THE EFFECT OF UNCONFORMITIES AND SUBSEQUENT LOADING ON PORE PRESSURE PROFILES

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ABSTRACT

In many basins in SE Asia such as the Nam Con Son Basin, offshore Vietnam, East Java Basin, Indonesia, basins offshore Thailand and the North-West Shelf of Australia e.g. Browse and Carnarvon basins, we have observed unusual pore pressure profiles in thick shale packages that are beneath unconformities such as the Middle Miocene Unconformity (MMU). These pressure profiles are parallel to the regional hydrostatic gradient, although still overpressured. The amount of overpressure within these shales appears related to the post-unconformity magnitude of re-burial.

We present several examples of these “atypical” profiles. In the case from the Nam Con Son Basin, Vietnam, we have used the ‘Swarbrick Method’ to determine the overpressure created by recent loading. That is, from the depth of the MMU, we use sedimentation rates to calculate the shale pressure at unconformity - this then provides a guide to shale pressure (and overpressure) below the unconformity.

In the other main case, from the Dampier sub-basin, Carnarvon Basin, North-West Shelf, we note a relationship between the unconformity associated with the Walcott Formation whereby the thickness of the seabed to Top Walcott i.e. the loading by this interval, provides a guide to deep shale pressure by providing a limiting factor.

In summary, a combination of the ‘Swarbrick Method’ and an unconformity/loading model can be invoked to explain shale pressures in many basins. This geologically-based model for shale pore pressure has proved to be a successful forward-modelling approach in well planning in these basins, where the only inputs required are ages of seismic markers and depth of the relevant unconformity to give maximum shale pressures, matching kicks taken in wells such as Montague-1 and Angel-1.

INTRODUCTION

When shales are buried pore fluids are expelled as porosity decreases (increasing effective stress) due to compaction as a result of increasing overburden stress (Sv). If this process is effective, i.e. pore pressure can maintain equilibrium with the hydrostatic (normal) pressure gradient, the shales are said to be normally compacting and the velocity and density of these shales increases with depth. If pore fluids are not expelled from the shales fast enough to maintain equilibrium, either due to low permeability and/or high sedimentation rates, overpressure starts to build-up as more of the additional overburden (Sv) during burial is carried by the pore fluids. If all fluid is retained, porosity and effective stress remains constant, pore pressure in shales tends to build roughly parallel to the overburden gradient.

We have observed these types of shale pressure profile in many basins in SE Asia and Australia. Examples are basins such as the Nam Con Son Basin, offshore Vietnam, East Java Basin, Indonesia and the Browse and Carnarvon Basins of the North-West Shelf, Australia. However, in these same basins we have also observed a different type of shale pressure profiles below significant

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unconformities – one which is both parallel to the hydrostatic (normal) pressure gradient of the area, but overpressured, and without any major porosity anomalies. A possible explanation for overpressure without a porosity anomaly is that the overpressure is related to gas generation i.e. fluid expansion (Bowers, 1995; Osborne and Swarbrick, 1997). An alternative explanation for this observation is that the unconformity/unconformities allowed pressure to dissipate. This dissipation allowed the shales to normally compact. These shales are then re-buried but maintain a hydrostatic-parallel profile.

In this paper, we focus on these hydrostatic parallel pressure profiles below the unconformities such as the Middle Miocene (MMU) in Indonesia. In Indonesia, for instance, we observe that the shales below the MMU are too shallow for temperatures to reach levels where gas generation is likely. Therefore, the overpressure within them is more likely due to post-unconformity re-burial. The magnitude of overpressure currently within these shales is proportional to the post-unconformity burial/overburden load – this subsequent overpressure can be calculated using the “Swarbrick” Method (Swarbrick, 2012). A variation of this “loading” model is shown from the Madeleine Trend and Kendrew Trough areas of the Dampier sub-basin, Carnarvon Basin, Australia. As the Tertiary is dominated by carbonates, there is little evidence for an overburden-parallel trend above unconformities and typical shale-based pressure analysis not useful. In this situation the loading above the unconformity can be simply related to the Jurassic shale pressures directly. The complexity in the Carnarvon Basin is that there are multiple unconformable events thus loading models may only work locally.

