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Why Oilwells Leak: Cement Behavior and Long-Term Consequences

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Abstract

Oil and gas wells can develop gas leaks along the casing years after production has ceased and the well has been plugged and abandoned (P&A). Explanatory mechanisms include channelling, poor cake removal, shrinkage, and high cement permeability. The reason is probably cement shrinkage that leads to circumferential fractures that are propagated upward by the slow accumulation of gas under pressure behind the casing. Assuming this hypothesis is robust, it must lead to better practice and better cement formulations

Introduction, Environmental Issues

This discussion is necessarily superficial, given the complexity of the issue and attendant practical factors such as workability, density, set retardation, mud cake removal, entrainment of formation gas, shale sloughing, pumping rate, mix consistency, and so on. A conceptual model will be developed in this article to explain slow gas migration behind casing, but we deliberately leave aside for now the complex operational issues associated with cement placement and behavior.

In 1997, there were ~35,000 inactive wells in Alberta alone, tens of thousands of abandoned and orphan wells[1], plus tens of thousands of active wells. Wells are cased for environmental security and zonal isolation. In the Canadian heavy oil belt, it is common to use a single production casing string to surface (Figure 1); for deeper wells, additional casing strings may be necessary, and surface casing to isolate shallow unconsolidated sediments is required. As we will see, surface casings have little effect on gas migration, though they undoubtedly give more security against blowouts and protect shallow sediments from mud filtrate and pressurization.

To form hydraulic seals for conservation and to isolate deep strata from the surface to protect the atmosphere and shallow groundwater sources, casings are cemented using water-cement slurries. These are pumped down the casing, displacing drilling fluids from the casing-rock annulus, leaving a sheath of cement to set and harden (Figure 1). Casing and rock are prepared by careful conditioning using centralizers, mudcake scrapers, and so on. During placement, casing is rotated and moved to increase the sealing effectiveness of the cement grout. Recent techniques to enhance casing-rock-cement sealing may include vibrating the casing, partial cementation and annular filling using a small diameter tube.

Additives may be incorporated to alter properties, but Portland Class G (API rating) oil well cement forms the base of almost all oil well cements.[2] Generally, slurries are placed at densities about 2.0 Mg/m^3, but at such low densities will shrink and will be influenced by the elevated pressures (10-70 MPa) and temperatures (35 to >140ºC) encountered at depth.

The consequences of cement shrinkage are non-trivial: in North America, there are literally tens of thousands of abandoned, inactive, or active oil and gas wells, including gas storage wells, that currently leak gas to surface. Much of this enters the atmosphere directly, contributing slightly to greenhouse effects. Some of the gas enters shallow aquifers, where traces of sulfurous compounds can render the water non-potable, or where the methane itself can generate unpleasant effects such as gas locking of household wells, or gas entering household systems to come out when taps are turned on.

Methane from leaking wells is widely known in aquifers in Peace River and Lloydminster areas (Alberta), where there are anecdotes of the gas in kitchen tap water being ignited. Because of the nature of the mechanism, the problem is unlikely to attenuate, and the concentration of the gases in the shallow aquifers will increase with time.

This implies that current standards for oilwell cementing and P&A are either not well founded, or the criteria are based on a flawed view of the mechanism. This is not a condemnation of industry: all companies seek to comply with standards.[3] Nevertheless, we believe that the AEUB Interim Directive 99-03[4] is flawed with respect to gas leakage around casings. To rectify this, the mechanisms must be identified correctly. Practise can then be based on correct physical mechanisms, giving a better chance of success (though we do not believe that the problem can be totally eliminated because of the vagaries of nature and human factors, despite our best efforts).

There is also need for better quality oil-well cement formulations that can resist thermal shocking. For example, leakage of fluids along thermal wells in cyclic steam operations in Alberta has proven a challenging problem for Imperial Oil.[5] If poor quality or poorly constituted cement is used, high injection pressures, thermal shocking, plus non-condensible gas evolution lead to leakage behind the casing that could break to surface under exceptional conditions.

Finally, in production management for conservation purposes, zonal isolation is multiple-zone wells.[6]

There are initiatives to identify old leaking wells and undertake mitigating action in Alberta and Saskatchewan, the "orphan well" program of the AEUB, initiatives by the Petroleum Technology Alliance Centre in Calgary, and so on. This article is to try and clarify the mechanisms involved.

Cement Behavior

Cement Shrinkage: If cement is placed at too high a water content, it loses water to the porous strata under lower pressure (p_o) through direct filtration because the cement hydrostatic head is greater than the pore water pressure head. The annulus width between casing and rock is small (e.g. 175 mm casing in a 225 mm hole = 25 mm), so even a small shear strength development between rock and cement will support the weight of the cement. If this shear stress is only ~0.5 kPa, the entire "hydrostatic" head of the cement ($\gamma_c \cdot z$) can be supported by stress transfer to the rock mass. (Of course, because of temperature and pressure effects, this degree of set is not attained simultaneously along the entire cement sheath.)

