Causes of disparity between predicted and measured pore pressure

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The term *pore pressure* can be confusing. Pore pressure is *predicted* in relatively impermeable beds (shale and clay) and *measured* in reservoir quality rocks (sand). However, in many occasions, there is not a direct link between the pressure in the sand and in the sandwiching shale. Assuming such an immediacy can lead to serious drilling problems. The relationship between predicted (PPP) and measured (MPP) pore pressure is often complicated and establishing the relationship involves analysis of the geologic setting and expected hydrocarbons. This article will discuss the various causes for differing PPP and MPP and construction of an accurate pore pressure profile.

In relatively clastic young sediments (Pleistocene-Tertiary), porosity indices (e.g., sonic slowness) are widely used to calculate PPP. Prior to drilling, seismic velocities are very helpful in estimating PPP.

In reservoir type rock (sand, sandstone, oolites, etc.), pore pressure is measured using wireline tools and drilling stem gauges. MPP in wet sand usually follows the main hydrostatic gradient in the region as long as the formation water density stays the same. MPP in pay zones follows the gradient of the hydrocarbon which, in turn, depends on the density of the oil or gas column.

The envelope shift in the pressure gradient (PG) between two compartments usually takes place in the seals (shale and clay). Most borehole problems (e.g., sloughing shale, enlarged and backed off-hole) take place when the PG slope changes from linear in the reservoir to exponential in the shale, especially near the seal base. Blow-outs, kicks, flow-kill-breakdown, and loss of circulation problems usually occur along the interface zone between the seal and the compartment below.

The age of the deposits, rate of sedimentation versus rate of accommodation, structural setting of a prospect, and the fault plane lithology juxtaposition play a substantial role in pressure differential distribution in sand versus shale. On the structural crest, MPP usually exceeds predicted pore pressure (PPP). In the trough, it is vice versa. The presence of hydrocarbons, especially gas, usually leads to a significant increase of MPP in the reservoir relative to PPP calculated in the seal.

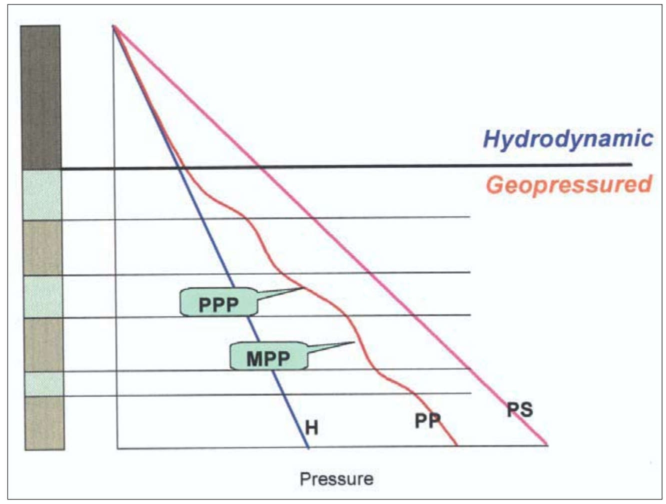

Figure 1. The two main subsurface pressure subdivisions—the normal pressured hydrodynamically active upper section and the compartmentalized geopressured lower section. Hydrostatic, pore pressure, and principal stress are represented as H, PP, and PS, respectively. Pore pressure in the seal and reservoir are PPP and MPP, respectively.

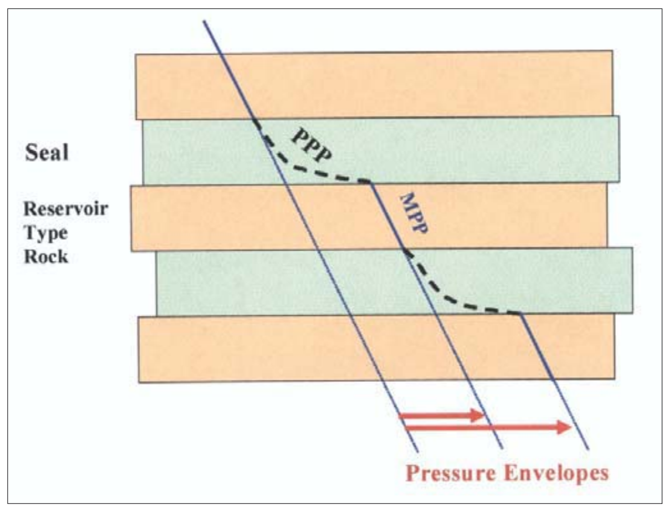

Figure 2. MPP cascade fashion progress with depth in active sedimentary basin.

