Pressure Control During Oil Well Drilling

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Contents

1 Introduction

1.1 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 and think like a drilling engineer. As an example of such thinking, the engineer always expresses the parameter hydrostatic pressure $p_{hydr} = \rho gh \cdot TVD$ along the x-axis (instead of along the y-axis) as a function of increasing depth, as shown in Figure 1-1.

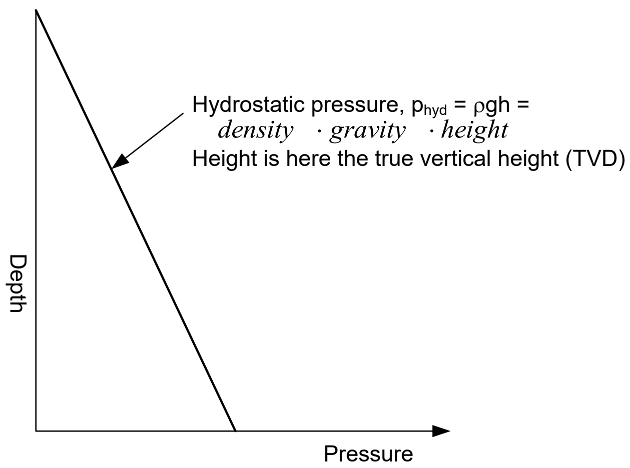


Figure 1-1: Hydrostatic pressure diagram for engineers.

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 Reference section for references.

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 of oil wells. All students with an interest in Petroleum Engineering can read the book without special additional preparations.

1.2 The drilling process

An oil well is drilled by means of the equipment systems as illustrated in Figure 1-2. To crush the rock and carry the cuttings away from the rock bit and up through the annulus, three types of energy are transmitted to the rock bit.

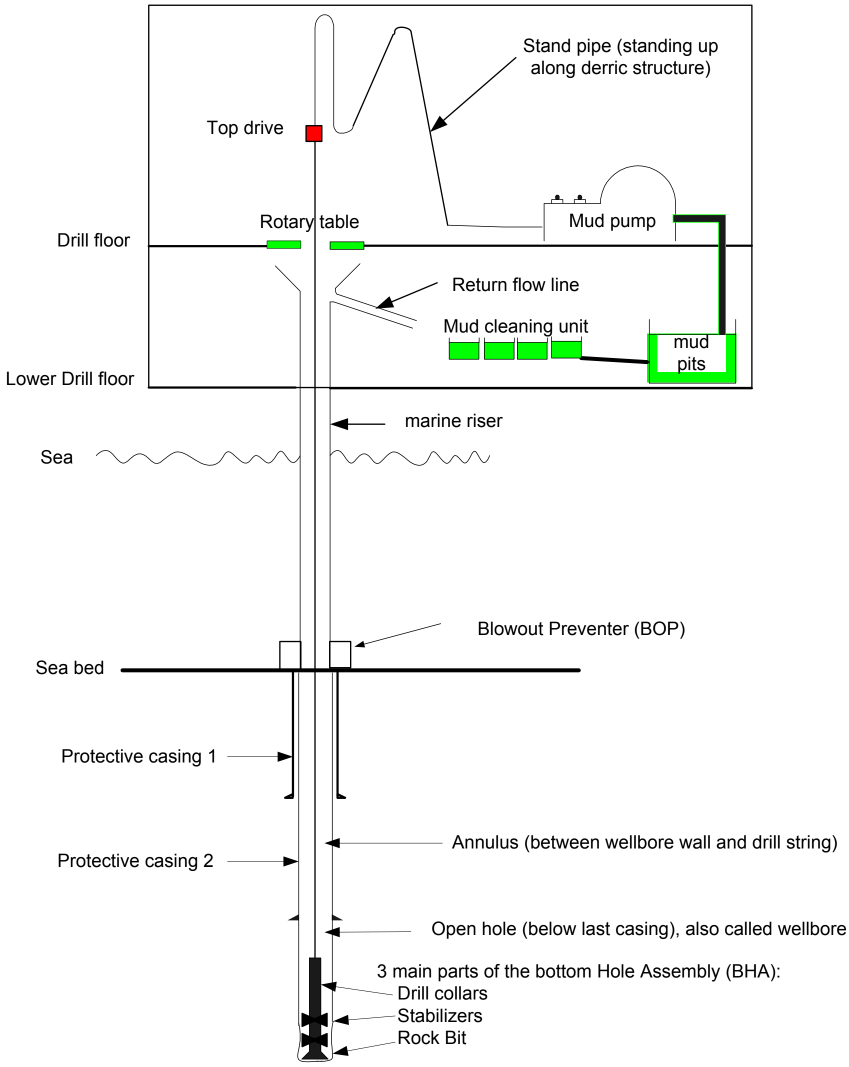


Figure 1-2: The drilling process.

- Downward force: Created by the drill string and especially the heavy drill collars.
- Rotation: Created for insurance by the top drive, which turns the complete drillstring, to which the rock bit is fastened at its bottom end.
- Fluid flow: The mud pump takes the drilling fluid from the mud pit and circulates 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 cleaned mud is returned to the mud pit.

1.3 Geological sediments

The search for hydrocarbons occurs in geological sedimentary rocks (as opposed to *volcanic* rocks). Several complex processes are involved before the sediments are deposited. First, the inland continental 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 ever 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 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 which the three most important sediments go through is presented and briefly discussed in Figure 1-3. It is the sediments at its second stage, sedimentary porous rock, that are the main focus of the petroleum industry. Here we find the source rock of oil and gas, which, after being squeezed out and migrated upwards are trapped in porous reservoirs with impermeable ceilings and walls.

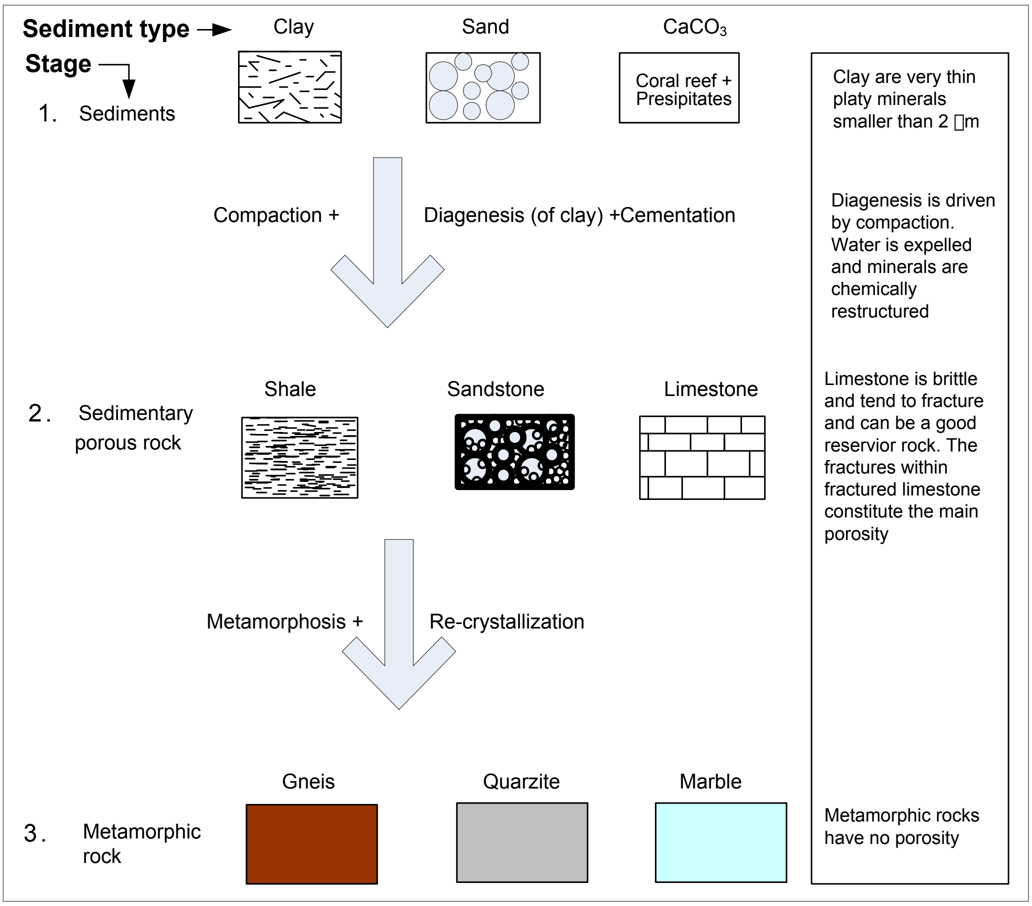


Figure 1-3: Three stages during the evolution of three sediments.

Sediments undergo gradual burial, compaction, diagenesis, cementation and re-crystallization when burial depth increases. If the sediments are buried deep enough of the earth crust a fourth stage is reached; the sediments melt and return to magma.

Porosity and permeability are the two most important parameters of the sediments, at least for petroleum engineers. The ultimate goal is to find hydrocarbons in the sedimentary rock. Porosity 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 1-4. 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 liquid to flow through the sedimentary rock. Normally the permeability is higher the higher the porosity.

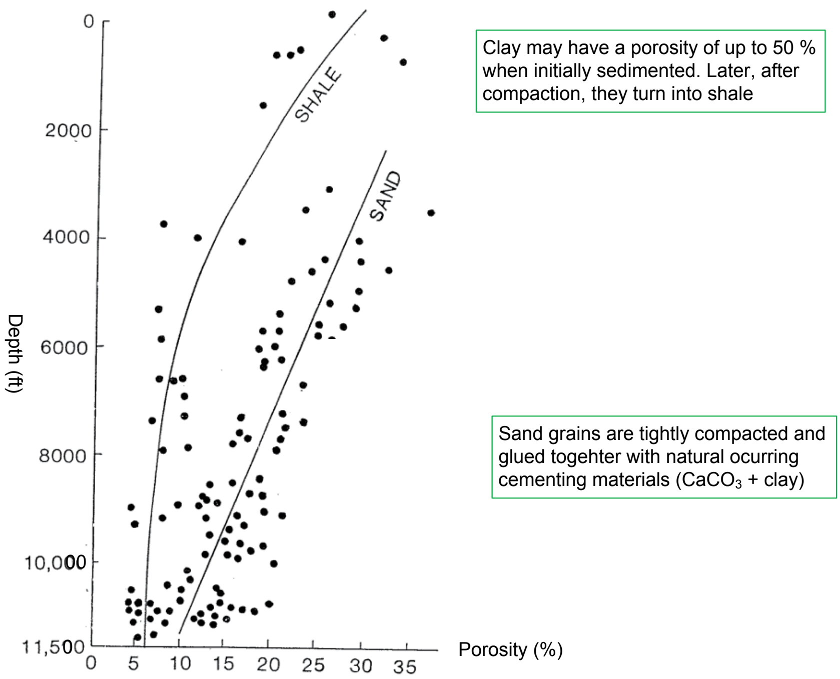


Figure 1-4: Porosity of shale and sandstone vs. depth of burial.

1.4 About Pressure Control in sedimentary rocks

All formations penetrated by the rock bit are porous to some degree as indicated in Figure 1-5. The pore spaces can contain fluids such as oil, gas or salt water or a mixture of these. Pore pressure, ppore, is exerted by the fluids contained in the pore space.

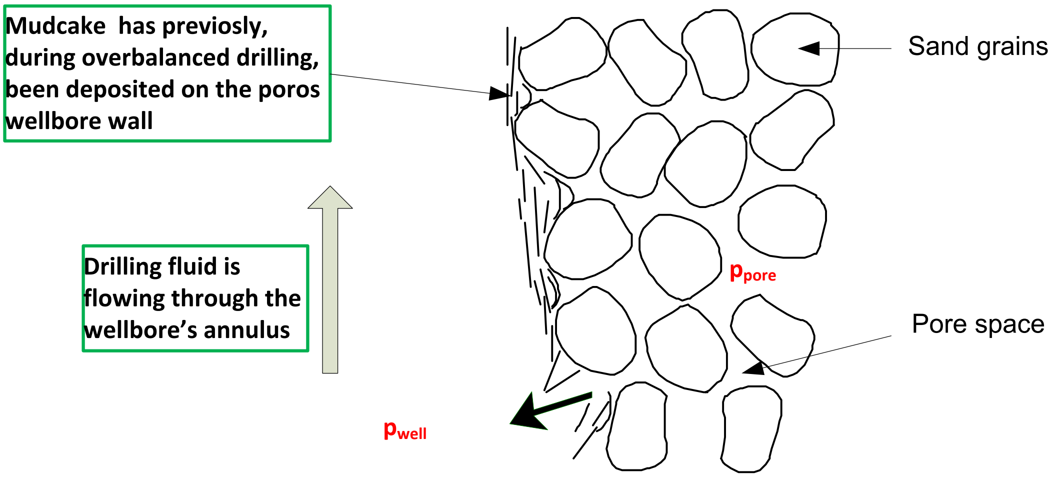


Figure 1-5: When wellbore pressure becomes lower than the pore pressure; pore fluid flows into the wellbore (kick).

In order to overbalance the pore pressure a drilling fluid with a proper density is circulated into the drill string, through the nozzles of the rock bit, and back to the platform through the annulus (the annular space between the drillstring 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 getting 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 string into (or out of) the well (latter activity is 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 flow back into the well, as illustrated in Figure 1-5. If the influx is small, it will merely mix in with the pumped drilling fluid and cause a minor decrease of its density (mud weight, MW). MW is being continuously measured at the surface. In such cases 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 occurs, an increase in mud pit volume (a pit is typically a 100 m3 large mud tank 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. Most frequently this happens in the following situations:

1. Mud density is too low due to gas cut mud or due to encountering or 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. When pulling the drill string out of the well too fast, a suction pressure will arise, called swabbing pressure
4. Drilling into neighboring producing wells (this happens very rarely)

Any kick requires some action to regain control. Because fluids like 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 behavior of gas. The driller, who is in charge of the well, will be dependent upon their knowledge of gas behavior 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 operation is called the killing operation or killing procedures.

Statistics indicate that typically every 100th kick results in one 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 the equipment

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 through the soil around the rig, causing major safety problems. 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, through fractures and into a formation zone located higher up (where the formation is weaker). This situation can ruin valuable reservoirs and charge shallow formations, making further drilling difficult or impossible in this area.

1.5 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 drilled well. In deep wells (> 3 000 mTVD), the kick frequency rises to 1–2 kicks pr. drilled well. The consequences of a blowout could be catastrophic. While a kick can be controlled, a blowout means the ability to control the influx is lost. It may take months to stop the blowout, and it is sometimes accompanied by the loss of human lives as well as large material and economical losses.

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

Barrier one: The hydrostatic pressure of mud is larger than the pore pressure
Barrier two: The envelope consisting of the blowout preventer, the well head, the casing and the drill string. This envelope can be closed in case barrier one fails.

2 Pressure in the sediments

Methods for determination of formation pressure fall in general into two groups:

- Predictive methods
- Verification methods

During planning and before reaching depth of interest the formation pressures must be predicted through predictive models and/or empirical correlations.

The predictive models are continuously improved or upgraded during the drilling operations or through experimental investigations.

2.1 Predictive models

Figure 2-1 presents the different pressure types necessary for the understanding of pressure control. In this chapter we will define pressure types and their predictive models.

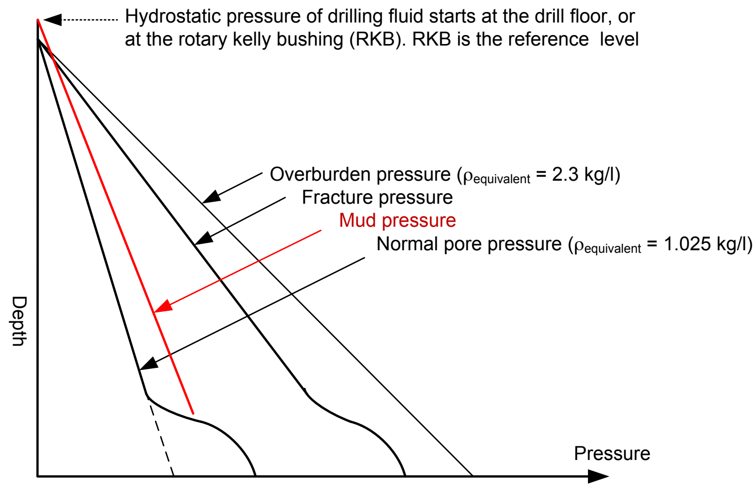


Figure 2-1: Pressure types in sedimentary rocks.

2.1.1 Overburden pressure and associated porosity

Overburden pressure is the combined weight of formation materials and fluids in the geological 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.

$$\textit{Overburden pressure} = \textit{weight of matrix and fluid / area} \quad (2.1)$$

Generally, formation stress is 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 weight. In addition, the two horizontal stresses σ_h and σ_H, are often assumed equal, but σ_H is taken as the largest (stresses in the earth are defined in chapter 2.1.4 and in the Nomenclature). For compacted and cemented sediments, 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:

$$\sigma_{ovb} = g \int \sigma(z)dz = \rho_z gz \tag{2.1}$$

ρ_z is the local or in-situ overburden density of the fluid-saturated formation at depth z. As a first approach, we assume that a porous formation has evenly distributed pores as shown in Figure 2-2, and that the speed of sound (obtained from the travel time between two sensors) is transmitted through the formation in accordance with eqn. 2.3.

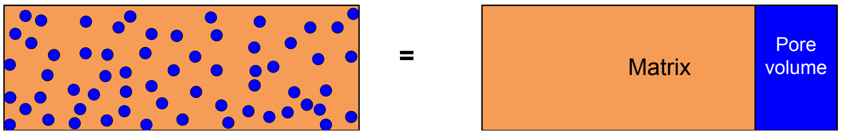


Figure 2-2: Porous formations consist of matrix (orange) and pores (blue), and the two are assumed additive.

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

Ø represents the porosity, and being a function of depth it becomes:

$$Ø(z) = (\Delta t - \Delta t_{matrix}) / (\Delta t_{fluid} - \Delta t_{matrix}) \tag{2.4}$$

Further assume that the matrix is represented by compact limestone (porosity equal zero, like marble). Typical material data are listed in Table 2-1.

Material	Transit time (ms/ft)	Transit velocity (m/s)
Fresh water (ρ = 1.00)	218	1 400
Sea water (ρ = 1.025)	200	1 500
Saline water (ρ = 1.06)	195	1 550
Saline water (ρ = 1.15)	189	1 600
Clay	150	2 030
Salt (ρ = 2.1)	67	4 200
Sandstone (unconsolidated)	58	5 100
Sandstone (consolidated)	52	5 700
Shale (compact)	47	6 500
Limestone (compact)	47	6 500

Table 2-1: Typical matrix and fluid transit times

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

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

A typical porosity of 0.15 will result in a local overburden density of 2.45 kg/l. By combining eqn 2.4 and 2.5 and applying compact limestone or shale, ρ = 2.7, as material, and ρ_{fluid} = 1.06, we obtain:

$$(\rho_z = 2.70 - 1.64 * (\Delta t - \Delta t_{matris})/(\Delta t - \Delta t_{matris}) \tag{2.6}$$

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

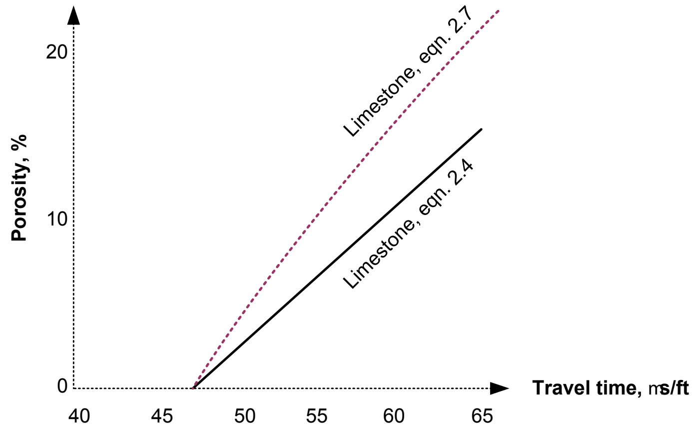


Figure 2-3: Porosity vs transit travel time in porous limestone (free after service companies).

In the porosity range of 0–25%, the data from Figure 2-3 indicate a correction factor of 1.288. Eqn 2-4 then becomes:

$$\text{Ø}(z) = 1.288 * (\Delta t - \Delta t_{matris})/(\Delta t - \Delta t_{matris}) \tag{2.7}$$

Combining Eqns. 2.6 and 2.7 yields:

$$\rho_z = 2.70 - 2.1 * (\Delta t - \Delta t_{matrix}) / (\Delta t_{fluid} - \Delta t_{matrix}) \tag{2.8}$$

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.

Pore fluid which is connected to the groundwater table or to the ocean through permeable sediments, are creating a normal pore pressure.

2.1.3 Abnormal pore pressure

The term abnormal pore pressure refers to abnormally high pore pressure. Pore pressure larger than normal pore pressure defines abnormal pore pressures, i.e. larger than the pressure of a column of salt water starting at the groundwater table. 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 normal groundwater at the drill site, or higher than the natural outlet of the formation (higher hydrostatic pressure), as indicated in Figure 2-4.

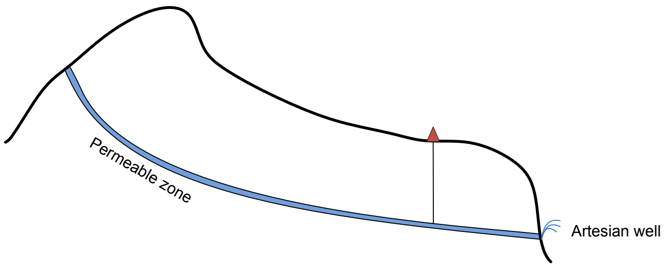


Figure 2-4: Artesian water.

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 is in the process of being buried, the pore water will tend to be squeezed out due to porosity decrease as a result of increased compaction.

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. Pore water fills the cylinder below the piston. An increase in load will compress the spring or move the mineral grains closer together. The spring and the water carry the load together. The water can escape through the permeable sediments (indicated by the high permeable opening in Figure 2-5). 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; and is associated with partly closed reservoirs, with no or poor communication to other permeable zones; high porosity, up to 50%.

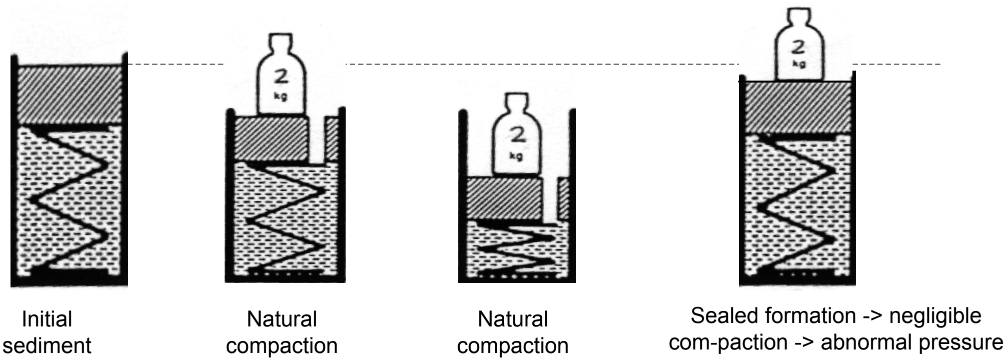


Figure 2-5: Model of consolidation process in sedimentary rocks (free after service company).

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.

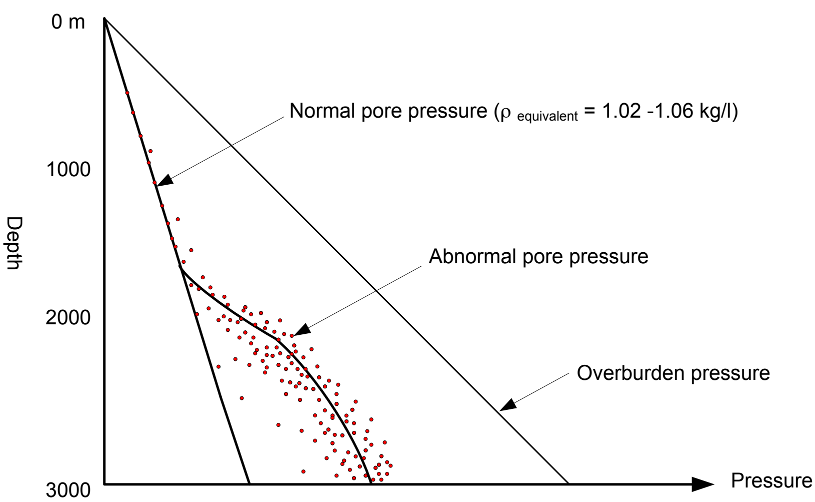


Figure 2-6: Typical pore pressure occurrences (red dots) in a sedimentary basin.

2.1.4 Fracture Pressure

There is no doubt that knowledge of formation-fracture pressure as a function of depth is an imperative requirement to plan today's wells in onshore and offshore environments. Especially since many of the wells today are drilled on very deep water where there is a smaller pressure window (the difference between the pore and fracture pressure). This causes a larger demand for the determination of both pore and formation fracture pressure.

Fracture pressure is defined as the pressure at which an exposed formation will rupture and accept the drilling fluid from the wellbore. Lost circulation, or lost returns, is the consequence of fractured formations. Formation fracture resistance is directly related to the weight of the formation overburden, also called the geostatic load; in other words, the vertical stress at a given burial depth. The fracture pressure also depends on the inter-granular strength of the formations, and the formation type. There are a lot of models and correlations to predict fracture pressure. However, for simplicity we present only three correlations:

1. Eaton
2. Breckels and van Eekelen
3. Mohr-Coulomb (MC) failure criteria

1. The Eaton Correlation is one of the earliest (1969) correlations that is still used for fracture pressure estimation today. Many of the later developed correlations have used the Eaton correlation as a basis. The Eaton correlation calculates the strain in an element of the buried rock. The correlation is derived from fundamental physical laws of elasticity (Hookes law), and is dependent on two central ratios; the Poisson's ratio (μ) defines the ratio of deformation perpendicular to the direction of stress deformation and parallel to the direction of stress. Young's modulus (E) is defined as the ratio of change of compressive or tensile stress to the corresponding change of deformation. The Poisson's ratio of relative deformation and the Young's modulus of stress vs. strain are, respectively:

$$\mu = \varepsilon_h / \varepsilon_z, \; E = \sigma / \varepsilon \qquad (2.9)$$

The Eaton correlation states that adding a specific amount of, to the pore pressure, additional stress, σ_{min}, 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:

$$p_{frac} = p_{pore} + \sigma_{\min} \qquad (2.10)$$

This is shown in Figure 2-7 and 2-10. σ_{min} has two synonyms: $\sigma_{min} = \sigma_h = \sigma_x$. Instead of the x, y, z coordinates, h, H, z are chosen. Our task is therefore to estimate σ_h, expressed with familiar parameters. In accordance with Figure 2-7 and with Hook's Law the parameter σ_h is expressed as:

$$\sigma_h = F_h / A = E * \varepsilon = E * \Delta l / l \tag{2.11}$$

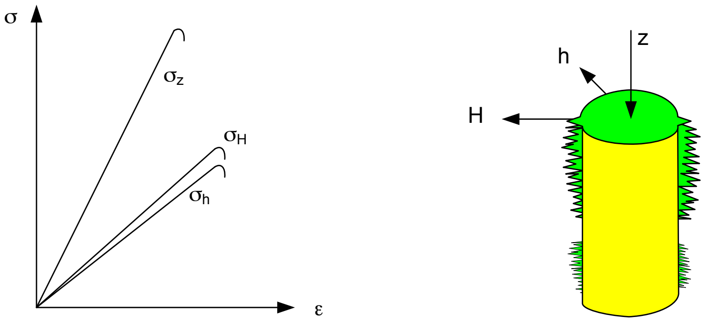


Figure 2-7: Hook's Law of elastic deformation.

In the h direction, which is devoted to the weakest stress direction, the relative elongation is:

$$\varepsilon_h = \sigma_h / E \tag{2.12}$$

a 3D setting the elongation is counteracted by a contraction in the two other directions:

$$\varepsilon_h = \sigma_h / E - \mu * \sigma_H / E - \mu * \sigma_z / E \tag{2.13}$$

At zero deformation, eqn. 2.13 reduces to:

$$0 = \sigma_h / E - \mu * \sigma_H / E - \mu * \sigma_z / E \tag{2.14}$$

Moreover, stress in the weakest direction becomes:

$$\sigma_h = \sigma_{min} = \mu / (1- \mu) * \sigma_z \tag{2.15}$$

The Poisson's ratio value of 0.5 represents a completely elastic material, like steel, rubber and volcanic rocks. For sedimentary rocks at shallow depths the Poisson's ratio starts typically at 0.2–0.3 and approaches asymptotically 0.5 at large depths. Low values represent materials that undergo a plastic deformation. For homogeneous materials, it is therefore accepted that the higher the confining pressure the higher the Poisson's ratio. For isotropic materials the Poisson's ratio should not exceed 0.5. However, for laminated materials like shale, the material becomes strengthened perpendicular to the bedding, and the Poisson's ratio can become as high as 0.8! Anisotropy, heterogeneity, confinement and test conditions (drained or undrained) are all factors contributing to altering the Poisson's ratio in shale.

