Introduction

Failure to control...high pressures can cause an uncontrolled flow of formation fluids...

Highly pressured formations have caused severe drilling and completion problems in almost every area in the world. Failure to control these high pressures can cause an uncontrolled flow of formation fluids (blowout), which can result in extreme financial losses for the operator, possible pollution of the environment, loss of petroleum reserves and potentially unsafe conditions for workers.

Therefore, it is important to predict these high formation pressures before drilling, so that a safe casing and cementing program can be designed. While drilling, it is imperative to detect and safely control pressures, as discussed in the chapter on Pressure Control.

Subsurface Pressures

Subsurface pressures are a result of gravitational forces acting on overlying formations and fluids. This is similar to what occurs in the atmosphere, in which the accumulated weight of the atmosphere causes the air pressure at sea level to be about 14.7 psi. Logically, bodies of water and subsurface formations have a higher pressure gradient due to the greater density of the material from which they are made.

Overburden pressure

Overburden is the volume and weight of all formations and fluids above a given formation.

Overburden is the volume and weight of all formations and fluids above a given formation. The total stress imposed by the overburden on a subsurface formation is called the geostatic, lithostatic or total overburden pressure (P_O), and can be calculated by:

$$P_O = \rho_B \text{ x TVD}$$

Where:
ρ_B = Combined bulk density of the sediments plus fluids
TVD = Total Vertical Depth

Overburden pressure (P_O) is equal to the total pressure from the weight of the sediments (P_S) plus the pressure from the weight of the fluids (P_F) that exist above a particular formation and which must be mechanically supported by the formation or $P_O = P_S + P_F$. For English units, the P_O can be calculated with the following equation:

$$P_O \text{ (psi)} = 0.052 \text{ x } \rho_B \text{ (lb/gal) x TVD (ft)}$$

Where the unit's conversion factor 0.052 is 12 in./ft ÷ 231 in.^{3}/gal.

The relationship between pressure and depth is commonly referred to in terms of a "gradient," the pressure divided by depth. The overburden pressure gradient (P_{OG}) can be calculated by:

$$P_{OG} \text{ (psi/ft)} = 0.052 \text{ x } \rho_B \text{ (lb/gal)}$$

Since sediment bulk densities vary from area to area and with depth due to compaction, bulk density is usually taken as 144 lb/ft^3 (19.25 lb/gal or Specific Gravity (SG) 2.3); therefore, the geostatic or overburden gradient is 1 psi/ft (0.23 kg/cm^2/m). For example, average Gulf of Mexico Tertiary deposits exert an overburden pressure gradient of about 1.0 psi/ft. This is based roughly on the overburden being 20% pore space filled with 1.07 SG water and 80% formation (sand and shale) with an average density of 2.6 SG.

Pore pressure is the pressure of the formation fluids... which must be balanced with mud weight.

The overburden pressure gradient varies, depending on the formation density, percent pore space and pore fluid density. These variables are dependent on historical geological conditions, such as chemical composition and distance of transport of the sediments.

Total overburden pressure is supported by the rock in two ways. The first is through intergranular pressure (P_I), a matrix stress caused by the force transmitted through grain-to-grain mechanical contact. As formations are compacted by the overburden with increasing burial depth, pore water escapes so that pore pressure is equal to the hydrostatic pressure of the pore water density. Pore pressure (P_P) is the pressure of the formation fluids (water, oil and gas) which must be balanced with mud weight. Therefore the total overburden pressure is equal to the sum of the intergranular pressure and the pore pressure (see Figure 1):

$$P_O = P_I + P_P$$

PORE PRESSURE

Hydrostatic pressure (P_{HYD}) is the pressure that is caused by the vertical height of a column of fluid. Hydrostatic pressure is independent of aerial size and shape of the fluid body; pressure at any depth is equal in all directions. P_{HYD} may be calculated mathematically by:

$$P_{HYD}\text{ (psi)} = 0.052 \times \rho\text{ (lb/gal)} \times \text{TVD (ft)}$$

Where:
ρ = Pore fluid density

The hydrostatic-pressure gradient (P_{HYDG}) can be calculated by:

$$P_{HYDG}\text{ (psi/ft)} = 0.052 \times \rho\text{ (lb/gal)}$$

The pore-pressure gradient is affected by the concentration of salt in the fluid density of the column. Typical gradients are:

Fluid	Density (lb/gal)	Pressure Gradient (psi/ft)
Freshwater	8.335	0.433
Seawater	8.55	0.444
Saltwater (100,000 ppm)	8.95	0.465
Saturated saltwater (10 lb/gal)	10.0	0.520
16-lb/gal mud	16.0	0.832

So, depending on the salinity of the water in the depositional environment of the particular geological region, normal pore pressure will have different values.

Normal Pressure

A "normally" pressured formation has a pore pressure equal to the hydrostatic pressure of the pore water.

A "normally" pressured formation has a pore pressure equal to the hydrostatic pressure of the pore water. Since many more wells are drilled in sediments characterized by 8.95-lb/gal saltwater, a "normal" pressure gradient, for the purposes of this discussion, is considered to be 0.465 psi/ft.

Any deviation from the normal hydrostatic pressure environment is referred to as abnormal. High pressures are called geopressures, overpressures or sur-pressures. Low pressures are called underpressures or subpressures.

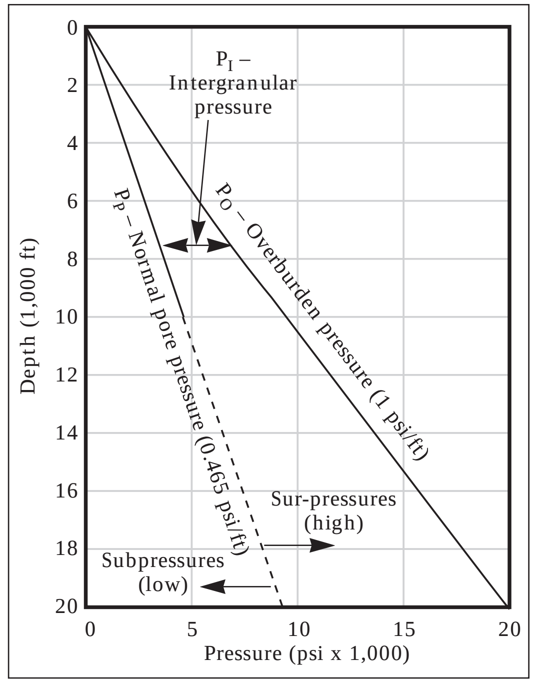

Figure 1: Normal pressure profile.

Abnormal Pressure

Abnormal overpressures are always caused by a particular zone becoming "sealed" or isolated.

Abnormal pressure is caused by the geological processes that have occurred in a given geological area and involves both physical and chemical actions within the earth. Pressures that are lower than what is considered normal can be detrimental and problematic to the drilling process. Conversely, abnormally high pressures are common and can cause severe drilling problems. Abnormal overpressures are always caused by a particular zone becoming "sealed" or isolated.

