# Predicting Pore Pressure in Carbonates: A Review*

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Search and Discovery Article #41830 (2016)**
Posted July 25, 2016

*Adapted from extended abstract prepared in relation to oral presentation at GEO 2016, 12th Middle East Geosciences Conference and Exhibition, Manama, Bahrain, March 7-10, 2016. Bahrain:


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## Abstract

Carbonate reservoirs are the target of many drilling programs in the Middle East. One of the challenges in developing these reservoirs is to mitigate the risk caused by potential abnormal pore pressure. There is a tendency in the industry to use seismic velocity data and porosity-based, shale-proven techniques to predict pore pressure in carbonates. This approach, at best, will only give a local, empirical fit, and in reality, the next well drilled may encounter very different pore pressures. The variation in encountered pore pressure is due to porosity varying by other processes, such as fracturing and dissolution rather than simply stress; carbonates are stress-invariant.

## Introduction

Carbonate reservoirs are the target of many drilling programs in the Middle East. One of the challenges in developing these reservoirs is to mitigate the risk caused by potential abnormal pore pressure. The variation in pore pressure is highlighted in Table 1, a summary of the pressure regimes from selected global carbonates. The pressures from reservoirs in the Middle East can vary dramatically from relatively benign, such as in the Arab C and D formations, to highly overpressured, e.g., Gotnia Formation (19.5 ppg EMW, Oman/Kuwait in the Upper Jurassic). Within the same formation the pressure regime can vary dramatically, e.g., Khuff Formation. Even in those reservoirs where pressures are essentially normal, such as in the North Dome and Ghawar fields, aquifers have been demonstrated to be active, i.e., hydrodynamic (driven by hydraulic head of fresh water), and fluid distributions are controlled, in part, by overpressure differences in the aquifer.

Understanding the pressure regimes in these carbonates is clearly vital for safe drilling because if the mud-weights designed to drill the well are too high, losses may be taken into normally pressure reservoirs; conversely, if the mud-weights are too low, kicks may be encountered. Either incident can lead to loss of wells. When fields enter their development and production cycle, understanding fluid distributions significantly affects the placement of injector wells, for instance, and any calculations of reserves-in-place.

A problem arises, however, and this is the feature of this article, that existing techniques for pore pressure prediction (that were developed for shales) are being applied to these targets with little consistency. These techniques rely on remote detection of porosity anomalies and using seismic and/or log data. This process is then coupled with analysis of results from Wireline Formation Tests (WFTs) in associated porous units. A common and incorrect approach used in carbonates is to use seismic velocity data to look for these porosity anomalies and thus estimate pore pressure; i.e., carbonates are treated as shales. This approach is flawed for the reasons given below.

A better approach is the one featured in this article, where these limitations are accepted, and a more geological approach is taken within the current lithostratigraphic context and considering the paleo-history of a carbonate will dictate its current pressure regime. Furthermore, an extended geological-pressure model is discussed that not only looks at the basin history, but couples this with sensible pressure modelling in any associated shales, and understanding the elastic and mechanical properties of the carbonates.

Newer technologies based on understanding rock properties, i.e., Poisson's Ratio and Young's Modulus (seismically-derived) in combination with seismic inversion may provide a possibility for remote pressure prediction; these data could provide information on porosity distribution and compressibility that could then be linked to pore pressure. Currently, this approach has been attempted, but part of the relationship involves an empirical constant; this means that the method is non-transferrable unless it can be re-calibrated.

## The Problem

One of the main reasons that traditional pore pressure prediction fails in carbonate rocks is because the rocks are characterized by a porosity variation controlled not only by effective stress but also a wide variety of physical parameters, such as variable depositional, dissolution, and diagenetic fabrics (Brasher and Vagle, 1996; Anselmetti and Elberli, 1999). These factors mean that porosity can vary on a scale of only 10s to 100s of meters. This is not the case in shales which are more chemically inert and vary internally much less over short distances.

