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**Research Paper**

# A robust assessment and prediction of reservoir pore pressure using well data and 3D seismic data over a gas field, onshore Niger Delta

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***ABSTRACT***
*An initial 2D seismic data was acquired and a discovery well was drilled in an onshore field of the Niger Delta for gas prospectivity. The field was found to have high overpressure and accompanying high operational costs which prevented a successful drilling operation, as the well did not reach the planned target depth. This hindered the well from a full evaluation of the target reservoirs. However, postdrill analysis revealed that the field has limited potential due to pore reservoir quality, little gas column and challenging drilling environment. Furthermore, a new anisotropic 3D seismic prestack long cable data sets were acquired and processed, followed by integrated multidisciplinary workflows, which successfully derisked the petroleum system of the structure, providing a more optimistic and fantastic results of the field's hydrocarbon potential. With enthusiasm, four appraisal wells, two wells in each of the two blocks of the field were drilled consecutively, and resulted in one of the major giant gas discoveries in the Greater Ughelli depositional belt of the Nigerian Delta. At approximately 800 m – 1,200 m TVDSS, the wells observed a steep increase in pressure as evidenced in the wireline log readings. The wireline logs estimated an average porosity of 24 %.*
***KEYWORDS****: Pore pressure, Porosity, Velocity, P-impedance, Density*

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## I. Introduction

Pore pressure or 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 increased exploration and production activities in deepwater and a need to lower cost without compromising safety and environment, and manage 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 [1]. 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 geopressure 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 [2]. Before a well is drilled, especially in frontier areas such as the deepwater 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 geopressure 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 geopressured 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 geopressure [3].

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 [2] and [3].

**LOCATION AND GEOLOGIC SETTING OF THE STUDY AREA**

The field is located within Licence OML 21 (Figure 1), in the north eastern corner of the OML 21 licence, 70 km northwest of Port Harcourt in the Greater Ughelli depobelt of the Niger Delta of Nigeria, 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, channelized and fluvio-deltaic environments [4].

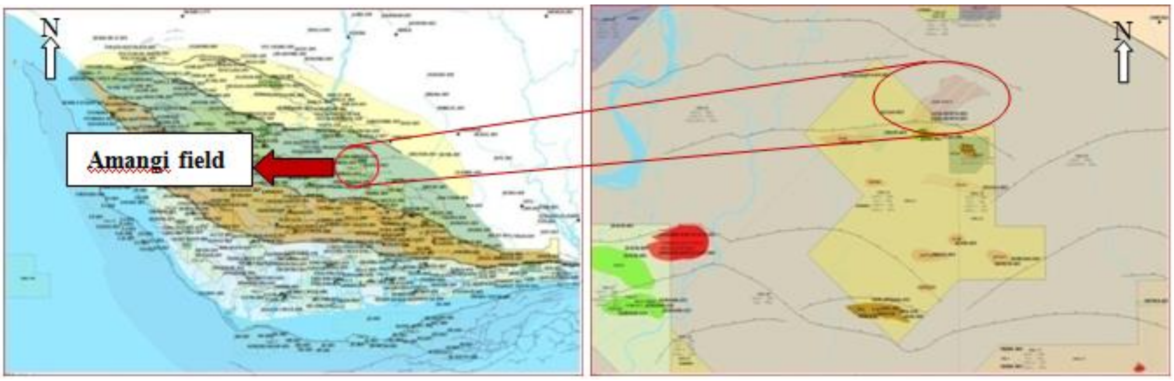


Figure 1. Map of the Niger Delta showing the study area. The encircled portion is the location of Amangi Field. (Source: Shell Petroleum Development Company of Nigeria Ltd.; [5]).

## II. MATERIALS AND METHOD

A more robust assessment of the reservoir model, maximum column that the structure could hold and pore pressure estimation requires the use of 3Dseismic data which was available for this work. Six wells were available, of which logs from five wells that encountered the structure were used [1,2,3,5l., 2014a; Kalra et al., 2020).