Seals are impermeable layers and boundary zones that will not permit the release of pressure generated by the percolation of fluids and gases to higher zones and subsequently to the surface. These seals may consist of many rock types: dense shales, calcareous shales, cemented limestone, calcareously cemented sandstone, solidified volcanic ash (tuff), anhydrite and/or others.

It is important to have a basic understanding of the sedimentary processes that result in the formation of petroleum reservoirs and seals. Transportation of debris (boulders, gravels, sands and silts) from higher land masses into oceans has formed the sedimentary basins of the world. Winds and water are the agents in this transportation procedure. A process known as "transfer" fills sedimentary basins via: (1) erosion of rock materials in a source area, (2) transport to a basin principally by water and (3) sedimentation in the sedimentary basin.

The velocity of flowing water at the sedimentation site is the primary determinant of grain size within the deposited sediments. Sand accumulates in the stream channels and along beaches where the velocity of flowing water is sufficient to winnow clay and silt from the sand. Silts and clays accumulate at sites where the water is more quiescent, such as may occur in bays or offshore. Most of the sediment that accumulates in sedimentary basins consists of silt and clays. During long periods of time, beach locations and stream channels migrate and often form sheets of sand that cover large areas. The sedimentary basin fills with sand, which is typically permeable, and shale, which is relatively impermeable. Many basins are filled with alternating layers of sand and shale (see Figure 2).

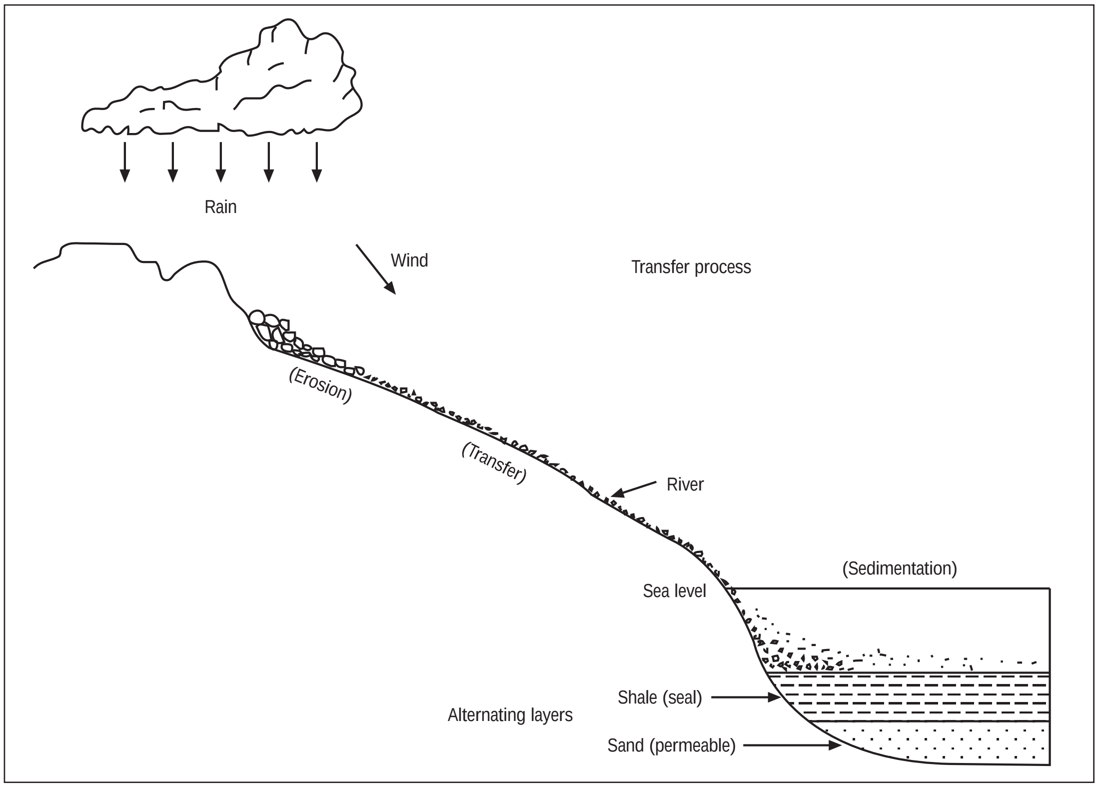

Figure 2: Transfer process and alternating layers of sand and shale.

Subnormal pressures are encountered in zones with pore pressures lower than normal...

Subnormal pressures

Subnormal (low) pressures are encountered in zones with pore pressures lower than the normal hydrostatic pressure. Severe lost-circulation problems may occur in these zones when muds are used in drilling. Subnormal pressure conditions often occur when the surface elevation of a well is much higher than the subsurface water table or sea level. The most common example occurs when drilling in hilly or mountainous locations. Another example is in arid areas such as West Texas, where the water table may be more than 1,000 ft deep. In this instance, the hydrostatic pressure of the drilling fluid exceeds the pore pressure of the shallower formations, allowing the drilling fluid to invade permeable formations. Lost circulation is the result (see Figure 3).

Another common cause of abnormally low pressures is depleted sands. These are sands whose original pressure has been depleted or drained away. Depleted sands are found most frequently in reservoirs from which oil and gas have been produced, a common phenomenon in many so-called "mature" oil and gas areas.

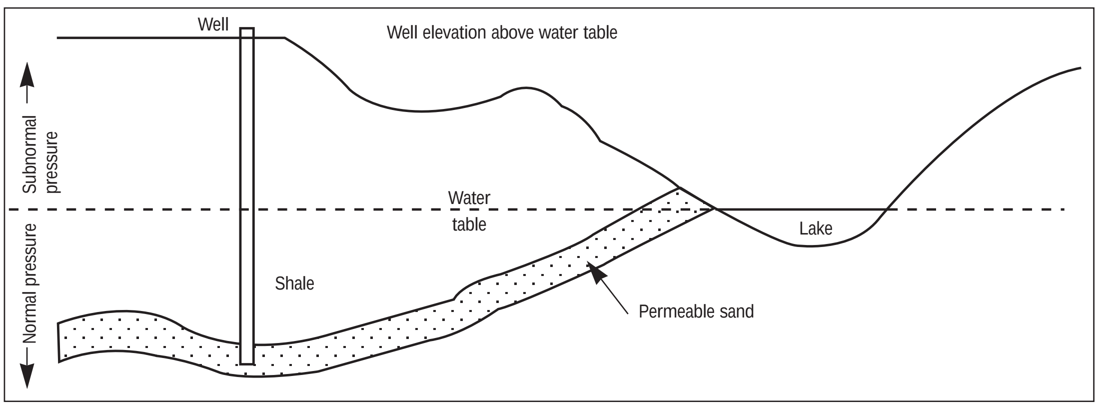

Figure 3: Illustration of subnormal pressure.

Sur-normal pressures characterize those zones that have pore pressures higher than normal...

