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Geo-pressure Estimation and Productivity Analysis for a Gas Field Reservoirs in the Nigerian Delta

***Inichinbia, Sonny**[1], Yikarebogha Yibudongha[2]

[1]Department of Physics, University of Port Harcourt, Port Harcourt, Nigeria
[2]NNPC Limited Research, Technology and Innovation (RTI) Abuja, Nigeria, +2348034697856

***Email:** sonny.inichinbia@uniport.edu.ng **Phone:** +2347030087653

Abstract

Gas productivity is usually influenced by geologic factors such as total organic content, porosity, rock mechanics, completion design and overpressure. In countries with long histories of conventional gas production and gas flaring, like Nigeria, issues of depletion induced seismicity caused by fault reactivation due to differential compaction of reservoir compartments that are juxtaposed at faults, is a growing concern. Overpressure mechanisms and distribution are studied to understand their relationship with well productivity. The objective of this study was to understand the role of overpressure in gas production and to identify the overpressure sweet spots for future well development. Overpressure was estimated from petrophysical logs such as density, resistivity and sonic velocity corrected for gas effect and calibrated to reservoir pressure data and other well data. A sonic velocity versus density crossplot could not reveal a clear picture of overpressure generation, primarily due to complex geology and distinct compositional variation. 1D pore pressure was estimated from sonic velocity using traditional methods with pressure reference trend in the drilled wells and calibrated to the available insitu pressure measurements. 3D pore pressure was then estimated with upscaled 1D pore pressure profiles and 3D seismic velocity data. The results show that the area having higher overpressure of over 240.0 psi produces about 55 % more gas than the lower overpressure area. Further, understanding the spatial variation of overpressure in the field would facilitate better field development planning**,** as pressure increase leads to increase in production rate.

Keywords: Overpressure, Overburden, Pore pressure, Porosity, Reservoir, Temperature, Velocity.

Introduction

Knowledge of pore pressure along with other critical geologic and engineering parameters could help better target gas resources in a discovered field. Pore pressure alternatively called formation pressure is defined as the pressure acting on the fluids in the pore space of a formation. Pore pressure prediction has become very essential in exploration and production because of the increased exploration and production activities in deepwater and a need to lower cost without compromising safety and environment, as well as manages risk and uncertainty associated with very expensive drilling. Pressure prediction from seismic data is based on fundamentals of science, especially those of rock physics and seismic attribute analysis. The most successful approach to seismic pressure prediction is one that combines a good understanding of rock properties of subsurface formations with the best practice for seismic velocity analysis appropriate for rock physics applications, not for stacking purposes. Prediction of geopressure before drilling is critical at several stages in the exploration and development process. In the exploration phase, it can assist in assessing the seal effectiveness and in mapping hydrocarbon migration pathways. It can also assist in the analysis of trap configurations and basin geometry, and provide calibration for basin modeling. In the drilling phase, an accurate pore pressure prediction and the ability to update and revise predictions quickly can be vital for safe and economic drilling. Proper pore pressure prediction gives, among other variables, the mud weights to be used in a given well and casing depth to withhold the formation pressure while drilling. Estimates of proper geo-pressure and fracture pressure (defined as the pressure at which tensile fractures are created) are also essential for an optimized casing program design and for avoiding well control problems, such as blowouts [1]. Before a well is drilled, especially in frontier areas such as the deep-water provinces, seismic data are the only available data and have been used extensively for pore pressure analysis. Many authors have described how seismic velocities can be used for geo-pressure analysis. The seismic methods detect changes of interval velocities with depth from a velocity analysis of common-mid-point (CMP) seismic data. These methods exploit the fact that a geo-pressured formation exhibits several of the following properties when compared with a normally pressured section at the same depth: (1) higher porosities, (2) lower bulk densities, (3) lower effective stresses, (4) higher temperatures, (5) lower interval velocities, and (6) higher Poisson's ratios. Each of these indicators affects seismic interval velocities and reflection amplitudes which are the keys to seismic detection of geo-pressure.

The velocity of sound (compressional seismic, or *P-wave*) waves propagating through a piece of rock is called the rock velocity. The rock velocity depends on many parameters: porosity, fluid saturation, state of stress, pore and confining stress, pore structure, temperature, pore fluid type and its thermodynamic state, lithology, clay content, cementation, and frequency of the propagating waves. Furthermore, these parameters are not independent of each other. Using *P*-wave information alone can be ambiguous, because a drop in P-wave velocity (V_p) can be caused both by overpressure and by presence of gas. The ratio of P-wave velocity to *S*-wave velocity (V_p/V_s), which increases with overpressure and decreases with gas saturation, can help differentiate between the two cases. Since P-wave velocity in a suspension is slightly below that of the suspending fluid and $V_s = 0$, V_p/V_s and Poisson's ratio must increase exponentially as a load bearing sediment approaches a state of suspension. On the other hand, presence of gas will also decrease V_p but V_s will remain unaffected and V_p/V_s will decrease. Analyses of ultrasonic P- and

S-wave velocities in sands show that the V_p/V_s ratio, especially at low effective pressures, decreases rapidly with pressure [2].