Concepts and causes. The pore pressure profile in the subsurface is usually divided into two main segments. They are the normally pressured upper section and the compartmentalized geopressured lower section (Figure 1). The upper section is usually open and in communication with the seafloor offshore and groundwater onshore. The fluctuation in sea level and groundwater flows directly impacts the hydrologic behavior of this section. Therefore, hydrodynamic activities dominate this shallow section. Differential fluid flow between high and low permeable beds gives the false impression of the presence of geopressure compartments (Shaker, 2001). This phenomenon is demonstrated in some areas in deepwater as shallow water flows. MPP and PPP (static condition) in this normally pressured segment are supposed to be functions of depth and water density with slight increase due to tortuosity effect.

But, on the contrary, the compartmentalized geopressured system is confined and sealed from the free flow of the upper segment. The divergence between the pore pressure in the shale (PPP) and the pore pressure in the sand (MPP) is a consequence of compaction and entrapment of the formation fluids in the geopressured section. MPP usually exhibits the hydrostatic gradient of the formation fluid (0.46 psi/ft in GOM) and progresses in a cascade fashion with depth (Figure 2). The shift from one envelope to a deeper one across the seal defines the sealing capacity of the interbedded shale. The pressure gradient in the shale tends to follow a higher gradient in the geopressured sealed system. The PPP gradient is usually determined by the PP shift difference between consecutive compartments.

However, on occasion this anticipated cascade-shaped pressure profile (PPP + MPP) changes course and shows progressive and even regressive trends (Figure 3). Several geologic factors (e.g., sedimentation versus accommodation, geometry of deposits, lateral facies changes, and faults) are the driving mechanism behind this phenomenon (Shaker,

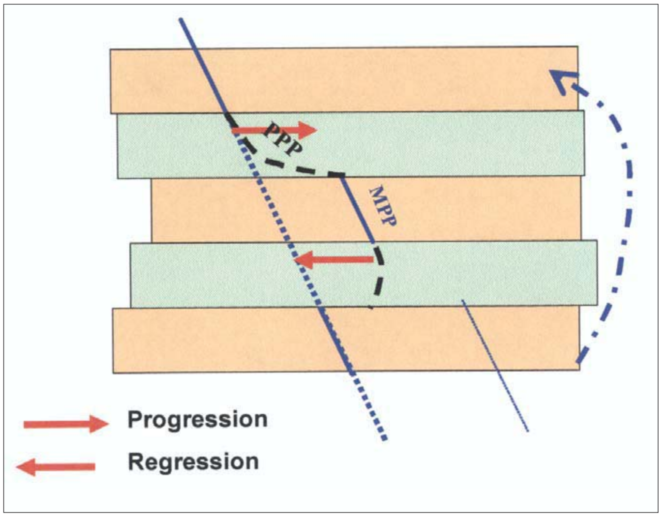

Figure 3. Pressure regression due to communication between the deeper compartment and shallow ones.