Sur-normal pressures

Sur-normal (high) pressures characterize those zones that have pore pressures higher than the normal hydrostatic pressure of the pore fluids. The amount of abnormal overpressure that develops depends on the structure and geologic depositional environment. Generally, the upper limit of geopressures is considered to be the fracture gradient or the minimum horizontal stress that may approach the overburden.

Structural, physical and/or chemical processes can cause abnormal overpressure. Complex chemical reactions that take place at the high temperatures and pressures encountered at great depths can cause abnormal sur-pressure. The principal factors that influence the magnitude of sur-pressure are the relative thickness and quality of the seal. Massive formations with strong, continuously impermeable seals develop the highest pressures. However, no seal is completely impermeable. It should be anticipated that during a long period of geological time, the original abnormal zone would eventually become normalized through fracturing, faulting and the migration of fluids.

Geopressures are caused by a number of conditions:

Under-compaction. In the most common scenario, a seal has formed, trapping pore water so that compaction (due to increasing overburden with depth) does not occur as in a normally pressured environment. When the sediments are not compacted enough to form grain-to-grain contact, the overburden is supported in part by the pore pressure, causing abnormally high pore pressure (see Figure 4).

Uplift. One cause of geopressure is the geologic uplifting displacement of a formation, which physically places a higher-pressured formation from a greater depth to a shallower depth. When a previously normal pressure zone at great depth is displaced by tectonic actions to a shallower depth with the seals remaining intact, the resulting pressure gradient will be abnormally high.

Consider a porous sand full of water at an original depth of 10,000 ft, with impermeable shale overlying it as a potential seal. The normal pressure for this zone would be about 4,650 psi (0.465 psi/ft). If rapid uplift — such as massive salt intrusion (or faulting), followed by erosion — causes this sand with the overlying shale seal to be repositioned to a depth of only 5,000 ft, then the hydrostatic pressure gradient at 5,000 ft would be abnormally high

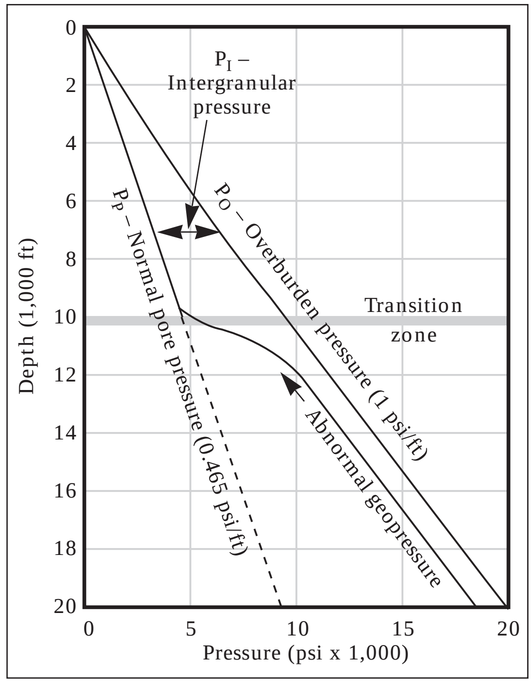

Figure 4: Typical geopressure profile.

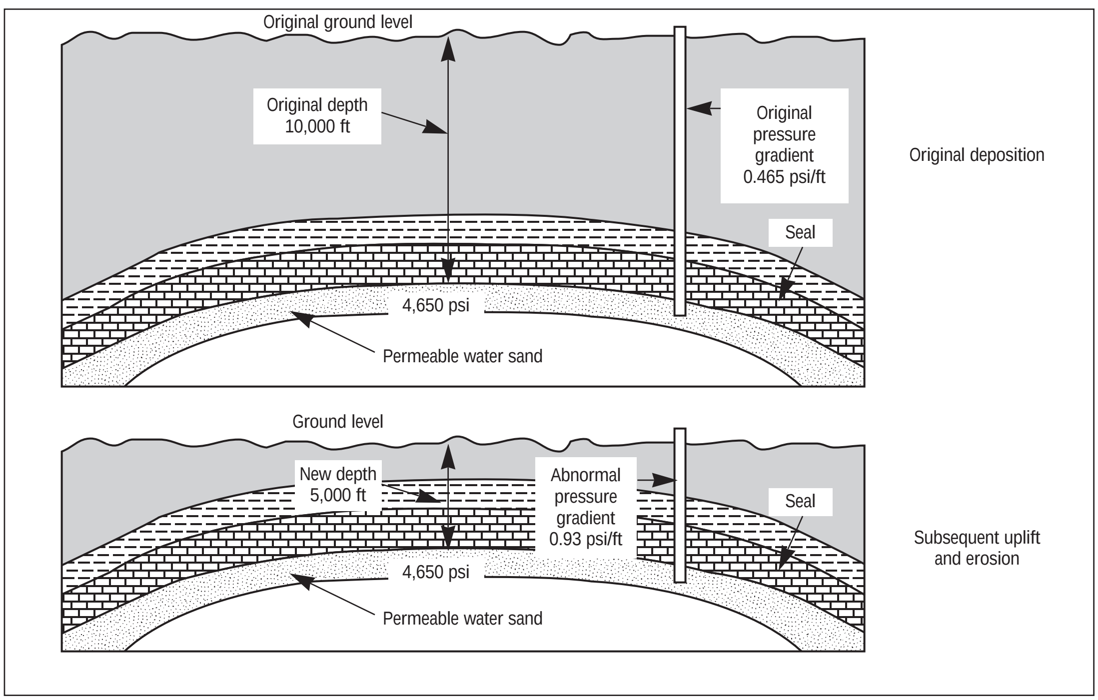

Figure 5: Illustration of vertical displacement resulting in sur-pressure (after Treckman).

