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Exercises in Pressure Control During Drilling

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Contents

Preface

These exercises have been made to fit the content of the book Pressure Control During Oil Well Drilling (http://bookboon.com/no). In present exercise book all the exercises have been solved by students in the corresponding course at the Department of Petroleum Engineering and Applied Geophysics at NTNU of Trondheim, Norway, and revised in 2015. If still any unclear formulations occur, it would be appreciated if the readers contacted me at pal.skalle@ntnu.no along with comments to this collection of exercises.

Pål Skalle
Trondheim, May 2015

1 Formation Pressure

1.1 High pore pressure zone

a) Define the term High Pore Pressure, also referred to as abnormal pore pressure.
b) List geological key processes involved in the forming of high pore pressure and its seal over a wide geological timeframe and discuss each process briefly.
c) Characterize the transient zone, from normal to high pore pressure by its mechanical stresses, permeability and porosity.
d) Describe each of the following recorded parameters while drilling through high pore pressure zones.

- drilling operational process-parameters
- logging-parameters of any kind

e) Discuss the equation. ROP = K · $e^{a_3 D} \cdot e^{a_4 D(ECD - \rho_{pore})}$.
f) Explain the term Dynamic Hold Down, a term used while drilling in sedimentary rocks. What effect does that term have on the drilling operation?
g) Can drilling engineers utilize the three ROP-terms from the question in task e) in any beneficial manner?
h) Define first normal formation pressure. Explain then briefly the following concepts, related to abnormal pressure; Artesian water, Under-compaction, Clay diagenesis, Tectonic area.
i) Explain how Darcy law is involved in determining the **magnitude** of the equivalent pore pressure density. How far above normal pressure, as defined by the salt water density, can it rise?

1.2 Sedimentary formation pressure

Give a physical explanation of why the pressure gradients typically vary between the two extremes as indicated below. Gradients are listed in terms of equivalent density (kg/l). Discuss which parameters and which geological processes that have resulted in this number.

Support your discussion of the two extremes by mathematical relationships if appropriate:

a) Pore pressure gradient: 1.025 – ρ_{frac}
b) Overburden gradient: 2.0–2.7
c) The effect of sea water depth can be commented separately.

During drilling it is essential to detect high pressure zones. We know that the zone's porosity has high importance for this task.

d) Why is porosity so high in high pressure zones?
e) Select 5 methods or tools for pore pressure detection and explain principally how the formation's porosity influences the result.
f) Why is the in-situ overburden different from the one we report from rotary kelly bushing-level?

1.3 Porosity. Overburden. Sonic log

The sonic data presented in Figure 1-3 are recorded in an offshore well, in 500 m sea depth.

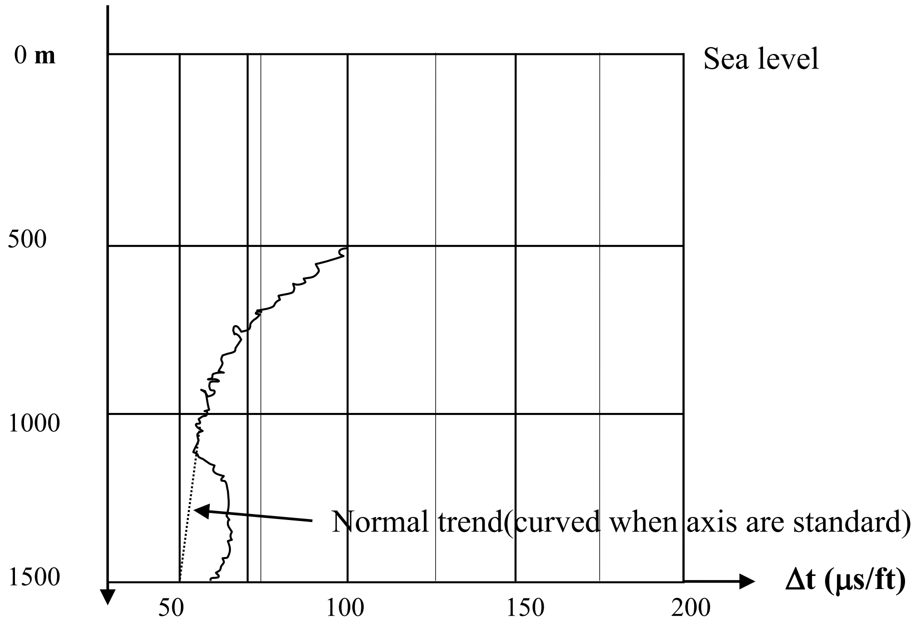


Figure 1-3: Sonic log example.

