Pål Skalle

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Contents

1 Introduction

1.1 The drilling process

An oil well is drilled by means of the sharp teeth of a rock bit as illustrated in Figure1-1.

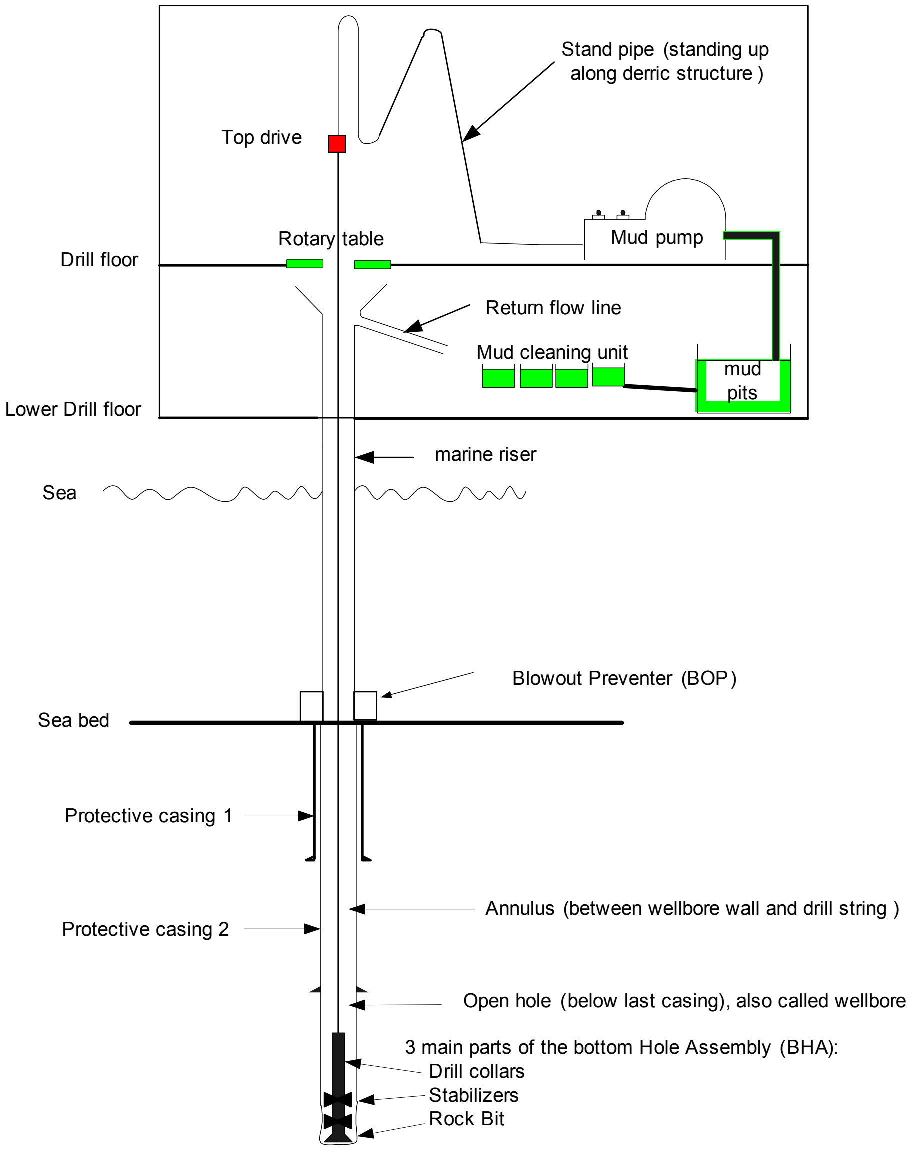


Figure 1-1: The drilling process.

To crush the rock and carry the cuttings away from under the rock bit and up through the annulus, three types of energy are transmitted to the rock bit.

- Downward force; created by the drill string and especially the heavy drill collars.
- Rotation; created by the top drive which turns the whole drill =string, to whose bottom part the rock bit is fastened.
- Fluid flow; mud pump takes mud from the mud pit and circulate it through the drill string, through the nozzles of the bit and back up through the annulus. Cuttings are separated out in the cleaning unit, and clean mud is returned to the mud pit.

1.2 Geological sediments

The search for oil occurs in geological sediments, as opposed to volcanic rocks. Several processes are involved in the creation of sediments. First, the inland continental volcanic rock is continuously being weakened and eroded by weathering processes (mechanical (through water, ice and wind) and chemical erosion). Secondly and simultaneously, the eroded material is being transported by water, ice and wind and gradually the material may be broken down into smaller pieces (from boulders to gravel, to sand, to silt and finally to clay). When finally ending up in calmer environments, the material is settling out and falling to the bottom (as sediments). Here it will start forming layers of sediments, adding a few μm or mm every year. This process has been going on almost since the birth of mother earth. The sediments will grow in thickness over the millions of years, and a continental shelf can become as thick as 10 – 15 kilometers!

The cycle of the three most important sediments is presented and briefly discussed in Figure 1-2. It is the sediments at its second stage, sedimentary porous rock, that are of interest for the petroleum industry. Here we may find oil and gas, trapped in porous reservoirs with impermeable ceilings and walls.

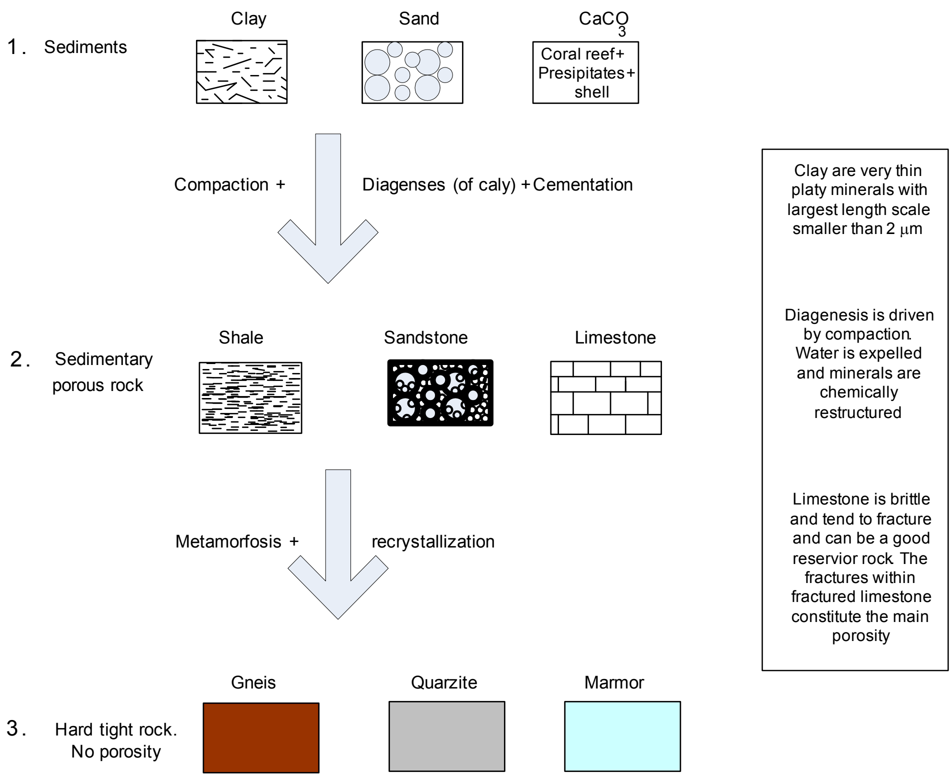


Figure 1-2: Three stages of sediment's cycle.

Sediments undergo gradual burial, compaction, digenesis, cementation and re-crystallization after being continuously deposited. If the sediments are buried and pressed deep enough into the earth crust a fourth stage is reached; the sediments melt and return to magma.

Porosity and permeability are the two most interesting parameters of the sediments, at least for petroleum engineers. The ultimate goal is to find hydrocarbons in the sediments. Porosity of sediments is simply the quotient between pore volume (void volume around the grains) and total volume. Since sediments are normally deposited in the sea, the pores are normally filled with sea water. Their initial porosity will decrease with burial depth as shown in Figure 1-3. The fundamental difference between shale and sandstone is their permeability, which is practically zero for shale, and high (10 – 2 000 mD (milliDarcy)) for sandstone. Permeability is defined as the ability of gas or fluids to flow through the sedimentary rock. Normally the permeability is higher the higher the porosity.

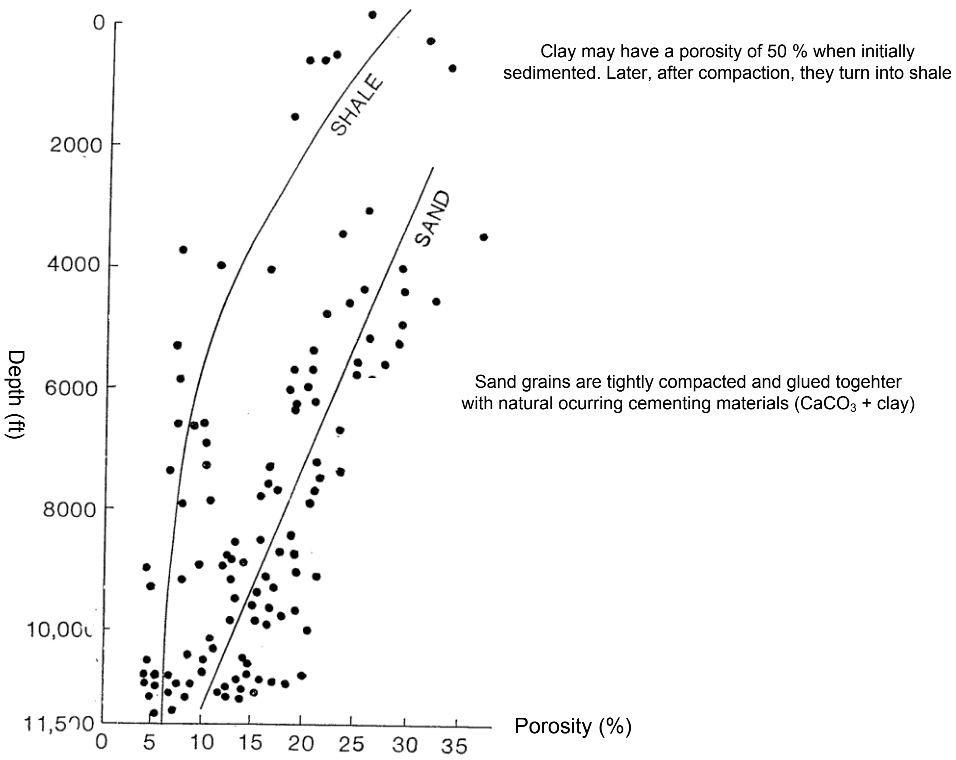


Figure 1-3: Porosity of shale and sandstone vs. depth of burial.

1.3 About Pressure Control in sedimentary rocks

All formations penetrated by the rock bit are porous to some degree as indicated in Figure 1-4. The pore spaces can contain fluids such as oil, gas or salt water or a mixture of these. Pore pressure, p_{pore}, is exerted by the fluids contained in the pore space.

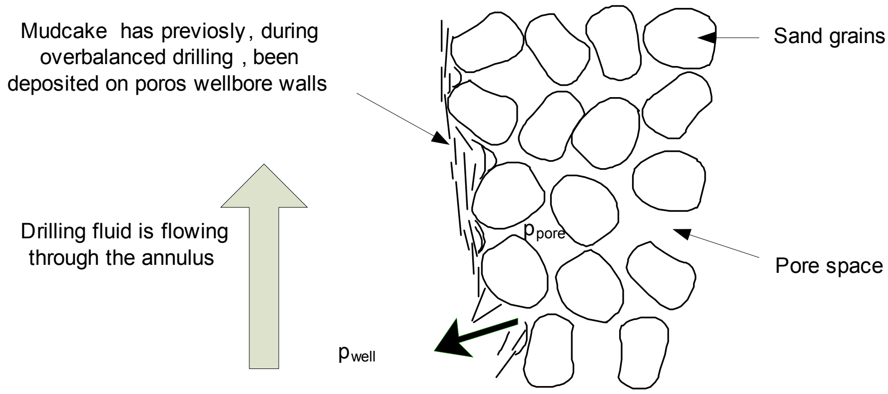


Figure 1-4: When wellbore pressure becomes lower than pore pressure; pore fluid flows into the wellbore (kick).

In order to overbalance the pore pressure a drilling fluid with a proper density is circulated into the drill string, through the rock bit, and back to the platform through the annulus (the annular space between the drill sting and the borehole wall). Drilling fluid is referred to as mud. Since the drilling fluid is a suspension of solids in water, the drilling fluid is restricted to enter into permeable formations because small solids settle against the borehole wall and partly block off the entry of mud. The settled solids are referred to as "mud cake". In this over-balanced situation it is possible to drill, to circulate cuttings to the surface, lower (or hoist) the drill strig into (or out of) the well (referred to as tripping–in and tripping–out operations), set protective casings (steel pipe lowered into the drilled hole and cemented in place), etc. When, for some reason the hydrostatic pressure of the drilling fluid drops below the formation fluid pressure, formation fluid will enter the well, as illustrated in Figure 1-4. If the flow is small, it will merely mix in with the pumped drilling fluid and cause a minor decrease of its density (mud weight). Mud's density is continuously measured at the surface. In the case of small influxes the drilling fluid is said to be "gas cut", "salt water cut", or "oil cut". When, on the other hand, a noticeable influx ocurrs, an increase in mud pit volume (100 m^3 large mud tanks at the surface) is seen. Such an event is known as a kick. Kicks derive their name from the behavior of the resulting flow observed at the surface. Mud is "kicked" out of the well. When a kick occurs, blowout prevention equipment and accessories are needed to close the well.

Kicks occur when the pore pressure is higher than the wellbore mud pressure, as in the following situations:

1. Mud density is too low due to gas cut mud or due to encountering of high pore pressure
2. Lowering of mud level in annulus due to lost circulation or to removal of drill pipes from the well during tripping-out
3. Drilling into neighboring producing wells
4. When pulling the drill string out of the well too fast a suction pressure arises called swabbing pressure

Any kick requires some action to regain control. Because salt water and oil are incompressible, these fluids are not as troublesome to handle as gas. It is important for those who must control kicks to understand the behaviour of gas. The driller, who is in charge of the well, will be dependent upon his knowledge of the way gas behave under different well conditions, as discussed in chapter 4.

In order to create a new overbalance in the borehole, a drilling fluid with a greater density must be pumped into the hole to achieve a mud pressure higher than the pore pressure. This operations is called the killing operation or killing procedures.

Statistics indicate that every 100th kick turns into a blowout. A blowout is an uncontrolled kick or uncontrolled influx into the wellbore. Kicks may develop into blowouts for one or more of the following reasons:

- Failure to detect potentially threatening situations during the drilling process
- Failure to take the proper initial action once a kick has been detected
- Lack of adequate control equipment or malfunction of it

Most blowouts occur through the annulus, due to malfunctioning or failed surface BOP equipment. However, the most troublesome blowouts are those that blow out below the surface. If the pressure in the annulus exceeds the fracture pressure of the formation, the tensile stress of the sedimentary formation has been surpassed and fractures open up and mud may flow into the formation. One or more of the following problems can occur: First and most severely, if only a short string of casing has been set, a fracture can extend to the surface causing a blowout around the rig. The second problem is the possible creation of a downhole blowout. Underground blowout is defined as the process when fluid from a high-pressure zone flows through the well bore and into a fracture located higher up in the well where the formation is weaker. This situation can ruin valuable reservoirs and charge shallow formations, making further drilling difficult or impossible in this area.

1.4 Principle of barriers and safety aspects

Operational safety is an important issue during drilling: When drilling in normal depths (< 3000 mTVD) it is normal to experience a kick in every 3-7 well. In deep wells (> 3 000 mTVD), the kick frequency rises to 1-2 kicks pr. well. The consequensis of a blowout could be catastrofal.

While a kick can be controlled, a blowout means lost control of the influx. It may take months to stop the blowout, and it is often accompanied by the loss of human lives and large material and economical losses.

Pressure control during drilling is therefore imposed with the princip of redundancy; double up of all equipment systems in order to increase level of safety. This princip holds true for blowout equipment systems, as you will learn later in chapter 3. The same princip is applied in order to estasblish two independent barriers against the pore pressure;

Barrier one;	The hydrostatic pressure of mud is larger thanthat of pore pressure
Barrier two;	The envelope consisting of the blowout preventer,the casing, the exposed wellbore below the casing shoeand finaly the drill sting. This envelope can be closed incase barrier one fails.

In underbalanced drilling, barrier number one has to be adjusted. It is now composed of the drilling fluid columen (which can be composed of two or three different phases) and a separate back pressure choke. Both components contribute to the control of the bottom hole pressure.

1.5 Scope of this book

Pressure control while drilling represents an art of engineering and is not so much about computational and analytical skills. You need to understand the drilling operation to some extent and think like a drilling engineer. As an example of such thinking, the engineer always expresses the parameter "hydrostatic pressure" along the x-axis (instead of along the y-axis) as a function of increasing depth, as shown in Figure 1-5.

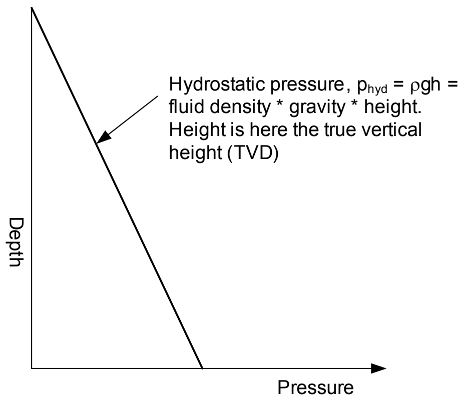


Figure 1-5: Hydrostatic pressure diagram for engineers.

Many textbooks are available, and all major oil companies and major drilling fluid service companies have their own Pressure Control Manuals. Details about Pressure Control are found in such textbooks and manuals. See References for details.

This book aims at presenting the procedure of how to control pore pressure whenever a pressure imbalance occurs during drilling, and at explaining the physics and engineering approaches behind killing wells. All students with an interest in Petroleum Engineering can read the book without special preparations.

2 Pressure in the sediments

2.1 Sedimentary pressure prediction models

Figure 2-1 presents the different pressure types necessary for the understanding of pressure control. First in this chapter we will define pressure types, and thereafter discussed how to detect them and finally how to quantify them.

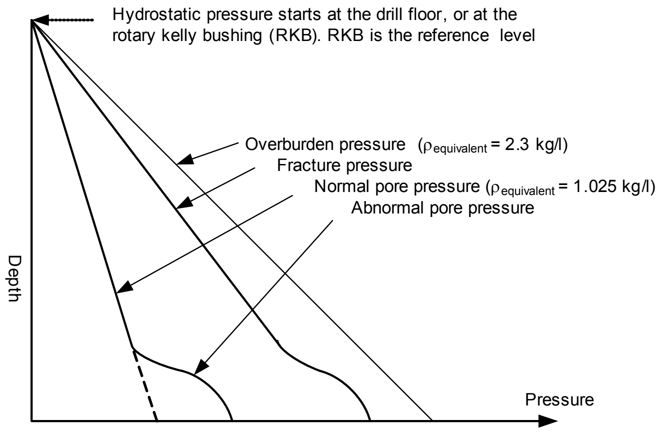


Figure 2-1: Pressure types in sedimentary rocks.

2.1.1 Overburden pressure and associated porosity

Overburden pressure is the combined weight of formation materials and fluids in the sedimentary formations above any particular depth of interest in the earth.

An expression of overburden pressure may be obtained by adding the weights of solid material (the matrix) and fluids in the pores and dividing the sum by the area that supports this weight.

$$Overburden\ pressure = \frac{weight\ of\ matrix + weight\ of\ fluids}{area} \tag{2.1}$$

Generally, formations stresses are classified in terms of in-situ stresses as either normally stressed or abnormally stressed. In a normally stressed region, the greatest compressive stress, σ_z, is vertical and caused by the overburden stress. In addition, the two horizontal stresses σ_h and σ_H, are often assumed equal, but σ_H is taken as the larges[1]. For compacted and cemented formations, the overburden stress increases linearly with increasing depth as seen in Figure 2-1, with a gradient approximately equal to - 1.0 psi/ft or 23 kPa/m. Since porosity and fluid portion will decrease with depth, the density of the formation will increase. The overburden vertical stress is found through eqn. 2.2:

$$\sigma_z = g\int_o^z \rho(z)dz = \rho_{ovb} \cdot g \cdot z \tag{2.2}$$

ρ (z) is the local or in-situ overburden density of the fluid-saturated formation at depth z, while ρ^{ovb} is the average density over the total depth z.

As a first approach, we assume that a porous formation has evenly destributied pores as shown in Figure 2-2, and that the speed of sound (here travel time between two sensors) is transmitted through the formation in accordance with eqn 2.3.

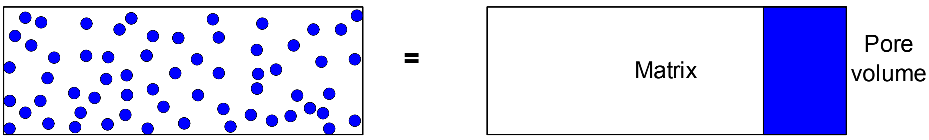


Figure 2-2: Porous formations consist of matrix (white) and pores (blue), and the two are assumed additive.

$$\Delta t \;\; = \Delta t_{matrix} * (1\text{-}Ø) + \Delta t_{fluid} * Ø \tag{2.3}$$

1 Stresses in the earth are defined in chapter 2.1.4 and in Nomenclature.

Ø represents the porosity, which becomes:

$$Ø = \frac{\Delta t - \Delta t_{matrix}}{\Delta t_{fluid} - \Delta t_{matrix}} \tag{2.4}$$

Further assume that the matrix is represented by compact limestone (porosity equal zero, like marmor). Typical data are:

ρ_{matrix} = 2.70 kg/l
Δt_{matrix} = 47 μs/m (compact marmor)
ρ_{fluid} = 1.00 1.06 1.146 kg/l (depending on salt content)
Δt_{fluid} = 200 195 189 μs/m

From Figure 2-2 the in-situ overburden density is:

$$\rho_{ovb} = \rho_{matrix} * (1-Ø) + \rho_{fluid} * Ø \tag{2.5}$$

A typical porosity of 0.15 will result in a local overburden density of 2.45 kg/m³. By combining eqn 2.4 and 2.5 and applying limestone, we obtain:

$$\rho(z) = 2.70 - 1.64 \frac{\Delta t - \Delta t_{matrix}}{\Delta t_{fluid} - \Delta t_{matrix}} \tag{2.6}$$

The above mentioned assumptions of additiveness, with respect to sound transmission, have to be adjusted to fit better to reality. Figure 2-3 shows the difference between idealized and real behaviour.

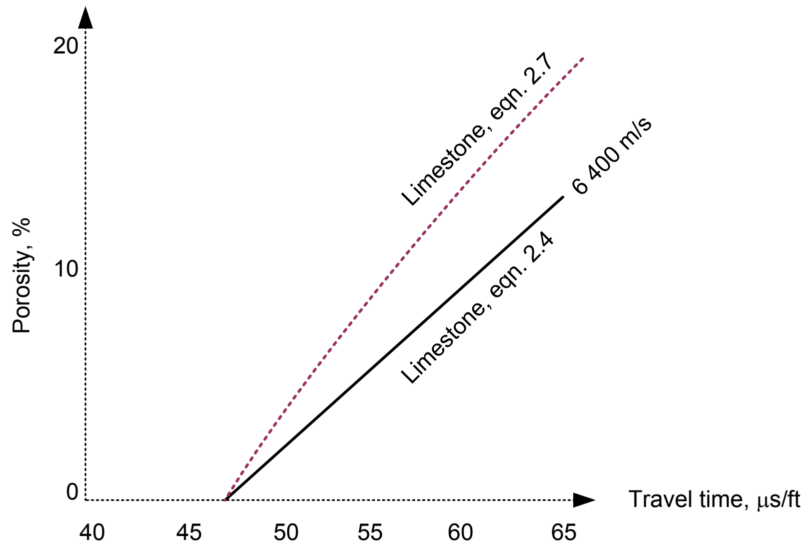


Figure 2-3: Porosity vs transit travel time in porous limestone (free after service companies).

In the porosity range of 0-25 %, the data from Figure 2-3 indicate a correction factor of 1.288. Eqn 2-3 then becomes:

$$\varnothing = 1.228 \frac{\Delta t - \Delta t_{matrix}}{\Delta t_{fluid} - \Delta t_{matrix}} \tag{2.7}$$

Combining Eqns. 2.6 and 2.7 yields

$$\rho(z) = 2.70 - 2.11 \frac{\Delta t - \Delta t_{matrix}}{\Delta t_{fluid} - \Delta t_{matrix}} \tag{2.8}$$

2.1.2 Normal pore pressure

Normal pore pressure is equal to the hydrostatic pressure exerted by the pore fluid above the depth of interest. Pressure is proportional to the density of the pore fluids. For water, it varies with salinity. Salinity in turn is related to geographic and geologic location. For example, the density of fresh water is 1.0, of seawater it is 1.025 and of 20 % saline pore water 1.06 kg/m^3.

Formations containing normal pressure are connected to the water mirror or to the ocean through permeable sediments.

2.1.3 Abnormal pore pressure

The term abnormal pore pressure refers to abnormally high pore pressure. Pressure larger than normal pressure defines abnormal pressures, i.e. larger than the pressure of a column of salt water starting at the water mirror. Abnormal pressure can exist due to at least three reasons:

1. Artesian water
   A formation may extend to the surface at an elevation higher than the ground water of an oil well drilled into the artesian water, or higher than the natural outlet of the fomation, as indicated in Figure 2-4.

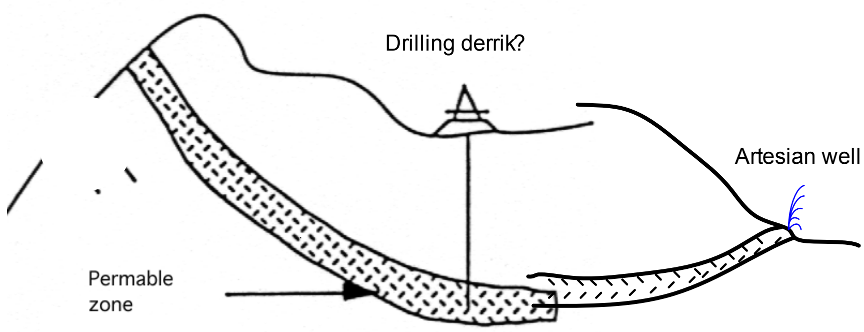


Figure 2-4: Artesian water.

2. Rapid sedimentation of clay
   An abnormal formation pressure can result from rapid burial of clay. At the time of deposition, the clays and associated minerals have a high volume of water. As the material becomes buried more and more, the contained water will tend to be squeezed out by the pressure from the overburden. The porosity will decrease.

Figure 2-5 illustrates the compaction process. An elastic spring represents the elastic mineral grains (the matrix). The spring is fitted inside a cylinder that is sealed by a friction-less piston equipped with a stopcock. Pore water fills the cylinder below the piston. An increase in load will compress the spring or move the mineral grains closer to each other. The spring and the water carry the load. The water can escape through the permeable sediments (here through the stopcock). The water will slowly flow up to the surface over the millions of years. Eventually the system will come to equilibrium. The two middle cells represent how normal pore pressure develops; the water is not hindered to escape during compaction. The right most cell represents abnormal pressure; high porosity, up to 50 %, and is associated with partly closed reservoirs, with no or poor comunication to other permeable zones.

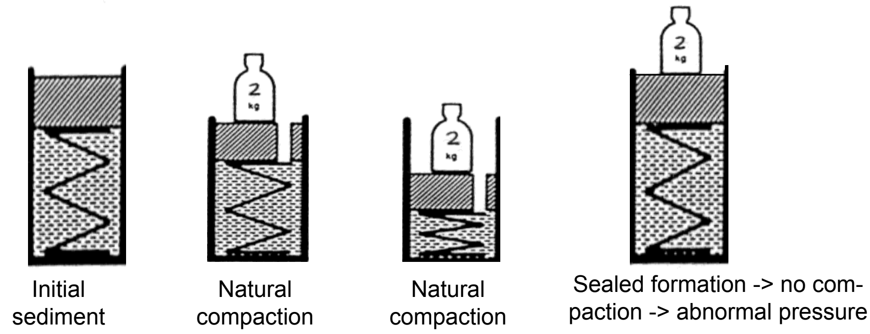


Figure 2-5: Model of consolidation process in sedimentary rocks (free after service company).

3. Charged formations
   Shallow sandstones may become charged with gas from lower formations. Once trapped inside a sand layer, the low density of gas causes the gas pressure to be almost constant throughout its vertical column.

Examples of abnormal pressures in sediments are shown in Figure 2-6. The probability of encountering abnormal pressure increases with depth. Normal pore pressure is seldom found below 2500 mTVD.

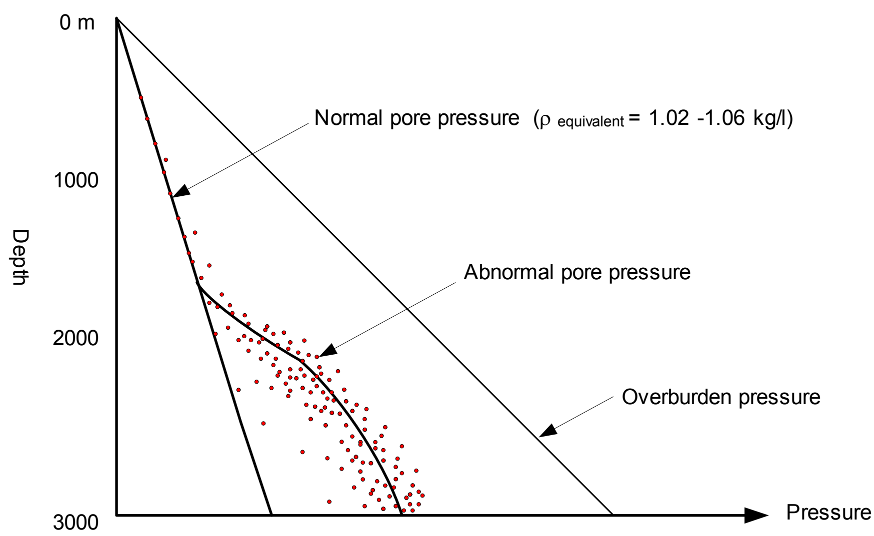


Figure 2-6: Typical pore pressure occurrences (red dots) in a sedimentary basin.

2.1.4 Fracture Pressure

When wellbore pressure surpasses the fracture pressure of the formation, a tensile fracture ocurrs, perpendicular to the plane of least horizontal stress as illustrated in Figure 2-7.

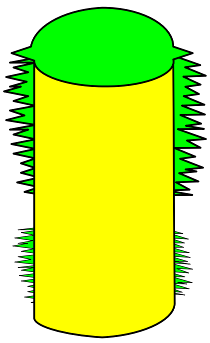


Figure 2-7: Tensile fracture.

Figure 2-8 summarizes important parameters involved in rock stresses. Adding a specific amount of additional stress, ρ_{min}, to the pore pressure, will cause the rock to fail in the direction perpendicular to the direction in which the rock can withstand the least stress. A tensile fracture arises when well pressure reaches:

$$p_{frac} = p_{pore} + \sigma_{min} \tag{2.9}$$

In this book, the most common prediction model of the least stress will be presented. σ_{min} has two synonyms: $\sigma_{min} = \sigma_h = \sigma_x$. Instead of the x, y, z coordinates, H, h, z are chosen.

