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AMANGI FIELD RESERVOIR POROSITY AND SATURATION ESTIMATION USING SEISMIC AND WELL DATA

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ABSTRACT

The scientific knowledge of mapping reservoir geometries provide useful displays for understanding the sediment fairway orientation and transport direction, they are not detailed enough to define the best quality well connected reservoir areas needed for planning development wells. Knowing that that long term development of this field will require excellent subsurface imaging to optimize the placement of future development and production wells, so to plan for this, we used strong reflected primaries (PP) and primary-shear (PS) waves imaging for the reservoir characterization. Porosity of two hydrocarbon reservoirs is investigated for the purpose of planning production operations in Amangi field of the Nigerian Delta. Well log derived porosities were measured at five appraisal wells in the field. Point information about the porosity of the reservoirs were determined from these well log data. However, lateral variations of porosity could not be delineated from measurements made only at the sparsely located wells in the field. A 3D seismic data covering an area of about 20 km x 17.5 km were acquired to delineate the extent of the porous sand. After careful data processing, the lateral variations of seismic amplitudes were transformed to changes in rock impedances, which, in turn, are indirectly related to porosity. In contrast with the sparse well observations, the 3D seismic method provided a dense and regular areal sampling of the acoustic properties of the reservoir intervals. The results of the transformation of the 3D anisotropic seismic reflection data were integrated with petrophysical measurements at the wells to significantly improve the spatial description of porosity in this field.

INTRODUCTION

Estimation of porosity and saturation requires finding the fundamental rock physics relationships that relate porosity and saturation to the elastic properties responses of the rocks. The objectives of this work were to relate seismic attributes to rock properties and provide reservoir property maps for selection of optimal well location and production enhancement (Karthikeyan *et al*., 2018; Lanzarone *et al*., 2019; Ma *et al*., 2020; Silva *et al*., 2011; Singleton, 2018).

Gas in an unconsolidated sand reservoir encased in shale often results in a dramatic increase in amplitude of the seismic reflection from the shale/gas-sand interface (Domenico, 1976). Shaly sandstones and shales comprise a major component of sedimentary basins and are of foremost relevance to hydrocarbon reservoirs, The acoustic properties of shaly sandstones and shales are thus of great interest in seismic and well log interpretation.

Subsurface heterogeneity delineation is a key factor in reliable reservoir characterization. These heterogeneities occur at various scales and can include variations in lithology, pore fluids, clay content, porosity, pressure, and temperature (Merkuji *et al*., 2001).A successful seismic-based reservoir properties estimation effort has three steps: accurate seismic inversion in 3D to obtain relevant reservoir parameters, rock physics transformation to relate reservoir parameters to the seismic parameters, and mapping these parameters in 3D.One of the main challenges in inferring changes in a reservoir parameter like porosity from the variations of seismic amplitudes is the fuzzy nature of the geophysical information. Uncertainty enters the problem at two levels. First, the impedance model of the reservoir that can be derived from band and limited and noise-contaminated seismic data is inherently nonunique. Second, even if the exact impedances were recovered, they are related to porosity only ambiguously. In fact, changes in acoustic properties across the reservoir interval integrate the effects of a number of different geologic variables, such as lithology, fluid saturation, pore pressure, and temperature. Accordingly, the contribution of porosity to the acoustic response must be separated from the effects of the other variables (Doyen, 1988). Conventional methods for estimating porosity from seismic data rely on regression formulas that are constructed by crossplotting impedances or interval transit times in the reservoir interval against porosity measurements at the wells. These traditional approaches treat the data as spatially independent observations and neglect spatial patterns in the variations of the subsurface properties. Moreover, the reliability of the porosity estimates and their consistency with the data are rarely assessed (Doyen, 1988).