Thus, while the cement is still in an almost liquid, early-set state, massive shrinkage can occur by water expulsion, but annular cement settling to compensate for the loss of water is impeded by the shear stress transfer to the rock mass. The consequence is shrinkage in the cement sheath.

Portland cements continue to shrink after setting and during hardening.[7,8] This autogenous shrinkage occurs because hydration reaction products occupy less volume than the original paste. Judicious proportioning control of the cement slurry and the use of admixtures and additives can limit the physico-chemical effects of the autogenous shrinkage processes. Mostly, the careful control of water content by using superplasticisers and the control of macro-shrinkage by using appropriate aggregates benefit the properties of the set grouts.

Silica flour (SiO_2, ground to –20 μm) is often used to make "thermal cement". It is added in quantities approaching 75% of the dry constituents, the remainder being cement powder. Silica flour has also been added to cement in an attempt to counteract shrinkage. Unfortunately, for physico-chemical reasons, silica flour can enhance both drying and autogenous shrinkage.[9]

Silica flour is a ground product, usually made from pure quartz sand. Physically, the silica flour, by virtue of its grain size ($D_{50} \approx$ 10-20 μm) has a large surface area; this provides not only enhanced reaction areas for kinetically controlled hydration processes, it provides a need for additional wetting for slurry formulation. Physico-chemically, a freshly fractured silica surface possesses a high chemical reactivity because of the presence of unsatisfied bonds arising from the breaking of the silica chemical lattice. These fresh surfaces will electrostatically bind polar water molecules to satisfy these broken bonds. Experiments on pure silica using magnetic resonance and dielectric permittivity show that up to 9-11 layers of water can be absorbed on the surface, and the closest layers are of course the most tightly bound.

The surface area increases inversely as the square of the mean particle diameter, therefore reducing the surface area by a factor of five (grinding 100 μm sand to 20 μm flour) increases the area by 25, and because the new surface area is chemically fresh, it is more reactive. Thus, the electrostatic bound water volume for silica flour is vastly larger than for geochemically "old" sand. Furthermore, electrostatically bound water thickness is reduced by temperature (Brownian motion), so cool slurry will have a surfeit of water when it becomes heated through contact with geothermal temperature.

Alternative fillers are required to control the macro-shrinkage properties of the materials. We recommend 60-100 μm quartz sand be substituted for SiO_2 flour when possible.

Other processes can lead to cement shrinkage. High salt content formation brines and salt beds lead to osmotic dewatering of typical cement slurries during setting and hardening, resulting in substantial shrinkage.[10,11] Experiments with recommended cement grout formulations placed against salt and potash strata clearly show massive dewatering of the cement and the formation of free brine at the interface between the cement and the salt. The same effect must occur when fresh-water cement grouts are in contact with low permeability rocks with highly saline pore fluids. By ensuring that the grouts are placed at high density, conducive to a stable grout microstructure, the effects of osmotic dewatering can likely be minimized, but this should be quantitatively assessed.

Recently marketed finely ground cements (Microfine™ and Ultrafine™) are Portland cement-based materials. They are generally finer than normal Portland cements and include pozzolanic additives, such as finely ground pumice. Slurries of these materials penetrate fine fissures and pores in rock more readily than more conventional grouts but in bulk suffer from very high shrinkage and, hence, without further modification, are not suitable for grouting the annulus between oil-well casings and the borehole wall.[12]

Dissolved gas, high curing temperatures, and early (flash) set may also lead to shrinkage. It is not clear if non-shrinkage additives have substantial positive effects at great depth and high temperature. These additives (e.g. Al powder) generally produce some gas, which in the laboratory provides volume increase. Additives may enhance some properties; however, they may induce negative impacts on other properties, or lose effectiveness at elevated temperatures, pressures, or in the presence of certain geochemical species. Also, autogeneous shrinkage continues long after these agents have acted.

Cement Strength and Rigidity. API standards for oilwell cement specify certain strength criteria. Strength is not the major issue in oil well cementing under any circumstances. Based on extensive modelling, cement clearly cannot resist the shear that is the most common reason for oilwell distortion and rupture during active production.[13] If compaction or heave (from solids injection) is taking place, the cement itself provides minimal resistance to buckling (compression) or thread popping (tension). If the annulus could be filled with relatively dense sand, the resistance to shear would be better than current ordinary oilwell cement formulations.

Based on over 50 triaxial tests at various confining stresses, we have shown that 28-day cured oilwell cements are contractile (volume reduction during shear) at all confining stresses above 1 MPa (150 psi). This is also the case for 70% silica flour cements, and for the new products based on extremely finely ground cement. (Specimens were cured under water at 20°C or at 90°C.) However, dense concretes used in Civil Engineering are dilatant, and therefore resistant to shear, at all working stresses.