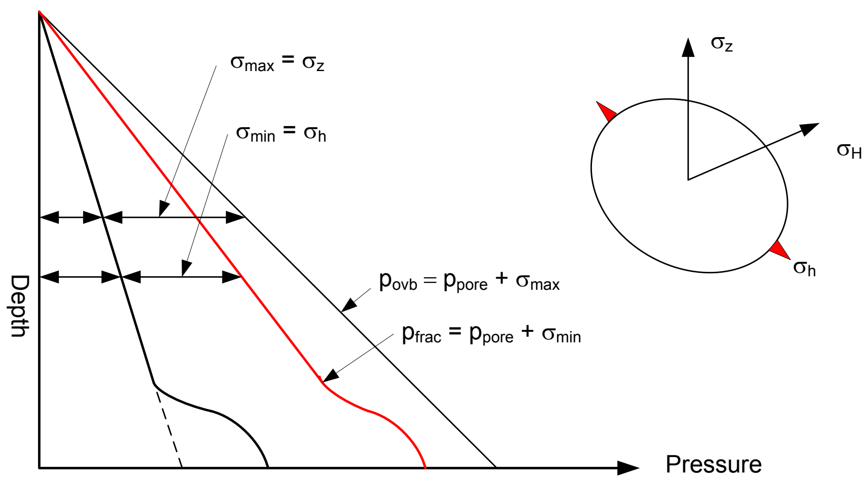


Figure 2-8: Important stress parameters of sedimentary formations.

In accordance whth Figure 2-9 and with Hook's Law the parameter σh is expressed as:

$$\sigma_h = F_h / A = E * \varepsilon = E * \Delta l / l \qquad (2.10)$$

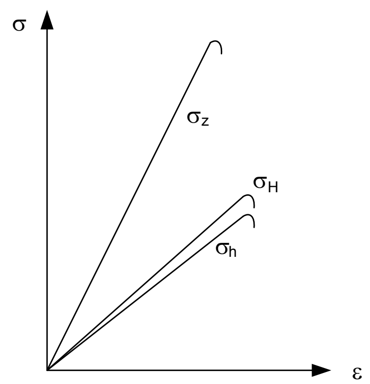


Figure 2-9: Hook's Law of elastic deformation.

In the h (x) derection, which is devoted to the weakest stress direction, the relative elongation is:

$$\varepsilon_h = \sigma_h / E \qquad (2.11)$$

In a 3D setting the relative elongation is resulting in a contraction in the two other directions:

$$\varepsilon_h = \sigma_h / E - \mu * \sigma_H / E - \mu * \sigma_z / E \qquad (2.12)$$

Here μ is the Poisson's Ratio of relative deformation:

$$\mu = \frac{\varepsilon_h}{\varepsilon_z} \qquad (2.13)$$

At zero deformation, eqn. 2.12 reduces to:

$$0 = \sigma h / E - \mu * \sigma H / E - \mu * \sigma z / E \qquad (2.14)$$

Moreover, stress in the weakest direction becomes:

$$\sigma_h = \sigma_{\min} = \frac{\mu}{1-\mu} \cdot \sigma_z \qquad (2.15)$$

Low values of Poisson's Ratio represent materials that undergo a plastic deformation, while the value of 0.5 represents a completely elastic material, like steel, rubber and volcanic rocks. For sedimentarery rocks at shallow depths Poissons Ratio starts typically at 0.2 – 0.3 and approaches asymptotically 0.5 at large depths.

2.2 Quantifying formation pressure

2.2.1 Overburden pressure

The local density is unknown and can be determined from several sourses;

- overburden density in neighbouring wells; assume same
- core sample
- cuttings density; may have reacted with mud during transport
- sonic log

The equivalent, average overburden gradient is commonly found from the sonic log as exemplified through the sonic log in Figure 2-10. By discretizing eqn. 2.2, the overburden density, ρ_{ovb}, can be found. From Figure 2-10, the in-situ[2] density, ρ_i, can be estimated from porsosity at certain intervals. The equivalent overburden density is equivalent to the mud density in the sence that its fluid column is extending to the RKB and thus using RKB as the reference level. Now the overburden density is comparable with the mud density.

$$\rho_{ovb} = \rho_{balancing\ \rho_i\ from\ RKB-level} =$$

$$= \frac{1}{D}\int_o^D \rho_i \cdot \Delta D = \frac{1}{\Sigma\Delta D} \cdot (\rho_1 \cdot \Delta D_1 + \rho_2 \cdot \Delta D_2 + \rho_3 \cdot \Delta D_3 + ...) \qquad (2.16)$$

2 In-situ means the parameter's value at that specific postition, as opposed to the average and the equivalent values.

Table 2-1 represents the results from these equations and data from Figure 2-10:

Table 2-1: Example data used to produes ovburden densities. Distance from ground level to RKB is 150 m.

Formation depth	From RKB	Δt	Ø (Eqn. 2.7)	ρ_i (Eqn. 2.8)	ρ_{ovb} (Eqn. 2.9)
m	m	ms/ft	%	kg/l	kg/l
500	650	125	51	1.62	1.44
900	1150	105	38	1.90	1.62
1300	1450	85	25	2.17	1.77

These are typical offshore overburden porosities, i.e. very high. Going deep enough will make the influence of sea water and high porosity disappear.

2.2.2 Abnormal pore pressure

Accurate prediction of pore pressures has become very important during oil well drilling since both drilling costs and drilling problems can be reduced substantially by early recognition of abnormal pore pressures, thus avoiding downtime related to killing operations. Pore pressure can be determined with information from several sources:

- seismic data
- wire-line logs (now a days replaced by measurements while drilling (MWD))
- drilling rate of penetration (ROP)
- mud properties like gas content, temperature etc

In this book, ROP, sonic log and two mud properties were selected as examples of how to quantify increasing pore pressure.

a) From the sonic log:

Figure 2-10 indicates how the sonic log and the resistivity log are applied for prediction of higher pore pressure.

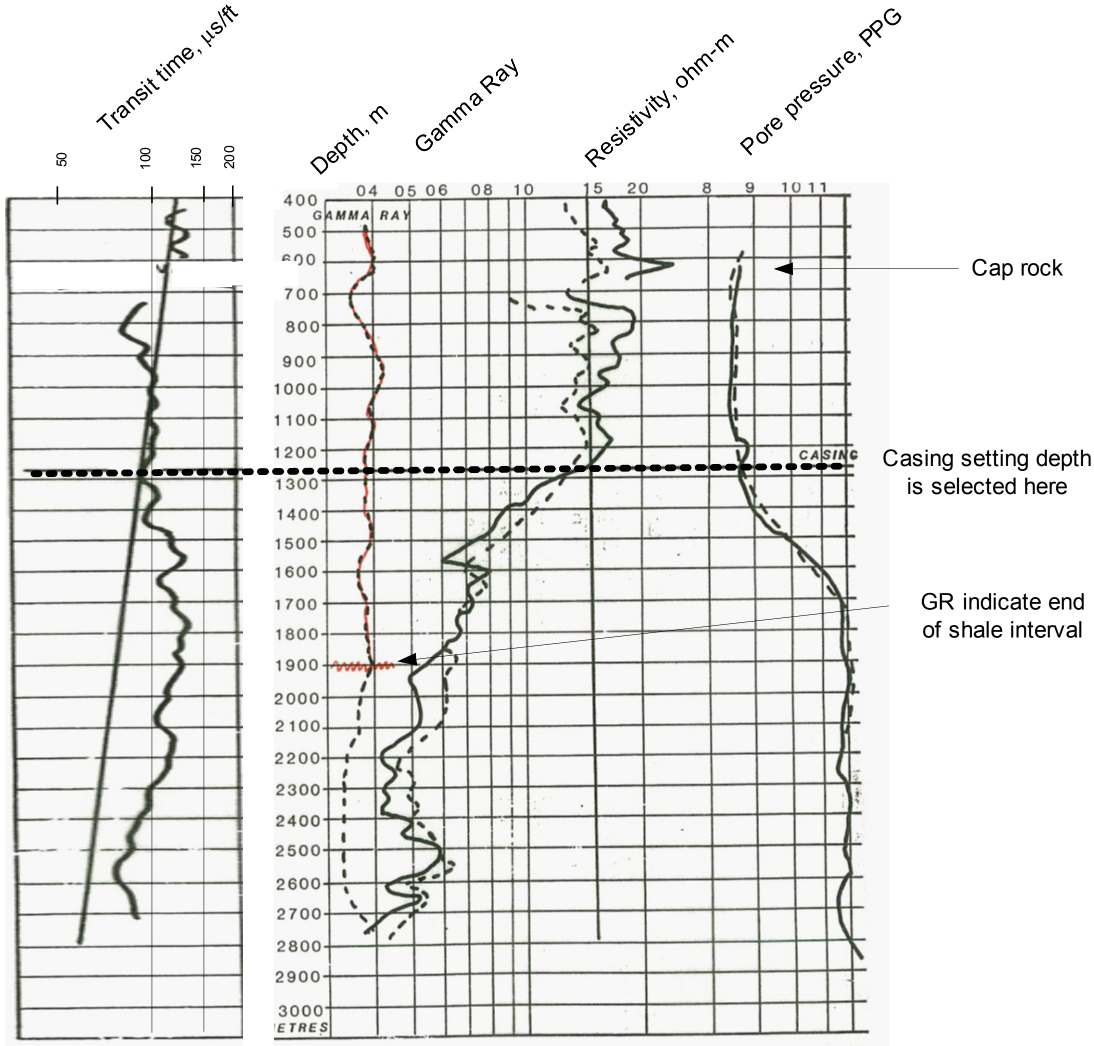


Figure 2-10: Abnormal pore pressure prediction through log interpretation (Bourgouyne et. al (1986)).

Log based methods for detecting abnormal pressure relies on the assumption that abnormally pressured shale has higher porosity and thus higher water content than normal.

Since rock matrix is a poorer electric conductor than salt water, resistivity will thus increase with depth in normally pressured shale. The same reasoning is true for propagation of sound vawes (sonic log).

A normal trend line is estasblished in normally compacted sediments. In Figure 2-10 the normal trend line of transit travel time deviates from the data when encountering abnormal pressure (below the dashed line).

In order to estimate pore pressure quantitatively, Eaton's method is applied. His method is based on the assumption of the overburden being composed of pore pressure and vertical stress:

$$p_{ovb} = p_{pore} + \sigma_z \tag{2.17}$$

Equivalent vertical density is governed by eqn. 2.18:

$$\rho_z = \rho_{ovb} - \rho_{pore} \tag{2.18}$$

Figure 2-11 demonstrates very clearly how the vertical stress is relived in a high pressure zone.

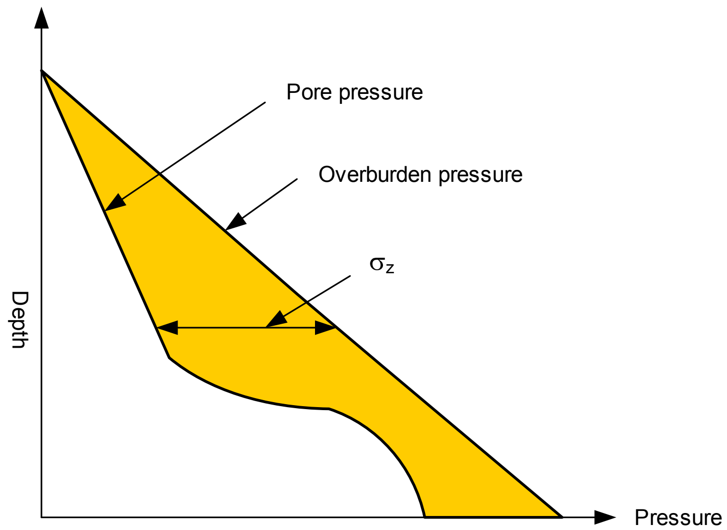


Figure 2-11: Vertical stress vs. high pore pressure.

Eaton expanded this relationship for three different logging parameters;

$$\rho_{pore} = \rho_{ovb} - \left((\rho_{ovb} - \rho_{normal})(\Delta t_{normal} / \Delta t)^3\right) \tag{2.19}$$

$$\rho_{pore} = \rho_{ovb} - \left((\rho_{ovb} - \rho_{normal})(R / R_{normal})^{1.2}\right) \tag{2.20}$$

$$\rho_{pore} = \rho_{ovb} - \left((\rho_{ovb} - \rho_{normal})(d_c / d_{c,normal})^{1.2}\right) \tag{2.21}$$

where x_{normal} = reading of x from normal trend-lines at actual depth (see Figuer 2-13).

Some of the best qualitative and quantitative abnormal pressure detection and evaluation techniques were based on these logs. A 4 m long steel cylinder is lowered to the bottom of a well, a steel spring is released pressing the cylinder towards the wall, while being pulled slowly upwards by a reinforced electrical cable. The tool contains a sender and a receiver, typically one meter apart. Wire line logging represents "after-the-fact" techniques, i.e. the well bore has to be drilled prior to enable logging, requiring an exta roundtrip. With the introduction of MWD this problem is more or less eliminated. MWD tool are typically positioned 15 m above the bit.

b) From the d_c-exponent:

Drilling rate is a very useful parameter for the detection of immediate changes in pore pressure. The following parameters affect drilling rate:

- Lithology changes (soft or hard formation)
- Bottom hole cleaning (removed cuttings are not re-drilled)
- Bit weight
- Rotary speed
- Fluid properties (especially concerntration of fines)
- Bit type (aggressiveness)
- Bit dullness (aggressiveness is reduced)
- Differential pressure

If other parameters are kept more or less constant, the difference between hydrostatic pressure and pore pressure has a large immediate effect on drilling rate. Only tight shale is able to keep (hide) the information of this pressure difference. Figure 2-12 illustrates the effect of higher pore pressure on ROP.

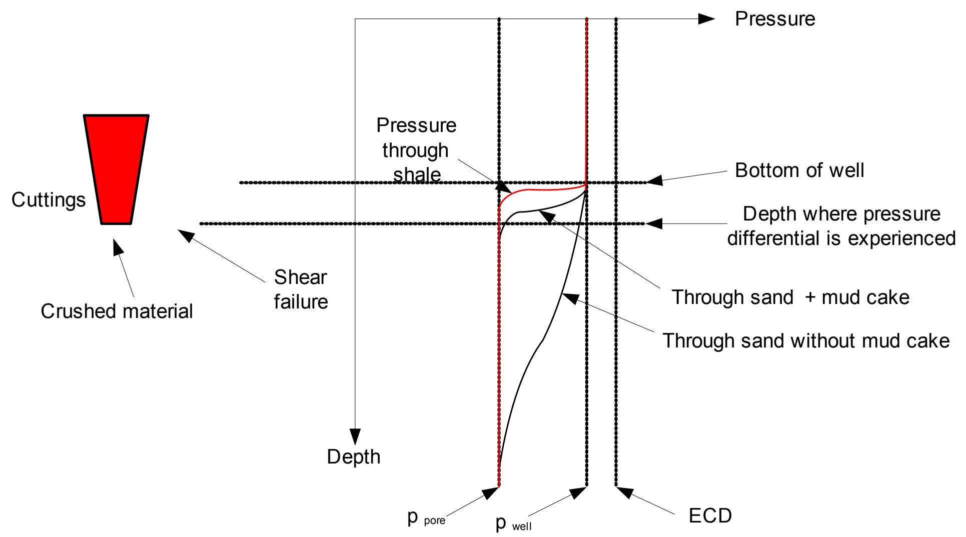


Figure 2-12: Pressure differential vs ROP.

The key to changes in penetration rate, assuming all other factors affecting drilling rate remain constant, is the magnitude of the differential pressure expressed through equivalent densities ($\rho_{pore} - \rho_{mud}$); the higher the difference, the higher the ROP. Thus, if mud weight remains constant, increased pore pressure will lead to increased ROP.

For practical applications, Jordan and Shirley (Bourgoyne et al. (1991)) developed a useful but simplified method of evaluating drilling rate, known as the "d" exponent. The theoretical base for this exponent is derived from equation 2.22, in which d represents the deviation in ROP caused by differential pressure:

$$ROP = K \cdot RPM \cdot \left(\frac{WOB}{d_{bit}}\right)^{d} \tag{2.22}$$

Note that drilling rate is directly proportional to rotary speed. This is especially true in soft formations such as normally compacted shale. K represents the hardness of the formation and is also called the "drillability constant". The above equation can be rearranged to the form;

$$d = \frac{\log \dfrac{ROP}{60\,RPM}}{\log \dfrac{12\,WOB}{10^{6}\,d_{bit}}} \tag{2.23}$$

The estimation of the pore pressure from changes in the "d" exponent depends on empirical correlations. Figure 2-13 shows a plot of the "d" exponent versus depth, shows an increasing trend in normally pressured shale (the increase of d with depth instead of the expected decrease (ROP decreases) is because the log expression in the numerator is < 1).

As for many other parameters, drilling rate will decrease with depth because of higher compaction. When the transition zone is penetrated, the value of the "d" exponent departs from the trend line toward a lower value as shown in Figure 2-13. By normalizing or correcting the d-exponent with respect to the mud weight the d_c becomes;

$$d_c = d \cdot \frac{\rho_{normal}}{\rho} \tag{2.24}$$

The deviation from the trendline will be magnified by using the dc instead of the d exponent. ρ_{normal} is the mud density that balances the normal pore pressure, normally equal to 1.02 – 1.06 kg/l.

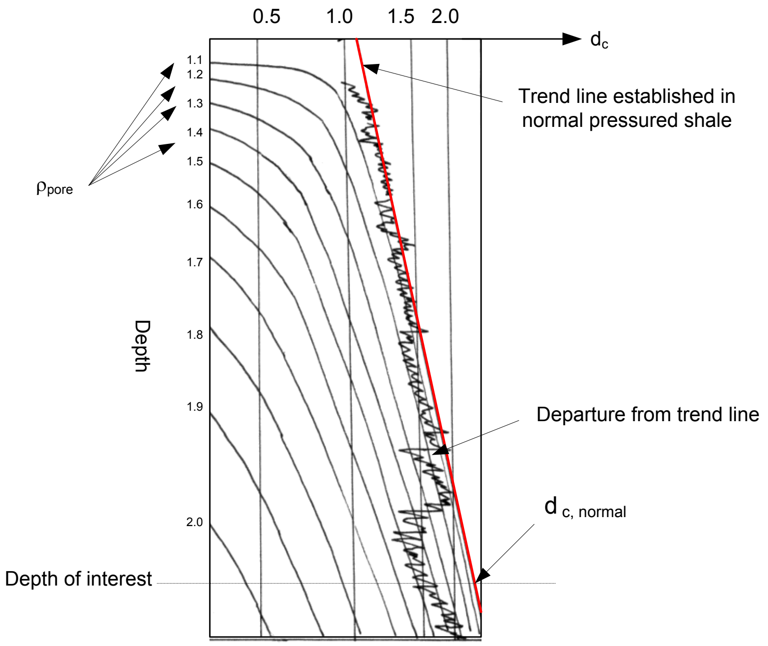


Figure 2-13: dc-exponent example from an offshore well.

c) From mud properties:

The measurement of mud temperature or gas content of the mud returning from the well may provide an early warning of higher pore pressure. Figure 2-14 gives an overview of how important parameters are gathered at the surface.

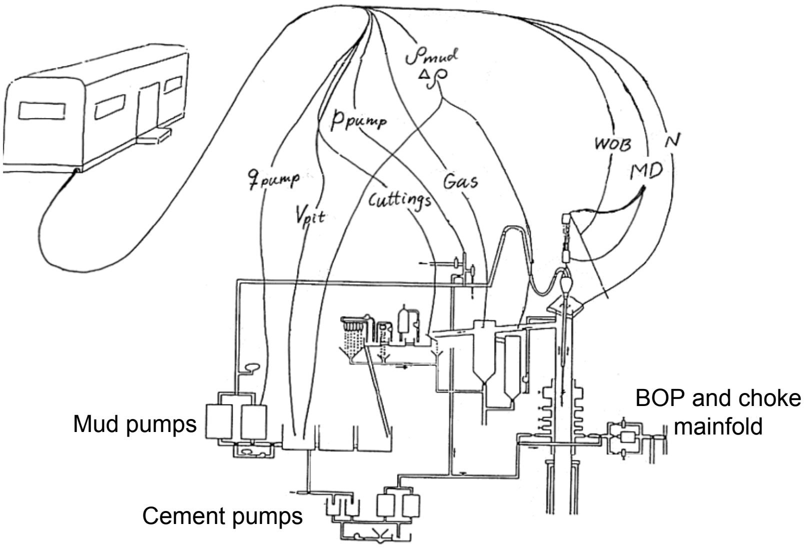


Figure 2-14: Gathering of drilling fluid and other data at the surface.

Imagine we are approaching a high-pressure gas reservoir. During 100 million of years, the gas has diffused into the overlaying shale and saturated its pore water with gas. While drilling into the shale, its pore water will be mixed in with the mud. As mud is approaching the surface and a lower pressure, gas will be liberated and then recorded. Figure 2-15 presents a resulting gas log.

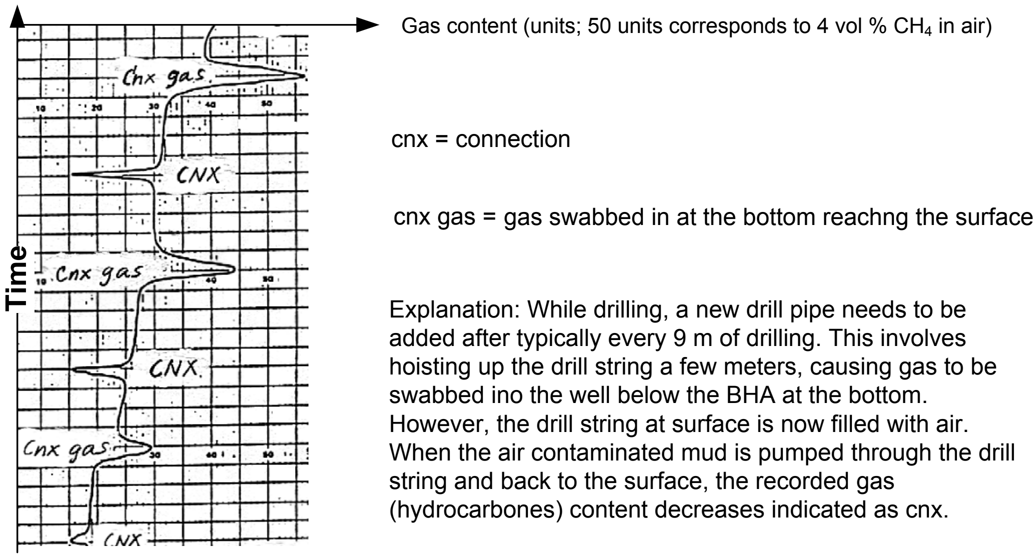


Figure 2-15: Relative gas content in the resturning mud (free after service companies).

If the high-pressure zone was not detected, drilling further into the porous and permeable formation saturated by gas would cause an increase of the gas content in the mud. This may result in severe amount of gas and severe reductions of mud weight near the surface. A reduction in mud weight near the surface has negligible effect on the average mud density in the whole well. The operator needs to be aware of this and not interprete it as a kick, and erroneously increase the mud weight.

Mud Temperature: The rate of heat flow from the inner of the earth depends on the thermal conductivity of the geological formations through which the heat flows. Thermal conductivity is a function of degree of compaction; the higher the thermal conductivity, the higher the compaction.

Continuous recording of flow line temperature may therefore be an aid in detecting increasing pore pressure. Figure 2-16 shows a typical formation temperature profile. In many areas, the temperature log may be the most definitive tool available.

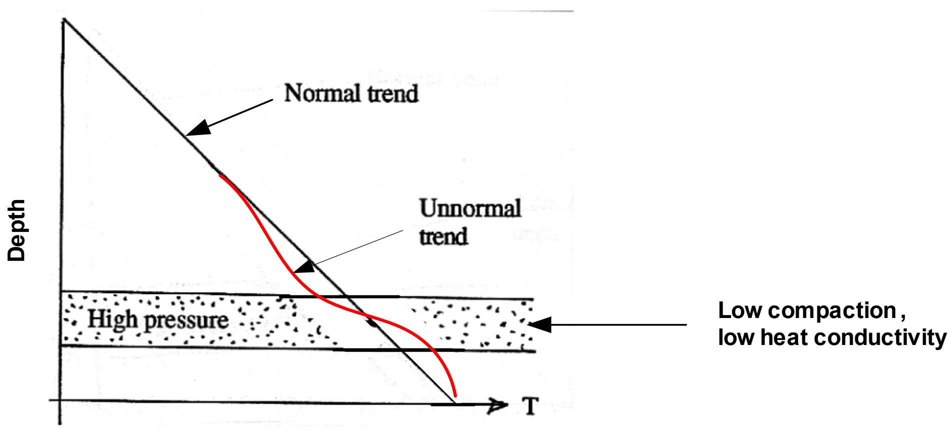


Figure 2-16: Temperature profile through a high pressure zone which acts as an insulator.

One symptom of increasing pore pressure may not be definite enough to draw a precise conclusion. For this reason it is neccessary that all available methods are used to detect and predict pore pressure. If more than one of these detection methods indicate increasing pore pressure, the operator should either accept the indicator or intensify the evaluation.

2.2.3 Fracture pressure

Fracture pressure is determined through a Leak Off Test (LOT). A LOT, also called formation intake strength test, is earried out at the casing shoe. The purpose of the LOT is to investigate the wellbore capability to withstand pressures immediately below the casing shoe in order to allow proper well planning with regard to safe mud weight, and to determine the setting depth of the next casing string. This is especially important when abnormal pressure is expected further down in the sediments.

Figure 2-17 presents the well during a leak-off test and the resulting fracture pressure. Figure 2-18 presents the pump pressure during a leak-off test.

The following leak-off test procedure is an example of how to obtain the fracture pressure:

- Drill out the cement in the bottom casing plus 3 m of new formation.
- Pull the bit back into the casing; make sure the hole is filled up with mud and close the BOP around the drill pipe.
- Pump mud slowly with the cementing pump, a high-pressure low-volume pump, until the pressure builds up initially (with negligible friction).
- Then pump 15 liters and wait for 2 minutes or the time required for the pressure to stabilize.
- Note the mud volume pumped and the stabilized pressure. See the red dots in Figure 2-18.
- Continue the procedure until the stabilized pump pressure deviates from the pressure trend line. This point is called the leak off pressure, p_{LO}.

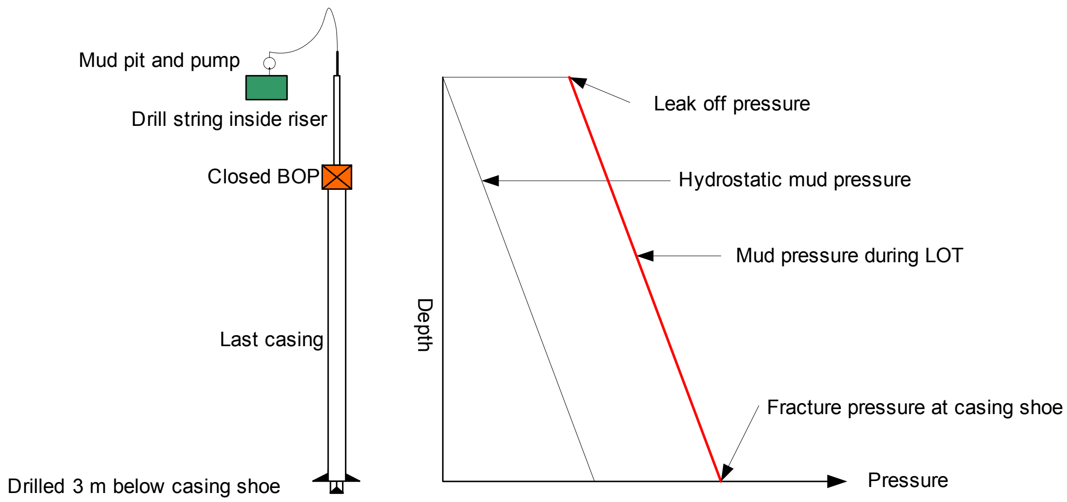


Figure 2-17: Well configuration and final pressure during a LOT.

Further pumping, beyond the leak off pressure, would start fracturing the rock until a sharp pressure drop is observed, at which the fracture propagates into the formation. The given pressure where this occurs (and flattenes out) is called the formation breakdown pressure.

Sometimes a maximum limit is set for the pump pressure during a formation strength test. A "maximum required mud holding capability" is recorded. The test is called a limit test or a formation integrity test (FIT).

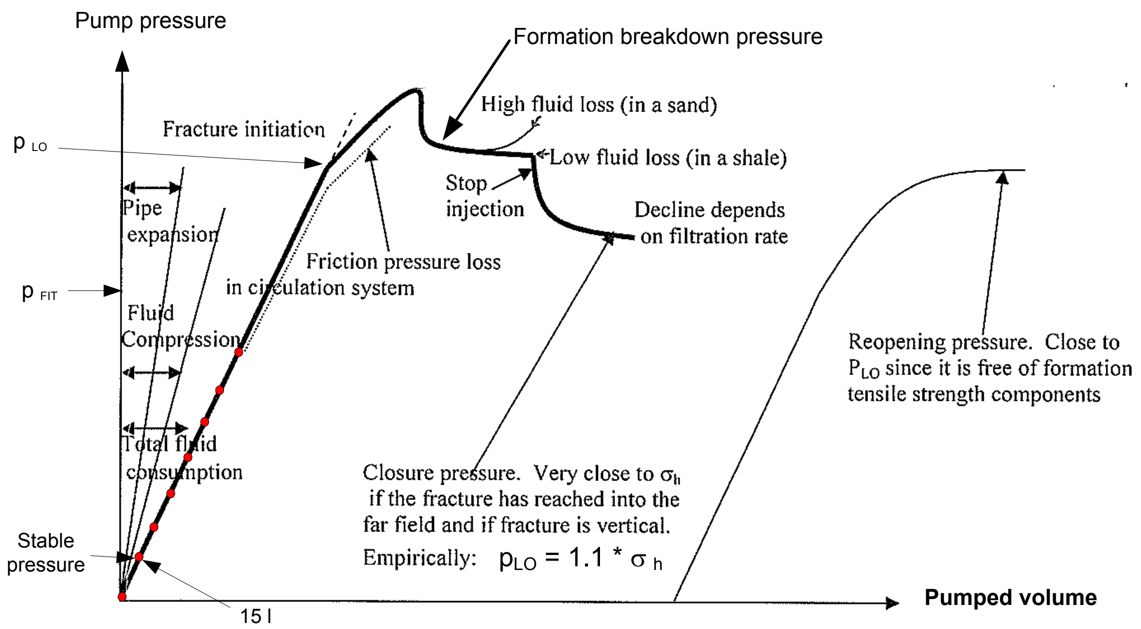


Figure 2-18: A full leak-off test, including breaking down the formation.

3 Well Control Equipment

Blowout preventers and accessory equipment give the driller the capability to:

1. Close the borehole when high-pressure formation fluids enter it. For onshore drilling the closing takes place just below the drill floor, for offshore drilling (from a floater), the closing takes place at the sea floor
2. Control the release of high-pressure pore fluids
3. Pump weighted mud under high pressure into the well to restore balanced pressure situations
4. Move the drill string through a closed BOP while the well is under pressure
5. Disconnect, cut off, and leave the drill string inside the closed well if necessary

Figure 3-1 gives an overview of the blowout preventer (BOP) and associated equipment on a floating drilling rig, together with the mud circulating system.