Analysis of rock velocities is essential for pore pressure prediction by relating rock velocities to pore pressures. The rock velocity is defined as the velocity of sound wave through a piece of a rock, a rock composite, or a particular rock formation containing pore fluids, akin to, say, checkshot, sonic log, or laboratory measurements. This can be, and usually is, very different from the interval velocity obtained from the stacking velocity. The purpose of the processing velocities is to produce a stacked seismic section to highlight the structural details. However, the interval velocities derived from conventional stacking velocity analysis, without special reprocessing, such as 3D prestack depth imaging, including dip moveout (DMO) and anisotropy processing of large offset reflection data; usually do not resemble the rock velocities. A routine use of the conventional stacking or processing velocities, without a proper understanding of how the seismic data are acquired, processed, and interpreted and of the data's limitations, can result in disastrous consequences in geopressure analysis [1].

A great deal of attention was paid to the low frequency trend obtained either from bandpassed well data or from a variation based on Dix type models. Otherwise, the inversion could yield an apparently noisy velocity function rendering any pressure prediction totally useless. Not all seismic data can be inverted for high frequency velocity information, especially if the S/N ratio is low. Such is the case in the subsalt and subbasalt areas. Inversion techniques are extremely valuable. They add resolution, but always require a reliable low frequency model and calibration. Prestack migration methods are essential for pressure analysis in structurally complicated areas such as subsalt basins. However, any inversion technique, no matter whether it be poststack or prestack, must start with a reliable and petrophysically acceptable rock velocity model [2].

For prestack inversion, the data must have sufficient offset range at larger depths (angles greater than 35^o) so that the moveout velocities can be derived with some confidence. Otherwise, the amplitude analysis for high frequency velocity estimation would be fraught with uncertainty. While this comparison is conceptually simple, the reality is far from the truth: the formation pressures are always measured in permeable formations (sandstone), whereas most of the pressure indicators (rock model based transforms) are only valid for impermeable formations (shales). So how can one obtain a true measurement of pore pressure in the shales? If the shales are in hydraulic communication with adjacent sandstones, then there is no problem. However, this is not always the case [2].

Field Location and Geologic Setting

The field is located within the Greater Ughelli depobelt of the Niger Delta, as shown in Figure 1. It consists of alternating units of sandstone and shale, which makes it the major petroleum bearing stratigraphic unit. The Formation consists of silliciclastics of 2,500 metres thick and are accumulated in delta-front, and fluvio-deltaic environments. The age of the producing sand intervals of this Formation ranges from Eocene to Pliocene and becomes progressively younger southward. In the lower Agbada Formation, shale and sandstone beds are deposited in equal proportion while the upper layer is mostly sand with minor shale intercalation. Due to the high sedimentation rates of this Formation, the sand is under-compacted. Deepwater channel and turbidite equivalents of this sand are found seaward. Agbada Formation which consists of hydrocarbon bearing sands and transgressive sealing shale, is readily influenced by fault which provides pathway for petroleum migration. Hence, Agbada Formation forms structural traps and stratigraphic traps which help to accumulate hydrocarbon. The known onshore and near shore Tertiary reservoirs of the Niger Delta Basin are all units of the Agbada Formation, and most significantly this stratigraphic unit accounts for about 58% of the Basin recoverable oil reserves and 55% of the Basin recoverable gas reserves [3].

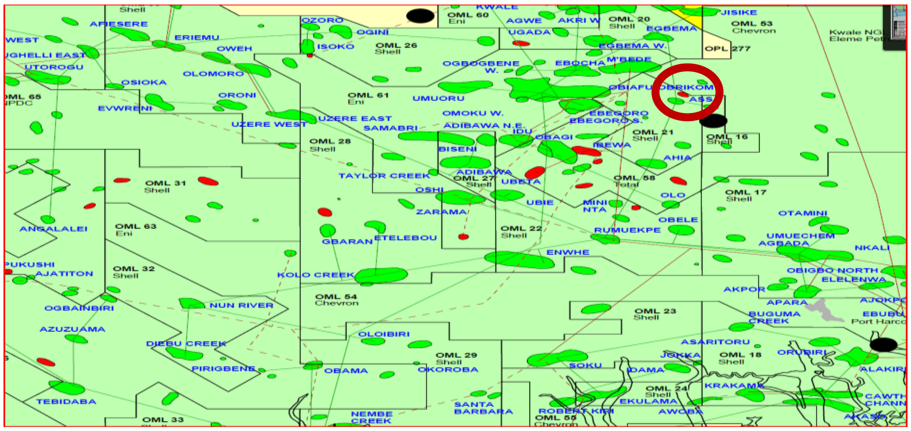

Figure 1. OML map of the Niger Delta showing the study area. The portion encircled red is the location of Amangi field. (Source: Shell Petroleum Development Company of Nigeria Ltd.).

