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Normal Compaction Trends in Pore-Pressure Prediction: Complexities, Options, and Alternatives

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Abstract: ***Pore-pressure prediction has been a critical concern for the oil and gas industry for many decades. As drilling moves into deeper formations and more complex geology, predicting overpressures and drilling through them safely have become increasingly difficult and technically challenging. Sedimentary rock compaction is most reliably evaluated in shales. In shaly intervals, assuming shale-water salinity remains constant, resistivity variations reflect changes in shale porosity and, therefore, compaction. Vertical effective stress is derived from the transport and bulk properties of sediments (resistivity, velocity, and density), accounting for compaction effects on porosity. It quantifies departures from normal compaction by comparing measured values with those predicted at the same depths using an extrapolated normal-compaction trend to estimate the VES. Terzaghi's relation is then used to determine pore pressure. Although widely accepted and used with varying degrees of success, this best-fit normal compaction line is more mathematical and statistical than geological. Because the models are based on disequilibrium compaction, they assume compaction is the only process involved and that overpressure results from fluid being retained during compaction with communication to the surface. The method is limited to the primary overpressure-generation mechanism within the 80-100 °C temperature range; secondary mechanisms are triggered above this range. As deeper exploration in HPHT regimes expands globally into frontier areas beyond established heartlands, a holistic, more geoscientific approach is needed- one that adequately incorporates the rock physics of pressure-generating mechanisms. vertical effective stress-void ratio method is a proven approach that uses separate models for primary and secondary mechanisms. Rather than constructing a normal compaction trend, it uses a shale trend plotted across all pressure regimes. Users have found that it works better across all mechanisms, and its adoption is advocated.***

Keywords: Normal Compaction trend, shale trend, transport property, bulk property, void ratio, vertical effective stress

1. Background

Predicting pore pressure has always been essential for safe drilling and well planning. Disequilibrium compaction is a major cause of overpressure in sedimentary basins. For decades, relationships between effective stress and compaction state have been used to model compaction and predict pore pressure in these settings. They have proved reliable when calibrated and applied to formations with comparable geological histories, lithologies, and pressure calibrations. In some cases, effective stress is linked to a rock property through a normal compaction trend[1]. Alternatively, rock properties may be correlated directly with effective stress using a broad range of multivariate relationships[2,3,4]. However, these relationships also fail in several cases. Such failures often prompt practitioners to propose various complicating processes, whether or not geology supports them; alternatively, researchers may resort to arbitrary, piecewise adjustments that force-fit the data[5]. In a young sedimentary basin undergoing rapid subsidence, the transition from normal pore pressure to overpressured intervals can change rock geophysical and drilling parameters. In uniform lithologies, these changes typically appear as trend reversals when compaction-related geophysical properties are plotted against depth[6]. Shale is commonly used to predict pore pressure. Most prediction techniques rely on defining a normal compaction trend (NCT) for the relevant rock properties. Under normal pore-pressure conditions, density, resistivity, compressional-wave velocity, and rock compaction are expected to increase with depth, while formation porosity decreases exponentially. However, lithologic variation can make it challenging to establish the appropriate NCT[7]. Mechanical compaction is the primary mechanism that reduces porosity in sediments. Because compaction occurs mainly in one dimension, vertical effective stress alone can define the compaction stress acting on the sediment. Porosity reduction and fluid compressibility change overburden stress. In general, porosity decreases with depth and age, while water compressibility increases inversely (Figure 1). Accordingly, Terzaghi and Peck (1948)[8] established the rock-mechanics principle of effective stress. Mechanical compaction depends on effective stress and dominates in the basin's shallow regions, extending to depths of 2–4 km (80–100 °C), depending on the geothermal gradient. This defines the boundary condition of this process. As deeper exploration in HPHT environments expands into frontier regions beyond established basins, a more comprehensive, geoscience-led approach is required- one that properly accounts for the rock physics of pressure-generating mechanisms.

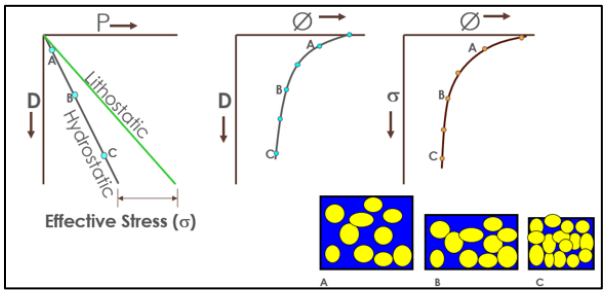


Figure 1: Porosity response to effective stress

2. Why Shale is preferred for Compaction studies

Shale lithology is broadly consistent across all depth intervals, and temperatures are sufficiently low that chemical

compaction has little effect on porosity. Pore-pressure prediction commonly relates shale properties, such as porosity or compressional velocity, to effective stress, then uses these relationships to estimate fluid pressure from well logs or seismic data. Shale responds more strongly to changes in effective stress than most other rock types.

Here, "shale" refers to rocks with a clay-supported matrix. Shales are preferred for pore-pressure analysis because the relationship between their properties and mechanical-compaction state is stable and predictable. Clays typically have an initial porosity of 65–80% at deposition and continue to compact through grain rearrangement and ductile deformation at greater depths, reducing porosity to 5-10% of rock volume[9]. By contrast, sands have a narrower porosity range affected solely by mechanical compaction; at depth in HPHT zones, chemical porosity loss through cementation often predominates. The clay-matrix structure and potentially less extensive cementation make the relationship between shale properties and stress more straightforward.

