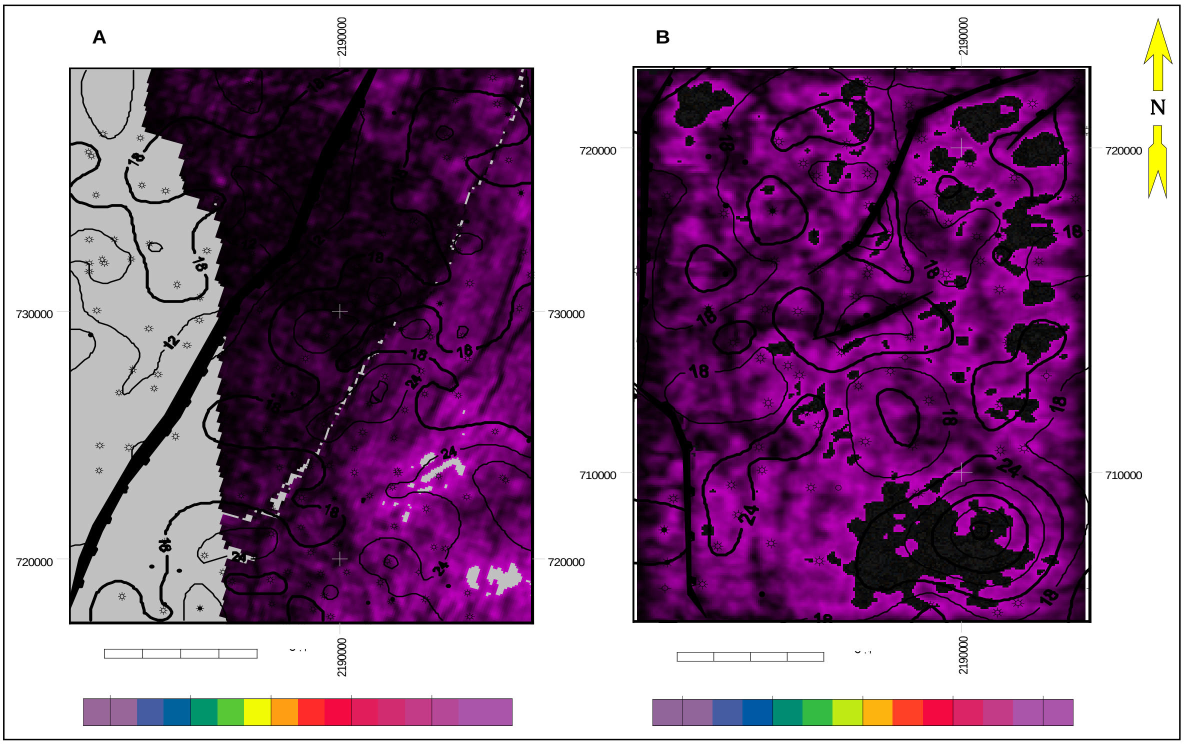

Fig. (13). Integration of net sand thickness and RMS amplitudes for the F39 interval in the UPR (A) and BEG (B) 3-D seismic survey areas, Stratton field, south Texas. C.I.= 6 ft

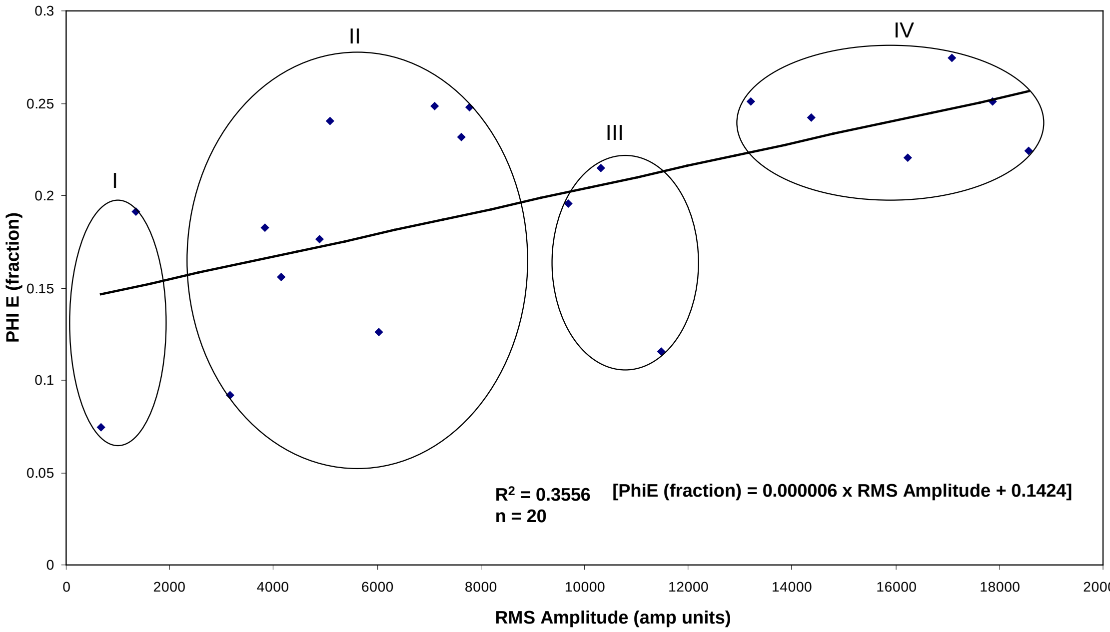

Fig. (14) Crossplot of RMS amplitude vs. effective porosity (PHI E) for the F11 interval in the BEG area. Despite the weak correlation between the two variables, the data points can still be separated into four groups of facies.

CONCLUSION

RMS amplitude-to-rock property relationships can be used to predict net pay thickness, hydrocarbon pore volume, facies type, number of sand bodies (SB's) and reservoir quality (net sand content and porosity) for other reservoirs in the middle Frio Formation in the Stratton-Agua Dulce fields and in the Texas Gulf Coast. The validity or tolerance of the models presented in this paper range from 36 % to 82 %.

ACKNOWLEDGEMENTS

This paper is a part of the author's Ph. D. dissertation conducted at the Geosciences Department of the University of Tulsa, Oklahoma. The author thanks the Geosciences Department especially Dr. Dennis Kerr and Dr. Christopher Liner, dissertation co-advisors, for their dedication and encouragement and for providing the necessary information and facilities to accomplish this work.

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