Your task is to find the following parameters at all depths, but especially at 1500 m;

a) Determine the porosity: Assume linear relationship between porosity Ø and transient travel time; $\rho_{in\,situ} = \rho_{matrix} \cdot (1-Ø) + \rho_{liquid} \cdot Ø$. Travel time in compact shale (zero porosity) is 47 ms/ft and 200 ms/ft in pore water.
b) Determine the overburden pressure and the equivalent gradient: Assume that compact shale has a density of 2.8 kg/l. The air gap between RKB and the sea level is 30 m.

1.4 Porosity. Overburden. Sonic

Sonic log data are shown in Figure 1-4, recorded in formation starting at 600 m and one starting 1500 m of sea depth, after performing calibration tests in the sea water. Assume a third data set was available, recorded onshore, and, for the sake of comparison, that the sonic velocities are the same for the onshore sediments as for the off shore sediments (not really true since compaction would probably be different for on- and offshore, but acceptable assumption for comparison purposes).

a) Find first the local overburden density (the data in Table are difficult to read. Use your interpreting ability).
b) Find then the equivalent, ρ_{ovb}, where the logged formation were placed onshore, (i.e. 0 m water depth), under 600 m and under 1500 m of water. Plot results for three conditions: 0, 600 and 1 500 m water depth. Distance from RKB and to the surface is 32 m. Start by finding the average velocity for every 500 m interval and select an arbitrary midpoint in the intervals. The first midpoint, between 0–600 m could be at 332 m, the next one at 832 m etc.
c) Find pore pressure at 2 500 mRKB (in 600 m sea depth) by means of sonic log (Eaton's method), ρ_{ovb} is assumed constant = 2 kg/l.
d) Find fracture pressure for the same case as in c, under the assumption that the Poisson's ratio = 0.25, and ρ_{pore} = 1.73 kg/l.