V_p/V_s relations are key to the determination of lithology from seismic or sonic log data, as well as for direct seismic identification of pore fluids using amplitude variation with offset (AVO) analysis. Gassmann fluid substitution analysis was performed in order to investigate the effect of fluid substitution in different scenarios. Using Gassmann's fluid substitution method, the brine and gas sand interval shown in method

Field location and geology

Amangi Field is in the Niger Delta, which is in the Gulf of Guinea on the west coast of Central Africa (Figure. 1). The delta is in the southern part of Nigeria between latitudes 4° N and 6° N and longitudes 3° E and 9° E. It is bounded in the south by the Gulf of Guinea and in the north by older (Cretaceous) tectonic elements which include the Anambra Basin, the Abakaliki uplift, and the Afikpo syncline (Figure 1). Amangi Field is located within licence OML 21(Figure 1), in the north eastern corner of the OML 21 licence and extends into the adjacent licence OML 53. The field measure about 12 km x 5 km and it is 70 km northwest of Port Harcourt as shown in Figure 1. The Field is in the Greater Ughelli depobelt of the Niger Delta (Figure 1).

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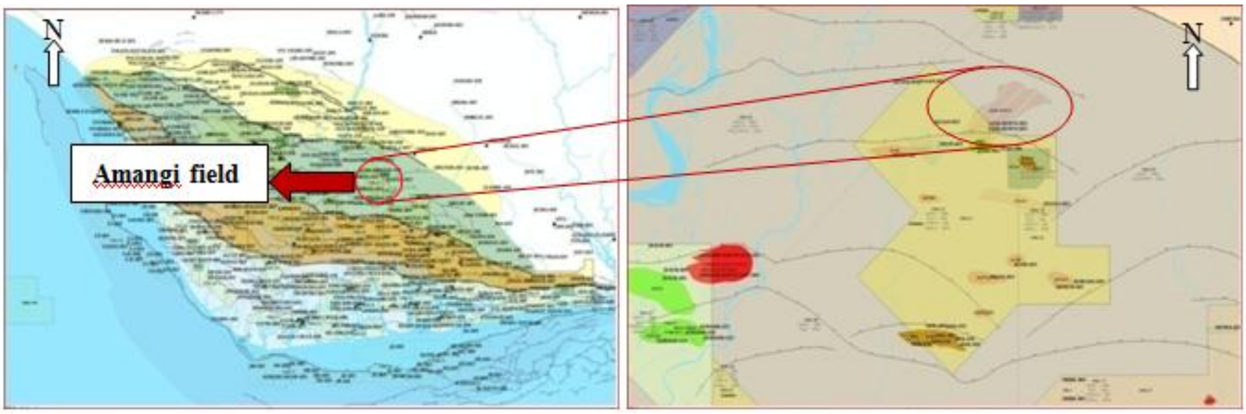

Figure 1. Map of the Niger Delta of Nigeria showing the location of the area of study (Shell Petroleum Development Company (SPDC) of Nigeria Limited).

In the regional Niger Delta sedimentological and geological framework the Amangi field is a part of the Greater Ughelli depobelt. It is bounded to the north and south by large listric normal faults associated with gravity collapse in the delta. The Tertiary age siliciclastic deposits forming the Niger Delta are attributed to three different lithostratigraphic formations: the Akata Formation, the Agbada Formation, and the Benin Formation (Short and Stauble, 1967 and Tuttle *et al*., 1999). The Agbada Formation (Paralic Cycles) makes up the majority of the oil and gas reservoirs of the Niger Delta including Amangi field, and comprises alternating sandstone/shale bed sets interpreted to represent the delta front, distributary channels and the deltaic plain. The upper part has higher sandstone content than the lower part, demonstrating the progressive seaward advance of the Niger delta through geological time (Omudu *et al*, 2008). The Amangi field sediments comprise a series of sand and shale successions that have been deposited during different relative sea level changes. These sediments have characteristic coarsening-upward, fining-upward, blocky and serrated gamma ray/self potential log profiles (Omudu *et al*., 2008). The E-sands are deposited within the thick Uvigerinella-5 shale package and are dominated by incised prograding shoreface deposits. The H-sands are thicker sands comprised of more stacked channel sand deposits with some estuarine influences and tidal channel deposits.

Well location

The distribution of the six wells used in the study area is shown in Figure 2.