In offshore drilling at shallow or moderate depths, the drill string and drilling components are guided to the drilling location along guidelines extending from a guide frame, previously placed on the ocean floor. The blowout preventer stack is attached to the guide frame.

In deep sea drilling situations, the use of guidelines is impractical. Guideline-less drilling with a video system allows precise spotting and re-entry of the hole.

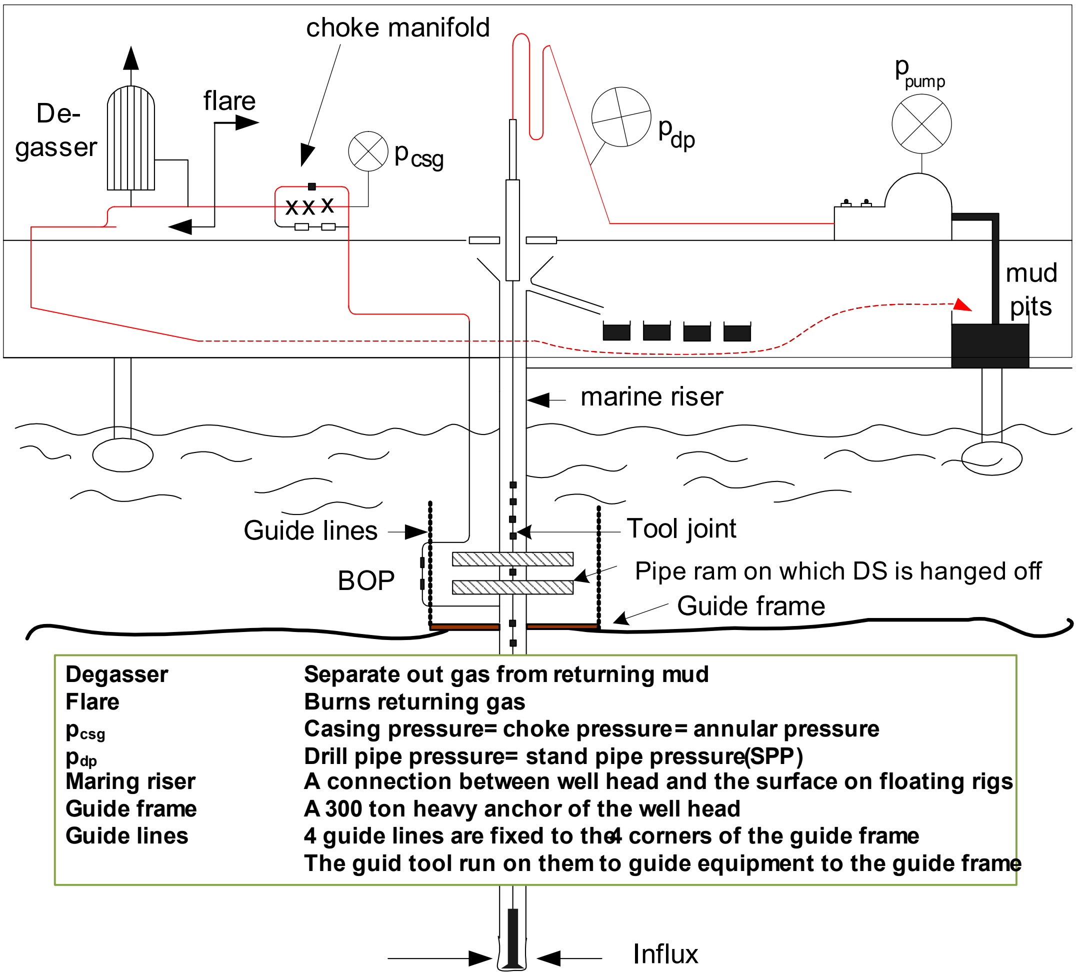


Figure 3-1: Kick control on an offshore rig. Surface mud lines in red.

3.1 BOP stack and associated equipment

Figure 3-2 gives an overview of well control equipment (closing equipment).

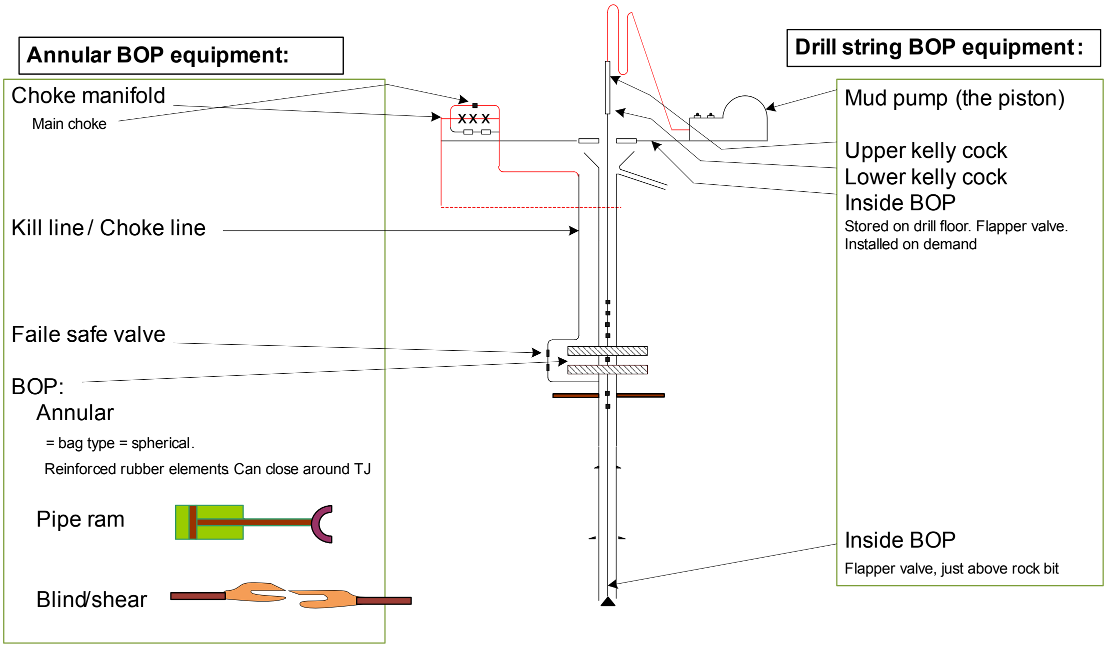


Figure 3-2: Well control equipment applied to close the drill string (left) and annulus(right).

3.1.1 Shutting off the annulus

Figure 3-3 presents a BOP stack and its communication to the rig. The strongest BOP equipment is rated to withstand a pressure of 15 000 psi (1060 bars) from below.

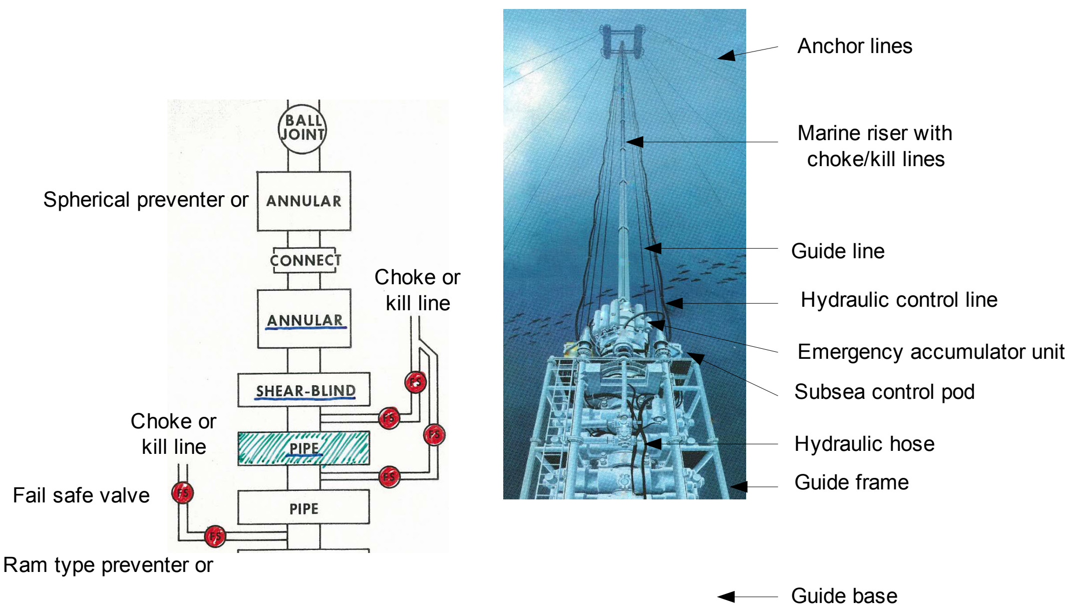


Figure 3-3: Standard Offshore BOP stack (left) and communication to the rig floor (right).

Four ram type preventers and two annular type preventers give the driller full capability to meet the requirements of a preventer system. When the fail safe (FS) valves of the choke line outlet are in an open position, control of the pressure is taken over by the surface choke-manifold. Shear rams may, in emergencies, be used for cutting off a drill pipe, deform it and hold it, hindering it to fall into the hole, and seal the wellbore, in one and the same operation.

Blowout preventers have side outlets for choke and kill lines, but most operators prefer to connect these lines to a drilling spool instead. The advantage of incorporating the side outlets directly onto the blowout preventer is that the entire BOP stack becomes shorter.

Figure 3-4 shows an annular (or spherical) type preventer. It is located at the top of the BOP stack, above the ram-type preventers. Usually the spherical preventer is the first preventer to be closed when the well experiences a kick. The spherical preventer's elastomeric packing quickly seals around the outside of the drill string (could be made up of the drill collars or the tool joints) when hydraulic pressure is applied to its driving piston.

Spherical preventers can also be closed in an open hole, completely shutting off the well bore. With its steel and rubber-packing element, it can effectively fill the annular space or the wellbore if the drill pipe is out of the hole. However, this practice should only be applied in emergency situations, because the life of a packing element will be greatly reduced due to this action. Furthermore, the spherical preventer allows the drill pipe to be rotated and the entire drill string to be stripped in or out of the well while maintaining a positive seal on the drill pipe at all times. The pressure regulator of the hydraulic oil maintains a constant hydraulic force from the packer on the drill string regardless of whether the drill pipe or tool joint is being stripped through the preventer.

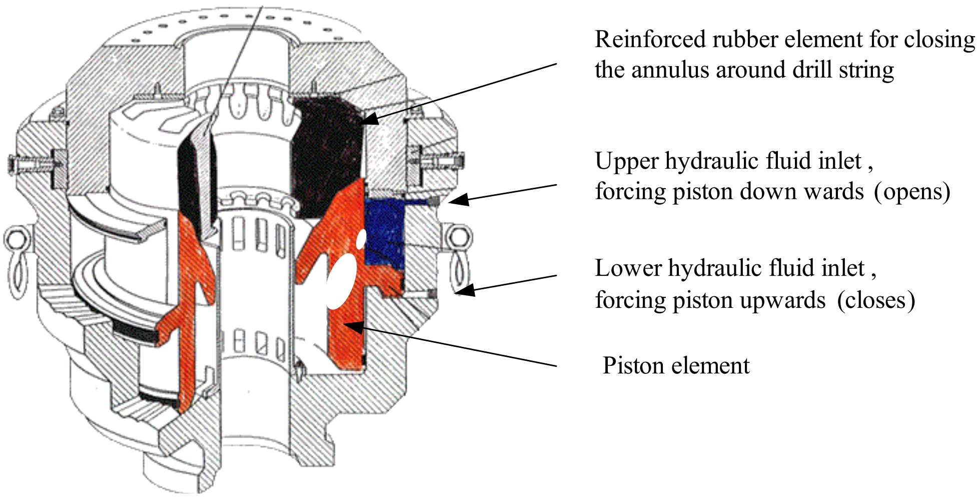


Figure 3-4: Spherical preventer.

Figure 3-5 presents a pipe ram and gives an indication of how it is operated.

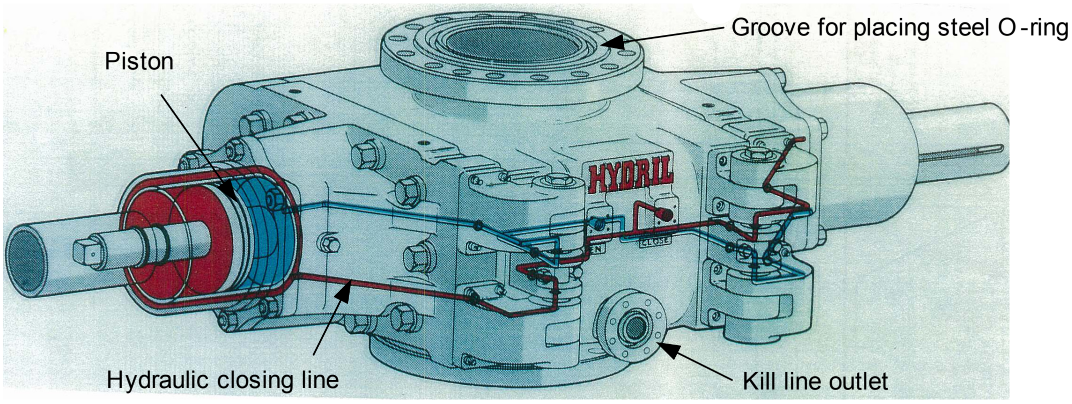


Figure 3-5: Pipe preventer.

On top of the upper connector, the marine riser is attached to the ball joint as shown in Figure 3-6. The upper connector enables a fast disconnection in an emergency situation. The bottom connector joins the BOP stack to the wellhead. The kill and choke line are integrated with the riser.

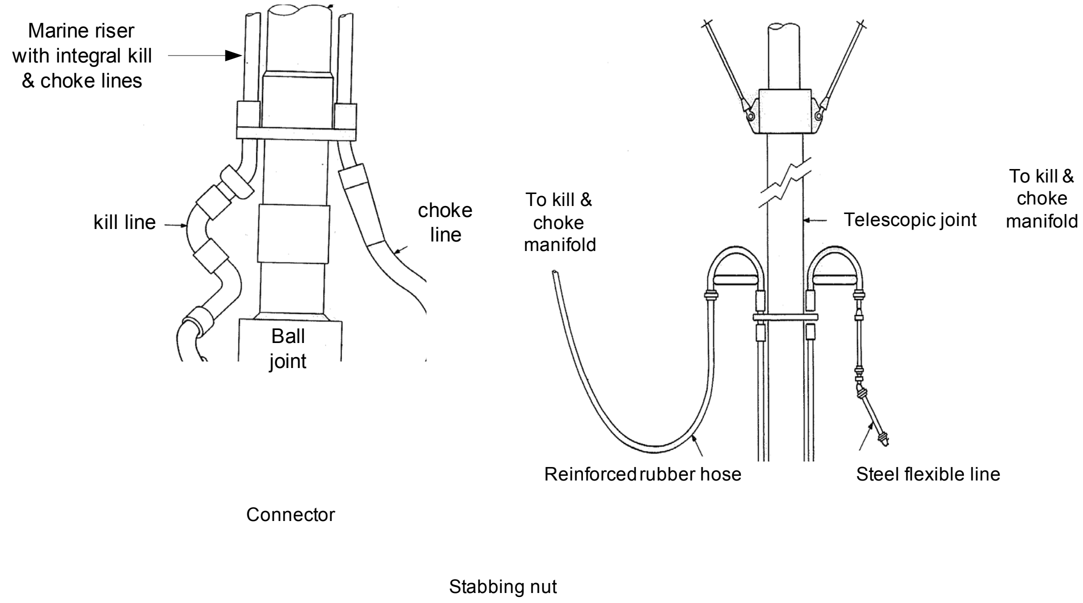


Figure 3-6: Top part of the BOP stack (left), the marine riser and its upper part (right).

3.1.2 Shutting off flow through the drill string

The drill string can be closed by tree means:

- Kelly cock, lower and upper
- Inside BOP
- The mud pump

A Kelly cock is a ball valve, shown in Figure 3-7, installed on and/or above the Kelly to ensure easy access. Kelly cocks are designed to withstand the same well bore pressure as the other BOP components. An inside BOP is a flapper valve, kept in shut position by a weak steel spring. Downwards mudflow will open it, and upwards flow will immediately close it again (float valve).

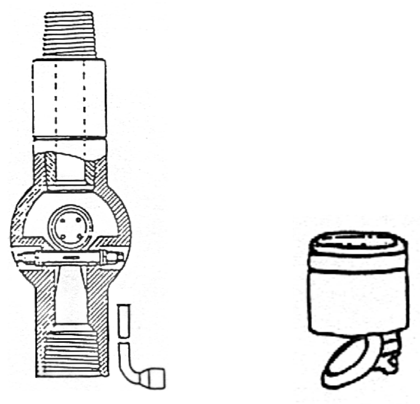


Figure 3-7: Kelly cock (left) and Inside BOP (right).

It is the operator's difficult task to decide if the one-way float valve should be installed in the drill string or not. The disadvantage of installing a float valve is that it is more difficult to find the correct SIDPP during kick situations; it is not possible to reverse circulate the well and it will result in higher surge pressure when tripping into the well. Some operators use a float valve that has a 2 mm opening in the disc in order to counteract the first mentioned disadvantage.

However, the advantages of a float valve are many. Kicks will not enter the drill string during tripping or when drill pipe is open at the surface. Good volume control is achieved when tripping into the well. Back-flow is avoided on connection.

3.2 Remote control of the BOP

In the old days surface BOPs used to be manually operated. Now they are often hydraulic/ electric operated through a remote control system. Figure 3-8 presents a hydraulic control system. Two control pods contain the valves that direct the hydraulic fluid to the various stack components. Hydraulic fluid supplies the pods through control hose bundles that extend back to hose reels on the rig and finally to the accumulators. The two control pods are color coded blue and yellow and provide redundant control. They can be independently retrieved for repair.

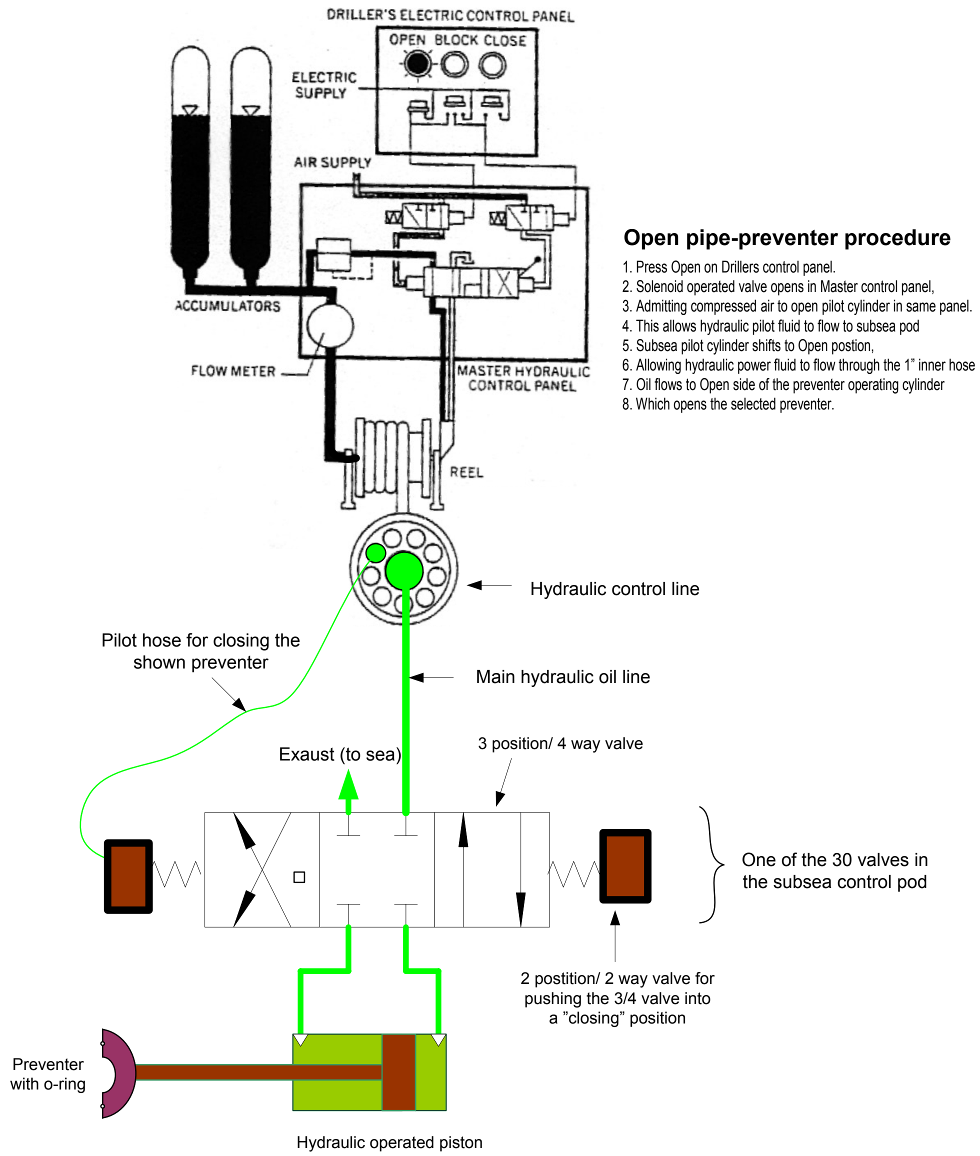


Figure 3-8: Hydraulic control system for BOPs with electric control panels on the platform.

3.3 Volumetric unstable well (kicking well)

Whenever the pore pressure becomes higher than the well pressure (and the pores are permeable) an influx from the formation will occur, referred to as a kick. Two different instruments, the return flow meter (Flow Paddle) and the pit level indicator in the active mud tanks (see Figure 3-9) can detect kicks. During tripping, the variation in the mud volume at the surface is controlled in the trip tank as shown in Figure 3-10.

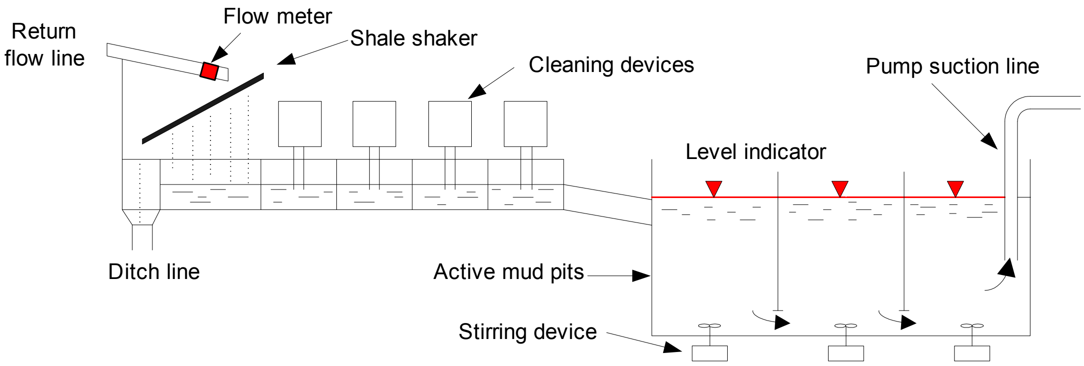


Figure 3-9: Surface metering of delta flow out (compared to input flow) and of accumulated volume change in the pit.

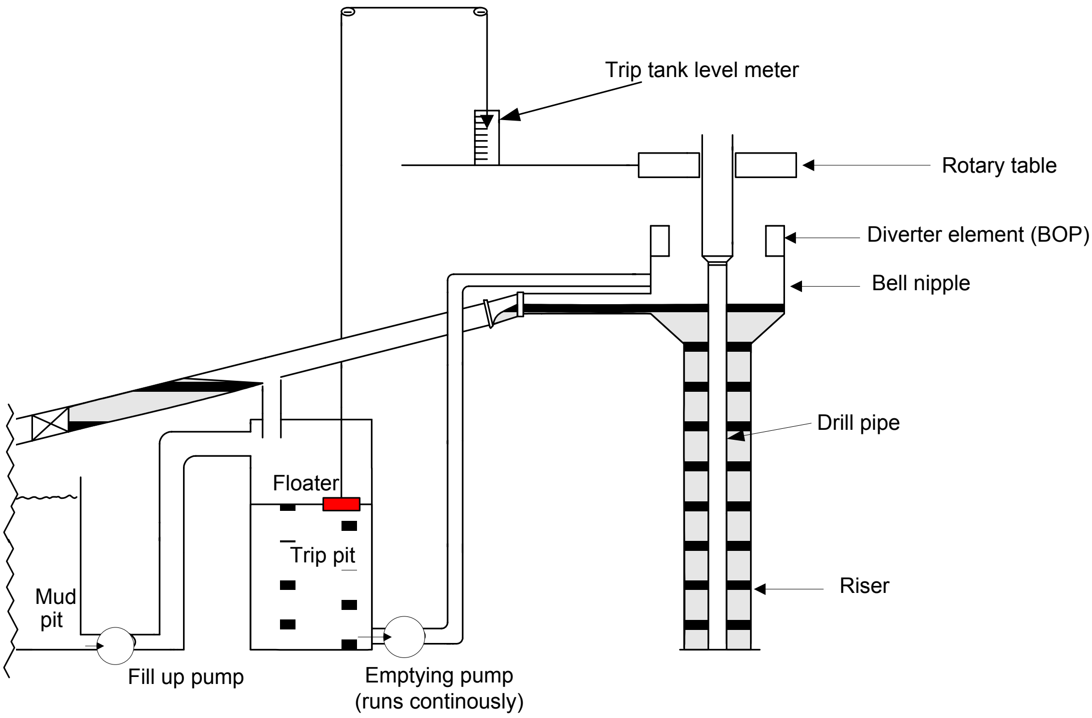


Figure 3-10: Kick detection during tripping.

3.4 Closing procedure during drilling operations

For closing operations, it is convenient to refer to Figure 3-1, where most of the relevant items are included. Standard procedure for closing the well on floating rigs during drilling is:

0. A kick alarm is initiated.

1. Hoist up drill string at least 5 m. This will hinder fill (of cuttings and weighting material) to block bit nozzles during killing.

2. Stop pump, check for flow. Is it a real kick or a false alarm?

3. First priority-closing elements:
   a) Close upper annulus first (the preventer can close around TJ. Do not need to know TJ's position at this initial stage).
   b) Close drill string if not already closed (e.g. by the mud pump) .
   c) Open inner and outer fail safe valve (if not already open, in accordance with alternative procedure) and slowly close adjustable choke in choke manifold.
   d) Observe MAASP.

4. Close the remaining valves in the BOP and hang off the drill string by letting it rest on a tool joint in the BOP
   a) Find position of the TJ closest to the pipe preventer to be closed.
   b) Adjust position of TJ by hoisting drill string up.
   c) Close pipe ram preventer.
   d) Lower drill string carefully and hang it off on TJ on the closed pipe preventer.

5. Read: SIDPP, SICP, V_{kick}

3.5 Well barriers during drilling operations

During drilling operations the regulatory authority (Oil Directory) requires two independent barriers against influx of pore fluids

Drilling of top hole can be conducted with the fluid column as the only well barrier. Potential shallow gas zones should not be penetrated prior to drilling out of the surface casing.

In all activities the following barriers are common:

Well Barrier One:	Fluid column
Well Barrier Two:	1. Drilling BOP 2. Wellhead 3. Casing 4. Casing cement

Additional items belonging to Well Barrier two are listed in Figure 11 under their respective option.

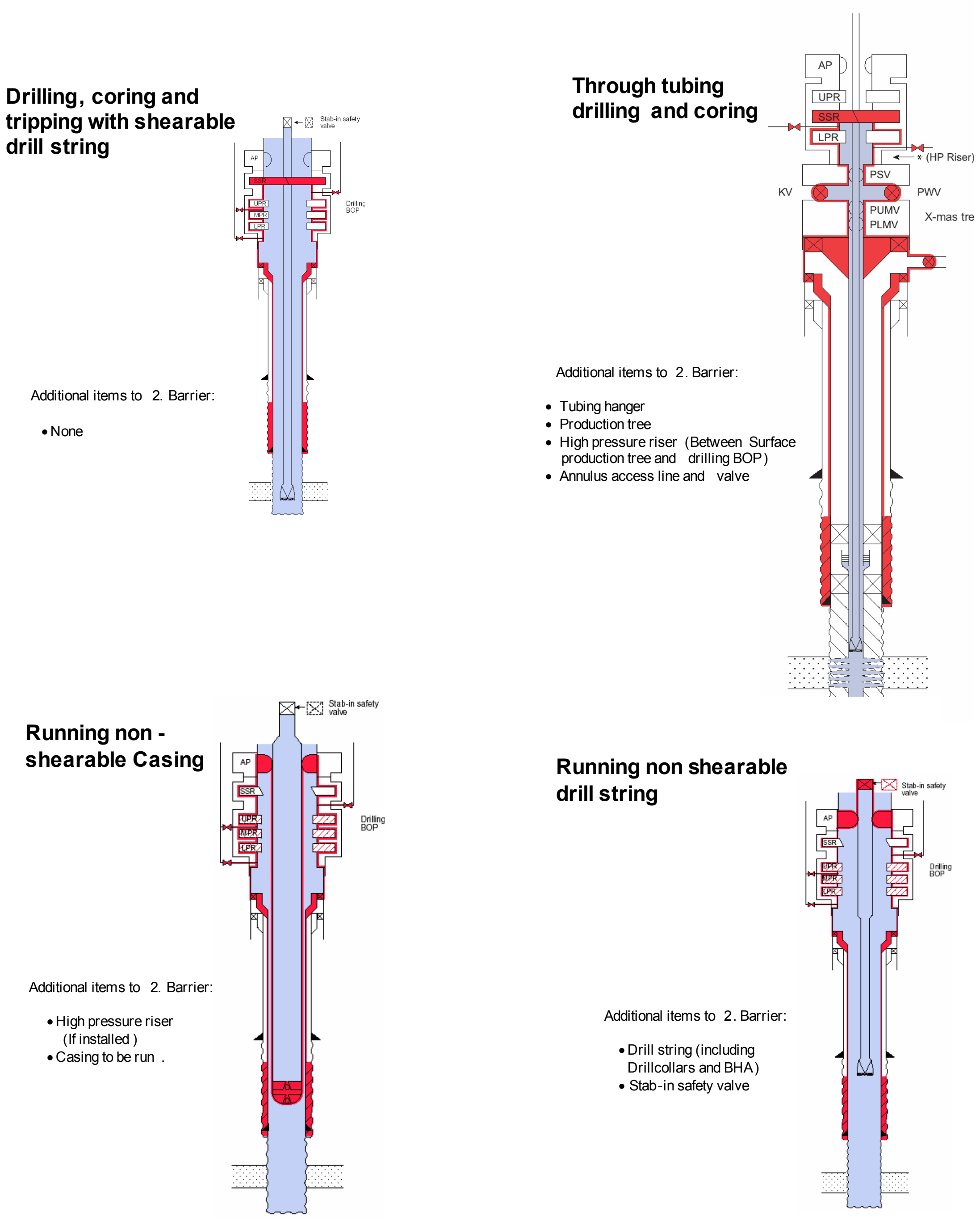


Figure 3-11: Four optional drilling operations together with their two barriers.

4 Standard killing methods

Figure 4-1 shows how to, in general, maintain safety against threatening high pore pressure while drilling.