2. The Breckels and van Eekelen empirical correlations for sh is a function of depth. They based these relationships on hydraulic fracture data from different regions around the world. The relationship developed for the US Gulf Coast is most commonly used in the North Sea;

$$\sigma_h = 0.0053\, D^{1.15} + 0.46\, (p_{pore} - p_{pore,n}); \qquad D < 3\,000 \text{ m}$$

$$\sigma_h = 0.0264\, D - 31.7 + 0.46\, (p_{pore} - p_{pore,n}); \qquad D < 3\,000 \text{ m} \tag{2.16}$$

Here D is depth (TVD), p_{pore} is the pore pressure, $p_{pore,n}$ is the normal pore pressure (1.025 bar/10 m) and σ_h is the smallest horizontal stress. The last term in these relations reflect abnormal pore pressure. The predicted horizontal stress will hence reflect changes in the pore pressure gradient. These relations were developed at zero or shallow water depths. As the water depth increase, predictions at shallow formation depth should be avoided. The correlations are derived from physical laws with many simplifications and assumptions and one can therefore question the reliability of the result obtained from the correlations. Most correlations depend on different geological parameters from specific geological areas, and therefore no universal correlation exists.

3. The Mohr-Coulomb (M-C) failure criteria. In geotechnical engineering the M-C failure criteria is used to define shear strength of soils and rocks at different effective stresses. In structural engineering it is used to determine the failure load as well as the angle of the fracture in concrete and similar materials. Coulomb's friction hypothesis is used to determine the combination of shear and normal stress that will cause a shear failure and a fracture of the material. Mohr's circle is used to determine which principal stresses that will produce this combination of shear and normal stress, and the angle of the plane in which this will occur. According to the principle of normality the stress introduced at failure will be perpendicular to the line describing the failure condition. Based on triaxial test data, shear strength can be calculated. A Mohr-Coulomb failure hypothesis is presented in Figure 2-8. It can be shown that a material which is failing according to Coulomb's friction hypothesis will show the displacement introduced at failure will form an angle to the line of fracture equal to the angle of friction. This makes the strength of the material determinable by comparing

- the external mechanical work introduced by the displacement and
- the external load with the internal mechanical work introduced by the strain and stress at the line of failure.

The following mathematical expression can be used to determine the lower failure limit, σ_h, for normal faulting:

$$\sigma_1 / \sigma_3 = (\sigma_z - p_{pore}) / (\sigma_h - p_{pore})^h = ((\alpha + 1)^{0.5} + \alpha)^2 \qquad (2.17)$$

The failure angle or friction angle, a, can be determined from tri-axial test results in Figure 2.8.

Here τ_0 = cohesion, tan α = friction coefficient υ. Shear stress can thus be expressed as:

$$\tau = \tau_0 + \upsilon\,\sigma \qquad (2.18)$$

This shear failure line, occurring at the angle of a, assumes that many small in-situ fractures will start to open at large stresses. The internal friction cannot withstand higher loads.

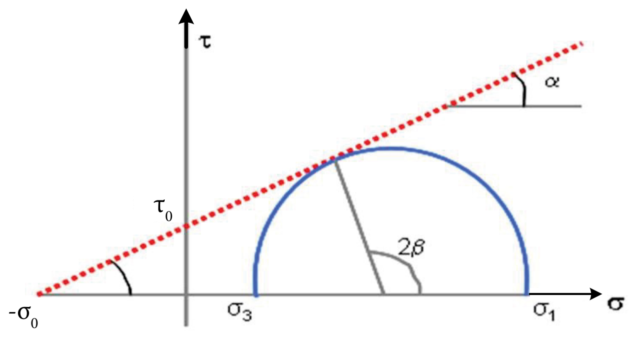


Figure 2-8: Mohr-Coulomb failure criteria.

Three different in-situ stress regimes may exist. Here we limit ourselves to the Normal faulting (NF) stress regime, which is associated with $\sigma_v > \sigma_H > \sigma_h$. Therefore, when σ_1 is vertical, normal faulting will occur, as shown in Figure 2-9. In most sedimentary basins NF is created by gravitational forces.

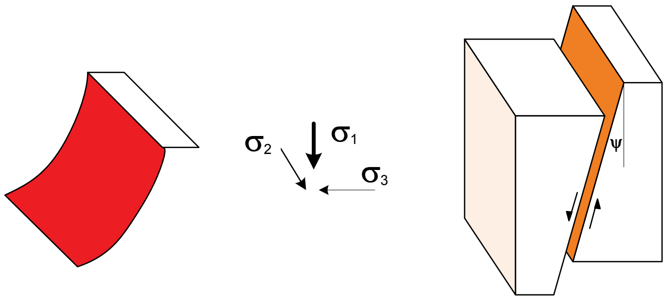


Figure 2-9: Stress axes and faults for relative stress magnitudes in normal (NF). The angle between the maximum principal stress and the failure plane is ψ.

Figure 2-10 summarizes important factors involved in fracture initiation. When wellbore pressure surpasses the fracture pressure of the formation, a tensile fracture occurs, perpendicular to the plane of least horizontal stress.

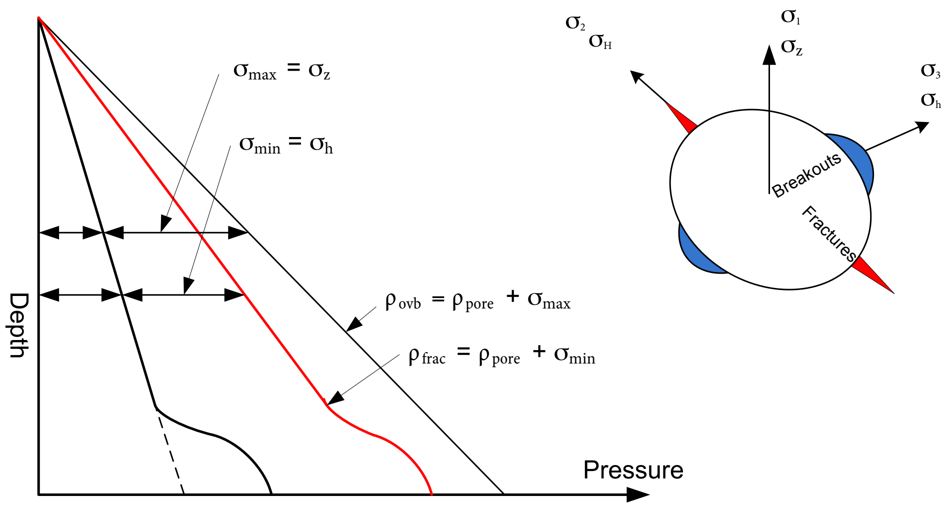


Figure 2-10: Important stress parameters of sedimentary formations. Both fractures and breakouts occur, depending on wellbore pressure.

The wellbore will fracture in the direction of perpendicular to the largest horizontal in-situ stress, and breakout occurs in the direction of the largest horizontal in-situ stress as illustrated in Fig. 2-10. This is well known but valid only for vertical boreholes. The fracture and breakout position are altered with well trajectory.

2.2 Quantifying formation pressure

2.2.1 Overburden pressure

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

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

The overburden gradient is commonly found from the sonic log as exemplified through the sonic log in Figure 2-11. Here ρ οϖβ is the average density should be along the total depth z, averaged from the height of the Rotary Kelly Bushing (RKB), since pressure applied during the drilling process must be controlled/compared to the hydrostatic fluid pressure. By discretizing eqn. 2.2, the overburden density, ρ_{ovb} can be found.

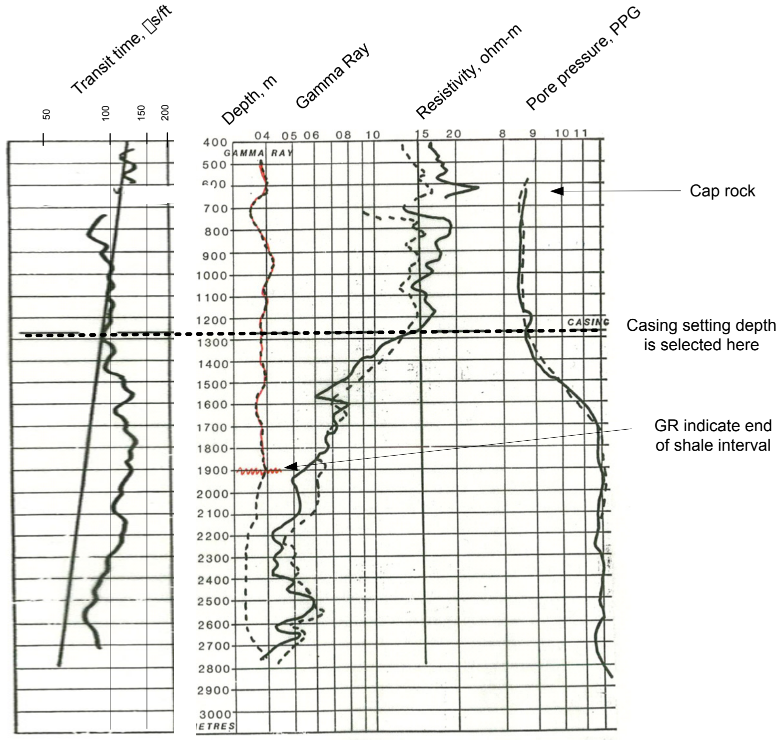


Figure 2-11: Log data from an abnormal pore pressure interval. Sea depth is 370 m. Distance from sea level to RKB is 30 m (Bourgouyne et. al (1986)).

From the sonic data in Figure 2-11, the in-situ or local density is found first. The local or in-situ density, ρ_{local} can be estimated from the porosity of the selected interval through Eqns 2.3–2.8. The equivalent overburden density is found by using RKB as the reference level. Now the overburden density is comparable with the mud density. The ρ_{ovb} is also referred to as the equivalent mud weight, but also as the cumulative overburden.

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

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

Table 2-2 represents the results from these equations and data from Figure 2-11:

From RKB m	Δt ms/ft	Ø %	ρ_i kg/l	ρ_{ovb} kg/l
0-30			0	0
30-400	200		1.02	0.94
400-600	105	0.38	1.90	1.26
600-800	95	0.31	2.05	1.46
800-1000	83	0.24	2.19	1.61

Table 2-2: Example data used to produce ovburden densities. Distance from ground level to RKB is 400 m.

We exemplify the result at the bottom of interval 2:

$$\emptyset = \frac{\Delta t - 47}{200-47} = \frac{105-47}{153} = 0.38$$

$$\rho_i = 2.7 - 2.11 \cdot \emptyset$$

$$\rho_{ovb} = \frac{\sum \rho_{local} \cdot \Delta h}{\sum \Delta h} = \frac{0 \cdot 30 + 1.02 \cdot 370 + 200 \cdot 1.9}{30+370+200} = 1.26$$

These are typical offshore overburden porosities, i.e. very high. At larger depths the influence of sea water will vanish and the porosity becomes normal. Figure 2-12 presents the results in terms of pressure and pressure gradients.

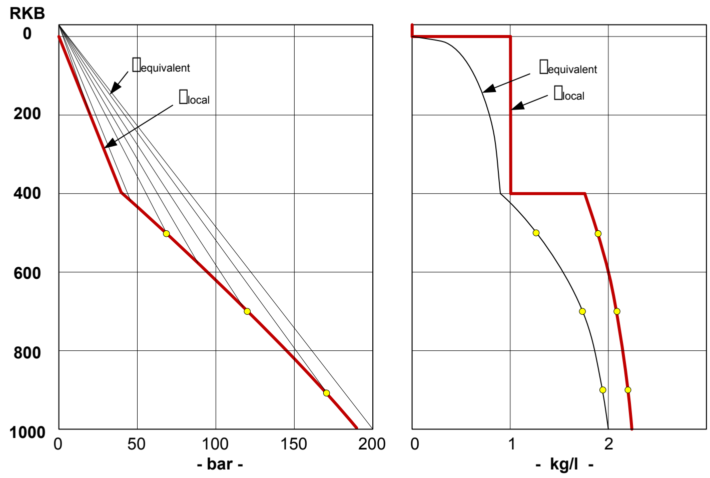


Figure 2-12: Results of example from Figure 2-11 and Table 2-2.

2.2.2 Abnormal pore pressure

Accurate prediction of pore pressures has become very important during oil well drilling. 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 (sometimes replaced by measurements while drilling (MWD))
- Drilling rate of penetration (ROP)
- Mud properties like gas content, temperature etc.

In this book the sonic log, ROP/d_c-exponent and two mud properties are selected as examples of how to quantify increasing pore pressure:

From the sonic log: Log based methods for quantifying abnormal pressure relies on the assumption that abnormally pressured shale has higher porosity and thus higher water content than normal; the propagation speed of sound waves will decrease.

Since rock matrix is a poorer electric conductor than salt water, resistivity will thus increase with depth in normally pressured shale.

First a normal trend line is established in normally compacted sediments. In Figure 2-11 the normal trend line of transit travel time deviates from the data when abnormal pressure (below the dashed line) is encountered.

In order to estimate pore pressure quantitatively, Eaton's method is applied. His method is based on the assumption that the overburden is supported by the pore pressure and the 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 2-13 demonstrates very clearly how the vertical stress is revealed in a high pressure zone: It dramatically reduces.

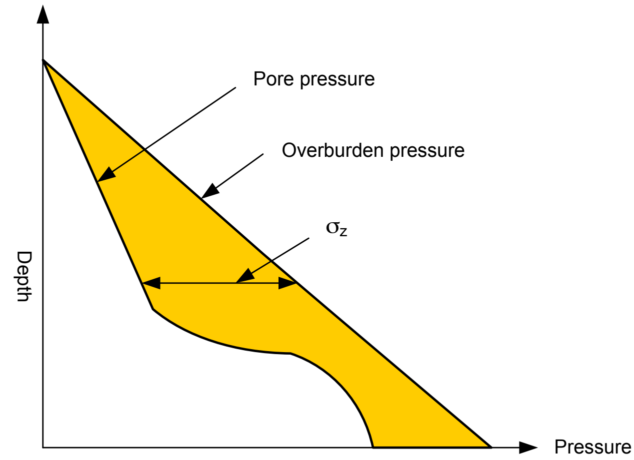


Figure 2-13: Vertical stress vs. high pore pressure.

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} is found through the normal trend-lines at actual depth (see Figure 2-11).

Wireline logging represents "after-the-fact" techniques, i.e. the wellbore has to be drilled prior to enable logging, requiring an extra roundtrip. 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. With the introduction of MWD this problem is more or less eliminated, at least offshore where time is costly. The MWD tool is typically positioned 15 m above the bit.

From ROP/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 (to ensure cuttings are not re-drilled)
- Bit weight
- Rotary speed
- Fluid properties (especially concentration 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. For tri-cone rock bits two effects are used for explaining the effect from differential pressure on ROP (see also Figure 2-14).

The Dynamic Hold Down effect is active when a cutting is removed from its initial position. If water is hindered in flowing into the cavity created by removing the cutting, a vacuum pressure is created, holding the cuttings back.

The Static Hold Down is related to the increased rock strength generated by the differential pressure.

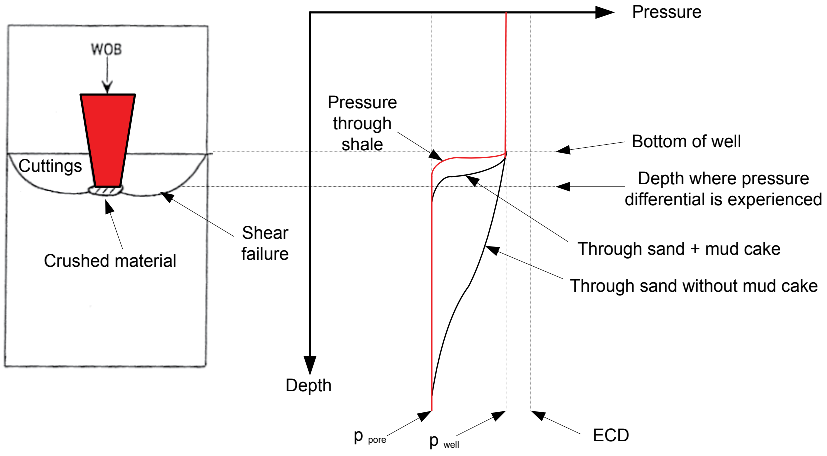


Figure 2-14: Wellbore pressure front below the bit is a function of Darcy flow and depth

PDC cutters show the same relationship to differential pressure (in Figure 2-15) as tri-cone bits, but the effect of permeability and fluid flow is not studied as specifically as for tri-cone bits.

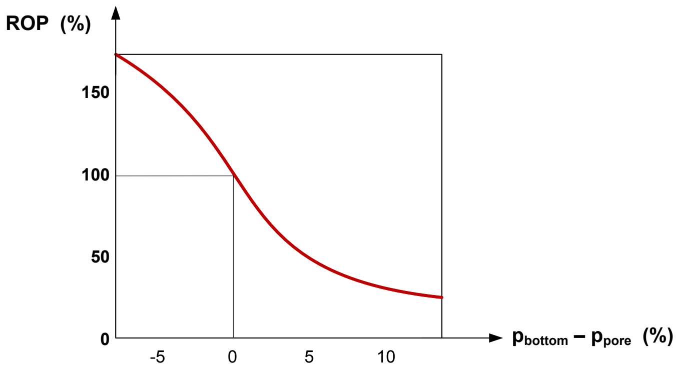


Figure 2-15: ROP vs. Dp at bottom.

The explanation of the overpressure effect on PDC bits is indicated in Figure 2-16. Under balanced pressure conditions only the shear strength of the grains has to be overcome. Under high overbalanced pressure the friction forces between the grains increases, the material's shear strength and the confined strength of the crushed material both become very high.

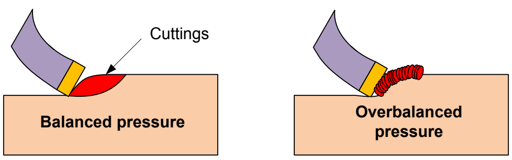


Figure 2-16: Much easier to form chips at balanced conditions (left) with PDC cutter than at overbalanced conditions (free after tests performed at the University of Tulsa).

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. This was shown in Figure 2-15.

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 the d-exponent 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 is rearranged:

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

This expression is made unit less by dividing by "normal" operating parameters. The estimation of the pore pressure from changes in the d-exponent depends on empirical correlations. Figure 2-17, 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 (since ROP decreases) is because the log expression in the numerator is < 1).

The strange constants in the expression are there to normalize the parameters and to obtain a d-exponent value around 1.0.

As for many other parameters, drilling rate will decrease with depth due to higher compaction. The normal compaction trend line is defined by the slope of two points along the normal compaction zone. Note that the normal trend line may shift its position along the d_c-axis as a result of non-compaction related pressure mechanisms (like salt, faulting, dipping beds). 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 2-17. By normalizing or correcting the d-exponent with respect to the increasing mud weight, the d_c becomes;

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

The deviation from the trend line will be magnified by using d_c values instead of d-exponent values. ρ_{normal} is the mud density that balances the normal pore pressure, normally equal to 1.02–1.06 kg/l, and the mud weight, ρ, is gradually becoming higher.

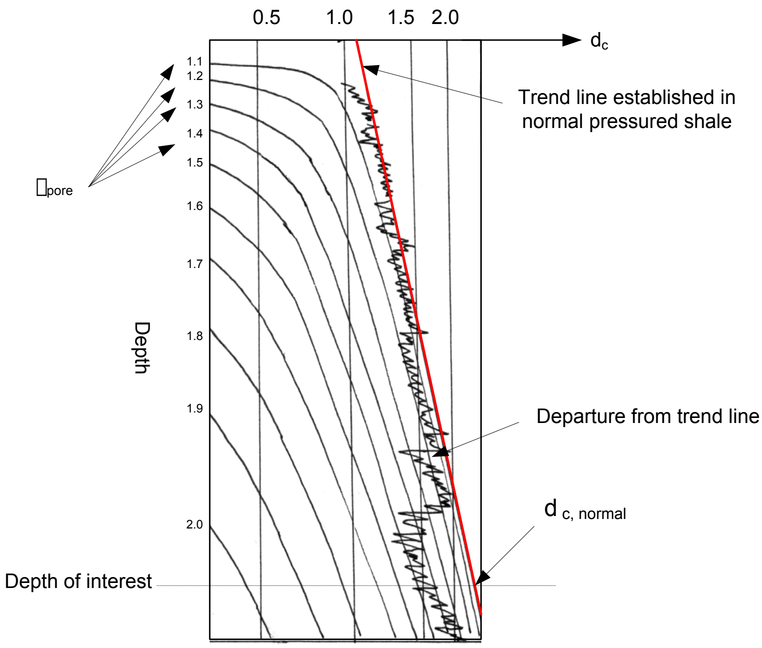


Figure 2-17: d_c-exponent example from an offshore well.

From mud properties:

The measurement of mud temperature and/or gas content of the mud returning from the well may provide an early warning of higher pore pressure. Figure 2-18 gives an overview of how different parameters are gathered at the surface.

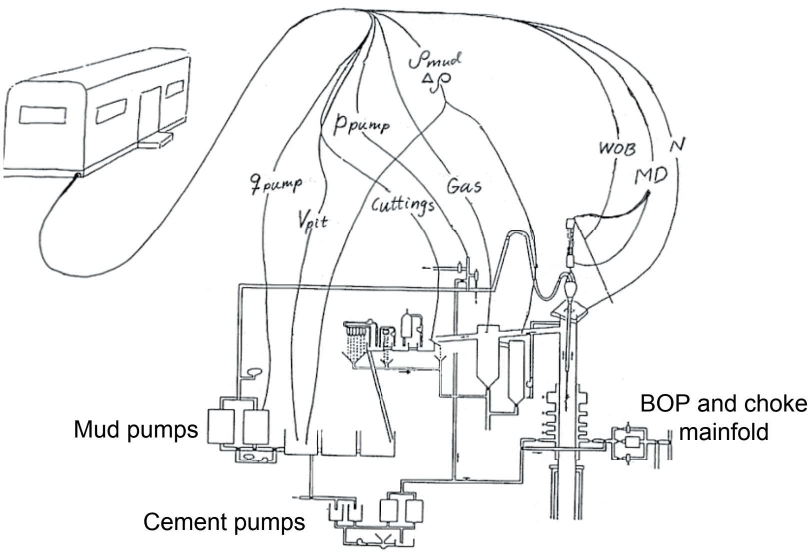


Figure 2-18: Gathering of drilling fluid and other information at the surface.

Gas content: 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 with the circulated mud. As the mud is approaching the surface and a lower pressure, gas will be liberated and then recorded. Figure 2-19 presents a resulting gas log.

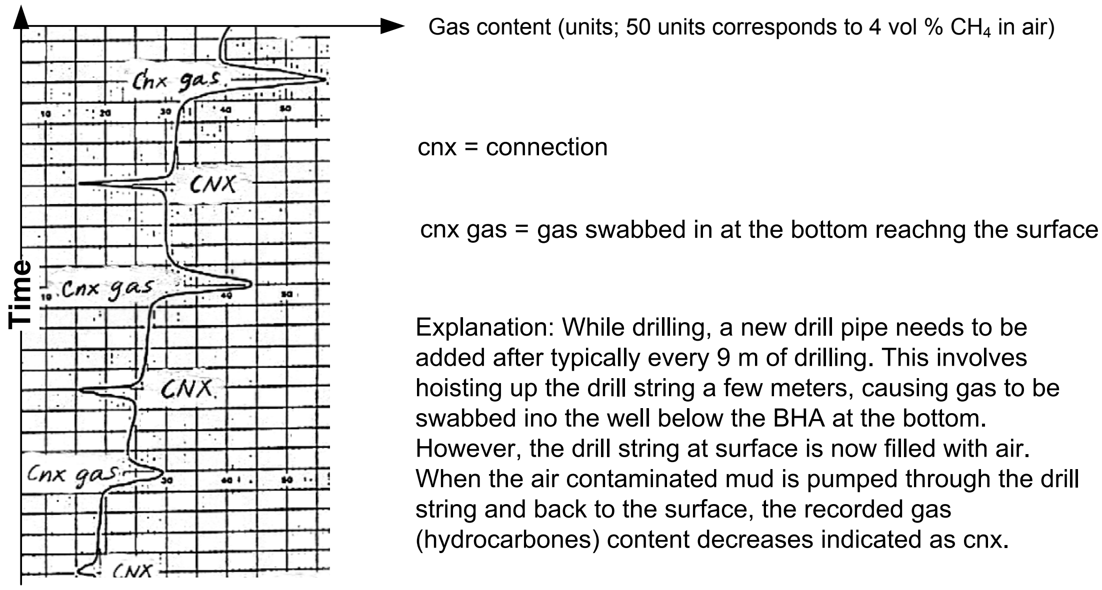


Figure 2-19: Relative gas content in the returning mud (free after service companies).

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 as well as 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 interpret 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 compaction, the higher the thermal conductivity.

Continuous recording of flow line temperature may therefore be an aid in detecting increasing pore pressure. Figure 2-20 shows a typical formation temperature profile. In many areas, the temperature log may be the most definitive tool available.

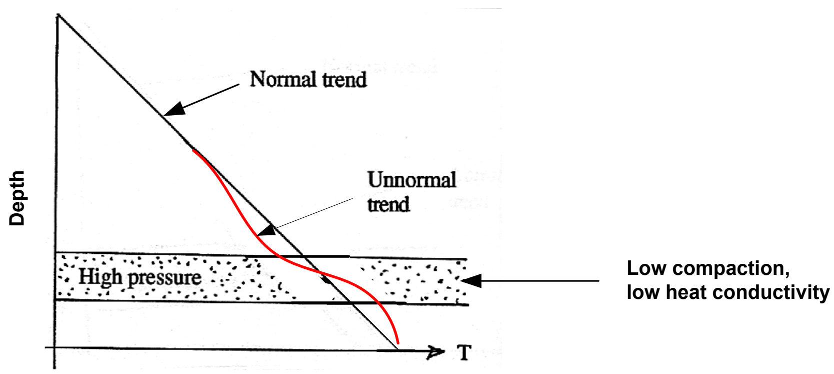


Figure 2-20: Temperature profile through a high pressure zone which acts as an insulator.

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

2.3 Fracture pressure

Fracture pressure is determined through a Leak Off Test (LOT). A LOT, also called formation intake-strength-test, is determining the tensile strength of the formation 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 2-21 presents the well during a leak-off test and the resulting fracture pressure. Figure 2-22 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:

1. Lower drill string inside the casing, above the cement, close BOP and perform
    a) pressure tests (to determine the system stiffness)
    b) pressure – volume slope
2. Drill out the cement in the bottom casing plus 3 m of new formation.
3. Pull the bit back into the casing; make sure the hole is filled up with mud and close the BOP around the drill pipe.
4. Pump mud **slowly** (negligible friction pressure) with the cementing pump, a high-pressure low-volume pump, until the pressure builds up initially.
5. Continue the procedure until the increasing pump pressure deviates from the straight trend line; the point of divergence, also called the leak off pressure, p_{LO}.

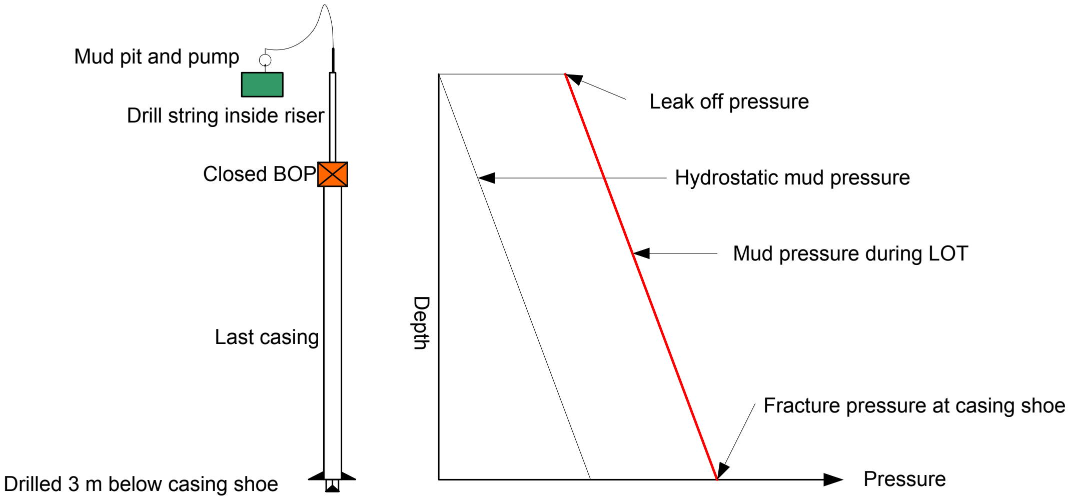


Figure 2-21: Well configuration and final pressure during a LOT.

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 flattens out) is called the formation breakdown pressure.

The curve in Figure 2-22 is largely dependent on the permeability in the formation to be tested. Normally, however, the casing shoe is placed in compatible shale, which is impermeable.

Sometimes a predetermined 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).