For example;

i. Carbonates with sufficiently well plumbed, interconnected porosity, such as grainstones and packstones (here termed "high-energy" deposits) form good reservoirs, with high porosity and permeability and, as such, tend to have the same aquifer overpressure from base to crest; which can lead to enhanced crestal pressures due to pressure transfer from down-dip.

ii. By contrast, carbonates with tight porosity, such as marls and wackestones (here termed "low energy deposits") make good seals and baffles. They tend to act as pressure transition zones or rather define pressure ramps with increased pressure gradients.

From a pressure prospective, this complexity means that carbonates reservoirs can be both overpressured (e.g. Minagish Oolite, Najmah/Sargelu and Marrat formations) and normally pressured (e.g. Arab C and D Formations; Table 1). Therefore, understanding the possible variability in carbonate properties is essential in order to generate robust and predictive basin models. Reliance on simple porosity changes as is routinely performed for shales will lead in inaccurate pressure prediction.

## Understanding the Compaction Behaviour of Carbonates

Velocity/porosity-effective stress relationships are usually implemented in the prediction of sub-surface pore pressures in shales, which in-turn form a fundamental input to both elastic property models and geomechanical simulation models. In shales, these relationships are derived from suites of wireline logs (or seismic velocity data) since the velocity deviation, a proxy for porosity, from a normal compaction trend can be an important indicator of overpressure where disequilibrium conditions or ineffective dewatering during burial occur (Figure 1).

Carbonates undergo the same mechanical compaction and porosity reduction as shales but with a further complication; a diagenetic overprint that can lead to both an enhancement (recrystallization, solution enlargement, dissolution and replacement) and/or reduction (recrystallization, replacement and cementation) in porosity (Ahr, 2008). The diagenetic complexity associated with carbonate porosity variability gives rise to velocity/porosity-depth relationships that are inherently unpredictable and, therefore, rendering traditional porosity-based shale pore pressure prediction methods invalid (Lubandazio et al., 2002). By way of an example, Chuhan et al, 2001 present the results of an experiment whereby compaction of carbonates (ooids) is compared to sand grains. Ooids are less compressible than quartz grains and carbonate shell sand. As effective stress is increased to 50MPa, carbonate ooids change porosity by only 5% compared to 30% for the sands.

Carbonates are distinctly different from shales in several respects. Carbonates are primarily made of calcium carbonate, $CaCO_3$, which is mineralogically reactive at low temperature (<80°C). In fact calcite is more reactive at low temperatures and becomes more stable/less soluble at elevated temperatures. The opposite is true for silica although at low temperatures (<80°C) micro quartz can form as coatings on detrital quartz grains in sandstones, stiffening the sediments (Thyberg et al., 2009). In mudstones, diagenetic quartz can form as a consequence of the smectite to illite reaction. Consequently both calcite and quartz cementation in sands and shales cause higher velocities than those expected for a given depth due to the stiffening effect it has on these sediments (Edwards et al., 2015) (Figure 1). In carbonates, the effects would be more pronounced early in burial when temperatures are lower.

Carbonate reservoirs have many types of porosities; intergranular and intragranular, vuggy/dissolution, mouldic, and fracture porosities. Other porosity increases can be formed by volume changes through reaction mass balance reactions as is the case with dolomites, which form by the replacement of limestone (Machel, 2004). In fine-grained carbonates, chemically-driven diagenetic processes are the principal cause of porosity reduction, rather than mechanical compaction (Mallon and Swarbrick, 2008). By contrast with shales, most carbonates become cemented at shallow depths creating a rigid pore framework preventing further mechanical compaction taking place.