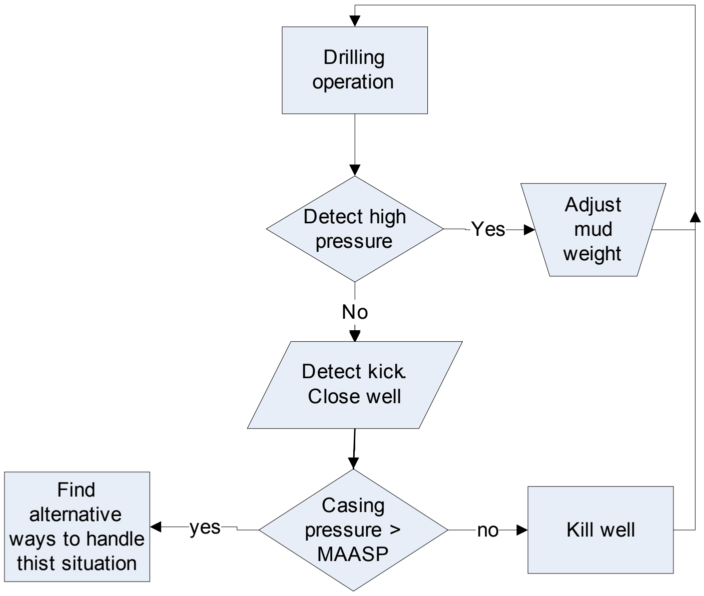


Figure 4-1: General procedure to maintain safety during drilling.

There exist a number of different killing methods, the two main methods being the Driller's and the Engineer's Method. The Engineer's Method is also called the Wait & Weight Method, abbreviated to W&W. The most common method of restoring an overbalanced situation after a kick has occurred is the Driller's Method, and this method will in this course be used to demonstrate the principles of killing a well.

Before any trouble occurs it is decided what circulation rate should be used to kill the well. In the Driller's Method the pore fluid is displaced before kill mud is injected. This row of action simplifies the operation. However, this method induces higher pressure in the un-cased annulus and more time is required for the entire operation than with the Engineer's method.

The Engineer's Method differs from the Driller's method by the simple fact that the mud weight is being increased and pumped into the well immediately.

Gas is a much more difficult kick fluid to handle than liquids, and from here on, we mainly discuss gas kicks. A small volume of gas at the bottom of a well is potentially dangerous because it expands when approaching the lower pressure near the surface. At low pressure it will expand and displace a corresponding amount of mud from the well, thus reducing the bottom hole pressure which in turn allows more gas to flow in from the pores. In this course we simplify the gas law by assuming constant temperature and compressibility, yielding:

$$pV = \text{constant} \tag{4.1}$$

Small influxes of gas are not likely to be detected with present kick detection methods, but during expansion of gas on its way up the annulus, it will most likely be noticed in the pits.

Annular pressure becomes higher when applying the Driller's Method, and the choke nozzles erode quicker. If there is a risk of fracturing the casing shoe, the W & W-method must be chosen. W & W is used in long open hole sections to reduce the pressure in the annulus, otherwise the Driller's Method is preferred.

But in situations when the casing shoe is set deep, the gas bubble will be inside the casing before the kill mud reaches the bit, and W&W will give no advantages. The Driller's Method is simple, and the total time it takes is practically the same as for W & W. It is important to get started fast to avoid the pressure increase due to gas percolation as discussed in chapter 4.1.2.

Another problem with gas kicks is that gas decreases mud rheology, especially in OBM, and barite falls out. Barite must, by the way, be delivered from the supply base in adequate amounts to sufficiently increase the mud weight of the total active mud volume. Typical active mud volume for offshore operations is 200 m^3 in the surface tanks, and 200 – 400 m^3 in the well.

4.1 Surface and bottom pressure of a shut in well

4.1.1 Stabilized pressure just after shut in

It is sometimes easier to view the circulating system as a U-tube like in Figure 4-2. The important point is that the two "t"; drill string and annulus, are connected at the bottom, and here the pressure is identical. Figure 4-3 shows how the pore pressure affects the pressure in a shut-in, static well, after it has stabilized.

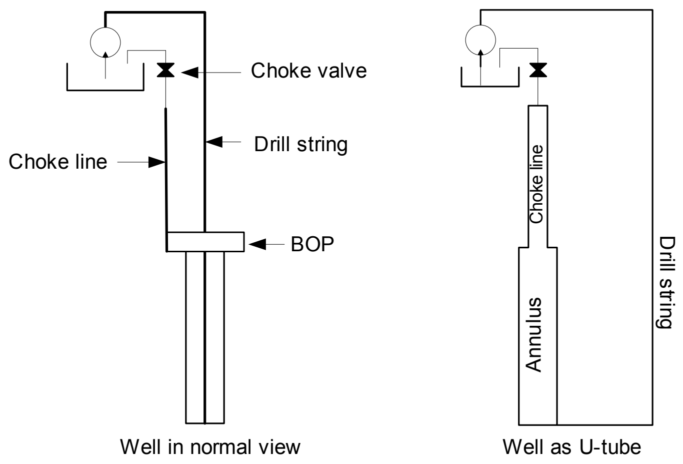


Figure 4-2: Well in two different views.

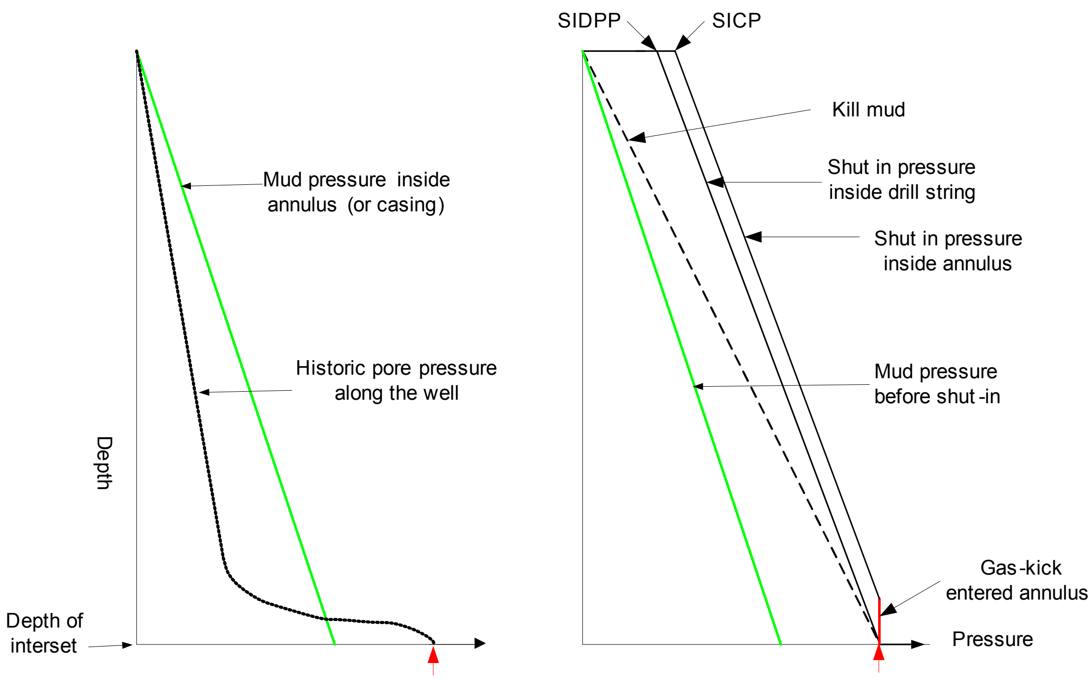


Figure 4-3: Pressure before (left) and after shut in.

4.1.2 Gas percolation in a closed well

After closing the well, gas will rise due to buoyancy, but the volume remains constant in accordance with eqn. 4.1 since it is not allowed to expand. Therefore, also the pressure of the gas bubble will remain constant. If the gas kick arrives at the surface without breaking the formation or the equipment, the pore pressure has been brought along with the gas bubble as shown in Figure 4-4.

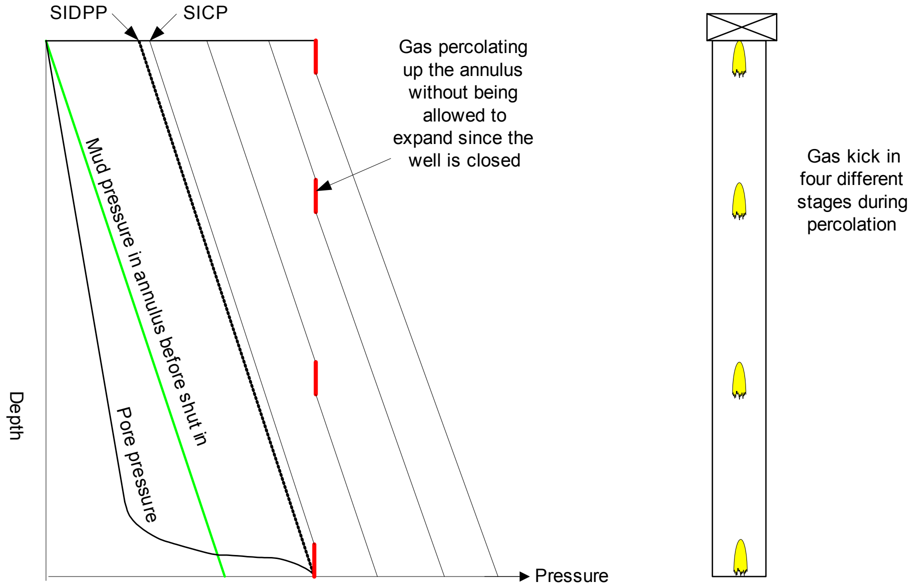


Figure 4-4: Pressure development as gas percolates to the surface in a closed well (assuming the formation will withstand the high pressure).

4.1.3 MAASP

Figure 4-5 demonstrates the importance of the expression MAASP (maximum allowable annular surface pressure). If the surface pressure rises above MAASP, the formation below the casing shoe will fracture.

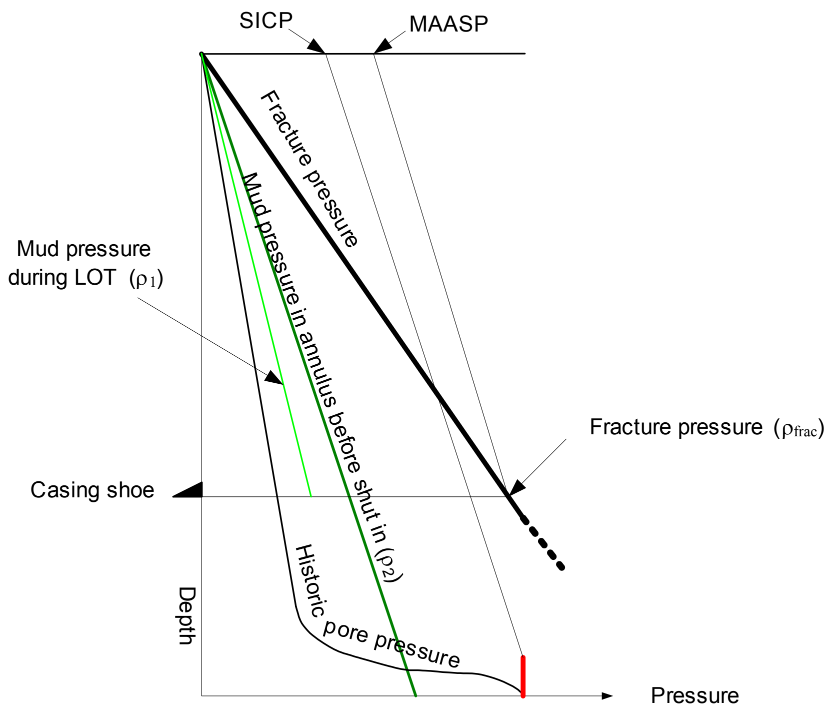


Figure 4-5: MAASP.

MAASP can be estimated through eqn. 4.2.

$$MAASP = (\rho_{frac} - \rho_2) \cdot h_{csg.shoe} \cdot g = p_{LO} - (\rho_2 - \rho_1) \cdot h_{csg.shoe} \cdot g \qquad (4.2)$$

ρ_{frac} is the equivalent density that balances the fracture pressure.

4.1.4 Estimating kill mud weight and safety factors

Before any killing method is studied in detail, some parameters must be established on basis of information from the static shut-in well. After the close-in action is completed, the pumps seal the well at the drill string end and at the other end by means of closed BOP and surface choke. Inside the drill string, the liquid composition is assumed to be uncontaminated, so that the new formation pressure becomes:

$$p_{pore} = p_{SIDP} + \rho_{mud} \cdot g \cdot h_{well} = \rho_{kill} \cdot g \cdot h_{well} \qquad (4.3)$$

and hence the required mud weight to balance the pore pressure:

$$\rho_{kill} = \rho_{mud} + \frac{p_{SIDP}}{h_{well} \cdot g} \tag{4.4}$$

A safety margin has to be added; typically 0.05 kg/l. It should at least be sufficient to avoid swabbing during the subsequent tripping operations. An empirical formula sometimes seen is:

$$\text{Trip margin} = 0.01 \cdot \tau_y \Big/ \{(d_{bit} - d_{drill\ collar})\ g\} = \left(\frac{0.01 \cdot 20\ Pa}{0.05 \cdot 9.81} = 40\ kg/l\right) \tag{4.5}$$

A special type of safety margin (SM) for offshore operations is the Riser Margin as illustrated in Figure 4-6. When the location has to be abandoned for some reason, the riser is disconnected at the upper connector in the BOP, and mud in the riser is automatically replaced by sea water and an air gap. The necessary mud weight to balance the pore pressure is:

$$\rho_{balance} * g * h_3 = \rho_{kill} * g * (h_2 + h_1 + h_3) = p_{pore} \tag{4.6}$$

Then the Riser Margin is defined as the excess mud density above the kill mud:

$$\text{Riser Margin} = \rho_{balance} - \rho_{kill} \tag{4.7}$$

and the resulting mud weight becomes:

$$\rho_{total} = \rho_{kill} + \text{Riser Margin} \tag{4.8}$$

In deep water drilling, the Riser Margin becomes large and unpractical (see chapter 7.2).

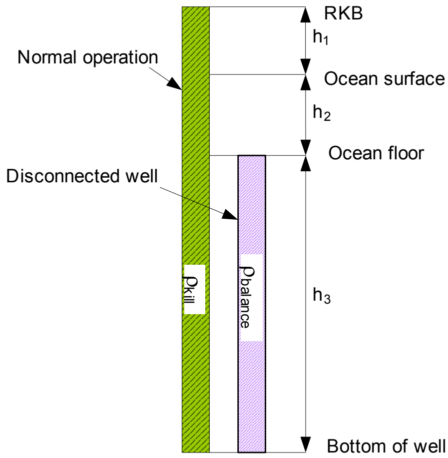


Figure 4-6: Riser Margin determination.

4.1.5 Composition of influxing pore fluid

It is always of importance to check what type of fluid that has entered the well. If only liquid (oil, water or mud) has entered the well, the displacement procedure is simplified and will, by far, not be so critical as for a gas kick. However the killing procedure will still be the same

Volume gained in the pit, V_{kick}, represents the quantity of the formation fluid entering the well bore. The length of the annulus occupied by the unknown fluid is estimated, and the difference between p_{SIC} and p_{SIDP} determines its gradient. The height of the fluid is determined from the volumetric capacity at the bottom part of the well:

$$h_{kick} = \frac{V_{kick}}{C_{ann}} \tag{4.9}$$

Figure 4-2 and 4-3 show that the bottom hole pressure can be calculated from two fluid columns; the annulus column and the drill string column.

$$p_{SIDP} + g \cdot \rho_{mud} \cdot h_{well} = p_{SIC} + \rho_{mud} \cdot g \cdot (h_{well} - h_{kick}) + \rho_{kick} \cdot g \cdot h_{kick} \tag{4.10}$$

Assuming gas density is negligible and the capacity is constant, then solving for ρ_{kick} yields:

$$\rho_{kick} = \frac{h_{kick} \cdot g \cdot \rho_1 - (p_{SIC} - p_{SIDP})}{g \cdot h_{kick}} \tag{4.11}$$

4.2 Hydraulic friction during killing

A dynamic well, i.e. one that is being circulated, is more complicated than a static well. Figure 4-7 and 4-8 present a well during a dynamic situation. Figure 4-7 contains purely hydraulic friction losses in a simplified view of the well, without hydrostatic pressure. Total friction loss = SPP. Then, in Figure 4-8, the reality is added in two steps; first in a vertical view, but still with air as reference pressure, then finally with mud as reference:

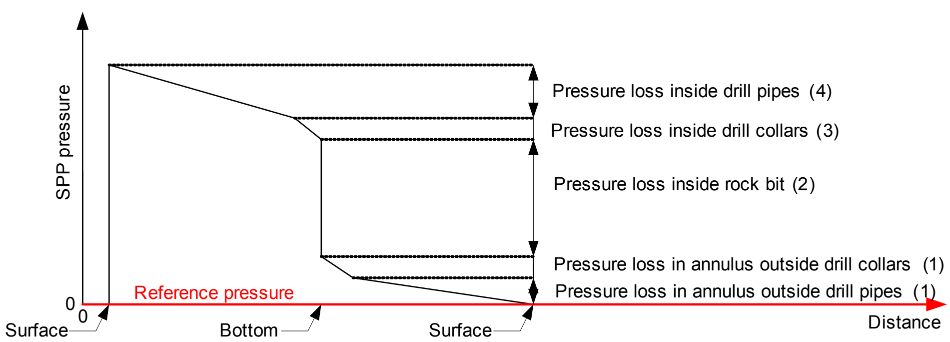


Figure 4-7: Pressure loss in the well during circulation through it in a horizontal, stretched-out view. Reference pressure is air (red line).

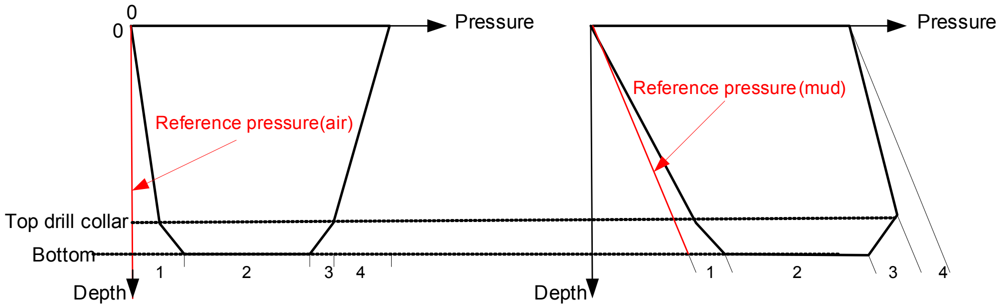


Figure 4-8: Well pressure during circulation through the well in a U-tube view. Numbered friction losses are: 1- annulus, 2- bit nozzles, 3- inside drill collars, 4- inside drill pipes.

4.3 Killing by means of Driller's Method

Killing of a well that had to be shut-in because of a kick follows three principles:

1. Bottom pressure must balance the pore pressure with a small over balance
2. Bottom pressure is controlled through the drill string, which is filled with a mud of known density
3. After pump is turned on and running with a constant, predetermined rate, bottom pressure is regulated with a back pressure valve at the surface

4.3.1 Six phases of killing

The Driller's killing procedure could best be understood by dividing the operation into six separate phases. Figure 4-9 presents the complete procedure exemplified through the following kick situation:

Mud in use:	ρ_{mud}	= 1100 kg/m^3
Depth of well (TVD):	D	= 2000 m
Previously recorded circulation pressure:	pc1	= 28 bar (SCP)
at Slow Circulation Rate:	SCR	= 30 SPM
Pump capacity:	q	= 20 l/stroke
SIDPP:	p^{SIDP}	= 18 bar
SICP:	p_{SIC}	= 22 bar
Kick volume:	V_{kick}	= 1 m^3
Annular capacity around BHA:	Cap_{BHA}	= 14 l/m
Drill string internal capacity:	C_{dp}	= 8 l/m

Bottom hole pressure must be kept constant, and pressure in annulus observed closely. 45 and 60 SPM are common "slow circulation rates". 30 and 40 SPM are normal on a floating rig, while 15 SPM is used when the gas is entering the choke line. Too quick expansion makes it difficult to keep track of the change in pressure.

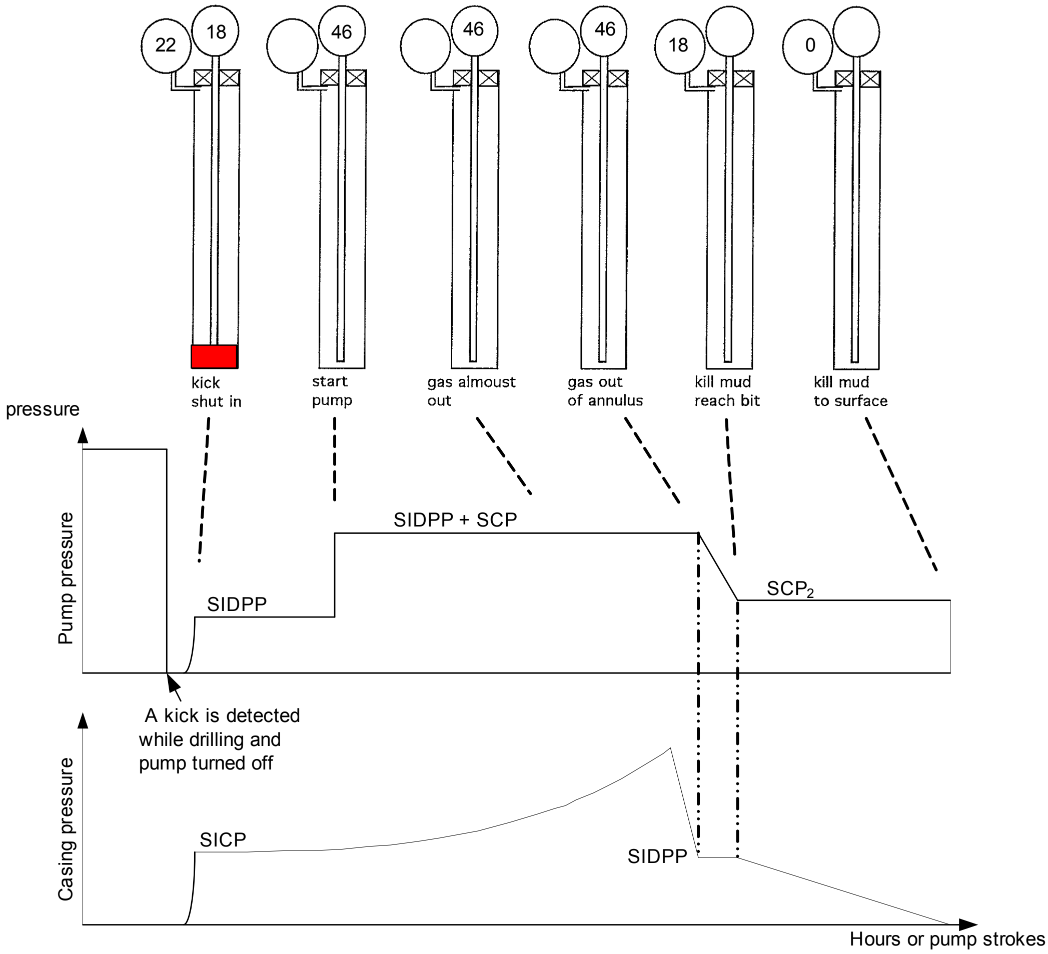


Figure 4-9: A gas kick in six stages handled by means of the Driller's Method.

Phase 1: The kick has been shut in and we estimate the following parameters:

$$p_{pore} = p_{SIDP} + \rho_{mud} \cdot g \cdot D = 18 \cdot 10^5 + 1100 \cdot 9.81 \cdot 2000 = 205 \cdot 10^5 = 205\ bar$$

$$\rho_{kill} = \rho_{mud} + \frac{p_{SIDP}}{h_{well} \cdot g} = 1100 + \frac{28 \cdot 10^5}{9.81 \cdot 2000} = 1134\ kg/m^3$$

Type of kick composition:

h sub = 1000 l / 14 l/m = 71 m

$$\rho_{kick} = \frac{71 \cdot 9.81 \cdot 1100 - (22-18) \cdot 10^5}{9.81 \cdot 71} = 526\ kg/m^3$$

Phase 2: Start the pump. Pump starting-up procedure is difficult; well pressure may easily go below the pore pressure, causing new, small influxes: Open the choke slowly and increase the flow rate slowly and steadily, i.e. over a period of 15 s, until pump has reached the reduced, predetermined pump speed. Regulate the choke so that:

$$p_{dp} = p_{SIDP} + p_{C1} \text{ (+ safety margin)} = ICP \tag{4.12}$$

The low pump rate while killing the well (usually one-half of normal pump rate or less) induces very small pressure drops in the annulus. The friction loss in the annulus contributes, at normal circulation rates typically with only 10 % of the total friction, at killing rate even lower percentage. The circulation pressure, p_{C1}, is mostly lost in the drill pipe, drill collar and bit nozzles, and may be disregarded in the annulus. This rejection results in an extra safety factor against the pore pressure, equal to the annulus pressure drop.

Phase 3 and 4: Circulation out the gas:

In the other end of the circulation system, the choke pressure, p_{choke}, should initially be equal to p_{SIC} (+ safety margin) and thereafter slowly increasing due to gas expansion, reaching a peak value just before gas surfaces, and then quickly dropping to a value equal to p_{SIDP}.

Phase 5: Filling drill pipe with heavy mud:

In the last moment of phase 5 the heavy mud has reached the bit. The original p_{SIDP} is now reduced to zero and friction pressure, p_{C1}, has increased to p_{c2}, due to the higher resistance of the heavier mud, which also is the Final Circulating Pressure:

$$p_{C2} = \frac{\rho_{kill}}{\rho_1} \cdot p_{C1} = \text{FCP} \tag{4.13}$$

The reduction of p_{SIDP} and the increase of p_{C1} is assumed to be a linear change (although it is not) and is completed when DP is filled with kill mud. We want to know how long it takes:

Volume of drill string:	2000 m * 8 l/m	= 16 000 l
Strokes to bit:	16 000 l / 20 l/stroke	= 800 strokes
Time to bit:	800 strokes / 30 strokes /min	= 27 min

When this p_{DP}-schedule is held, the pressure exerted at the bottom of the well will never be less than p_{pore} + SM + annular pressure loss, and no further influx of formation fluid will take place. Observe that the casing pressure during phase 5 is constant.

Phase 6: Filling the annulus with heavy mud:

The DP has now been filled with a mud of known weight, and if the pump speed is held constant, the pressure loss (p_{C2}) will not be altered from this point on. If p_{DP} (stand pipe pressure or pump pressure) is kept equal to p_{C2} + SM by means of the choke, the pressure will now be under control, both in the drill pipe and the annulus.

Offshore killing operations take typically one day.

4.3.2 Critical pressures during killing

Figure 4-10 indicates that the most critical situation during killing is when the pressure at the casing shoe is maximum, because then the formation may fracture. This could be either just after shut in (static) or when gas reaches the casing shoe. Casing shoe pressure becomes highest when gas reaches the casing shoe, due to the expansion of gas on its way to the surface. However, due to low capacity around BHA, the gas height may be largest in situation 1. Situation 3 is the least critical with respect to casing shoe pressure.

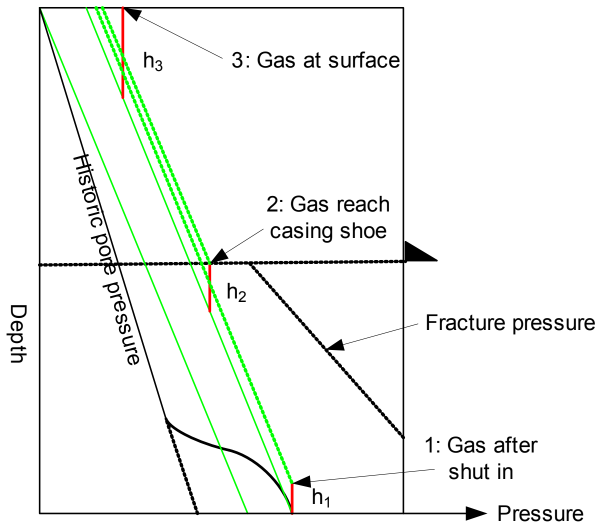


Figure 4-10: Three situations when pressure in the well can be critical due to gas height.

4.4 The Engineer's Method and kill sheet

The Engineer's Method is always the first optional method. An extra safety factor is added through this method because the annular pressure will become lower compared to the Driller's Method. In the Engineer's Method kill mud circulattion as soon as possible, reducing the drill pipe or pump pressure as soon as heavy mud enters the annulus, as illustrated in Figure 4-11.

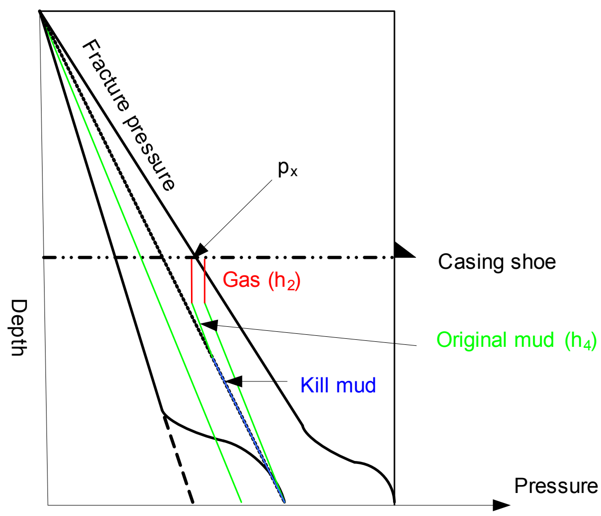


Figure 4-11: Comparing critical annular pressure for Driller's and Engineer's Method.

The procedure is much quicker, and the annular pressure will be lower, but all the control functions are similar to those in the Driller's Method.

The complete killing procedure is always administered through a kill sheet. Figure 4-12 presents a typical example of a kill sheet. Through a kill sheet the user obtains a complete overview of pressure at any time. Most of the necessary data are known ahead of time and entered into the sheet. The slow circulation pressure, pc_1, changes whenever any of the contributing parameters change, and must be recorded at least once a day.

Like for the Driller's Method, maximum pressures must be checked at shut in and when gas reaches the casing shoe. Now the gas pressure has risen to p_x (see Figure 4-11):

$$\begin{aligned} p_{bottom} &= p_{down the annulus} = p_{down the drillstring} \\ &= p_x + 0 \cdot g \cdot h_2 + \rho_{mud} \cdot g \cdot h_4 + \rho_{kill} \cdot g \cdot (h_{well} - h_2 - h_4) = p_{SIDP} + \rho_{mud} \cdot g \cdot h_{well} \end{aligned} \quad (4.14)$$

Discussion of assumptions and other details will be tended to through exercises.