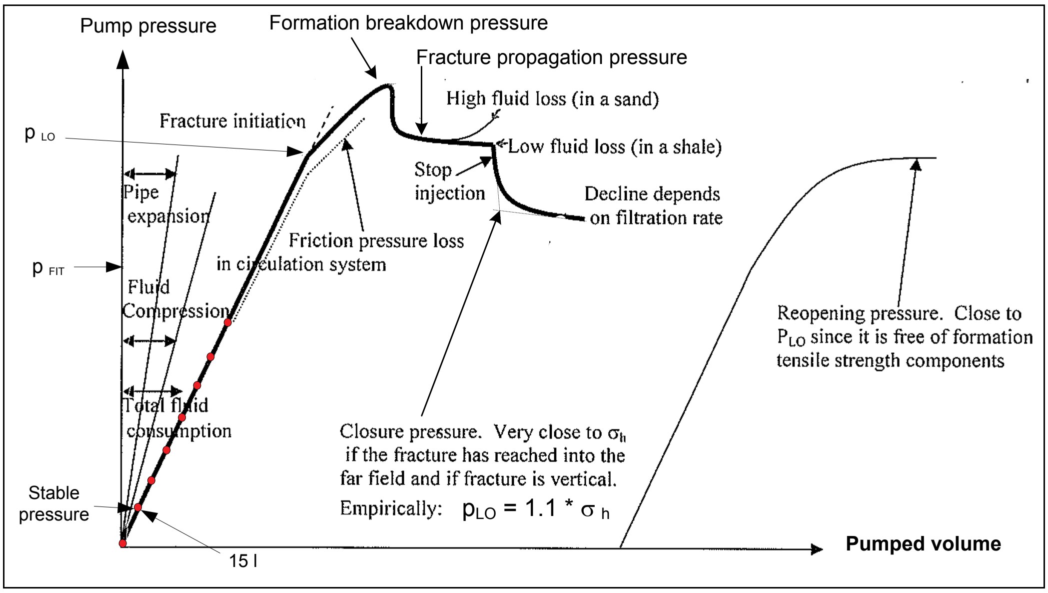


Figure 2-22: A full leak-off test. The linear pressure increase reflects the elastic properties of the fluid and the casing. The first sudden pressure drop reflects the breaking down of the formation. Data point sampling interval varies normally from 1 to maximum 5 seconds.

Limitations: The correlation used to decide fracture pressure relies on data collected from already drilled wells. The leak off test gives ideal fracture pressure for the specific formation at the test depth. In many cases this recorded fracture pressure can be used as an upper limit of fracturing for the rest of the section. However, the possibilities of entering zones further down in the section with different lithology and pressure conditions must be considered.

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.

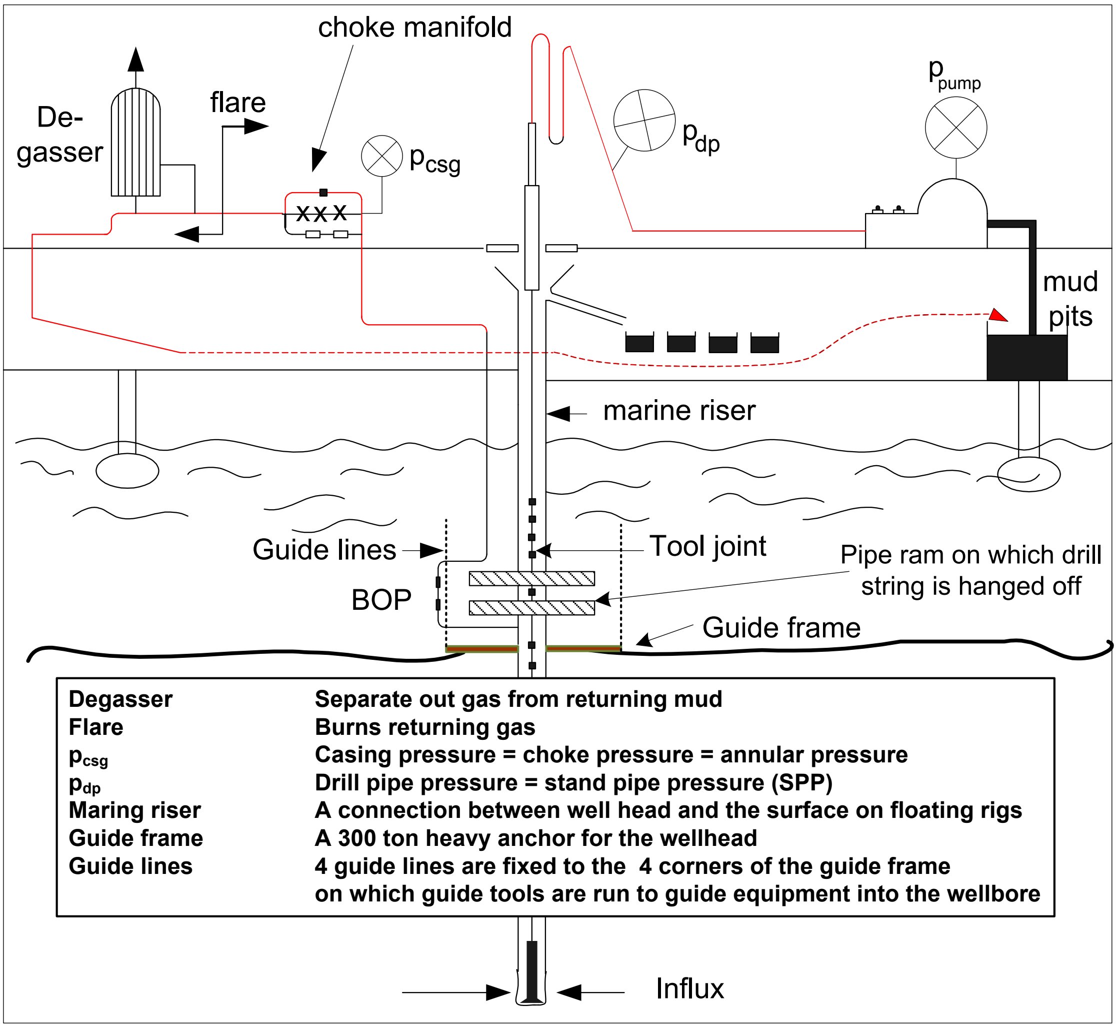


Figure 3-1: Kick control on an offshore rig. Surface mud lines in red.

3.1 BOP stack and associated equipment

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

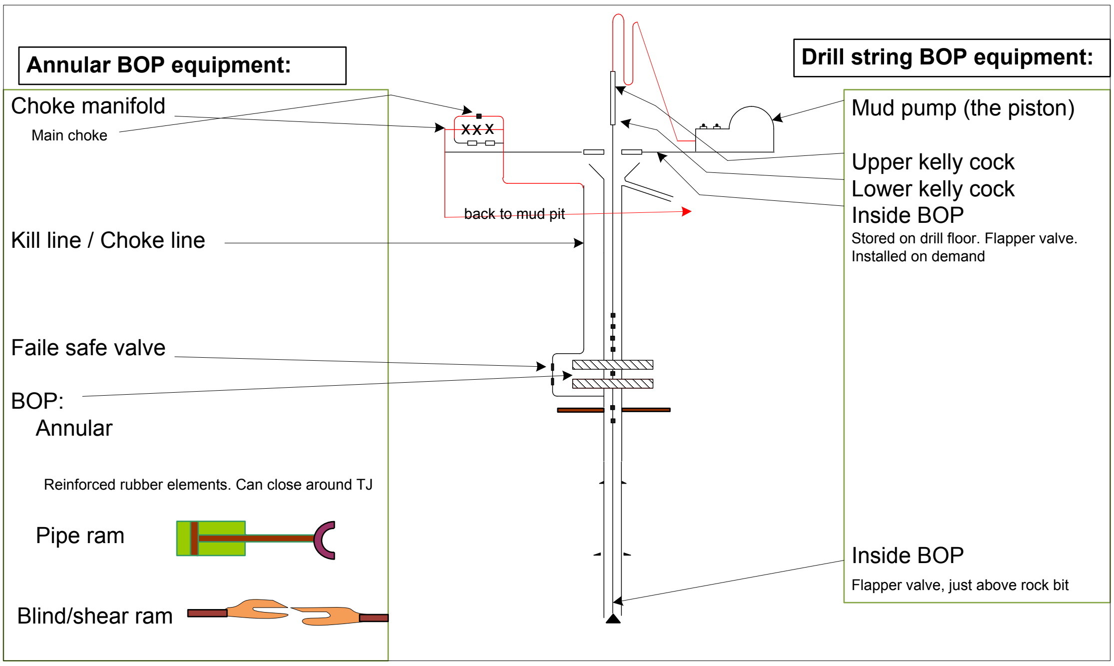


Figure 3-2: Well control equipment applied to close the drill string (left) and annulus (right).

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 20 000 psi (bars) from below.

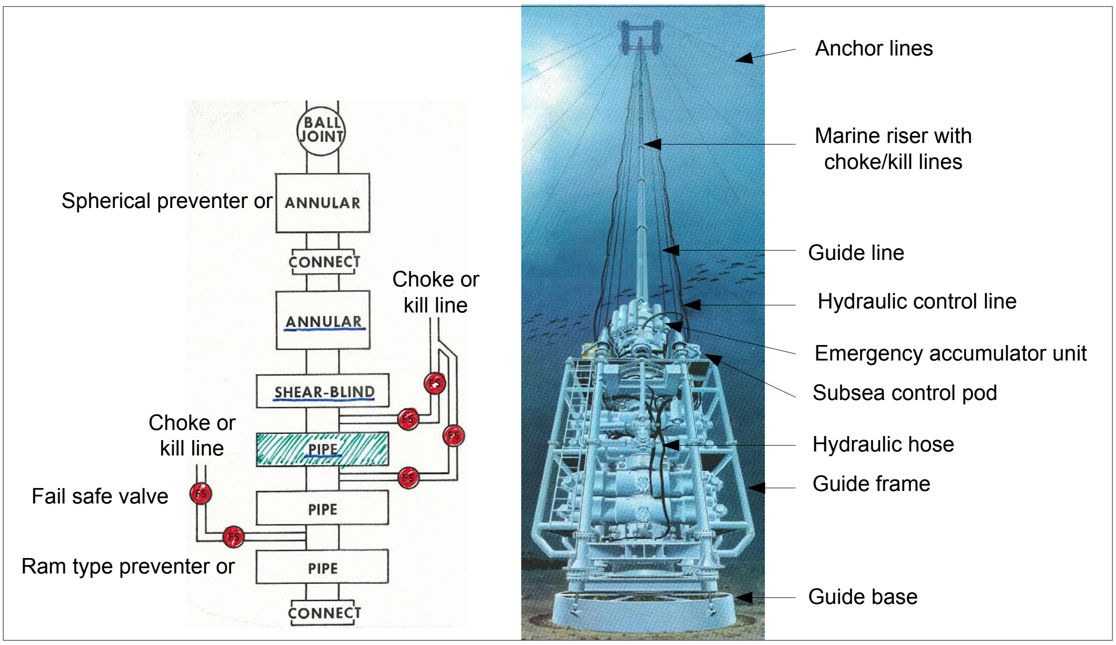


Figure 3-3: Standard Offshore BOP stack (left) and communication to the rig floor (right).

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 (often called spherical or "Hydril" or bag 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 packer quickly seals the wellbore independently of the geometry of the drill string (could be made up of drill collars or 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.

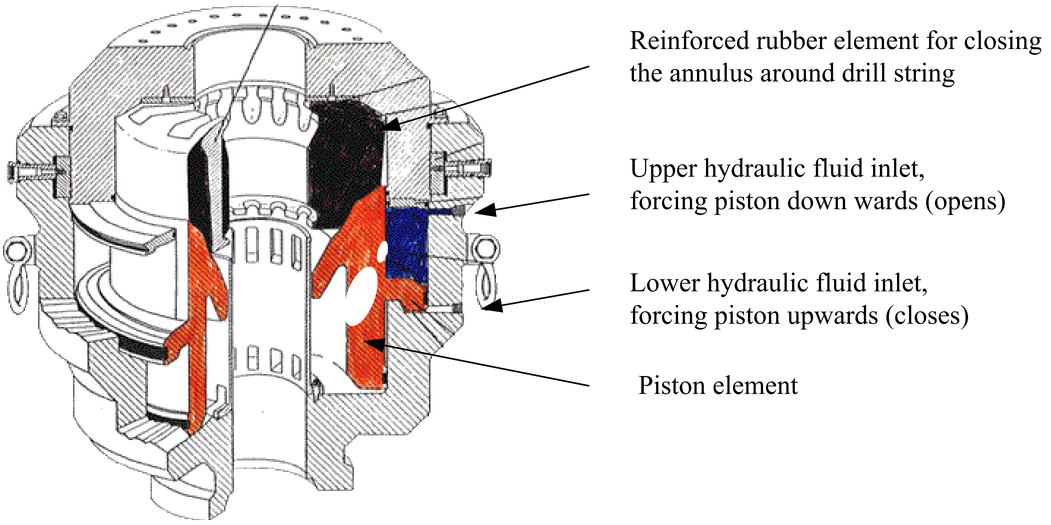


Figure 3-4: Spherical preventer.

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

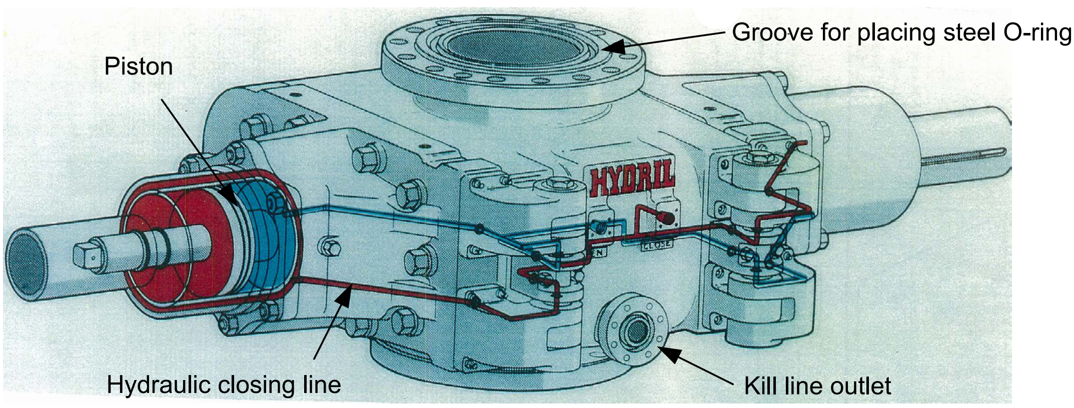


Figure 3-5: Pipe preventer.

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.

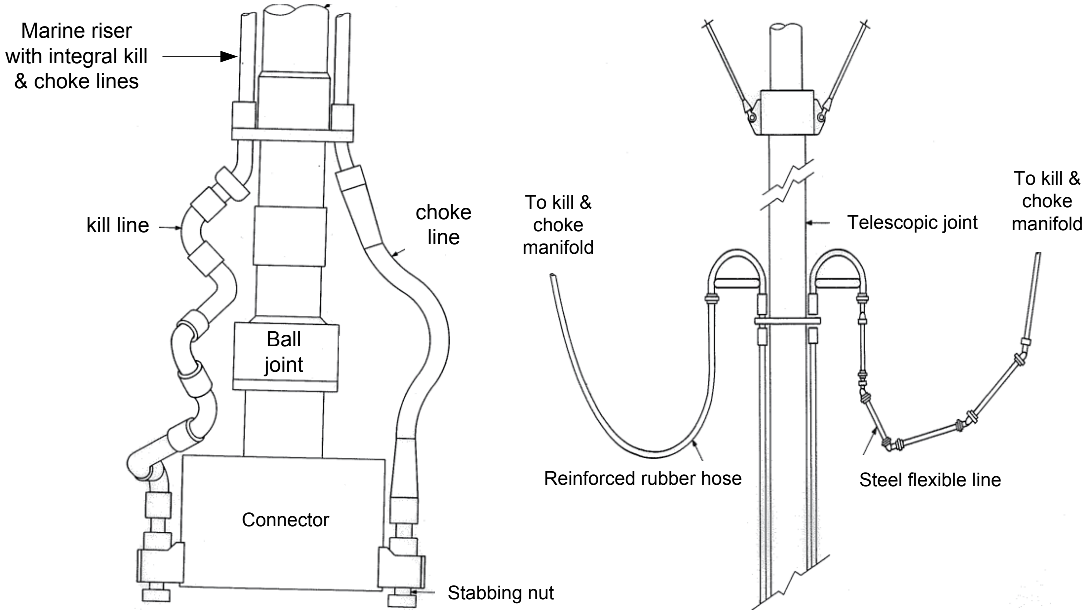


Figure 3-6: Top part of the BOP stack (left), the marine riser and its upper part (right).

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 wellbore 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).

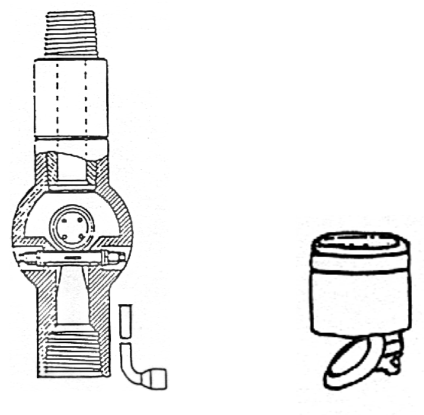


Figure 3-7: Kelly cock (left) and Inside BOP (right).

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.

The mud pump when shut off, can withstand at least the maximum rated pressure of the piston/liner in use. The option of shutting the well during MPD/UBD is not discussed in this book.

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.

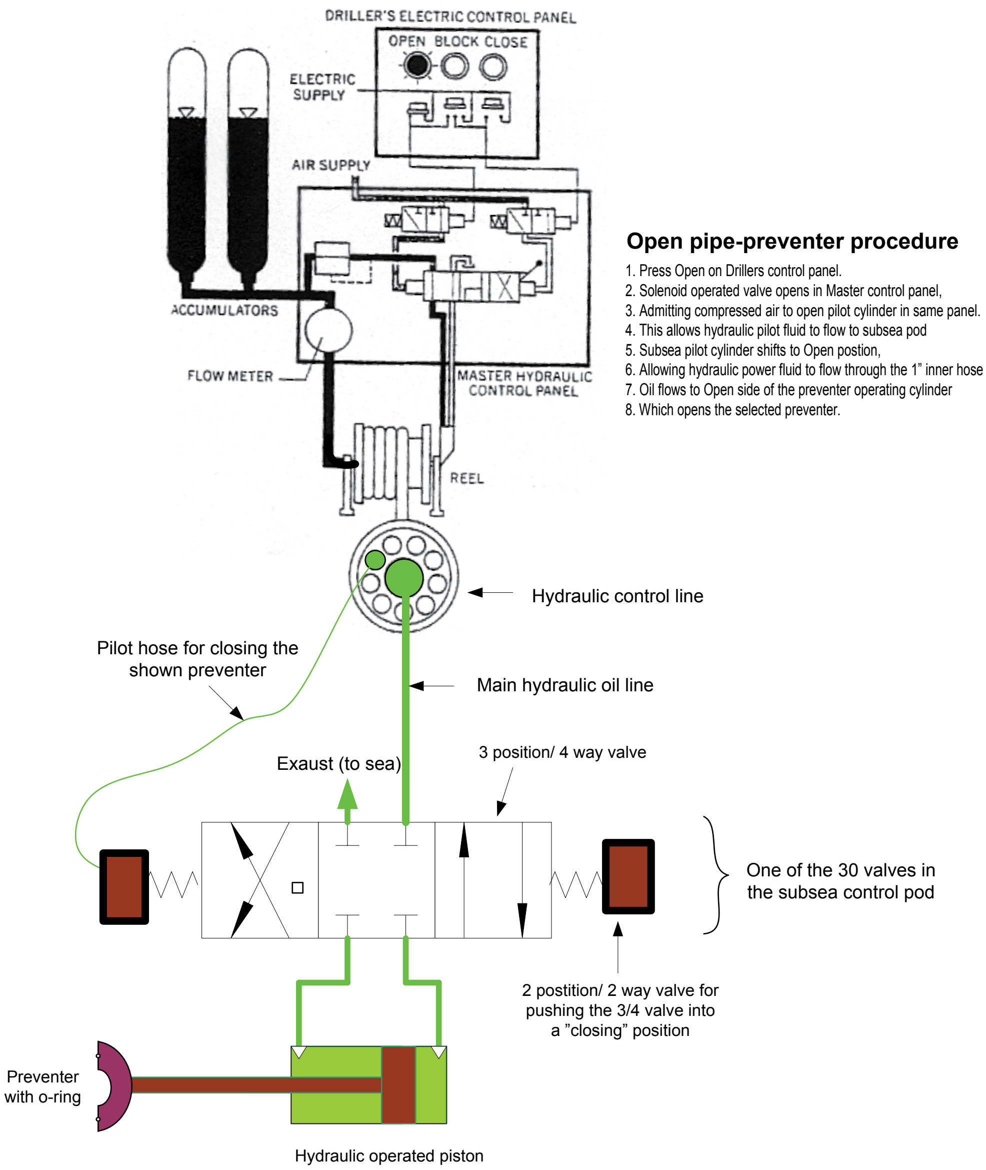


Figure 3-8: Hydraulic control system for BOPs with electric control panels on the platform.

3.3 Volumetric unstable well (kicking well)

Whenever the pore pressure becomes higher than the well pressure (and the formation is 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 normal drilling operations. For tripping operations, the variation in the mud volume at the surface is controlled in the trip tank as shown in Figure 3-10.

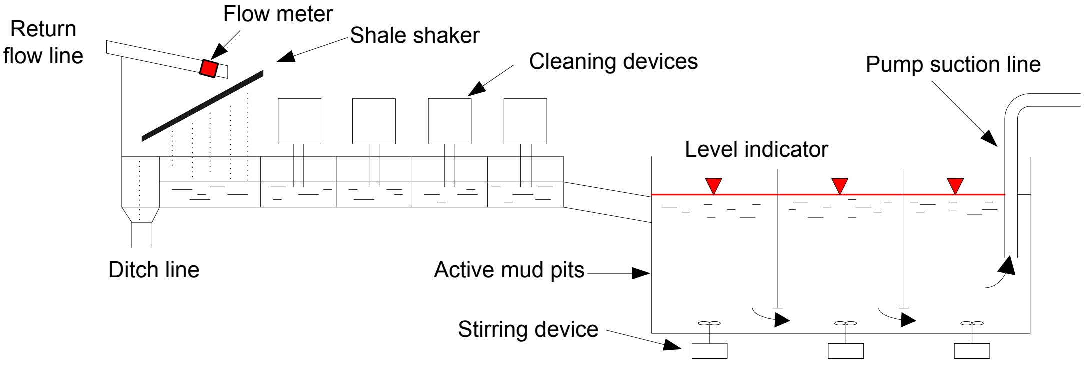


Figure 3-9: Surface metering of delta flow out (compared to input flow) and of accumulated volume change in the pit.

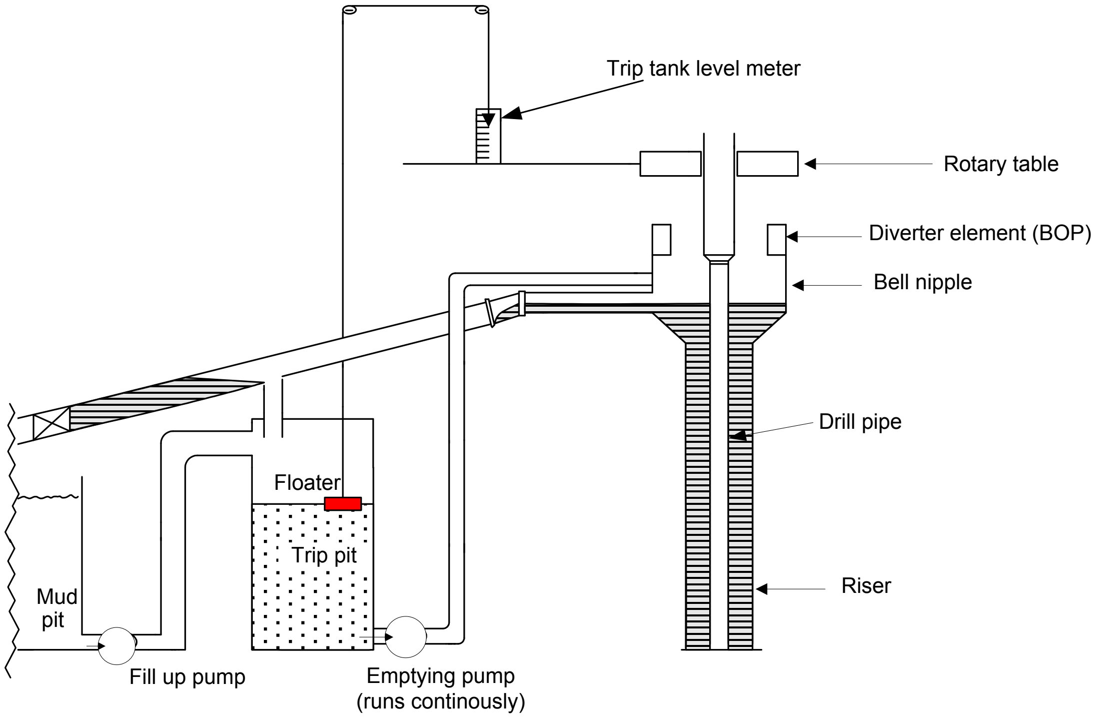


Figure 3-10: Kick detection during tripping.

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 (to make sure no fracture occur).

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) Check 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 SICP and kick volume. Shut-in pressures of drill pipe (SIDPP) and of casing. The shut-in pressures are also referred to as P_{SIDO} and P_{SIC}.

3.5 Well integrity during drilling operations

During drilling operations the regulatory authority around the world 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 3-11 under their respective option.

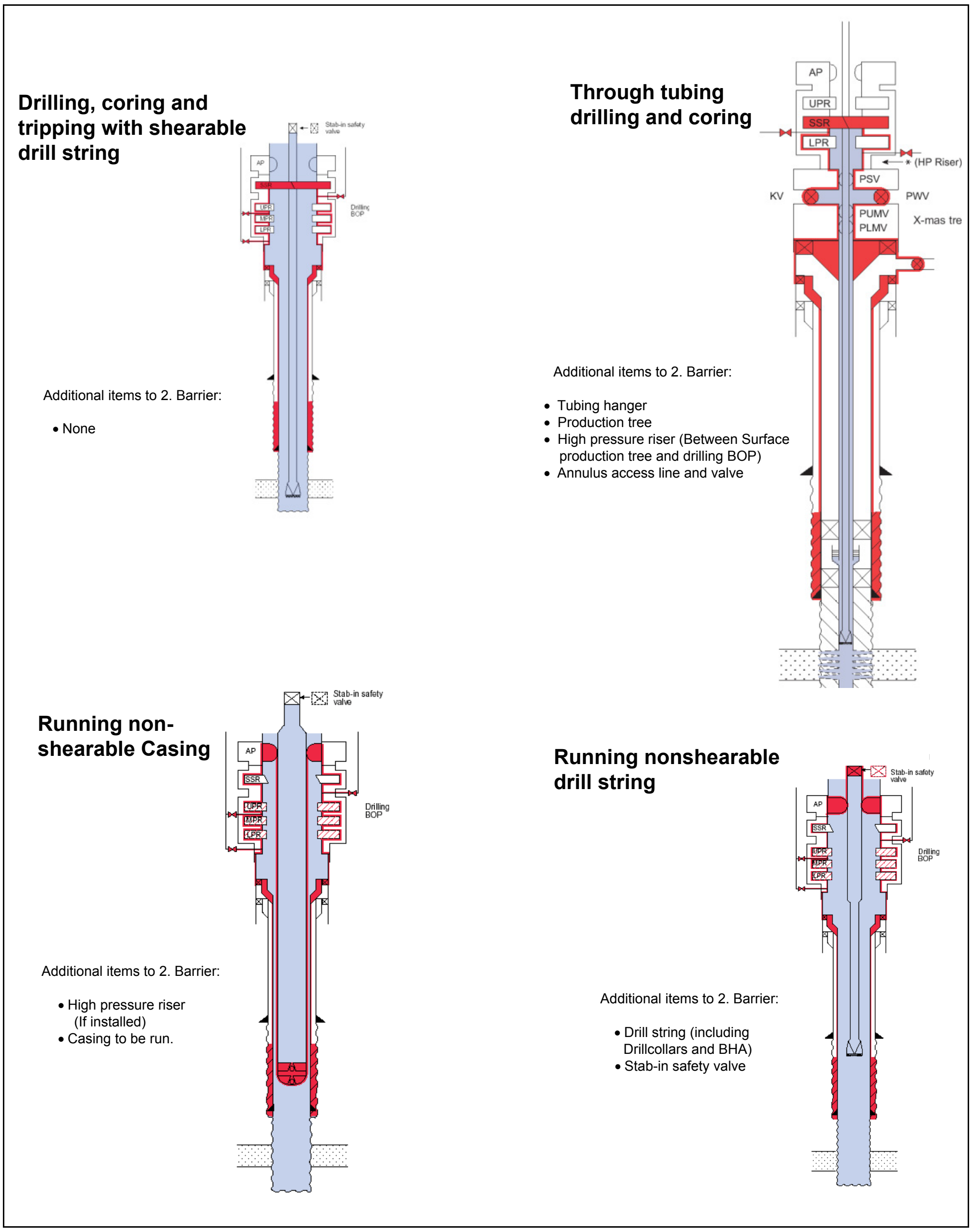


Figure 3-11: Four optional drilling operations together with their two barriers. Red color indicates required elements (Norsok Standard, 2004).