Materials and Method

Anisotropic 3D prestack seismic data and well data were used for this work following [8], [9],[1], [5]. Before a well is drilled, seismic is often the only source of the velocity. Seismic velocities or interval transit times are often used for remote detection and prediction of high pore pressure regions. All seismic methods for pressure prediction use either explicitly or implicitly a relation between the rock velocity and the effective pressure. The overpressure generated by burial and various other secondary mechanisms could be estimated at any particular depth assuming that the system has undergone disequilibrium compaction and fluid expansion, and where there exists the clear relationship between porosity and vertical effective stress. The overburden stress (S_v) at any depth due to the weight of overlying Earth material was estimated by integrating the density obtained from the wireline bulk density logs of the overburden formations, given as:

$$S_v = g \int_0^z \rho(z) dz \quad (1)$$

where g is the acceleration due to gravity, and ρ(z) is bulk density at depth of z below the surface. In this research, compressional sonic log was corrected by removing gas effects and used for 1D pore pressure estimation along with pressure reference trend, which was then calibrated with available well data (complete suite of logs) and reservoir pressure data. The V_s log was generated from the compressional sonic log using appropriate relationships [6], [4], [5]. These 1D pore pressure estimates are then used in 3D pore pressure prediction using geostatistical methods described by [2], [6] and [7]. Anisotropic 3D prestack depth migration seismic cube was used for the estimation of 3D pore pressure.

Results and Discussion

Where high fluid pressure zones are encountered, that is, zones in which the fluid pressure is well above that given by the normal gradient with depth. Such wells provide an opportunity to study the relation between velocity, the difference between overburden pressure and fluid pressure, and consolidation with depth. Where there is no excess fluid pressure, the interval traveltime ΔT, in microseconds per foot, decreases with depth Z, in feet. For sands in normally pressured sections, one important feature is that the effect of consolidation outweighs the effect of pressure.
The rapid increase of velocity with depth normally continues until the time-average velocity is approached. Below this depth, the layers behave like other well consolidated rock and the velocity depends mainly on porosity. It is for the shallower layers that the fluid content, (i.e., water, oil, or gas) has an appreciable effect. Overburden pressure refers to the vertical stress caused by all the materials, both solid and fluid (water/brine, gas and oil) above the formation.
It is noteworthy that acoustic impedance contrasts govern seismic reflection coefficients at a plane interface between two media. As such, in the first few thousand feet the reflection coefficient at the boundary between a shale and a sand would be significantly greater if the sand contains gas than if the sand contains brine. This observation might possibly be of practical significance when there is a lateral change from a brine-filled sand to a gas filled sand. However, at considerable depths the reflection coefficient becomes almost independent of the nature of the fluid content. The field was analyzed using an integrated 3D pore pressure prediction approach by using well data and anisotropic 3D prestack depth migration seismic volume. The overpressure generated by burial and various other secondary mechanisms were estimated at particular depths and Figure 2 displays the overburden trend (left) and the normal compaction trend (right). The normal compaction trend shows wide variation in velocity with depth including velocity reversal.