These two approaches, the Swarbrick Method and the hydrostatic-parallel post-unconformity loading profile, become a useful tool to produce pressure profiles in these basins - one that is independent of seismic velocity data or as a useful sense-check of a seismic velocity interpretation. Indeed, as many of the shales are not associated with a porosity anomaly, using seismic velocity data to determine pore pressure may be more problematic/not possible.

In this paper, we present examples from the Nam Con Son Basin, Vietnam and the North Carnarvon Basin, Australia. We also discuss the application of this model to other examples such as the Miocene pinnacle reefs in Sarawak (Heller et al, 2014).

BACKGROUND

Shales are highly compressible and hence, pore pressure prediction in low-temperature sediments is normally done by analysis of preservation of shale porosity by overpressure increase, relative to expected porosity for normally compacting shales during progressive burial. In this situation, pore pressure (Pp) is generated by ineffective dewatering (disequilibrium compaction) and is related to vertical stress (Sv) and vertical effective stress ($\sigma_v'$) in the Terzaghi (1953) equation (I):

$$Sv = \sigma_v' + Pp \quad \text{Eq. (I)}$$

If vertical or lateral loading ceases (e.g. a period of non-deposition or non-burial) this will allow pressure to dissipate. Unconformities may be generated during basin inversion, where sediment is uplifted and removed. The longer the hiatus, for a constant permeability, the more pressure can dissipate. If the overpressure reduces sufficiently, the shale will normally compact and the porosity reduces to a magnitude consistent with that predicted by a normal compaction curve. If sonic, density or resistivity data or seismic velocity data are used in this situation, the resulting pore pressure profile will sit on the hydrostatic gradient.

If re-burial occurs then these shales may become overpressured again. However, the hydrostatic-parallel pressure profile will remain. As burial continues, pore pressure builds up parallel to the overburden above the unconformity, controlled by the rate of sedimentation and permeability. The hydrostatic-parallel profile (and the unconformity) also moves to greater depth, parallel to the overburden. If sedimentation rates are high i.e. the isopach thickness from seabed to unconformity, then this will build significant overpressure in the pre-unconformity shales, however, as these have re-compacted there will be no porosity anomaly to suggest that they are overpressured.

There are several approaches presented here to predict what the shale pressures are below the unconformity. These are very useful as they only require sedimentation rates derived from depth-converted seismic data whose ages are known. Some assumptions about shale lithofacies as well are needed; are the shales clay-rich (lower permeability) or silt rich (higher permeability). Solid evidence for a hiatus/unconformable event is also needed.

APPROACH 1
Swarbrick et al. (2002) and Swarbrick (2012) demonstrated a relationship between the log of sedimentation rate and Fluid Retention Depth ("FRD"). This latter is the depth below the seabed (when offshore) from which an overburden-parallel shale pressure profile commences. The profile originates as disequilibrium compaction is the mechanism of pressure generation i.e. by loading of the overburden. The original relationship published in Swarbrick et al (2002) has been updated with sub-sets of shale lithofacies from a larger global data set (Figure 1; taken from Swarbrick, 2012). These examples come from basins where there are assumed to be no large, known tectonic (horizontal compressive) stresses and no uplift evident. Examples are areas such as the Niger and Nile deltas, Gulf of Mexico and several basins in SE Asia. For accuracy, this approach should only be used in the Tertiary as the data in Swarbrick (2012) is Tertiary in age.

(i) Miocene pinnacle reefs, Sarawak

An example of this approach from Sarawak is shown in Heller et al (2014) where the sedimentation rate for a shale above the target reservoir of Middle Miocene in age is 483 m/My (or approximately 1600 feet/My; this results in, for a silty shale an FRD of 2950 feet, and for a clay-rich shale, 1650 feet. In this previously published example we used the depth to Top Reservoir. This produces a shale pressure profile, confirmed by drilling history. This can be very useful if seismic velocities are poor, or log data such as resistivity or sonic.

(ii) Nam Con Son Basin in offshore Vietnam

A number of sedimentary basins of various ages are located offshore Vietnam. These basins include, in the south, Cuu Long Basin and Nam Con Son basins, the latter a major gas production province in Vietnam, and in the north, Song Hong.

Exploration plays in these Vietnamese basins are focused on either (a) oil-bearing fractured granite basement which now accounts for 80% of Vietnam’s total annual production or (b) clastic, consisting of reservoirs both above and below the MMU horizon, a substantial regional unconformity. Examples of the clastics in the Nam Son Con are sands from the Dua Thong and Mang Cau Thong Formations.