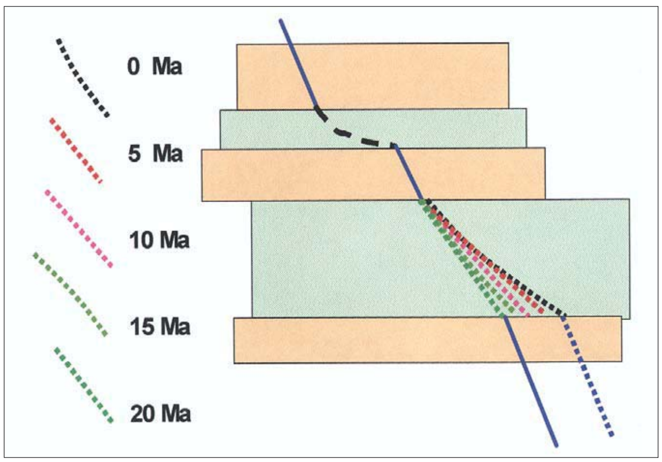

Figure 4. Pressure decay, through the seal only, illustrated over the course of time in a progressive system. Structural failure is not accounted for in this case.

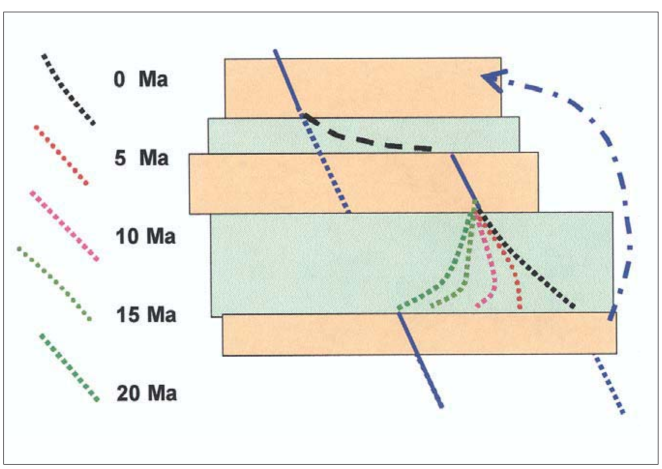

Figure 5. Pressure decay in a regressive geopressure system, over the course of time. The communication passage is the blue dashed line. Notice that MPP and the PPP differences are a function of time. Permeability in the seal dictates the rate of decay.

2002). The centroid effect and the presence of hydrocarbons contribute to the magnitude of this shift.

Pressure decay and sedimentation rate. The rate of sedimentation accompanied by the subsiding of the basin, to accommodate for the influx of sediments, is responsible for the pore pressure acceleration. This is due to the increase of the principal stress (overburden). In active basins where sedimentation rate exceeds or equals the rate of accommodation, pore pressure accelerates with depth. On the other hand, in basins where deposition has been ceased, pressure decay takes place.

The rate of pressure decay depends on the communication between the deeper section and the shallow compartments. The communication usually takes place across the seals and/or through structural passages such as faults, amalgamated sediments and gouge zones. Decay across the seals is very slow and does not cause a great shift between MPP and PPP (Figure 4). In case of structural failure, communication between the deep and shallow compartments leads to pressure regression and accelerates pressure decay in the seals. Therefore, MPP regresses very fast relative to regression of PPP in the shale (Figure 5). The misfit in this case depends on the time lapse between the structural failures and the rate of decay in the seal (permeability dependence).

Geometry of deposits and facies change. In fluvial clastic basins, sediments are deposited in different architectural forms and lithology. They range from mouth bars in the shallow water to basin floor fans in the abyss. High and low sea-level stands play an essential role in the vertical distribution of seals and compartments. This complex facies laid out on a spatial scale in a basin creates zones of communication between amalgamated permeable beds. These breaching zones usually exist at the shallow updip flanks where coarse deposits dominate.

The pressure profile in this case will be represented by a hydrostatic gradient at the shallow section (normally pressured). PP will show a progressive gradient in the upper effective seal (geopressure cap).

As soon as the drill bit penetrates a sand body in this abnormally pressured section, PG returns to hydrostatic gradient. The cascade progressive trend accelerates with depth until the borehole trajectory penetrates a reservoir type rock in communication with a shallower one. As a result, MPP regresses and returns to the same envelope of the shallow bed having the same gradient (Figure 6). The porosity profile usually reflects the pressure behavior in seals.