4 Standard killing methods

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

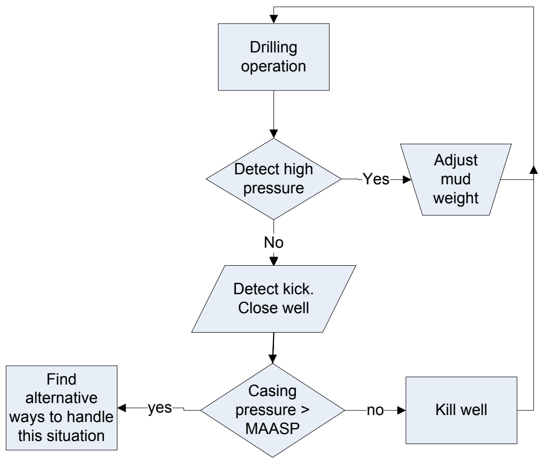


Figure 4-1: General procedure to maintain safety during drilling.

There exist a number of different killing methods, while the two main methods are 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 has in this course been selected to demonstrate the principles of killing a well.

Before any kick 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 only discuss gas kicks. A small volume of gas at the bottom of a well is potentially dangerous because it expands while approaching the lower hydrostatic pressure near the surface. At low pressure it will expand and displace a corresponding amount of mud from the well, thus reducing the bottomhole pressure which in turn allows more gas to flow in from the pores. In this book we simplify the gas law by assuming constant temperature and compressibility, yielding:

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

This assumption simplifies the presentation of the principles. In reality gas is not ideal, and has to be taken into account. Small influxes of gas are not likely to be detected with standard 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 openhole sections to reduce the pressure in the annulus; otherwise the Driller's Method is preferred.

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 will be discussed in chapter 4.1.2.

Another problem with gas kicks is that gas leads to a decrease of mud rheology, especially in OBM, and the barite may fall out and thus a reduction in mud weight is experienced. Barite must be delivered from the supply base in adequate amounts to sufficiently increase the mud weight of the total active mud volume. A 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 "tubes"; the drill string and the 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).

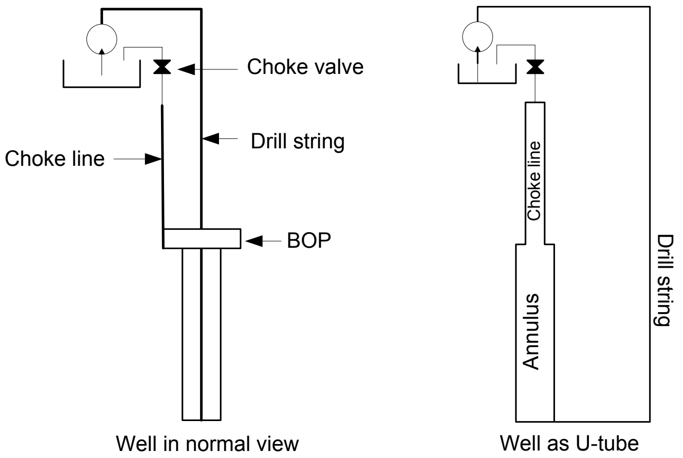


Figure 4-2: Well in two different views.

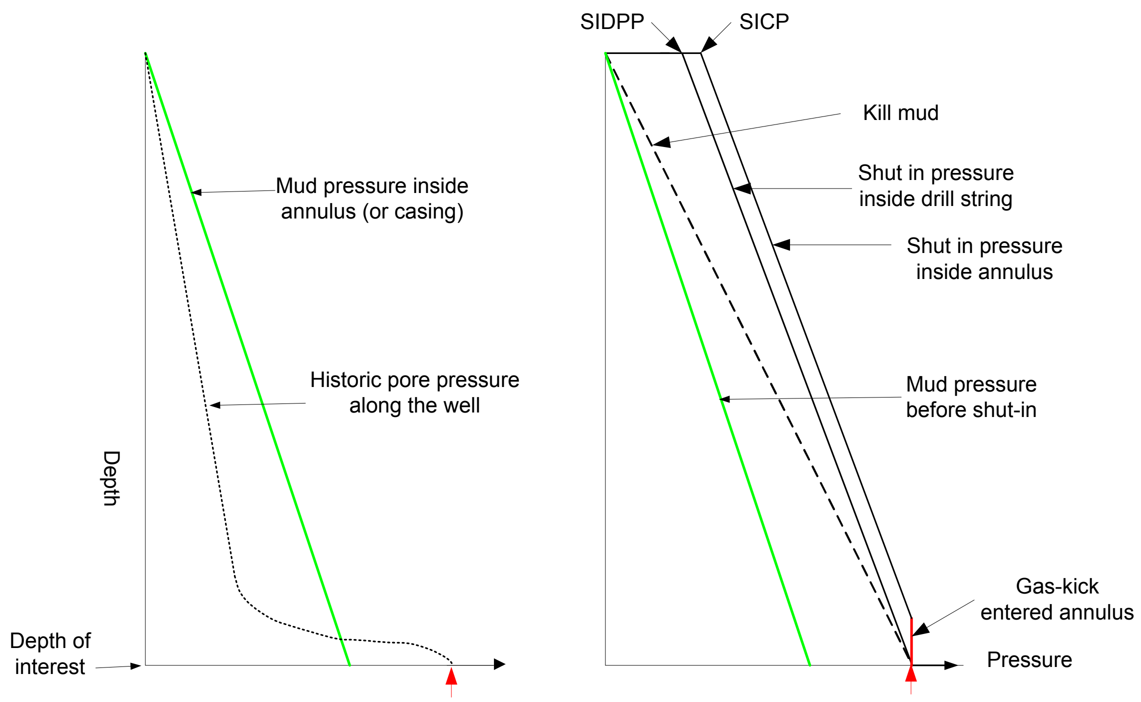


Figure 4-3: Pressure before (left) and after shut-in.

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 the gas 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.

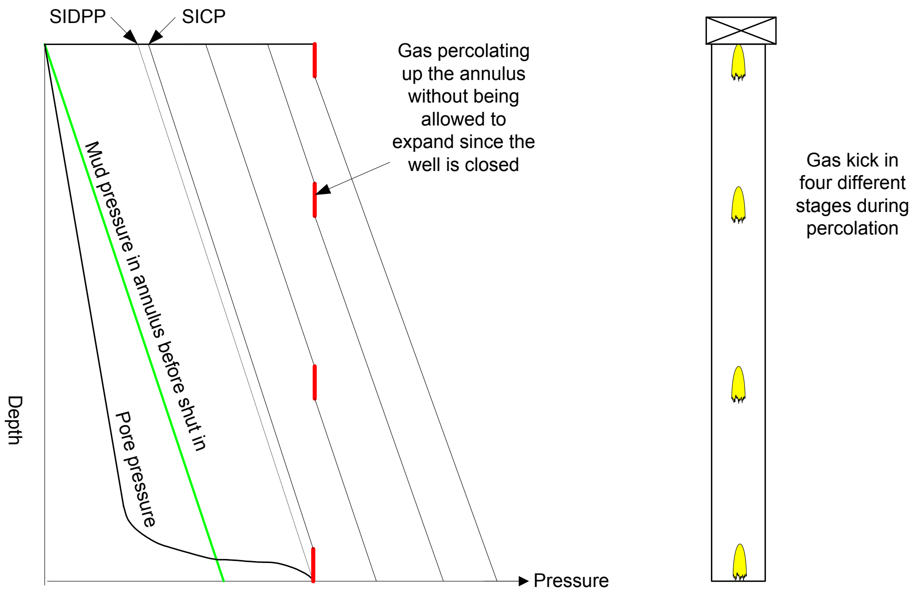


Figure 4-4: Pressure development as gas percolates to the surface in a closed well (assuming the formation will withstand the high pressure).

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.

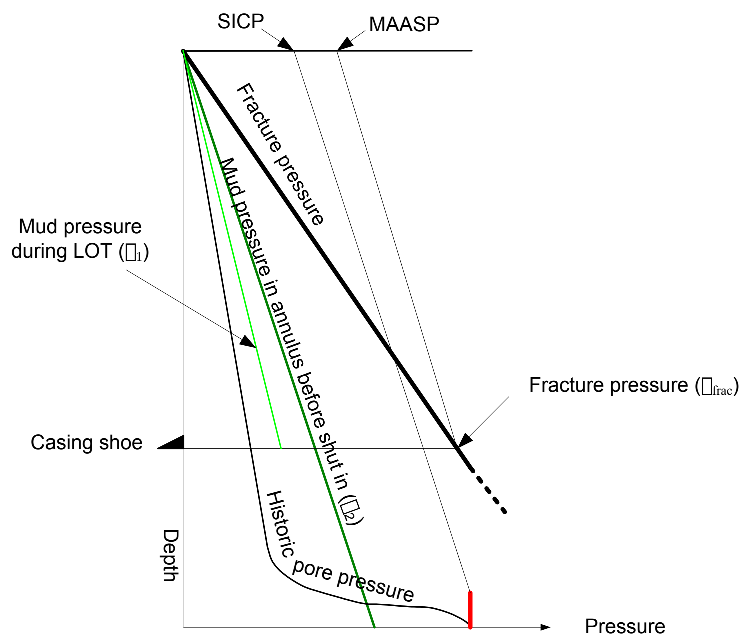


Figure 4-5: MAASP.

MAASP can be estimated through eqn. 4.2.

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

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:

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

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

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

Trip Margin: 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:

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

Riser margin: 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:

$$0 + p_{water} + \rho_{balance} \cdot g \cdot h_3 = \rho_{kill} \cdot g \cdot (TVD) = p_{pore} \tag{4.6}$$

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

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

and the resulting mud weight to balance pore pressure becomes:

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

In deep water drilling, the Riser Margin becomes large and unpractical (see chapter 7.2.1).

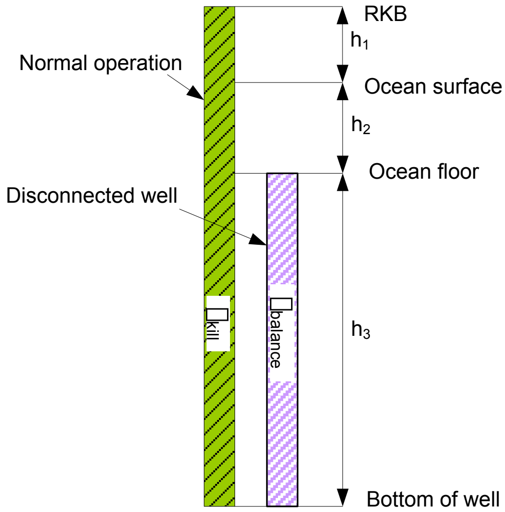


Figure 4-6: Riser Margin is the additional fluid density added to the hole below the mudline to compensate for the differential pressure between the fluid in the riser and seawater in the event of a riser disconnect.

Kick tolerance: Kick Tolerance is the maximum kick volume, V_{influx}, which can be taken into the wellbore and circulated out without fracturing the formation at the weakest point.

The involved parameters are shown in Figure 4-7. Here the gas kick is shown at time of shut-in as V_{influx} and later, during killing, when it reaches its critical position; the casing shoe, V_{cs}.

$$V_{influx} = \text{Kick tolerance} \tag{4.9}$$

We need to back-calculate it from p_{frac} to V_{influx}:

$$\rho_{frac} + g_{gas} \cdot g\, H + \rho_1 g\, (h_{well} - h_{cs} - H) = p_{pore} \tag{4.10}$$

Knowing the capacity of the well and the p_{pore} we find:

$$p_{pore} \cdot V_{influx} = p_{frac} \cdot V_{cs} \tag{4.11}$$

$$H = V_{cs} \,/\, Cap_{cs} \tag{4.12}$$

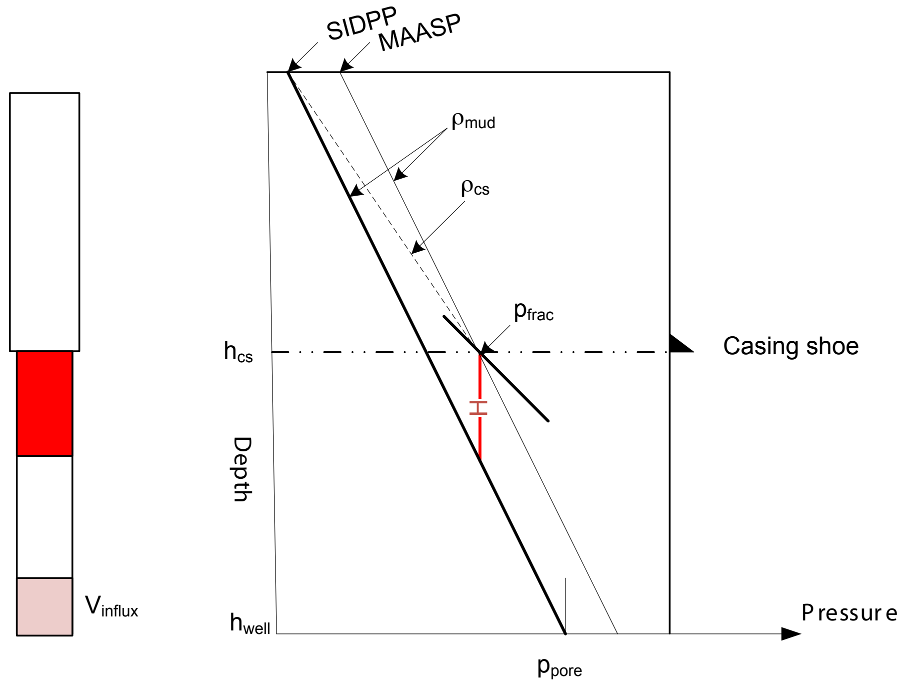


Figure 4-7: Parameters involved in estimating kick tolerance

4.1.5 Composition of inflowing 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 as 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, which is estimated in Equ.4.14, and the difference between shut-in pressures; p_{SIC} and p_{SIDP}, determines its gradient. The height of the fluid is determined from the volumetric capacity, C_{am}, at the bottom part of the well:

$$h_{kick} = \frac{V_{kick}}{C_{ann}} \tag{4.14}$$

Previous figure showed that the bottomhole pressure can be calculated from two fluid columns; the annulus column and the drill string column.

$$p_{SIDP} + g \cdot \rho_{mud} \cdot h_{well} = p_{SIC} + \rho_{mud} \cdot g \cdot (h_{well} - h_{kick}) + \rho_{kick} \cdot g \cdot h_{kick} \tag{4.15}$$

Assuming the capacity is constant, then solving for ρ_{kick} yields:

$$\rho_{kick} = \frac{h_{kick} \cdot g \cdot \rho_1 - (p_{SIC} - p_{SIDP})}{g \cdot h_{kick}} \tag{4.16}$$

4.2 Hydraulic friction during killing

A dynamic well, i.e. one that is being circulated, is more complicated than a static well. Figure 4-8 and 4-9 present a well during a dynamic situation. Figure 4-8 contains purely hydraulic friction losses in a simplified view of a horizontal well, i.e. without hydrostatic pressure. Total friction loss = SPP. Then, in Figure 4-9, 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:

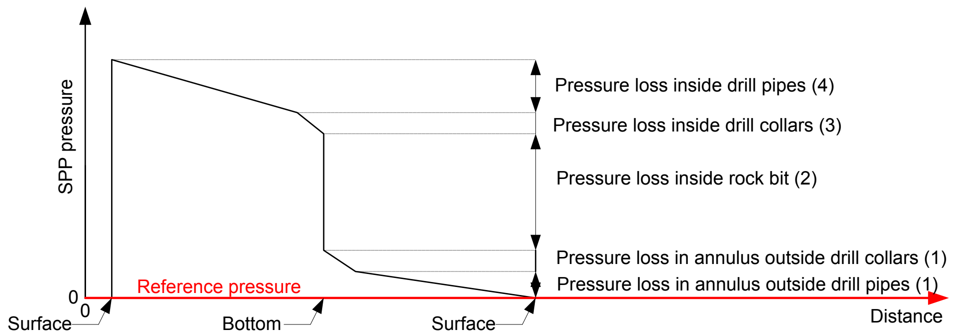


Figure 4-8: Pressure loss in the well during circulation through it in a horizontal, stretched-out view. Reference pressure is air (red line).

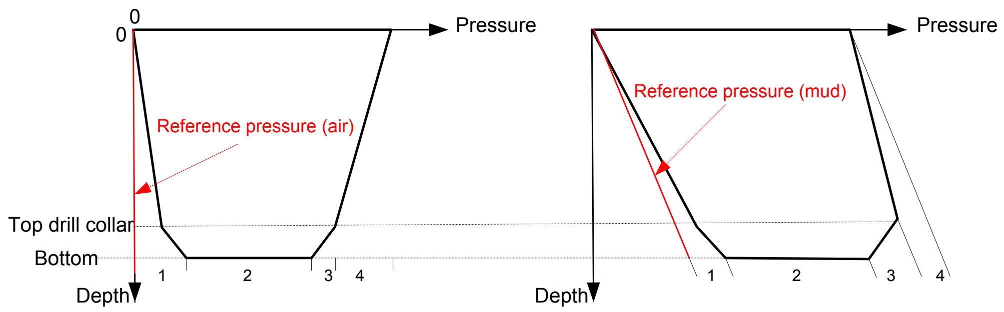


Figure 4-9: Well pressure during circulation through the well in a U-tube view, without gyrostatic pressure (left) and with (right). Numbered friction losses are: 1 – annulus, 2 – bit nozzles, 3 – inside drill collars, 4 – inside drill pipes.

4.3 Killing by means of Driller's Method

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

1. Bottom pressure must balance the pore pressure plus a small overbalance.
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

Killing by means of the Driller's procedure can best be understood by dividing the operation into six separate phases. Figure 4-10 presents the complete procedure exemplified through the following kick situation:

Mud in use:	ρ_{mud}	= 1 100 kg/m^3
Depth of well (TVD):	D	= 2 000 m
Previously recorded circulation pressure:	p_{c1}	= 28 bar (SCP)
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

Bottomhole pressure must be kept constant, and pressure in annulus observed closely. 45 or 60 SPM are common "slow circulation rates", while 30 or 40 SPM are normal on a floating rigs, sometimes even 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.

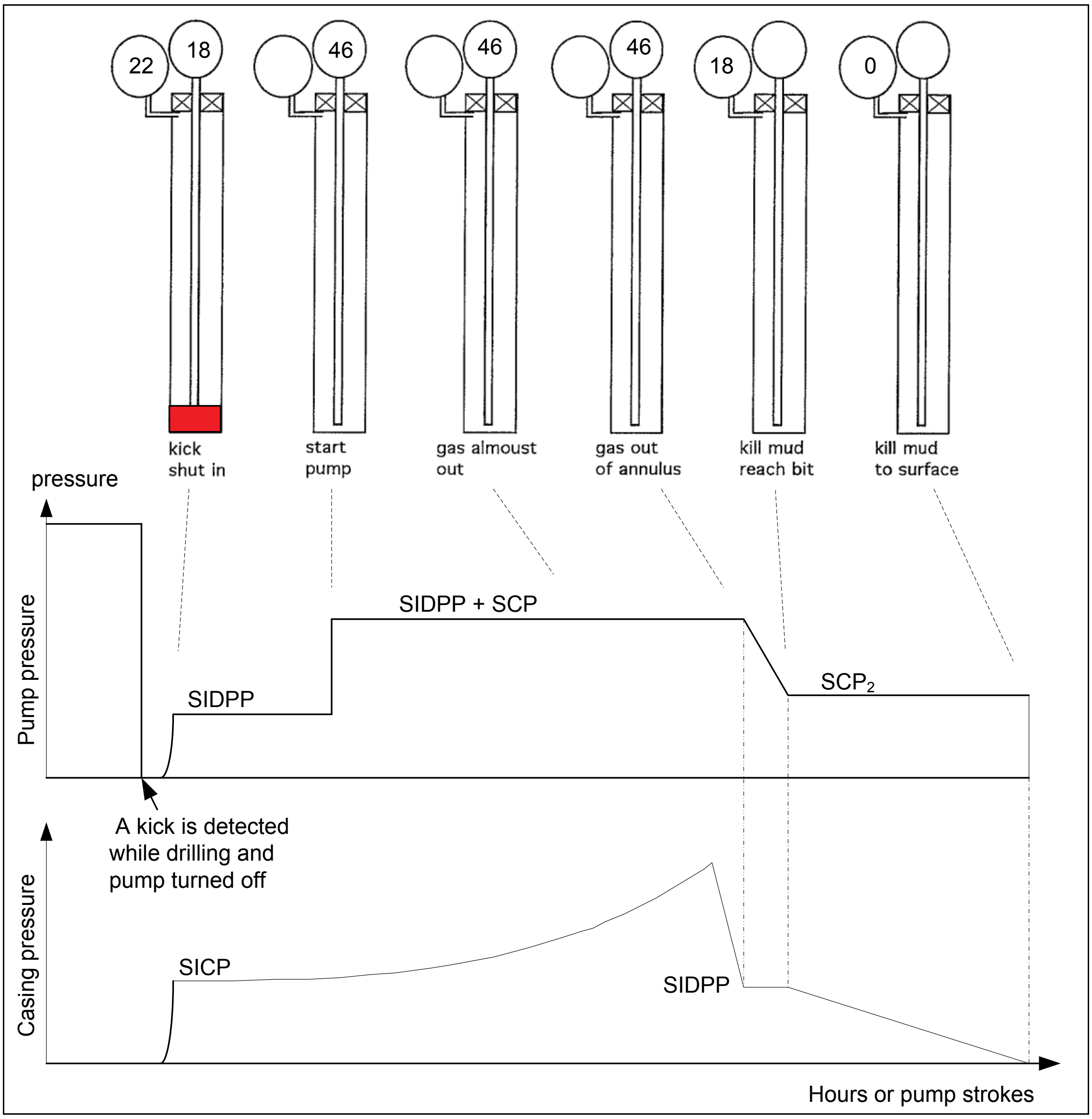


Figure 4-10: A gas kick in six stages handled by means of the Driller's Method (without including the Safety Margin).

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

$$p_{pore} = p_{SIDP} + \rho_{mud} \cdot g \cdot D = 18 \cdot 10^5 + 1100 \cdot 9.81 \cdot 2\,000 = 234 \cdot 10^5 = 234\,bar$$

$$\rho_{kill} = \rho_{mud} + \frac{p_{SIDP}}{h_{well} \cdot g} = 1100 + \frac{18 \cdot 10^5}{9.81 \cdot 2\,000} = 1192\ kg/m^3$$

Type of kick composition:

$$h_{kick} = V_{kick} / Cap_{BHA} = 1\,000\ l / 14\ l/m = 71\ m$$

$$\rho_{kick} = \frac{h_{kick} \cdot g \cdot \rho_{mud} - (p_{SIC} - p_{SIDP})}{h_{kick} \cdot g} = \frac{71 \cdot 9.81 \cdot 1100 - (22-18) \cdot 10^5}{9.81 \cdot 71} = 526\,kg/m^3$$

Phase 2: Start the pump. Pump start-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 the initial circulation pressure (ICF) at the stand pipe (SPP) becomes:

$$ICP = SPP = p_{dp} = p_{SIDP} + p_{C1}\,(+\text{ safety margin}) = \text{ICP} \tag{4.17}$$

The slow circulating rate (SCR) while killing the well (usually one-half of normal pump rate or less) induces very small pressure drops in the annulus. The slow circulation pressure (SCP or p_{C1}) is mostly lost in the drill pipe, drill collar and bit nozzles, and may be disregarded in the annulus. This neglection 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, pchoke, 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}. Figure 4 presents a graph of the choke opening:

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 the 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:

$$p_{C2} = \frac{\rho_{kill}}{\rho_1} \cdot p_{C1} = \mathrm{FCP} \tag{4.18}$$

The reduction of p_{SIDP} and the increase of p_{C1} is assumed to be a linear change (although it in reality is not) and are 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 4-11 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.

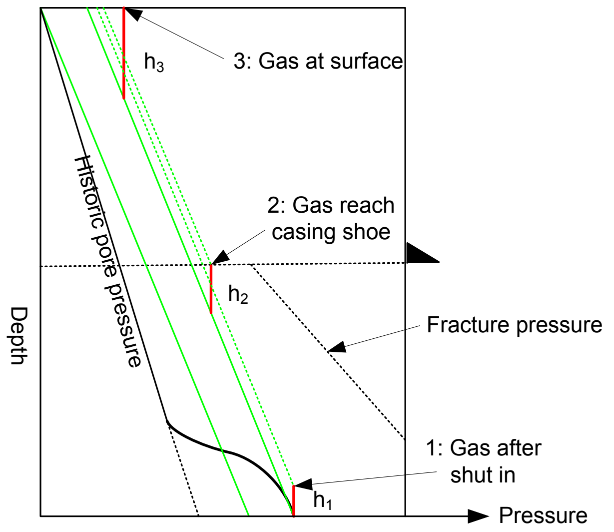


Figure 4-11: Three situations when pressure in the well can be critical due to gas height.

4.4 Engineer's Method

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 circulation is initiated as soon as possible, reducing the drill pipe or pump pressure as soon as heavy mud enters the annulus, as illustrated in Figure 4-12.

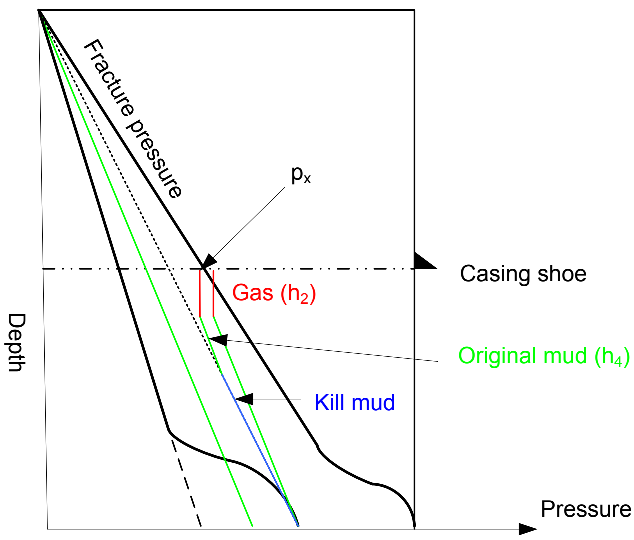


Figure 4-12: Comparing critical annular pressure for Driller's and Engineer's Method.

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 4-13 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, p_{c1}, 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. In the latter case the gas pressure has risen to p_x (see Figure 4-12):

$$\begin{aligned} p_{bottom} &= p_{down\,the\,annulus} = p_{down\,the\,drillstring} \\ &= p_x + 0 \cdot g \cdot h_2 + \rho_{mud} \cdot g \cdot h_4 + \rho_{kill} \cdot g \cdot (h_{well} - h_2 - h_4) = p_{SIDP} + \rho_{mud} \cdot g \cdot h_{well} \end{aligned} \quad (4.19)$$

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

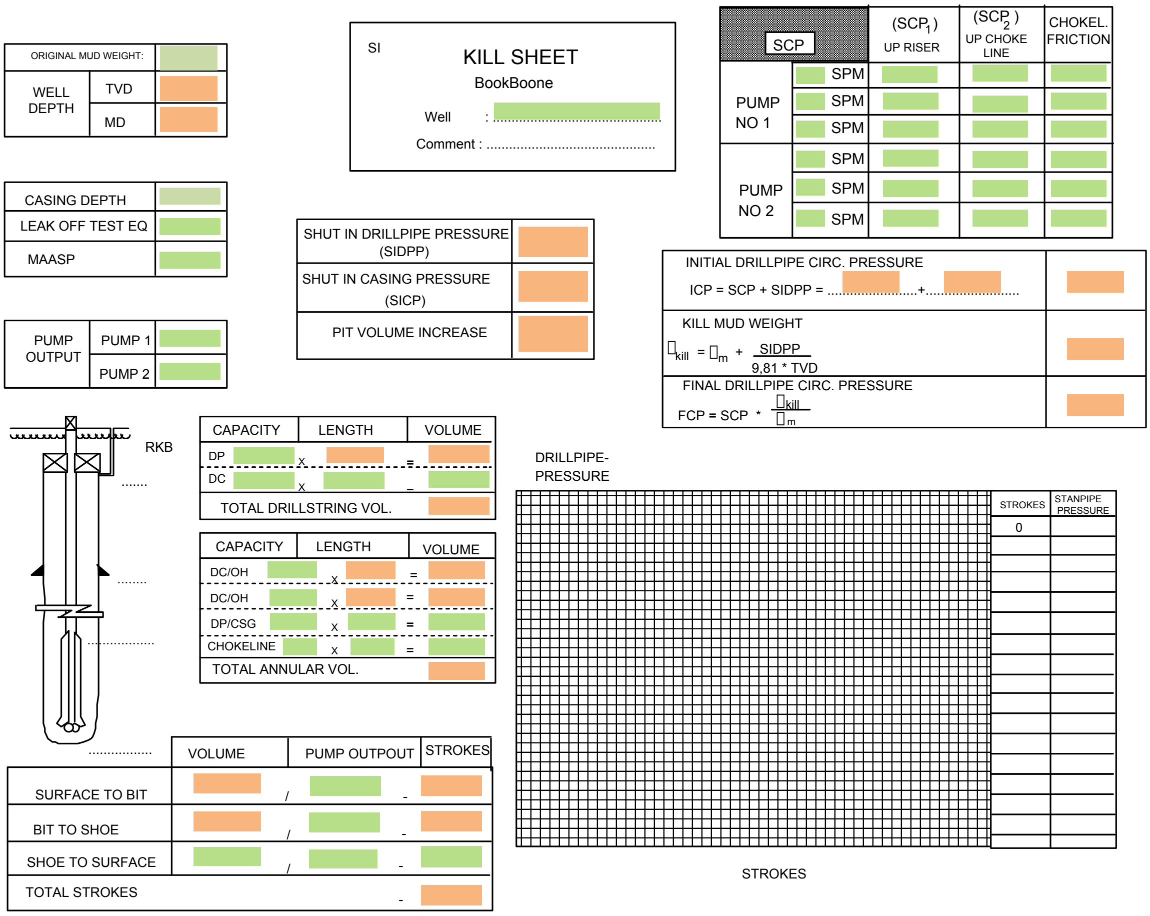


Figure 4-13: An example of Kill sheet. Green boxes indicate information known before a kick is taken. They must be updated at least every shift (every 12 hours). Red boxes represent information that is known after shut-in.