## III. RESULTS AND DISCUSSIONS

All seismic methods for pressure prediction use either explicitly or implicitly a relation between the rock velocity and the effective pressure. For a given rock, seismic velocity has been shown to be a strong function of effective pressure that is, the confining pressure reduced by the pore pressure (Figure 1). There exist relationships between the rock velocity and the effective stress as well as between the rock velocity and porosity. The first relationship then yields the pore pressure upon subtraction from the overburden pressure. Hydrostatic pressure, $P_h$, is the pressure caused by the weight of a column of fluid:

$P_h = \rho_f gz$ ……………………………………………… (1)

where $z$, $\rho_f$ 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 second relationship yields bulk density and, hence, overburdens stress from velocity by assuming values for grain and pore fluid densities. In general, the hydrostatic pressure gradient, $P_g$ (in psi/ft), can be defined by

$P_g$ 0.433 x fluid density (g/cm$^3$) ………………………. (2)

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.

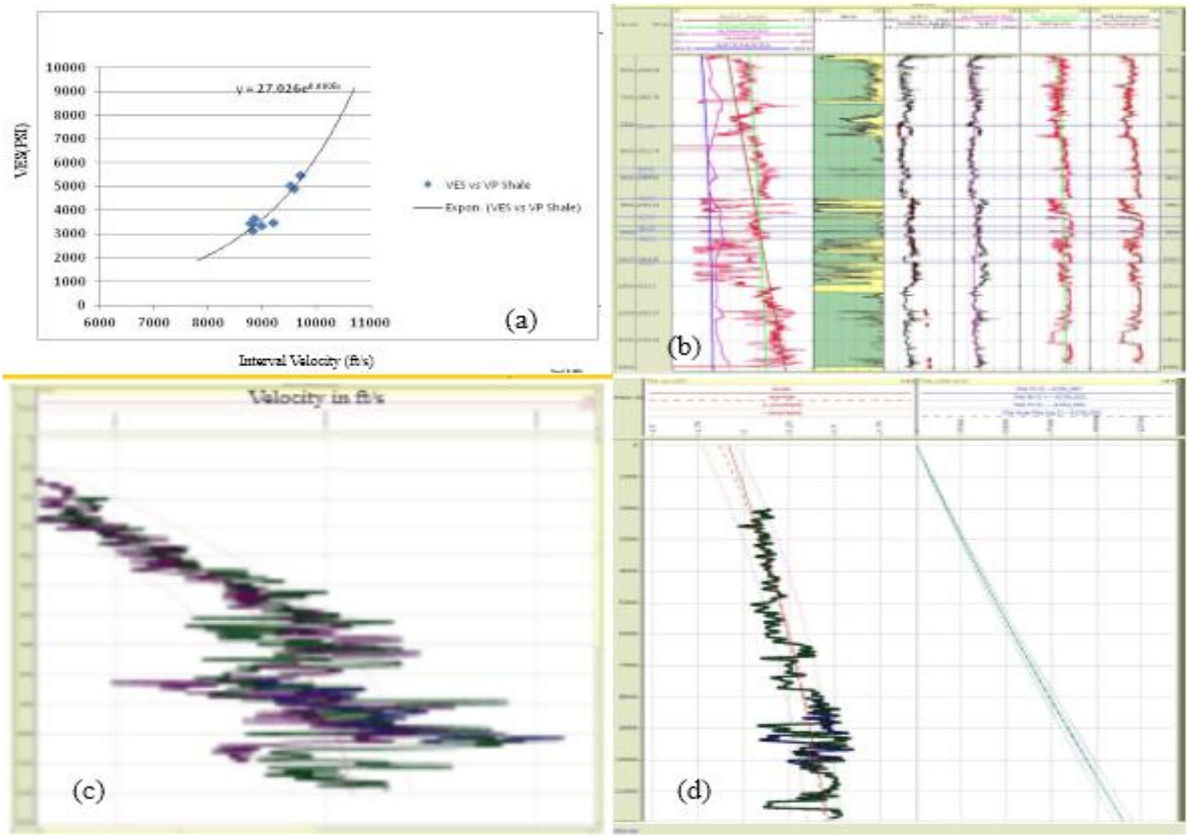


Figure 1. (a) Plot of interval velocity versus VES (PSI) relating velocity to vertical effective stress (b) Panel showing log used in the study (c) Plot of velocity versus depth – TVDSS (ft) showing normal compaction trend (d) Plot of density and pressure versus depth showing overburden trend.