## Our Solution - A Coupled Geological-Pressure Model

A clue on how to predict carbonate pore pressure can be determined by analysis of large areas of North Sea Chalk, where overpressures up to many 1000s of psi (Japsen, 1998) are observed. In general, the amount of overpressure increases from the edge of the Central Graben towards the basin centre. Data from regional mapping suggests that the increase in sedimentation rate in the overlying Tertiary section is coincident with higher overpressures in the Chalk. Moreover, the magnitude of overpressure in the underlying Jurassic/Triassic reservoirs is similar to the high overpressures close to Base Chalk (Swarbrick et al., 2010). These observations imply that the Chalk overpressures are linked to those of the overlying Tertiary and the underlying Jurassic/Triassic, and, indeed, the Chalk acts as a pressure transition zone (Figure 2). The shape of this transition zone may be controlled by chalk thickness and permeability variations (Figure 3). The Chalk therefore acts as an aquitard or pressure seal. Pressure measurements (which are rare in the chalk section) point to a continuously increasing pore pressure with increasing depth, implying a linear increase of pore pressures through the Chalk. Simply put, carbonate pressures are influenced by the pressures in their surrounding clastics. Thus, shale pressure prediction techniques can be applied in these encasing (and interbedded, non-cemented) shales to give a sense of carbonate pressures. Seismic inversion can be used to reveal the presence of such shale layers within a well.

Any encasing shales, if sufficiently hot, mineralogically complex and TOC-rich, may generate additional overpressure to that generated by rapid burial (disequilibrium compaction). These processes, such as volume expansion (principally gas generation) and/or development of load transfer/framework weakening, can generate 1000s psi of overpressure in shales. These can be modelled using shale-based techniques. Carbonates themselves do not internally generate overpressure. Maturation of kerogen is unlikely to be responsible for the generation of overpressure in carbonates because kerogen is not usually a major component of carbonate systems. Stylolite formation results in overburden shortening and porosity loss, which, if extensive enough, could lead to a load transfer effect (Lahann and Swarbrick, 2011). Lastly, flushing with alkali-rich formation waters would produce $CO_2$ that cause a drilling issue. Flushing with meteoric water would decrease with more burial.

In the above discussion, we have assumed that the carbonates are at their maximum burial depth. The stable platform interior of the Arabian plate is surrounded by tectonically active margins. Compressional terranes define the northern and eastern margins of the plate and form the Taurus thrust suture zone of SE Turkey and the Zagros thrust suture zone that trends from Iraq to Oman. A common feature of these compressional settings is high and unexpected pore pressure; e.g., the highly folded zone of Kurdistan where pore pressures can reach 19 ppg and where uplift has been more than 2 km. There are many issues with predicting pore pressure in these types of environments. The thrusting affects the overburden; gas expansion can cause elevated pressure, and the vertical stress is no longer dominant. Unconformities are a common feature in such environments which can allow pressure dissipation. In these scenarios the need to back-strip to the time of deposition and forward model pressure build-up and dissipation is even more important to calculate than in the cases where carbonates are at their maximum burial depth. Indeed, this is the only way to successfully model pore pressure. Simple assumptions about rates of deposition, geothermal gradient, hiatus duration, and published data on permeability and pressure escape rates can provide a surprisingly accurate range of potential pore pressures.

Exceptions to this are laterally extensive, high-energy carbonates, e.g., in the Miocene, Northern Java; here, the reservoir may be normally pressured despite the presence of overpressured shales above, as a consequence of lateral drainage, i.e., lateral pressure escape to a leak point. These scenarios present drilling challenges as the mud-weight used through the non-reservoir section may be significantly overbalanced with respect to the reservoir pressures and may cause reservoir fracturing/damage. In some cases, e.g., Miocene pinnacle reefs in Sarawak, crestal pore pressures in these carbonates may be higher than surrounding shales due to down-dip lateral transfer of pressure (Heller et al., 2014). Knowing if target reservoirs are laterally extensive on seismic, coupled with knowledge of facies, i.e. high energy, can qualify any chance of pressure escape and potentially the mud-weights can be lowered. If such reservoirs are observed to have relief on seismic, this may warn of elevated crestal pressures. Low-energy carbonates will not be affected by these processes. A robust facies model is therefore important.

The challenge to using the process outlined above is any environment where there is little shale; i.e., the sequence is comprised of kilometres of carbonate (and/or evaporites). In these scenarios a pressure model cannot be built from shales and applied to carbonates; therefore, an alternative approach is needed. The most recent innovations within the industry are to characterise the pore structure and study the effects of sonic velocity on permeability. The future solution to accurate pore pressure prediction in carbonates may be related to bulk/shear compressibility and its relationship to effective pressure.