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 length of the annulus to control the formation. The same situation arises when the circulation system is plugged or broken. Before a controlled killing procedure can be carried out, an intact 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.

It is not possible to carry out the stripping procedure when surface pressure rises too high, which will become the case when large gas bubbles travel upwards. We are then left with one option; 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 head, 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 bottomhole pressure (like in the Driller's method).

The procedure starts by selecting a suitable volume of mud, V_{mud} , e.g. 1.0 m³. This volume is easy to measure and to relate to. It must correspond to the mentioned casing pressure increase, Δp_{incr}, as indicated in Figure 4-14.

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

$$\Delta h = \frac{\Delta V_{mud}}{Cap_{ann}} = \frac{1}{0.020} = 50\ m \tag{4.20}$$

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

$$p_{loss} = \rho_{mud}\ g \cdot \Delta h = \Delta p_{incr} \tag{4.21}$$

Figure 4-14 shows how pressure varies at the choke (p_{csg}) and at the bottom.

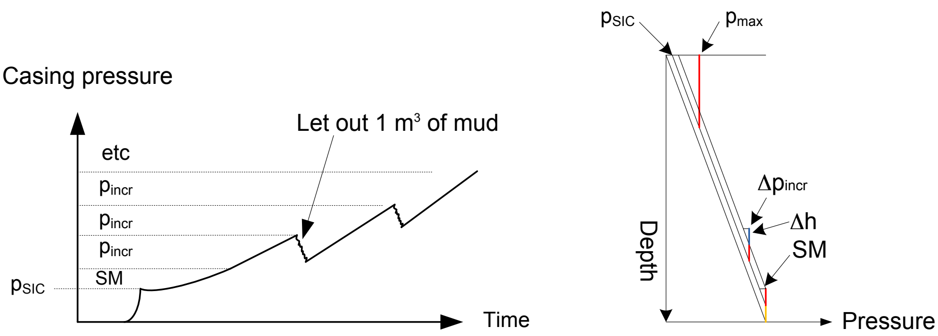


Figure 4-14: Casing pressure (at surface) as gas rises in a closed well with intermittent release of mud (left). Annular pressure when all gas has reached the surface (red line, upper right).

Procedure indicated in Figure 4-14 is summarized here:

1. Determine, the safety margin (SM) 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 Δp_{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 4-14 (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 Δp_{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).

4.6 Pressure control during Underbalanced Drilling

4.6.1 Introduction

There are three general regimes of wellbore pressure during drilling operations. See Figure 4-15.

a) Normal overbalanced drilling (OBD) uses a fluid density typically 0.2 kg/l above the equivalent formation pore pressure. The overbalance is based on experience and best drilling practice.
b) During balanced pressure drilling or managed Pressure Drilling (MPD) the fluid column, either static or circulating, is balancing the formation pressure with the aid of a surplus surface pressure
c) Underbalanced drilling operations (UBD) are where the fluid column is deliberately kept below the formation pore pressure. This may include drilling with air of gas, drilling with a light single-phase fluid column, or drilling with a two-phase fluid column that has been made less dense by the addition of a gas.

Until now (2013) few offshore wells are drilled underbalanced or balanced.

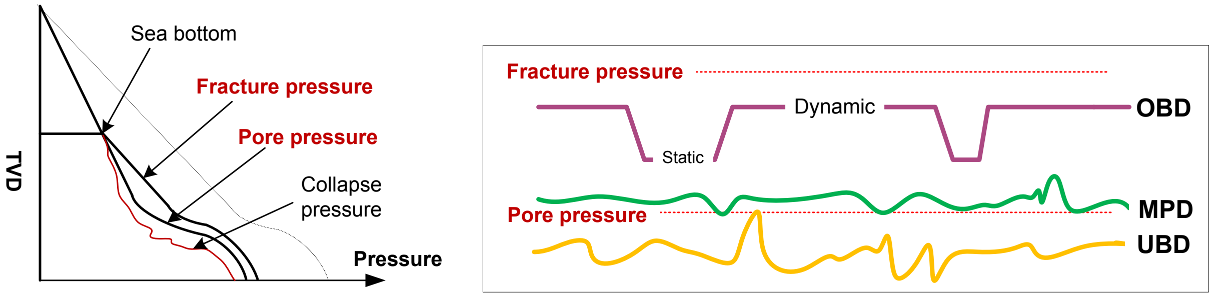


Figure 4-15: Wellbore pressure for thee method of drilling.

Situations where UBD is preferred

- Narrow window of pore pressure
  - o In deep waters or in ERD wells, both diminishing the pressure window
  - o Excessive water injection: pressure increase
  - o Depleted reservoir zones. Original pore pressure maintained in shale and thin sand zones

- Borehole stresses due to pressure cycling

Advantages of UBD

The extra cost and extra complexity involved in UBD are worthwhile in many cases because of the valuable merits of the method. In general, two main reasons drive operators to drill underbalanced:

1) Drilling incentives-to improve the drilling process and avoid drilling problems:
   a) Increasing drilling rate
   b) Avoiding differential sticking
   c) Allowing safe drilling in areas with complex reservoir pressure and rock strength regimes
   d) Avoiding lost circulation. Especially important when using expensive OBM
   e) Increase bit life

2) Production incentives. Avoid impairment of the reservoir near the wellbore:
   a) Prevents the drilling fluid from entering the reservoir and thus limits skin damage
   b) Reveals hidden productive formations
   c) May allow earlier production
   d) Reservoir flow measurements may be taken during the drilling operation

Challenges with UBD

Underbalanced wellbore pressures can cause significant challenges, most notably:

Flow of Formation Fluids or Gasses to the Surface: Wellbore fluids to the surface can be fortuitous if the fluids can be sent to the sale line, but problematic if there is no convenient way to dispose of them. This is, of course, speaking of oil, gas, sour gas, salt water, or in some cases, acid salt water. Disposal is a local problem of regulations and environment.

Wellbore Instability: The problem of wellbore instability can be a challenge: Wellbore instability is one of the main problems that disqualifies or limits the use of UBD. Wellbore instability takes several different forms:

- Areas where stress is building or has built due to geologic activity
- Fractured or disturbed zones, especially in high pressure areas found near the junctions of the continental plates
- The younger sediments found in some of the ocean basins where the fracture pressure, pore pressure and stability pressures tend to converge
- Massive shale that has an elevated internal pore pressure (geo-pressured shale)
- Salt is plastic and will flow into the wellbore when it is penetrated. The rate of flow into the wellbore is a function of the pressure differential, temperature, and the composition of the salt, (primarily how many water molecules are part of the salt structure)

Cuttings carrying capacity

In two-phase flow the carrying capacity for cuttings and cavings can be lost. As a general practical solution in UBD, constant circulation for connections and trips is the best and simplest solution.

4.6.2 Pressure control equipment

The standard set of special equipment used with UBD operations is presented inside Figure 4-16. For UBD operations based on only one single liquid phase the equipment is simpler. In underbalance operation, the top of the well is continuously pressurized and the drill string has to rotate and move axially through a seal at the top of the well. There are two categories of rotating annulus seal elements:

- Passive seal or force-fit seal
- Active seal

The passive seal equipment, also called Rotating Control Heads, use the elasticity of the rubber element with added energy from the well pressure, to maintain the seal around the drill string. In the active seal equipment, often called Rotating BOP or Control Device (RBOP or RCD), the seal is energized by hydraulic pressure as shown in Figure 4-17.

Snubbing is an operation of forcing pipe or tools into a high pressure well when the weight of the pipe is not large enough to push or pull the pipe trough the activated Rotating BOP. Snubbing units offer the same benefits of traditional rigs while working underbalanced. A snubbing system is shown in Figure 4, and can be utilized as a “rig assist” to aid a drilling operation where well pressures at the surface exist. Snubbing involves the use of a special hydraulic system, and a series of slips and cylinders to overcome the forces on tubulars generated by hydraulic and frictional force pressures in the wellbore that limits the ability of the drilling operation to freely move the tubulars.

In offshore platforms, the stack-up is extended over several platform decks from the lower wellhead deck, through the BOP deck, and to the drilling floor at the top. The various elements of the pressure retention system need to be spaced up according to the elevation of the various platform decks. The vertical gaps between the various elements of the stack are bridged by high pressure risers (often refer to as spool pipes). See Figure 4-18.

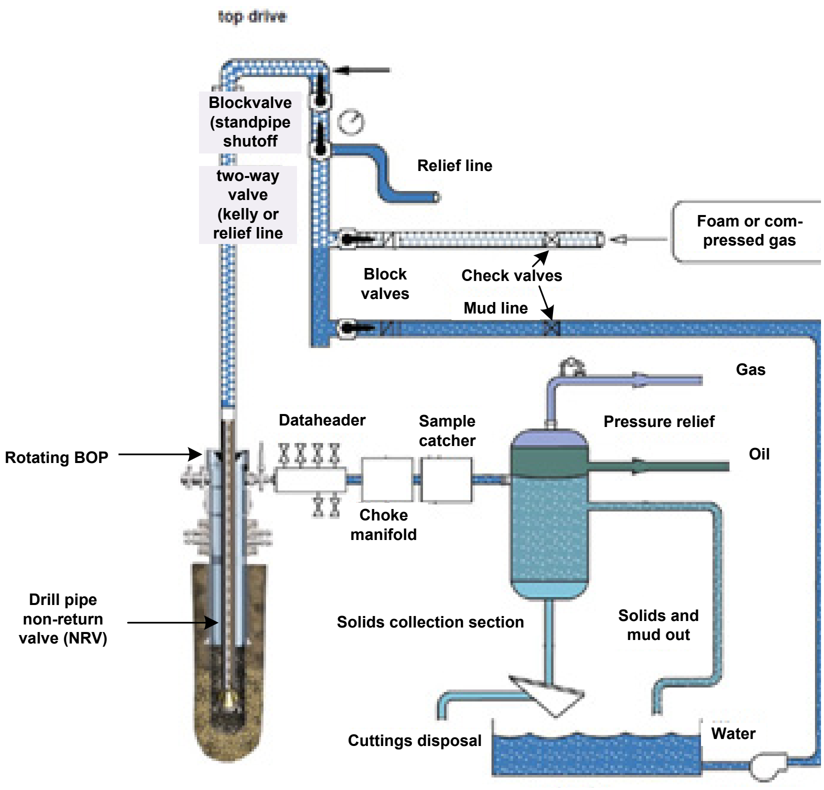


Figure 4-18: A standard closed loop UBD circulation system (Rehm et al., 2007).

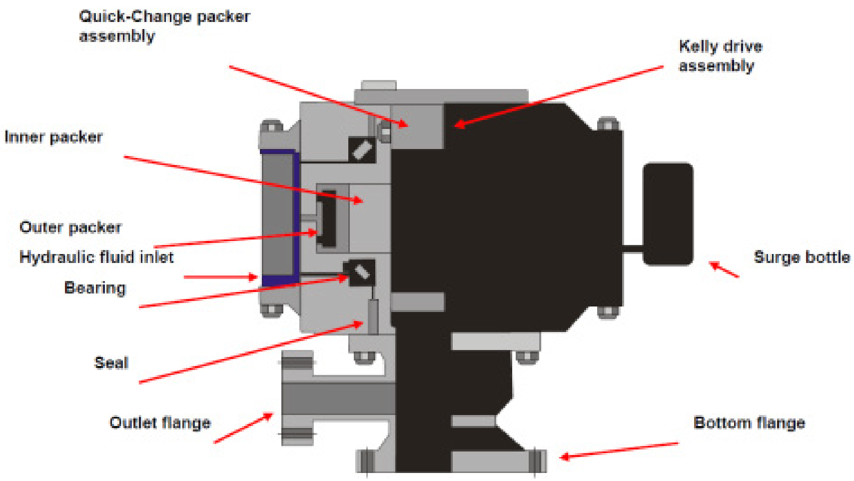


Figure 4-17: RBOP (Rehm et al., 2007).

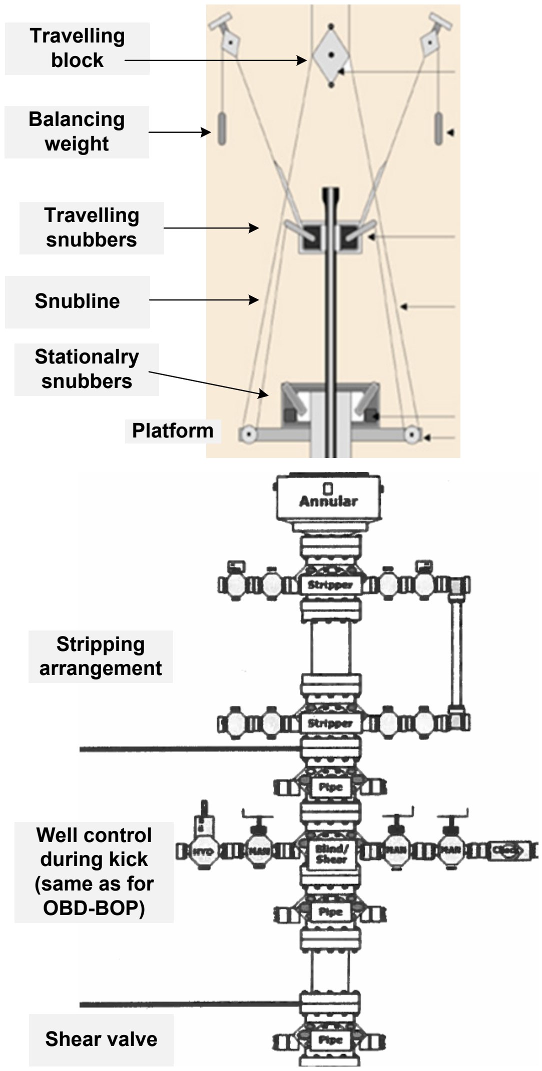


Figure 4-18: A schematic, simplified snubbing unit on top of a well control system for UBD (Rehm et al., 2007).

Now to some of the other drilling activities in UBD:

Stripping is the action of removing pipe from, or putting pipe in the whole through activated annular seal equipment such as BOP, or bowl stripper, or rotating BOP. To keep downhole pressure constant during stripping operation, a wellbore bleeding process should compensate for the pipe volume inserted, or fill-up for pipe volume retrieved.

"Pipe light" is the term for the condition where the force on the bottom of the drillpipe of tubing is greater than the downward force (weight) of the pipe. When stripping or snubbing and there is pressure in the wellbore. This is based on the largest area of the section of pipe, collar, or tool in the well.

$$W_{ds} - \left(\pi r^2{}_{largest} \cdot \Delta P_{ann}\right) \to 0 \tag{4.22}$$

Despite the practical approach, the pipe light point should be calculated in advance and a graph posted to alert the driller to the potential of this occurring. In using the equation above, the force required to push the pipe through the RCD is a hidden margin.

Lubricating or Staging is an action to pass equipment with large diameter and non-uniform external shape through a BOP stack. The tube between the upper and the lower closing elements is called lubricator.

Connections: During a connection, the underbalanced condition actually may revert to a balanced system where the annular surface pressure (from the choke) and mud column pressure balance the formation fluid pressure. On a long connection, some upward migration of gas will occur and surface pressures may rise; as a result, formation fluid may be pushed back into the formation. When the drillpipe is lifted off bottom on a connection, a swabbing effect occurs. General good practice requires that the pump be kept on until the drillpipe is in the slips. This limits some of the swabbing effect due to pipe movement.

The use of a down-hole casing valve flapper valve effectively closes off the hole during a trip, improves safety, simplifies procedures, and reduces time for tripping. In a wellbore where gas is capable of flowing to the surface from a high permeability formation, the down-hole casing valve is a significant improvement over mud caps and snubbing.

4.6.3 Controlling the bottom hole pressure

Two phase drilling fluid

One of the principle differences between conventional overbalance drilling and underbalanced drilling is in the manner by which the desired pressure is maintained at the bottom of the wellbore.

In underbalanced drilling, the desired static bottom-hole pressure is governed by a combination of fluid density and top column pressure as shown in Figure 4-19.

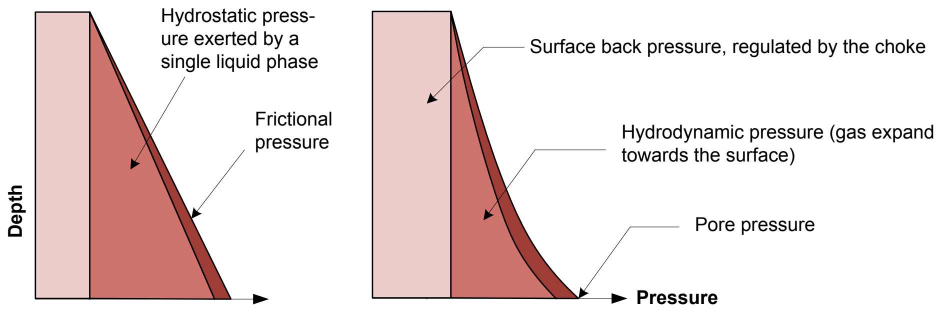


Figure 4-19: Wellbore pressure is composed of three contributing factors.

$$p_{bottom} = p_{top} + p_{hydr} \tag{4.23}$$

When the fluid is circulated, the frictional pressure element plays an important role in UBD pressure control, like in conventional drilling where the ECD is of importance.

When liquid mud is circulated, as in conventional drilling, the bottom-hole pressure equals to the sum of the wellhead pressure, the hydrostatic pressure and the frictional pressure losses.

$$p_{bottom} = p_{top} + \Delta_{phydr} + \Delta p_{fric} \tag{4.24}$$

When the mud is mixed with gas the bottomhole pressure is a more complex function of the wellhead pressure. The gas pressure is affected by the elements in the gas law.

$$pV/ZT = \text{constant} \tag{4.25}$$

Single phase drilling fluid (flow drilling)

The use of a single fluid that provides an environment for underbalanced drilling simplifies the entire process. Two-phase systems are more difficult to control and are generally more expensive to use. While there is always a potential problem with equivalent circulating density (ECD), changes that occur when moving the pipe up or down or changing the pump speed in a single-phase system is easier to predict and control than dual-phase systems. Underbalanced single-phase systems may phase into managed pressure drilling (MPD) with a minor change in down-hole pressure regime. Since there is no gas in the drillpipe in UBD flow drilling, conventional mud pulse tools can be used such as MWD, LWD, and PWD.

Single phase fluid systems allow a much tighter control of bottom-hole pressure than does gasified fluid or foam; however careful consideration needs to be given to annular pressure loss. This is especially critical in two areas:

1. Pressure surges from the upward or downward movement of the bottom-hole assembly (BHA) during connections and trips.
2. Pressure changes from changes in pump rate.

Long “horizontal” wellbores develop significant annular pressure loss during circulation, which makes the wellbore pressure at the toe of a well higher than at the heel. The pressure difference is not always a problem since in some cases there is an adequate margin between lost circulation and a well kick or wellbore instability. In other long wellbores, this causes lost circulation at the heel and a well kick at the toe.

The mud-cap method

Underbalanced wells make hole fill-up easy when tripping, but it is very different from a normal trip fill up. It there is reasonable fluid permeability and/or lost circulation zones, the fluid is going to seek its own level. Drillpipe fill-up will make a difference. This is a place where a mud cap might be used to keep the formation fluid from coming to the surface.

A mud cap is a column of heavy and often viscosified mud spotted over a limited interval in the annulus, practical limit of a mud cap length of 300 to 600 m, to increase bottomhole pressure. To keep the reservoir fluids from coming to the surface in a well with a complete lost circulation. Mud is lost into the loss zone (until a protective casing is set across the zone) as shown in Figure 4-20. Mud from mud cap used on a trip is normally recovered, stored and reused in the next trip.

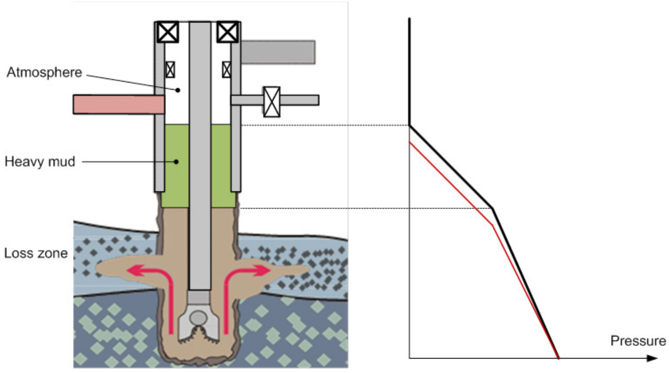


Figure 4-20: Drilling with mud cap through loss zones (free after Rehm et al., 2007).

In mud cap drilling (drilling blind), a sacrificial fluid, typically water, is pumped down the drill pipe to flush the drill cuttings into the zone of lost returns. Drilling continues without returns to the surface. A semi-static annular fluid column is used to prevent kicks without having to continuously pump down the annulus. No attempt is made to control the problems of lost circulation while drilling in fractured formations. This technique reduces the time and cost associated with continuous well control issues and loss of drilling fluid. Periodically the well would kick and additional heavy drilling fluid was bullheaded down the annulus until the well was again on a vacuum. Significant volumes of this heavy "kill" mud were often required to maintain control of the well. A lot of drilling fluid and water was lost while drilling and tripping, but the total mud and time loss was much less than trying to drill conventionally.

With a floating mud cap, the annular fluid is generally 0.1 to 0.4 kg/l. heavier than the drilling fluid. The floating mud cap tends to be somewhat unstable during drilling and the cap often has to be replenished with additions of fluid, sometimes even requiring a small constant stream of fluid. To help reduce the rate at which gas migrates through the annular fluid and thereby reduce the amount of mud required, the viscosity of this "cap" may be increased. The higher the viscosity of the annular mud, the slower gas will migrate through it. Also, the higher the viscosity of the cap mud, the lower the rate at which "fluid swapping", due to differences in density, will occur. Thicker muds have a tendency to require a higher pressure to "break circulation," and this may cause new lost circulation or intensification of existing.

4.7 Killing operations

Almost all UBD operations involve circulating a well as a closed system with constant pump rate and choke control (not gas drilling). During killing with an ECD and choke system, the bottom-hole pressure can be maintained by using a constant pump rate and controlling the standpipe pressure with the choke as in the Driller's Method of Well Control. Changing bottom-hole pressure to respond to too much or too little formation fluid flow is obtained through:

- Increase or decrease the choke pressure. This is a good immediate response to increased flow
- Change the density of the drilling fluid
- Change pump rate. This is not often done (Friction Controlled Drilling or Dynamic killing)

In flow drilling the typical well control rule applies: Using a constant pump rate, changes in bottom-hole pressure are reflected in the change in drillpipe (circulating) pressure.

With two-phase flow while the direction (±) of the change in bottom-hole and wellbore pressure follows the drillpipe pressure change, the exact amount of change requires a model or some hard math (e.g. OLGA), because compression of the gas changes the volume of liquid in the drillpipe.

The driller's method of well control is summarized in these steps:

1. Shut in the kick
2. Read (SIDP) (SICP), and kick size (pit volume increase)
3. Start circulating by holding the casing pressure constant at the shut-in pressure with the choke until the pump rate is up to the planned slow rate circulating pressure. The circulation path is identical with the one for standard OBD as seen in Figure 4-21
4. When planned rate, ICR, hold the ICP constant on the standpipe using the choke on the annulus. Keep the pump strokes constant. Start mixing kill mud
5. Circulate until the kick is out of the annulus
6. Switch to kill mud. Hold now the annulus pressure constant at the shut in pressure until the new heavier mud fills the drillpipe
7. Then hold the new drillpipe pressure constant until annulus is replaced by kill mud and the well is now dead

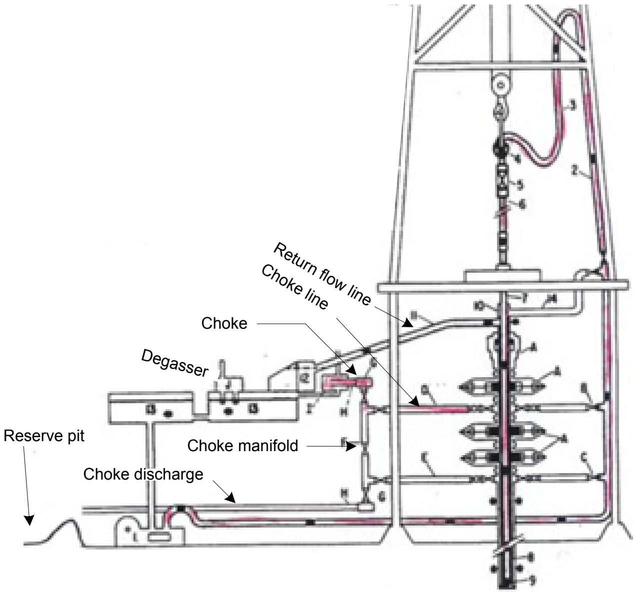


Figure 4-21: Killing operation during UBD (Rehm et al., 2007).

5 Modification of the standard killing method

5.1 Modification due to narrow pressure window

Narrow pressure window refers to a relatively small 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 bottomhole assembly (BHA) and the wall in slim holes is extremely narrow. Above the BHA the ratio between the outer wall and the drill pipe is less extreme. The most 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 Narrow 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 5-1 clearly demonstrates this fact.

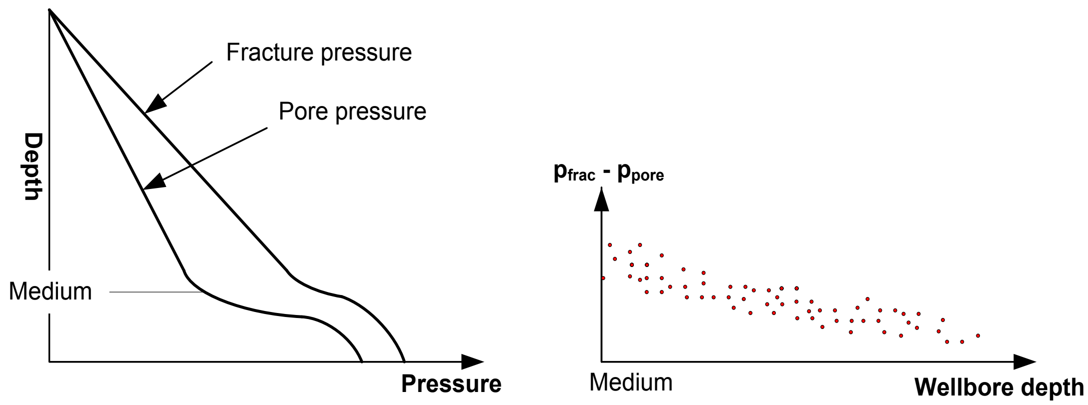


Figure 5-1: Pressure window vs. depth, starting at medium depth. At "medium" depth abnormal pore pressure is encountered, and the difference between fracture and pore pressure decreases.

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

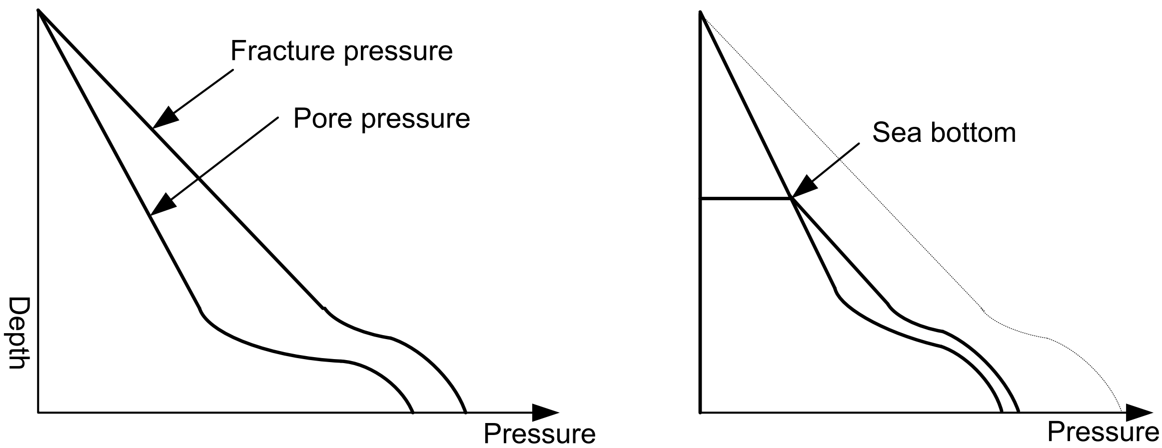


Figure 5-2: Onshore (left) and offshore (right) high-pressure formation in relation to pressure window. Offshore it is small since fracture pressure is so low (it is here assumed that high pore pressure starts at same total depth as onshore).