3. Compaction Process and Pore Pressure

Under normally pressured conditions, the growing weight of overlying sediments compacts the underlying sediments and expels connate water (Figure 2)[10]. As a result, porosity decreases with depth through normal compaction. Under abnormal conditions, water cannot escape, disrupting compaction. Porosity then stops decreasing and, in most cases, increases, creating an overpressured zone. The point where this zone begins- marked by the pore pressure gradient's departure from the hydrostatic gradient- is commonly called the top of the pore pressure ramp or the transition zone (TOP). This is the most common overpressure-generation mechanism in sedimentary basins and underlies many pore pressure prediction methods.

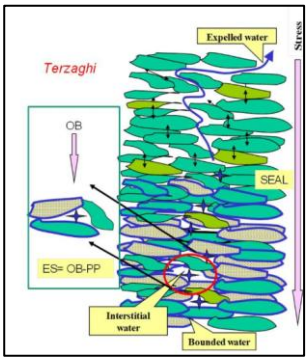


Figure 2: Compaction model[10]

As shale is buried and dewatered, it compacts along a single trend: at each depth, its porosity- and therefore its sonic response- reflects the effective stress borne by its grains. This trend is called the normal compaction trend. Shale that lies below it, with greater porosity and slower sonic velocity than expected at that depth, is interpreted as overpressured; the degree of deviation indicates the pressure magnitude[11]. In shale, measured resistivity and sonic data depend on porosity: all else being equal, higher porosity corresponds to lower resistivity and greater sonic slowness. Normal compaction occurs where sediments have sufficient time to dewater. Compaction, and the associated loss of porosity, is driven by effective stress. Hottman and Johnson were the first to recognise that compaction levels could be estimated using shale resistivity derived from well logs[11]. Overpressured shales conduct electricity more readily, and therefore have lower resistivity, because they contain more saltwater than normally pressured shales at the same depth (Figure 3). Since resistivity varies inversely with conductivity, a general decline in resistivity relative to the Normal Compaction Trend Line (NCTL) indicates overpressure. Subsequently, other log measurements used as porosity proxies were applied to establish normal compaction trendlines. The most commonly used measurements are sonic slowness, resistivity, and density, recorded along the wellbore.

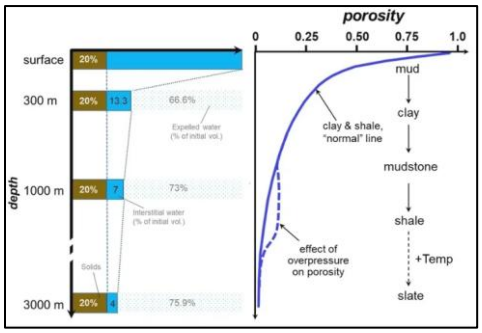


Figure 3: Left: Water expulsion from clay-rich sediments as a function of depth. Right: Expected reduction in porosity (solid line) as burial depth increases, and the effect of overpressure (dashed line) on the porosity trend[12]

Many widely used methods are based on the definition of a NCTL, including the Ratio, Equivalent Depth, Eaton's, and Bowers' methods. A common limitation of these approaches is their reliance on "clean shales" that follow a single, monotonic compaction-related trend. Consequently, they do not account for other mechanisms that may generate overpressure, such as mineral diagenesis, elevated temperatures, or cementation in chemically active systems. Eaton[1] developed a correlation relating the formation pore-pressure gradient to the overburden gradient, the normal pore-pressure gradient, and the resistivity or velocity ratio. Eaton[1] proposed three sets of pore-pressure prediction models based on 86 resistivity measurements, acoustic measurements, and a corrected d-exponent computed from drilling parameters. Eaton's models are given by:

$$Gpp = Gob - \{Gob - Gnp\}[Ro/Rn]^{1.2},$$
$$Gpp = Gob - \{Gob - Gnp\}[\Delta tn/\Delta to]^{3}$$
$$Gpp = Gob - \{Gob - Gnp\}[dco/dcn]^{1.2}$$

where Gpp: Pore Pressure (psi) Gob: Overburden Pressure (psi) Gnp: Normal Pore Pressure(psi) Ro: Resistivity (ohm) actual dco: dc-exponents for actual, Δto: Sonic transit time(μsec/ft) for actual Rn: Resistivity (ohm) normal dcn: dc-exponents for normal Δtn: Sonic transit time (μsec/ft) for normal: pressure gradient (psi/ft)

Holbrook et al. (1995)[13] expressed vertical effective stress as a function of formation porosity given by:

$$VES = A^{*}(1-\phi)^{B}$$

Where A and B are fitment parameters.

Because most pore-pressure prediction methods do not account for the origins of overpressure mechanisms, Bowers[2]

introduced techniques for estimating formation pore pressure from compressional sonic velocity using the principle of effective stress. Bowers' models account for excess pore pressure caused by both undercompaction and fluid expansion[6]. The method estimates vertical effective stress from compressional sonic velocity, then calculates pore pressure by subtracting effective stress from overburden pressure. Bowers' first relation describes the normal pore-pressure regime and overpressure conditions resulting from undercompaction (the virgin curve), and is given by:

For Normal/Mild Pressure (virgin curve)
Vp= Vp surface +A* B^{VES}

For hard overpressures (unloading)

$$VP_{shale} = VP_{surf} + A * \left(VES_{MAX} * \left(\frac{VES}{VES_{MAX}} \right)^{(1/U)} \right)^{B}$$

where VP is the compressional velocity at a given depth; VPsurf or VPml is the compressional velocity at the ground surface or the sea floor; and VESmax is the estimated effective stress at the onset of unloading.