## Potential Future Solutions – Integration of Elastic Rock Properties for Pore Pressure Prediction

At the outset, more sophisticated inversion can more accurately model intra-carbonate shales, and thus it may be possible to make shale pressure estimation on these layers which can infer the associated carbonate pressures. These inversions can also help with understanding connectivity, lateral extent, and vertical relief of carbonate bodies that can be used to model pressure more effectively.

Recently, Kumar et al. (2010) predicted pressures in carbonates in the West Kuwait Minagish Field, where wells have encountered 18 ppg Equivalent Mud-Weight (EMW) in the Cretaceous and Late Jurassic Formations, namely, the Minagish Oolite, Najmah/Sargelu and Marrat formations (carbonates, clastics, and salt). Using high resolution, processed Pre-Stack Time Migration (PSTM) gathers combined with VSP data for time/depth conversion, a variety of velocity interpretations were generated; a) high density picked NMO, b) elastic inversion and c) tomographic inversion. Interpretations of pore pressure using Eaton (1975) and Bowers (1994) were then attempted using the three velocity models. All the velocities were observed to show sensitivity to pressure changes in offset wells, particularly using the inversion-derived velocities and the Bowers (1994) primary loading relationship. This approach will only give predictive capability on a local scale as the potential for significant lateral and vertical porosity variation means that away from well control, pressure prediction is unreliable due to there being no consistent porosity/effective stress relationship in carbonates. What this approach does indicate is that a reliable P-wave and S-wave velocity and bulk density inversion model can be generated for carbonates, calibrated to wireline/VSP data, which can then be used in the derivation of other elastic properties; e.g., dry rock moduli, which could be used with geomechanical models to constrain the pore pressure. A petrophysical approach based on elastic and dry rock moduli and effective stress was also attempted by Kumar et al. (2010), but the lack of shear velocity data (Vs) meant there was insufficient data to test the theory and compare results. Variation in the dry rock moduli can be expressed by Q, the Quality Factor (the inverse of attenuation), and use of the Q factor as a method to predict pore pressure has been successfully achieved in clastic sequences (see Carcione and Helle, 2002) but has yet to be demonstrated to be effective in carbonates.

Atashbari and Tingay (2012) discuss a new method for effective stress calculation within carbonates using the compressibility of rocks as pore pressure is dependent on the changes in pore space, which is a function of rock and pore compressibility. A carbonate reservoir in Iran provided the case study with which to attempt to establish the new method for pore pressure prediction in carbonates. The analysis should also help the reservoir modellers by providing a better understanding of the reservoir properties. A correlation constant was required to adjust the results of the pressure prediction with observed field data. The correlation constant needs more investigation by further field studies and as such prevents this technique from being easily applied to other carbonate reservoirs globally; the correlation constant is comparable to the Eaton exponent (Eaton, 1975). This method of pore pressure prediction is based on the detected values of bulk and pore compressibility which are obtained from special core analysis and is limited to the areas in which the cores are available. Since these types of data are not available in all wells, further research would improve the method by estimating compressibility from well logs (e.g., Khatchikian, 1996) and possibly generating compressibility as a seismically constrained inversion.

Marin-Moreno et al. (2013) presented a new technique to derive pore pressure based on a case study from the Eastern Black Sea, an area which is predominantly clastic but does include shallow and deep carbonates within the section, and marl (calcareous shales) also. The authors demonstrate a new model to calculate overpressure whose input model parameters include Vp, bulk density, bulk compressibility, permeability and temperature. Given that the model utilises compressibility, then it can be considered to be complementary to the work presented by Atashbari and Tingay (2012). The model output also provides estimates of: (1) surface porosity, (2) compaction factor, (3) intrinsic permeability at surface conditions, (4) a parameter controlling the evolution of the intrinsic permeability with porosity, (5) the ratio between horizontal and vertical permeability and (6) uncompacted thickness (so sedimentation rate assuming known time intervals), for each sedimentary layer, aiding basin/geological modelling. The main limitations associated with this model are the determination of the input parameters and the validation of the results. Correct values of these parameters are required to model pore pressure accurately and are commonly based on literature values used in other locations. Marin-Moreno et al. (2013) overcome these limitations through the use of an inverse model that allows the introduction of observed seismic attributes, layer boundaries and geological constraints for a better pore-pressure prediction and the inclusion of an iterative misfit-minimising function that correlates the modelled and observed pressure values. This technique has not been applied directly to carbonates, but the work to-date does show that such an approach may be helpful in carbonates as it moves away from using a regional/basin-scale porosity-effective stress relationship.

