Pore pressure terminology

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Fluid pressures in the pore spaces of rocks are critical to several aspects of petroleum exploration and production. However, a general understanding of some basic concepts has been obscured by a lack of consistency in terminology. It is the intent of this paper to clarify the meaning of certain terms so that the many disciplines involved with, and affected by, pore pressures can communicate effectively and clearly.

A most confusing aspect of pressure terminology arises from mixing the terms for pressure and pressure gradients. The word "gradient" is often dropped when referring to pressure increases with depth. Even when the gradient distinction is made, it can confuse because it can either mean pressure changes referenced from the surface or pressure changes measured over short depth ranges. It is important to understand pressures in absolute terms before beginning to work with gradients.

Please note that the terms "pressure" and "stress" are used interchangeably in the following. They are not strictly the same, but can be so considered for this discussion. (Stress is a tensor while fluid pressure is isotropic.)

Pressure concepts. Figure 1, a very stylized diagram of pressure versus depth for a fictional well, illustrates several concepts. The "hydrostatic" line gives the pressure due to a column of water. The slope would be .433 psi/ft for pure water, but is usually .45 - .465 for formation waters. An important concept is that, for a simple porous rock with pore spaces continuously connected to the surface (i.e. an open system), the pressure of the fluid in the pore space is just the pressure exerted by the weight of the overlying fluids. This "normal or hydrostatic pressure" is simply the pressure due to a column of water.

The "overburden" stress is the pressure exerted by all overlying material, both solid and fluid. Below the water bottom, this line has an approximate slope of 1 psi/ft, but the true slope depends on the density of the rock and tends to increase with depth because rock density tends to increase with depth.

The "pore pressure" is the pressure of the fluid in the pore space of the rock. As suggested in Figure 1, this can be higher than hydrostatic pressure. The point at which pore pressures exceed hydrostatic pressures is the "top of overpressures." In overpressure, fluids are trapped in the pores and bear part of the weight of the overlying solids.

Two definitions are illustrated in Figure 1. First, the amount of pore pressure exceeding the hydrostatic line is termed the *overpressure* (i.e., it is the amount of pore pressure in excess of the hydrostatic pressure for a given depth). Any pressure over the hydrostatic pressure is overpressure.

The second definition is *effective stress*. It is the difference between overburden stress and pore pressure—essentially the amount of overburden stress that is supported by the rock grains.

Another concept implied in Figure 1 is that pore pressure does not reach overburden stress. As pore pressure approaches overburden stress (actually, the least principal confining stress which is usually less than overburden stress), fractures in the rock open and release fluids and pressures.

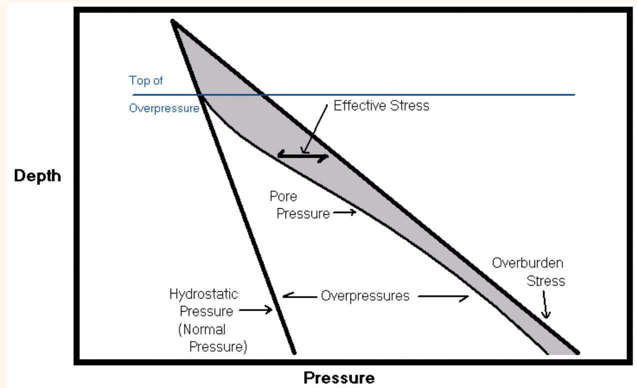

Figure 1. Pressure plotted against depth in a fictional well. Overpressure is the amount of pore pressure in excess of hydrostatic pressure.

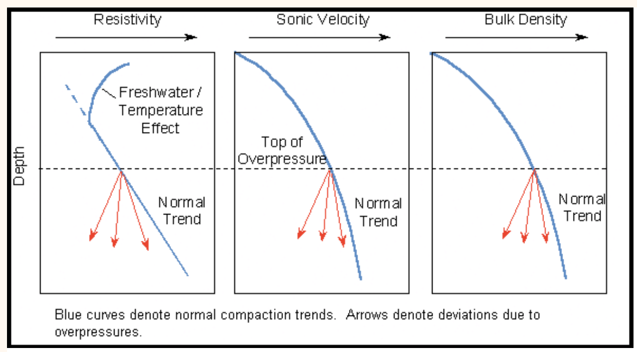

Figure 2. Typical trend curves for resistivity, sonic velocity, and density. Blue curves denote normal compaction trends. Arrows indicate deviations due to overpressure.