The Bowers unloading model works only in intervals with velocity reversals. This makes physical sense, but unfortunately seismic velocities may not always accurately resolve reversals in deep zones, which could potentially be affected by unloading

A locally calibrated velocity-dependent pore pressure prediction model was proposed by Shell using the Tau-effective stress concept[3] and is given by:

$$VES = A\varepsilon^{B}$$

where $\varepsilon = \phi/(1-\phi)$

Zhang (2011)[14] proposed a modified Eaton's sonic model by using a depth-dependent normal compaction trend equation as given by

$$P_{pg} = OBG - (OBG - P_{ng}) \left(\frac{\Delta t_m + (\Delta t_{ml} - \Delta t_m) e^{-cz}}{\Delta t} \right)^{3}$$

where Δt_m is the matrix transit time, Δt_{ml} transit time at mudline and Δt, the transit time.

4. Normal Compaction Trend Lines

Traditional NCTL-based methods detect the onset and magnitude of overpressure by identifying departures from the "normal" porosity–depth trend. They are effective in basins such as the Gulf of Mexico, where compaction is primarily driven by progressive burial and undercompaction.

Sediment deposited at the surface typically has high initial porosity. As sedimentation progresses, the increasing overburden causes porosity to decrease in a predictable manner. This depth-dependent decrease in porosity and the rocks that follow it have hydrostatic pore pressure. The NCTL is the best-fit linear trend through measurements from low-permeability beds within normally compacted sediments and is associated with hydrostatic, or normal, pore pressure. It is generally established in shallower intervals where sediments are normally compacted. A departure from the NCTL indicates rising pore pressure[1,15]. Experience shows that the NCTL is best represented by a logarithmic function, plotting as a straight line on semi-log paper. In effective-stress transformation models for pore-pressure (PP) prediction, the NCTL's slope and extent are treated as constant, predetermined geological components. Defining the NCTL's slope and extent from petrophysical measurements- velocity, density, and resistivity- is fundamental to converting effective stress into pore pressure (Figure 4)[16]. Accordingly, the key parameter in this prediction method is the rock property ratio observed by established methods, which is determined primarily by the NCTL's slope. Precise delineation of the normal compaction trend is therefore essential for pore-pressure prediction.

A fundamental requirement of all such methods is to establish the Normal Compaction Trend, which describes the decrease in porosity with increasing burial depth under normal depositional conditions. Various soil-mechanical and mathematical models describe the compaction trend, including linear, power, exponential, and polynomial

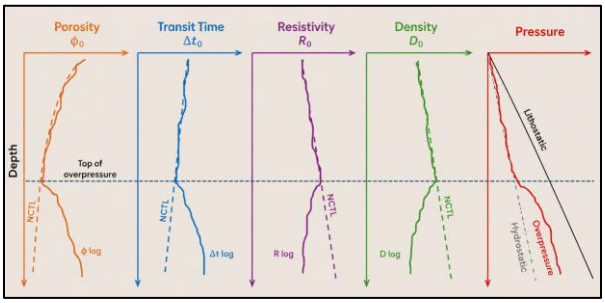


Figure 4: Bulk and transport properties response to burial[16]

functions; these models can differ substantially. Mondol et al. (2007) compiled published porosity–depth trends (NCTs) for shales and argillaceous sediments from regions worldwide[17]. Given this variability, pore-pressure analysts often define the NCT manually, introducing significant human interpretation. Establishing the NCT depends fundamentally on the trend of the input data within the depth interval considered to be normally pressured. In offshore environments, shallow sediments—typically extending 600–1,200 m below the seabed—are generally assumed to be normally pressured unless specific data indicate otherwise. In Figure 5, with velocity on a linear scale for linear and power expressions, the NCTL is questionable, and the deeper part falls outside the primary pressure-generation regime, rendering the evaluation suspect.

Establishing an appropriate Normal Compaction Trend is essential and requires extensive human judgment and geological expertise. An incorrectly defined NCT can introduce substantial uncertainty into the final pore-pressure prediction. Establishing the NCT purely through a statistical approach increases uncertainty in pore-pressure estimation. In contrast, a manually defined NCT based on sound reasoning produces a more robust, reliable, and regionally consistent pore-pressure model with lower uncertainty.