## Conclusions

There is a tendency in the industry to use seismic velocity data and porosity-based, shale-proven techniques to predict pore pressure in carbonates. This approach, at best, will only give a local, empirical fit, and in reality, the next well drilled may encounter very different pore pressures. The variation in encountered pore pressure is due to porosity varying by other processes, such as fracturing and dissolution rather than simply stress; carbonates are stress-invariant.

This article reaches the following conclusions about pore pressure in carbonates:

1. Carbonates differ substantially from shales in their diagenetic history and compaction; i.e., they have been chemically lithified. They compact via both mechanical and chemical processes such that there may be no basin-scale relationship between porosity and effective stress. Therefore, primary methods of predicting overpressure (and their detection) associated with shales do not work in carbonates.
2. Carbonates are not prone to generate overpressure internally.
3. Overpressured carbonates are those found in association with overpressured shales.
4. Isolation of the reservoir (i.e., where there is little or no lateral escape of pressure to the surface) preserves the overpressure in these carbonates.

The results of this paper suggest that currently the best approach to predicting the pore pressure within a carbonate is based on:

A. Use seismic inversion to identify carbonates in the subsurface and their associated shales as accurately as possible.
B. Understanding the mechanisms of pressure generation in these shales and use shale techniques to establish the surrounding pore pressures.
C. Modelling the carbonate as a PTZ-based on the best understanding of its internal geometry and porosity from the geological facies model (e.g., high-energy vs. low-energy deposition).

D. Careful thought on the type of carbonates present, such as facies, and their abilities either to drain laterally or have elevated crest pressures due to seismically visible, down-dip extension.

The integration of geopressure, rock physics and geomechanics may result in a way to accurately tie the pore pressure regime to the elastic properties of the carbonate in a way that will allow more accurate prediction of the pore pressure. A multi-stage and multi-disciplinary approach is required, integrating the geological-pressure model described above with geomechanical and rock physics studies. Geomechanical modelling is supported by accurate pressure prediction, but it can also provide a constraint to the pore pressure; i.e., the pore pressure predictions which may not be calibrated must also satisfy the geomechanical model which is constrained by laboratory measurements from cores and by image log analysis. Rock physics modelling would aim to build a relationship between the elastic logs (Vp, Vs, and Rho) and empirical models linking the mineralogy of the carbonate to its porosity and its compressibility. The use of data types derived from seismic attributes, calibrated to the 1D well-based analysis, could allow for field/basin-scale models to be accurately built. The final output of this analysis would be a powerful basin model (or inputs to a basin model) that would have far-reaching and major positive implications for pore pressure prediction in carbonates world-wide.

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| Reservoir | Pressure Regime |
|---|---|
| Arab C and D Formations | Normal pressure |
| Qatif Formation | Normal pressure |
| Khuff Formation | Highly variable |
| North Dome Field | Low Pressure – hydrodynamic |
| Ghawar Field | Low Pressure – hydrodynamic |
| Intra-salt Ara reservoirs of the South Oman Salt Basin | Low Pressure |
| Gotnia Formation, Oman/Kuwait | High Pressure |
| Minagish Oolite, Najmah/Sargelu and Marrat Formations | High Pressure |
| West Kuwait Minagish Field | High Pressure |

Table 1. Distribution of selected normally pressured and overpressured carbonate reservoirs world-wide.