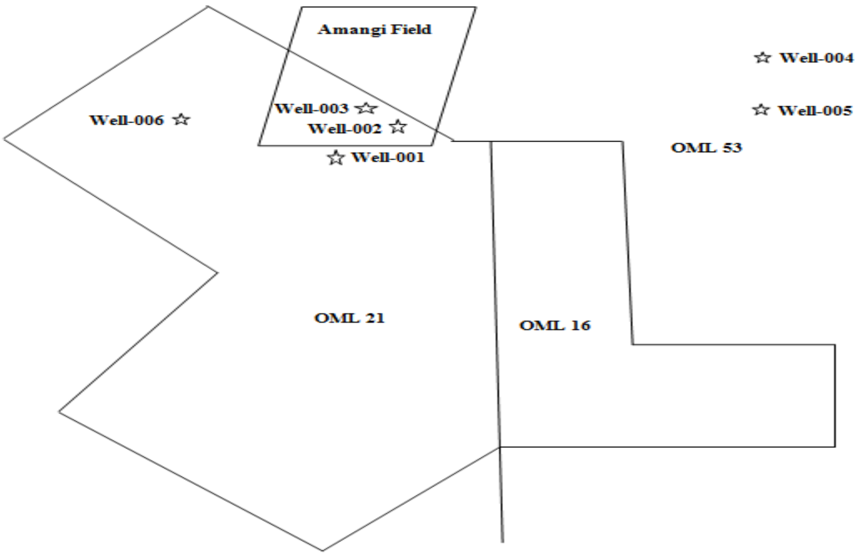

Figure 2. OML map of the study area showing the locations of the wells used in this study. Four out of a total of six wells are located in OML 21 whereas the rest two wells are sited in OML 53.

METHODOLOGY

We used the methods adopted by Silva *et al*. 2011; Doyen, 1988 and Bachrach, 2006, for this study. These methods produce geologically reasonable inversion models. Porosity inversion was based on rock physics relationships and well log calibration. Porosity and elasticity relationship is highly dependent on lithology, burial history and diagenesis (Silva *et al*. 2011).

RESULTS AND DISCUSSION

Figure 3 displays porosity distribution across the field as we consider porosity logs from some of the wells on the field. The purpose is to compare well porosity and porosity of the field from inversion results which is displayed in Figure 5. There is no significant difference between inversion porosity and well porosity as shown in Figure 5. We observe that lateral variation in porosity ranges from 0.21 to 0.23. The porosity was derived from the sonic log and density log.

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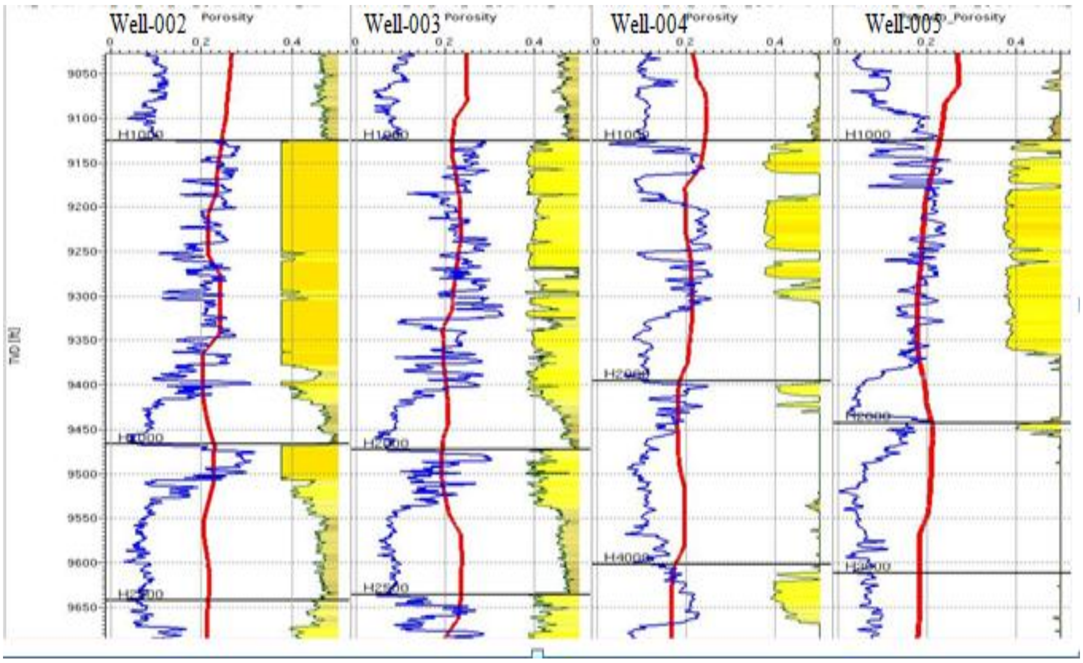

Figure 3(a). Porosity logs of four wells on Amangi field showing porosity variations. An average value of 0.23 (23 %) is estimated for this field.