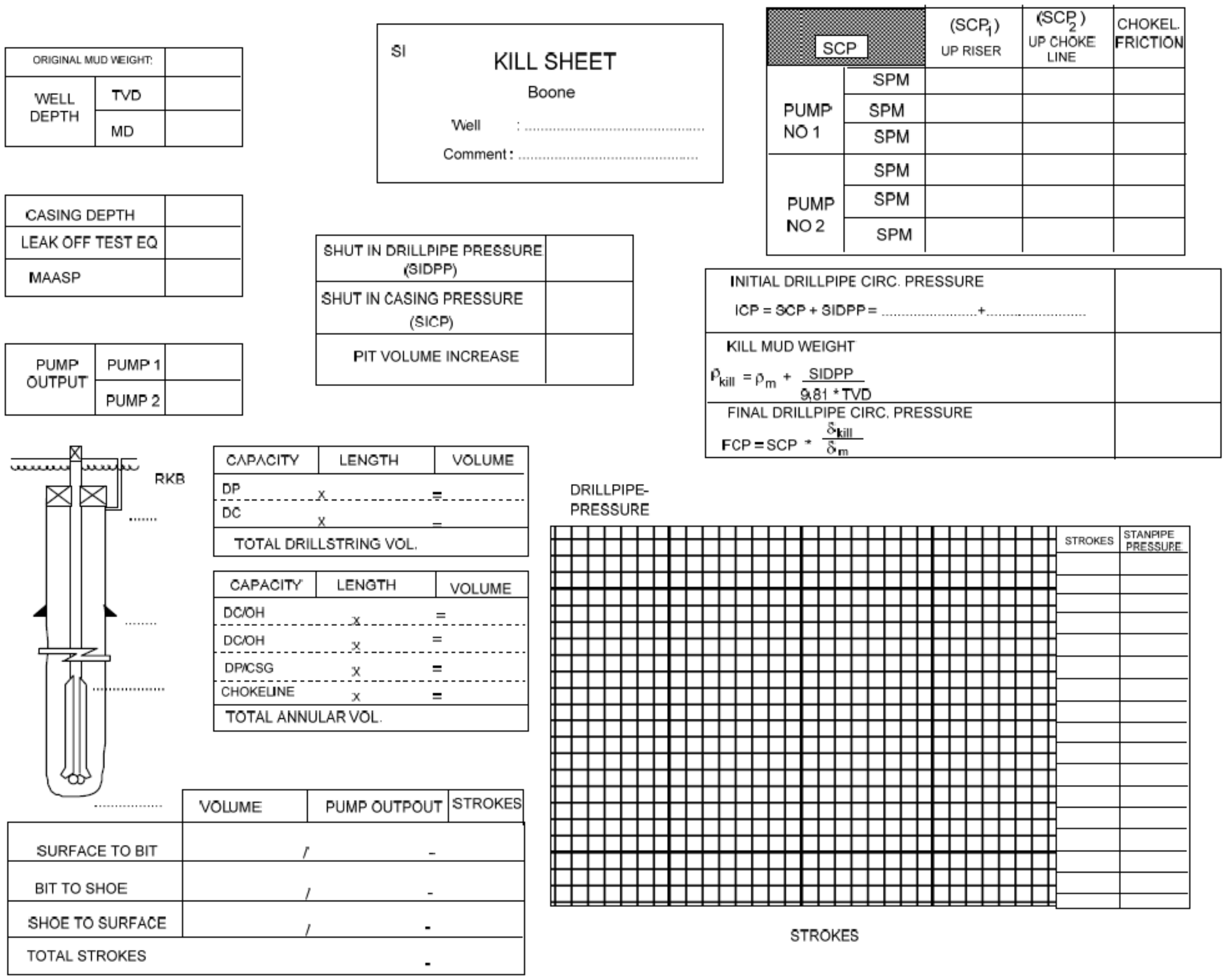


Figure 4-12: Kill sheet.

4.5 Killing when unable to circulate from bottom

A kick is difficult to handle when the DP is off bottom; it is impossible to bring a uniform mud into the complete annulus to control the formation in this type of cenarios. The same situation arises when the circulation system is plugged or broken. Before a controlled killing procedure can be carried out, the drill pipe must be on the bottom. Every effort is therefore made to strip the string back on bottom or repair the plugged circulation system.

The stripping procedure is not possible when surface pressure rises too high, which will become the case when large gas bubbles travel upwards. We are left with the volumetric method.

The Volumetric Method involves allowing a controlled amount of mud to be let out from the well as gas simultaneously moves up the hole and expands. By assuming that gas is weightless, the removal of heavy mud from the annulus leads to loss of hydrostatic column, p_{loss}. The casing pressure must therefore be allowed to increase by the same amount through gas expansion in a closed well in order to maintain a constant bottom hole pressure.

The procedure starts by selecting a suitable volume of mud, V_{mud} , e.g. 1.0 m^3. This volume is easy to measure and to relate to. It must corresponds to the mentioned casing pressure increase, pincr, as $_{indicated}$ in Figure 4-13.

One unit of mud, V_{mud}, occupies a vertical height, h, in the annulus, and with an example capacity of 20 l/m, the gas height becomes:

$$h = \frac{V_{mud}}{Cap_{ann}} = \frac{1}{0.020} = 50\ m \tag{4.15}$$

This column of gas represents the loss of a mud column of same height and must correspond to an identical increase of pressure;

$$p_{loss} = \rho_{mud}\, g \cdot h = p_{incr} \tag{4.16}$$

Figure 4-13 shows how pressure varies at the choke (pcsg) and at the bottom.

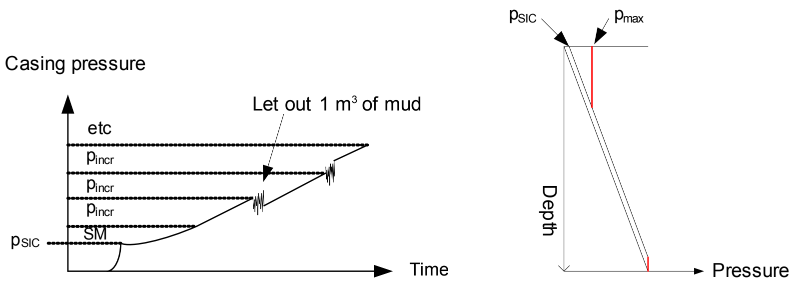


Figure 4-13: Casing pressure (surface) as gas rises in a closed well with intermittent release of mud (left). Annular pressure when all gas has reached the surface (right).

Procedure indicated in Figure 4-13 is summarized here:

1. Determine SM, the safety margin against formation pressure; it prevents further influx from the formation, even if bottom pressure fluctuates quite a bit during gas release.
2. Every time when casing pressure has increased p_{inc}, V_{mud} is bled off through the choke.
3. When the gas finally has percolated to the surface and reached the choke, all the gas is on top of the mud column. Maximum expansion and backpressure is reached as shown in Figure 4-13 (right), and casing pressure is stabilized; it does not change anymore.
4. Mud can now be pumped into the well through the drill pipe or through the kill line. For each unit of mud, V_{mud}, pumped into the well, the casing pressure should stepwise be reduced by p_{incrc}.
5. After all gas is displaced by mud, the annular pressure should be equal to p_{SIC} + SM. Now there is time to repair the plugged circulation system or lower the drill string to the bottom and kill the well properly (by means of the Driller's Method).

5 Modification of the standard killing method

5.1 Modification due to narrow pressure window

Narrow pressure window refers to a low difference between fracture pressure and pore pressure (or formation collapse pressure if higher than pore pressure). It represents the balance between lost circulation on one side and a kick on the other side. This problem occurs especially in wells drilled in deep water, in deep wells (HTHP wells) and in long, slim wells.

In deep and long, slim wells the friction pressure in the small annular space become large while pumping, and ECD approaches the equivalent fracture density. The reason behind a narrow pressure window in deep water wells is different than for long, slim wells, but the challenge is the same. Drilling in deep waters necessitates long choke lines and narrow annuli. The two main problems associated with deep wells, drilling in deep water or long, slim holes are:

1) Lower pressure window
2) High annular pressure losses

Hydraulic pressure loss in the annulus depends largely on annular clearance. The annulus between the bottom hole assembly (BHA) and the wall in slim holes is extremely narrow. Above the BHA the ratio between the outer wall and the internal drill pipe is less extreme. The extreme example is; continuous coring operations. Here the annular gap is only a few millimetres. The annular pressure loss amounts to up to 80 % of the total pump pressure. Deep wells also have a long and narrow annular path, with varying rheology due to temperature and pressure variation. At the same time the gap between pore, collapse and fracture pressure decreases. ECD control becomes essential.

5.1.1 Lowered mud window in deep wells and in deep water

Since the pore pressure gradient increases with depth, the relative difference between pore pressure and fracture pressure also decreases, Figure 6-1 clearly demonstrates this fact.

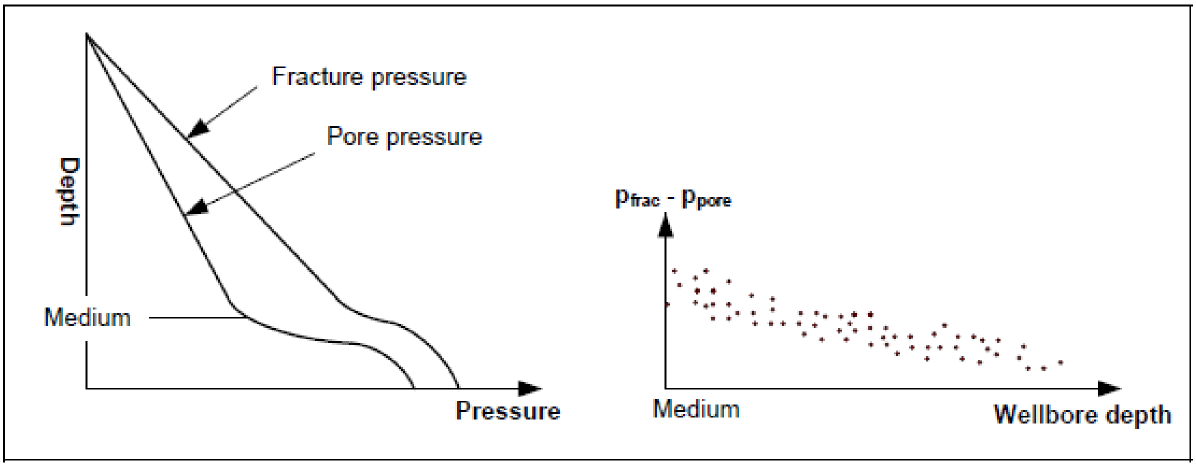


Figure 5-1: Pressure window vs. depth, starting at medium depth.

The effect of water depth is even more dramatic than formation depth. Figure 5-2 speaks for itself on this issue.

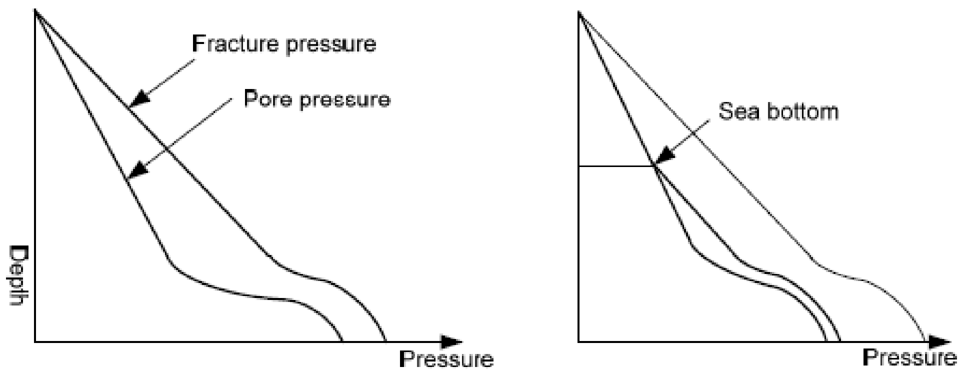


Figure 5-2: Onshore (left) and offshore (right) high-pressure formation in relation to pressure window. It is here assumed that high pore pressure starts relative shallower offshore.

Offshore fracture gradients are lower at the same relative depth since the overburden is water.

5.1.2 High annular friction pressure hidden in SICP

When annular pressure loss is large killing operations are planned and carried out similar to conventional operations, with similar kill sheets and choke operation procedure. However, if the annular friction pressure, Δp_{ann}, is causing the weakest point in the annulus to be exceeded, a modified slim hole well control procedure must be applied. The modified slim hole killing procedure is summarized in Figure 5-3. It is necessary to subtract the large annular friction pressure, Δp_{ann}, from the SICP. The SICP must be reduced by this value when circulation starts, and later increased by the same amount. The point at which the circulating pressure is brought back to its true value, is indicated in Figure 5-4. This point occurs when the choke reaches the full open position in order to keep the circulating pressure constant. At this point, although the well is not dead, the formation pressure is exactly balanced by hydrostatic heads and frictional losses.

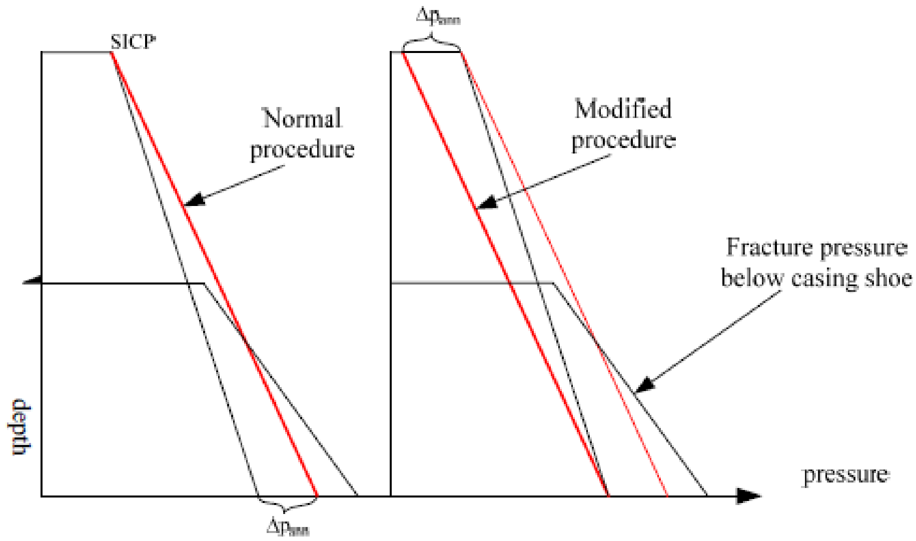


Figure 5-3: Modified slim hole killing procedure; hide Δpann in SICP.

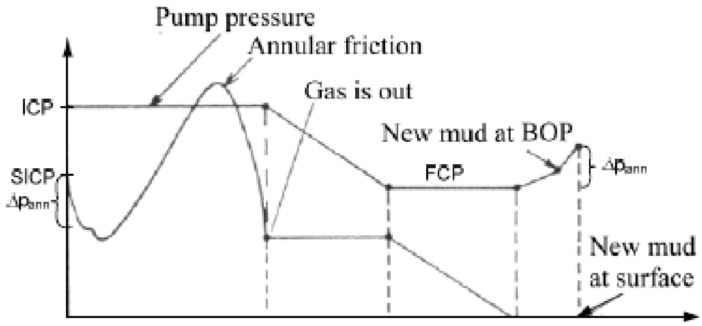


Figure 5-4: Fracturing during killing due to large choke line friction is avoided by means of the modified killing method; hide Δpann in SICP. The hidden Δpann must be gained back at the end of the circulation.

5.1.3 Modified killing procedure with BOP on seabed

Drilling with BOP on the seabed requires both kill & choke (C&K) lines from the seabed to the choke manifold at the surface. The C&K lines are slim, typically 4 " inner diameter (ID), and the pressure loss through them becomes high. With regard to the modified procedure, it is sufficient to hide only the additional choke line friction in the SICP, not the complete annular pressure loss since $\Delta p_{choke\ line}$ makes up a major part of Δp_{ann}. Figure 5-5 illustrates the modified procedure for offshore conditions.

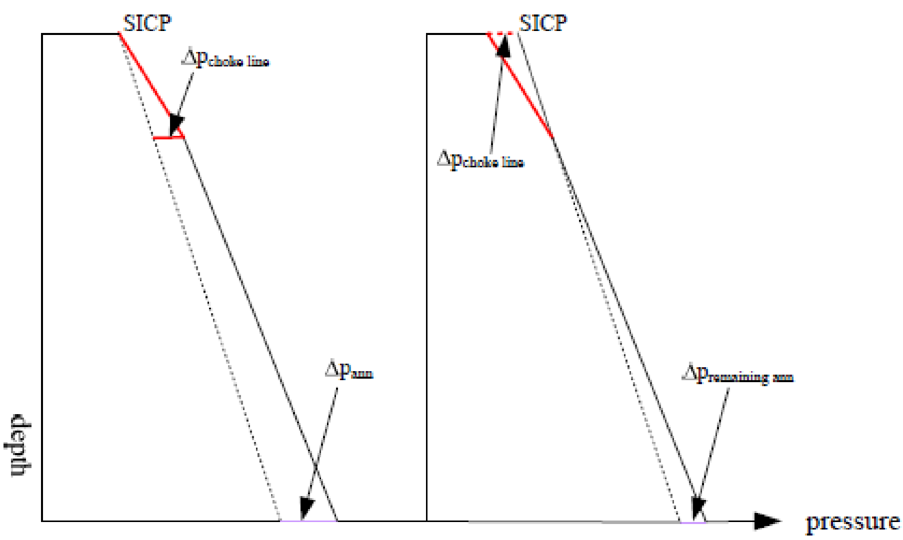


Figure 5-5: Modified offshore kill procedure, where choke line friction is hidden in Δpann.

One important advantages of the Driller's Method over the Engineer's include a reduced probability of hydrate formation since immediate start of circulation will maintain the wellbore heat in the BOP area, helping to keep temperatures above hydrate-forming temperature.

Friction at slow pump rate, SCP, is measured through both the riser and the choke line. The difference between the two is the choke line friction, $\Delta p_{choke\ line}$, shown in Figure 5-5. By applying through-riser-recorded SCP, the $\Delta p_{choke\ line}$ is automatically subtracted. If a surplus kill line is available, it can in fact be applied as a prolonged manometer during the initial killing phase. This static line is not influenced by choke line friction. In Figure 5-6 the difference between the two are shown, with two different colours.

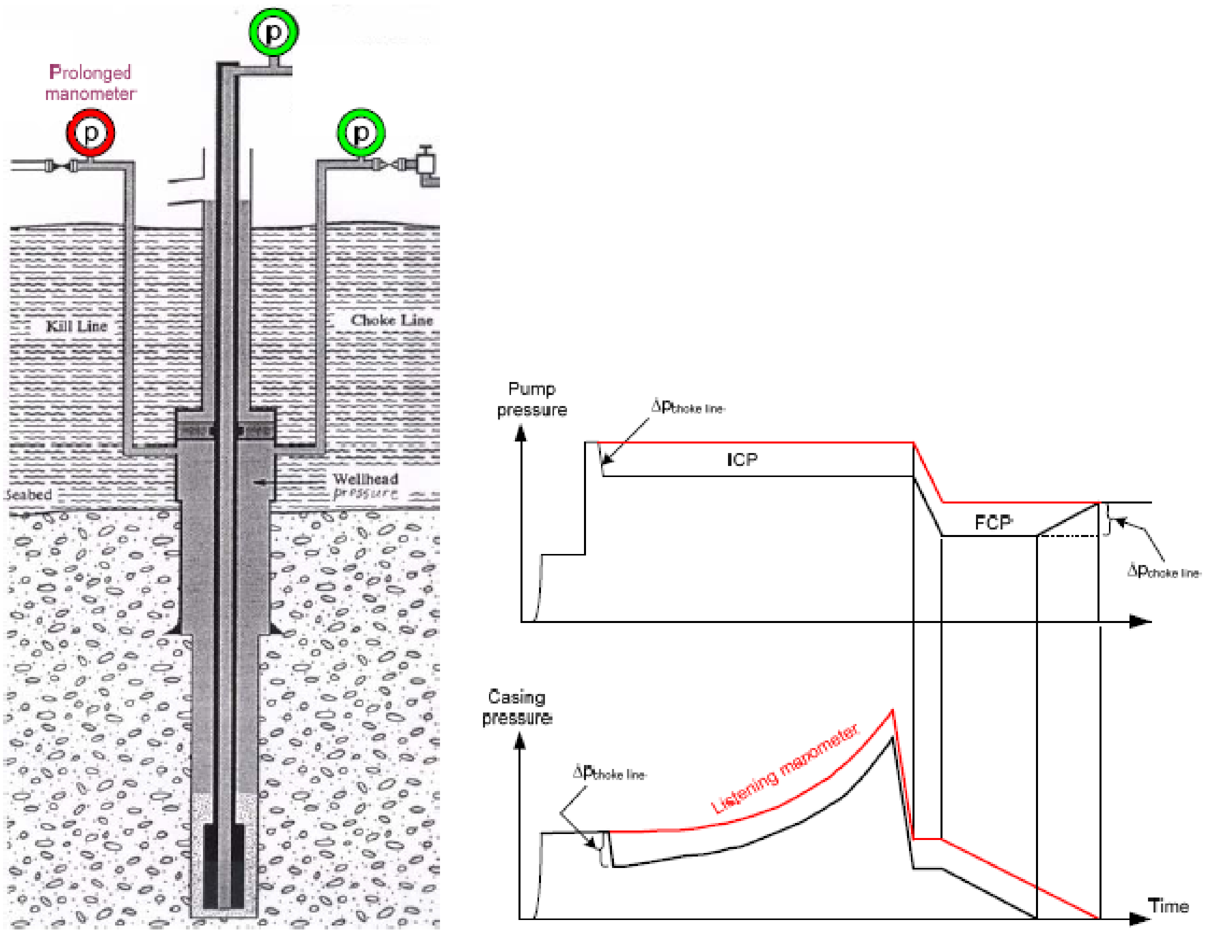


Figure 5-6: Kill line applied as prolonged manometer with resulting pressure shown to the right. Red (thick) line represents the surface choke pressure or the pressure in the prolonged manometer (without choke line friction drop). With this line the operation is identical with conventional killing.

However, often it is desirable to use both C&K lines. It has two advantages; the $\Delta p_{choke\ line}$ is reduced by 50 % since the flow area is doubled. Secondly, they reduce the fluctuations in surface pressure.

5.2 Killing with irregular drill string geometry

Irregular drill string geometries, compared to simple, vertical wells are appearing in the following situations.

- Developing an oil field from a central offshore installation (horizontal sections)
- When multilaterals are needed (several different pipe-ID)
- Drilling relief wells (S-profile)

The pump pressure decline, from ICP to FCP, while filling the drill pipe with heavy mud during a killing operation, is not always a linear curve as indicated in Figure 5-7. In fact, it is non-linear in most of the killing cases. The SIDPP has been assumed to be decreasing linearly with TVD as kill mud descends. But in deviated well, TVD is not linearly proportional with pumping time, since the inclination varies. Likewise, the additional friction is also assumed to be linearly increasing with depth. But no, instead it is proportional to measured depth (MD). In inclined wells (EVD not increasing linearely) the equation for estimation of the pressure profile during injection of kill mud in the drill string becomes:

$$\begin{aligned} p_{DP} &= ICP \qquad - f(p_{SIDP}) \qquad + \qquad f(\Delta p_{fric}) p_{SIDP} \\ &= p_{SIDP} + SCP_1 \quad - p_{SIDP}\left(\frac{TVD_{killmud}}{TVD}\right) + \quad (SCP_2 - SCP_1) \cdot \frac{MD_{killmud}}{MD} p_{DP} \end{aligned} \tag{5.1}$$

The p_{SIDP} –part will gradually decrease from p_{SIDP} to 0 by the rate of $p_{SIDP} \cdot \frac{TVD_{killmud}}{TVD}$, depending on how **deep** the kill mud has reached. The SCP–part will gradually increase from SCP_1 to SPC_2, depending on how **long** the kill mud has reached into the drill string. Tapered strings are normal, and here it will be a non-linear pressure development as well. And around 50 % of the friction change is placed over the nozzles of the bit.

Figure 5-7 demonstrates how the pressure schedule differs between a vertical well and a deviated well. The horizontal well is killed when kill mud has arrived to where the horizontal section starts.

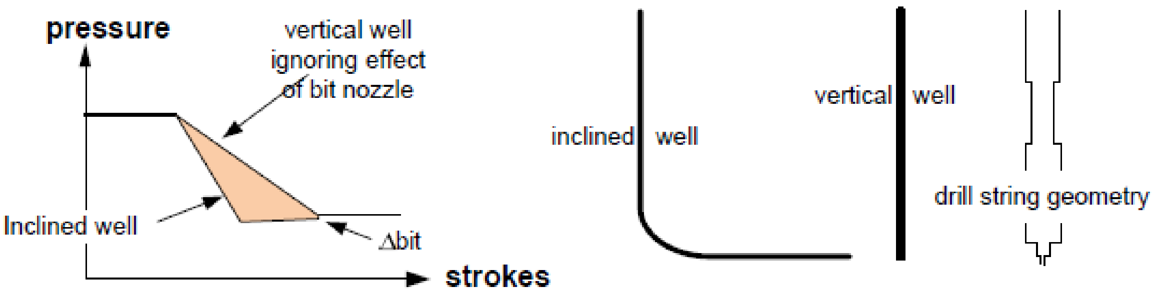


Figure 5-7: Pressure profile by circulating a kick while considering drill string geometry.

5.3 Best practice while drilling through narrow pressure windows.

Most oil companies have developed their own best practice to avoid problems and costly downtime when repair is required to restore the operation back to normal. Typical best practise in narrow pressure windows are aiming at lowest possible ECD and avoid kick or losses:

- Flow check drilling breaks and possibly circulate bottoms up to determine if a weight pill is necessary during tripping out.
- Use WBM as far as possible. Utilize sweep pills as deemed necessary to clean the well.
- Run shaker with finest screen possible.
- Use LCM when small losses are encountered.

6 More realistic gas behavior

Several factors will influence the progress of a gas kick and cause it to deviate from the schedule presented in standard killing methods in previous chapter. Only two parameters will be discussed here; gas deviatory behavior when it is transported by the drilling fluid and gas solubility in the drilling fluid.

6.1 Transport of gas

6.1.1 Gas bubble types

When drilling into a gas reservoir the drilled out gas or the influxing gas (the kick) will mix with the mud. Water and gas are practically insolvable, and will therefore form two phases. Since gas and liquid are two immiscible phases, a gas kick will, after entering the wellbore, either form small, dispersed bubbles, or large slugs, referred to as Taylor bubbles. Figure 6-1 presents the two forms, which are especially important for determining their travelling velocity.

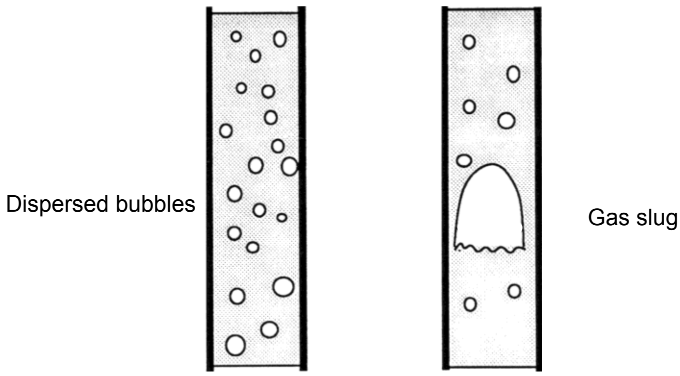


Figure 6-1: Two types of gas bubbles in liquids. Gas bubbles are defined as a gas slug when the length > 2 * diameter.

None of the two bubble forms are very stable. Factors like buoyancy, surface tension, collision frequency, etc., determine their preferred form and if the given bubble form is stable over time. Nevertheless, it is especially the concentration of the gas, C_{gas}, and flow pattern, that determine bubble form and its stability.

For laminar flow the stability criteria suggested by Govier & Aziz (1972) were:

When $C_{gas} > 0.3$. Dispersed bubbles te nd to form slugs.

At turbulent flow, gas concentration at which stable, dispersed bubbles can be maintained, increases.

Stability is the balance between fragmentation of slugs and coalescing of dispersed bubbles. Coalescence can occur when two bubbles are colliding. The collision frequency is governed by parameters like; C_{gas}, Reynolds Number and surface tension between the two phases.

Fragmentation, on the other hand, form at high shear stress, which is especially intense at flow past tool joints. Fragmentation occurs when change of angle in the flow direction is ≥ 18°, at this point eddies will form, even at laminar flow. Eddies lead to radial velocity components as shown in Figure 6-2.

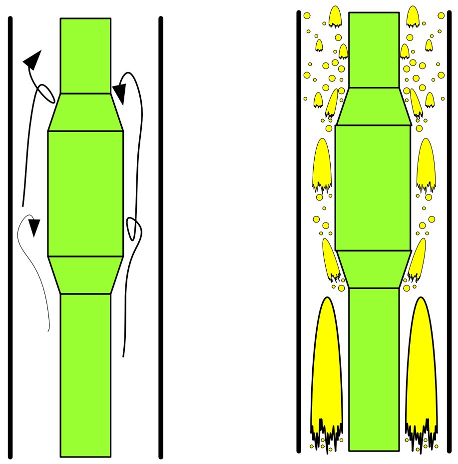


Figure 6-2: Eddies (left) results in fragmentation of gas slugs during flow past tool joints (right).

In deviated holes, the drill pipe eccentricity is large, and long stable slugs form at the high side of the pipe. This will lead to larger pressure at the surface during killing operations (chapter 6.3).

6.1.2 Gas bubble velocity

Govier & Aziz (1972) suggested that gas velocity, v_{gas}, in two-phase flow, can be expressed through eqn. 6.1:

$$v_{gas} = C_{deviation} \cdot v_{mean} + v_{rise,0} \tag{6.1}$$

$C_{deviation}$ is a constant, usually equal to 1.2, which means that the gas flows 20 % faster than the mean velocity. This is caused by the fact that the concentration profile coincides with the velocity profile, and axial dispersion is taking place. $v_{rise,\,0}$ is the gas rise velocity in still-standing liquid (v_{liquid} = 0). The mixture velocity is defined through eqn. 6.2.

$$v_{mean} = \frac{q_{gas} + q_{liq}}{A_{pipe}} \tag{6.2}$$

Experimental results (Skalle et al. (1991)) for both dispersed bubbles and slugs in drilling fluids showed that:

Dispersed bubbles: $v_{gas} = 1.2\ v_{mixture} + 0.20$ (6.3)

Gas slugs: $v_{gas} = 1.2\ v_{mixture} + 0.40$ (6.4)

Buoyancy velocity of slugs was twice that of dispersed bubbles.

6.2 Wellbore pressure during two phase flow.

6.2.1 Well bore pressure during stationary gas flow

In this chapter it is examined what effect free gas has on well pressure during stationary two-phase flow. More advanced simulators must be applied to study effects with higher precision than obtained here. The objective of this chapter is to demonstrate how more realistic behavior of gas (than expressed in Chapter 4 and 5) would affect wellbore pressure.