The stiffness modulus of typical oilwell cement is small compared to that of low porosity rocks, and vastly lower than that of steel.[14] The stiffness moduli are roughly 2-4% that of steel, though there is a wide range depending on density, content, and confining stress. Depending on depth (~stress) and induration (~porosity), rock moduli may vary from 2% to 50% of steel, and a reasonable value is 5-15% in most intermediate cases of moderate porosity (10-20%).

Bond. Cement will not bond to salt, oil sand, high porosity shale, and perhaps other materials. Also, bond strength (i.e. the tensile resistance of the cement-rock interface) is quite small; in fact, the tensile strength of carefully mixed and cured oilwell cement at recommended formulations is generally less than 1-2 MPa. Given that fluid pressures of 10's of MPa may have to be encountered, given that pressure cycling of a well can easily debond the rock and cement (there is strain incompatibility because of the different stiffnesses), and given that de-bonding is generally a fracturing process with a sharp leading edge rather than a conventional tensile pull-apart process, a large cement bond to rock cannot be assumed in any reasonable case. Initiation and growth of a circumferential fracture ("micro-annulus") at the casing-rock interface will not be substantially impeded by a cohesive strength at this interface.

The presence of "good bond" on a cement bond log is in fact not an indicator of bond, but an indicator of intergranular contact maintained by a sufficient radial effective stress. The lack of bond on a bond log is actually evidence of the inability to transmit high frequency sonic impulses because of the presence of an "open zone", that is, a circumferential fracture that is open by at least a few microns. Thus, maintaining "bond" actually means maintaining effective radial stress. Note that if effective radial stress cannot be maintained, then hydraulic fracturing conditions must exist at the interface.

The Gas Leakage Model

A good conceptual model must explain the following typical aspects of oilwell behavior that are observed in practice.

- Generally there are no open circumferential fractures detectable after a typical good quality cement job ("good bond" is observed on the log traces).
- Such fractures develop over time and with service.
- Even in cases where bond appears reasonable over substantial sections of the casing, gas leakage may be evidenced some years or decades later.
- The process is invariably delayed; thus, there must be physically reasonable rate-limiting processes.
- The gas often appears at surface rather than being pressure injected into another porous stratum encountered in the stratigraphic column.
- The presence of surface casing provides no assurance against gas leakage.

Whereas we do not deny that mud channeling, poor mud cake removal, gas channeling, and so on can occur in isolated cases, we believe that a better hypothesis exists to rationally explain the points listed above.

Figure 2 shows the effect of shrinkage on near-wellbore stresses. (Plots are qualitative, but have been confirmed by numerical modeling, to be published later.) Initially, cement pressure $p_c(z) = \gamma_c \cdot z$, almost always higher than p_o, but lower than σ_{hmin} (lateral minimum total stress). Set occurs and a small amount of shear stress develops between the rock and the cement; then, hydrostatic pressure in the cement is no longer transmitted along the annulus. Thereafter, even minor shrinkage (~0.1-0.2%) will reduce the radial stress ($\sigma_r = \sigma'_r + p_o$) between cement and rock because rock is stiff (4-20 GPa for softer rocks), and small radial strains (0.001-0.003) cause relaxation of σ_r and increase in σ_θ. A condition of $p_o > \sigma_r$ (σ_3) is reached; i.e. the hydraulic fracture criterion. A circumferential fracture (i.e. $\perp$ to $\sigma_3 = \sigma_r$), typically no wider than 10-20 μm, develops at the rock-cement interface.

A thin fracture aperture is sufficient to appear as "loss of bond" in a geophysical bond log. Because in situ stresses are always deviatoric (e.g. $\sigma_{hmin} \neq \sigma_{HMAX}$), bond loss will usually appear first on one side of the trace, or on two opposite sides (direction of σ_{hmin}). Wells that have experienced several pressure or thermal cycles will almost always show loss of bond, sometimes for vertical distances in excess of 100 m.

A zone of $p_o > \sigma_r$ (σ_3) can extend for considerable heights. Nevertheless, this is still not a mechanism for vertical growth. To understand vertical growth, consider Figure 3, where a hypothetical case is presented. The static circumferential fracture of length L is filled with formation water of density γ_w, giving a gradient of about 10.5 kPa/m for typical oilfield brine, but the gradient of lateral stress ($\partial\sigma_h/\partial z$) is generally on the order of 18-24 kPa/m. This means that if the fracture contains a fluid pressure sufficient to just keep it open at the bottom, there is an excess pressure at the upper tip equal to ~$L \cdot (21-10.5) \approx$ about 10 kPa/m, in typical Alberta conditions, for example. Thus, because of the imbalance between the pressure gradient in the fracture and the stress gradient in the rock, an inherent fracture propagation force is generated that tends to drive the circumferential fracture upward. (In a perfectly horizontal section, this cannot happen, but the process develops equally at higher elevations in the well where it becomes inclined.)