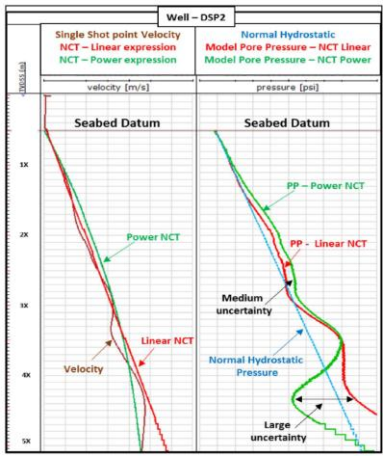


Figure 5: Uncertain Linear-scale velocity plot and below 4X falling outside the purview of NCTL model[18]

4.1 Geological conditions affecting the NCT

Model development requires geological knowledge to understand the relationship between the calibration dataset and the well under prediction. Understanding how geology influences velocity through lithology helps strengthen the model. Geological factors affect the slope and reach of NCT stratigraphy. Younger sediments build pressure and develop faster than older ones. The sand-to-shale ratio affects NCT slope and TOP depth, so shale picks must be selected carefully. Identifying shale points requires a detailed understanding of regional geology and the log signatures of different formations. In clastic extensional sedimentary basins, the interaction between shale/salt movement and sediment weight affects the direction and magnitude of principal stress. This stress can create excess pressure on structural highs while slowing pressure development in structurally lower areas. The slope varies with structure. Wells drilled in intra-basinal areas show slower pressure build-up because of the NCT's low slope gradient. Major faults and unconformities also affect the NCT. Complex burial histories, gas effects, thermal anomalies, and late-stage erosion can undermine the assumptions behind log-derived NCTLs, which underpin most pore-pressure workflows.

Lithological variations, diagenesis, anisotropy, fluid invasion, borehole conditions, and measurement-resolution limits can generate responses that mimic pressure-related anomalies. For instance, a high sonic transit time should not be regarded as evidence of undercompaction without first considering other geological and measurement-related causes. Likewise, a resistivity decline may result from changes in salinity, clay content, fluid distribution, or thin-bed effects, rather than from increased pore pressure[19].

Pore pressure prediction practice includes adjusting or manipulating the NCT slope for calibration, disregarding NCT data where faults are present, and assuming a uniform NCT in specific areas. Instead, apply the following criteria: consider the geological setting; exclude data from very shallow subsurface intervals; carefully determine the top of overpressure; and develop a temperature model to identify where the secondary pressure-generating mechanism begins (Figures 6a and 6b).

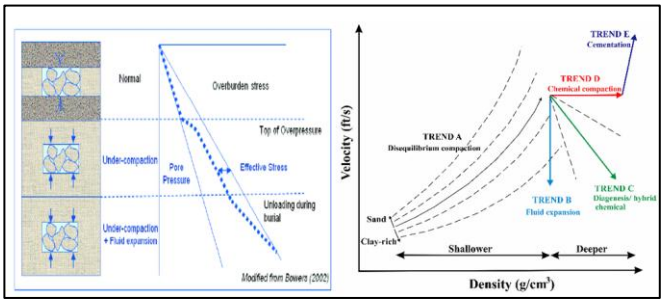


Figure 6 (a): Undercompaction segment of overpressure[20]and (**6b):** Velocity and density cross plot modified from Swarbrick[21]

4.2. Uncertainty related to NCT

Authors such as Bartetzko et al.[22] and Wessling et al.[23] have sought to reduce uncertainty in determining the NCT using statistical and linear regression techniques. In such cases, they attempted to keep the spread between the minimum and maximum velocity values in the input dataset at a given depth as small as possible.

A key step is determining the NCT using offset wells. Formation resistivity can be influenced by salinity, anisotropy, and temperature, so corrections are required when these effects are significant. The NCT may also vary across offset wells(Figure 7). In such cases, use parameters from the nearest well (s) for the real-time well, then refine them using pore-pressure indicators observed during real-time drilling. The slope on the NCT and the TOP at a specific location may be established differently across data sets. Integrating visual plotting with digital data facilitates determining the NCT slope and TOP depth.

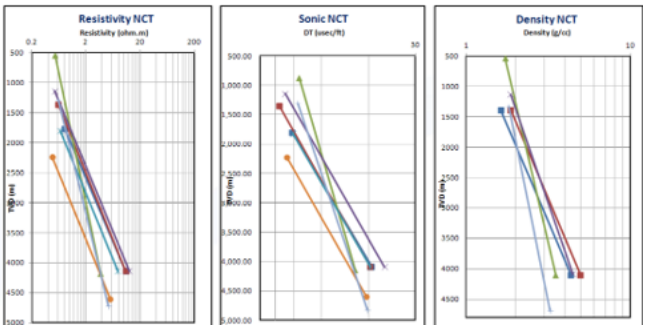


Figure 7: Variation in NCT across the offset wells

Dividing the NCT into multiple segments to match predicted pore pressures with drilling records and pressure measurements taken during and after drilling is another interpretive pitfall (Figure 8). This artificially adjusts geophysical property values for calibration and compromises the effective-stress transformation model.

However, use separate segments when distinct stratigraphic packages have different depositional histories or burial rates; when there are major lithologic changes, such as a transition from marine shale to silty shale, carbonate-rich mudstone, or volcaniclastic material; or when structural domains differ, such as a structural high versus a basinal low.

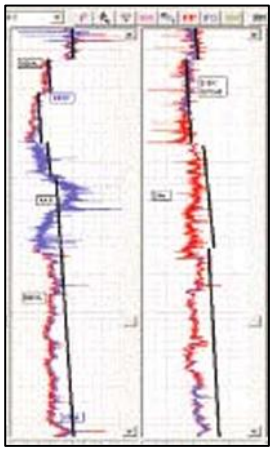


Figure 8: Segmented NCTL[24]

However, using separate segments for different seal or reservoir architectures with distinct compaction and fluid-expulsion histories, or for a clear break in the normally compacted shale trend that persists across several nearby wells or seismic sections, is unwarranted. Treat differences in log response caused by tool or environmental effects as corrections, not geology to be modelled.