Figure 3(b) displays the model based well log interpolations performed on the field. Figure 3b(i) shows the model based on well log interpolation while Figure 3b(ii) is the model based well log interpolation constrained by seismic.

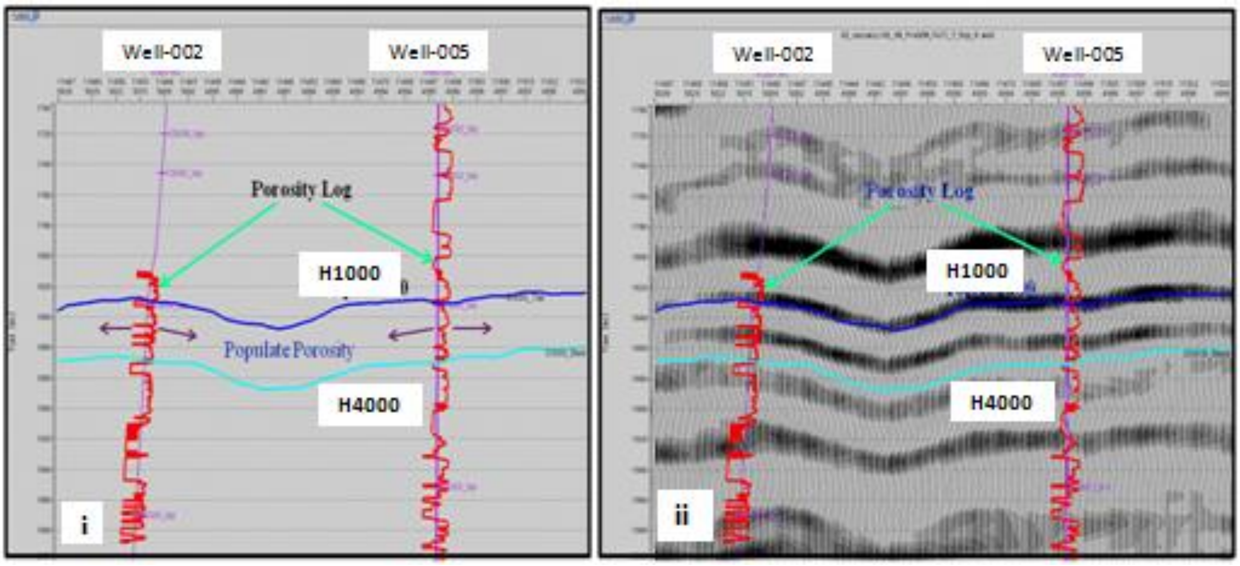

Figure 3(b). Well log interpolation. (i) The model based on well log interpolation and (ii) is the model based well log interpolation constrained by seismic.

The model for the target zones was built. The interfaces which separate the layers were defined by interpreting two main horizons (H1000 and H4000) from a stacked section. Initial values for the *P*-wave velocities and the densities were obtained from the well log. Extraction of subsurface information from amplitude variation with offset (AVO) analysis was not a problem because in this area the signal-to-noise ratio is high and desirable.

Figure 4 is the crossplot of well log derived sandstone porosity from four wells on the field and acoustic impedance showing a good linear relationship supporting seismic inversion for porosity prediction at the field. From Figure 4, the data from the wells show a good linear correlation between porosity (POR) and acoustic impedance (AI). Therefore, porosity determined from seismic inversion can be used to predict the reservoir's quality. Elastic seismic inversion was then carried out by using the anisotropic 3D seismic data to quantify the range of porosities expected of the field.