Now, consider what happens when a circumferential fracture between the cement and the rock is exposed to a thin stratum that contains free gas (there are invariably several such zones in any well). Cementing a casing leads not only to the development of a cement sheath, but the cement paste also slightly penetrates the interstitial space in the surrounding rock (a few grain diameters deep for typical sandstone). This reduces the permeability substantially, and because of capillary exclusion effects associated with two-phase flow and the reduced pore throat diameter arising from cement particle invasion, gas flow into the circumferential fractures is almost certainly through diffusion. This means that when the fracture is small, the rate of gas influx is modest. However, as the fracture grows in height, the contact area with surrounding sediments increases, and eventually (and particularly when the pressures are being reduced by surface leakage or flow into a higher stratum), the gas diffusion rate is large enough to lead to continuous but slow gas leakage.

In the fracture, once solution gas saturation is achieved, free gas at the top of the fracture develops. The gradient in gas is less than 1 kPa/m (rather than ~10.5 kPa/m for water) so there is an even greater excess driving pressure at the upper tip. In addition, this gradient effect tends to favor driving the liquid in the fracture back into the formation, albeit slowly, and the fracture becomes more and more gas-filled. Thus, there is a self-reinforcing process: the greater the vertical height of the fracture, the greater the excess driving force at the tip. The fracture grows vertically upward, and eventually leads to gas leakage behind the casing at the surface. It will migrate up around the outside of any casing strings at higher elevations because the excess pressure that can be developed at that stage is large enough to fracture even excellent bond (Figure 4). However, why does it take so long for the gas to get to surface (sometimes decades)?

Gas must migrate to surface through a circumferential fracture perhaps only 10-20 μm thick extending over only a limited part of the circumference of the rock-cement interface. Note that fracture aperture develops between p_f and σ_r (= σ_3) when the pressure acts to maintain it open, but because the rock and cement have elastic stiffness, they act to severely restrict the aperture. Thus, there are at least two rate-limiting aspects to gas evolution at the surface: diffusion rate of gas into the fracture, and the low "hydraulic conductivity" of the circumferential fracture arising because of its narrow aperture.

Why does the fracture grow so slowly? When the micro-annular circumferential fractures are not connected and are short, the excess pressure at the tip is small. Also, if the casing pressure is large because of production pressure, this leads to a small outward flexure that may be enough to maintain the fissures closed. (Note that if a "better" bond log response is desired, simply pressurize the casing as the bond log is run!) As the production pressure declines with time, the fissure will tend to open more because the casing is less pressurized. Also, fracture growth in the vertical direction is undoubtedly aided by pressure and thermal cycles.

Nevertheless, it is common for gas bubbling at the surface to be noticeable only years and sometimes decades after P&A. Over time, the effective fracture length increases, and this leads to the driving pressure increase discussed above. Because the velocity of a fracture is a very strongly non-linear process that is positively coupled to the driving pressure, it probably takes years for diffusion processes to lead to a condition where growth starts to accelerate. However, once acceleration begins, the fracture length increases, and complete upward propagation is fast (days? months?), limited only by the rate at which fluids can enter the fracture at depth and flow to the tip. Thus, before P&A, a cement bond log may show that the well is in good condition, yet this is no guarantee that, years later, leakage will not occur.

As the fracture rises, the condition that the pressure in the fracture exceeds the pore pressure in the surrounding strata will arise. This will lead to flow from the fracture out into the strata. If this flow is unimpeded, it will occur and the fracture vertical growth will terminate. Now, a condition exists where gas and liquids are entering the wellbore region behind the casing and leaving it at a higher elevation. This is a loss of zonal seal, and could have negative effects, such as pressurizing higher strata, or leakage of brines and formation fluids into shallower strata causing contamination. It can also have positive environmental effects, properly executed.

Yet, despite the existence of permeable zones, gas is still observed at the surface, and also as deep-sourced gas in shallow groundwater aquifers. The reason is probably that the cement paste in the pores of permeable strata acts to exclude gas by capillarity effects along the entire length of the stratigraphic column (it takes a large Δp to overcome surface tension effects in small pores). This means that gas must leave the fracture mainly by liquid-phase diffusion. So, it seems that in leakage cases the flow rate from depth simply exceeds the diffusive bleed-off rate at higher elevations, leading to the excess appearing at the surface. An interesting chromatographic effect probably occurs with mixed gases; because of differing pressure solubility, more soluble gases will diffuse into adjacent strata more rapidly, and the least soluble, CH_4, will arrive at the surface almost pure.

Unfortunately, even if no gas appears at the surface, it is no guarantee that the well is not leaking. In fact, the common occurrence of household water sources being charged with deep-sourced gas is clear evidence that there are many cases of leakage where the gas simply enters the water aquifer, and may never bubble around the casing.

Discussion

The hypothesis satisfactorily explains the phenomena associated with well behavior. Thus, it leads to a number of approaches to solve the problem. Eliminating cement shrinkage is one, but there are other practical solutions that are workable.