Stationary gas flow situations could take place when:

- Producing liquid and gas (for low gas concentration)
- Dynamic killing operations
- Drilling overbalanced through a gas reservoir
- Drilling underbalanced through gas reservoirs, but also above it (dissolved gas in the pore water)

It is assumed that the fluids are injected or produced at a constant rate and that the flow pattern of the gas is dispersed bubble flow (low gas concentration). The pressure gradient can be expressed as follows:

$$\frac{dp}{dz} = \left(\frac{dp}{dz}\right)_{hydrostatic} + \left(\frac{dp}{dz}\right)_{friction} + \left(\frac{dp}{dz}\right)_{accelleration} =$$
$$= \rho_{mixture} \cdot g + 2\ f_{mixture} \cdot v^2_{mixture} \cdot \rho_{mixture} / h_{well} + \rho_{mixture} \cdot \frac{\Delta v^2_{mixture}}{2 \cdot \Delta h} \qquad (6.5)$$

The fluid mixture density is affected by its composition:

$$\rho_{mixture} = C_{gas} \cdot \rho_{gas} + (1 - C_{gas}) \cdot \rho_{liquid} \qquad (6.6)$$

Gas concentration, C_{gas} , is defined by:

$$C_{gas} = A_{gas} / A \quad or \quad V_{gas} / V \tag{6.7}$$

If gas is moving at a velocity v_g through a pipe segment of length l, then during the time l/v_g, gas will traverse the length l and a fresh volume of gas, $q_{gas} \cdot l/v_{gas}$, will enter this pipe segment. The volume fraction of gas is thus:

$$C_{gas} = \frac{V_{gas}}{V} = \frac{q_{gas} \cdot l / v_{gas}}{l \cdot A} = \frac{q_{gas}}{A} \cdot \frac{1}{v_{gas}} = \frac{v^s_{gas}}{v_{gas}} \tag{6.8}$$

For clarity, Hold-Up (H), differs from C_{gas}. When gas is slipping through a liquid due to buoyancy, the input concentration will differ from the flow concentration. The slip ratio or Hold-Up is defined as;

$$H = v_{gas} / v_{liquid} \tag{6.9}$$

Now back to the estimation of mixture density. We need to differentiate between actual velocity, v_{gas}, and superficial velocity of gas, v^{s}_{gas};

$$v_{gas} = q_{gas} / A \qquad (6.10)$$

$$v^{s}_{gas} = q_{gas} / A_{gas} \qquad (6.11)$$

From chapter 5.1.2 dispersed bubble gas velocity is given by:

$$v_{gas} = 1.2 \cdot v_{mixture} + 0.20 \qquad (6.3)$$

We now simplify by assuming that the acceleration term of eqn. 6.5 is negligible and that the friction term is equal to 5 % of the hydrostatic pressure term:

$$\left(\frac{dp}{dz}\right)_{friction} = 0.05 \cdot \left(\frac{dp}{dz}\right)_{hydrostatic} \qquad (6.12)$$

We further simplify by assuming:

$$C_{gas} \cdot \rho_{gas} = 0 \qquad (6.13)$$

Eqn. 6.5 finally reduces to:

$$\frac{dp}{dz} = (1 - C_{gas}) \cdot \rho_{liq} \cdot g \cdot 1.05 \qquad (6.14)$$

If the friction part later should be calculated, the necessary two-phase formulas are:

Fanning friction factor, laminar flow: $f_F = 16 / N_{\mathrm{Re}}$

Friction factor, turbulent flow: $f_F = a \cdot N_{\mathrm{Re}}^{-b}$

Constant a: $a = (\log n + 3.93) / 50$

Constant b: $b = (1.74 - \log n) / 7$

Reynolds number:

$$N_{\mathrm{Re},ann} = \frac{v_{mean}^{2-n} \cdot (d_0 - d_1)^n \cdot \rho_{mixture}}{K \cdot \left(\frac{2n+1}{3n}\right)^n \cdot 12^{n-1}}$$

Two phase mixture velocity:

$$v_{mixture} = \frac{q_{liq} + q_{gas}}{A} = v_{mean}$$

Rheology constants K and n are derived from testing the rheology of the mixture in the lab. Assume that rheology is best fitted to the Power Law Model: $\tau = K \dot{\gamma}^n$

For more details of rheology and hydraulic friction, please refer to Skalle (2010).

Since the fluid column is normally lighter than the equivalent pore density, a surface choke is involved in controlling the wellbore pressure. The situation is shown in Figure 6-3.

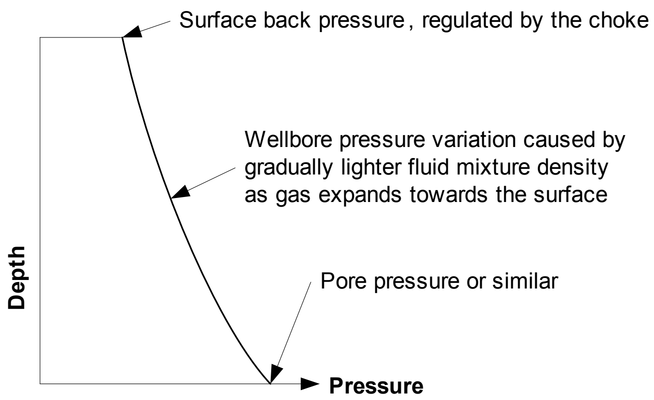


Figure 6-3: Wellbore pressure during stationary two phase flow conditions.

We will now exemplify drilling underbalanced through the overburden: Mud and compressed gas is pumped through the drill pipe. Drilled out cuttings will contribute marginally to the mixture density, and its effect is therefore neglected. Wellbore pressure is mainly controlled by the surface backpressure, p_{choke}, and by the flow rates of the two fluids. Since the mixture density is interrelated with wellbore pressure, an iterative procedure is required. Figure 6-4 presents the procedural flow sheet and a graph of the pressure during the iteration process.

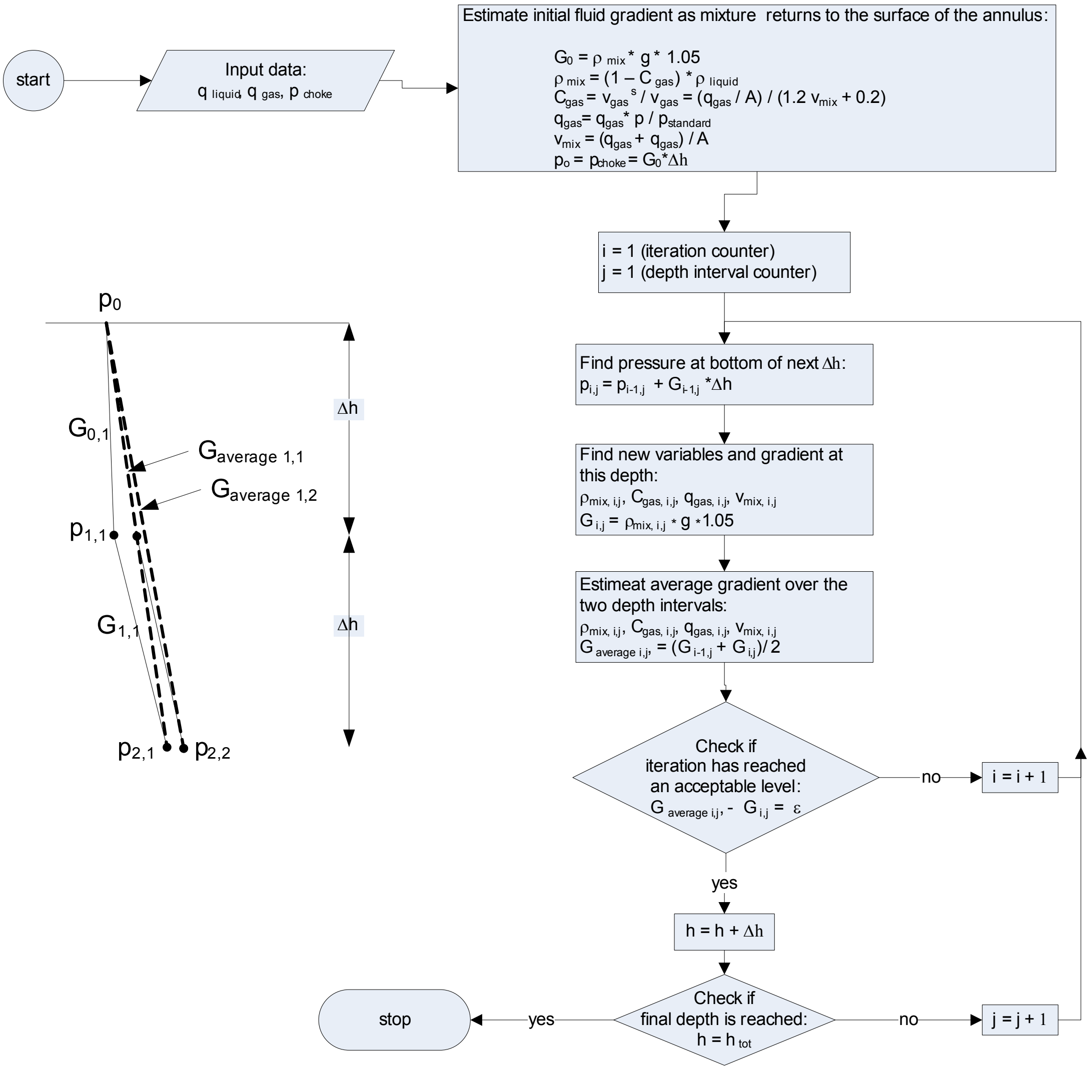


Figure 6-4: Flow chart of estimating wellbore pressure during underbalanced drilling.

6.2.2 Bottom pressure when gas cut mud reaches the surface

Assume that we are drilling through a gas bearing formation in overbalance. The gas we see at the surface is further assumed to represent a stationary situation, i.e. drilling through the reservoir is resulting in gas being drilled out at a constant rate.

Normally gas cut mud will not cause much reduction in bottomhole pressure, although gas concentration at times can be very high at the surface. This phenomenon is therefore not causing the well to become underbalanced. Please stay calm and just circulate bottoms up if you are in doubt. An increment in mud weight, which is the normal but wrong reaction, will have no effect besides of possibly fracking the well just below the casing shoe.

At the surface we are able to indirectly estimate the gas amount through measuring the mud density in the return flow line, ρ_{fl} Few rigs have radioactive densitometers for continuous recording of the return mud weight. However, by means of a pressurized mud balance good result can be obtained (if the procedure includes the escaping gas). Gas density is neglected throughout the well depth. Original mud density is equal to the density of the liquid phase, ρ_l By referring to Figure 6-5, the liquid mass, m_l, at the surface is expressed through eqn. 6-15.

$$\begin{aligned} m_l/\rho_l &= V_{tot} - V_{gfl} \\ m_l &= \rho_l \cdot V_{tot} - \rho_l \cdot V_{g.fl} \end{aligned} \qquad (6.15)$$

At bottom of well	In annulus at depth z	At flow line (fl)
$\rho_o = \rho_l$	ρ_l, ρ_g	$\rho_l, \rho_{g,fl}$
$V_{tot} = V_l +$	$V_{tot} = V_l + V_{g,z}$	$V_{tot} = V_l + V_{g,fl}$
$C_g = 0$	$C_g = C_{g,z}$	$C_g = C_{g,fl}$

Fig. 6-5: The parameters involved during drilling out gas cut mud at a constant rate. We assume the gas concentration at bottom is neglectable due to the high pressure.

The density at the flow line can then be written as; assuming gas is weightless, and inserting from eqn. 6.15:

$$\rho_{fl} = \frac{m_l}{V_{tot}} = \rho_l - \frac{V_{g,fl}}{V_{tot}} \qquad (6.16)$$

The latter term of eqn. 6.16 is gas concentration at the surface $C_{g,fl}$. Rearranging eqn. 6.16 yields:

$$\rho_{fl} = \rho_l - C_{g,fl}$$

$$C_{g,fl} = \rho_l - \rho_{fl} \qquad (6.17)$$

Now we want to estimate pressure p vs. z assuming gas that behaves according to the ideal gas law:

$$p \cdot V_{g,z} = p_{fl} \cdot V_{g,fl}\, p_{fl} \qquad (6.18)$$

At the flowline the pressure, p_{fl}, is the atmospheric pressure. Dividing both sides by V_{tot} we obtain:

$$p \cdot C_{g,z} = p_{fl} \cdot C_{g,fl}$$

$$C_{g,z} = C_{g,fl} \cdot p_{fl} / p \qquad (6.19)$$

From Eqn. 6.14 we take only the hydrostatic part:

$$\frac{dp}{dz} = (1 - C_{g.z}) \cdot \rho_{liq} \cdot g \qquad (6.20)$$

Separating the variables and inserting from eqn. 6.19:

$$dp = \rho_{liq}\left(1 - C_{g,fl} \cdot \frac{p_{fl}}{p}\right) g\, dz \qquad (6.21)$$

Rearranging

$$\frac{p}{(p - C_{g,fl} \cdot p_{fl})} dp = \rho_{liq} \cdot g\, dz \qquad (6.22)$$

Integrating from surface to an arbitrary pressure:

$$\int_{p_{fl}}^{p} \frac{p}{(p - C_{g,fl} \cdot p_{fl})} dp = \rho_l \cdot g \int_0^z dz \tag{6.23}$$

This type of integral is solved in accordance with Thomas (1973) and results in:

$$p + C_{g,fl} \cdot \ln(p - C_{g,fl} \cdot p_{fl}) + C = \rho_{liq} \cdot g \cdot z \tag{6.24}$$

With known boundary conditions (p_{fl} = 1 bar), eqn. (10) yields:

$$\rho_{liq}\, gz - p = C_{g,fl} \cdot \ln \frac{(p - C_{g,fl})}{(1 - C_{g,fl})} - 1 \tag{6.25}$$

Example:

$z = 3000$ m
$\rho_l = 1.5$ kg/l
$\rho_{fl} = 0.4$ kg/l
$C_{g,fl} = 1 - \frac{0,4}{1,5} = 0,73$
$\rho gz = 1500 \cdot 0.81 \cdot 3000 = 441.5$ bar

The solution is obtained through iteration. We try first with 4.5 bar difference:

$$4.5 = 441.5 - 437.0 = 0.73 \cdot \ln\left(\frac{437 - 0.73}{1 - 0.73}\right) - 1 = 4.39$$

We are sufficiently close to have proven the point. The conclusion must be that a lot of gas causes a relatively small pressure reduction at the bottom, in this example a reduction of 1 %.

6.2.3 Surface pressure during killing

From chapter 6.1.1 and 6.1.2, we learned how a concentrated gas kick (i.e. a bubble of gas) would fragment and stretch out while flowing through the annulus. The effect of such behavior on surface pressure will be discussed in this part.

A simple experiment, presented in Figure 6-6, demonstrates the deviatory behavior of gas when flowing through the annulus.

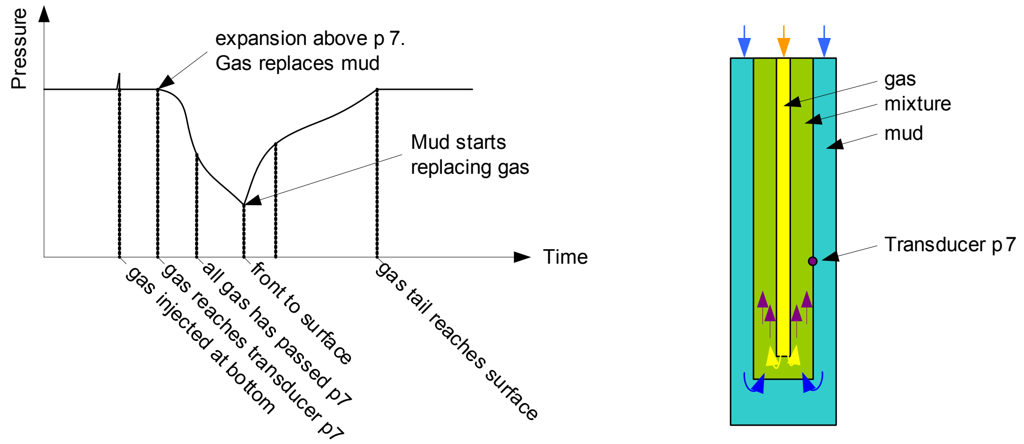


Figure 6-6: Pressure recorded at pressure transducer # 7 during and after injection of one gas bubble in still standing liquid. Relative position of transducer p7 is shown to the right, positioned in the annulus where two phases are flowing by.

Figure 6-6 reveals the complete story of the experiment. Initially the gas is concentrated. The time it takes to reach transducer p7 is recorded. When the front of the gas bubble reaches the surface and pressure starts to climb again, more new liquid will enter than liquid expelled from the annulus caused by expanding gas. Finally, the tail of the gas has reached the surface, and the original hydrostatic column is restored.

In Figure 6-7 the observations described in Figure 6-6 have been interpreted for two liquid flow rates, q_{liquid} = 0 and 200 GPM.

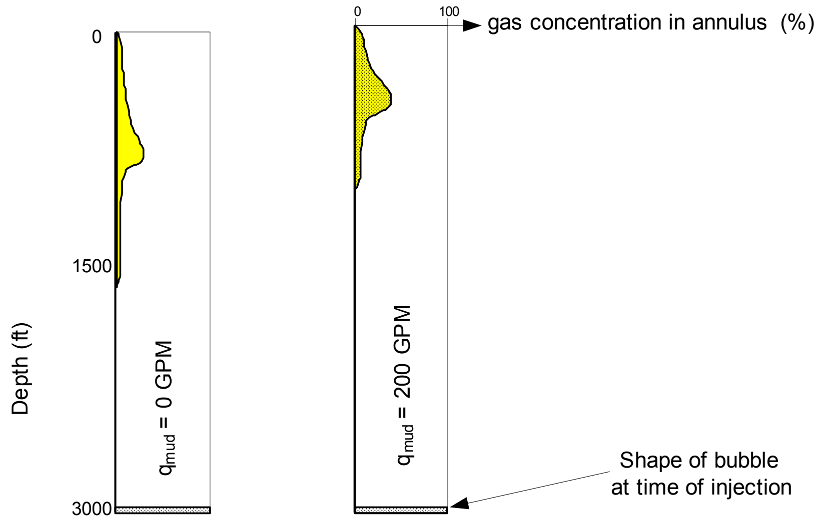


Figure 6-7: The stretching effect of a gas bubble as it moves towards the surface. The gas moves upwards in a still standing fluid column (left) and in fkuid, which is flowing at a rate of 200 GPM (right).

If real gas bubble behavior is compared to idealized gas behavior, which was applied in chapter 4 and 5, we will see differences as indicated in Figure 6-8:

1. The real gas arrives at the surface 20-25 % faster than gas bubble which follows the mudflow. This is due to two facts:
1. The gas concentration profile of the cross section coincides with the mud velocity profile, causing gas to travel 20 % faster than the liquid alone.
2. Buoyancy causes gas to percolate at an additional velocity.
2. Pressure profile will become flatter and have lower maximum pressure due to stretching (axial dispersion) of the gas, thereby also stretching the expansion effect.

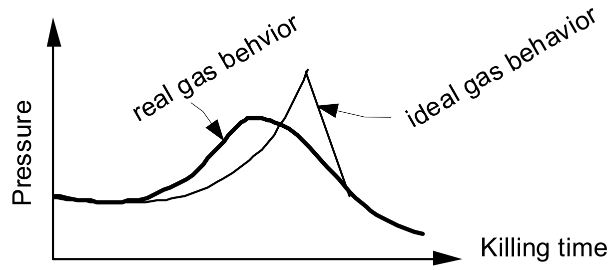


Figure 6-8: Annular surface pressure variation of a standard killing operation (the gas follows the mud) compared to a more realistic behavior.

6.3 Gas solubility

6.3.1 Solubility in general

Substances dissolved in a solvent are called the solutes, which may be solids, liquids or gases. If two liquids are soluble, they are said to be miscible. Water is a good solvent due to its polar orientation. Ionic compounds are highly soluble in water; the attractive forces between oppositely charged ions are weakened by polar water, and individual ions are separated from its lattice. After dissolution, each dissolved ion becomes surrounded by a shell of water molecules. The ions are said to become wetted or hydrated. Figure 6-9 shows hydration of of dissolved sodium chloride ions in water.

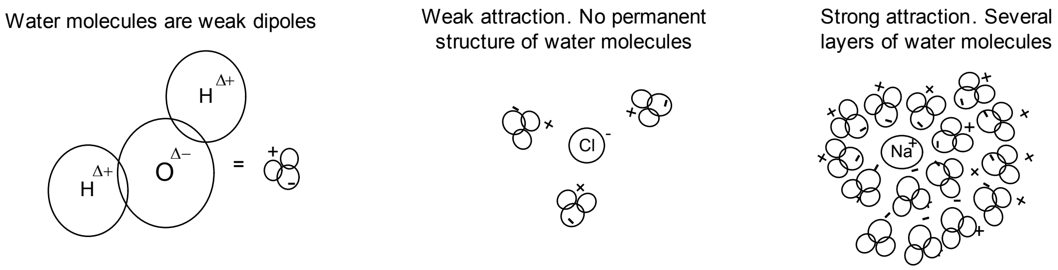


Figure 6-9: Hydration of sodium chloride in water. In still standing water several layers of water molecules will form around the ions.

Ionic compounds are not soluble in non-polar liquids, such as oil. Multivalent (i.e. the valence is larger than one) compounds are weakly soluble. The internal attraction between multivalent ions like $CaCl_2$ and $CaCO_3$ are much stronger than between univalent ions. Covalent compounds are soluble or miscible if they are polar. Examples of soluble covalent compounds include sugar, alcohol and starch.

Polar water molecules which are attached to dissolved salt ions reduces the number of free water molecules (water activity is being reduced). One effect of reducing the number of free water molecules is seen as a reduction of water's ability to dissolve gas. Figure 6-10 show the reduction of gas solubility in salt water.

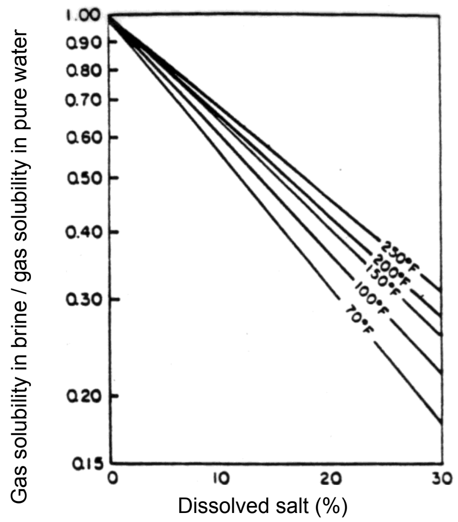


Figure 6-10: Correction of gas solubility for salt content (Petrucci (1989)).

6.3.2 Solubility of gas in liquids

Small quantities of dissolved gases like oxygen, carbon dioxide or hydrogen sulfide have a strong effect on the properties of solvent liquids like water. Water based mud becomes highly corrosive. Hydrogen sulfide is in addition extremely poisonous and represents a real hazard to rig personnel.

Temperature effects on solubility: The condensation of a gas is an exothermic process; the energy requirement is much greater than the energy needed to separate solvent molecules to make room for the solute molecules. The solubility of gases will therefore slightly decrease with increased temperature. We can observe this behavior when we see bubbles of dissolved air (gaseous solute) escaping from cold tap water being slowly heated to room temperature. This observation also helps us to understand why many fishes cannot live in warm water; there is not enough dissolved air (oxygen) present in the water.

Pressure effects on solubility: Pressure generally affects the solubility of gas in liquid more than temperature, and, as noted in Figure 6-11, the effect is always the same: The solubility of gas increases with increasing gas pressure.

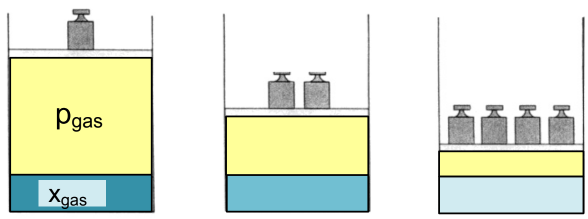


Figure 6-11: Effect of pressure of the solubility of a gas. The solubility of gas molecules in the liquid solvent increases with increased pressure - the color become lighter (free after Petrucci (1989)).

In 1803 the English chemist William Henry proposed the generalization that the concentration, x_{gas}, in terms of the mol fraction of gas dissolved in liquids [atm/ (atm / mol fraction)] is proportional to the gas pressure, p_{gas}, above the solution;

$$x_{gas}=p_{gas}/H \qquad [mol_{gas} / mol_{liq}] \tag{6.15}$$

If the need to quantify the solubility arise, mol fraction must be translated to mass of gas, m_{gas}:

$$m_{gas}=x_{gas}\cdot\frac{M_{gas}}{M_{liquid}} \qquad [g_{gas} / g_{liq}] \tag{6.16}$$

where M_{gas} is mol weight of gas [g_{gas}/mol]. Combining eqn. 6.15 and 6.16 yields:

$$m_{gas}=p_{gas}/H\cdot\frac{M_{gas}}{M_{liquid}}\left[g_{gas}/g_{liquid}\right] \tag{6.17}$$

We can rationalize Henry's law in this way: Equilibrium is reached between the gas above and the dissolved gas within a liquid when the rates of evaporating molecules and rate of condensation of the gas molecules become equal. To maintain equal rates of evaporation and condensation, as the number of molecules per unit volume increases in the gaseous state (through an increase in the gas pressure), the number of molecules per unit volume must also increase in the solution (through an increase in concentration). When applying Henry's law we assume that the gas does not react chemically with the solvent.

A practical application of Henry's law is seen in soft drinks. The dissolved gas is carbon dioxide, and the lower the gas pressure above the liquid, the more CO_2 escapes, usually rapidly enough to cause fizzing.

6.3.3 Operational problems related to dissolved gas

A small gas kick, taken in OBM produces a relative small initial increase in annulus pressure and in pit level as the kick is being circulated to the surface, because dissolved gas behaves like a liquid. Gas will come out of solution as gas pressure decreases while the kick is being circulated up the annulus. The gas is often released in large volumes over a short interval of time and at shallow depths like indicated in Figure 6-12. Unfortunately, these phenomena can lead to inappropriate decisions since the behavior is quite different from situations when gas does not dissolve (practically none in WBM).

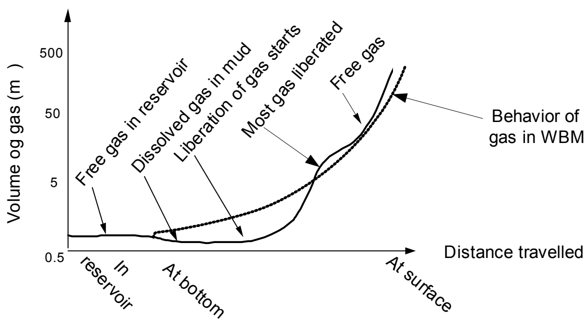
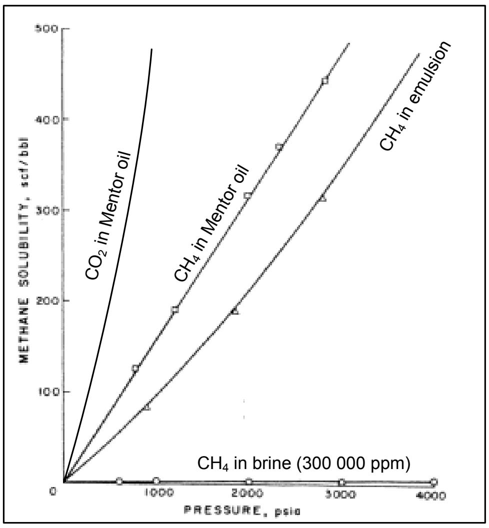


Figure 6-12: Volumetric behavior of 200 kg liquid methane swabbed in during connections while tripping out, dissolved in OBM and later circulated out, undetected until liberation.

Dissolved gas is related to the volume of gas at standard condition pr. volume of liquid solvent, the so-called gas-liquid ratio, R_s, where the s refers to standard conditions. When oil is the solvent, it is called the gas oil ratio (GOR). Figure 6-13 exemplifies the GOR, while in Figure 6-14 the GOR is translated to R_s.



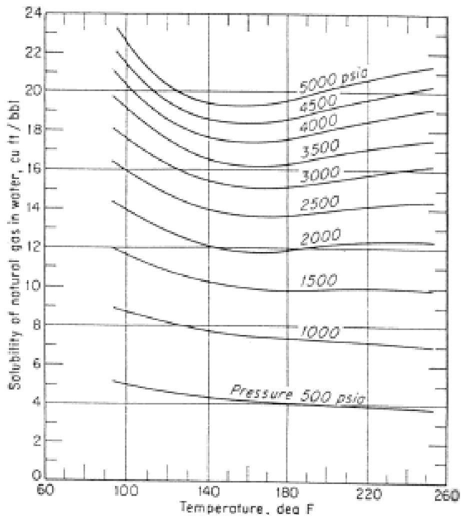


Figure 6-13: Gas solubility in Mentor 28 oil, in emulsifier and in 300,000 ppm brine at room temperature. Here oil field units of gas/oil ratio (GOR) are applied. Methane solubility in water (is shown to the right).

To account for the situation described in Figure 6-12, R_s must first be calculated at the bit, where we assume the gas entered the well bore:

$$R_s = q_{gas}/q_{mud} \tag{6.18}$$

If $R_s \le R_{s.saturated}$ then all the formation gas dissolves in the mud and the free gas volume fraction is zero, as indicated in Figure 6-12. If, on the other hand, a large enough amount of gas enters the wellbore, so that the local value of R_s at the bit exceeds $R_{s,saturated}$, then the mud becomes saturated with gas and any excess appears as free gas. In the annulus the extent to which gas dissolves in the mud or evolves from the solution is obtained by comparing the local value of the dissolved gas fraction, R_s, with its saturation potential, $R_{s,saturated}$.

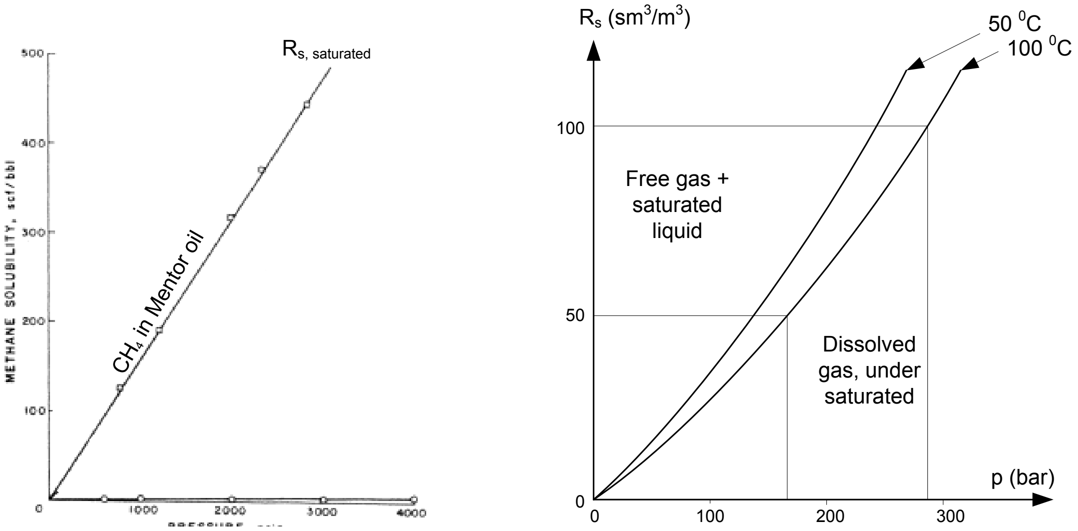


Figure 6-14: Rs for CH4 in Mentor oil vs. well pressure. In figure to the right data points above the saturation curve indicate free gas in fully saturated base oil.

The data in Figure 6-14 has been translated from OFU to metric units. We want to demonstrate the important effects regarding kicks in OBM, where the solubility may cause the gas kick to sometimes be fully dissolved.

Assume the following situation:

A small kick entered the well:	1 m^3
Well depth:	2000 m
Influx period	3 minutes
Mud pump rate:	1500 l/min
Mud density:	1.5 kg/l
Mud temperature:	100 ^{0}C

Question: Will the gas dissolve or be "free" at time of influx?