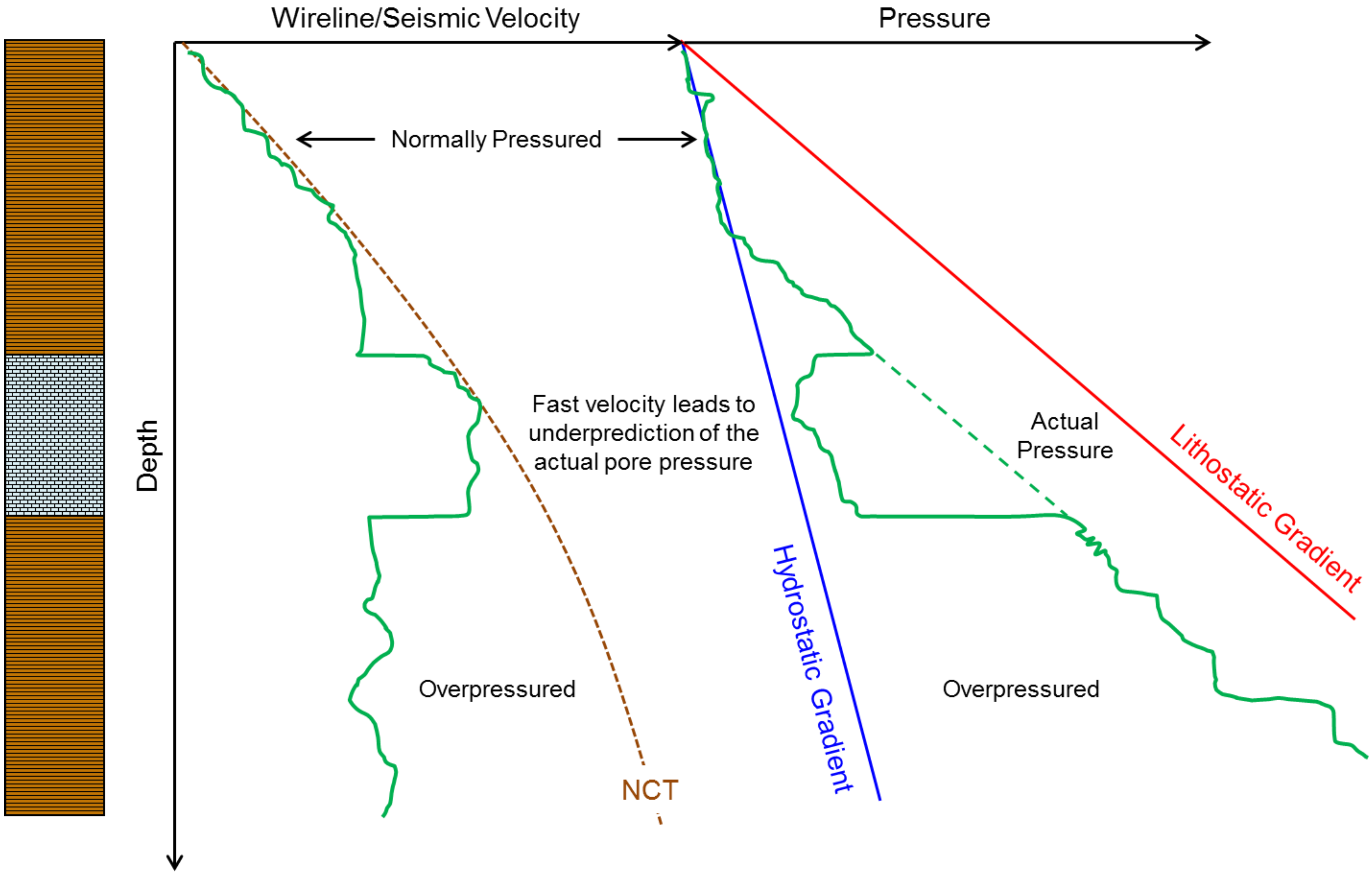


Figure 1. On the left-hand side, is a velocity profile (as measured from either wireline or seismic data) as the shale compacts. The velocity increase stops and the magnitude becomes constant as overpressure develops-- lithostat parallel. The carbonate layer has a typically fast velocity which would appear as a low pressure interval if a standard shale-based approach was used (green line on right-hand side). The actual pore pressure in the carbonate is shown by the dotted green line. The determination of the actual pressure profile though the carbonate is based on a regional geological pressure model including analogues.