A particular challenge of developing these clastic plays has been to understand the pore pressure regime. For example, in the Song Hong Basin, the Cua Lo 1 ST-1 well is a sidetrack well to the original Cua Lo-1 exploration well, which commenced drilling on 11 August 2013 and was then subsequently plugged back from a depth of - 2,531 TVDSS and side-tracked due to an unexpected high pressure kick. High pressure-high temperature conditions have been reported in the Hai Thach and Moc Tinh gas fields in Blocks 05-2 and 05-3 of the Nam Con Son basin (Dang et al, 2006). A review of the pressure and stress regimes in the Nam Con Son Basin and Cuu Long Basins in presented in Binh et al (2007). In this study, pore pressure was derived from repeat formation tests (RFT) and drill stem tests (DST) data from exploration and production wells.

No shale pressure interpretation is included in the study by Binh et al (2007). However, Dang et al. (2006), show, from a well in the central part of the Nam Con Son Basin, a shale pressure ramp commencing in the Pliocene that builds towards the overburden. Below the MMU, a pressure profile, assumed to represent shale pressure, is hydrostatic-parallel. From our experience, (i) the pressure ramp through the Bien Dong Formation (Late Miocene to Pleistocene) commences in younger/older stratigraphy depending on the sedimentation rates (the higher, the shallower the pressure ramp) and (ii) this pressure ramp is often parallel to the overburden. We show an adapted version from Dang et al. (2006) in Figure 2.

Locally variation in sedimentation rates and silty intervals may cause alteration of this overburden-parallel pressure gradient. In Figure 3, neutron and density data from 10 wells in a Tertiary Delta is shown. This approach allows low clay and high clay content trend lines to be defined on the cross-plots to assist in interpretation of changes in shale lithofacies. All wells have a very similar shale lithofacies profile suggesting the same compaction model can be applied. Knowing this means that pore pressure prediction over the area represented by these wells is more reliable as the shales are homogenous and a robust normal compaction model can be derived, and the correct relationship on Figure 1 can be chosen.

In summary, referring to Figure 4, if seismic markers are established, then depth to the MMU can be determined. This unconformity is approximately 6 Ma in age. If the MMU is shallow i.e. the sedimentation rates are low (see A in Figure 4), then the overpressure in the shales below the unconformity will be low. Conversely, C shows that...
if the MMU is deep, and it can be as deep as 3.0km in the Nam Con Son Basin, then substantial overpressure can be generated.

Of note is that;

(i) Below then MMU, there are source rocks such as coals and coaly shales interbedded with claystones in the Oligocene continental and Lower Miocene marine intervals. If the MMU is sufficiently deep, then these may be generative, and excess pressure generated as a result. This will cause the pore pressure profile below the MMU to converge on the overburden and,

(ii) In horst structural settings which are common exploration targets in Nam Con Son, reservoir pressures may be in excess of the shales if pressure transfer up the horst faults charges them. This is reported in Hoskin et al, (2015) from the Carnarvon Basin where the Parker-1 well drilled into a very similar structural setting and experienced unexpected high pressure in the Mungaroo reservoir. The pressures were in excess of that created purely by cross-fault juxtaposition with overpressured Dingo Claystone shale in the hanging-wall, and more likely to be caused by up-fault transfer. Pressure transfer is not a new observation globally as various studies such as Offshore Brunei (Grauls and Baleix, 1994), Eugene Island 330 Field, Gulf of Mexico (Finkbeiner et al., 2001) and Brunei (Tingay et al., 2007; 2009) highlight this process as an important mechanism for generating overpressure in reservoirs. Vertical transfer has similarly been identified in the Malay Basin by Madon (2007) and in the northern Malay Basin (Tingay et al., 2013).

APPROACH 2

(i) Dampier sub-basin, Northern Carnarvon Basin, Australia

The geological history of the Northern Carnarvon Basin, Australia can be sub-divided into three main phases; (a) Late Palaeozoic (Silurian) - Late Triassic extensional pre-rift phase creating significant accommodation space, (b) Early Jurassic to Early Cretaceous (Valanginian) syn-rift phase resulting in well-defined NE-SW trending rift depocentres and (c) Early Cretaceous (Valanginian) to Recent passive margin conditions (punctuated by periods of inversion and compression) with marine sag phase shales, overlain by prograding Mid Cretaceous (e.g. Muderong shales) to Recent carbonate shelf deposits (He and Middleton, 2002).