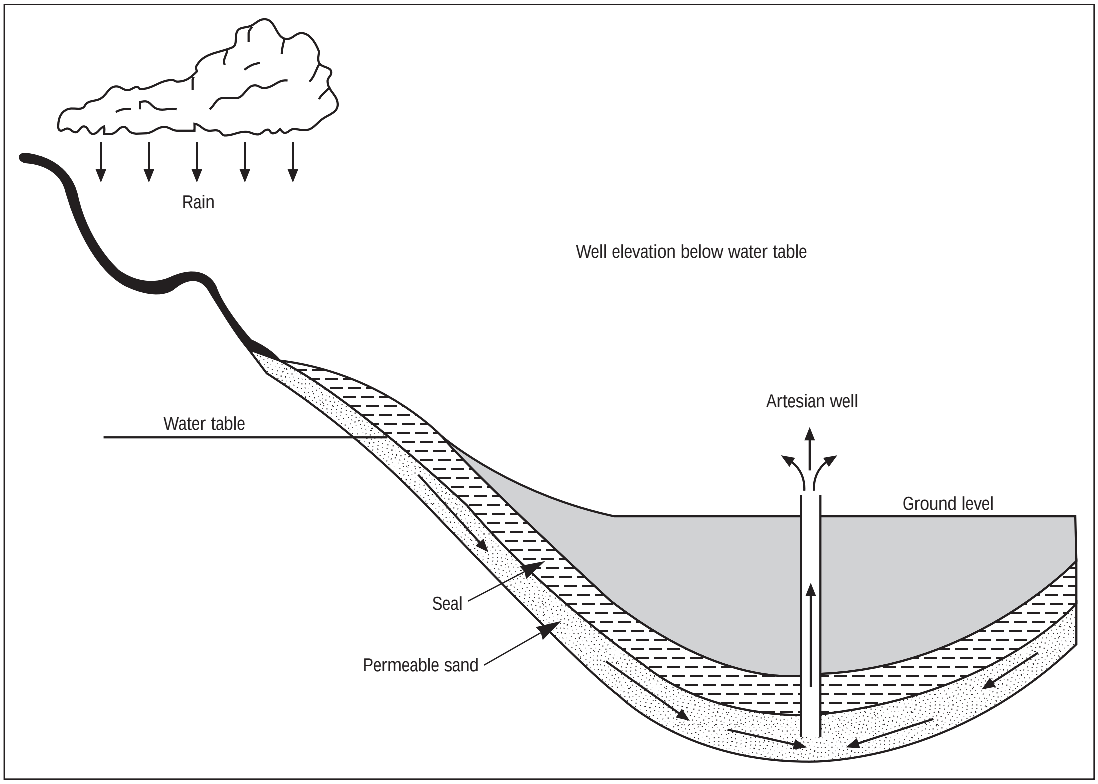

Figure 6: Artesian system results in high pressures.

Artesian systems are… examples of physically originated sur-pressure.

(4,650 psi ÷ 5,000 ft = 0.93 psi/ft), as shown in Figure 5.

When drilling into this zone, it becomes obvious that the density of the drilling mud must be increased to 17.9 lb/gal (0.93 psi/ft ÷ 0.052) to prevent a blowout.

Aquifer. Artesian systems are unique, classic examples of physically originated sur-pressure. In this situation, the surface elevation of the well is below sea level or the water table (see Figure 6). The most common example can be seen when drilling in a valley or basin surrounded by hills or mountains — locations where a connected water table is charged by water from the higher location. Although troublesome, these water flows generally are easily balanced with increased mud weight and can be readily cased off.

Abnormal pressures caused by structural effects are common adjacent to salt domes…

The same principle also applies to structural situations in which permeable formations (or fault planes) — which are highly dipping — allow the pressure transmission from a higher-pressured deep zone to a shallower depth. This is illustrated for isolated sands in Figure 7. Abnormal pressures caused by structural effects are common adjacent to salt domes, where the rising, migrating salt has uplifted

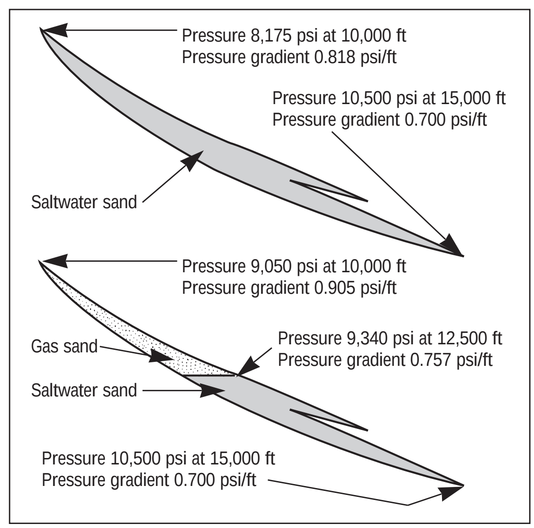

Figure 7: Abnormal sur-pressures caused by the effect of structure on pressure gradients (after Dickinson).

Overpressures can occur in shallow sands if higher-pressured fluids charge them…

Massive shale sections… tend to develop their own seals and chemically caused pressure zones.

the surrounding formations, making them highly dipped and sealing the permeable formations.

Charged sands. Overpressures can occur in shallow sands if higher-pressured fluids charge them from lower formations. This migration of pressured fluids can occur along a fault or through a seal in a network of microfractures. In addition, man-made actions can charge upper sands. Poorly cemented casings, lost circulation or hydraulic fracturing, and underground blowouts all can cause sur-pressures in charged, shallow sands.

Biochemical. Overpressured zones can be caused chemically by several different factors. The simplest is the formation of swamp or marsh gas. This phenomenon is common around the world in recent Tertiary sediments. It occurs as a result of a massive deposition of organic material (such as plants from forest beds and animal matter) being sealed or trapped by a subsequent impermeable zone (generally shales). With time and exposure to higher temperatures, the organic matter undergoes a chemical reaction, producing methane and other hydrocarbons that have a high pressure (see Figure 8).

Sulfate-water. The conversion of gypsum ($CaSO_4 \cdot 2H_2O$) to anhydrite ($CaSO_4$) with increasing depth (pressure and temperature) expels water and may allow overpressures to be present. Conversely, anhydrite that is exposed to water may form gypsum in a chemical-physical bond, which results in as much as a 40% increase in volume. If the anhydrite is sealed and in contact with a water-filled permeable zone, it may become highly pressured as a result of the anhydrite absorbing water and attempting to expand into gypsum.

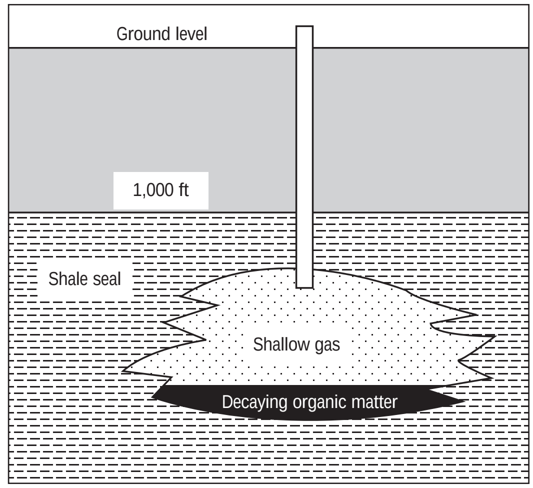

Figure 8: Trapped organic matter forms shallow, high-pressure "marsh gas."

Massive shales. Massive shale sections (several thousand feet thick) tend to develop their own seals and chemically caused pressure zones. The many relatively small seals and chemical actions throughout the total section do not allow a precise delineation of individual zones. The low permeability prevents an accurate measurement of the pore pressure. This will not result in a blowout, but severe drilling problems in the form of sloughing shales and stuck drill pipe can be the result. This stressed, massive shale environment can be stabilized only by increasing the mud weight. In addition, sand lenses in the rich shale section can become pressured, as described in the Shale and Wellbore Stability chapter.