4.3. Commonly Observed Technical Deficiencies

Exponential and power-law relationships capture the fundamental behaviour of many differential equations that describe physical processes 25(e.g., Schmidt and Housen[25]; Rainville and Bedient[26]. In the case of compaction, a suitable differential equation can plausibly be derived from physical considerations of the sediment overburden. Compactional pore pressure analysis applies to sequences containing fine clastics and can use parameters such as the d-exponent, sonic transit time, and resistivity. Normally compacted and overpressured intervals can be identified quickly on a semi-log plot. An exponential function appears as a straight line when plotted on linear-scale paper using a semi-log plot. This is achieved by applying a logarithmic scale to the y-axis, which linearises the exponential relationship. The line's slope represents the base of the exponential function, while its y-intercept indicates the initial value. This approach is particularly useful for analysing data that follows exponential growth patterns, such as population growth or radioactive decay. A straight line reveals exponential models on semi-log plots (Figure 9)**.** This is not adhered to in most NCT studies.

Common misconceptions include: A straight line on a semi-log plot does not mean the data is linear. The slope of the straight line is not B itself but the natural log of B. The intercept is not A but the natural log of A. Only the depth axis is linear, while the transport and bulk properties are on a semi-log scale. An example from Mumbai Offshore shows how an incorrect scale can lead to misinterpretation (Figure 10).

4.4. The drawbacks of NCT

NCT-based pore-pressure prediction is widely used and valuable; however, its principal limitation is the strong sensitivity of predicted pressures to the selected NCT. An inappropriate NCT may lead to systematic overestimation or underestimation, particularly in heterogeneous, faulted, or non-compaction-driven pressure environments.

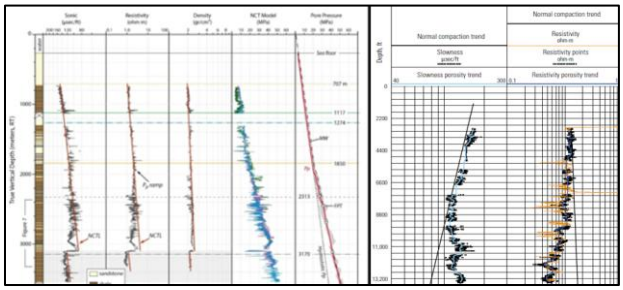


Figure 9: Example of a pore pressure profile defined using NCTL in sonic, resistivity and density logs[27]

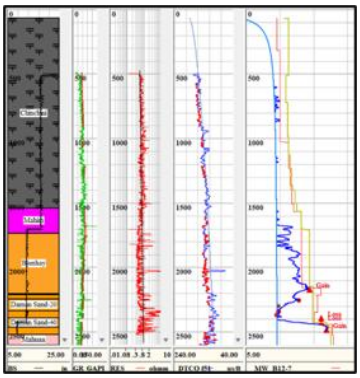


Figure 10: Incorrect deployment of sonic log in a Mumbai offshore well

1) Strong dependence on subjective NCT selection: The NCT is typically fitted to data from "normally compacted" shale or mudstone, using sonic, resistivity, or density logs. In practice, selecting suitable data points, defining the trend slope, and choosing the depth interval can involve substantial interpretation. Even minor adjustments to the NCT may cause large changes in predicted pore pressure, since the estimate depends on the difference between the measured log value and the assumed normal value.

2) Assumes a valid normally compacted reference trend: NCT methods generally presume that formations follow a predictable compaction relationship under normal pressure. This assumption may not hold when sediments have undergone an unusual burial history, uplift, erosion, cementation, dissolution, overpressure, or rapid deposition.

3) Best suited to compaction disequilibrium—not all overpressure mechanisms: The method is most reliable when overpressure results primarily from undercompaction and incomplete fluid expulsion. Its reliability may be lower when pressure arises from tectonic compression, hydrocarbon generation, mineral transformation, thermal effects, or lateral fluid flow. In these cases, a velocity or resistivity anomaly may not uniquely indicate pore pressure.

4) Lithology and facies effects may be mistaken for pressure effects: Sonic velocity, density, and resistivity are influenced by mineralogy, clay content, cementation, organic matter, pore-fluid salinity, and texture. Consequently, a change in log response may indicate a lithological change rather than abnormal pressure. NCT methods require careful selection of comparable shale or mudstone intervals; applying a single trend across different facies can result in significant error.

Mudrocks in many areas are highly variable, with sandstones interbedded with siltstones and pure shale layers. Net-to-gross can be very high in the shallow onshore section of the Niger Delta, which consists of continental deposits. In the middle section, associated with a deltaic environment, shales and sands are present in roughly equal proportions. Deep formations are predominantly shale. These lithologic variations strongly influence rock properties. For instance, higher silt content within a mudrock layer can raise compressional velocity by more than 1,000 m/s and increase resistivity by several ohm-m. Such effects often exceed those caused by pore-pressure variations and can readily obscure them. It is therefore necessary to distinguish lithology-related effects from those associated with pore pressure.

5) Poor performance across faults and structural compartments: A single NCT may not accurately represent formations divided by faults, distinct depositional environments, or different burial histories. Pressure may vary laterally between compartments, yet conventional NCT workflows can impose excessive spatial smoothness or continuity. Structural setting may also influence the appropriate NCT slope and extent.