Thus, velocity provides information for both pore pressure and effective pressure. Here, the simple geopressure prediction process using velocities involved (1) obtaining seismic velocities, (2) reconditioning and calibrating the velocities, (3) relating seismic velocities to rock velocities, (4) construction of a rock model that relates velocity to effective stress and porosity, and (5) obtaining effective stress and pore and overburden pressures using the rock model and the conditioned and/or calibrated seismic velocity [1]. In the SI system, the unit of pressure is Pascal (Pa), and in the British system, the unit is pounds per square inch (psi). The formation pressure gradient, expressed usually in pounds per square inch per foot (psi/ft) in the British system of units, is the ratio of the formation pressure, P (psi) to the depth, *z* (feet).

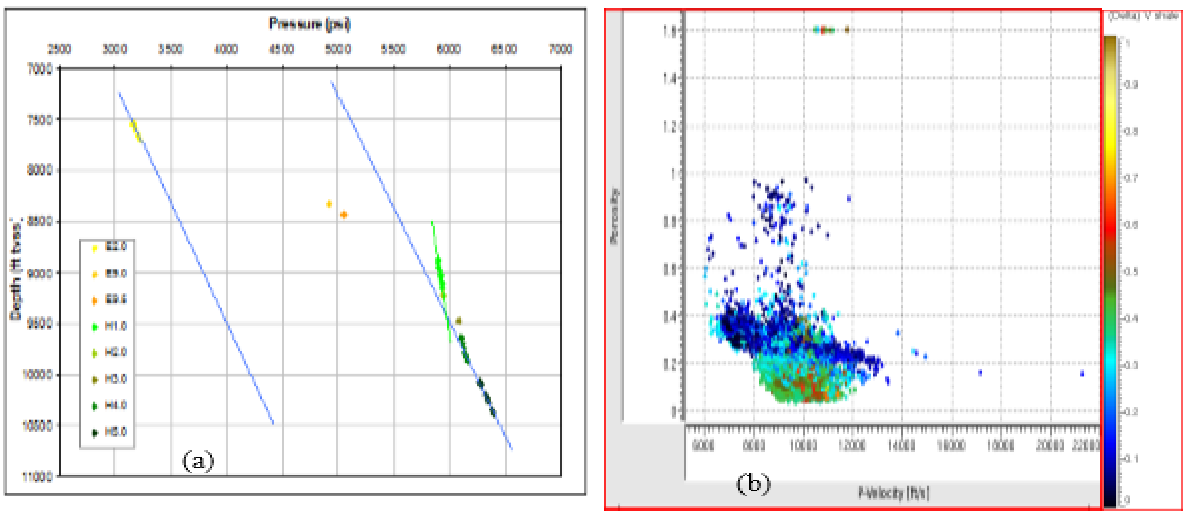


Figure 2. (a) Plot of pressure versus depth (b) Crossplot of P-velocity versus porosity colour coded with volume of shale ($V_{shale}$).

Since velocity also varies with the porosity and composition of the rock, an empirical relationship may permit us to estimate the effective pressure, and hence the pore pressure, from measurement of in-situ velocity. Compressional velocities are highest for brine saturation and lowest for gas saturation. The difference decreases with increasing pressure. The presence of a small amount of gas in brine as an immiscible mixture reduces the compressional velocities significantly, even below those of fully gas saturated values at some pressures. 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 [1] and [2]. 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 [6].