Bottom pressure:	1500 * 9.81 * 2000	= 294 * 10^5 Pa
Mud volume pumped:	2 m^3/min * 3 min	= 6 m^3

Gas ratio at standard conditions: $R_s = \frac{V_{gas}}{V_{mud}} = \frac{1\,m^3 \cdot 294/1}{6\,m^3} = 49\ Sm^3/m^3$

From Figure 6-14, we see that all the gas will be dissolved.

Question: When will the oil be saturated and gas begins to liberate?

a) At influx moment the pressure and oil require R_s to be 100 to be fully saturated, i.e. twice as high as 49, i.e. the kick volume needs to be 2 m^3.
b) Or, alternatively, the 1m^3 gas kick with R_s of 49 passes the pressure corresponding to point of saturation at 170 bar.

7 Special offshore safety issues

7.1 Low sea temperature

At large sea depths the ocean temperature can go below 0 °C as shown in Figure 7-1.

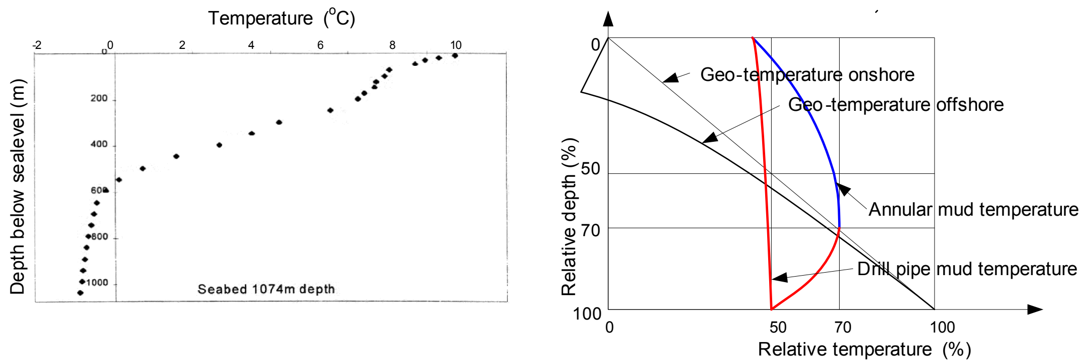


Figure 7-1: Typical temperature profile in deep oceans (left). Generalized (right).

Mud will move slowly in the large marine risers and cool down. Low mud temperature has two negative effects during oil well drilling:

- The possibility of hydrates formation
- High mud viscosity

7.1.1 Hydrates

Hydrate formation: Hydrates are a well-recognized operational hazard in deepwater drilling. Hydrates belong to a group of substances known as clathrates (substances having a lattice-like structure in which molecules of one substance are completely enclosed within the crystal structure of another). Water is acting as host molecules forming a lattice structure acting like a cage, to entrap guest molecules (gas) as shown in Figure 7-2.

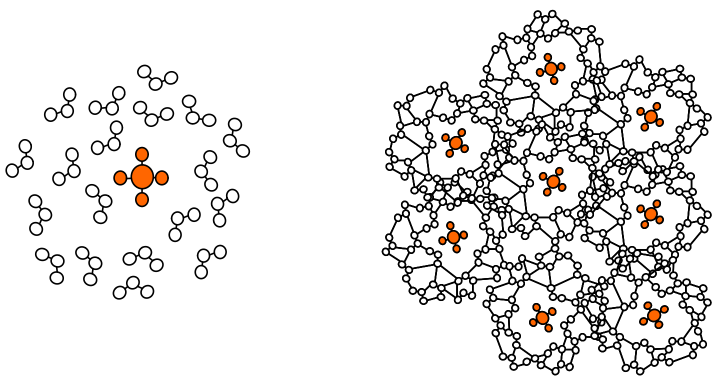


Figure 7-2: Gas hydrate: Dipolar water molecules are forming around a guest molecule (left). Water molecules become hydrogen bonded (right), forming a hydrate crystal structure.

Gas hydrates resemble dirty ice and can form in temperatures above 0 °C under sufficient pressure. They are solid in nature and have a tendency to adhere to metal surfaces. In deep water environments the potential for hydrate formation increases due to the combination of higher pressure and low temperature. Necessary conditions for hydrates to form are:

- Sufficient water
- Gas
- High pressure
- Low temperature

Figure 7-3 shows the effect of pressure and temperature on hydrate formation. Methane is by far the most common gas in oil well drilling. Methane has the lowest specific gravity of all gases. As the specific gravity of the associated gas increases so does the potential for hydrate formation. The points along this curve actually represent the temperature at which the last hydrate melts or dissociates at any given pressure.

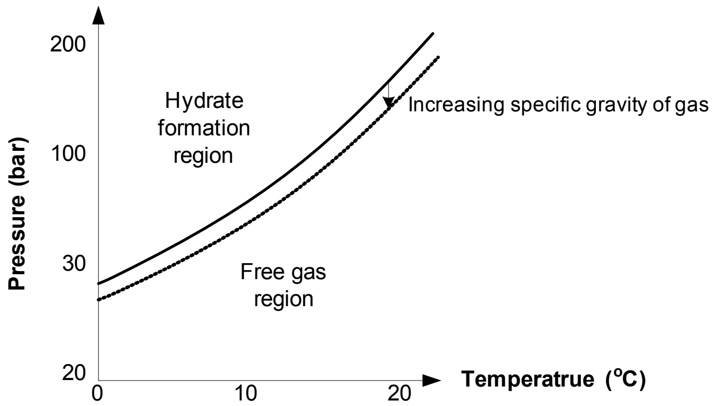


Figure 7-3: Effect of temperature, pressure and gas composition on hydrate formation.

Potential Problems: The three types of hydrate-formation problems are as follows:

1. Natural gas forming hydrates at shallow depths below see bottom.
2. Shallow gas percolating from gas bearing sands through an external unsealed annulus. Hydrates formed here may prevent hydraulic disconnection of the BOP.
3. Formation of hydrates inside the wellbore or BOP equipment, hindering control of BOP functions and access to the wellbore during killing operations.

Occurrences of the second type problem have been common, but can be eliminated or at least greatly reduced by inserting a hydrate seal in form of a so-called mud mat. This will cause any gas seepage to be diverted away from the BOP area.

The third problem, where hydrates form inside the wellbore or BOP equipment, is much more serious from a well control standpoint and can affect an operation in many different ways.

Usually hydrates do not form during routine drilling and/or circulating operations since the combination of required conditions do not exist (mud is too warm during drilling). Hydrates usually form when a gas influx is closed-in. Gas may now be caught and separated out below the BOP. During an extended shut-in period where the gas cools rapidly, hydrates form in the BOP area.

Many different scenarios involving this type of hydrate formation have been observed and documented:

- Hydrate plug in front of the choke/kill line causing inability to circulate out a kick
- Hydrate plug in the BOP cavities or just below the stack resulting in an inability to circulate and to perform pressure monitoring
- Hydrates extract free water from the drilling mud, causing it to dehydrate and its weighting material settles out, causing more problems.

Hydrate Inhibition: There are two common ways of inhibiting the drilling mud system to form hydrates:

a) *Thermodynamic inhibitors*
Thermodynamic inhibitors lower the activity level of the aqueous phase, thereby suppressing the temperature required for hydrate stability at any given pressure. These are salts ($CaCl_2$ and $CaBr_2$), methanol and glycol.

b) *Kinetic inhibitors*
Kinetic inhibitors (or crystal modifiers) alter the nucleation and delay the growth of hydrates by using a low concentration of polymeric and surfactant based chemicals.

Combinations of both inhibitors will most likely be required as conditions become increasingly severe. The degree of inhibition increases with increasing concentration.

Hydrate Removal: Once hydrate plugs have formed in subsea equipment, their removal is problematic. In one case, heated fluid was pumped down through a coiled tubing that was run inside the drill pipe to a depth a few hundred feet below the hydrates. Heat exchange with the annulus fluids below the mud line decomposed the hydrate.

7.1.2 Gelled mud in cold pipelines

Viscosity and gelling tendency increase within the choke and kill (C&K) lines due to low temperature. This can both mask shut-in casing pressure and increase $\Delta p_{chokeline}$ beyond previously measured during the start up of killing operations.

In order to reduce the gelling problem, mud in C&K lines are mixed with inhibitors.

In deeper water, the gel strength can become high in the annulus, especially with synthetic muds. Slow rotation of the drill pipe can be used to reduce the mud gel strength when breaking circulation.

OBM/SBM fluids exhibit complex fluid behaviour due to compressibility, pressure transmission, and high gel strengths. Therefore, the opening and closing of fail safe valves located on the seafloor does not result in an instantaneous increase/decrease in pressure at the bottom of the hole or in the pressures detected at the surface. This time delay behaviour needs to be understood and compensated for, i.e. break the gel strength:

- Close BOP below opened choke/kill line
- Circulate mud for a while
- Stop, open choke line to the well and read surface pressure

Pressure While Drilling (PWD) measurements are especially helpful in narrow pressure window areas. These measurements allow the true ECD to be known so that a sufficient margin can be used to prevent fracturing the formation. Utilizing PWD data to correlate and calibrate mathematical models for drilling fluid behaviour will allow more accurate predictions of e.g. surge and swab pressures.

7.2 Other deep water problems

7.2.1 Riser Margin and riser disconnect

Normal operating practices requires mud weights in excess of the formation pressure such that, in the event of an emergency disconnect, the mud column remaining in the hole will balance the formation pore pressure. This added mud weight will compensate for the loss of hydrostatic pressure of the mud column from the wellhead and back to the rig when the BOPs are closed and the riser is disconnected. See Chapter 4.1.4 for estimation of Riser margin.

Loss of hydrostatic column, p_{loss}, following a disconnection can be estimated:

In deepwater drilling, where the difference between formation and fracture pressures is very small, the practicality of this approach becomes difficult to maintain. The following drilling practices prevent exceeding the fracture gradient:

- Apply Riser Margin only in conjunction with riser disconnect operations
- Drill slowly to limit cuttings loading / increasing equivalent circulating density
- Use of Pressure While Drilling tools to monitor downhole ECD to enable real time decisions
- Avoid surge pressures during tripping-in
- Predict pore pressure early to prevent kicks
- Monitor pit level and return flow to reduce kick size

Plans and procedures should be developed for displacing and storing the mud in the riser during disconnects or when changing mud.

7.2.2 Gas trapped in BOP or hidden in Riser

Trapped gas: During well control with subsea BOP stack, gas may accumulate in the space between the closed preventer and the choke line outlets. Trapped gas creates problems in water depths greater than 300 m. When 20 liters of gas is released into the riser at 1000 m depth, it has expanded to 1000 liters when it is 10 m below the surface (here the absolute pressure is 2 bars + outlet friction).

Figure 7-4 indicates how to remove and vent trapped gas.

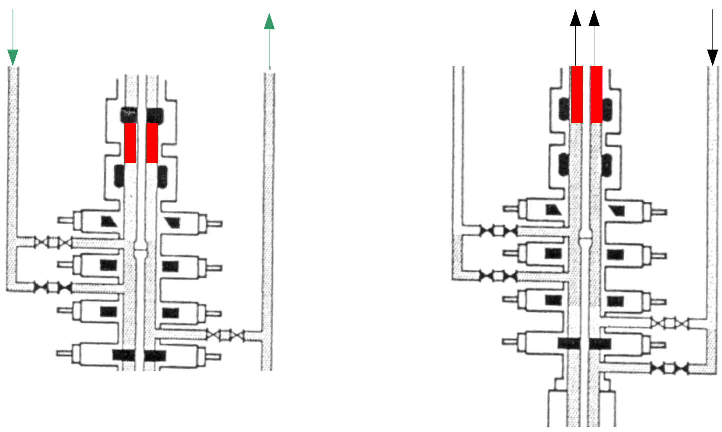


Figure 7-4: Gas trapped in BOP. Procedure to remove it is indicated. Left: Circulate to prepare for removing gas; circulate out through DS (right).

Gas hidden in the riser: When a kick is noticed and the well is shut in, small amounts of gas is already dispersed and / or dissolved in the mud column above the depth of kick entry. This is often true also for the mud already inside the riser, above the shut BOP. Normal well control operations are taking place at the same time as the gas slowly migrates up the riser, operations such as weighting up, pumping out the kick, etc. After some time of migration, the gas may begin to unload from the riser before anyone notices it. This potential situation is the very reason why gas diverters are installed and routinely closed simultaneously with closing of the BOP.

Free gas in the riser represents one of the most dangerous situations on a rig from a personnel safety point of view. Irrespective of the threat to personnel, there also exists the possibility of collapsed and/or parted riser, fire on the rig floor and damage to the riser.

7.3 Shallow sands below deep sea water

7.3.1 Shallow water flow

Shallow Water Flow (SWF) can be a problem when drilling with seawater returned to the mud line, before the BOP and riser are installed. It may also be encountered after the BOP is in place. The origin of the flowing water is weakly pressurized shallow, marginally compacted sands that are very porous and permeable.

Water flow rates can range from very low (near levels of detectability) up to several hundred liters per minute, and can often contain significant amounts of sand. The likely consequences of sustained shallow flow include:

- Formation-sand erosion
- Hole erosion
- Annular flow and broaching to the surface where craters are formed
- Surface subsidence (into formed craters)
- Loss of conductor/template support (due to annular flow / cement erosion)

Figure 7-5 illustrates some of the mentioned problems. SWF may not be noticed at first as the zone may be cased off and cemented. The flow may broach to the surface at a considerable distance from the wellbore.

Shallow water flow is encountered in shallow formations below the mud line in deep water. Overpressures are marginally greater than the hydrostatic pressure (usually in the 9.2 – 9.5 PPG range). Shallow flows are difficult or impossible to stop because of the narrow margin between the pore pressure and the fracture pressure.

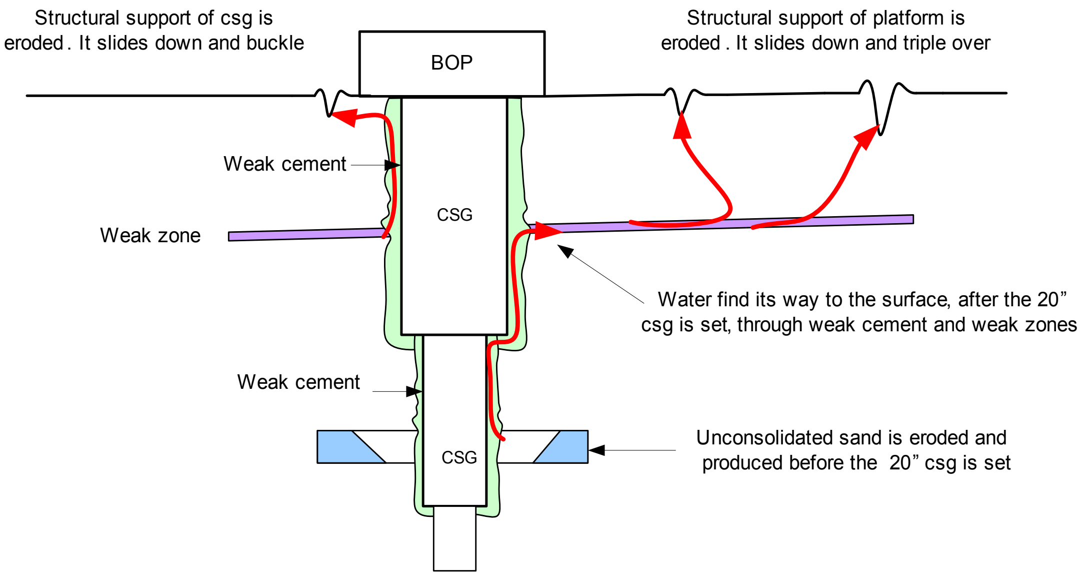


Figure 7-5: The SWF problem.

Origin of the weak over-pressured sand formations include induced storage during drilling through the sand, geo-pressured sands, and transmission of pressure through cemented annulus (internal channels in the cement). Geo-pressured sands originate from different mechanisms, the most likely cause being rapid sedimentation of clay. Figure 7-6 illustrates two causes behind charged, shallow sands.

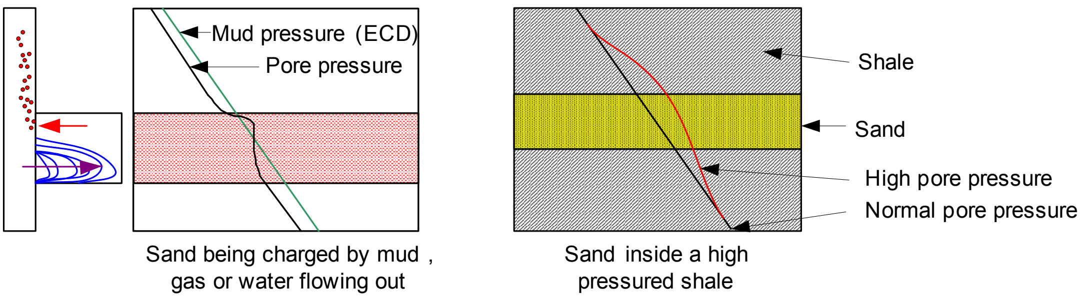


Figure 7-6: A small and permeable sand being charged by high ECD (left). Geo-pressured sand (right).

One method suggested for estimation of SWF potential is as follows: Calculate the sedimentation rate of the shallowest shale by seismic correlation to the shallowest available offset paleo-data. If the sedimentation rate is less than 500 ft per million years at the planned drilling site, the sands should have no significant pressure. If the rate has been higher than 500 ft per million years, then treat the sands (inside the shale) as potentially pressured.

Once the sand prone facies have been mapped, well locations can possibly be adjusted to avoid SWF or casing programs can be modified. LWD correlations should be made to ensure that the flow zone is not penetrated prior to reaching the casing point. LWD correlations include gamma ray, resistivity and pressure while drilling (PWD) data. Pressure while drilling devices have proved helpful as they indicate increased bottom hole pressure when the zone starts to flow.

Cementing is critical due to loss of hydrostatic pressure in the cement slurry during hydration of the cement. During the transition period when hydrostatic pressure of the slurry is decreasing below water pressure, the slurry strength is low, porosity and permeability is high, and, unfortunately, gas may enter the setting cement and find its way through it, or, through a micro annulus which is caused by shrinkage. The phenomenon is referred to as Gas Migration Through Cement, and partly explains how the gas finds it way to the surface. More details are found in Chapter 8.

7.3.2 Shallow gas

The term Shallow Gas represents the problem of drilling through gas bearing shallow sands. Shallow gas implies free gas or gas in solution that exists in permeable formation which is penetrated before the surface casing and BOP has been installed

The most common method of offshore drilling up to 1987 was to apply the riser when drilling all bit sections, and divert the gas through a gas diverter system on the rig. The equipment to handle gas and divert it on the surface is shown in Figure 7-7.

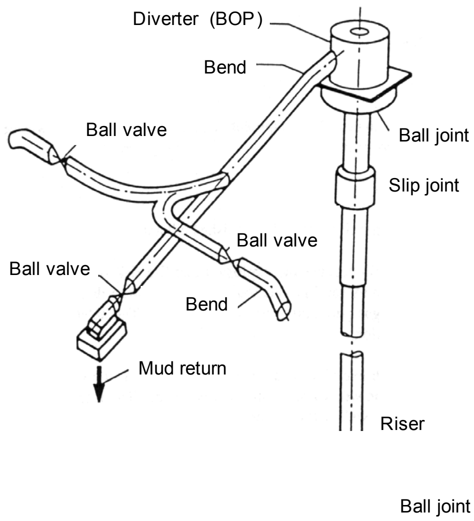


Figure 7-7: Gas diverter system.

After 1987 it became common to drill the two fist well sections without a riser. The problematic combination of riser – Shallow Gas became evident through many shallow gas blowouts, and especially in 1986 when the Haltenbanken blowout was investigated and made public (NOU 1986). The floating drilling rig West Vanguard was drilling outside Trøndelag on Haltenbanken when shallow gas blew out. The well blew for almost five months before it depleted and could be cemented and plugged. This incident will be presented in some detail because so much was learned from it. First, in Figure 7-8 the situation just before, during and after the blowout is summarized together with comments made by the investigation commission.

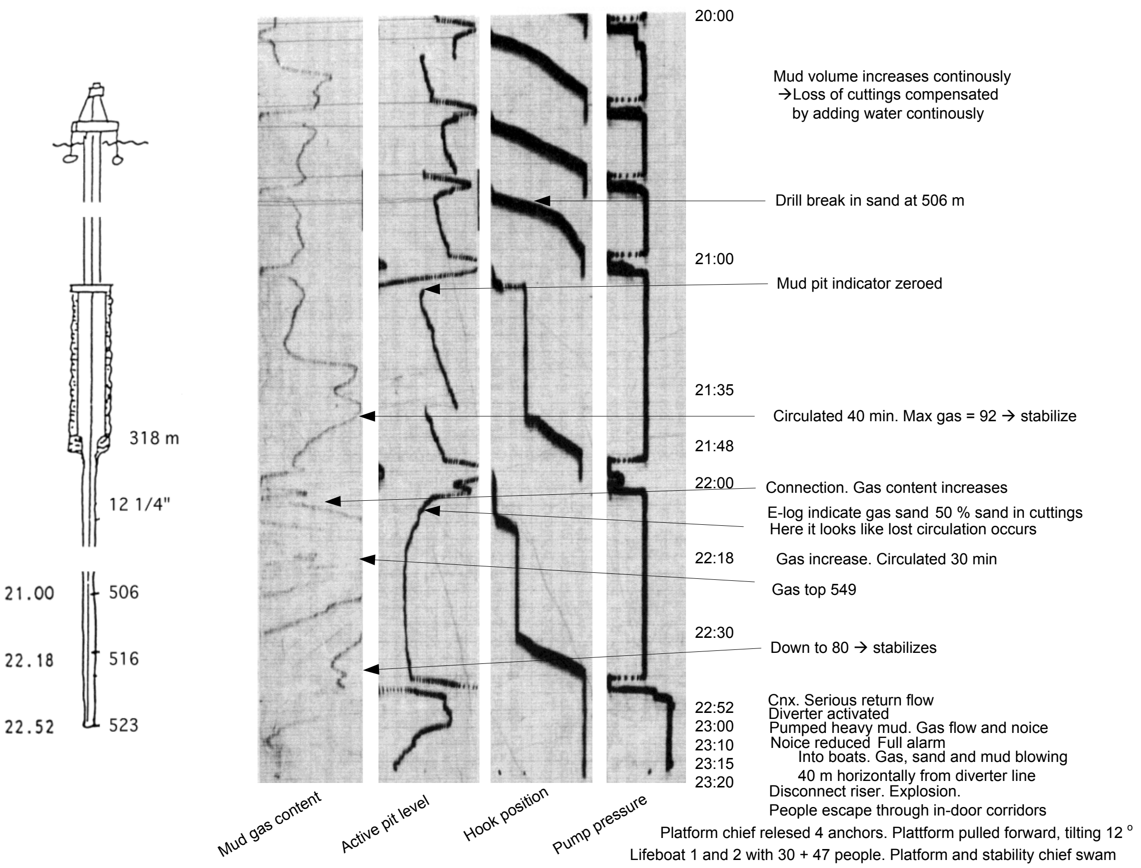


Figure 7-8: Summary of the shallow gas blowout on Haltenbanken, October 6, 1985, with comments to the mud log from investigators.

The investigation concluded by stating that the narrow pressure window was the root cause of the incident. Details are presented in Figure 7-9.

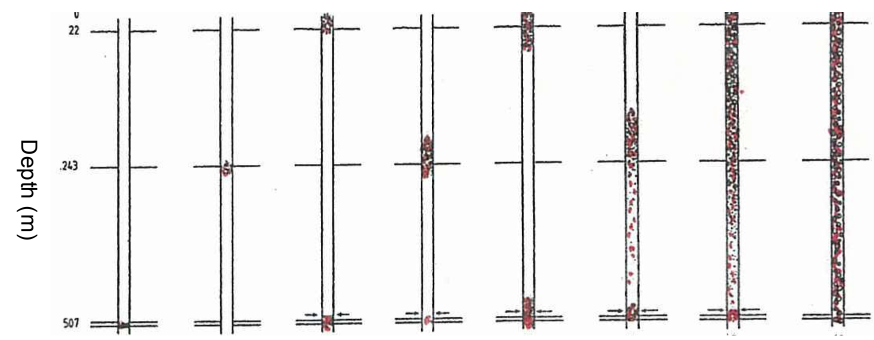


Figure 7-9: Hypothesis of cause behind the blow out: Shallow sand was being charged by the ECD and later feeding gas from it during connections.

Circulating out shallow gas through a diverting system is characterized by very high surface pressure and high gas velocities. When the well started to blow, very soon afterwards, critical flow (speed of sound) developed, and the reservoir pressure minus friction loss was transferred to the surface. The gas itself had negligible hydrostatic pressure. In such situations, it was very understandable that the following situations took place:

- Surface pipes and pipe bends in the diverter system eroded. Sand production of the formation caused severe sand blasting, especially in bends (see Figure 7-7)
- The riser slip joint was stretched beyond its elastic limit and caused leakage

The only solution to this problem was to avoid the riser and drill riser-less, as presented in Figure 7-10.

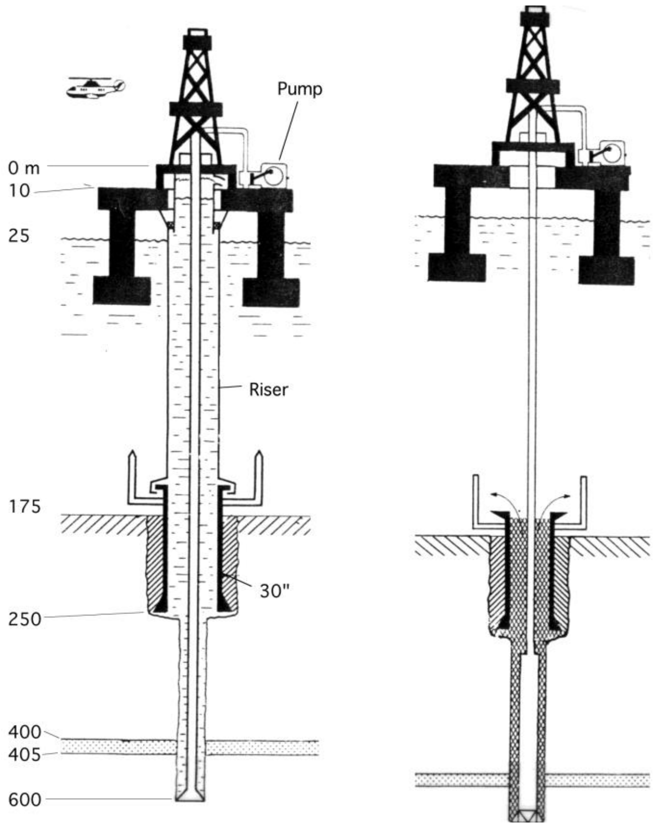


Figure 7-10: Offshore drilling before and after 1986.

Some distinguished advantages were achieved:

The overall drilling operation became safer, mainly because the risk of explosion and fire risk on the rig was very low. In addition it was important that the stability was not influenced by sand production through a broken diverter line any more. Experience and experiments showed that this probably affects the stability more than gas percolating up under the floater.

The deeper the water depth, the more likely it is that, without a riser, a gas plume from the well will be swept away from the vessel by the sea currents. When drilling top holes in deepwater, the relative merits of riser-less drilling included additionally that time was saved due to less riser running/pulling.

The all over control of the drilling operation was much lower than with a riser installed, but was compensated for through proper procedures like shown in the next section.

7.3.4 Best killing practice in shallow sands

When SWF or Shallow Gas is detected, the well must be killed fast. Since the wellbore is open, it requires special procedures. It also requires special precautions and mitigations:

- Use shallow seismic to offset data for selection of location that minimizes shallow sand.
- Dynamic and/or weighted fluid kill procedures, including mixed mud, should be ready to implement immediately. At least two hole volumes of kill mud must be at hand. If well is not dead after pumping two hole volumes, further pumping is rarely effective. Change mud density or pump rate.
- Add tracers (dye, mica, etc.) to sweeps to help identification in ROV video.
- Kill by using maximum pump rate with multiple mud pumps. Rate is limited by available mud pumps and drill string internal pressure drop.
- The bit nozzle selected should be large to minimize pressure drop.
- A small pilot hole (9 7/8" or less) increases the capability of dynamic killing.
- Trend today: Minimize exposure time and hole enlargement, drill and under-ream simultaneously at a high ROP.
- After dynamic killing, fill the hole with weighted mud to ensure pore pressure overbalance and improved wellbore stability.

8 Gas migration through cement

8.1 The cement slurry

This chapter is included to give a short summary of cement chemistry and point out some important factors that have influence on gas migration.

8.1.1 Composition & hydration

In table 8-1 the important components in cement manufacturing are presented.

Table 8-1: Raw material components in cement powder production. Slurry is made by mixing cement powder and water. For Portland cement the water-to-cement ratio, w/c = 0.4 (40 % water bwoc).

Raw material	Important components	Symbol	Weight % in dry material
For production:			
Lime	CaO	C	65
Clay	SiO_2	S	22
Aluminum oxide	Al_2O_3	A	6
	MgO		2
Iron oxide	Fe_2O_3	F	3
Gipsum	Ca SO_4 $2H_2O$		1-3
For slurry:			
Water	H_2O	H	40
Additives	-	-	-

In Figure 8-1 the first step of industrial procuction of cement powder is presented, the so called wet process.

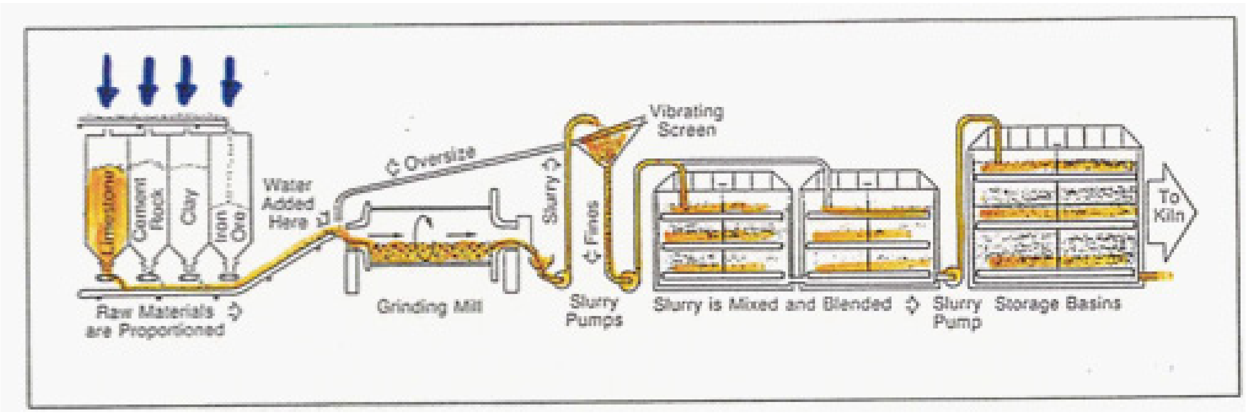


Figure 8-1: The wet process of cement raw material: Mixing and grinding the raw material.

The two next steps after the wet process are the Burning and the Grinding process. The cement powder goes then to storage and transport.

When the produced cement powder is mixed with water to make cement slurry, the reaction between the two is an exothermic reaction which produces some heat. This is presented in Figure 8-2. By recording the temperature evolution it is possible to follow the reaction (also referred to as hydration).