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.

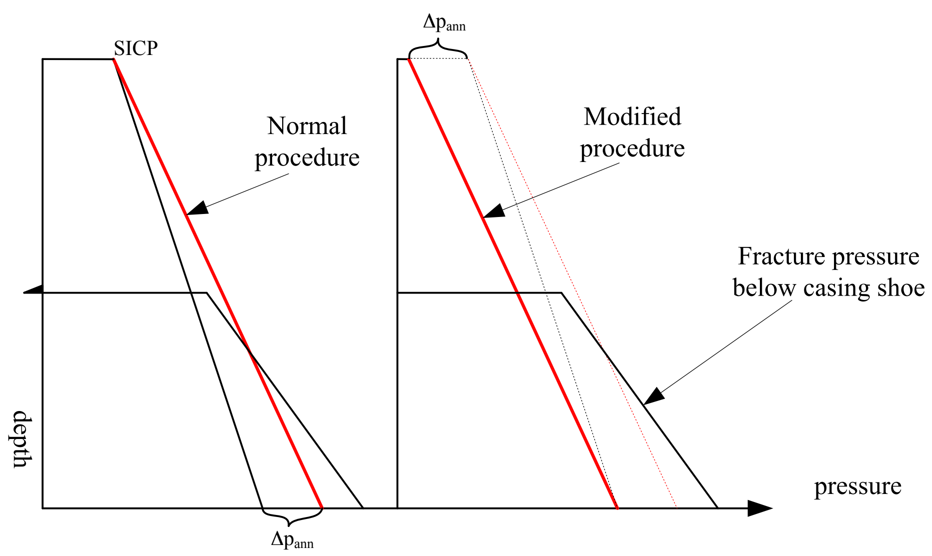


Figure 5-3: Modified slim hole killing procedure; hide Δp_{ann} in SICP.

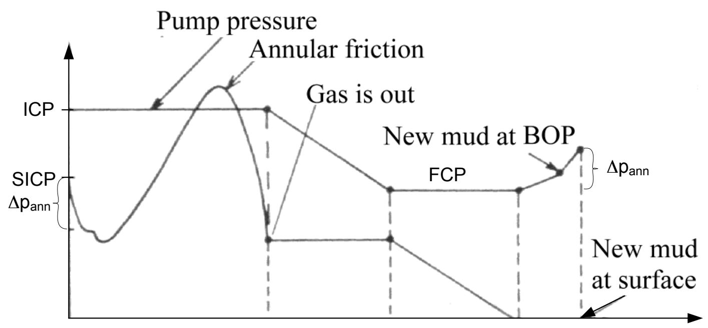


Figure 5-4: Fracturing during killing due to large choke line friction is avoided by means of the modified killing method; hide Δp_{ann} in SICP. The hidden Δp_{ann} must be gained back at the end of the circulation.

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 $\Delta p_{\text{choke line}}$ makes up a major part of Δp_{ann}. Figure 5-5 illustrates the modified procedure for offshore conditions.

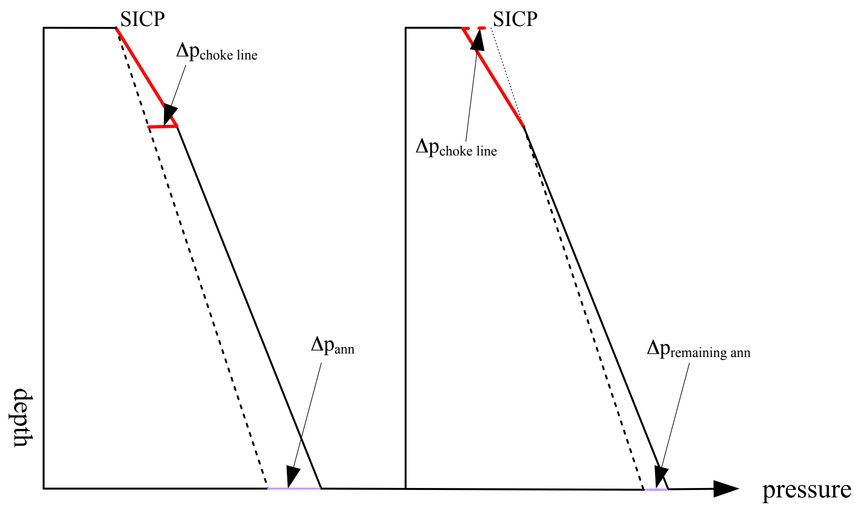


Figure 5-5: Modified offshore kill procedure, where choke line friction increases bottom pressures but where most of it is hidden in Δp_{ann}.

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.

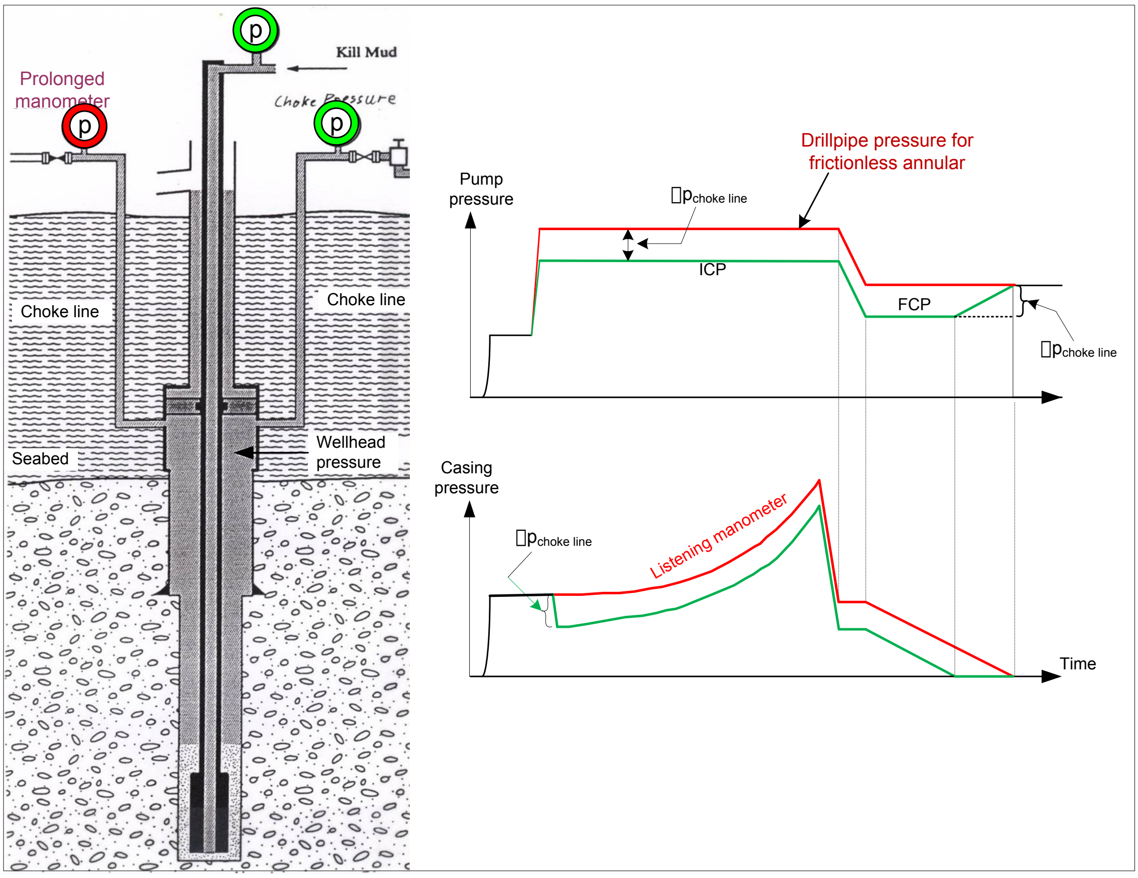


Figure 5-6: Kill line applied as prolonged manometer with resulting pressure shown to the right. Red line represents the surface choke pressure or the pressure in the prolonged manometer (without choke line friction drop). This line is identical with conventional killing.

However, often it is desirable to use both C&K lines. It has two advantages; the $Dp_{choke\ line}$ 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 the equation for estimation of the pressure profile during injection of kill mud in the drill string becomes:

$$p_{DP} = ICP \qquad - f(p_{SIDP}) \qquad + \qquad f(\Delta p_{fric}) \tag{5.1}$$

Expanding eqn. (5.1):

$$p_{DP} = p_{SIDP} + SCP_1 \qquad - p_{SIDP}\left[\frac{TVD_{killmud}}{TVD}\right] \qquad + \quad (SCP_2 - SCP_1)\left[\frac{MD_{killmud}}{MD}\right] \tag{5.2}$$

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 SCP_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.

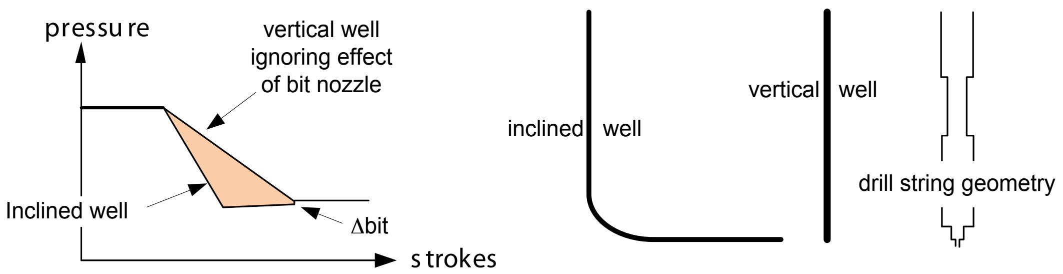


Figure 5-7: Pressure profile by circulating a kick while considering drill string geometry.

5.3 Wellbore strengthening

Typical problems related to depleted reservoirs are listed below and nicely illustrated in Figure 5-8:

1. Subsidence -> risk of (re)activate faults
2. Small pressure window
    1. ECD is a challenge
    2. Losses
    3. Underground blowouts
3. Δp-sticking
4. Fracture may propagate to neighbor well

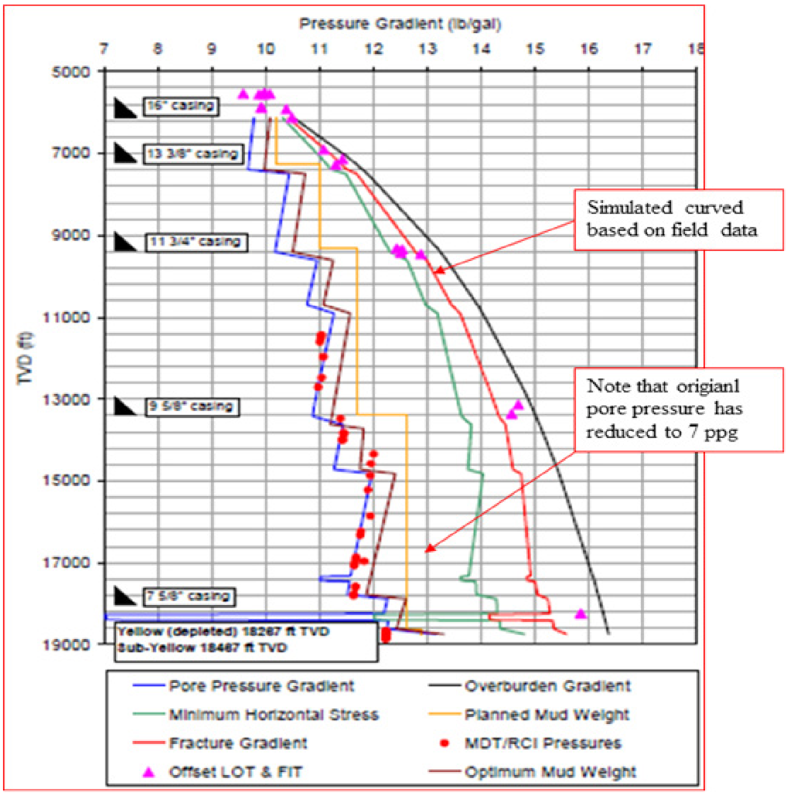


Figure 5-8: Pressure in conjunction with subsidence (van Oort et al., 2011).

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 on drilling breaks and possibly circulates 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 to minimize LGSC to avoid viscosity increase.
- Use lost circulation material (LCM) when small losses are encountered.

When large losses are encountered it may become necessary with more dramatic counter actions than LCM. One historically often applied method is the Gunk Squeeze. Gunk Squeeze is a mixture of Bentonite, Diesel oil and Cement (BDOC). Here is how it is performed:

Step 1: Mix BDO and store in a tank

Step 2: Pump a batch of BDO through the Drill String. The batch has to be separated by a pre and post flush of diesel to avoid gelling. Mud is also pumped slowly down the annulus to avoid BDOC entering the annulus and there through start "gunking" here and shutting off the annulus.

Step 3: When the batch hits water (WBM) it gels quickly, both in the well below the bit and also inside the fractures. The batch forms a base for a cement plug. The batch is followed by thixotropic cement slurry. The cement becomes rapidly viscous and holds its own hydrostatic pressure, in order to minimize any additional pressure on the loss zone. The DS is pulled slowly into the casing shoe while pumping cement. It may be necessary to pump several plugs. If BDO does not work, use silica- based solution instead. If loss not stoppable, plug back and sidetrack (the loss zone has limited horizontal extension.

Step 4: After WOC drill through the plug and set a casing.

If losses are becoming a nuisance a more resent methods must be applied; Wellbore Strengthening. Wellbore strengthening methods are relative resent (van Oort et al., 2011). We will present them as four different methods, although they are strongly related.

5.3.1 Cohesive strength

Chemical strengthening treatment of sandstone, fractured shale, faults etc. is seen in Figure 5-9.

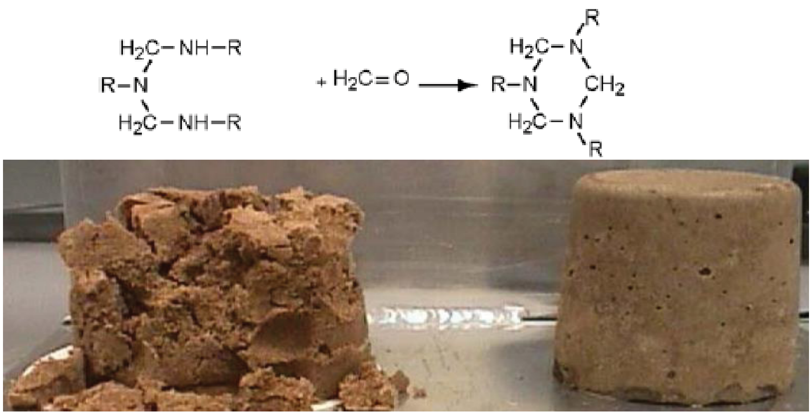


Figure 5-9: The soft sand is strengthened to become a hard sand stone. Complexion of melamine with formaldehyde. A strong 3-dimentioanl polymer network is formed. The resin can bond directly with the core itself thorough formation hydroxyl (-OH) groups (van Oort et al., 2011).

The unwanted loss zones are sealed-off by:

1. Spot a batch of no-fluid-loss control containing chemicals opposite the loss zone
2. Loss zone invaded by 1–2 ft
3. Polymerization is activated by monomers/resins, which are pumped in behind the spot batch

The resulting strengthening effect is seen in Figure 5-10, where the cohesive strength has been lifted.

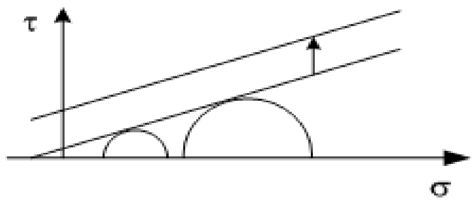


Figure 5-10: The Moor's circle before and after chemical treatment.

5.3.2 Hoop stress – Wellbore Strength Augmentation (WSA)

The second method involves added stress to the existing hoop stress. The method is performed in the following way, and demonstrated in Figure 5-11.

1. Create near-wellbore fractures
2. Pack with selected solids (frac-and-pack)
3. Collapse the fractures onto the solids by releasing the pressure
4. Tangential stress level has increased due to increased compressional stresses

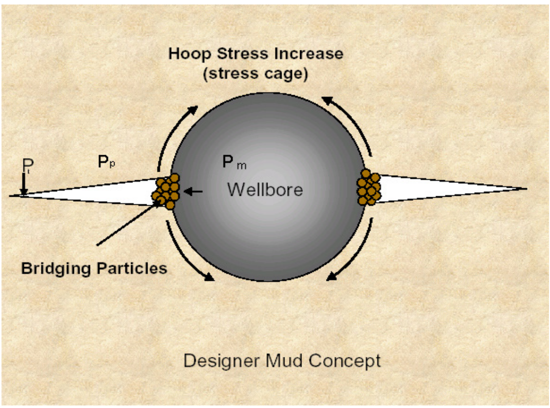


Figure 5-11: The principles of ho to increase the hoop stress (van Oort et al., 2011).

The increased hoop stress can be estimated through eqn. (5.2). Involved physics is defined in Figure 5-12.

$$\Delta p = \pi/8 \cdot w/R \cdot E / (1 - \mu 2) \tag{5.3}$$

In eqn. (5.3) w is the fracture width at the base, R the wellbore radius and μ is the Poisson's ratio.

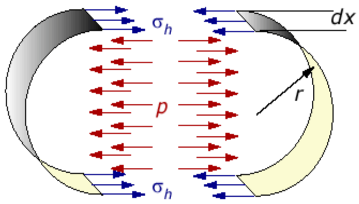


Figure 5-12: The physics involved in initiating a fracture.

The hoop stress increase is referred to as the Wellbore Stress Augmentation (WSA), and the resulting effect during a leak off test is presented in Figure 5-13.

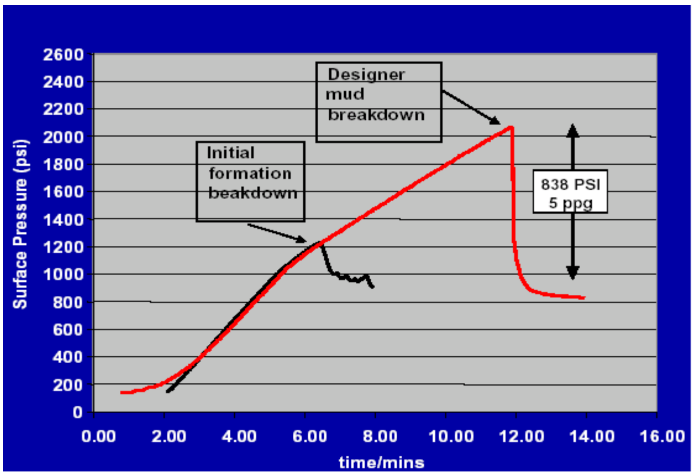


Figure 5-13: Expected increased formation break down pressure when applying the WSA method (van Oort et al., 2011).

The WSA method has been tried out with success. We present here an example if its application in the Middle East: A reservoir produced for 20 years. Assume that fracture resistance is reduced by ⅓–½ of the pore pressure reduction as indicated in figure 5-14. Three options to solve the problem were evaluated:

1. Use expandable casing
2. Use MPD
3. Use WSA

Pore pressure reduction is expressed in Eaton's formula through:

$$k = \mu /(1 - \mu) \quad (5.4)$$

For typical Poisson's rations the pressure reduction factor k becomes:

μ	k
0.25	0.33
0.33	0.50

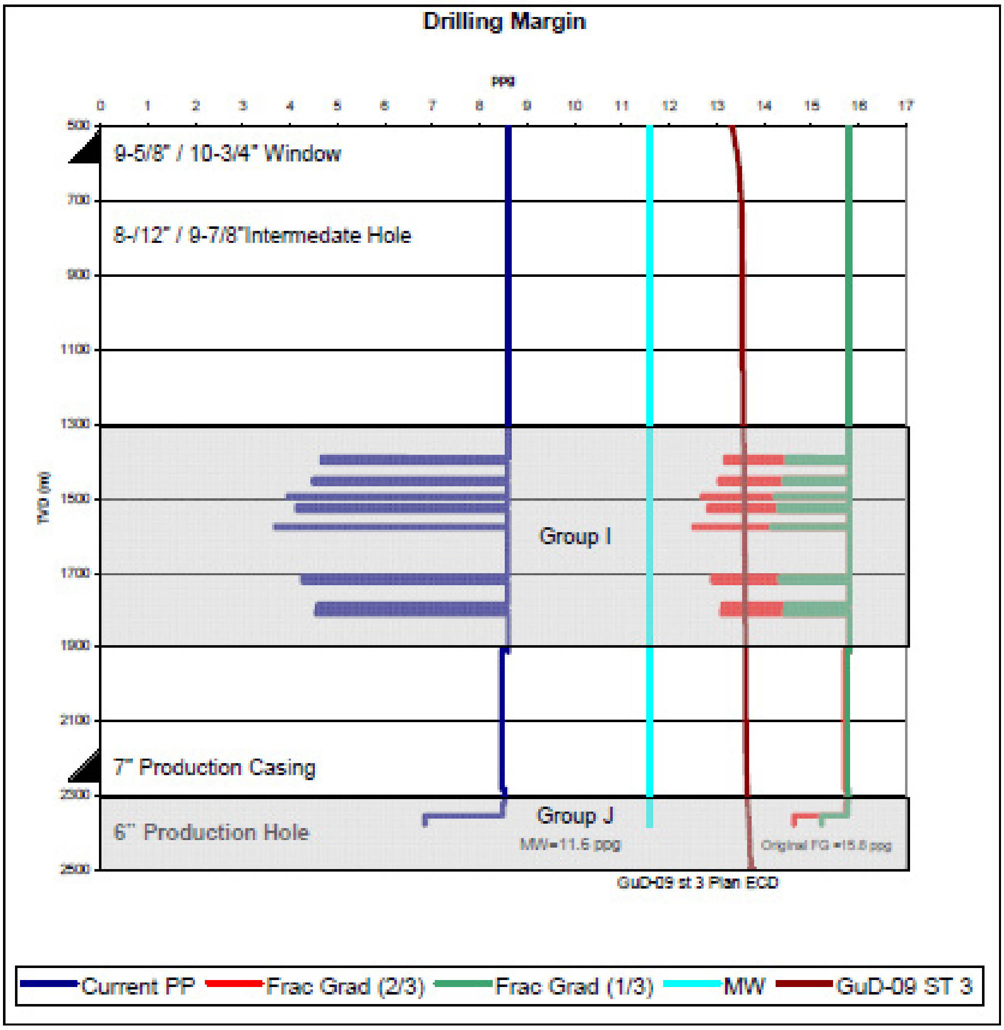


Figure 5-14: Current pore pressure (left horizontal lines) vs. estimated fracture pressure (right lines) (Niznic et al., 2011).

The two first problem solving methods were considered very expansive to implement. Therefore the WSA method was selected. A finite element program simulated the near wellbore hoop stress. The current case produced the hoop stresses presented in Figure 5-15.

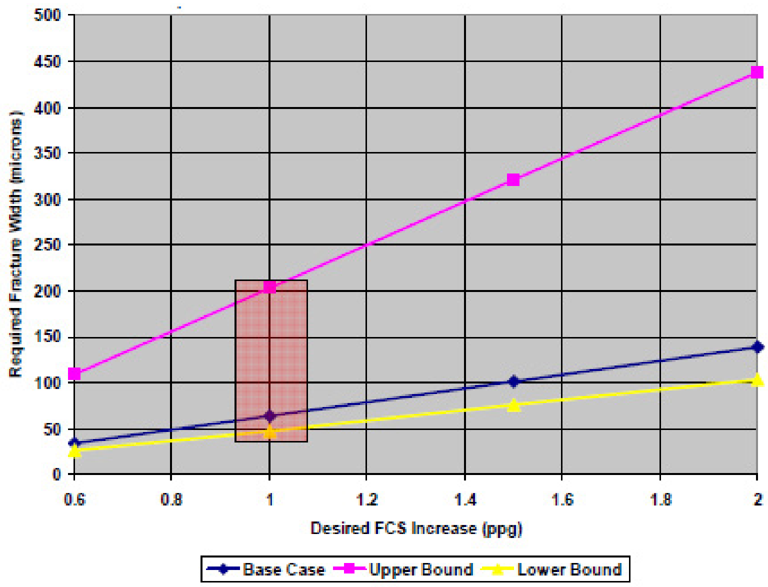


Figure 5-15: Required sieve width vs. desired FCS increase (Niznic et al., 2011).

In the current situation it was decided that an increase in hoop stress of 1.0 PPG would be sufficient:

$$\rho_{frac} - ECD \cdot \rho g < 1.0 \text{ PPG} \tag{5.5}$$

To obtain the desired effect the program required a certain fracture with (200 mm). Designed $CaCO_3$ at a concentration of 5–8 ppg from the list of d_{50} ranging as the list below:

25
50
200
300
400
300 + Graphite

Once loss is expected a pill with surfactants is ready for action 50 before drilling into loss zone. Losses stopped, but re-occurred during back reaming (destroying the fracture opening arrangement). 1000 m were drilled. When LSGC > 15% a dilution was necessary. 21 days were saved.

The main problem with the WSA method was that the fracture pressure dropped back to its original fracture pressure once the new, high fracture pressure was surpassed. This is shown in Figure 5-13.

5.3.3 FPR

The fracture propagation resistance (FPR) is being achieved by means of a dehydrating filter cake, as soon as the fractures are created. The method works much better in WBM than in OBM. In Figure 5-16 the methods are compared.

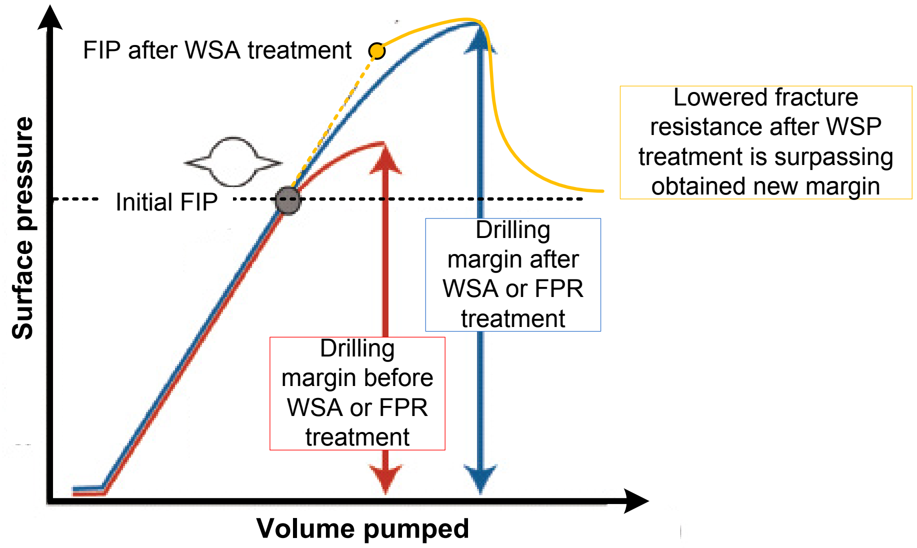


Figure 5-16: LOT response before (red curve) and after WSA (yellow curve and after FPR treatment (blue curve) (free after van Oort et al., 2011).

The difference between WBM and OBM behavior is presented in Figure 5-17

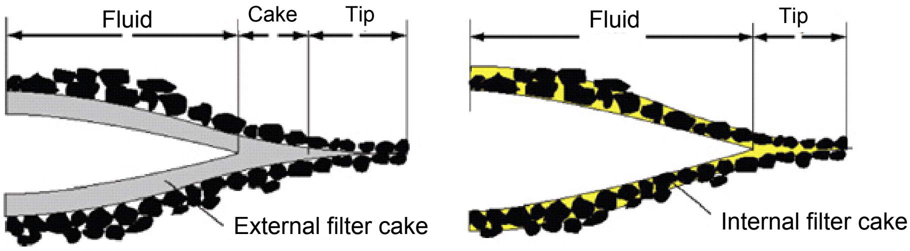


Figure 5-17: Fracture propagation in WBM (left), showing build-up of external filter cake that seals the fracture tip. In OBM (right) fracture propagation is allowing full pressure communication to the fracture tip, this facilitating fracture extension at a lower propagation pressure (van Oort et al., 2011).

WBM behavior:

1. Spurt loss
2. Dehydrated filter cake will pressure-isolate the fracture tip from full hydraulic force
3. Drilling fluid must first break through filter cake
4. → Higher fracture re-opening and propagation pressure is necessary

OBM behavior:

1. Emulsion blocks the formation internally. No spurt loss or filter loss. This makes OBM the preferred system for drilling depleted formation! But now this fact works against OBM for FPR
2. Tip is exposed to full hydrostatic force of the drilling fluid
3. → Lower resistance of fracture re-opening and propagation

The Wellbore Strengthening Material (WSM) must consist of hard particles (marble) to keep the fractures open (WSA);

- Combine calcium carbonate (marble) and graphite to form Resilient Graphite Carbon (see Figure 5-18)
- Graphite are used for highly innovative products in different applications
- Often used in packing and seals, due to its plastic and compressible properties.
- Deform like a plastic under high pressure

Figure 5-18: Natural Crystalline Flake Graphite is also used as Carbon Brushes. As pack and seal material it comes in the size of 5-425 microns.