Numerous empirical models exist to link P-wave velocity ($V_p$) to overpressure. However, using P-wave information alone can give ambiguous results. Both overpressure and pressure of gas can decrease $V_p$. Since S-wave velocity ($V_s$) decreases with overpressure but is unaffected by change in saturation, $V_p/V_s$, which will increase with overpressure and decrease with presence of gas, can be used to distinguish between them. Velocity and attenuation data can be 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 [6].

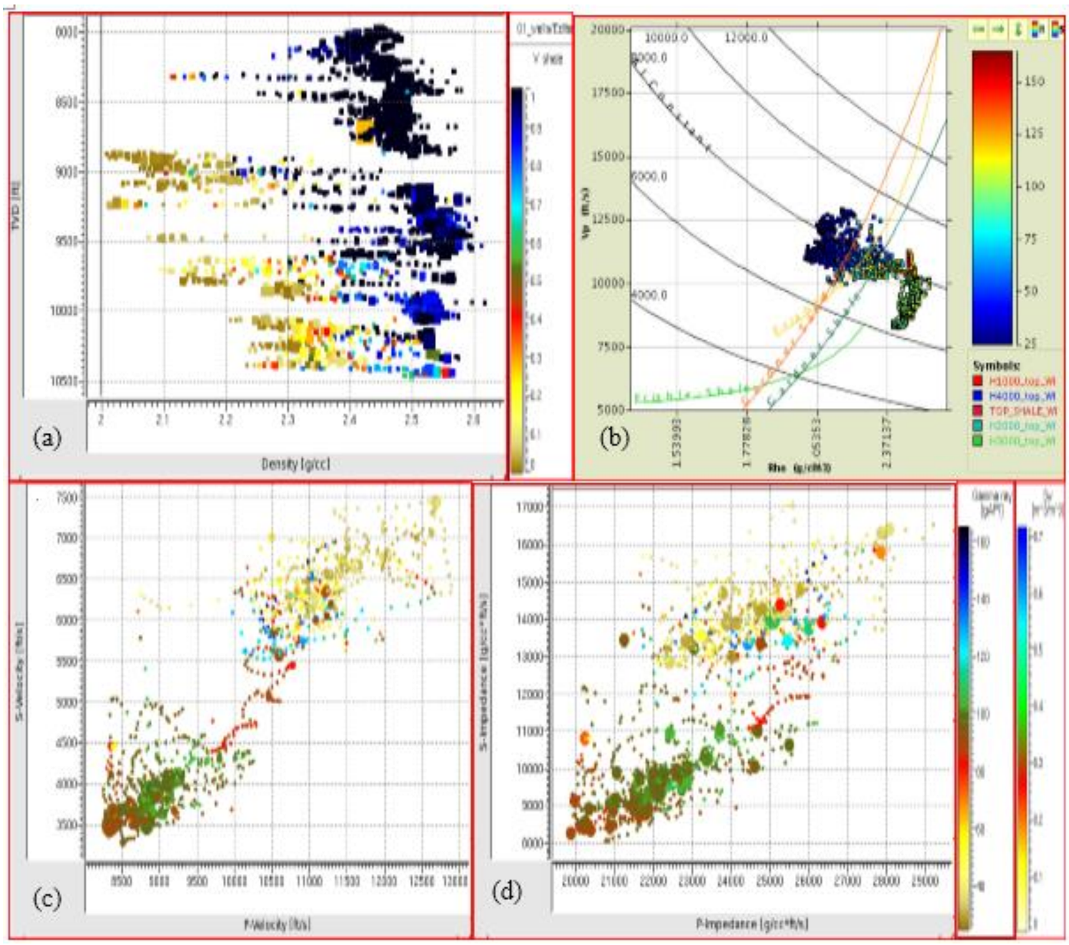


Figure 3. (a) Crossplot of density versus depth (b) Crossplot of density versus Vp (c) Crossplot of P-velocity versus S-velocity (d) Crossplot of P-impedance versus S-impedance colour coded with gamma ray, water saturation, and $V_{shale}$

The velocity of sound (compressional seismic, or P) 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 [6]. 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 [3].