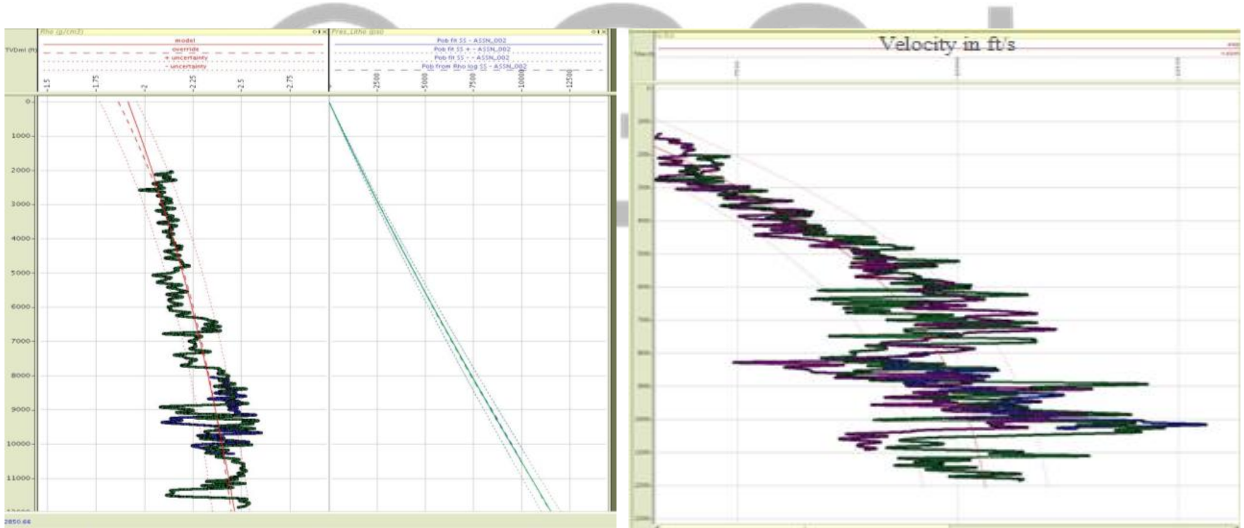

Figure 2. (a)Overburden trend and normal compaction trend. (b)Velocity versus depth for shale and insitu sands containing different fluids, showing consolidation effect of the insitu Tertiary sands.

Subsurface saturated porous rocksare usually subjected to hydrostatic pressure, as the rocks are under overburden pressure. This causes their elastic properties to change. This change depends upon the compressibilities of the rock matrix and saturating fluids, as well as changes in porosity. The first two effects are generally predictable. The compressibilities of the matrix materials are very small because bulk moduli are high, and at pressures relevant to seismic exploration, they do not contribute significantly to changes in bulk compressibility. The changes in the compressibilities of subsurface fluids especially gases as a function of pressure are appreciably large and this was taken into account while calculating the effective moduli of the saturated rocks as a function of pressure using appropriate equations of state depending on the exact properties (temperature, salinity and exact compositions) of the fluids. Increase in pressure causes low aspect ratio pores to close resulting to a net decrease in porosity. Long term compaction effects also lead to decrease in velocity with depth. Rock velocity as a function pressure for different saturating fluids reveals important information about the pore structure and the closing of fine pores as the pressure increases [1], [6], [7].

There exist relationships between the rock velocity and the effective stress as well as between the rock velocity and porosity (see Figure 3). As subsurface rocks are under overburden pressure, saturated porous rocks are subjected to hydrostatic pressure, their elastic properties change. This change depends on some factors such as the compressibility of the rock matrix and saturating fluids, and changes in porosity among others. The compressibility of the rock matrix and saturating fluids is predictable. The second relationship yields bulk density and, hence, overburden stress from velocity by assuming values for grain and pore fluid densities (see Figure 4). The first relationship then yields the pore pressure upon subtraction from the overburden pressure. Thus, velocity provides information for both pore pressure and effective pressure. A simplistic geopressure prediction process using velocities involves several steps: (1) obtain seismic velocities, (2) recondition and calibrate the velocities, (3) relate seismic velocities to rock velocities, (4) construct a rock model that relates velocity to effective stress and porosity, and (5) obtain effective stress and pore and overburden pressures using the rock model and the conditioned and/or calibrated seismic velocity [2].

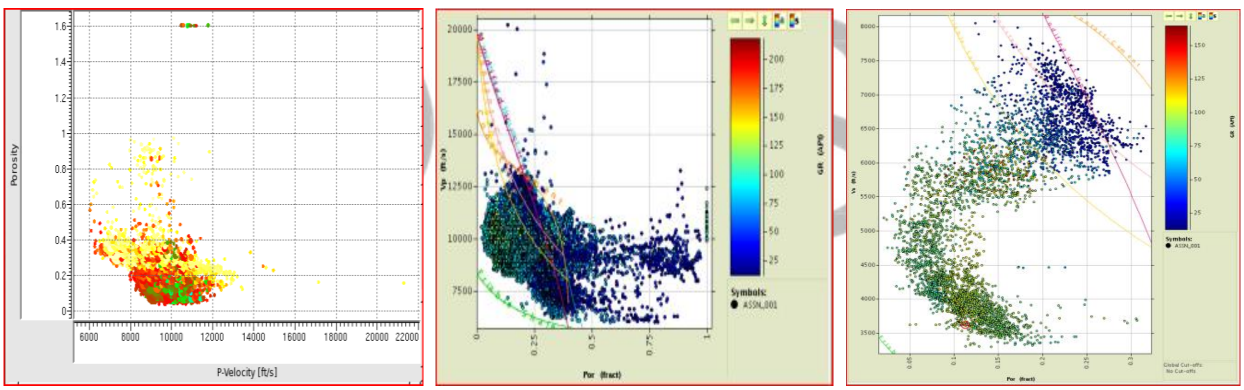

Figure 3. Crossplots of P-wave and S-wave sonic velocity versus porosity from the drilled wells on the field.