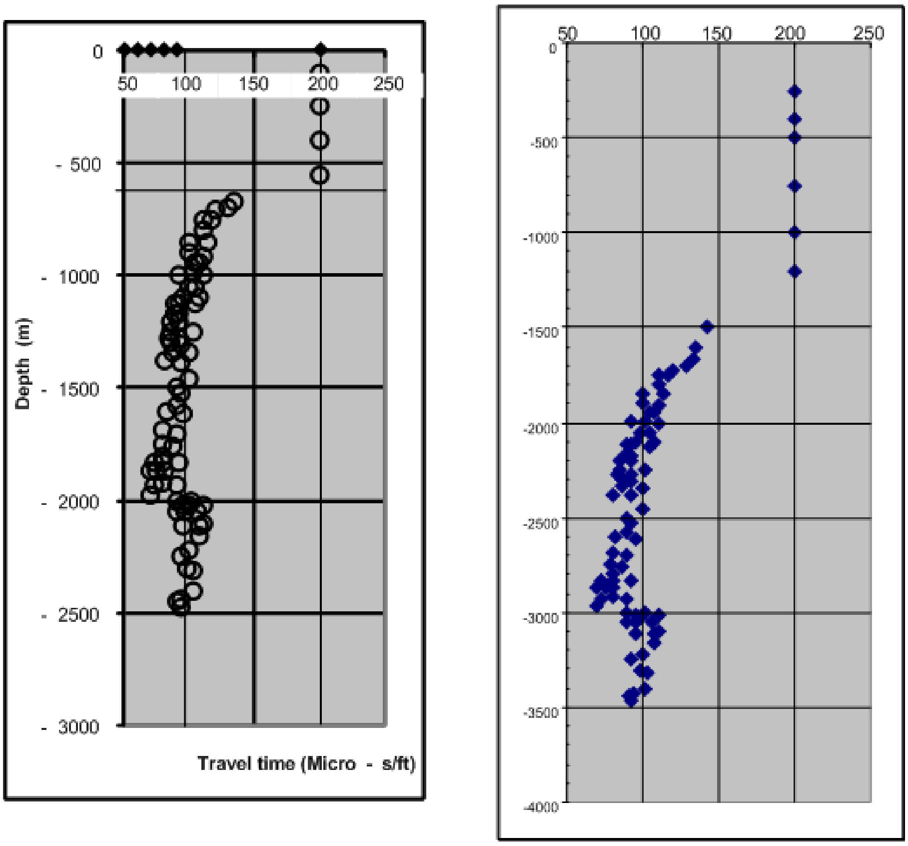


Figure 1-4: Sonic travel time in 600 (left) and 1500 m sea depth. Δt_{fluid} = 200 ms/ft, Δt_{matrix} = 47 ms/ft.

1.5 Pore pressure detection

a) On the Thursday's morning meeting you are asked to make an overview of methods of how to detect high pressure formations during exploratory drilling. The work has been initiated as indicated in the table below. Give a short description of the methods and its main pros and cons like indicated.

Method	Description and pros (+) and cons (-)
ROP	Normally the operator is applying constant WOB and RPM. An increase in ROP indicate either softer formation or, if lithology is constant, an increase in pore pressure. + Easily recordable; + Immediate response – Δp_{pore} is masked by changes in other drilling parameters

b) Explain why the pore pressure may be different in two different sedimentary, onshore formations at identical depth.

c) Explain 3 indications of when the well is being actually in underbalance.

d) Explain the change of ROP in Figure 1-4.1.

e) How is it in general possible to establish a normal trend line for the ROP parameters or other drilling parameters with respect to estimating the pore pressure? What requirements are necessary?

f) How is the difference between the mud pressure and the pore pressure preserved, an important piece of information for detection of high pore pressure?

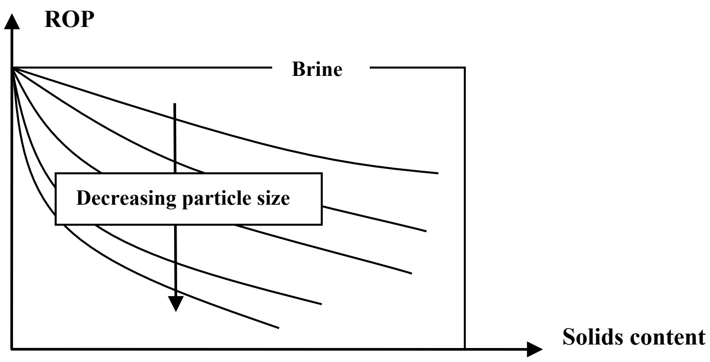


Figure 1-4.1: ROP decreases with increasing solids content (brine contains no particles) and with decreasing particle size. Solids content and mud density are proportional.

g) Find the pore pressure on basis of the sonic log data at 2000 m depth, from Figure 1-4.2. Use Eaton's formula:

$$\rho_{pore} = \rho_{ovb} - \left(\rho_{ovb} - \rho_{pore,n}\right)(\Delta t_n / \Delta t)^3$$

Derive or assume all necessary models and factors. The data from Figure 1-4.2 are taken from an offshore field. Due to the influence of the water column, the equivalent overburden density is only 1.75 kg/l.