6) Greater uncertainty away from calibration wells: NCT-based predictions are typically calibrated using measured formation pressures, leak-off tests, formation-integrity tests, mud weights, or drilling events. When calibration data are limited, a model may appear precise despite substantial underlying uncertainty. One study found considerably greater uncertainty in statistically derived NCTs than in a geology-guided NCT.

7) Results depend on the method: Different transformations, including Eaton, Bowers, and equivalent effective-stress formulations, can yield different pressure estimates from the same log anomaly. The selected exponent, reference trend, velocity model, and overburden stress therefore introduce further uncertainty.

4.5 A practical consequence and the most serious risk is false confidence: a smooth pressure profile may look geologically reasonable even when the NCT is wrong. NCT-based prediction should therefore be treated as a calibrated interpretation, not a direct pressure measurement. The options are to work out the impact of geology in the analogue wells, strictly adhere to analysis of geophysical properties using a semi-log plot (an algorithm which can take care of this must be used) and keep a tag on the temperature profile of the area to restrict the depth upto which the method can be applied. As such, the analysis of analogue wells can also lead to an alternative strategy that some oil majors adopt to circumvent the statistical and mathematical uncertainty related to NCTL, which is discussed later in this paper.

5. Effective stress and porosity relationship

Sediment compaction and the associated changes in porosity can be represented by a simple exponential function of depth. Although the porosity solution is derived analytically as a complex function of pore-water pressure, its underlying form approximates an exponential relationship, except near the surface, where it is linear[28]. Despite the analytical simplifications, which omit some detailed effects of sediment lithology, a large global collection of porosity measurements from compacted shales, silts, and sandstones supports this general exponential trend. Because porosity directly measures compaction, Athy[29] proposed the following exponential relationship between porosity and depth (Figure 11):

$$\phi(z) = \phi_0 e^{-cz},$$

where $\phi(z)$ denotes porosity at depth z, ϕ_0 is the porosity at z = 0, and c is a constant.

Subsequently, other modifications to this model were proposed, and the equation was reformulated as follows (Dutta,)[30]:

$$\phi(z) = \phi_0 e^{-k\alpha}$$

It is commonly accepted that formation porosity and effective stress have the following relationship (e.g., Rubey and Hubbert[31]; Dutta[30], Flemings et al.[32], Peng and Zhang[33], Tsuji et al.[34]). Any of these relationships can be used to calculate effective stress from porosity. Pore pressure can then be readily calculated using Terzaghi's relationship[35]:

S = P + σ.

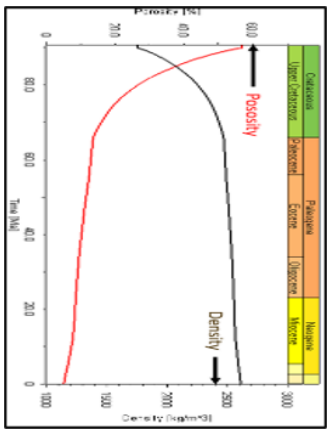


Figure 11 Porosity and Density versus Age/Depth in Tertiary Deepwater[36]

Porosity depends on effective stress and pore pressure, particularly when overpressure results from under-compaction or hydrocarbon cracking. Accordingly, pore pressure can be estimated from formation porosity. Porosity reversal indicates under-compaction and overpressure generation. The point where porosity reversal begins marks the top of under-compaction, or the top of overpressure (Figure 12). In under-compacted formations, both porosity and pore pressure exceed those in normally compacted zones. To reduce ambiguity and improve pore pressure predictions, efforts should focus on the following areas:

1) Improve understanding of the mechanisms governing pore pressure and their relationship to velocity.
2) Identify methods for recognising a formation's compaction history, primarily through geological interpretation and, where useful, multi-parameter analysis as proposed by Bowers.
3) Use experiments to better characterise the normal compaction trend across different lithologies and geological settings.
4) Give importance to the geothermal gradient and construct the temperature profile of the area of interest.

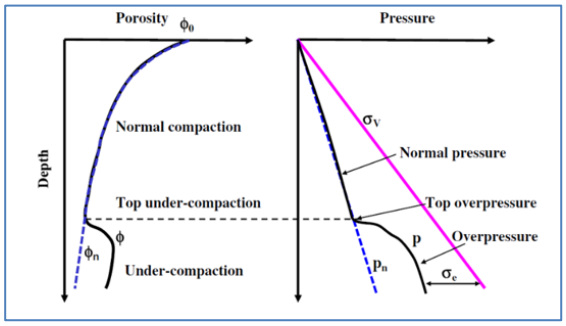


Figure 12: Schematic plots showing porosity and corresponding pore pressure in a sedimentary basin[37]

The normal compaction trend (NCT) associated with mechanical compaction can be described by an exponential or power-law relationship between porosity and depth (Athy[29], Magara[38],Dewhurst et al.[39]. This approach has been successfully used to predict pressure and identify overpressure mechanisms in young, low-temperature formations. Efforts have used porosity data to predict pore pressure in shales and mudstones. For example, Holbrook et al. presented a porosity-dependent effective-stress approach for pore-pressure prediction[40]. Heppard et al. used an empirical porosity equation, similar to Eaton's sonic method, to predict pore pressure from shale porosity data[41]. Flemings et al.[31]and Schneider et al.[42] likewise applied porosity–stress relationships to predict overpressures in mudstones.