Velocity smoothing, calibration, and interpretation are important and essential steps in the process leading to seismic prediction of pore pressure. The industry has suffered a great deal in this area due to two factors: routine use of commonly available stacking velocities without proper conditioning for pressure prediction, and lack of communication with the drilling community about the limitations of seismic velocity information. For example, picking stacking velocities in the intervals shorter than, say, 50 ms can result in a reversal of interval velocity. This will lead to a false prediction of a pore pressure (reversal of pore pressure). Further, such reversals are often exaggerated by trace interpolation schemes in the seismic display programs. These are false indicators of geology and have nothing to do with the pressure compartments or reversals associated with the real geology [2], [7].

Besides a stacking velocity analysis, the rock velocities can also be obtained from inversion of traveltime (tomographic inversion) and amplitudes of seismic data (poststack as well as prestack), again with proper conditioning. Hydrostatic pressure, P_h, is the pressure caused by the weight of a column of fluid and could be written as:

$P_h = \rho_f gz$ ……………………………………… (2)

where z, ρ_f and g are the height of the column, the fluid density, and acceleration due to gravity, respectively.

The size and shape of the cross section of the fluid column have no effect on hydrostatic pressure. The fluid density depends on the fluid type, concentration of dissolved solids (i.e., salts and other minerals) and gasses in the fluid column, and the temperature and pressure. Thus, in any given area, the fluid density is depth dependent. In the SI system, the unit of pressure is Pascal (abbreviated by Pa), and in the British system, the unit is pounds per square inch (abbreviated by psi). The formation pressure gradient, expressed usually in pounds per square inch per foot (abbreviated by psi/ft) in the British system of units, is the ratio of the formation pressure, P (in psi) to the depth, z (in feet). In general, the hydrostatic pressure gradient, P_g (in psi/ft), can be defined by

P_g 0.433 x fluid density (in g/cm^3) …………………………. (3)

Numerous empirical models exist to link P-wave velocity (V_p) to overpressure. However, using Compressional sonic (V_p) velocity information plays an important role in pore pressure estimation but V_p alone can give ambiguous results as both overpressure and pressure of gas can decrease V_p. A sonic velocity-density crossplot (Figure 3) of the drilled wells in the study area shows the overburden shale (green points) and the reservoir sands (blue points). Generally, the bulk density of the normally compacted and undercompacted formation will always be lower than the bulk density of the secondary overpressured zones (due to fluid expansion, clay diagenesis, and cementation), but the crossplot shows that the bulk density of the reservoir sands is lower than that of the overburden shale. The sonic velocity (see Figures 3, 4 and 5) is higher in reservoir sands than that of the overburden shale. This is due to compositional variation (heterolithics) between the overburden shale and the reservoir sands. The presence of organic material in the shale significantly lowers the velocity of the overburden shale. It is still difficult to infer the cause of overpressure from this crossplot. S-wave velocity (V_s) decreases with overpressure but is unaffected by change in saturation. Initially, the V_p/V_s crossplot acquired through wireline logging in the wells for the reservoir intervals showed that the data lie above the normal V_p/V_s trend of the mudrock line, probably due to gas effect V_p/V_s, but after correction for gas effect the data now lies on the established normal V_p/V_s trend line as shown in Figure 4(c).This was then used for pore pressure calculation, thus, V_p/V_s which will increase with overpressure and decrease with presence of gas, can be used to distinguish between them. Thus, velocity and attenuation data are indeed very useful tools to distinguish between different lithologies and between overpressure and saturation effects. Whereas both overpressure and saturation cause a decrease in V_p, V_s is unaffected by saturation state and decreases with overpressure. The effect of increasing pore pressure (decreasing differential pressure) is to increase V_p/V_s ratio.