Fault surface and lithology juxtaposition. Fault displacement contemporaneous to either sedimentation or postlithofication brings different lithologies in contact. In the growth fault system, sand sediment shows substantial thickening on the downthrown side. Therefore, the fault surface exhibits a sealing segment where shale beds obstruct fluid flow from the juxtaposing sand. On the other hand, where permeable beds meet communication takes place.

The fault plane itself can be a conduit depending on the fault surface gouge lithology and the fault capability to sustain the compartmentalization differential pressure, especially if hydrocarbon is present (Neimann and Krolow, 1997; Sales, 1997).

Pore pressure in a borehole on the downthrown side of a growth fault that tests the crest of the successive reservoirs follows the same concept. As depth increases, the progressive behavior takes place where reservoir beds are sealed. On the other hand, where compartments are breached to shallower ones across the fault surface, pressure regression occurs (Figure 7).

Salt-sediment interface. Salt tectonics and its interaction with the surrounding sediments is complex and leads to a variety of salt bodies, ranging from swells to stacked canopies (Jackson and Talbot, 1989). Most intriguing exploration plays are targeting the salt-basins flanks where struc-

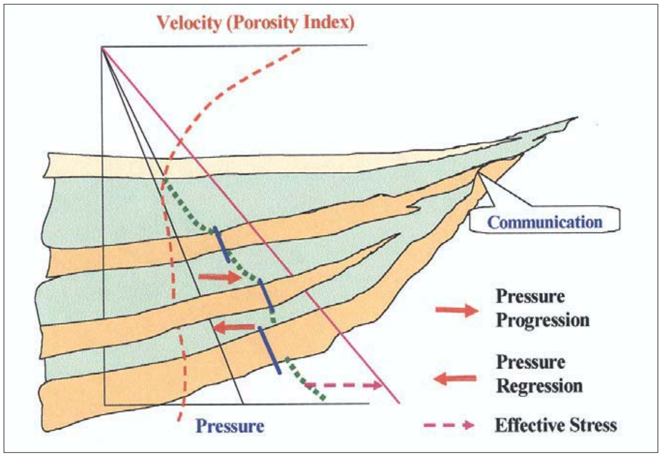

Figure 6. *Cross-section showing the effect of the geometry of deposits and facies changes on the subsurface geopressured profile. Note nonalignment between MPP and PPP at the lower compartment.*

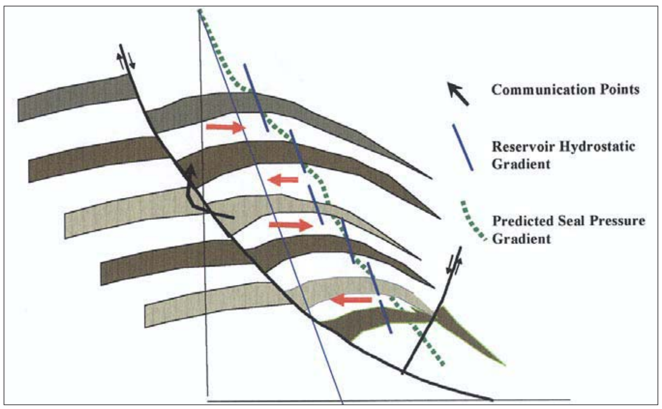

Figure 7. *An example of geopressure profile development due to communication across growth fault.*