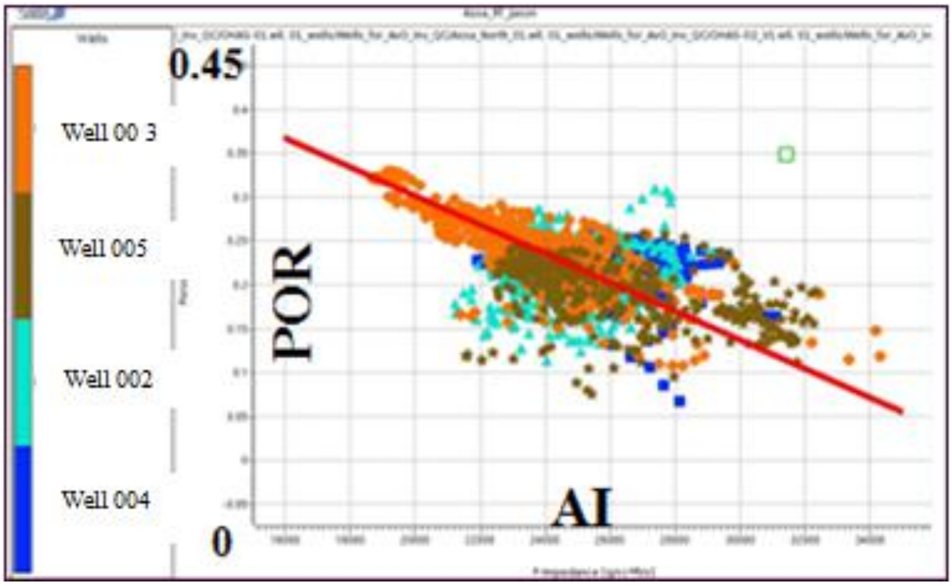

Figure 4. Crossplot of well log derived sandstone porosity and acoustic impedance shows a good linear relationship supporting seismic inversion for porosity prediction at Amangi field.

In Figure 5 the histogram of the porosity from the inversion matches the well log porosity histogram. There are noticeable variations in the models but they are smooth and reproduced the heterogeneities of the porosity. High porosity values for the most part are reproduced. The porosity ranges is reduced and narrow. Comparably, the inversion results show a correspondingly and approximately equivalent porosities which is consistent with the findings from the wells' porosities (Jamalullail *et al*., 2020 and Ma *et al*., 2020).

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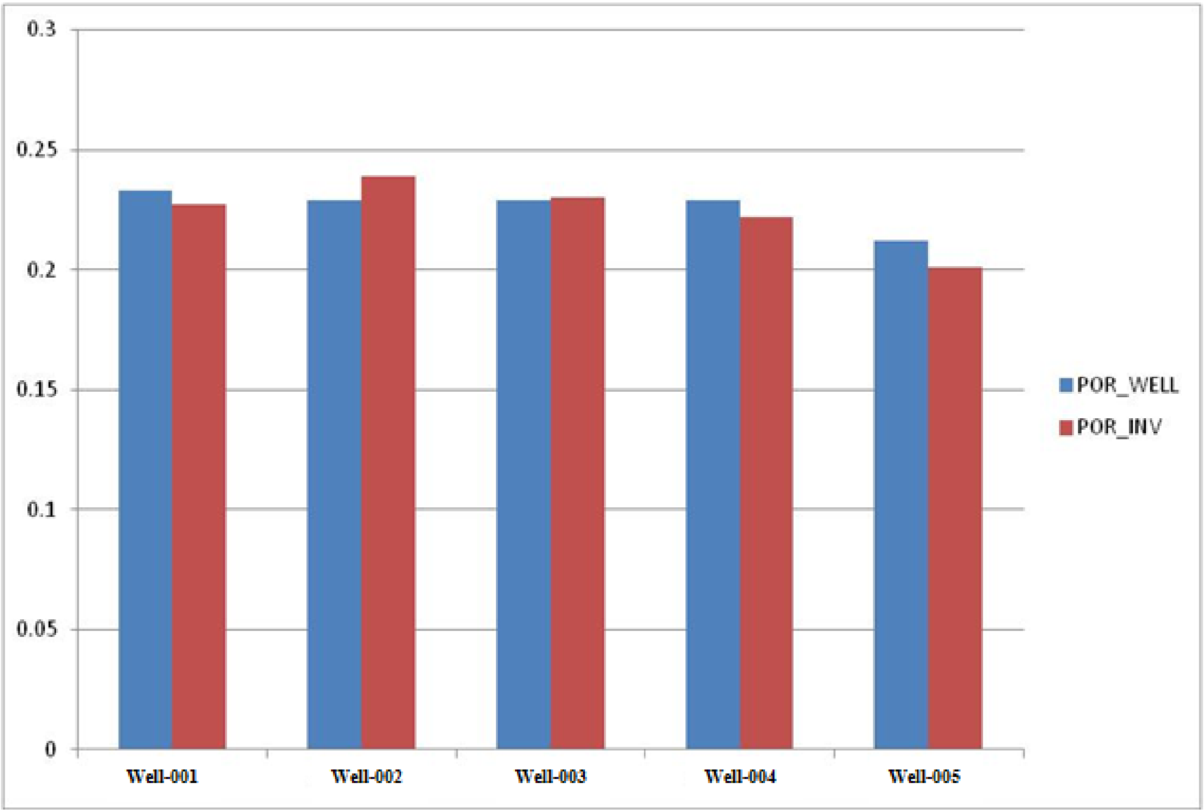