Cement shrinkage study and the development of new cement formulations that have no Portland phase[15] is an ongoing part of an industry-sponsored project, and new formulations will be available soon. Better recommendations for P&A are also being developed. These will be the subjects of other articles. This section will present an approach to environmental protection that can be operationally implemented at present.

Given that gas leak-off by Darcy flow (rather than diffusion) is likely impeded by the cement paste in the pore space of adjacent strata, one approach to environmental protection is to complete a well in the manner sketched in Figure 5. The open, non-cemented section is deliberately chosen to be across beds of sufficient permeability so that when excess pressure develops in the zone, the capillary exclusion effect can be overcome (less than 1 MPa typically, but depending on grain size and clay content). Because the rate of gas entry and transmission through the circumferential fracture is small, a permeable bed just a few 10's of centimetres thick will suffice to act as a drain. This bed will accept sufficient volumes of gas, and providing that it is laterally continuous, will act as a drain for a very long time, perhaps indefinitely.

Is there a need to revisit API standards on cement formulation, placement and completion practices, and industry quality control during placement?[16,17,18] We believe so, but this is a substantial issue, and specific suggestions await more results.

Closure

The elements of the gas leakage mechanisms that we propose are the following:

- Various mechanisms, but mainly cement shrinkage, lead to a drop in radial stress.
- When $\sigma_r < p_o$, a circumferential fracture will open.
- Differences between lateral stress gradients and pressure gradients provide forces for vertical growth.
- The excess pressure that develops at the upper leading tip increases as the (vertical) height.
- The fracture will tend to become gas filled as gas slowly diffuses into it, increasing the driving force.
- Fracture aperture is severely limited by the stiffness and geometry, limiting the upward propagation rate.
- Pore blockage because of cement paste penetration limits gas leak-off rates to those associated with diffusion because of capillarity effects.
- Eventually the fracture will rise, and gas will enter shallow strata or leak at the surface.

This working hypothesis has led to recommendations on cementing and casing strategies, and the pursuit of a cement formulation that can be easily placed yet not shrink is important, both for primary cementing, and for P&A.