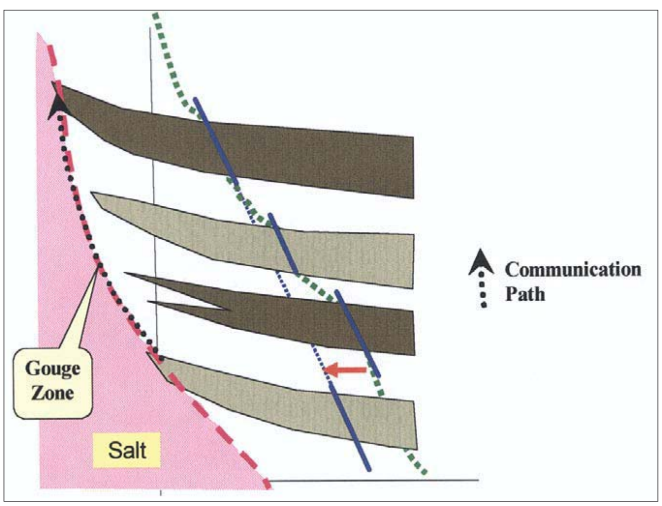

Figure 8. *Cross-section on a flank of salt basin. Communication takes place along the salt-sediment gouge zone. Notice pressure progression in progress with depth where beds are pinched out before reaching the gouge zone. On the other hand, regression and large PPP/MPP difference takes place where structural failure exists and communication occurs.*

tural closures culminate and sediments show multiple onlapping and pinch-outs. Along the salt-sediment interface, dragging and brecciation take place. This gouge interface sometimes acts as a good fluid-flow path. However, when sandy facies pinch out downdip from this interface, a perfectly sealed compartment exists.

The pore pressure profile of a borehole targeting the multiple closures on salt basin flank will follow the same concept. Pressure progression takes place in the geopressured section as long as the salt-sediment interface is sealed. On the other hand, pressure regression happens where sand beds communicate with shallower reservoir-type rocks through the gouged interface (Figure 8).

Centroid effect. The centroid concept (Traugott, 1997) predicts how pressure in the reservoir and the top seal changes due to structural relief. The concept assumes that PPP and MPP are equal at a hypothetical point (centroid) on the structure. The sand subsurface pressure profile follows the hydrostatic gradient whereas seals follow a higher gradient. Updip from the centroid, MPP exceeds PPP at the shale-sand interface depending on the structural gain but downdip MPP exhibits lesser value than overlaying PPP (Figure 9).

This phenomenon can be also explained by considering the overburden difference on high point versus low point on the structure. The low point exerts more compaction than the high point. Therefore, deposits in the low point (sand and shale) are more prone to exert higher pressure than the deposits in the high point. Due to the substantial lateral transmissibility difference between sand and shale, PP in reservoirs equates itself in a very short time. On the other hand, the pressure difference in the shale bed, due to compaction between the structurally high and low points, remains the same.

Drilling the crest of a structural closure leads to the possibility of finding MPP substantially higher than PPP in the top seal (Figure 10). Borehole kicks, well flow, sloughing shale, large size, and back-off wellbore frequently take place at the shale-sand interface zone. Conversely, drilling in a structurally low relief section can result in circulation loss and wellbore and formation damage.

Hydrocarbon accumulation. Hydrocarbons are usually lighter than the formation water except in very heavy oil. The pressure gradient of fresh water is 0.433 psi/ft. The pressure gradient of light oil is about 0.37 psi/ft and about 0.086 psi/ft for gas. These gradients possess a linear trend in permeable reservoir type rock. In oil- or gas-bearing sand, the hydrocarbon gradient overrides the formation water gradient envelopes and inflates the original pressure in the compartment. Due to the new excess pressure generated by the presence of hydrocarbon and the capillary forces, the pore pressure in the cap seal substantially increases, especially at the sand/shale interface (Figure 11).

The inflation of MPP due to the presence of oil and gas depends on their heights and densities. The height of the hydrocarbon column must be measured from the water-oil and/or gas contact. MPP in gas zones is substantially higher than the zones measured in oil-bearing formations. Drilling through the reservoir without advance preparation can be very hazardous. Blow out and hard kicks are frequent events.

PPP in the seal above the hydrocarbon-bearing formation shows accelerated gradient due to excess pressure seepage from below. Drilling troubles in this zone are usually represented by mud cuts and sloughing shale.

Perceptions and calibration. Porosity-effective stress relationship is widely and successfully used to predict pore pressure profiles in young clastic sediments. Petrophysical properties (seismic velocity, sonic, resistivity, and density) are used as porosity indicators in clastic basins. The keystone relationship of estimating pore pressure (PPP) is based on the assumption that effective stress is the difference between the principal stress (overburden) and pore pressure. (Note, effective stress = OB-PP.)