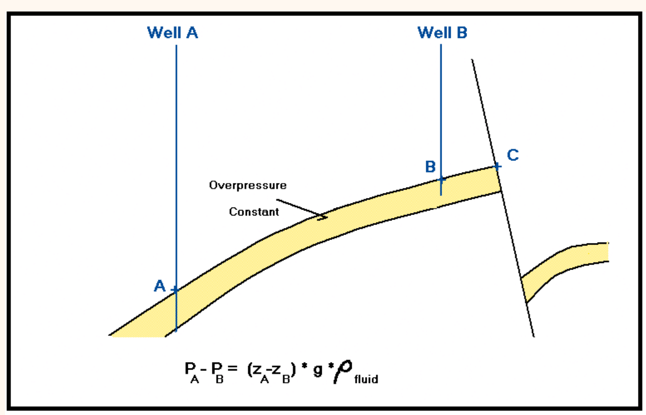

Figure 3. Cross-section of hypothetical reservoir unit. In the absence of fluid flow, the difference in pore pressure between points A and B is simply the weight of the fluid in the vertical reservoir column.

As seen in Figure 1, when pore pressure is normal (hydrostatic), effective stress increases with depth. Laboratory studies have confirmed that effective stress actually controls compaction. It follows that the sonic velocity, density, and resistivity of a normally pressured formation will generally increase with depth of burial. The way that a rock property varies with burial under normal pore pressure conditions is termed its "normal compaction trend." Figure 2 shows typical normal trend curves for resistivity, sonic velocity, and density. (Salinity and temperature effects often cause a resistivity increase near the surface, which is why the resistivity trend is different from that of the sonic and density trends in the shallow section.)

Figure 3 is a cross-sectional view of a hypothetical reservoir unit. It is easy to show that, in the absence of fluid flow, the difference in pore pressure between points A and B is simply the weight of the fluid in the vertical reservoir column. If this fluid is water, pore pressure at any elevation in the reservoir must follow a hydrostatic slope. If the reservoir is overpressured, pore pressures track a line parallel to the normal hydrostatic pressure curve, which means that overpressure at each depth is the same. This is important because it means that overpressure in a continuous reservoir unit must be constant throughout the water-bearing portion of the reservoir.

Figure 4 is a hydrocarbon-bearing version of the reservoir in Figure 3. The differences in pore pressure between points A and C are again simply due to the weight of pore fluids. Below the hydrocarbon/water contact, pore pressures follow a hydrostatic trend, albeit offset from normal hydrostatic pressure. Above the hydrocarbon/water contact, pressures follow a slope that depends on hydrocarbon density. (This slope may be 0.1 - 0.2 psi/ft for gas and 0.25 - .4 for oil.) Because hydrocarbons are lighter than water, the amount of overpressure in the hydrocarbon column increases with elevation above the hydrocarbon/water contact. This extra "boost" in overpressures is the "buoyancy effect." Figure 5 is a pressure profile for a hypothetical reservoir unit such as in Figure 4.

Pressure gradients. Because of its simplicity for some applications, the shorthand of pressure gradients is very useful. However, we need to keep clearly separated in our minds the concepts of absolute pressure and gradients (changes in pressure). We also need to be careful in referring to the reference points for measuring gradients.

A local pressure gradient defines how pressure varies over small depth ranges. At the smallest scale, it equals the slope of a pressure versus depth curve. We have tried to use slope throughout this discussion to mean the local gradient. An example of a local pressure gradient is the fluid density gradient. It is the rate at which pressure varies along a uniform column of fluid due to the fluid's own weight. A conversion factor for local gradients is 1 g/cm^3 = .433 pst/ft

Local gradients are most useful when working with absolute pressure. However, the most basic pressure gradient that we use is *equivalent mud weight (EMW)*. Weight, in itself, does not imply a gradient. If we relate weight to a volume, however, we have density and density does convert to a gradient. When we refer to mud weights as *ten point five* pounds, we mean the mud density is 10.5 lbs/gallon. This is a density. (Sea water is about 8.54 lbs/gal.) A conversion factor for equivalent mud weights is 1 lb/gal = .0519 psi/ft.

In Figure 6, another stylized plot of pressure versus depth, a scale has been added with mud weights. Its utility is that for any depth below the surface, we can derive the pressure of the borehole fluids by drawing a line from the origin through the appropriate mud weight to the depth and get the pressure for that depth.