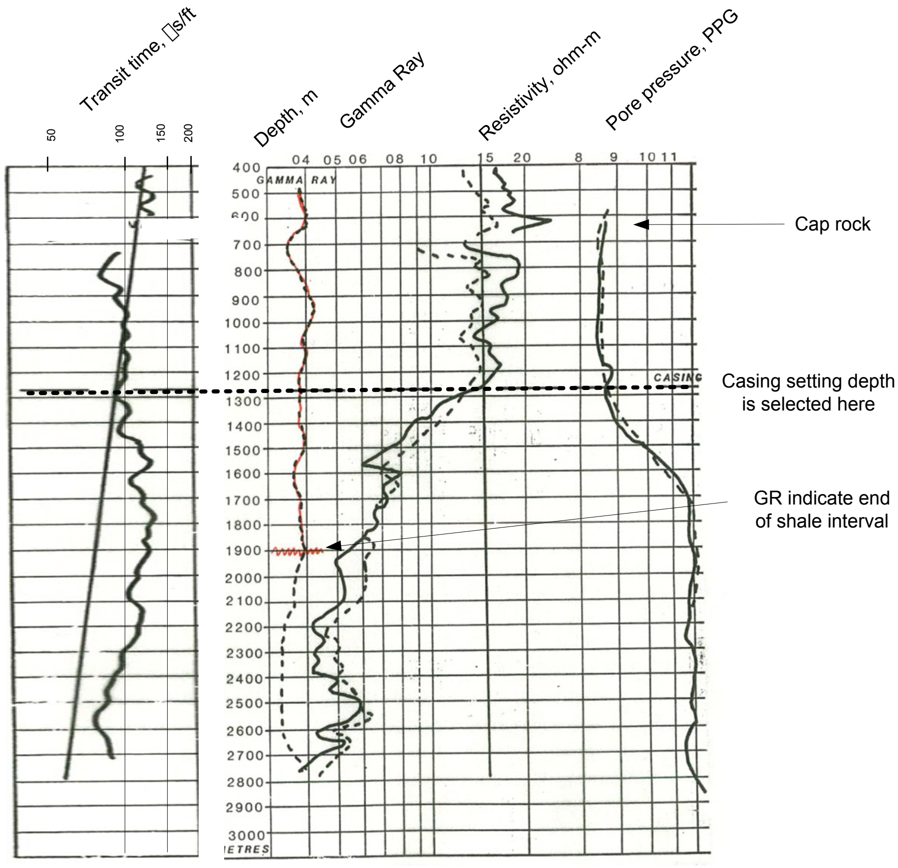


Figure 1-4.2: Logging through a high pore pressure transition zone.

1.6 Pore pressure, d_c

The 17.5″ section of a wildcat well was drilled in the Barents Sea. Applying seawater as mud, a WOB at 40 000 lb_f and rotary speed at 90 rpm; the ROP was averaging between 14 and 12 m/h at the depth from 600 to 1 500 m as shown in Figure 1-6. At the depth of 1 600 m the gradual decline in ROP took an increasing trend. At the depth of 1 750 m an eruption of mud through the rotary table took place. The inexperienced drilling crew hadn't noticed any changes in the operational parameters and the kick came therefore as a surprise.

While attempting to close the BOP, the well was already blowing gas, mud and sand. It turned out that the sealing elements were damaged, and the BOP could not be seated properly; the shear ram had to be activated. Six days in total were lost by killing, fishing and repairing before drilling could be resumed.

In the following evaluation-meeting it was agreed that this kick should not have been a surprise. A task force was set up to investigate the problem. One specific question was: Could the increased pore pressure have been avoided if the d_c exponent method had been applied?

The task force was therefore assigned the responsibility of estimating the true formation pressure from 1 600 to 2 300 m by means of the d_c method. Pore pressure was known to be normal (1.04 kg/l) down to 1 600 m. The 12.25″ hole section started at 1 750 m with the same drilling parameter as above, except for the mud weight which was increased from 8.8 to 10.5 PPG.

At the depth of 2 000 m the mud weight was increased to 13 PPG, and the well drilled at a constant WOB of 50 000 lb_f and 90 rpm. ROP continued to increase and reached an average value of 15.5 m/h at 2 100 m, where it stabilized. Assume ρ_{ovb} to be 2.2 kg/l.

Without a pc (at the exam) we simplify by assuming the ROP develop linearly between selected depth points.

a) Find the d-exponent at as many points as necessary
b) Find the d_c-exponent in the same points
c) Draw a graph and estimate pore pressure at 2 000 m.

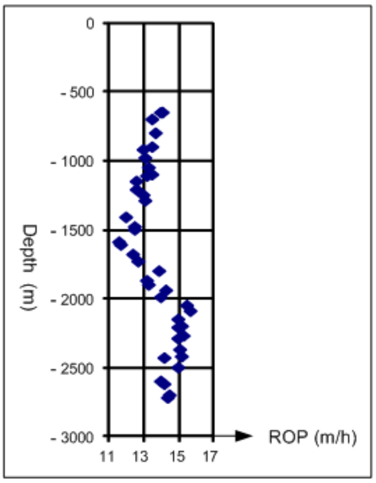


Figure 1-6: ROP in a well in Barent Sea. 600 m water depth.