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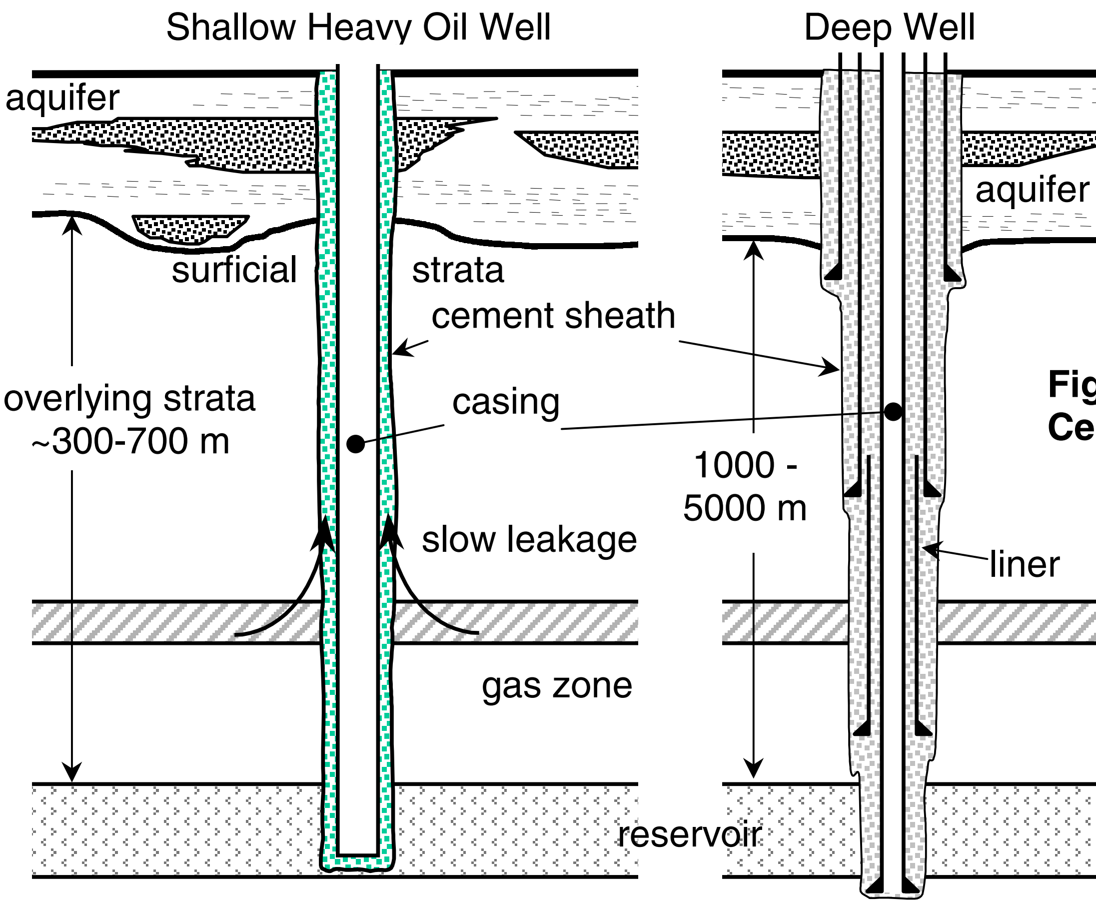
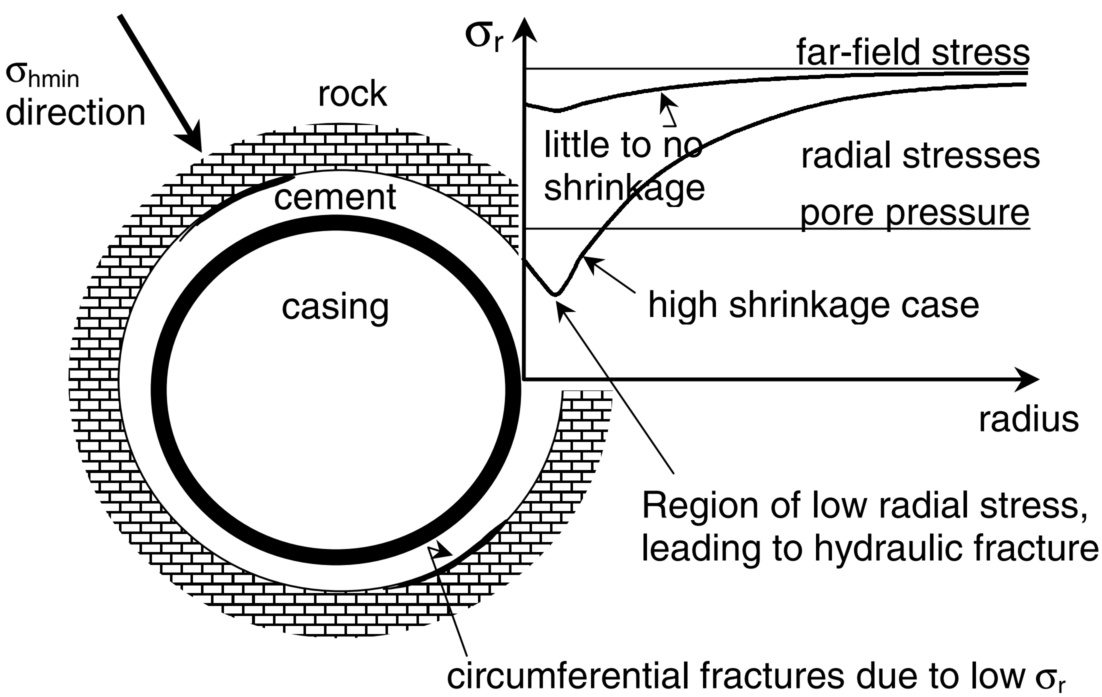