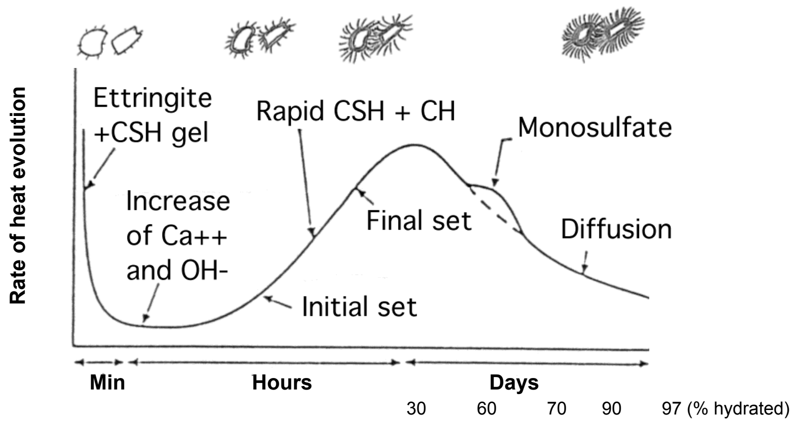


Figure 8-2: Hydration of cement after mixing with water.

In the upper part of Figure 8-2 we follow the development of two cement powder particles. A resulting needle-like mineral called ettringite is growing out of each particle. After a "dormant" period of typically 3-6 hours, the initial set state is reached; the needles are beginning to interfere with neighbouring needles, and the fluid-like slurry begins to stiffen. Soon afterwards it is not possible to pump it any more. At final set the cement is hard and inpenetratable by a Vicat needle.

8.1.2 Laboratory testing

The slurry needs to be tested in the laboratory, and many of the tests are similar to those applied on drilling fluids, like:

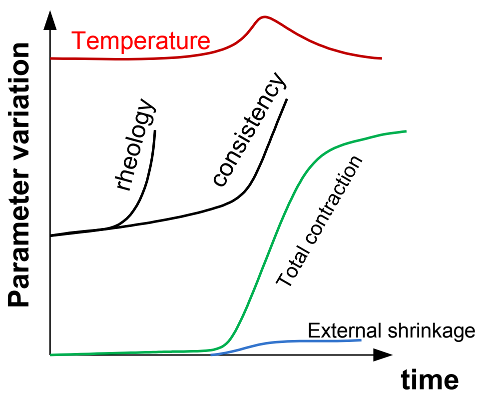


Figure 8-3: Some parameters measuredin the laboratory.

- density
- filter loss
- rheology

But some are specific for the cement slurry,as indicated in Figure 8-3. The special ones are:

- consistency (test the pumpability)
- contraction / shrinkage
- free water
- compressive and tensile strength
- permeability
- porosity

Some of these tests have to perform under HTHP conditions. Hydration rate is largelyInfluenced by temperature. **8-3:**

8.1.3 Additives and their effect

In order to achieve desired properties of a slurry, many additives are available as shown in Table 8-2.

Table 8-2: Cement slurry additives.

Additive Category	Benefit	Composition	Mechanism of reaction
accelerator	-shorter thickening time -higher early compressive strength	$CaCl_2$, Na Cl	increased permeability of C-S-H gel layer
retarder	longer thickening time	lignosulfonates hydrooxycarboxylic acids	adsorption onto C-S-H gel layer, reducing permeability
extender	-lower slurry density -higher slurry yield	bentonite	absorption of water
		sodium silicates	formation of C-S-H gel + absorption of water
		pozzolans gilsonite powdered coal microspheres	lower density than cement
		nitrogen	foamed cement
weighting agent	higher slurry density	barite ($BaSo_2$) hematite (Fe_2O_3) ilmenite ($FeTiO_3$)	higher density than cement
dispersant	lower slurry viscosity	polynapththalene sulfonate polymelamine sulfonate lignosulfonates	induce electrostatic repulsion of cement grains
fluid-loss additive	reduced slurry dehydration	cellulosic polymers	increased viscosity of aqueous phase of slurry
lost-circulation control agent	prevent loss of slurry to formation	gilsonite granular coal cellophane flakes	bridging effect across formation
		gypsum	induce thixotropic behavior of slurry

All additives will reduce the strength of the hardened cement. However, all the parameters, like the permeability of the cement are equally important parameter, and need special attention with respect to gas migration resistance.

8.2 Cementing operations

This chapter is a quick glance at cementing techniques and job evaluation, where factors that have influence on gas migration are pointed out.

8.2.1 Cementing techniques

Figure 8-4 shows how primary cementing is performed, and some of the equipment involved.

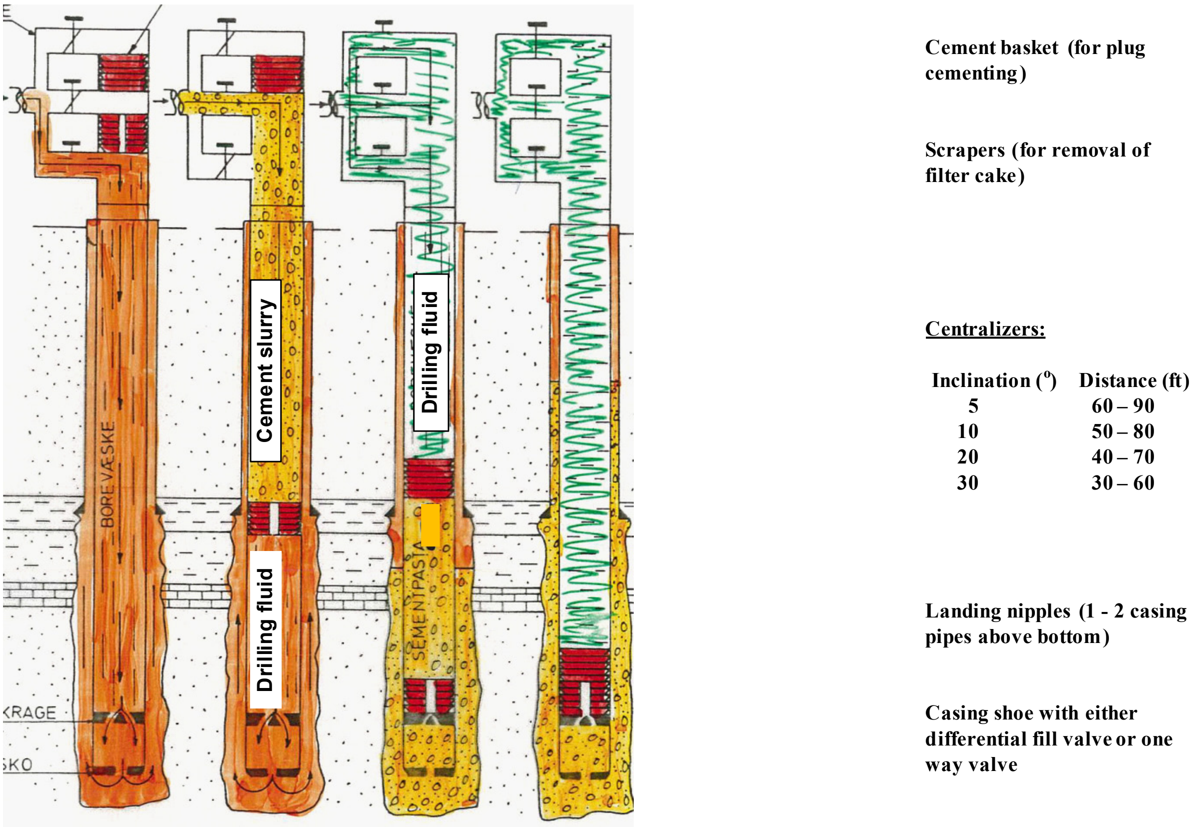


Figure 8-4: Primary cementing technique, including surface cement head and typical casing equipment when running in hole.

Figure 8-5 presents the primary cementing operation from floating vessel. The main difference between on - and offshore is that in offshore operations the cement head is partly situated at the surface (plug-control tools) and partly at the top of the uppermost casing (two plugs).

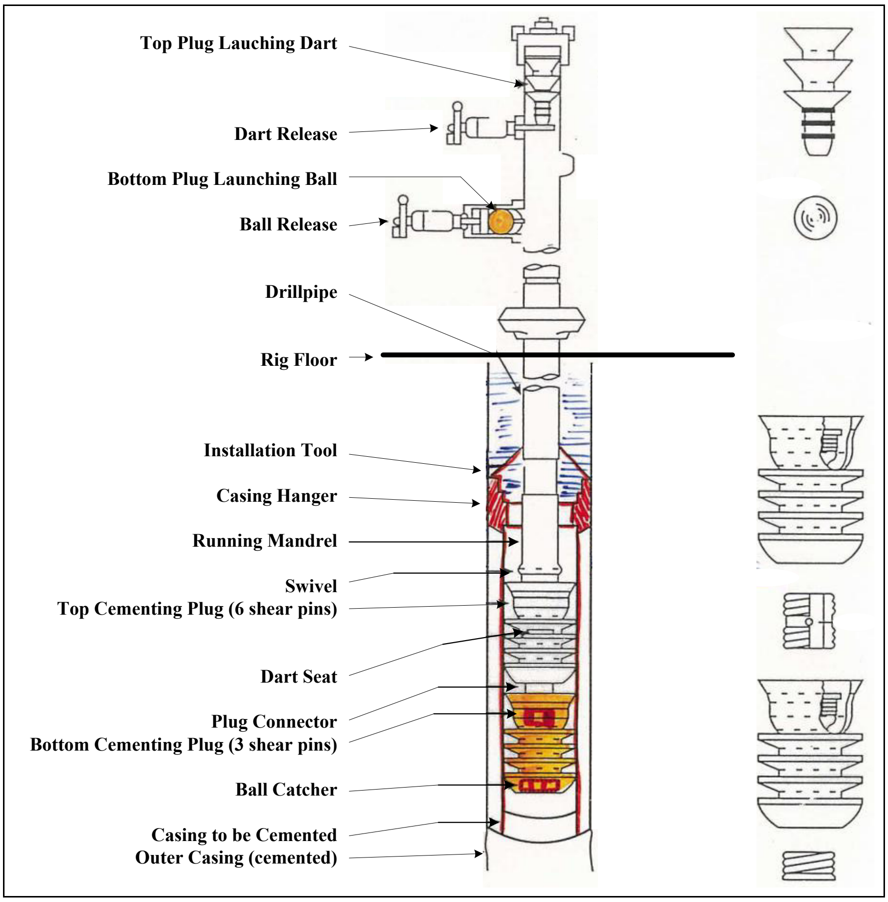


Figure 8-5: Two plug cementing from a floating rig.

One issue of high relevance for gas migration is the displacement process along the annulus. Since there is no-slip conditions at the walls, the velocity profile, assuming purely laminar flow, will cause the displacement profile to become distorted. The cement quality becomes very low, lower the nearer the surface, as indicated in Figure 8-6.

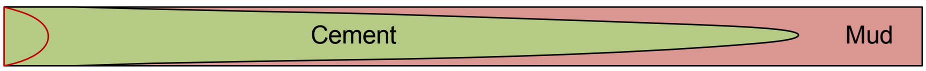


Figure 8-6: Initial velocity profile (left) and resulting displacement profile.

8.2.2 Job evaluation

To test the quality of the cement (behind the casing) several test methods are available;

- Hydraulic test at casing shoe
- T-log
- Radioactive tracer
- Acoustic log

Just before drilling through the cement when starting a new well section, a hydraulic test will reveal any leaks through the cement sheet at the casing shoe.

The following three methods are performed by running the tool from the bottom and up. In the T-log the generated heat (temperature) is recorded when the hydration rate is expected to be at its maximum. The radioactive log measures radiation intensity. Both methods obtain an indication of cement concentration behind the casing. The acoustic log is run after final set, when bonds to the walls have been established. Figure 8-7 shows its functionality.

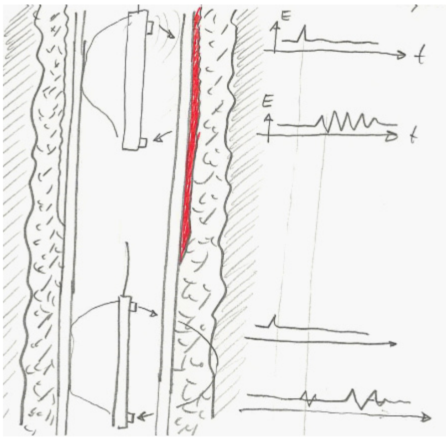


Figure 8-7: Principles of a cement-bond log. A sonic signal is sent out and recorded at the receiver (hydrophone)

8.3 Gas migration

After the blowout in Gulf of Mexico in 2010 the topic of gas migration has become more relevant again. Some of the material presented here is taken from the book by Nelson; Well Cementing, Chapter 8, plus resent (2010) papers.

8.3.1 The problem

Annular fluid migration also called gas communication, gas leakage, annular gas flow, gas channelling, flow after cementing, or gas invasion, may occur during drilling or during well completion, and has long been recognized as one of the most troublesome problems of the petroleum industry. It materializes as an invasion of formation gas into the annulus, partly because of a pressure imbalance at the formation face. The severity of the problem ranges from the most hazardous, e.g., a blowout situation when well control is lost to the most marginal, e.g., a gas pressure of a few psi in one or more annuli at the wellhead.

To try rectifying the leaks by means of squeeze cementing in such circumstances is not a good idea for three essential reasons:

1. Gas channels are difficult to locate, especially since most are small;
2. Gas channels may be too small to be fillable by cement;
3. The pressure exerted during the squeeze job is sometimes sufficient to break cement bonds, or even to initiate formation fracturing, worsening the downhole communication problems.

8.3.2. Pressure decline and its explanation

Gas migration occurs even when the annular fluid densities are such that the initial hydrostatic head is much higher than the gas pressure. Hydrostatic pressure reduction during cement hydration has previously been demonstrated in the laboratory, and confirmed by field measurements performed by Exxon in 1982. The use of external casing sensors permitted the observation of downhole temperature and pressure fluctuations, as well as the transmissibility of applied surface pressure as shown in Figure 8-8.

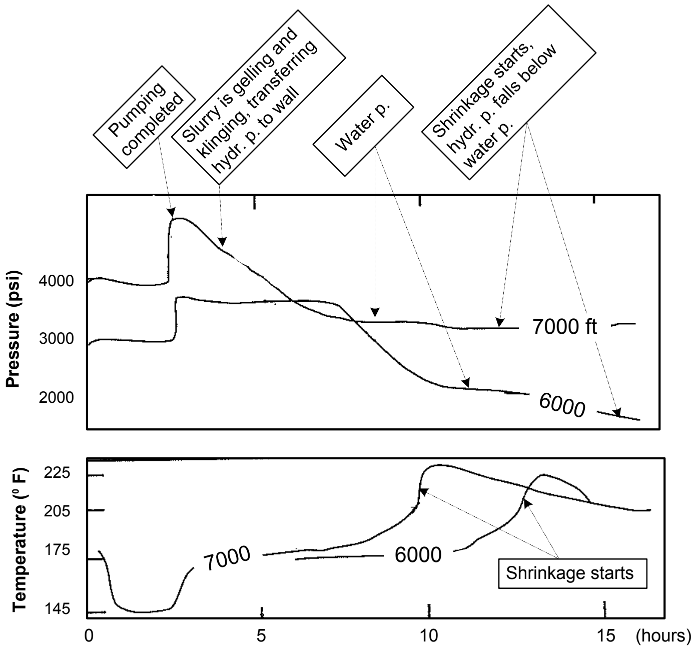


Figure 8-8: Annular pressure and temperature measurements from external casing sensors (from Exxon, 1982).

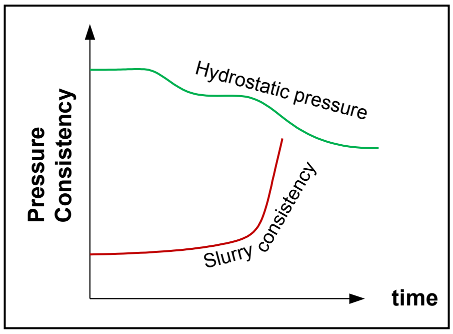


Figure 8-9: Annular gas flow test results.ments from external casing sensors (from Exxon, 1982).

Laboratory measurements in a vertical pipe with no external pressure source demonstrated that the hydrostatic pressure gradient gradually decreases to that of the mix water as shown in Figure 8-9. Later, when the hydration accelerates, the hydrostatic pressure quickly approaches zero. The hydrostatic pressure reduction is the result of shrinkage within the cement matrix due to hydration and fluid loss. At this point, the pore pressure cannot be re-established by the fluid column above.

The concept of transition state was introduced, an intermediate period during which the cement behaves neither as a fluid nor as a solid, and the slurry looses its ability to transmit hydrostatic pressure. The concept of transition state was quantified by a transition time, starting with the first gel strength increase, and ending when gas could no longer percolate within the gelled cement. Here follows more details of this possible explanation:

a) **Pore-Pressure Decrease Described by Soil Mechanics Theory**

Using the theory of soil mechanics, and assuming that the cement slurry behaves as a porous, permeable sedimentary soil before significant hydration occurs (Ettringite). The state of stress in the slurry can be described through the vertical stress, σ_z being a part of the "overburden".

$$\sigma_{ovb} = p_{pore} + \sigma_z$$

When gelation occurs during the induction or dormant period, there is no significant hydration of the cement grains, but essentially a build-up of intergranular forces mainly because of interparticle electrostatic forces and the precipitation of chemical species. In a first approximation, the total stress, σ_{ovb}, remains the same, but a transfer from p_{pore} to σ_z occurs. Eventually, σ_z increases to a point where the cement becomes self-supporting. At this time, the interstitial pressure drops to the water gradient.

b) **Pore-Pressure Reduction Below the Water Gradient due to Shrinkage**

Later, when the cement system enters the setting period and hydration accelerates, intergranular stresses, σ_z, increase because of the intergrowth of calcium silicate hydrates (Ettringite). If no volume change would occur at this stage, the pore pressure would remain at a low level, and the cement would behave as a porous formation. However, this is not the case. Cement hydration is responsible for an absolute volume reduction of the cement matrix, also called cement chemical contraction. The shrinkage is well documented in the civil engineering literature, and occurs because the volume of the hydrated phases is less than that of the initial reactants. This total chemical contraction is split between a bulk or external volumetric shrinkage, less that 1%, and a matrix internal contraction representing around 5 % by volume of cement slurry, depending upon the cement composition as exemplified in Figure 8-10.

Chemical contraction is responsible for a secondary porosity, mainly composed of free and conductive pores. The combination of chemical shrinkage and secondary porosity is responsible for the sharp decrease in cement pore pressure from the water gradient to the formation pressure, or at least less than the water, as seen in Figure 8-8 and 8-9..

8.3.3 Gas migration routes

Formation gas is flowing up to the surface through three different routes, shown in Figure 8-11.

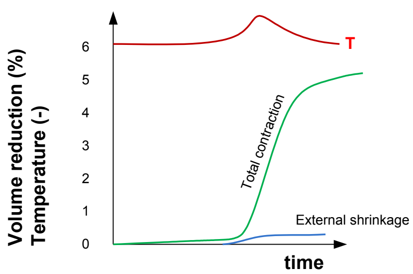


Figure 8-10: Typical contraction and external shrinkage after shrinkage after hydration starts.

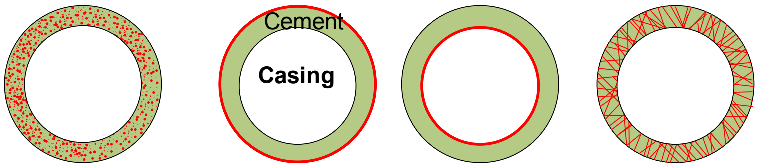


Figure 8-11: Three routes of the cement; through pore structure(left), along weak bonds and through cracks some time after setting.

a) **Through the cement pore structure**

Before the cement slurry sets, the interstitial water is mobile; therefore, some degree of fluid loss always occurs when the annular hydrostatic pressure exceeds that of the formation. The process slows when a low-permeability filter cake forms against the formation wall, or can stop altogether when the annular and formation pressures equilibrate. Once equilibrium is obtained, any volume change within the cement will provoke a sharp pore-pressure decline; consequently, gas percolation can be considered as a particular type of gas migration, where gas in the form of macroscopic bubbles invades the slurry, and rises due to buoyancy effects in accordance with Stokes' Law.

Poor fluid-loss control in front of a gas-bearing zone accelerates the decrease of cement pore pressure. API fluid-loss rates as low as 10 ml/30 min is said to be required to prevent gas invasion. Fluid loss occurring higher up in the hole hinders transmission of hydrostatic head from the column above the invasion point to the bottom of the hole.

A related problem in deviated wells is free water forming channels on the upper side of the wellbore, demonstrated in Figure 8-12 further down.

Gas migration may thus find its way through the pore structure of very permeable gelled or set cement, as well as the potential gas percolation beforehand within the gelling slurry.

b) **Along weak bonds**

Regardless of the cement system, gas can still migrate along the cement/formation or cement/casing interface if micro annuli have developed or along paths of weakness where the bond strength is reduced. Good bonding is the principal goal of primary cementing.

The principal potential causes for a bonding defect at the cement-to-casing or cement-to-formation interface are the following:

- Lack of roughness along the surface of the casing and formation
- Cement bulk volumetric shrinkage:
- Tensile stresses at the interface may arise at the early stage of hydration when cement undergoes an external volumetric shrinkage. However, this effect is minimal in long cement columns where consolidation and early creep of the formation may compensate for the shrinkage effect. And, bulk shrinkage occurring after initial set is generally only a few tenths of one percent.
- Mud film or mud channel forming at the interface
- Free-water channel or layer in deviated wells
- Excessive downhole thermal stresses

- Thermal stresses are the result of cement hydration, wellbore cool down treatments, steam injection, cold fluid injection, etc.
- Excessive downhole hydraulic stresses:
- Hydraulic stresses result from replacement of casing fluid density, communication tests, squeeze pressure, stimulation treatment pressure, etc. Downhole deformations resulting from thermal and hydraulic stresses constitute a major drive for gas migration at the cement-casing and cement-formation interface
- Excessive downhole mechanical stresses:
  Occasionally, gas migration through the annulus of an intermediate string occurs several days after cementing, i.e. after drilling has resumed. In such a situation, the influence of mechanical stresses generated by drilling cannot be overlooked, especially in cases where weak formations are present behind the cemented string (washout – poor cement)

It has been found that cement shrinkage by itself probably does not lead to the development of a microannulus, but instead to the development of reduced surface bound. Thus, the development of a true microannulus could only be due to an additional stress imbalance between one of the two considered interfaces

c) **After cement setting**

After setting, during the hardening phase, normal density cement becomes a solid of very low permeability, at the micro Darcy level. However, it should be noted that low-density cement systems with high water-to-cement ratios can exhibit fairly high permeabilities (0.5 to 5.0 mD). Therefore, it is possible for gas to flow, albeit at low rates, within the matrix of such cement, and to eventually reach the surface. Such events may take weeks or months to manifest themselves as measurable phenomena at the surface, where they usually appear as slow pressure buildups in the shut-in annulus.

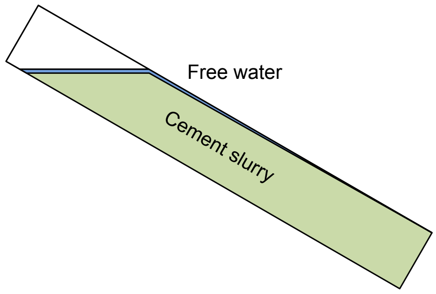


Figure 8-12: Schematic diagram showing fully developed water channeling.

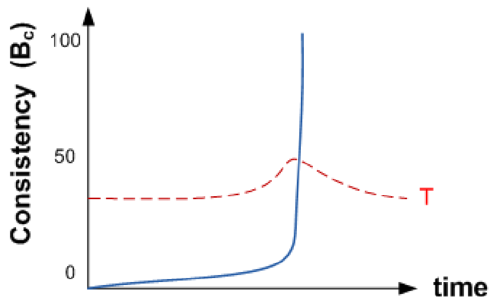


Figure 8-13: Pressurized consistometer output from Right-Angle-Set cement system.

8.3.4 Solutions

Over the years, a number of methods to control gas migration have been proposed. The basic "good cementing practices" is a prerequisite for controlling gas migration. This includes mud and mud cake removal

- Rotate/reciprocate during displacement to avoid fingering and unobtainable surfaces. Use scrapers and centralizers
- Flow rate maximum => flat flow profile results in improved sweeping
- Low fluid loss and free water, especially in deviated wells have been identified as promoting the occurrence of gas migration. To minimize the impact of these parameters on gas flow, both must be reduced to fairly low levels.

The most popular techniques to minimize gas migration that have been applied are listed below.

a) **Physical Techniques**
It has long been known that a number of physical techniques can, under certain circumstances, help control gas migration. These include the application of annular back-pressure, the use of external casing packers (ECPs), and the reduction of cement column height (including multistage cementing). Each of the attempts to delay the occurrence of downhole pressure restriction at the gas-bearing formation face until the cement is sufficiently hard and impermeable. Such techniques are certainly valid under a variety of conditions, but well conditions often limit their application.

b) **Compressible Cements**

Compressible cement slurries have been developed in an attempt to maintain cement pore pressure above the formation gas pressure. Compressible cements fall into two main categories – foamed cements and in-situ gas generators. Nitrogen foamed cement is also an additive with several advantages

- Low fluid loss and low free water
- High compressibility

c) **Expansive Cements**

Expansive cements have been advocated in places where a microannulus has been identified as the gas migration pathway, and successful field results have been reported. There are two principal techniques for inducing expansion in Portland cement: Crystal growth and gas generation. The latter operates on the same principle as the compressible cements with the exception that the concentration of gas-generating material (typically aluminum) is reduced. The former, on the other hand, relies upon the nucleation and growth of certain mineral species within the set cement matrix. The bulk volumetric expansion is usually controlled to be less than one percent.

d) **"Right-Angle-Set" (RAS) Cements**

RAS cement slurries can be defined as well-dispersed systems which show no progressive gelation tendency, yet set very rapidly because of rapid hydration kinetics. Such systems maintain a full hydrostatic load on the gas zone up to the commencement of set, and develop a very low-permeability matrix with sufficient speed (within minutes) to prevent significant gas intrusion. The increasing consistency is accompanied by a temperature increase resulting from the exothermic cement hydration reactions taking place in Figure 8-13 further up.

e) **Impermeable Cements**

Gas migration can be prevented by reducing the matrix permeability of the cement system during the critical liquid-to-solid transition time described earlier. Latex and silica fume (micro silica) have both been tried with positive results. The average particle size of micro silica is 1 μm; consequently, it is able to fill pore spaces and plug pore throats.

f) **Elastic Cements**

In recent years the focus has been on elastic cement systems. Elastic additives have very low Young's modules, and provide resilient, non-foamed cement that isolate wellbores cemented across gas sands.

A cement column in the annulus is subjected to external and internal stresses beginning at the time of cementing and throughout the drilling process, including LOT, drill string vibration transferred to the easing/cement sheet the well completion, perforation, stimulation, production and remedial operations. Together with gas migration (short term problem) it leads to growing leakage in the long run.

Total Oil Co. (Garnier et.al. 2010) tested commercial cements in their in-house methodology, directed at designing cement-sheath integrity for steam-assisted gravity drainage wells, and found that resilient cements with low Young's modulus and high tensile strength passed the tests.

Halliburton (Reddy at.al. 2010) tested commercial elastomeric additives (rubber-like) modified to contain anionic groups, that functioned as self-healing additives. They claimed that stress crack have a self-healing ability, and thus providing effective zonal isolation throughout the life of the well.

Nagelhout at. al. (2010) tested novel silicon material combined with bulk expansion material without the need of external water contact. The hardened cement had a Young's module around 1000 MPa. Long term gas sealing was obtained both in the laboratory and in the field.

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Nomenclature

Latin:

A	cross sectional area (m^2)
B	empirical constant = 1.2
C	concentration (-), capacity (m^3/m^3)
d	diameter (m)
D	depth (m)
E	Modulus of Elasticity
f	friction factor (-)
F	force (N)
g	acceleration due to gravity (m/s^2)
G	gradient (Pa/m)
h	height, depth (m)
H, h, z	stress field coordinates
H	Hold up (-), Henry's Constant
l	length (m)
m	mass (kg)
M	Molecular Weight (mol)
p	pressure (Pa)
q	volumetric flow rate (m^3/s)
r	radial position (m)
R	radius (m), el. Resistivity (ohm)
t	time (s or µs)
T	temperature (°K)
v	fluid velocity (m/s)
V	volume (m^3)
x	mol fraction (-)
x, y, z	Cartesian coordinates
z	vertical depth (m)
Ø	porosity (- or %)

Greek:

D	difference
e	relative elongation
m	Poisson's Ratio, micro = 1/1000
ρ	density (kg/m^3)
σ	stress (Pa)

Subscripts referring to:

1, 2	counters
c	corrected
frac	fracture
h	least horizontal stress
i, j	counters
H	maximum horizontal stress
liq	liquid
LO	leak off
ovb	overburden
Re	Reynolds number
z	vertical

Abbreviations

BHA	Bottom Hole Assembly
BOP	Blow Out Preventer
Cnx	Connection
CSG	Casing
ECD	Equivalent Circulating Density
ICP	Initial Circulating Pressure
FCP	Final Circulating Pressure
FIT	Formation Integrity Test
FS	Fail Safe
GPM	Gallons per Minute
GOR	Gas Oil Ratio
LOT	Leak Off Test
LWD	Logging While Drilling
HTHP	High Temperature High Pressure
MAASP	Maximum Allowable Annular Shut-in Pressure
MD	Measured Depth
MWD	Measurement While Drilling
NOU	Norsk Offentlig Utredning
OBM	Oil Based Mud
OFU	Oil Field Units
PPG	Pounds per Gallon
PWD	Pressure While Drilling
ROP	Rate of Penetration
RPM	Revolutions per Minute
RKB	Rotary Kelly Bushing
ROV	Remote Operated Vehicle
SCP	Slow Circulating Pressure
SCR	Slow Circulating Rate

SG	Shallow Gas
SI	System International
SICP	Shut in Casing Pressure¨
SIDPP	Shut in Drill Pipe Pressure
SPM	Strokes per Minute
SWF	Shallow Water Flow
TJ	Tool Joint
TVD	True Vertical Depth
WBM	Water Based Mud
WOB	Weight on Bit
W&W	Wait & Weight

Unit conversion factors

Variable	Symbol	Oil Field Units	Engineering	SI	To obtain SI multiply OFU by
Fluid					
Mass	m	lb	kg	kg	0.4536
Mud weight	ρ	lb/gal (PPG)	spec.gr. (SG)	kg/m^3	119.8264
Viscosity	μ	cP	dyne/cm^2	Pa*s	10^{-3}
Yield Point	τ_y	lbf/100 ft2	dyne/cm^2	Pa	0.4788026
Additives	c	lb/bbl (PPB)	g/l	kg/m^3	2.853010
Geometry					
Depth	h, TVD	ft	m	m	0.3048
Diameterhole	d_{well}	in	mm	m	0.0254
Nozzle dia	d_{nozzle}	1/32nd in	mm	m	.00079375
Volume	V	gal	1	m^3	3.785412*10^{-3}
Volume	V	bbl	1	m^3	0.158987
Operational					
Force	F	lb_f	kg_f	N	4.448
Pressure	p	psi	bar	Pa	6894.76
Power	P	HP_{hydr}	KW	W	745.7
Temperature	T	^oF	^oC	^oK	(^oF-32)/1.8