Without question, expressing pore pressures in units of density is scientifically incorrect. However, from the perspective of drillers and others concerned with planning and drilling wells, equivalent mud weight is a far more meaningful measure of pressure.

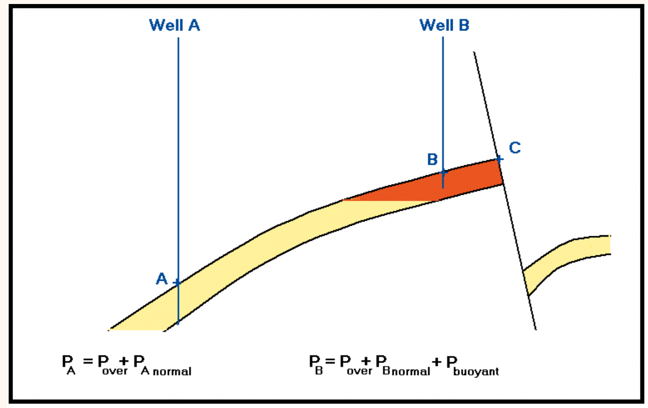

Figure 4. Hydrocarbon-bearing version of Figure 3.

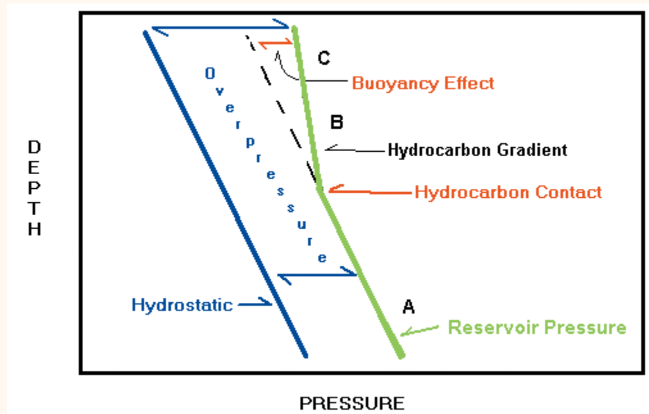

Figure 5. Pressure profile for hypothetical reservoir unit in Figure 4.

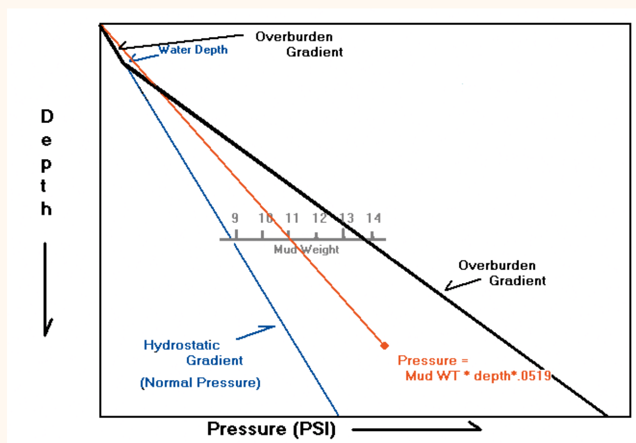

Figure 6. Pressure plotted against depth with mud weight scale added.

For example, knowing a formation has a pore pressure of 4500 psi gives no indication of how difficult or easy it will be to drill. At a depth of 10 000 ft, 4500 psi corresponds to hydrostatic pressure but at 5000 ft it represents substantial overpressure. This becomes apparent when the equivalent mud weights at these two depths are compared:

@ 5000 ft. EMW = 4500/5000 = 0.90 psi/ft = 17.5 lb/gal
@10 000 ft. EMW = 4500/10 000 = 0.45 psi/ft = 8.65 lb/gal

So drillers use mud weight as a fundamental measure. The

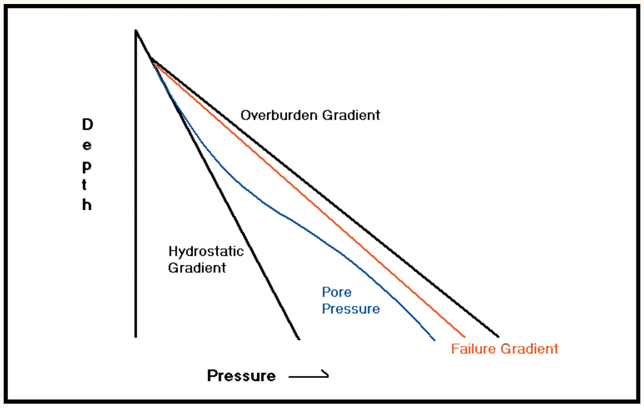

Figure 7. Diagram illustrating pore pressure between hydrostatic gradient and fracture gradient.