Figure 1: Cased, Cemented Wells

Figure 2: Radial Stresses and Circumferential Fractures



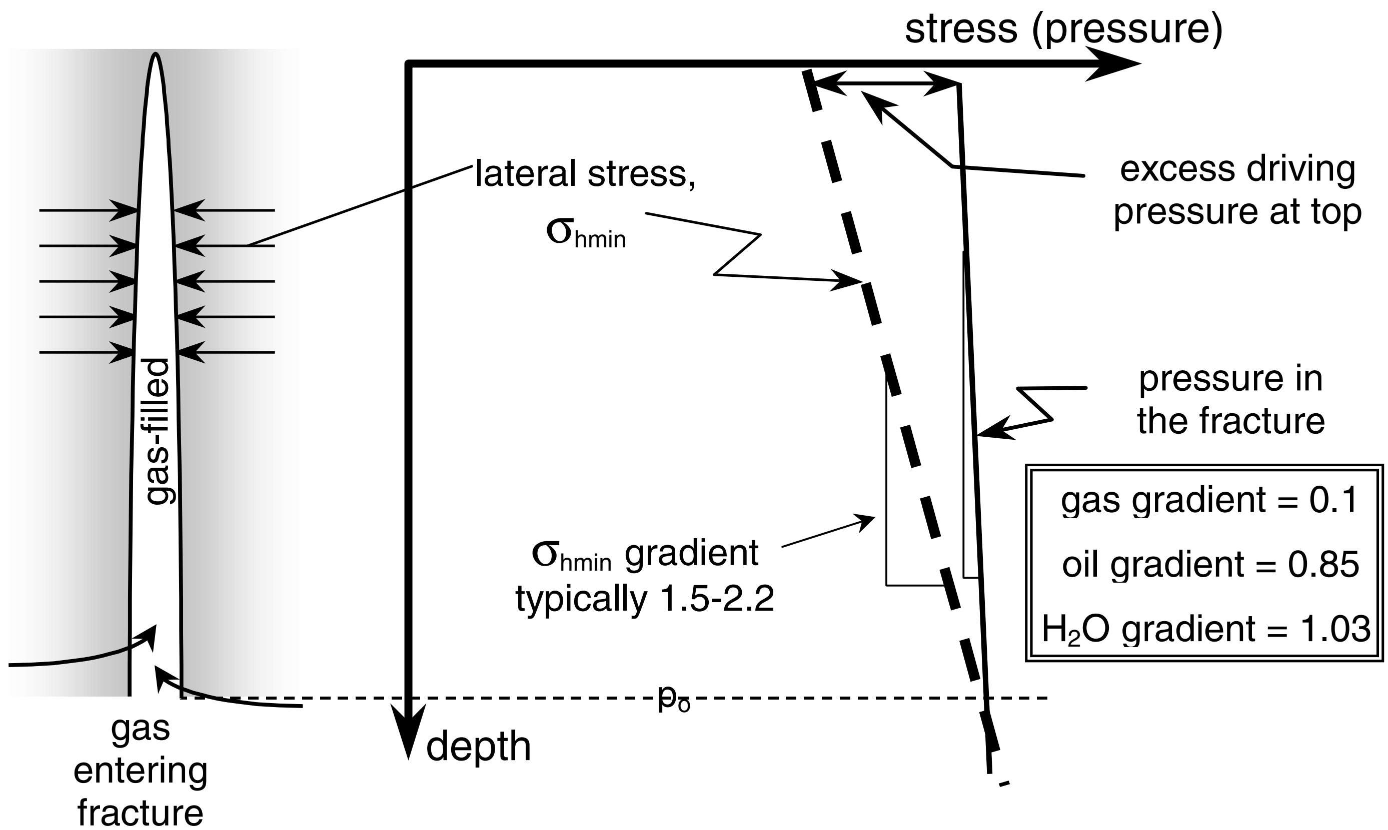


Figure 3: Fracture Driving Pressure from Gradient Differences