5.3.4 The final (?) FPR solution

Method # four is pt. the latest approach, based on the principles of FPR, which again is based on WSA). It was realized that the standard frac-and-pack solution of WSA and FPR method and are costly operations:

1. Heavy logistics and difficult screen-out of the Wellbore Strengthening Material (WSM)
2. Little protection higher up in the well and no protection ahead of the bit. The process must be repeated continuously
3. Solids build-up of LGS due to restricted use of shale shaker. Negative effect on the viscosity. Dilution when LGSC > 15%

Method four, the FPR solution was therefore developed. In principle steps this is how it must be performed:

1. Applied on a continuous basis
2. WSM-characteristics
    a) Material: Graphite, CaCO3, cellulosic material (oil-wet)
    b) Particle size
    c) Particle-size distribution
    d) WSM conc. (lower than for WSA; typically 15–0 PPB)
3. Whenever ECD > FIP → WSM automatically provides increased FPR. Typical fracture with at its base: 100–400 mm
4. It works also in shale: Cross-linked gelling polymers shield the fracture tips
5. New recycling/reintroducing technique

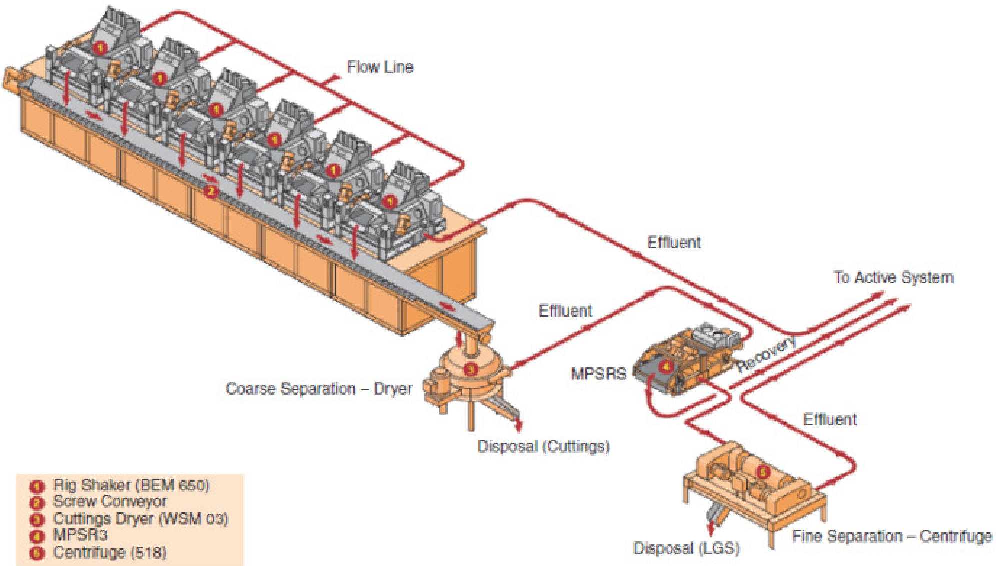


Figure 5-19: MPSR used at the rigsite for recovery of WSM (van Oort et al., 2011).

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 inflowing 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.

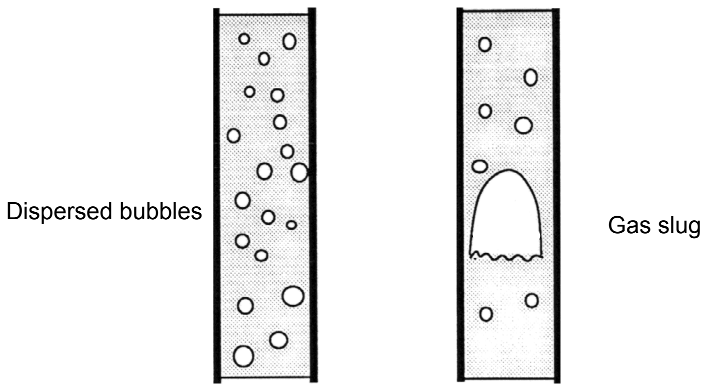


Figure 6-1: Two types of gas bubbles in liquids. Gas bubbles are defined as a gas slug when the length > 2 · diameter.

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 tend 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.

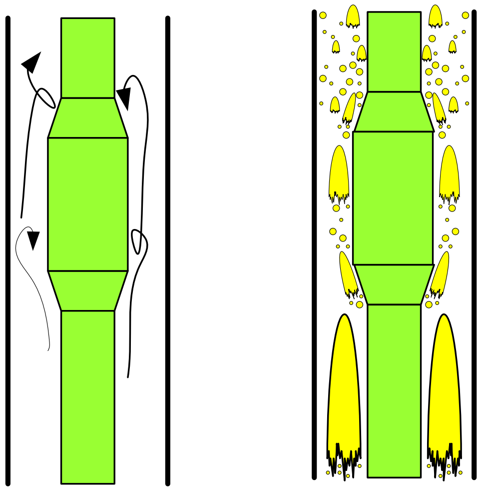


Figure 6-2: Eddies (left) results in fragmentation of gas slugs during flow past tool joints (right).

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), driven only by buoyancy. 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:

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

The fluid mixture density is affected by its composition:

$$\rho_{mixture} = C_{gas} \cdot \rho_{gas} + \left(1 - C_{gas}\right) \cdot \rho_{liq} \tag{6.6}$$

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;

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

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};

$$v_{gas} = q_{gas} / A_{gas} \tag{6.10}$$

$$v^s_{gas} = q_{gas} / A \tag{6.11}$$

From eqn. 6.3 dispersed bubble gas velocity is given by:

$$v_{gas} = 1.2 \cdot v_{mixture} + 0.20 \tag{6.3}$$

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:

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

We further simplify by assuming:

$$C_{gas} \cdot \rho_{gas} = 0 \tag{6.13}$$

Eqn. 6.5 finally reduces to:

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

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 (2012).

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.

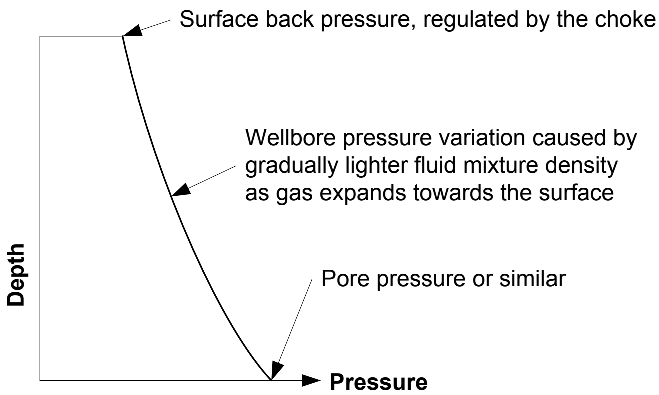


Figure 6-3: Wellbore pressure during stationary two phase flow conditions.

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.

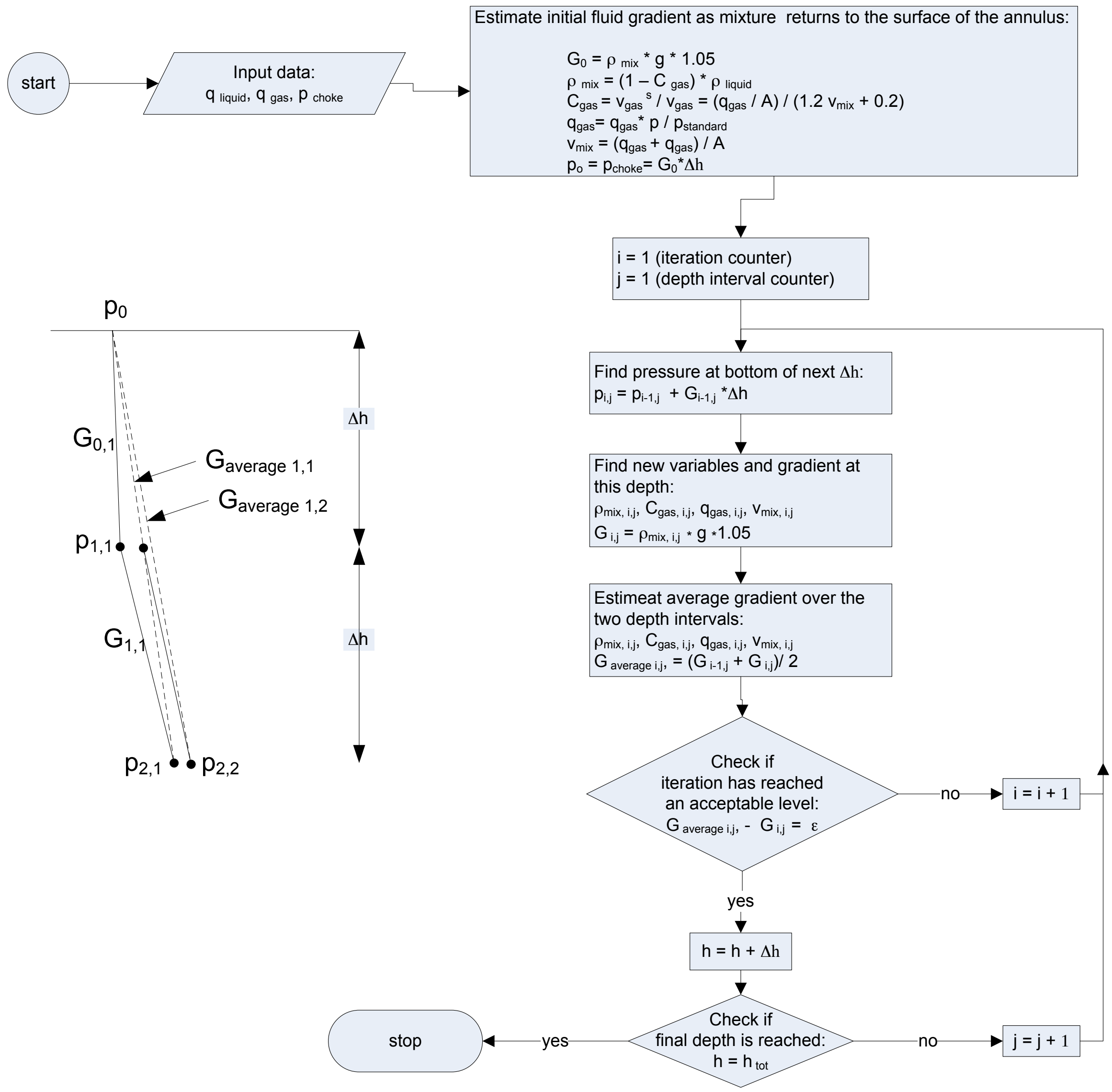


Figure 6-4: Flow chart of estimating wellbore pressure during underbalanced drilling.

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 bottom hole 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, r_{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.

$$m_1 / \rho_1 = V_{tot} - V_{gfl}$$
$$m_1 \quad = \rho_1 \cdot V_{tot} - \rho_1 \cdot V_{g.fl} \tag{6.15}$$

At bottom of well	In annulus at depth z	At flow line (fl)
$\rho_0 = \rho_l$	ρ_1, ρ_g	$\rho_1, \rho_{g,fl}$
$V_{tot} = V_l + 0$	$V_{tot} = V_l + V_{g,z}$	$V_{tot} = V_l + V_{g,fl}$
$C_g = 0$	$C_g = C_{g,z}$	$C_g = C_{g,fl}$

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 m_l from eqn. 6.15:

$$\rho_{fl} = m_l / V_{tot} = \rho_l - V_{g,fl} / V_{tot} \cdot \rho_l \tag{6.16}$$

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

$$\rho_{fl} = \rho_1 - C_{g,fl} \cdot \rho_1$$
$$C_{g,fl} = (\rho_1 - \rho_{fl}) / \rho_1 = 1 - \rho_{fl} / \rho_1 \tag{6.17}$$

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

$$p \cdot V_{g,z} = p_{fl} \cdot V_{g,fl} \, p_{fl} \tag{6.18}$$

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

$$p \cdot C_{g,z} = p_{fl} \cdot C_{g,fl} \tag{6.19}$$

From Eqn. 6.14 we take only the hydrostatic part:

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

Separating the variables and inserting from eqn. 6.19:

$$dp = \rho_l \,(1 - C_{g,fl} \cdot p_{fl} \,/\, p) g \, dz \tag{6.21}$$

Rearranging

$$p \,/ (p - C_{g,fl} \cdot p_{fl}) \cdot dp = \rho_l \, g \, dz \tag{6.22}$$

Integrating from surface to an arbitrary pressure:

$$p \,/ (p - C_{g,fl} \cdot p_{fl}) \cdot dp = \rho_l \, g \, dz$$

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

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

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

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

$$\rho_l \, g \, z - p = C_{g,fl} \cdot \ln \left[(p - C_{g,fl}) \cdot \rho_{fl}\right] / \left[(1 - C_{g,fl}) \cdot \rho_{fl}\right] - 1 \qquad (6.25)$$

Example:

z = 3000 m
ρ_l = 1.5 kg/l
ρ_{fl} = 0.4 kg/l
$C_{g,fl}$ = 1- 0.4/1.5 = 0.73
rgz = 1500 · 9.81 · 3000 = 441.5 bar

The solution is obtained through iteration. We try to guess p_{bottom} = 437.0 bar, a difference of 4.5 bars (441.5 – 437.0).

$$4.5 = 441.5 - 437.0 = 0.73 \cdot \ln (437 - 0.73 \cdot \rho_{fl}) / (1 - 0.73 \cdot \rho_{fl}) - 1 = 4.39$$

We are sufficiently close to have proven the point and that $p_{bott} \cong 437$ bars. 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.

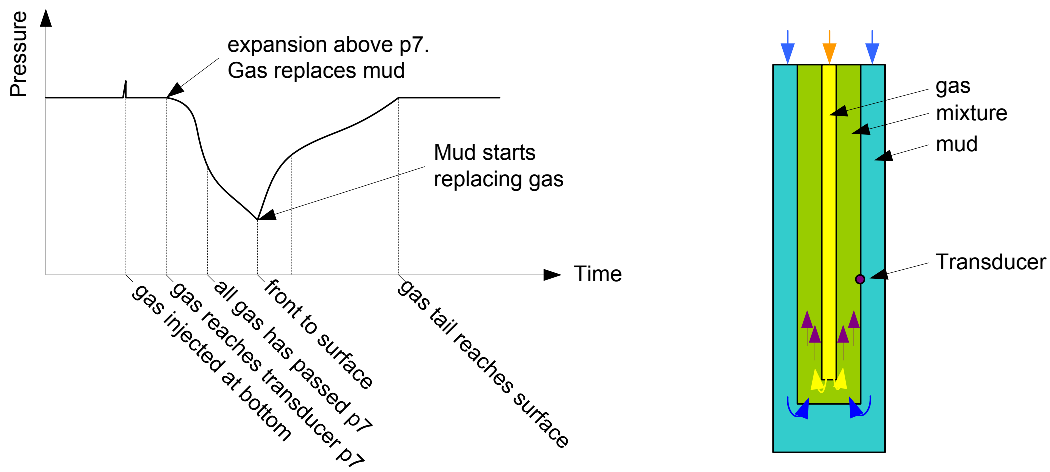


Figure 6-6: Pressure recorded at pressure transducer # 7 during and after injection of one gas bubble in still standing liquid. Relative position of transducer p7 is shown to the right, positioned in the annulus where two phases are flowing by.

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.

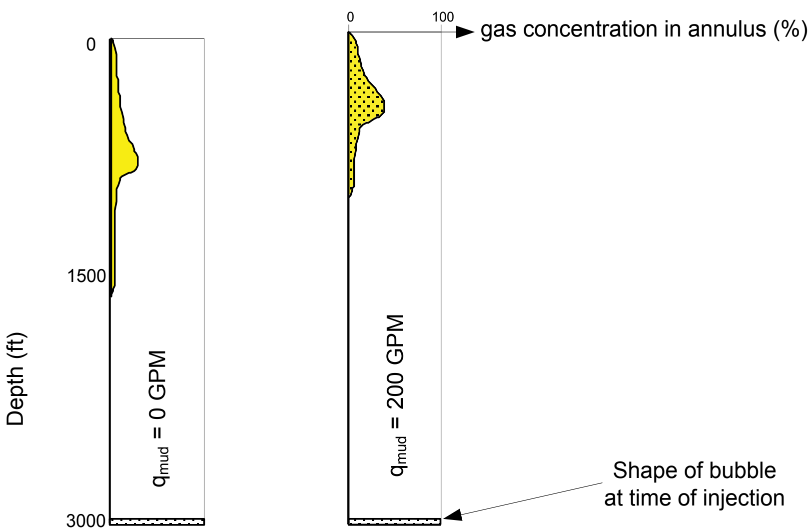


Figure 6-7: The stretching effect of a gas bubble as it moves towards the surface. The gas moves upwards in a still standing fluid column (left) and in fluid, which is flowing at a rate of 200 GPM (right).

If real gas bubble behavior is compared to ideal 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:
    a) The gas concentration profile of the cross section coincides with the mud velocity profile, causing gas to travel 20% faster than the liquid alone.
    b) 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.

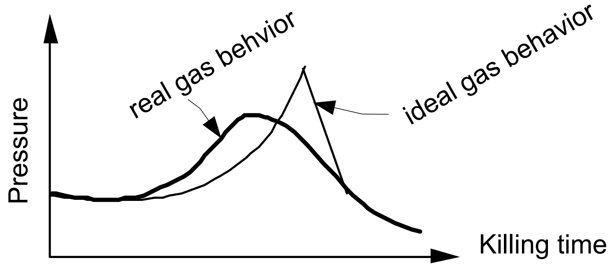


Figure 6-8: Annular surface pressure variation of a standard killing operation (the gas follows the mud) compared to a more realistic behavior.

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 dissolved sodium chloride ions in water.

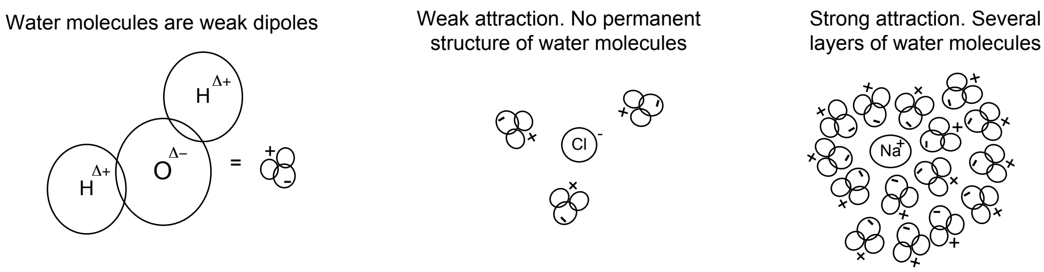


Figure 6-9: Hydration of sodium chloride in water. In still standing water several layers of water molecules will form around the ions.

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 reduce 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.

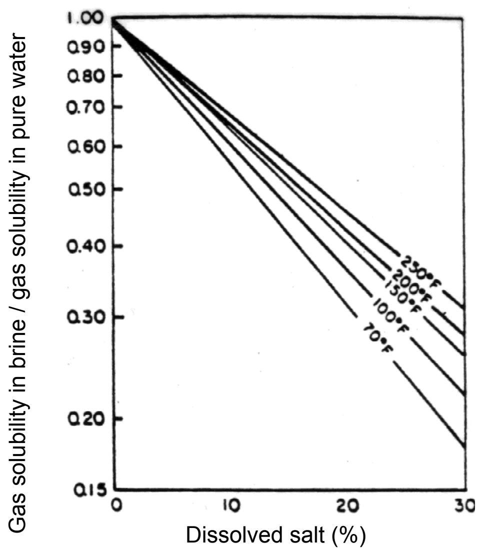


Figure 6-10: Correction of gas solubility for salt content (Petrucci (1989)).

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.

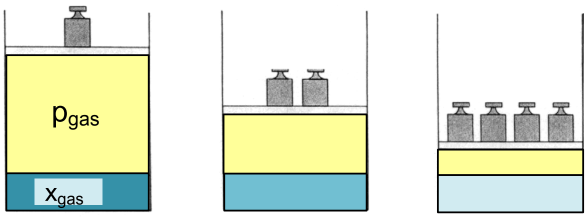


Figure 6-11: Effect of pressure of the solubility of a gas. The solubility of gas molecules in the liquid solvent increases with increased pressure – the color become lighter (free after Petrucci (1989)).

In 1803 the English chemist William Henry proposed the generalization (in eqn. 6.26) 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. The proportionality is taken care of through Henrys constant H:

$$x_{gas} = p_{gas} / H \quad [mol_{gas} / mol_{liq}] \tag{6.26}$$

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

$$m_{gas} = x_{gas} \cdot \frac{M_{gas}}{M_{liquid}} \qquad [g_{gas} / g_{liq}] \tag{6.27}$$

where M_{gas} is mol weight of gas [g_{gas}/mol]. Combining eqn. 6.26 and 6.27 yields:

$$m_{gas} = p_{gas} / H \cdot \frac{M_{gas}}{M_{liquid}} \left[g_{gas} / g_{liquid} \right] \tag{6.28}$$

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).

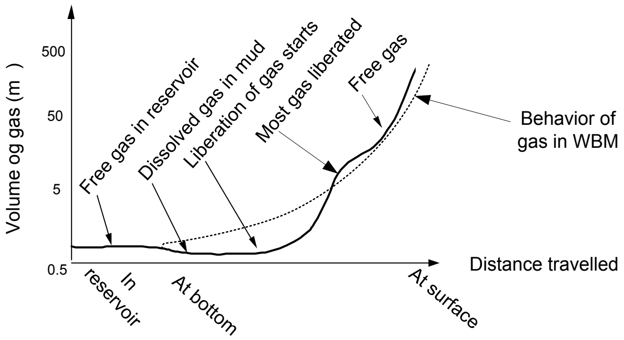
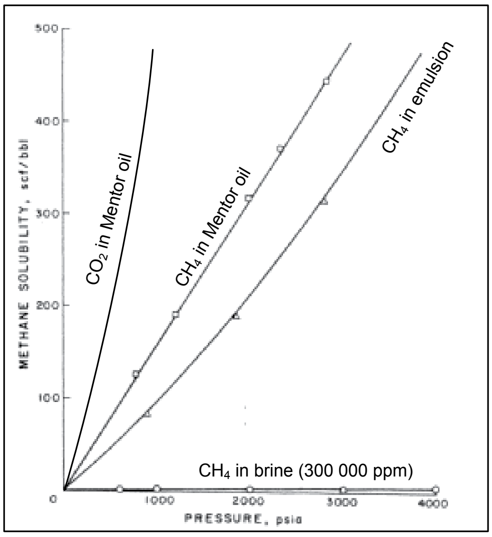


Figure 6-12: Volumetric behavior of 200 kg liquid methane swabbed in during connections while tripping out, dissolved in OBM and later circulated out, undetected until liberation.

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.



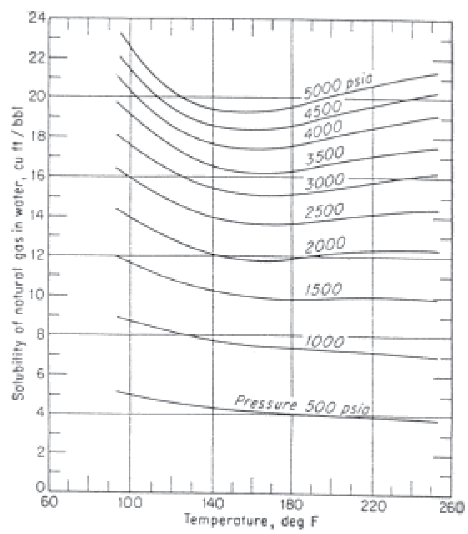


Figure 6-13: Gas solubility in Mentor 28 oil, in emulsifier and in 300,000 ppm brine at room temperature. Here oil field units of gas/oil ratio (GOR) are applied. Methane solubility in water (is shown to the right).

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 wellbore:

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

If $R_s \leq R_{s.saturated}$ 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, $R_{s,saturated}$.

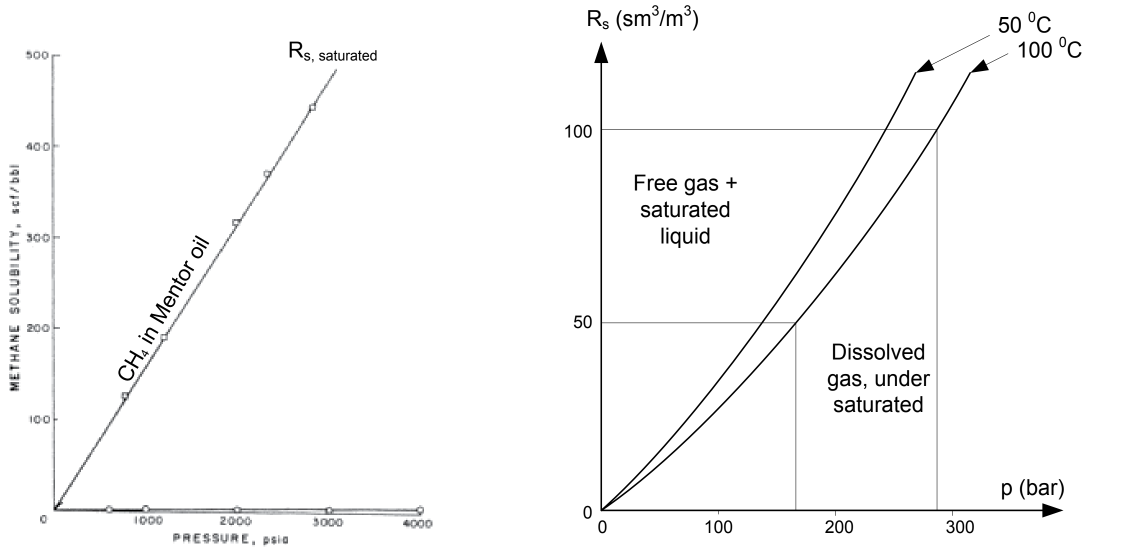


Figure 6-14: R_s for CH_4 in Mentor oil vs. well pressure. In figure to the right data points above the saturation curve indicate free gas in fully saturated base oil.

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:	2 000 m
Influx period	3 minutes
Mud pump rate:	2 000 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: $1500 \cdot 9.81 \cdot 2000 = 294 * 10^5$ Pa

Mud volume pumped: $2\ m^3/min \cdot 3\ min = 6\ m^3$

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

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. With given mud density this corresponds to a depth of around 1 140 mTVD.

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.

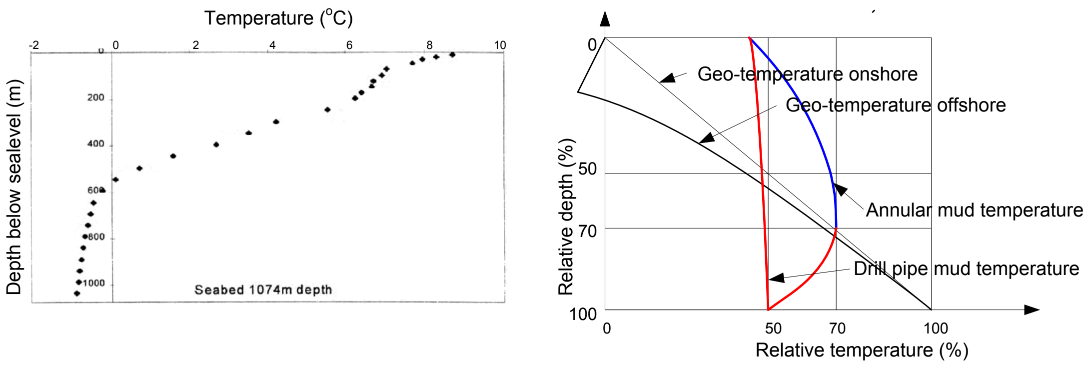


Figure 7-1: Typical temperature profile in deep oceans (left). Generalized (right).

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.

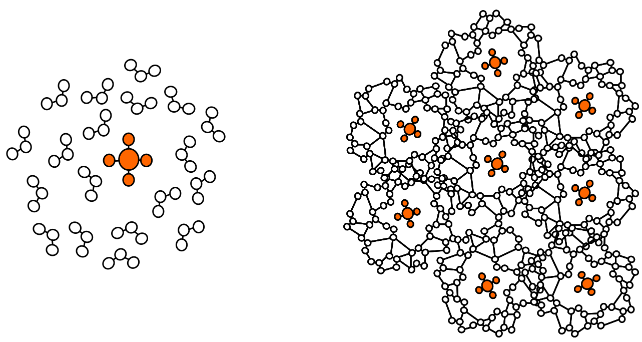


Figure 7-2: Gas hydrate: Dipolar water molecules are forming around a guest molecule (left). Water molecules become hydrogen bonded (right), forming a hydrate crystal structure.

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.

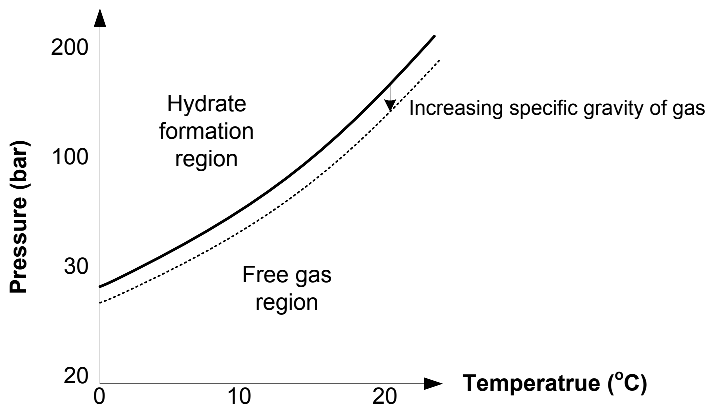


Figure 7-3: Effect of temperature, pressure and gas composition on hydrate formation.