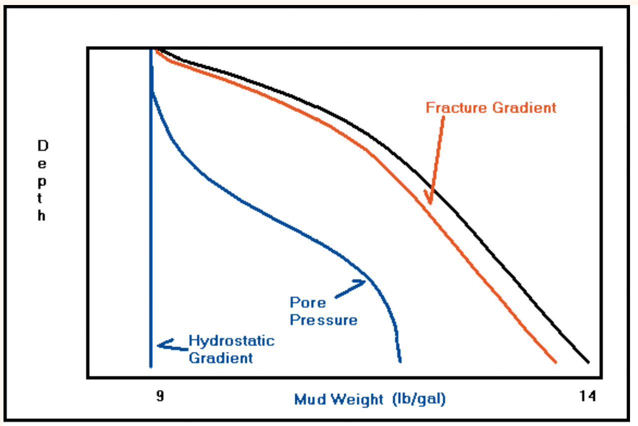

Figure 8. Using mud weight changes pressure axis of Figure 7 to gradient axis. This is the view preferred by drillers.

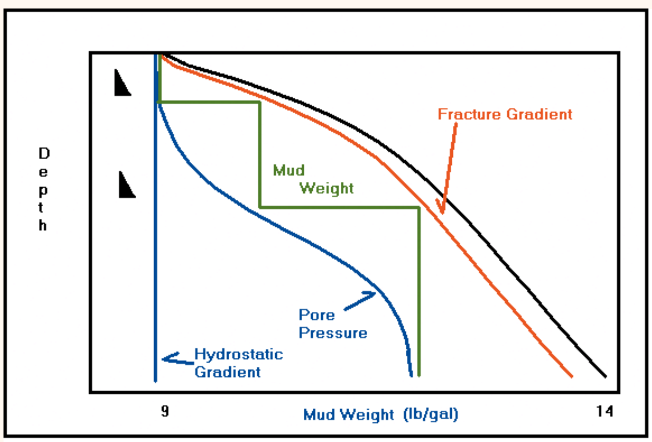

Figure 9. Casing points and mud weight profile for hypothetical situation in Figure 8.

pressures due to mud weight start at the surface and mud weight relates directly to pressure gradient as referenced to the surface.

Figure 7 is a schematic illustrating the pore pressure between the hydrostatic gradient and the fracture gradient. As mentioned previously, pore pressure is bounded on the upper side by the fracture gradient. Just as with pore pressures, if the borehole pressure exceeds the fracture pressure, fractures will form. There is a "window" between pore pressure and fracture pressure for the borehole fluid (mud) pressure. A mud-induced pressure that is too low would allow formation fluids to flow into the borehole and one that is too high may fracture the formation and lose mud into the formation. Either case presents a drilling hazard.

If we recast Figure 7 using the mud weight scale in Figure 6, we can change the pressure axis to a gradient axis. This is the preferred view of drillers (Figure 8).

We must drill with constant mud weights and these have to fall between the pore pressure equivalent mud weight and the fracture gradient equivalent mud weight. Figure 8 shows that there is a window between these two curves. If we were to begin drilling with 14 lb/gal mud, we would immediately fracture the formation, so drilling begins with lower weights. But lower mud weights will not be able to contain pore pressures as we drill deeper. To keep within the window, we drill to a specific depth and set casing. The casing protects the shallower formations from possible fracturing that could be caused by the heavier mud needed to contain pore pressures at greater depths (Figure 9).

Pressures in three dimensions. If we want to more fully understand pressures, we must consider what happens in three dimensions. Within the last several years consideration of pressures in 3-D has significantly improved understanding pore pressure mechanisms and basin plumbing. Such concepts as centroids, unloading, repressurization, and lateral transfer have emerged as keys to pressure prediction.

The centroid concept arose from the observation that shale pressures and sand pressures must follow different local gradients (Figure 10). Because overpressure of a sand is constant, pore pressure must follow a hydrostatic gradient. Shale pore pressure does not. The sand acts as a conduit to transfer pressures updip. At depth shale pore pressures exceed sand pore pressures but shallow sand pore pressures exceed shale pore pressures. The *centroid* is the depth at which sand and shale pore pressures are equal.