Before using any type of inversion technique, a great deal of attention must be paid to the low-frequency trend obtained either from band-passed well data or from a variation based on Dix-type models. Otherwise, the inversion can 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. 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 [4] and [6].

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 [6]. Calibration was done with the available wells in the field.

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. Figure 4 displays the velocity model of the field and a panel showing the slowness and the reservoirs and their depths in TVDSS – ft [3].

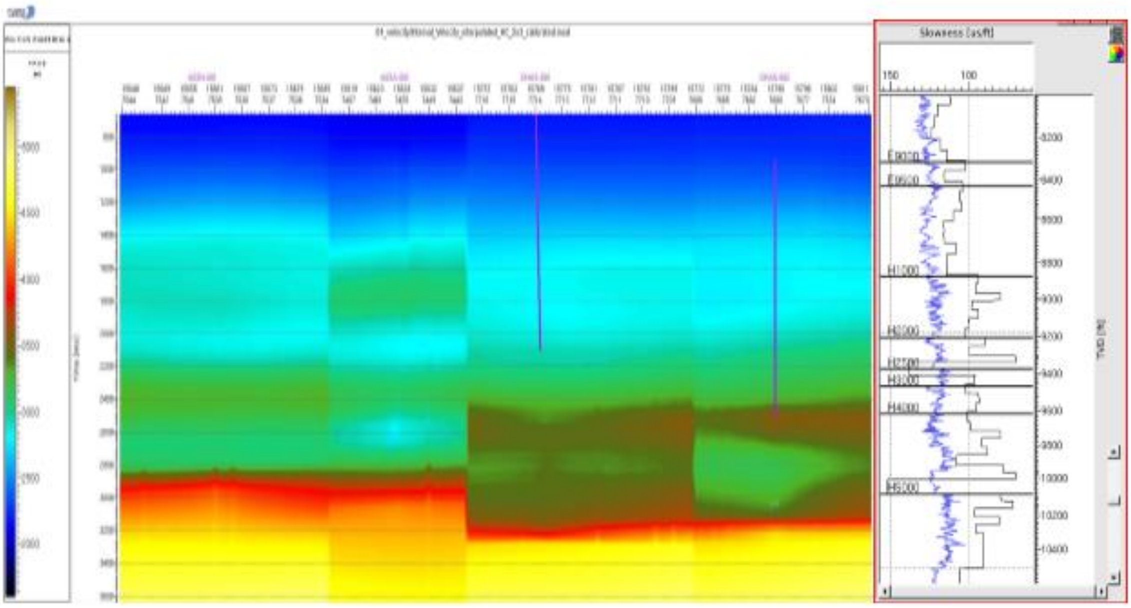


Figure 4. Velocity model of the field with velocity model from the wells overlain and panel showing the slowness and the reservoirs.

Predicting the thickest shales from seismic and avoiding them during well planning is highly desirable but there is uncertainty in reservoir targeting due to poor imaging and uncertain seismic velocities. This could result to errors in depth conversion and risk of drilling. 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. 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 [1]. Application of prestack inversion for pore pressure analysis is expensive, but where the S/N ratio is high and there is a good background low-frequency velocity trend that has been conditioned for rock velocity analysis, this technology could yield a high resolution image of subsurface pore pressure. Velocity smoothing, calibration, and interpretation are important and essential steps in the process leading to seismic prediction of pore pressure [2] and [7].