While the upper limit of high pressure is generally assumed to be roughly equal to that of the overburden, or about 1.0 psi/ft, the sur-pressure in some cases actually can be higher than 1.0 psi/ft and is limited only by the quality (permeability and strength) of the pressure seal.

Detection and Evaluation of Abnormal Pressures

...kicks and kill weights are considered to be a good measure and record of actual formation pressure.

Several methods are available with which to predict and detect the presence and magnitude of formation pressures. For proposed wells, some methods use drilling and mud records, electric logs, and formation test data from offset wells previously drilled to predict formation pressures. When drilling, other methods are used to detect the presence and magnitude of formation pressures (see Table 1).

PRIOR TO DRILLING

Mud histories and drilling reports. The traditional method used to recognize the presence of geopressures is to review and compare mud recaps and drilling reports from offset wells in the area. Mud weights give a good indication of both the location and magnitude of the pressures. Any problems such as kicks, lost circulation, differential sticking, etc., will be indicated in the mud recap. The drilling reports will provide more detailed information on the problems encountered during drilling. They also list casing points, bit records and pressure test results.

Sometimes, using mud weights to estimate formation pressure can be misleading. For example, many wells are drilled in an overbalanced condition, with mud weights 1 lb/gal or more higher than the actual formation pressure. Also, in areas of troublesome shales (fractured, brittle or bentonitic), excessive mud weights are used frequently to minimize problems. However, kicks and kill weights are considered to be a good measure and record of actual formation pressure.

Also, since this approach does not consider the stratigraphy of the area, knowledge of the geology is most useful. The information developed from the mud histories and drilling reports should be adjusted to allow for projected differences in elevation, faults, salt domes, etc.

Geologic correlation. In areas where the geology is known but where few or no wells have been drilled, geopressured zones should be expected if a known pressured formation will be penetrated. For example, the Frio, Vicksburg and lower Wilcox formations in South Texas nearly always are highly pressured. Special precautions must be taken in any wells designed to penetrate these formations.

I. Prior to drilling:
- A. Mud recaps and drilling reports from offset wells.
- B. Geologic correlation to similar areas.
- C. Evaluation of offset wireline logs.
  1. Induction (conductivity).
  2. Electrical (resistivity).
  3. Acoustical (Interval Transit Time (ITT)).
  4. Gamma-gamma (density).
  5. Neutron-gamma (porosity).
- D. Geophysical aspects.
  1. Seismic data (ITT).
  2. Gravity data (bulk density).

II. During drilling:
- A. Kicks.
- B. Presence of contaminating formation fluids.
- C. Increase in background and connection gas.
- D. Increase in shale penetration rate.
- E. Change in size and shape of shale cuttings.
- F. Abnormal trip fill-up behavior.
- G. Increase in fill on bottom.
- H. Increase in drag and torque.
- I. Decrease in d-exponent trend.
- J. Decrease in shale-bulk density trend.
- K. Increase in flow line temperature.
- L. Penetration rate/SP correlation.
- M. Evaluation of actual LWD or electric logs.
- N. Paleontology.

III. After drilling:
- A. Drill-stem tests.
- B. Shut-in pressure tests.
- C. Downhole pressure bombs.
- D. Wireline log evaluation.

Table 1: Detection and evaluation of abnormal pressures.

...most log interpretations are related to porosity, either directly or indirectly.

Evaluation of wireline logs from offset wells is one of the most reliable methods used prior to drilling the well.

Wireline logs. The above techniques provide generalized information, but the need for more accurate methods of locating these zones and determining their pressures is self-evident. Evaluation of wireline logs from offset wells is one of the most reliable methods used prior to drilling the well.

Numerous logs are available today to accomplish this purpose. Some logs are more accurate than others because they are less affected by borehole conditions. However, operators in various areas rely on the logs utilized in the particular area for pressure evaluation. For example, the sand-shale sequences along the Gulf Coast are best evaluated with Induction-Electric Logs (IEL). Acoustical logs are used extensively in the carbonates of West and East Texas for porosity determination and correlation (the IEL is rarely used in West Texas because of peculiar formation characteristics).

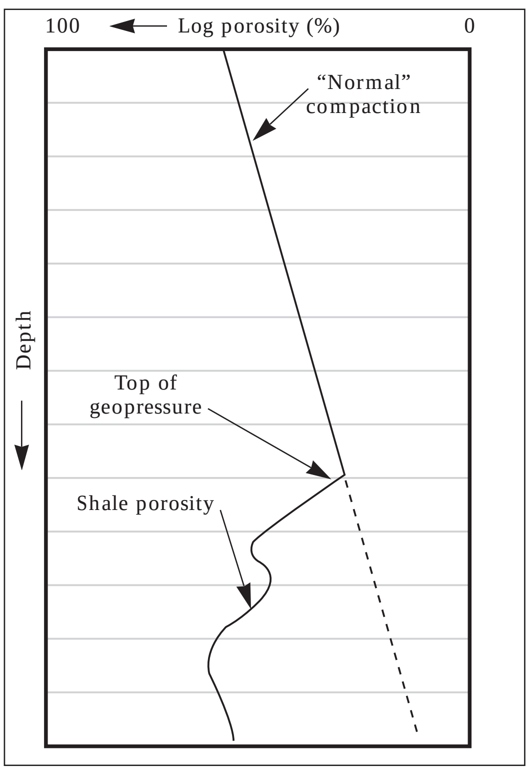

Figure 9: Porosity plot of shale showing "normal" compaction and trend reversal.

In any case, most log interpretations are related to porosity, either directly or indirectly. Shales compact with increasing depth in a very uniform and homogeneous manner. As they compact, the porosity decreases at a uniform rate with increasing depth and overburden pressure. The pressure of a porous reservoir can be estimated from the pressures of the surrounding shales. Intervals or sequences of "clean" shales are best evaluated with regard to porosity changes. However, due to their unpredictability, the porosities of sands are not suited to this kind of evaluation. Carbonate formations also are difficult to interpret based on porosity.

In a normally pressured environment, sediments are compacted as the increasing weight of the overburden squeezes out the connate water. Thus, the porosity (void space) decreases with depth. Under abnormal conditions, the water is not allowed to escape, and the compacting process is altered. The porosity no longer continues to decrease and, in most cases, will increase below the top of the geopressured zone. This often is referred to as the "top of the geopressure" or the "transition zone" (see Figure 9). Experience has shown that the normal compaction trend is best illustrated by a logarithmic function and will plot as a straight line on semi-log paper.

Hottman and Johnson first recognized that the degree of compaction could be estimated from log-derived shale resistivity. The overpressured shales are more conductive to electricity (have lower resistivity) because they contain larger volumes of saltwater than a normally pressured shale would at the same depth. Resistivity is the inverse function (1/1,000) of conductivity. A decrease in resistivity can be identified by the corresponding log response on the IEL (see Figure 10).