The value of the centroid concept is that it emphasizes the difference between sand and shale pore pressures. Most pore-pressure prediction techniques emphasize shale properties such as velocity and resistivity but do not address this essential mismatch of the shale and sand pore pressures. This concept also points out that sands provide a mechanism for vertical and lateral transfer of pressures. As basins subside and dewater, the sands (our reservoirs) provide the mechanism for fluid escape including hydrocarbons.

Figure 11 is a simple illustration of lateral transfer. If one side of a basin subsides and fills with shale, we have the case illustrated. The overburden in the subsided portion is higher and if the burial is sufficiently fast (i.e., the shale can't dewater quickly enough), it becomes overpressured. (This lack of dewatering is the basis for the overpressure mechanism known as disequilibrium compaction.) This may set up the case in Figure 10 in which sand and shale pressures follow different gradients with depth.

In some cases, lateral and vertical transfer of pressures to the updip position may actually reduce effective stress on the sands. If so, the sands go from one compaction state to a lesser one and are "unloaded" by this transfer of pore pressures. Note, however, that porosity reduction and compaction are not simply reversible under effective stress increase and reduction. Hysteresis effects may significantly complicate estimations of sand and shale pore pressures

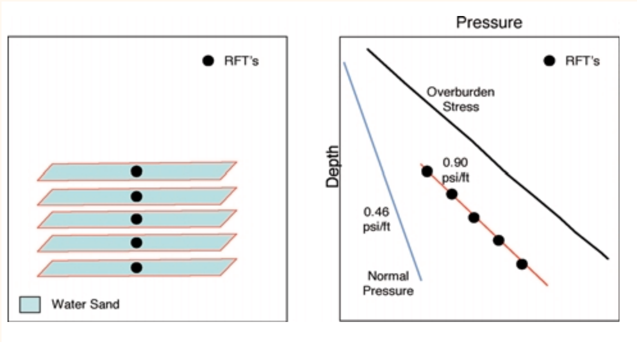

Figure 10. Idealized illustration of centroid concept.

from compaction effects on porosity, velocity, and resistivity. Other mechanisms for "repressurization" similarly complicate pressure prediction.

Conclusion. A few commonly used terms have not been discussed here. There has been, for example, no mention of *geopressure*. This term is often used interchangeably with overpressure, and it has become common to apply this term when equivalent mud weights exceed a certain value. But overpressure itself is not a gradient and should not be confused with one. Another term that has been avoided is "hard pressure." This could be defined as pressures approaching the fracture pressure, but that can cause confusion in other ways. Some have tried to refer to hard pressures as anything requiring 16 lb/gal mud. Unfortunately, deepwater drilling has shown that 16 lb/gal mud might always exceed the fracture gradient. It may be best to keep away from terms that have gained "baggage" through misuse.

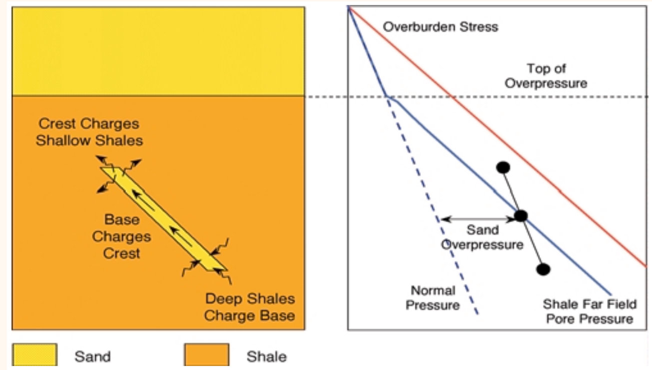

Figure 11. Simple illustration of lateral transfer when one side of a basin subsides and fills with shale. Overburden in the subsided portion is higher and, if burial is sufficiently fast that the shale can't dewater quickly enough, it becomes overpressured. This is known as disequilibrium compaction.

Applying pressure concepts to petroleum exploration and development is the next and significantly more interesting step to understanding pressures and their implications for our work. Much has been done to apply an understanding of pressures to improve drilling safety, to determine reservoir connectivity, and to predict hydrocarbon entrapment and migration. But more work needs to be done and that work will require clear communication between diverse disciplines.

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