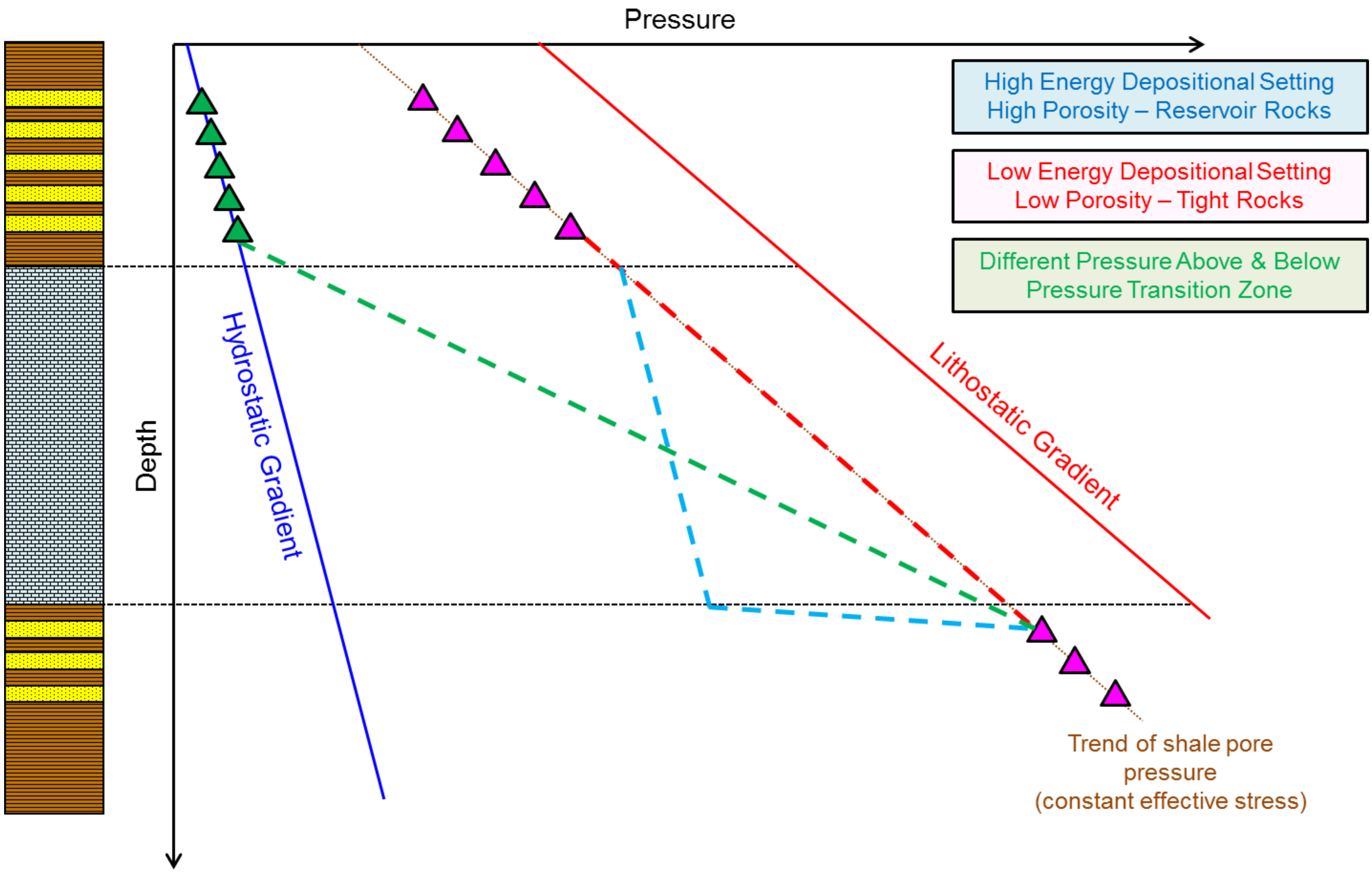


Figure 2. Potential Pressure Transition Zones (PTZs) present through carbonate intervals. The high-energy depositional setting trend is hydrostatic from the overpressure in the overlying units, here shown to be highly overpressured.