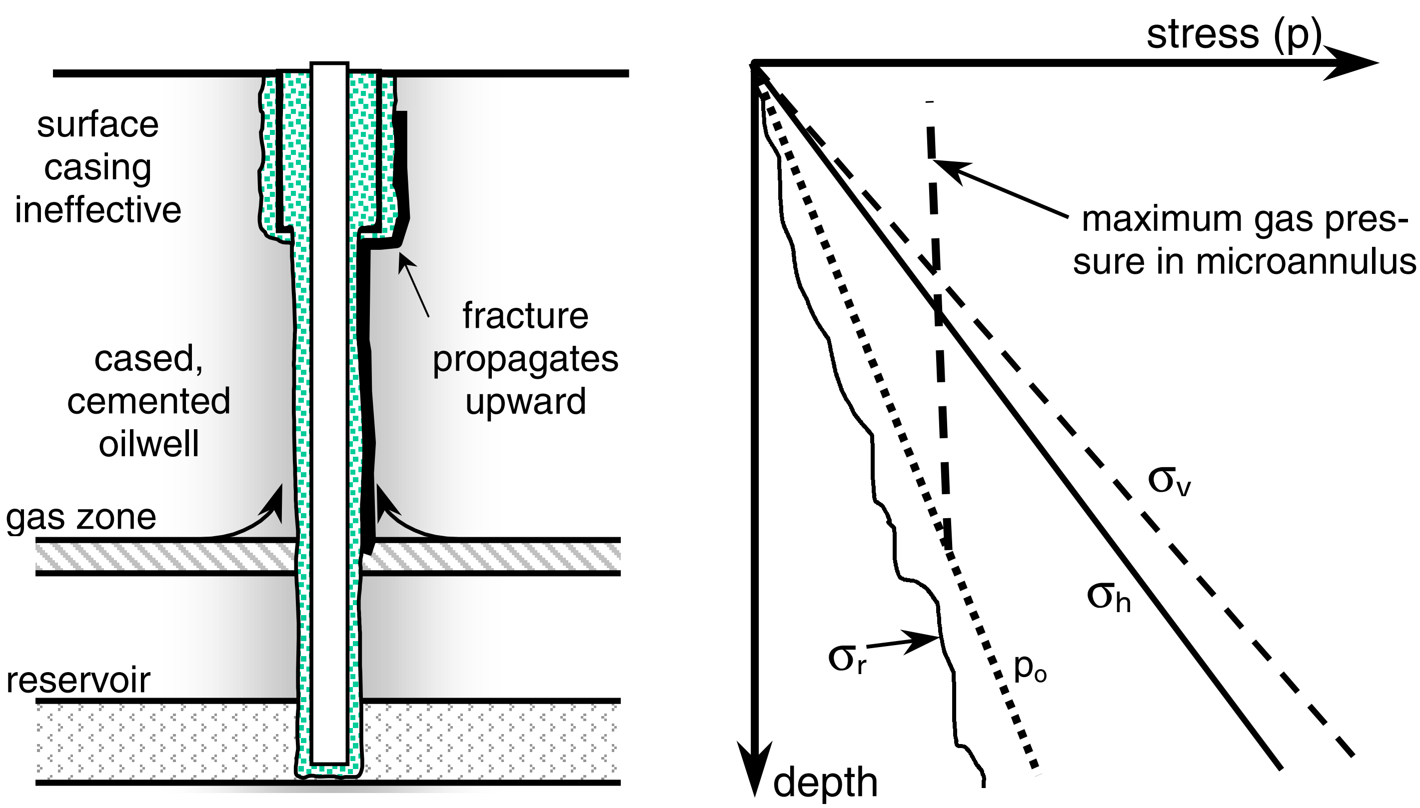


Figure 4: Fracture Approaching Surface

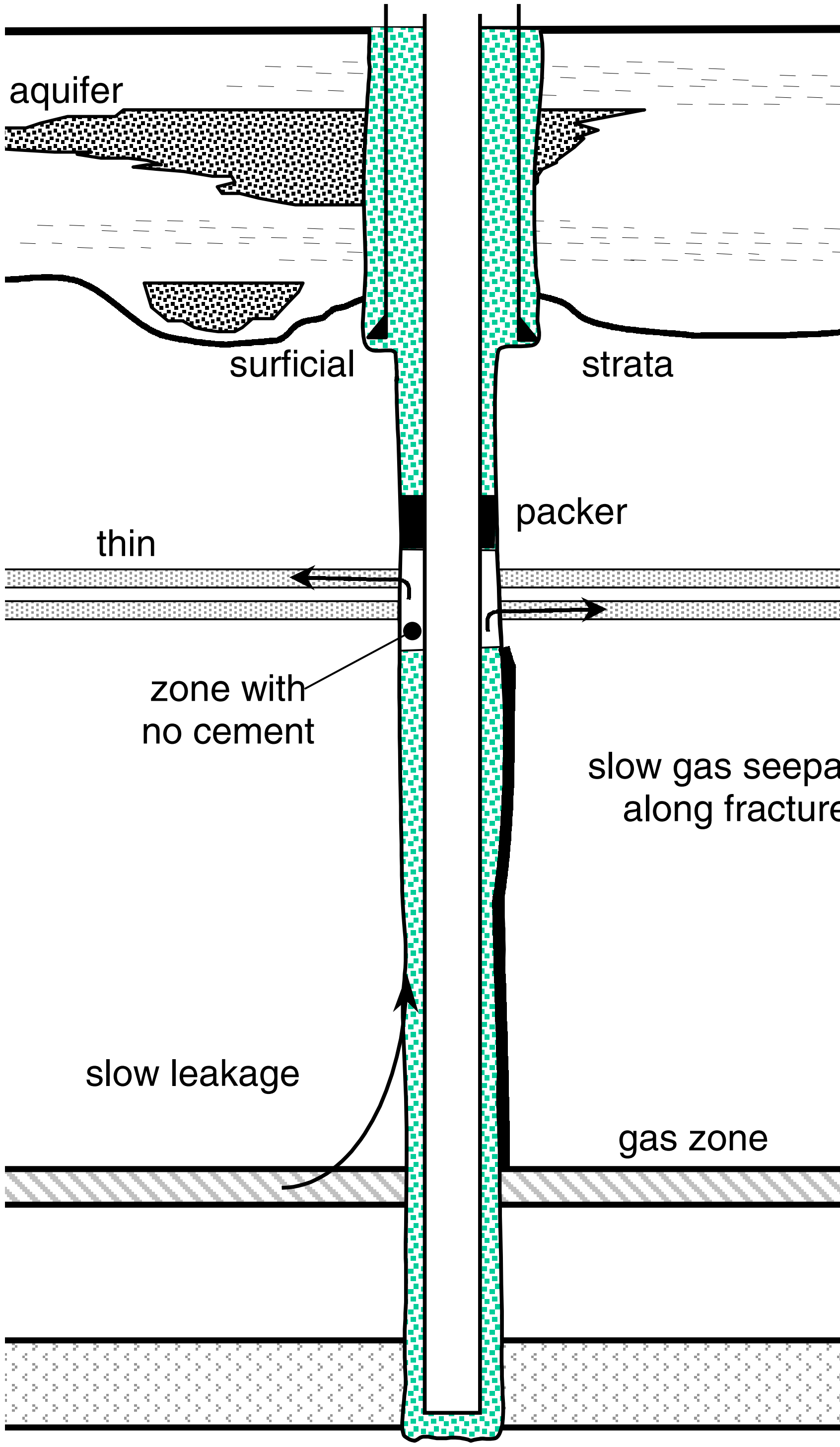


Figure 5: Leaving a Leak Off Zone to Arrest Gas Seepage