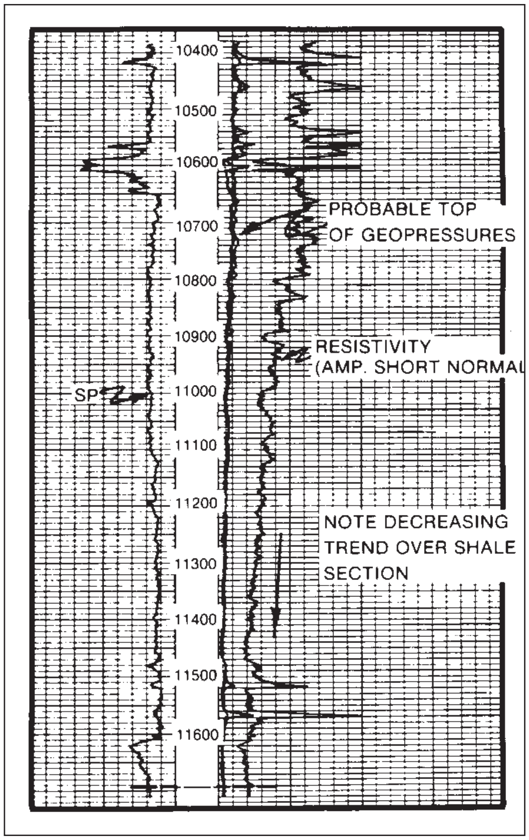

Figure 10: Electric log showing decreasing trend of shale resistivity in the top of a geopressured zone.

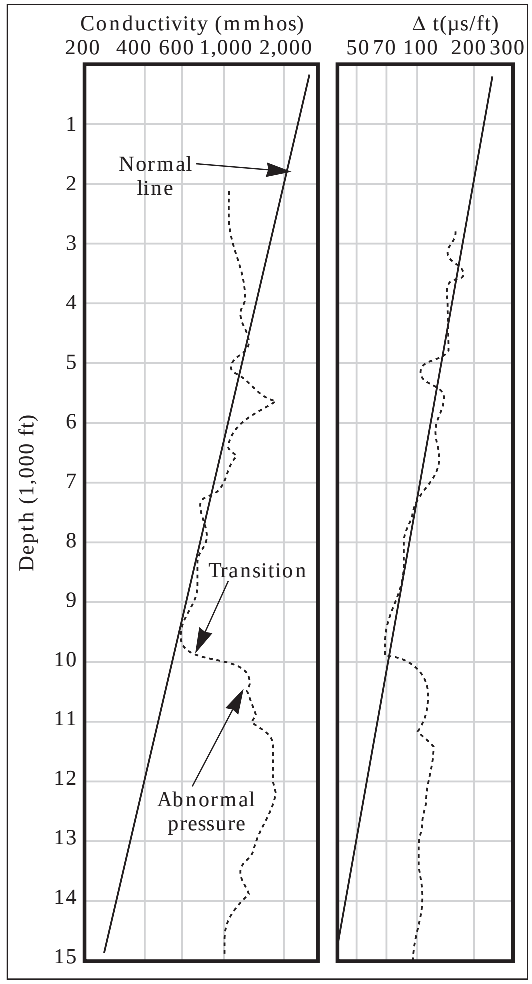

Figure 11: Shale conductivity and interval-transit-time plots for a geopressured South Texas well.

Either shale resistivity or conductivity values can be plotted vs. depth on semi-log paper to determine the presence of the pressured zones. For example, in Figure 11, there is a single trend line shale conductivity plot for a South Texas well. The formation pore pressure can be estimated from the departure of the measured values from the normal trend, as shown below about 10,000 ft. Also shown is a similar plot for an interval transit, or acoustic porosity, log.

The method for predicting shale resistivity/conductivity pore pressure from logs is the most popular for the Gulf of Mexico, due to the large volume of available offset data. Unfortunately, a number of variables affecting shale resistivity (other than compaction) can reduce the accuracy of the plot: (1) salinity, (2) matrix material or mineralogy, (3) temperature, and (4) wellbore conditions (mud type, filtrate, etc.). Modifications have been made in attempts to compensate for these variables and the inaccuracies they cause. The most logical approach to solving this problem was developed by J. Gill and involves plotting enough points to recognize these variables by the resulting shift in data, then shifting the trend lines accordingly. This procedure also can be used when plotting acoustic logs.

The acoustic velocity log is a porosity tool that is only slightly affected by wellbore conditions.

The acoustic velocity log is a porosity tool that is only slightly affected by wellbore conditions. It uses a two-receiver technique to compensate for deviations and is commonly called a "borehole-compensated" acoustic velocity log.

Acoustic tools measure in microseconds, the time it takes for sound to travel...

Acoustic tools measure in microseconds, the time it takes for sound to travel a specified distance. Sound is transmitted through pure substances at known velocities. If the substance is not pure, the constituents affect the interval transit time. For example, a pure shale (0% porosity) transmits sound at approximately 16,000 ft/sec or 62.5 microseconds/ft. If the porosity increases from 0 to 30% and the void spaces fill with seawater, the velocity drops to 12,700 ft/sec, and the interval transit time increases to about 103 microseconds/ft.

In the normally pressured section, the shale-interval transit time will follow a decreasing trend as the porosity decreases. When the top of the geopressured region is encountered, the trend will reverse (see Figure 11). Even though the acoustic log provides more accurate raw data, such logs are not readily available in many areas along the Texas/Louisiana coast, so the conversion method is less reliable than the induction log.

A less common log, the density log (or gamma-gamma), measures the bulk density of the formations in place. Although designed to estimate porosity and lithology for formation evaluation, the density log provides an excellent correlation to the normal/abnormal compaction of shales.

In a density log, the source irradiates the formation with gamma rays. These rays react with the electrons surrounding the borehole and are back-scattered. A detector in the tool records the intensity of the back-scattered rays, which varies with the bulk density of the rocks surrounding the borehole. The readings should be compensated to reflect hole-size irregularities and mud-cake thickness greater than ¼ in.

Since the bulk density of abnormally pressured shale is much lower than the density of normally pressured shale, a gravity survey is often used to detect such zones. Although limited by an inability to distinguish between shale and salt masses, other geophysical methods such as seismic refraction permit differentiation.

Pore-Pressure Plotting

Pore-pressure plotting involves picking the resistivity, conductivity or interval-transit-time values for shale from an electric log and evaluating the data against a normal slope trend line. This technique allows the mud weight to be estimated from the deviation in resistivity from the normal trend line (see Figure 12).

Current pore-pressure plotting methods use computer-assisted techniques that differ from traditional procedures in several ways. First, more points are plotted, and second, multiple trend lines are allowed if there is adequate evidence to support a structural change in geology. Keep in mind that the multiple trend line method is difficult to use properly because it is difficult to distinguish between increasing pressure and a true structural change in geology — which shifts the trend line. M-I's pore-pressure plotting computer program is named LOGPLOT.™

Trend lines or "overlays" were developed to reflect changes in the average slope...