These periods of inversion are associated with uplift of some of the main structural highs of the Northern Carnarvon e.g. 800 m along the Legendre Trend, and the Barrow Arch (Densely et al., 2000), and in excess of 900 m was determined from the Bambra Anticline. This uplift was calculated with reference to compaction of the Muderong Formation, Gearle Formation, and Toolonga Calcitutite.

The impact of these uplift events and the effect of any associated unconformities on the pore pressure, particularly in the Dampier sub-basin, is the focus of this second approach to looking at the effects of unconformities on pressure release. We focus on the NE end of the sub-basin, looking at data from wells located in the Madeleine Trend and Kendrew Trough areas. These wells lie parallel to the main structural grain of the Dampier, and comprise Lynx-1A in the SW to Angel-1, 2 and 3 in the NE, and Montague-1 in the NW; a distance of approximately 60 kilometres (Figure 5). We observe that in these wells, e.g. Montague-1, pore pressures in the Jurassic are similar to those that would be expected if simply generated by post-unconformity loading alone (Figure 6). A possible interpretation of this is that an unconformity has led to pressure dissipation and the re-burial has allowed pressure to re-build, in a similar way to that described in the first approach. Another example is Angel-4, shown in Figure 7.

In Montague-1, log evaluation interpreted 60.4m net gas sands in two separate bodies; (i) Kimmeridgian - Oxfordian 3930.9m - 4002.9m and (ii) Norian 4122.5m - 4216.0. Although excellent reservoir sands were encountered in the primary objective, Tithonian sands, no hydrocarbons were present. This is thought to be due to imperfect seal. Reservoir quality in the two gas sands was poor. Overpressuring in the Triassic indicates the occurrence of Triassic intra-formational seals. The section penetrated was close to prediction with seismic markers very close to prediction. Six disconformities were recognized. The gas-Water Contact was recognised at 4216.0m. Montague-1 was plugged and abandoned.

The overburden-parallel trend following the unconformity described as a feature of the Nam Con Son basin is however largely missing in these wells and indeed the basin as a whole as a basin-wide transition to carbonate-dominated deposition occurred during the Santonian (Hocking, 1990) with prograding shelfal carbonate sediments deposited
on the passive continental margin (Geoscience Australia, 2012). The Toolonga Calciolitite was deposited during the Santonian to Campanian, followed by the calcareous claystones of the Withnell Formation and the Miria Marl during the Campanian to Maastrichtian (Geoscience Australia, 2012).

In Figures 6 and 7, we use the Walcott Formation (Upper/Middle Eocene) as the key controlling surface i.e. the unconformity which controlled the initial pressure dissipation. As stated above, in this well there are reported six unconformable events, however using the sediment load i.e. thickness seabed to Top Walcott, this can generate the equivalent pressure represented by the mud-weight in the Jurassic and the kicks, as an approximation. On Figures 6 and 7, the hydrostatic-parallel line represents this loading by post-unconformity sediments. Also shown is a shale pressure interpretation. As mentioned above, the dominance of carbonate lithologies means that many of the “shales” in the interval Walcott to Muderong formation are affected by carbonate cements. This renders typical velocity based prediction invalid.

We have therefore used velocity/stress relationships based on:

(a) Recent to Early Cretaceous Valanginian, incorporating Withnell, Gearle, and Muderong Formations. Two trends are required as the clay content of the shale, particularly the Muderong shale, varies significantly. For this reason, the Muderong was separated in two groups: Silt-rich and clay-rich based on observations from cross-plots of CNL-Rho and Vp-Rho (the technique is highlighted in Figure 3).

(b) The third model for shale pressure was derived for shales aged from Berriasian in Early Cretaceous to Late Jurassic, including shales such as Barrow Group Shales, Forestier Claystone, Dingo Claystone, and Athol Formation. The shales at these depths are lower porosity and higher velocity/ density than their recent to Valanginian counterparts so had a different porosity to effective stress relationship.