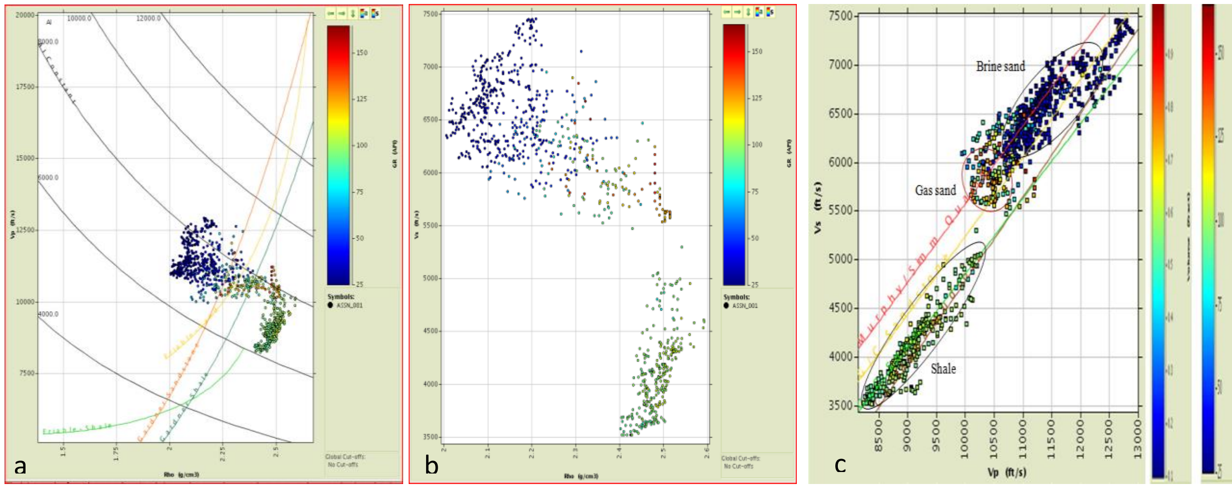

Figure 4. Crossplots of P-wave (a) and S-wave (b) sonic velocity versus density and V_p/V_s (c) colour coded to gamma ray and shale volume from the wells in the study area. Green dots represent the overburden shale, and blue dots represent the reservoir sands.

Figure 5 is the edited and calibrated sonic log from one of the wells on the field. A direct source of the velocity measurements appropriate at seismic frequencies is a checkshot survey (or a zero offset VSP survey). In this type of measurement, the sampling interval is of the order of 100 – 1000 ft (30 – 300 m), and the sources employ frequency bandwidths of 10 - 100 Hz, which overlap the exploration seismic frequency bandwidth. Acoustic logs are a direct source of insitu rock velocity data. Measurements are obtained at a much higher frequency (about 5 - 10 kHz). These measurements are carried out using sources and receivers in a borehole. The velocity information obtained from sonic logs is most frequently used for pressure analysis, especially for the calibration purpose. Further, these measurements are the only ones that can practically yield rock velocity data on shales under insitu conditions. This is particularly important when we note that every subsurface pressure analysis technique is invariably carried out on shales. The shale properties (velocity, porosity, etc.) are more consistent indicators of pressure than those for sandstone, and hence are ideally suited for pressure analysis ([2], [6]. The P-sonic data from well-01 and checkshot data from the wells are consistent. Well P-sonic data does not reflect the high pressure built up observed in the reservoirs. Predicted pressure at the calibration well shows poor match below 8700 ft TVDSS. Hence, pore pressure prediction from velocity alone cannot be relied upon below 8700 ft TVDSS (below H1000 reservoir). Additional pressure information from the neighbouring wells (if available) would be useful to further understand the data mismatch.

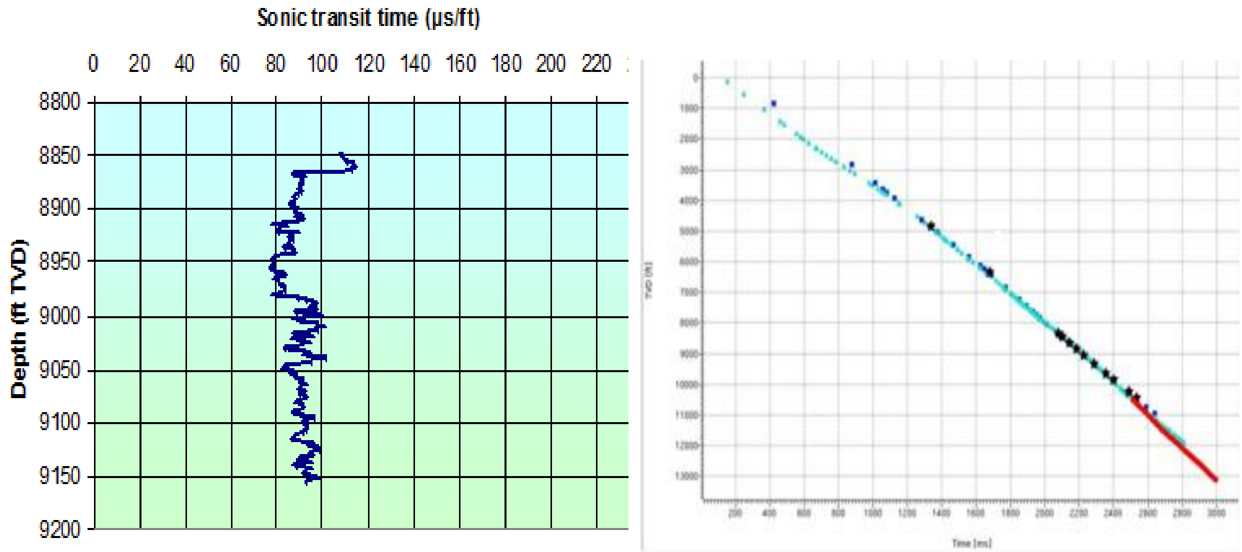

Figure 5. Edited and calibrated sonic log of well-01 and checkshot data from the wells.