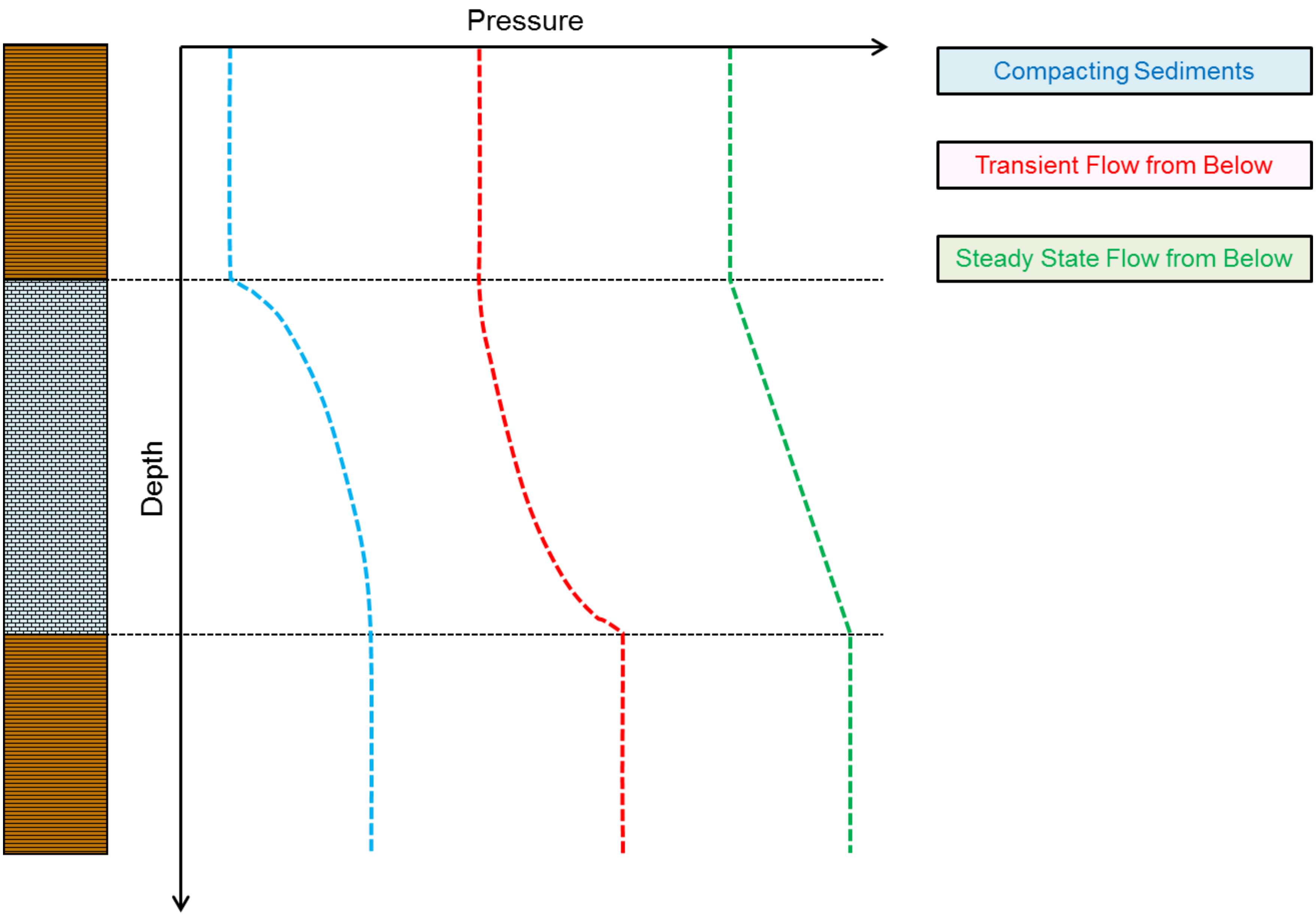


Figure 3. Schematic PTZs present through non-reservoir, fine-grained carbonate intervals highlighting the different pressure profiles depending on the nature of the compaction vs. the source of fluid flow into the carbonate unit.