The results suggest that the loading model in the Jurassic provides a useful approximation for shale and un-drained sand pressures. This approach, using the Top Walcott marker as the control for the loading model, appears to match in wells such as Angel-1 and 4, Cossack-1, Wanaea-3 and Plaineire-1. Interestingly, this approximation begins to under-predict mud-weights in wells such as Madeleine-1 and Lynx-1A which lie towards to SW of the Madeleine Trend and Kendrew Trough areas. An explanation for this may that the wells where the loading model appears to work are very uplifted e.g. up to 1km calculated from mean uplift in Denesley et al (1990). This uplift reduces towards the west along this trend such that mean uplift is significantly reduced in those wells such as Madeleine-1. This may mean the hiatus represented by the Walcott Formation and its unconformity is shorter thus less pressure escapes. Alternatively, another unconformity may be the control in other parts of the basin. It may be possible to map these seismically.

DISCUSSION AND CONCLUSION

Pore pressure prediction can be achieved accurately in environments where sediments are shale-dominated, young i.e. Tertiary, where shales have a similar clay content (i.e. shale lithofacies) and are low temperature. Examples include many Tertiary deltas and the Caspian Sea. There is usually a demonstrable porosity vs. effective stress relationship and Eaton (1975) and Equivalent-Depth can be used. If the shales become hotter, clay diagenesis and hydrocarbon maturation occurs. Both of these processes have implications for pore pressure. Some solutions are available such as the method presented by Bowers (1995).

In many basins, additional complexity is provided by non-shale lithologies such as carbonates and also basins where burial history is complication by inversion. Basins in Indonesia, Vietnam, Thailand and North West Shelf Australia e.g. Browse and Carnarvon have many of these extra complexities. An aspect that receives less focus is the effect of hiatus/unconformities on pressure dissipation. One reason is these may be seismically resolvable but the actual time represented by them is difficult to gauge. Also the permeability of any associated shales will control pressure escape, for any given hiatus period.

In Indonesian, Thai and Vietnamese basins such as Nam Con Son, Kra and East Java, inversion is present, however, generally not on the scale as on the North-West Shelf. In these basins, shale-dominated / shale dominated sections, using the Swarbrick Method (2012) can produce a sensible pressure profile in the shales above the MMU, and knowing the depth of the MMU from seismic, this provides a method to determine shale pressures.
below the MMU. These will follow a hydrostatic-parallel profile unless affected by gas maturation.

In the Carnarvon and Browse basins, there are several of these major events e.g. at the Santonian–Coniacian boundary with resultant fault reactivation and inversion (Romine et al, 1997; Cathro and Karner, 2006). Added to this, there is the absence of shale in the overburden. In this situation our loading model is likely an over-simplification on a basin scale, however in Madeleine Trend and Kendrew Trough areas tested, this approach appears to provide a mechanism whereby maximum shales (and undrained reservoir) pressures can be approximated in the Jurassic. Shallower pressures in the Muderong and the carbonate-affected Haycock and Withnell Formations may potentially reach the limits set by the loading model. In reality, the section from Walcott Formation (or other more locally suitable unconformity) to the Jurassic will represent a pressure transition zone.

The loading model in the Madeleine Trend and Kendrew Trough areas will not work in the Barrow sub-basin, where wells such as Barrow Deep-1 and Barrow L35J and F-24J are similarly uplifted (Dodds et al., 2001; Tingate et al. 2001, van Ruth et al, 2004 and Sagala and Tingay, 2012). These wells have been influenced by fluid expansion processes rather than purely disequilibrium compaction (Zaunbrecher, 1994, van Ruth et al, 2004 and Sagala and Tingay, 2012). The wells we have analysed in this paper are cited as being mainly affected by disequilibrium compaction (Nyein et al., 1977, Vear, 1998, Swarbrick and Hillis (1999, Tingate et al., 2001, van Ruth et al, 2004 and Sagala and Tingay, 2012). The Barrow wells also have not had significant Tertiary re-burial (Tingate et al. 2001).

REFERENCES


Nyein, R., MacLean, L., and Warris, B., 1977, Occurrence, prediction and control of geopressures...