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
- During formation hydrates extract free water from the drilling mud, causing the mud 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:

1. *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.

2. *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 is 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:

1. Close BOP below opened choke/kill line
2. Circulate mud for a while
3. 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 is estimated in Chapter 4.1.4.

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 due to its expansion potential. 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.

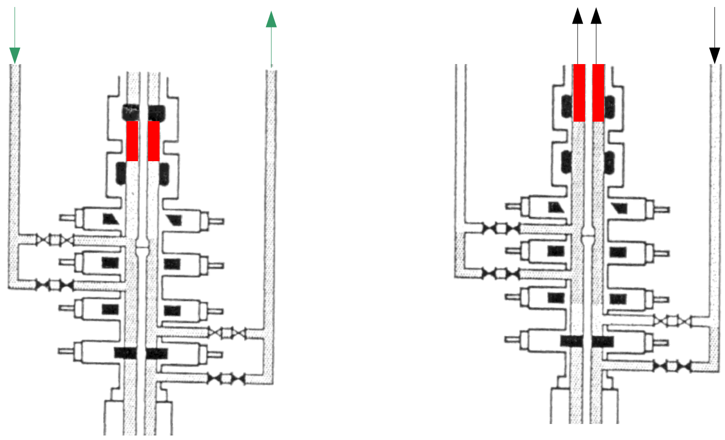


Figure 7-4: Gas trapped in BOP. Procedure to remove it is indicated. Left: Circulate to prepare for removing gas; circulate out through the riser-annulus and out through the surface diverter (right).

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 weak zone above 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.

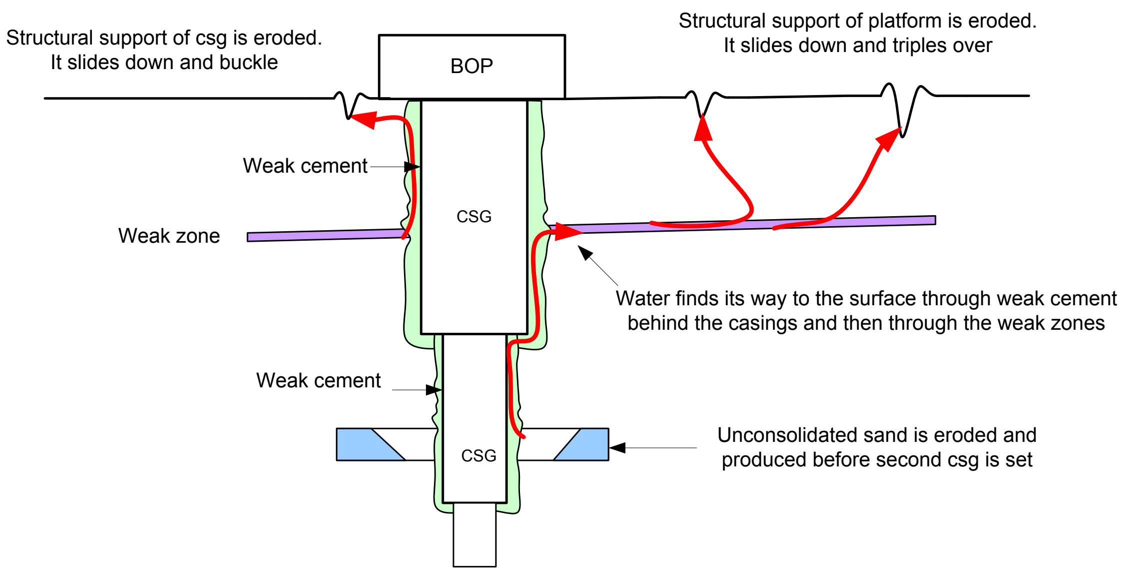


Figure 7-5: The SWF problem.

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.

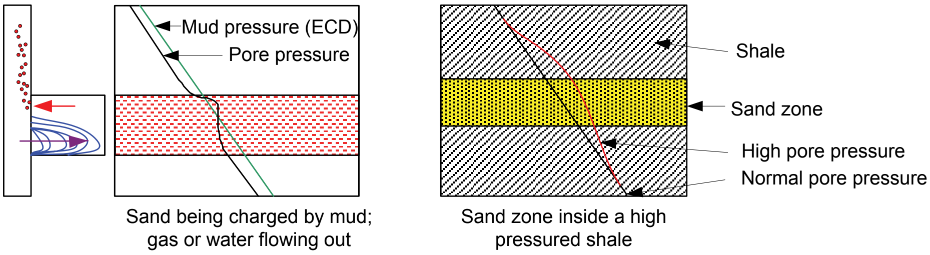


Figure 7-6: A small and permeable sand being charged by high ECD (left). Geo-pressured sand (right).

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 bottomhole 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.

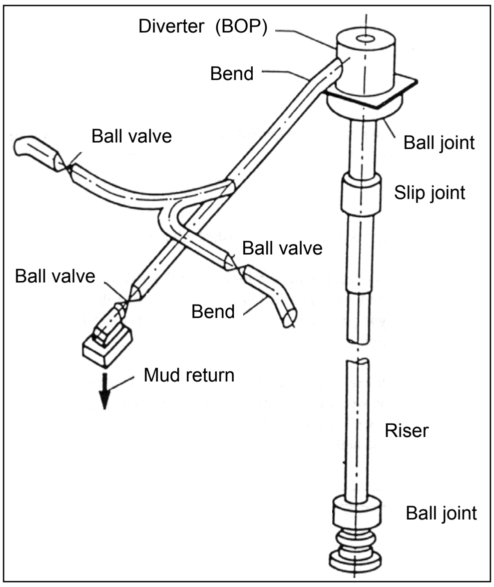


Figure 7-7: Gas diverter system.

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.

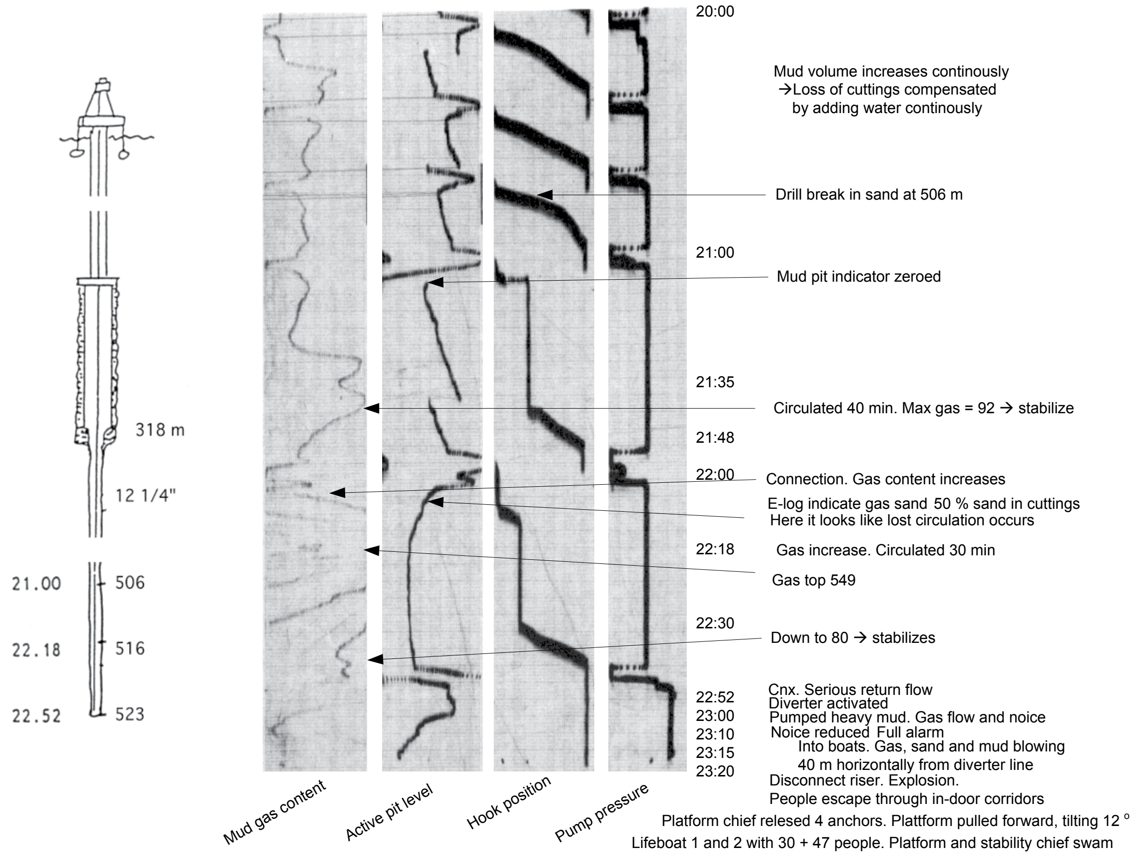


Figure 7-8: Summary of the shallow gas blowout on Haltenbanken, October 6, 1985, with comments to the mud log from investigators.

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

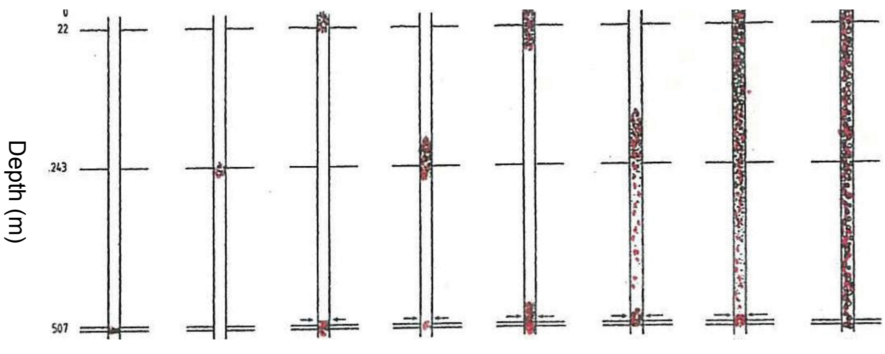


Figure 7-9: Hypothesis of cause behind the blow out: Shallow sand was being charged by the ECD and later feeding gas from it during connections.

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.

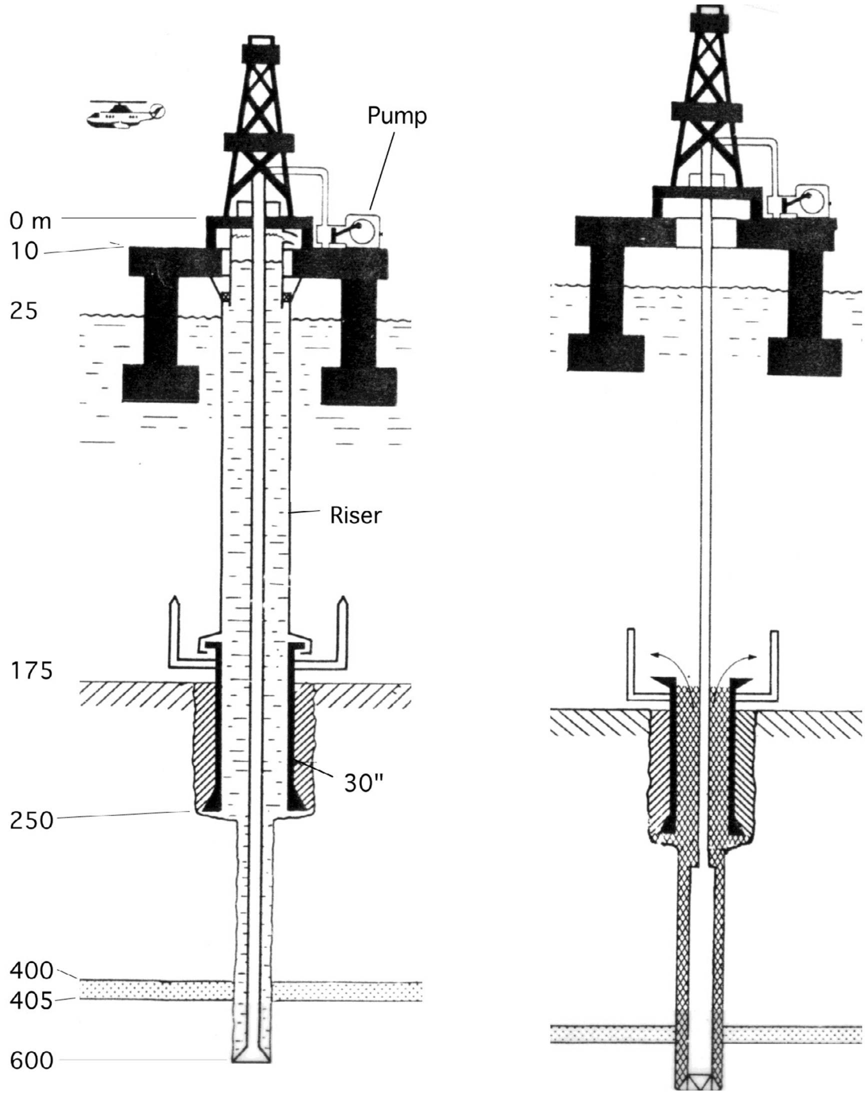


Figure 7-10: Offshore drilling before and after 1986.

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 fewer 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.

7.3.3 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.

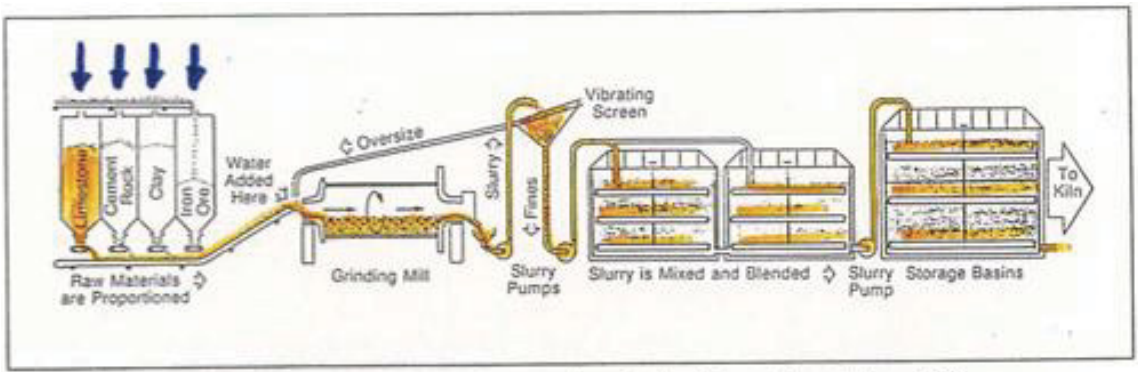
8.1.1 Composition & hydration

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

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

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).

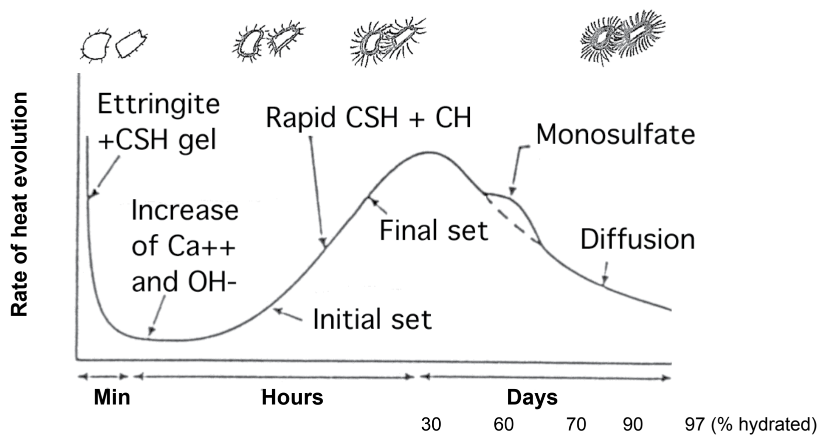
In Figure 8-1 the first step of industrial production of cement powder is presented, the so called wet process.



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).



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 in-penetrable 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:

- density
- filter loss
- rheology

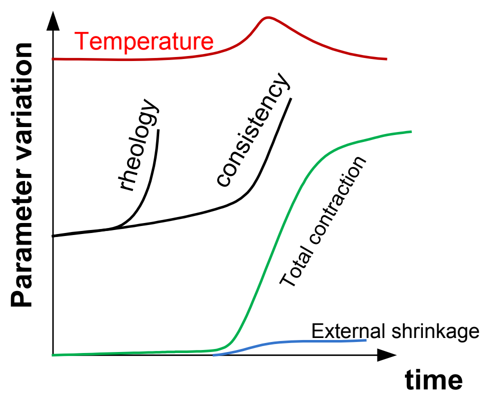


Figure 8-3: Some parameters measured in the laboratory.

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 largely Influenced by temperature. **8-3:**

8.1.3 Additives and their effect

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

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	reduce 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

Table 8-2: Cement slurry additives.

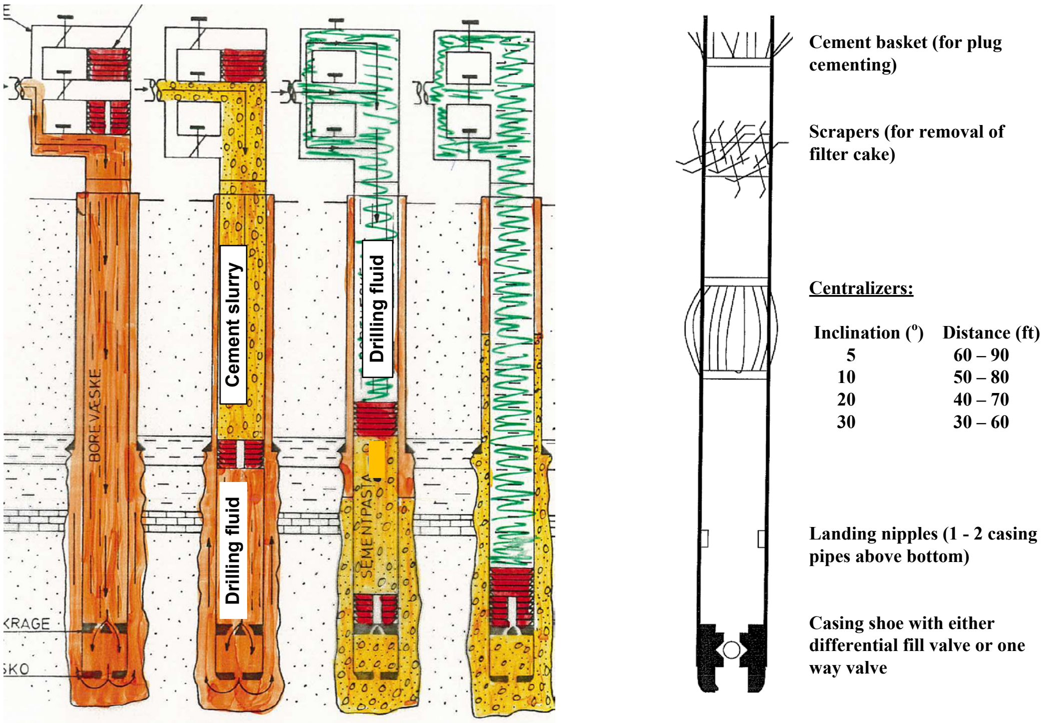
All additives will reduce the strength of the hardened cement. However, all the parameters, like the permeability of the cement are equally important parameter, and need special attention with respect to gas migration resistance.

8.2 Cementing operations

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

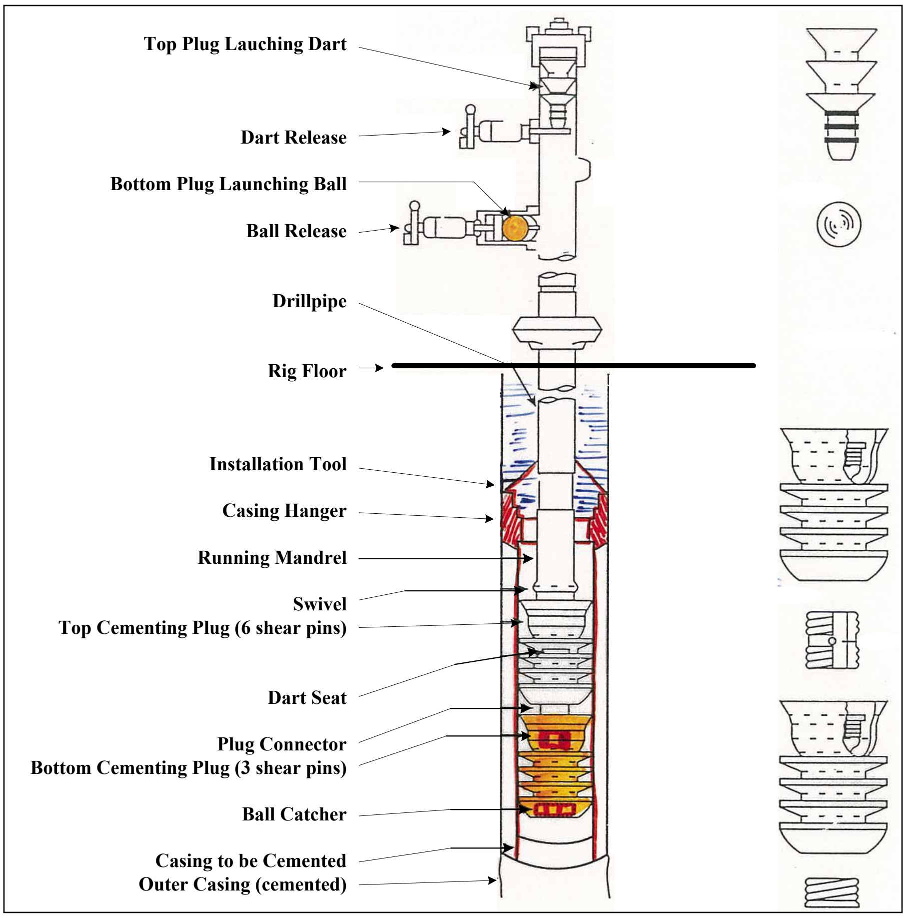
8.2.1 Cementing techniques

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



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 a 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).



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 a no-slip condition 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.

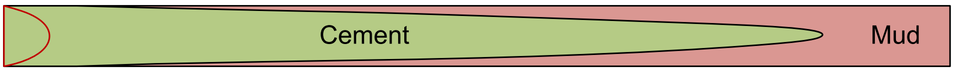


Figure 8-6: Initial velocity profile (left) and resulting displacement profile.

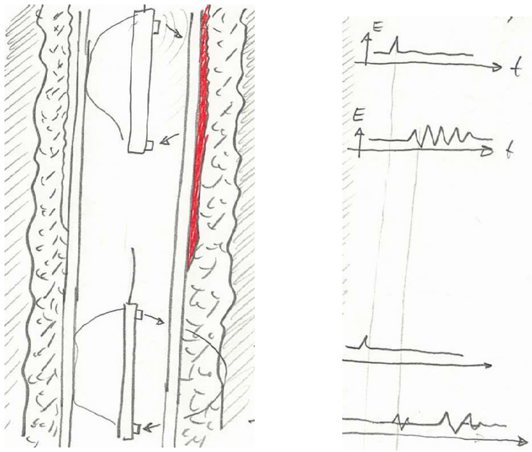
8.2.2 Job evaluation

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.



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.

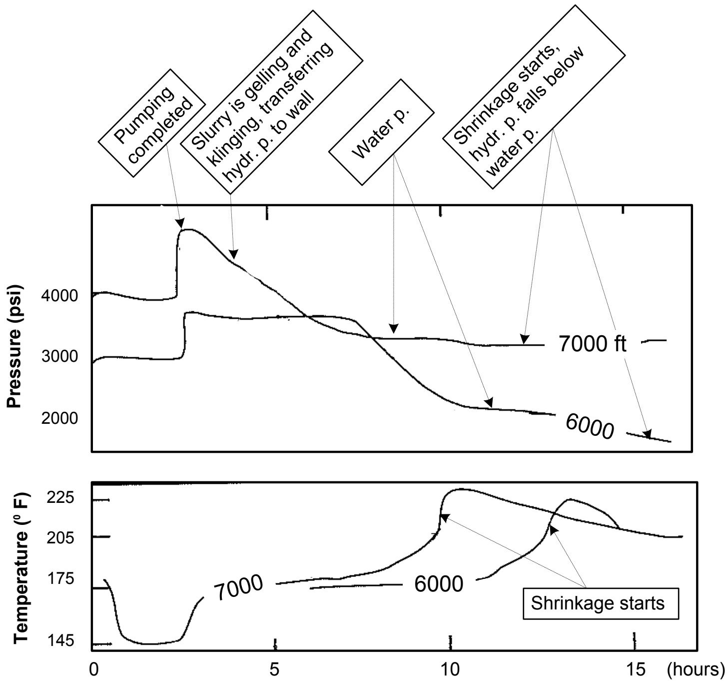


Figure 8-8: Annular pressure and temperature measurements from external casing sensors (from Exxon, 1982).

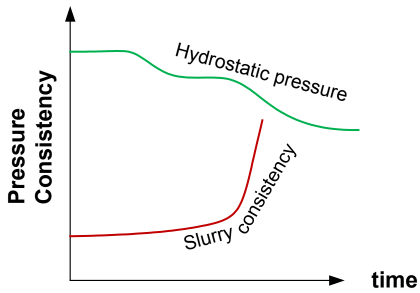


Figure 8-9: Annular gas flow test results.

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 loses 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 inter-granular forces mainly because of inter-particle 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, inter-granular 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.

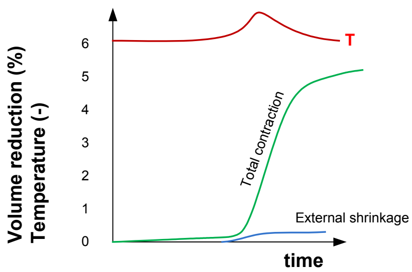


Figure 8-10: Typical contraction and external shrinkage.

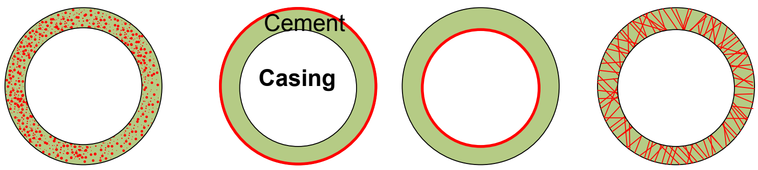


Figure 8-11: Three routes of the cement; through pore structure (left), along weak bonds and through cracks sometime after setting.

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.

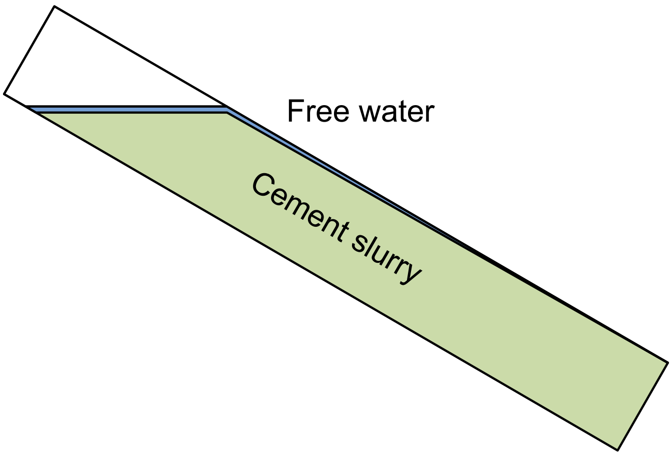


Figure 8-12: Schematic diagram showing fully developed water channeling.

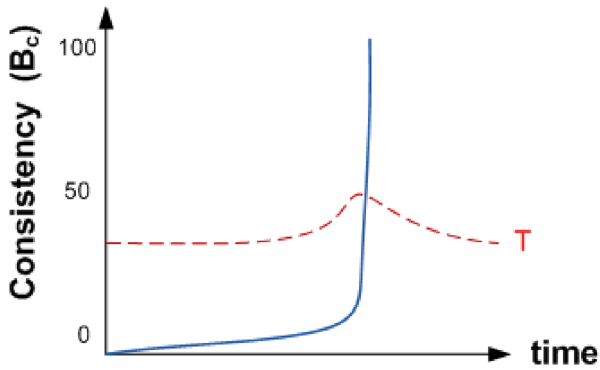


Figure 8-13: Pressurized consistometer output from Right-angle-Set cement system.

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:

⁰ Low fluid loss and low free water
⁰ 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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Drilling service companies:

Geosevices http://www.geoservices.com/
Halliburton http://www.halliburton.com/
M-I Swaco http://www.miswaco.com/
Schlumberger http://www.slb.com/

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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)
N	number
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:

Δ	difference
ε	relative elongation
μ	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
Hp	Horse Power
HTHP	High Temperature High Pressure
LCM	Lost Circulation Material
LOT	Leak Off Test
LWD	Logging While Drilling
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
SBM	Synthetic Based Mud
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	KW	W	745.7
	Temperature	T	ºF	ºC	ºK	(ºF-32)/1.8