Figure 5. Histogram comparison of porosity models from five wells and inversion of the field data showing an average value of 0.23 for the field

Figure 6 is a crossplot of porosity (fraction) and water saturation (S_w) for the reservoirs intervals colour coded to gamma ray. The blue points are the reservoir porosity and saturation while the red points are the values for porosities and saturations. The sands have higher porosity values (0.21 – 0.27) and low water saturation values (0.0 – 0.20) than the shales porosity (0.12 – 0.19) having higher water saturation (0.22 – 0.50) shows that the sediments are poorly consolidated and with high porosities.

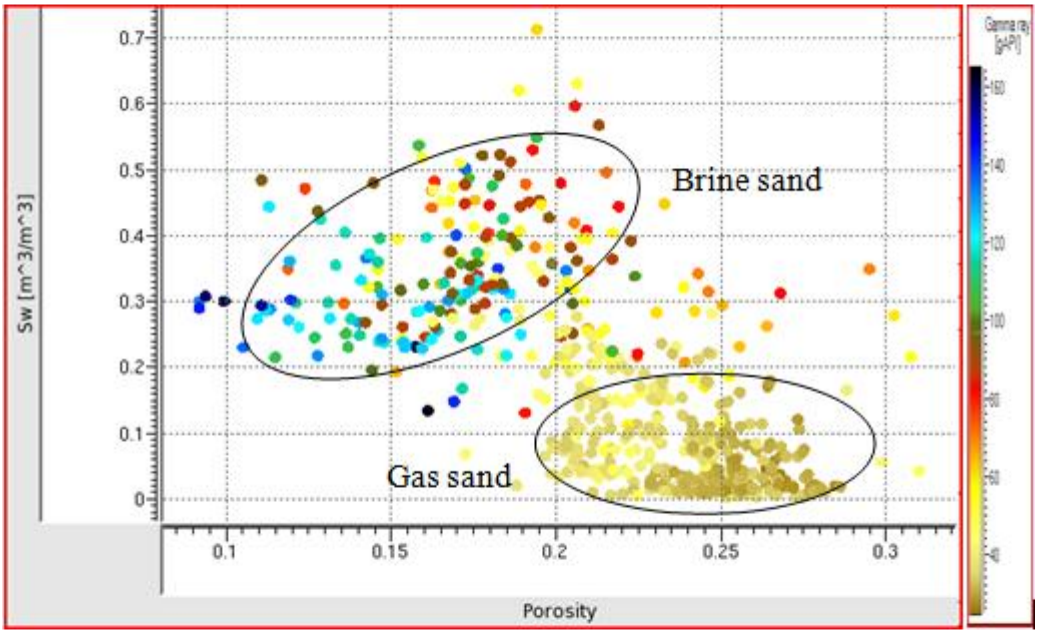

Figure 6. High porosity and low saturation poorly consolidated reservoir sand discriminated from low porosity shales by porosity versus water saturation crossplot from well information.