Several authors have published porosity–depth curves that vary considerably, particularly in the shallow section of the compaction trend (Figure 13a). Deep shale compaction curves depart from the general pattern of decreasing porosity with depth, especially at shallow depths, where mechanical compaction predominates. This indicates that mechanical compaction is not the sole cause of porosity change and that geological time is another important factor to consider.

Shale compaction is the process by which mud is compressed first into clay and eventually into shale. In sedimentary basins, mechanical compaction generally predominates at shallow depths, whereas chemical compaction becomes dominant at greater depths. Burst was among the first to quantify the effect of time on compaction. Using data published by Manger[43], Burst plotted porosity against geological time and proposed that shale porosity tends to decrease as time, or geological age, increases, as shown in Fig. 13b[44]. In their study, Avirut et al. (2020) reconstructed porosity-versus-time plots from the same Burst and Manger's data sets, while accounting for shale depth, as shown in Figure 14[43].

They were convinced that deep shale compaction curves deviate from the trend of porosity decreasing with depth, particularly at shallow depths, where mechanical compaction dominates. This suggests that mechanical compaction is not the only factor affecting porosity; geological time is also important[44].

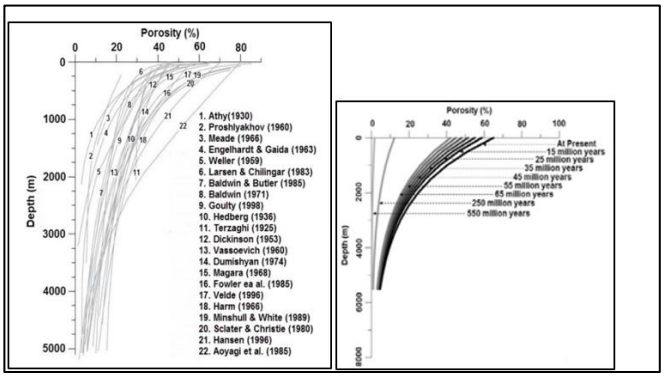


Figure 13(a): Porosity vs Depth[17] and **13(b):** Porosity vs Age[44]

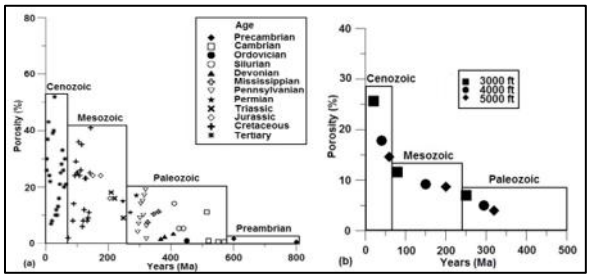


Figure 14: Porosity vs Geologic time plots [45]

6. Shale Trend Construction

Shales are preferred for pore-pressure analysis because their properties and mechanical compaction behaviour are relatively predictable. They are highly compressible: porosity typically decreases from 60–80% at initial deposition to less than 15% under the effective stresses associated with burial, as water is expelled and the rock compacts. Shale is generally the dominant clastic lithology and therefore exerts a major influence on the overall velocity profile in an area. A "shale trend" is generally a shale-specific log trend or baseline used to identify pressure-sensitive shale data points. It is fitted to selected shale- or clay-rich log data to reduce lithological effects and isolate the shale response. The data typically consist of shale-filtered sonic, resistivity, density, or porosity measurements, with shale-like points that are reasonably comparable. However, shale-related variations may arise from lithology, mineralogy, diagenesis, or regional changes-not pressure- unless the analogue data are analysed carefully. In shale-trend analysis, the aim is to identify the low-frequency data trend that reflects rock-compaction behaviour and, consequently, present-day pore pressure. High-frequency variations in the log data are mainly associated with lithological changes.

Pore pressure is predicted in shales because their compaction behaviour is best preserved and most clearly reflected in well logs. A common practice is to estimate pore pressure from shale data and calibrate the predictions against measured pressures in sandstones. Accordingly, low-frequency trends in rock-physical properties, such as acoustic velocity and resistivity, are essential: these shale trends can be used to develop rock-physics models for pore-pressure prediction. This study will apply a rock-physics model to seismic interval velocities at the prospect location to predict pore pressure. To support this analysis, shale trends in sonic velocity must be generated for each key analogue well. Identifying shale

lithology is therefore essential. Two methods are used in this study to calculate shale volume: (a) gamma-ray (GR) cutoffs and (b) the clay grain fraction (FGCL), derived from neutron porosity, density, and gamma-ray logs[46]. FGCL characterises lithology in sand–shale sequences as fractions of quartz and clay, making it useful for quantitatively analysing compaction in a consistent rock type (Figure 15). The calculated shale volume is then used to generate Vp–shale trends (Figure 16).