Previous pore-pressure plotting methods were done by hand. Values from electric logs were picked and plotted on semi-log paper; then, a transparent "overlay" was placed on top of the trend line to estimate the magnitude of the abnormal pressure increase from the normal pressure trend line. With current computer-assisted techniques, for a typical 10,000-ft well, 200 to 250 data points can be plotted easily, compared with the 10 to 30 data points traditionally accomplished by hand. The multiple compaction trend lines approach allows for each geologic age and fault sequence to be evaluated with its unique slope, instead of only one trend line for the entire interval. This is particularly important when plotting logs from wells in which formations of more than one geologic age are penetrated. Prime examples are wells drilled in deepwater offshore environments, where abnormal pressures are often encountered in formations of the Pleistocene and Pliocene geologic age, as well as those of the Miocene.

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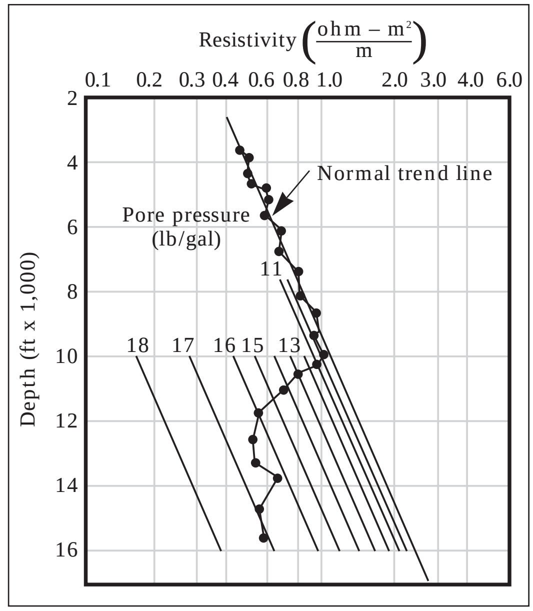

Figure 12: Pore-pressure plot.

Trend lines or "overlays" were developed to reflect changes in the average slope of the normal compaction trend by the geologic age of the formation. These overlays also reflect the pore pressure calibration by the spacing of the mud weight gradient lines for a particular age. If a formation (such as older, harder or more calcareous rocks) is deposited over a relatively long period of time, the increase in formation compaction with depth is moderate. This results in a moderate or more nearly vertical slope of the normal compaction trend line. The more rapidly deposited, loosely consolidated marine sands and shales are compacted at a more rapid

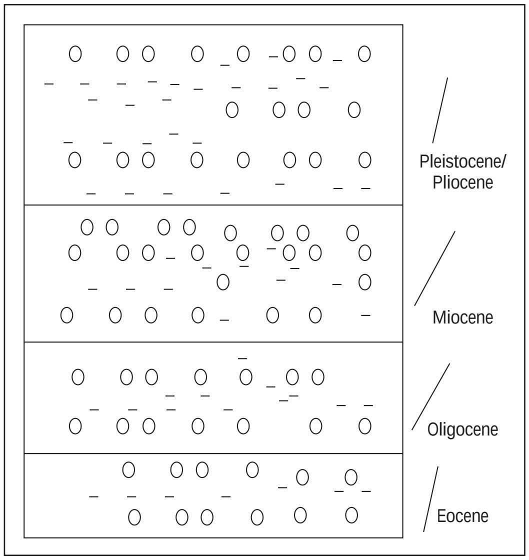

Figure 13: Trend lines for different geological ages.

rate with increasing burial depth. This results in a greater slope of the normal compaction trend line from vertical (see Figure 13).

These compaction trend slope changes for each geologic age can be seen in the published work of Matthews and Kelly, which was based on many wells along the Louisiana and Texas Gulf Coast, and is still considered the most reliable method for estimating pore pressures from well logs. Some who have plotted logs from many parts of the world are of the opinion that the slopes for the normal compaction trend lines, which Matthews and Kelly established for each geologic age, are repeated consistently throughout the world in their respective geologic ages.

Tips for pore-pressure plotting

1. Plot shale-resistivity, conductivity or interval-transit-time points every 25 to 100 ft or wherever a significant change in these values occurs. Pick mainly "clean" shale values — do not plot sands or "dirty" shales.
2. Plot high and low log values — do not average.
3. Plot shale points that appear to be abnormally high or low.
4. Plot shale points that are adjacent to sands.
5. Also, plot even thin shale points that are in the middle of large sand bodies, but flag them as being in a sand.
6. Plot points from limey caps.

Be sure to use the proper geological age trend line or overlay. There are several ways to identify the various geological ages and determine the proper overlay(s) to use. Some of these are:

1. Know the area in which the well is being drilled, which includes the Compaction Trend Sequence.
2. Note geological markings, such as formation tops, etc. on the log (if marked).
3. Obtain the formation tops from the geologist.
4. Verify that the slope of the plotted log data is parallel to the normal compaction trend line of one of the overlays.
5. Relate paleo markings on the log (if marked) to the Paleo-Stratigraphic column for the area. *CAUTION: In deepwater Gulf of Mexico environments, where the upper Miocene consists mostly of rapidly buried sands, fossils may not exist, since fossils are formed in shales. Therefore, if the top of the Miocene is picked from paleo data alone, this could result in picking the top of the Miocene much lower than it actually is. For this reason, comparing the compaction slope of the Miocene normal line on the overlay to the compaction slope of the data points on the plot is often more helpful in picking the top of the Miocene.*
6. Identify general shale types:
   - Pliocene — Alternating sand/shale sequences, but mostly sand. Resistivity is usually greater than 1.0 ohm meter.

- Miocene — Alternating sand/shale sequences with resistivity less than 1.0 ohm meter.
- Frio — High resistivity, limey shales.
- Vicksburg — Low resistivity, steeply compacting argillaceous shales.
- Wilcox or hard rock — Very high resistivity (usually greater than 5.0 ohm meter), sandy shales with low rate of compaction.

7. Use a trial-and-error fit along with mud weight used (i.e., a Miocene overlay placed over widespread Pliocene data points would indicate high pore pressures, when the interval may have been drilled with a 9.0- to 9.5-lb/gal mud weight. On the other hand, a Pliocene overlay placed over more-tightly spaced Miocene data points would indicate very low pore pressures when 12.0-lb/gal mud may have been required to drill the interval.)
8. Match known pressure points such as Repeat Formation Tests (RFTs), Drill-Stem Tests (DSTs), kicks, production and reservoir data, etc. Use of production and reservoir data is the most reliable method for determining formation pore pressures. Formation pressures calculated from shut-in drill pipe pressure readings from a kick also should be considered reliable.
9. Label limey caps or major sand bodies help pick positions of compaction trend lines and separate shifts from one geologic age or shale to another.

Transparent conductivity/resistivity overlays are designed to interpret conductivity plots with the printed side face up. Since resistivity is the inverse function of conductivity (1/1,000), the conductivity overlay should be turned face down to interpret resistivity plots. Interval transit time overlays should be used with the printed side up.