Rock properties like P-impedance, S-impedance and density extracted from seismic amplitudes are being used with good practice to estimate reservoir porosity and saturation. From Figure 7 we have P-impedance, S-impedance and V_p/V_s on the left and crossplot of log V_p/V_s versus porosity on the right, from well-002 colour coded with water saturation and gamma ray. V_p/V_s relations are key to the determination of lithology from seismic or sonic log data, as well as for direct seismic identification of pore fluids using, for example, amplitude variation with offset (AVO) analysis (Mavko and Merkuji, 1998). The porosities across the reservoirs were interpreted in wells from the density logs. For well-002, an effective fluid density was derived using the shallow resistivity log. For well-003 and well-004, the effective fluid density was derived on the assumption that the density tool reads 50 % mud filtrate and 50 % insitu hydrocarbons. Well-002 is drilled with pseudo oil based mud. The density-neutron separation, especially in the gas leg indicates little to no invasion, and the effective fluid density was derived based on no invasion.

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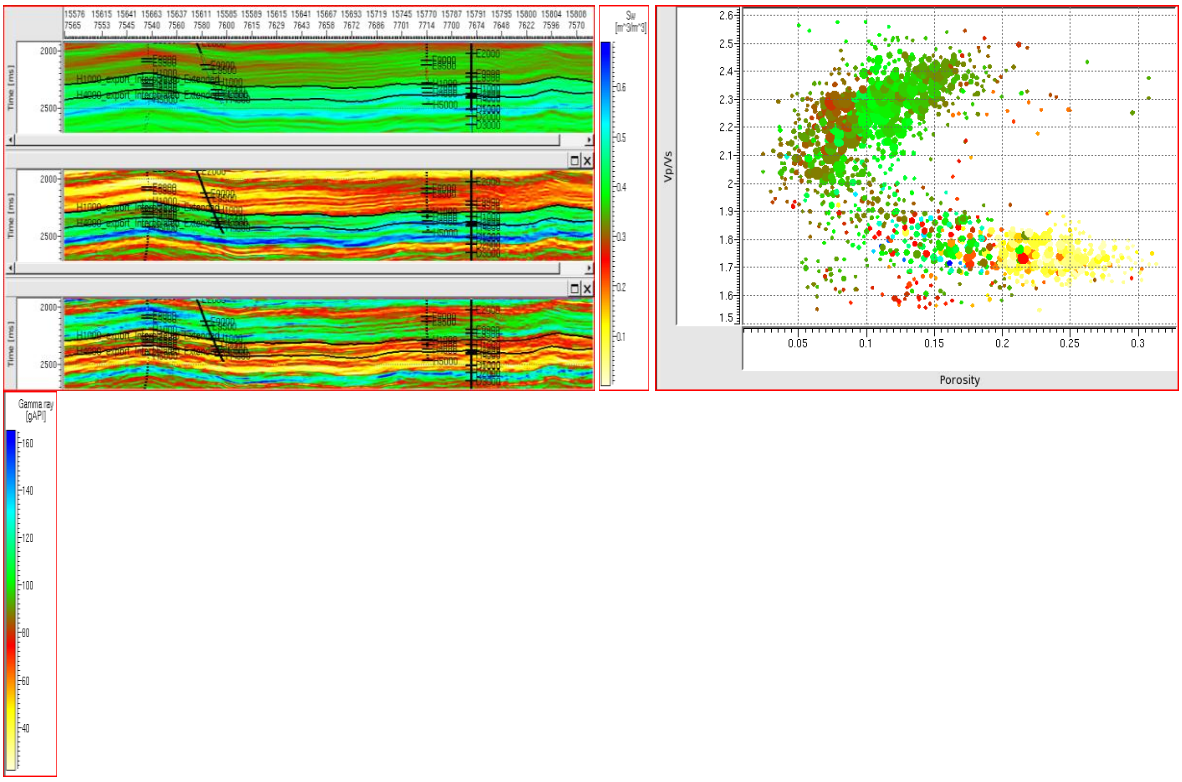

Figure 7. P-impedance, S-impedance and V_p/V_s and crossplot of log V_p/V_s versus porosity from well-002 colour coded to water saturation and gamma ray respectively.

Hydrocarbon saturation was estimated using the concept of the normalized cation exchange capacity per unit volume (Qv) method, which is the key to shaly sand evaluation. The cementation exponent *m* and the saturation exponent *n* are set to 1.8 in the absence of core data. The sands are considered loosely consolidated. For the H1000 reservoir, the R_w (0.30 Ohm m) is derived from Picket plot analysis from the well-003 and the well-002 wells. A similar R_w (0.30 Ohm m) was used for the H4000, based on Picket analysis from the well-001 and well-002. The deep resistivity log has been used as the true formation resistivity.