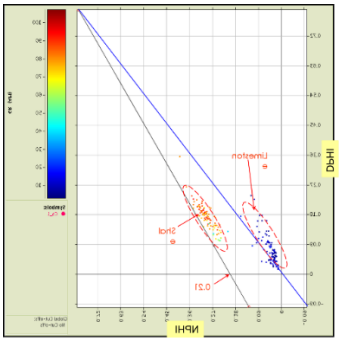


Figure 15: Density-Neutron plot to determine FGCL

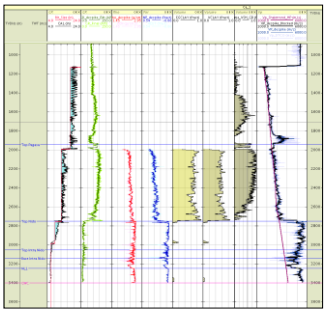


Figure 16: FGCL method to determine clay grain fraction

7. Adopt a porosity-based approach without framing NCT

Gas-charged mudrocks, uplifted sequences, and eroded basins exhibit non-unique porosity–stress relationships, so trendline-based predictions require adjustment to remain reliable. Most porosity-vertical effective stress relationships can be expressed more easily in terms of void ratio. Transform velocity into density using regional Vp- ρb trends, convert density to ϕ, calculate void ratio (ε = ϕ/(1-ϕ)), and then fit a void ratio-VES relationship using an equation from various models. Resistivity can also be transformed from the basic petrophysics. This makes it more physics-based; adaptations are essential for reliable pressure prediction.

A model is set up with the regional data, as in the NCT method. Log data such as gamma ray, compressional and shear velocities, deep resistivity, density, neutron porosity and caliper, along with direct pressure measurements from analogue wells, are gathered and analysed. Hydrostatic and overburden profiles for each of the analogue wells are generated. Shale trends for velocity and resistivity are generated for each analogue. The basic approach to identifying shale picks was detailed by Anjanava et al[47]. Crossplot of void ratio versus vertical effective stress are then generated(Figure 17). Various exponential and power models based on void ratio versus VES models are optimised to identify the best-performing model (Tau, Bowers, Mann Mckenzie[48], Holbrook, Millers[49], etc.). The models are set for the loading and unloading sectors separately (Figure 18). Thus, the best regression model for the area is identified. The preferred model is selected based on minimum residuals, i.e., the smallest difference between the predicted and measured pressures (Figure 19). The approach is ready for application.

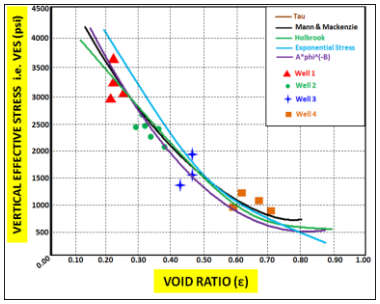


Figure 17: Void ratio versus VES models[47]

During application, identify the shale trend from resistivity and sonic logs for pre-drill and syndrill use. Any VES void ratio model may be applied, with preference given to the model that produces the smallest residuals. Validate the model using drilling and mud gas indicators. Ideally, include a pressure measurement tool in the bottom-hole assembly to support the prediction and optimise drilling.

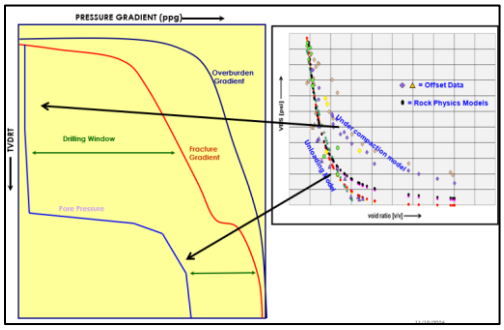


Figure 18: Void ratio versus VES models for both primary and secondary mechanisms

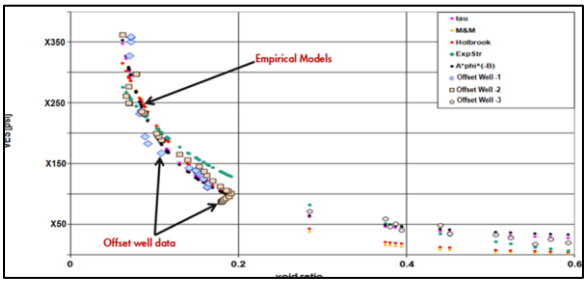


Figure 19: Void ratio vs. VES models: A deepwater example

8. Conclusions

The NCTL-based methodology is more statistical, but it does not fully honour the mathematics involved senso stricto. Confined to the window of the primary pressure-generating mechanism, it neglects the underlying geology and falls short on several occasions, sometimes aided by force-fitting regressions. As the exploration window broadens to the secondary pressure-generating mechanism driven by HPHT conditions, rock physics becomes necessary. Rock-property models predict pore pressure by relating porosity to vertical effective stress (VES). Mechanical compaction affects shales

across a broad porosity range, from high critical porosity (> 60%) to single-digit values. Attributes that partly reflect porosity, including velocity, resistivity, and density, can be used to establish this relationship with VES. Because porosity decays exponentially with age and depth due to vertical effective stress, the void ratio can be related to VES using various models and transformed into pore pressure using the traditional application of Terzaghi's relation. The shale trend encompasses the entire range of stratigraphy being probed, and this methodology has been found to be optimal for robust pore pressure prediction. It is prudent to adopt this methodology, which is sound from a rock-physics perspective and has proven successful in practice.

Nomenclature

HPHT = high pressure high temperature
OBG = overburden gradient
NCT = normal compaction trend
NCTL = normal compaction trend line
TOP = top of overpressure
FGCL = fraction of clay grain log
OP = overpressure
VES = vertical effective stress
PP = pore pressure

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