1. The properly selected overlay should be used in a precisely vertical position relative to the plot. This can be achieved by aligning the vertical margin of the overlay with any vertical line on the plot paper. This keeps the slope of the normal line on the overlay at the proper angle, which provides a more accurate plot and also helps differentiate between various geologic ages. Exceptions to this are directional wells, in which the vertical border is tilted as marked on the overlay to correspond with hole deviation from vertical.
2. When selecting the placement for the normal compaction trend line, slide the overlay to the left or right over the plot, maintaining its vertical orientation until the normal compaction trend line passes through the most likely compaction trend for a given interval.

   Look for small zigzag inflection points in near-equilibrium with one another, which follow a straight trend line of the proper compaction slope. In placing the trend line, avoid the large excursions on the plot. The more of these short, slightly different data points plotted, the more accurate the trend line placement will be.

   Look for shale data points immediately adjacent to, or stringers within, permeable sand bodies. These points often approach the normal trend line. Avoid extremely high or low values caused by saltwater or hydrocarbons within the adjacent sands.
3. Since plotting pore pressures from well logs is not a direct measurement of pore pressures, the interpretation should always be verified.

Compare the plot to the mud weights used to drill the well, since such mud weights are not always in agreement with the actual formation pressure. A significant disagreement should be accompanied by an explanation of the difference, when the data is available. Experience shows that most operators drill near-balanced to around the transition zone above geopressures, but overbalanced below that point. This overbalance usually is the result of overreacting to drill gas expansion at the surface. This gas can come from a sandy interval that has a pore pressure no greater than — and in some cases less than — the previous shale sections drilled. In such cases, the increase in mud weight is unnecessary.

The plot can reveal reasons for drilling and hole problems when such problems were caused by pore-pressure changes that were not balanced immediately by mud weight changes. These problems may include drilling breaks, kicks, connection gas, sloughing shale, hole enlargement, tight hole, bridges, fill, lost circulation, differentially stuck pipe, etc.

Plotting pore pressures from well logs is not a direct measurement of pore pressures, but an interpretation of pore pressures based on normal shale compaction vs. undercompaction. It is, at best, technology that includes considerable freedom of interpretation.

Advances in Pressure Prediction from Seismic Data

Seismic data can be converted to interval transit time...

Seismic data can be converted to interval transit time by using any of a variety of sophisticated computer techniques. The resulting data is very similar to that of an acoustic log. After velocity analyses have been constructed and interpreted satisfactorily, the interval velocities can be calibrated into pore-pressure gradients or mud-weight equivalents (see Figure 14).

Fundamentally, the techniques for analyzing and interpreting logs to evaluate formation pressures have changed little over the years, whereas the procedure for manipulating both sonic and seismic data has undergone substantial improvement. These advances are attributable mainly to advancements in computer processing and sophisticated diagnostic software. So, well planners no longer have to rely entirely on paper logs to determine shale conductivity, resistivity or sonic interval-transit-time values — key elements in the evaluation of pore pressures. Today, both proprietary and commercially available software packages deliver logs in electronic digital file formats, making it faster and easier to determine pressures

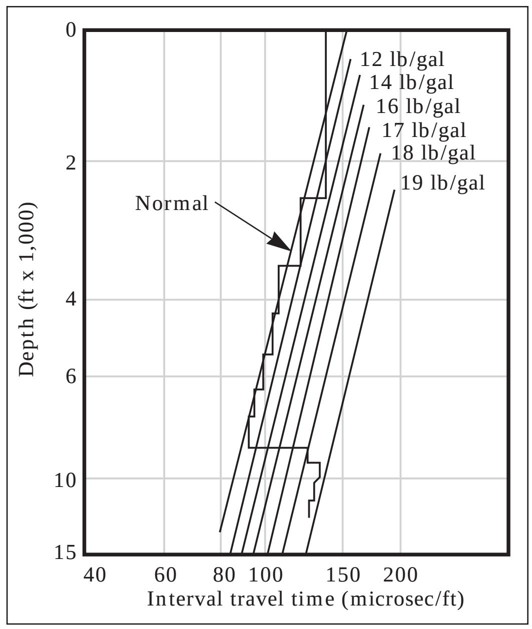

Figure 14: Evaluation of abnormal pressure from seismic data (after Pennebaker).

and fracture gradients for either an entire wellbore or selected intervals.

Pore pressure evaluation is an essential component of every aspect of well planning...

Pore-pressure evaluation is an essential component of every aspect of well planning, from determining wellbore stability to confirming the existence of trapping mechanisms. The advent of sophisticated and universally available

Sonic-oriented geological and geophysical personnel use values in terms of average velocities, while drillers think of mud weights and pressures.

electronic programs enables operators to filter log data to examine a specific interval of the well or compress the information to provide a comprehensive look at the entire wellbore. By so doing, it is possible to estimate the pressure and fracture gradients. Consequently, it becomes much easier to select mud weights that will be sufficient to control pore pressure but not exceed the fracture gradient.

This dramatic evolution in electronic information technology is particularly beneficial in deepwater exploration, where the formations are much younger and not as compressed as their shallow-water counterparts. In deepwater projects, the forces bearing down on the formations differ significantly from those in shallower waters, thus rendering tried-and-true methods of pressure determination invalid. For example, since the fracture gradient value is always below that of overburden, it was generally accepted in the past that in the shallow-water Gulf of Mexico, the overburden gradient was 1 psi/ft of water depth. Owing to the particular dynamics of deepwater wells, however, that rule-of-thumb is invalid.

With advances in electronic processing, operators can integrate density logs and readily identify the relationship of depth to density. For instance, data obtained from a well in 6,000 ft of water reveals a calculated overburden gradient that far exceeds the 1 psi/ft value.

Going hand-in-hand with the rapid and constantly evolving improvements in computer processing is more widespread use of seismic data to determine pressure valuations. It has long been recognized that seismic data contained much of the same information as sonic logs. The problem, however, had been in extrapolating that data to accommodate pressure evaluations. With contemporary electronic processing, seismic data can now be manipulated to produce a synthetic sonic log.

Currently, work is continuing to refine and more clearly define the similarities between seismic processing and sonic logs. While the industry has performed sonic interpretations for years, electronic processing systems did not allow it to be processed into an approximation of sonic data in a reasonable amount of time. Until recently, the process could take weeks and the result was all too often questionable data. Furthermore, compiling the results in a format that drilling personnel could understand was rarely done. Sonic-oriented geological and geophysical personnel use values in terms of average velocities, while drillers think of mud weights and pressures.

At this time, offset well information and comparison of sonic logs to seismic data for a particular project are used widely to obtain pressure determinations. Obviously, unlike seismic acquisition, sonic logs are run only in an interval that is actually drilled. However, by matching the response of the seismic data to the sonic data in the drilled interval, operators can comfortably extend the depth of the targeted well beyond that penetrated in the best available offsets.