Recent advances in seismic inversion techniques have improved our ability to estimate reservoir porosity and saturation leading to better reservoir appraisal and development. Bachrach (2006) developed a method to jointly estimate porosity and saturation using seismic inversion attributes and stochastic rock physics modelling. In his method, he used Monte Carlo simulation and Bayesian inversion in order to estimate porosity and saturation from rock properties estimated from seismic inversion (Silva *et al.*, 2011). Figure 8 is the porosity map of the field for the H1000 + 20 ms window, showing high porosity at the southern part of the field.

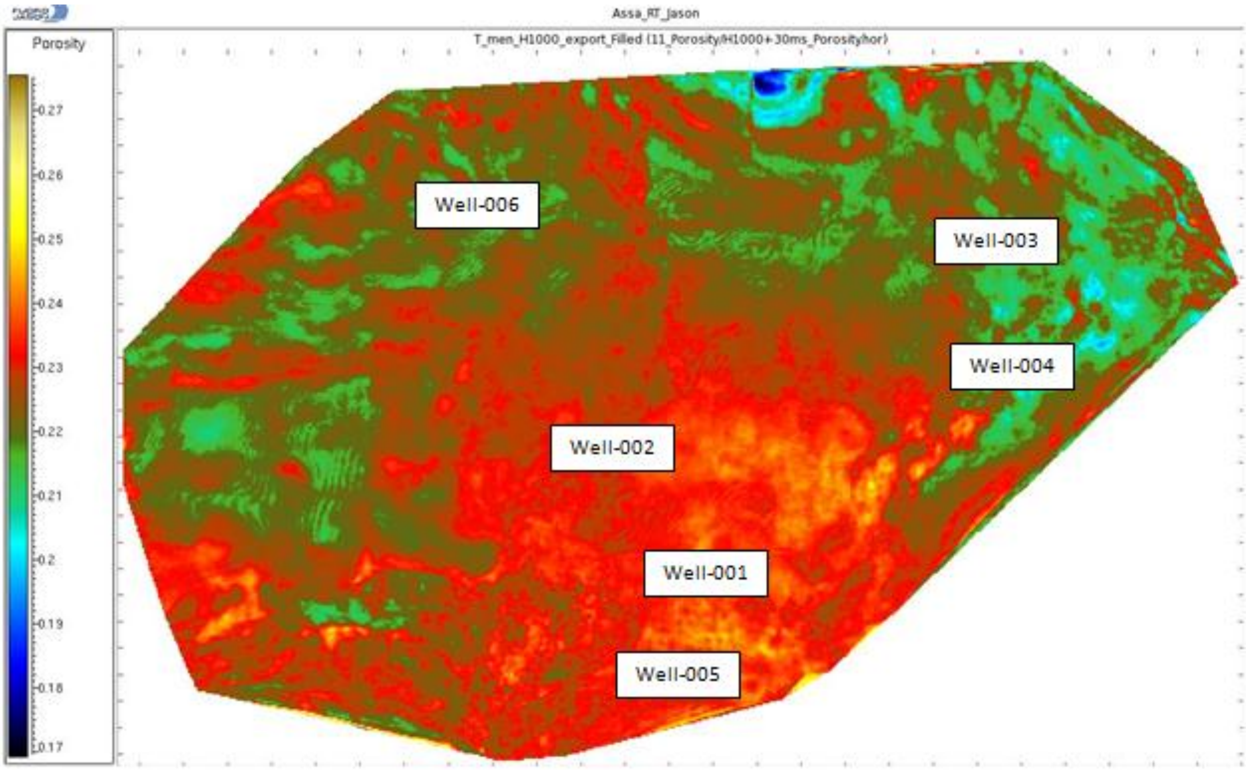

Figure 8. Porosity map for H1000 top +20 ms window

CONCLUSION

All the models honour the well log porosity data, though well data are too sparse. The models are smooth and reproduced the heterogeneity of the porosity. High porosity values for most part of the field are reproduced. The porosity values in the models are mainly impacted by well log porosities. The porosity is not stationary, lateral trend exists because the depositional facies model shows distinct spatial transitions.

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