The one dimensional (1D) pore pressure estimation was done using the approach described by [6]. The result of the 1D pore pressure plot from the drilled wells on the field is shown in Figure 6. The calculated pore pressures were calibrated and matched to the available pressure calibrated data which is the reservoir pressure data. The measurements are hydrostatic up to depths of 7700 ft TVDSS and shows good match with the well and the seismic velocity prediction up to depths of 8700 ft TVDSS. Where net-to-gross is high, the sands drain pressure variably and the shales encasing the sands are overpressured and the sands become pressure sinks [8].

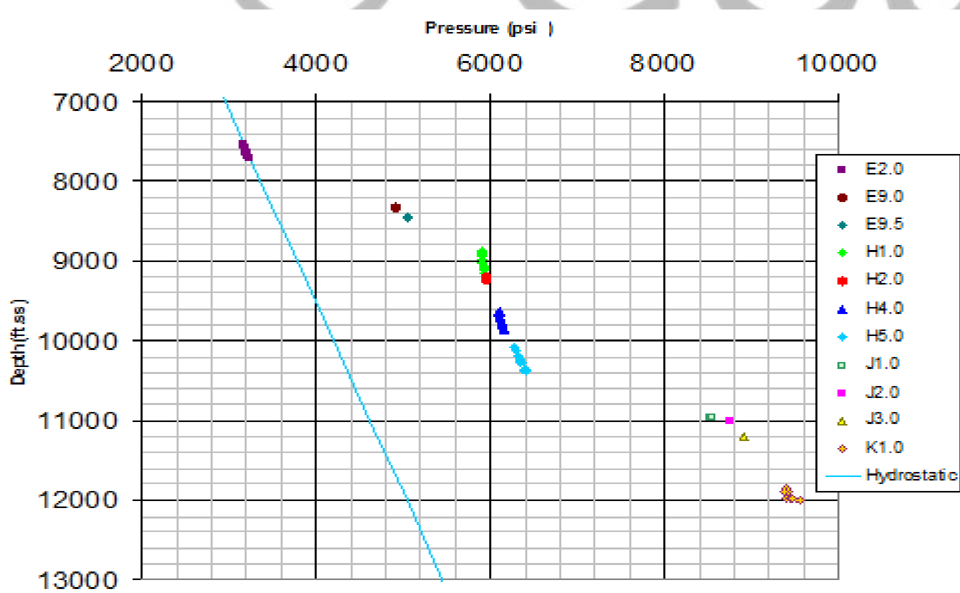

Figure 6. Calibrated 1D pore pressure profiles at the reservoirs' levels for the drilled wells.

The 3D pore pressure prediction was based on seismic velocities, which is expensive. At depths where there exist thick shale packages, significant overpressure is observed. However, if the signal-to-noise ratio is high and there is a good background low frequency velocity trend that has been conditioned for rock velocity analysis, the technology can yield a high resolution image of subsurface pore pressure [9]. An integrated approach which captures the lateral variation of seismic velocity described by [6], was adopted. Figure 7 shows the input CMP gather on the left, anisotropic 3D prestack seismic volume in the middle, and the acoustic impedance volume on the right. The inversion process followed the data in the 20 ms interval and used a rock model to convert the resulting P-wave velocity to the effective stress and the pore pressure. Results such as these are useful in well planning applications, provided calibration data are available and a proper interpretation of the results is made. A limited testing on this procedure shows its potential power [2].