Figure 5 shows the input CMP gather (top left), the acoustic impedance (top right), and the resulting pore pressure profile (bottom left) and porosity versus P-sonic crossplot (bottom 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 [7].

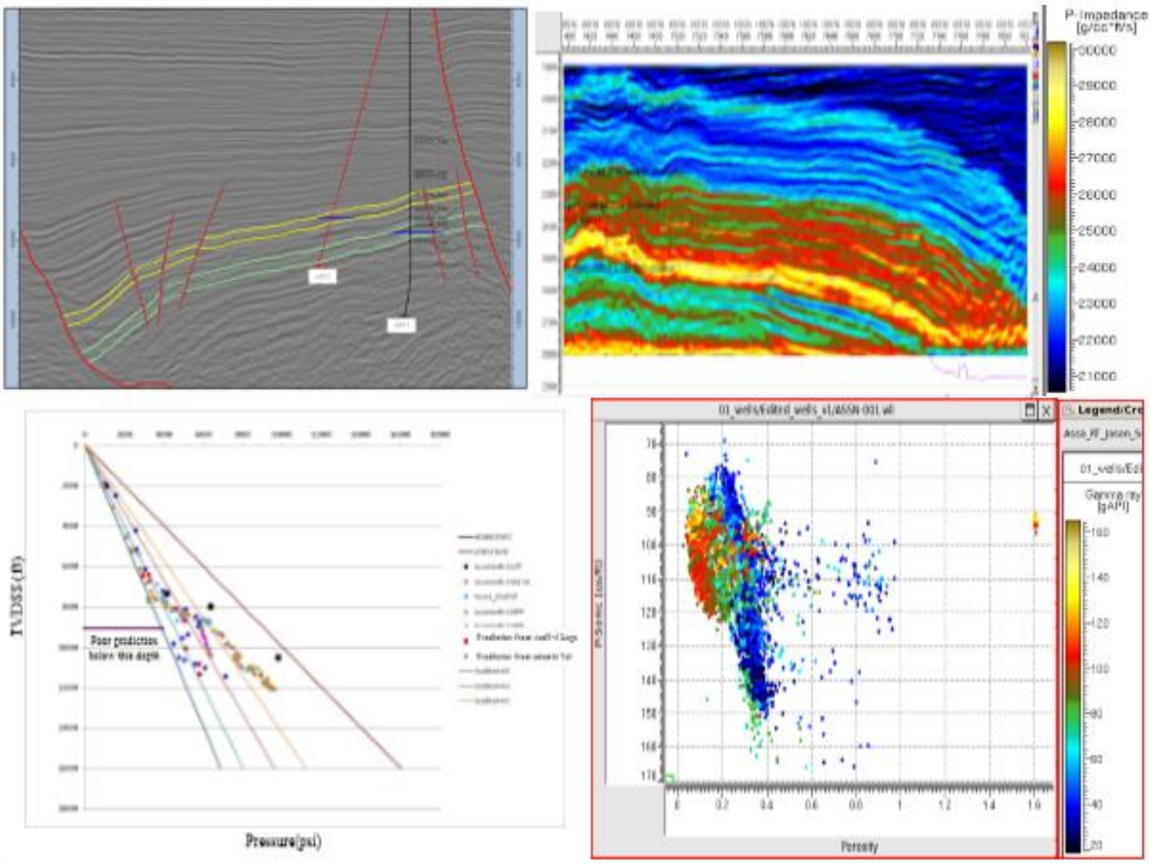


Figure 5. The input CMP gather (top left), the acoustic impedance (top right), and the resulting pore pressure profile (bottom left) and porosity versus P-sonic crossplot (bottom right) colour coded to gamma ray and P-impedance values.

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 [3]. 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 [8].

## IV. CONCLUSIONS

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 an unlikely case is; 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 as outlined in this paper, one can obtain pressures to within 0.50 ppg 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.

However, 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. 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. 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 essential.

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