Figure 1 - Relationship between rates of sedimentation and the Fluid Retention Depth published in Swarbrick (2012). Shale lithofacies has a large influence on this depth so an understanding of shale type is important. This relationship relies on the process of pressure generation being mechanical compaction only.
Table: Schematic Pressure-Depth plot re-drawn from Dang et al (2006) of a well from the central part of the Nam Con Son Basin. This schematic shows a pressure ramp commencing in the Pliocene that builds towards the overburden; below the MMU, a pressure profile, assumed to represent shale pressure, is hydrostat-parallel. From our experience, (i) the pressure ramp through the Bien Dong Formation (Late Miocene to Pleistocene) commences in younger/older stratigraphy depending on the sedimentation rates (the higher, the shallower the pressure ramp) and (ii) this pressure ramp is often parallel to the overburden. The ramp can be predicted using the Swarbrick Method discussed in this paper, and this in turn, can be used to establish the likely pre-MMU pore pressures. Note that in some wells in this basin, the pressures are higher than would be expected by this “Base Case”; we presume this is due to additional shale pressure via coals, coaly shales, interbedded with claystones in the Oligocene continental and Lower Miocene marine intervals, and/or pressure transfer up horst faults into reservoirs.

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<th>Stratigraphy</th>
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Figure 2 - Schematic Pressure-Depth plot re-drawn from Dang et al (2006) of a well from the central part of the Nam Con Son Basin. This schematic shows a pressure ramp commencing in the Pliocene that builds towards the overburden; below the MMU, a pressure profile, assumed to represent shale pressure, is hydrostat-parallel. From our experience, (i) the pressure ramp through the Bien Dong Formation (Late Miocene to Pleistocene) commences in younger/older stratigraphy depending on the sedimentation rates (the higher, the shallower the pressure ramp) and (ii) this pressure ramp is often parallel to the overburden. The ramp can be predicted using the Swarbrick Method discussed in this paper, and this in turn, can be used to establish the likely pre-MMU pore pressures. Note that in some wells in this basin, the pressures are higher than would be expected by this “Base Case”; we presume this is due to additional shale pressure via coals, coaly shales, interbedded with claystones in the Oligocene continental and Lower Miocene marine intervals, and/or pressure transfer up horst faults into reservoirs.
Figure 3 - Neutron and density data from 10 wells from a Tertiary Delta. All wells have a very similar shale lithofacies profile suggesting the all data plotted by data density contours. The low and high-end member clay content lines can be defined and then the shale types related directly to the correct trend line in Figure 1. In this case, a silty shale line would be used to calculate the FRD.
Figure 4 - Schematic to show how a simple loading model combined with an understanding of the effect of unconformities can provide a Base Case shale pressure interpretation. The horizontal red lines A, B and C represent the MMU or other unconformities. These unconformities allow any previously generated overpressure by dissipate. This allows the shale below the unconformity to re-compact, and become normally pressured. Subsequent burial of the unconformity and the shales underneath occurs. The pre-unconformity shales retain a hydrostatic-parallel gradient as they become successively buried, and their pore pressure is controlled by the rates of burial of the overlying sequences. The final shale pressure below the unconformity is there predictable using the data in Figure 1. Rates of sedimentation above the MMU are higher in C than in A, thus producing higher overpressure.
Figure 5 - A map of the Dampier sub-basin in green, one of a series of sub-basins that comprise the Carnarvon Basin, offshore Australia. We note that many of the wells shown, all have deep shale pressures (as suggested by kicks) that corresponds to the equivalent load of the seabed to Top Walcott Formation. This marker is associated with a major unconformity. This area is also uplifted to potentially 1km (Denesley et al, 1990). This “loading” model can be used locally but begins to under-predict shale pressure at depth towards wells such as Lynx-1A, where uplift is less. This suggests the duration of the unconformity is reducing letting less original pressure dissipate or that, as there are many unconformities in the Tertiary in the Carnarvon, another is the key control to the SW.
**Figure 6** - Pressure-Depth plot for Montegue-1 (see location on Figure 5). The blue line parallel to the hydrostatic gradient represents the theoretical pressure that the seabed to Top Walcott Formation could generate i.e. the unconformity associated with the Walcott has allowed all previous pressure to bleed off. The remaining shale pressure (see kicks and several log-based shale interpretations) could be interpreted as therefore being only as a result of post-unconformity burial.
Figure 7 - Pressure-Depth plot for Angel-4 (see location on Figure 5). Similarly to the previous figure, the blue line parallel to the hydrostatic gradient predicts the deep shale pressure implying the unconformity has allowed complete pressure bleed off, followed by “re-pressuring” by the subsequent burial. This provides a useful guide to background shale pressure locally. More complete basin modeling is required to extend this approach over larger areas.