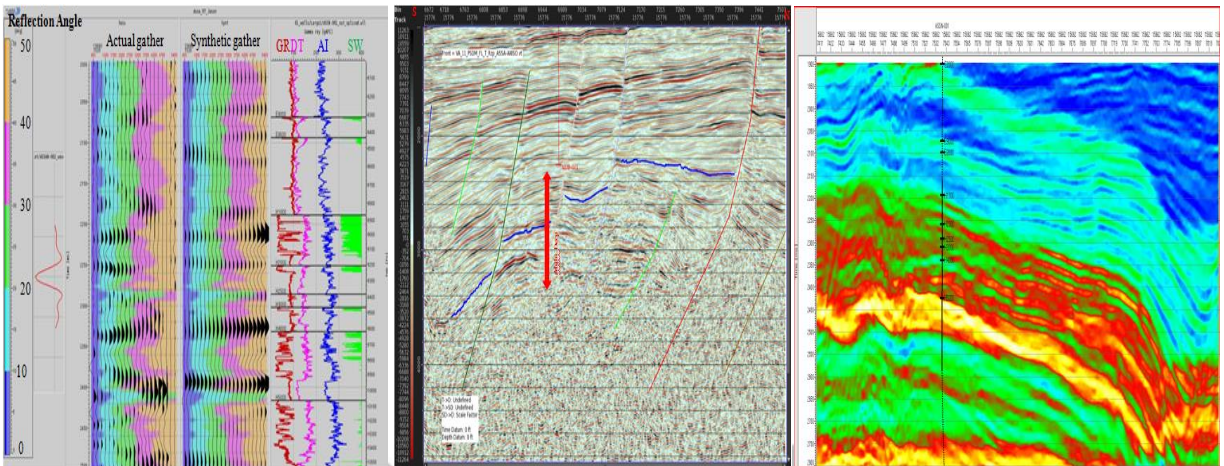

Figure 7. Input CMP gather, anisotropic 3D prestack seismic volume and P-impedance volume

Pressure prediction from seismic data has two major components, a rock model that relates effective stress to velocity, and the velocity field. The errors in the predicted pressure arise from both sources. It is true that even if the rock model were perfect, which is an unlikely case; there would still be errors in the predicted pore pressure due to inherent errors in the seismic velocity field. Drilling experience has indicated that when seismic velocities are processed and conditioned, one could obtain amazing pressures at target depths in the deepwater, provided that the low frequency trends in the seismic interval velocity curves are of good quality and lie within 5 % – 10 % of well velocities. However, seismic velocities still lack resolution, even when including the high frequency components provided by various inversion methodologies. Quite often, pressure regressions within thin overpressured sands and shales (thickness less than a quarter wavelength of the dominant frequency of seismic waves) are not detected by seismic techniques prior to drilling. This can result in expensive downtime. At present, there still is no consistently reliable methodology to predict the occurrence of such an event [2].

Results of the 1D pore pressure profiles from the wells were used as inputs for the 3D pore pressure prediction. Geostatistical mapping of upscaled well velocity was guided by anisotropic 3D prestack seismic volume, for the propagation of the well velocities in the reservoir intervals. The use of horizons helped to maintain the consistency between data and geologic structure. The velocity to pore pressure transformation established at well-01was applied to the trend velocity volume to generate 3D pore pressure. The average pore pressure and overpressure within the reservoir intervals range from 5,800 – 6,300 psi and about 1,700 – 2,400 psi respectively. Overpressure is relatively higher in the southeastern part of the field. These higher overpressure areas are the sweet spots that could be used to optimize development well locations for better field performance. Currently the central part of the H4000 accumulation is defined by the two wells. The proposed new drainage points would be located in this most crestal area to minimize water production. All wells would be drilled from one surface location (close to the existing well-01 well location) and have a maximum 46^o deviation with kick-off at around 2,200ft. The selected option for the H4000 reservoir is to drill three development wells with one in the Main Block updip of well-01, one down south of well-01 and one to the east of well-01.

Further, before a well is drilled, one does not know the exact location of shales and sandstones, let alone whether they are in hydraulic communication or not. Thus, in the predrill sense, the seismically predicted trend of pressure with depth is perhaps the most reliable indicator. The details of pressure regressions and other variations can be reliably tracked only if a calibration well is available within the same geologic and formation environment.

However, caution must be taken as there is a serious limitation to a methodology mainly based on seismic information. Methods based on seismic information are not reliable if beds are thinner than typical wavelengths contained in the velocity curve. These hidden beds are usually the source of unexpected pressure problems while drilling. Velocities interpretation is a critical step in this process, one that should not be done separately. An interdisciplinary team, including geologists, geophysicists, petrophysicists, and drilling engineers, will do it best. Further, pressure prediction is essentially an expectation and risk management process, teamwork and open communication between the team members is paramount.

Conclusion

The effective pressure governing the elastic properties of the skeleton of porous sedimentary rocks is the difference between the total external pressure (or overburden pressure) and the internal fluid pressure. Increase in the skeleton pressure increases the elastic reactions at intergranular interfaces and the velocity of the whole rock. Low pressure areas negatively impact production whereas the relatively high pressure areas are favourable for production. These predicted pressure data enabled us demarcate sweet spots for optimization of development wells locations. The sonic logs helped enhance depth control of the seismic velocity for better pore pressure prediction.

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