1.7 Pore pressure detection. d_c Overlay curves

By means of overlay curves placed on top of the d_c curve on transparent paper, it is possible to read the pore pressure directly. Make overlay curves based on overburden data in offshore formations below 1 500 m water depth. The d_c is estimated and presented in Figure 1-7.

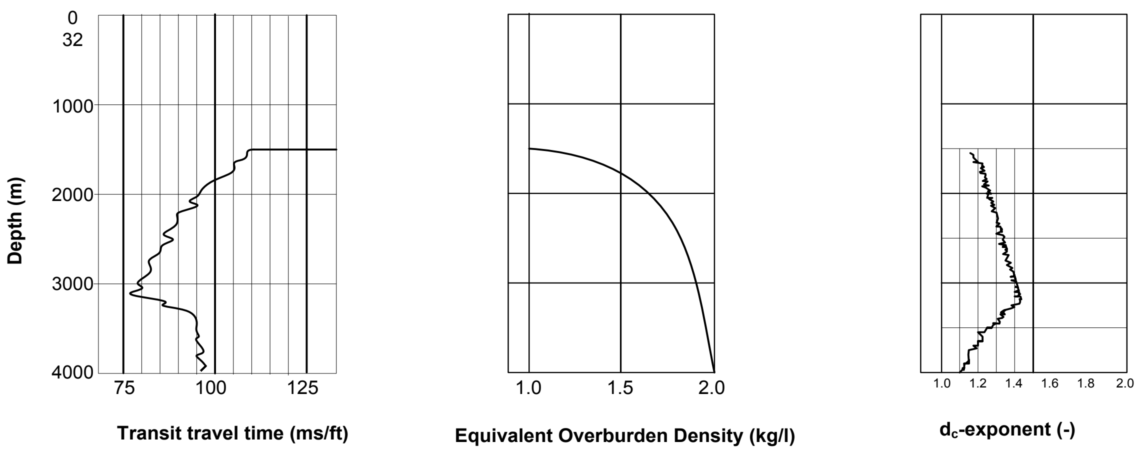


Figure 1-7: Sonic log, overburden and d_c-plot.

1.8 Fracture pressure. Poisson's ratio.

a) Give a physical explanation of why the fracture gradients typically vary between the two extremes as indicated below. Gradients are listed in terms of equivalent density (kg/l). Support your discussion of the two extremes by mathematical relationships if appropriate:

Fracture gradient (Eaton): From 1.33 to ($\rho_{ovb} - \rho_{pore}$)

$$p_{frac} = p_{pore} + \sigma_{min}, \qquad \sigma_{min} = \frac{\mu}{1-\mu} \cdot \sigma_z$$

b) Prove that the Poisson's ratio is equal to 0.5 for elastic materials for small (1%) deformations (compression). Use a cylinder with diameter d and height h for this purpose.

c) Why is Poisson's ratio < 0.5 for sedimentary rocks?

1.9 Fracture pressure. LOT

a) Explain as detailed as possible all the information we can get out of a complete Leak Off Test.

b) The 13 3/8″ casing is set at 2 400 m vertical depth. The mud weight is 1.32 kg/l. During the Leak Off Test (LOT) the surface pressure started to level off at 60 bar as shown in Figure 1-9. Calculate the LOT and translate it into equivalent mud weight.

c) Discuss the slope of the pressure – volume curve before the leak off pressure is reached.

d) Explain in detail the reason behind the need of pumping 84 liters (before fracturing) in Figure 1.10-4 (see next exercise). What would be the practical consequence of a LOT if the mud was a) oil and b) water? Compressibility of oil and water are $11.2 \cdot 10^{-10}$ and $4.58 \cdot 10^{-10}$ Pa^{-1} respectively, at 20 °C.

e) Drilling continued to 2 800 m, and the mud weight was increased to 1.38 kg/l. What is the MAASP before and after changing the mud weight?

f) Discuss the possibility of elevating the fracture pressure in the next wellbore section, in order to improve the narrow pressure margin while killing a well.

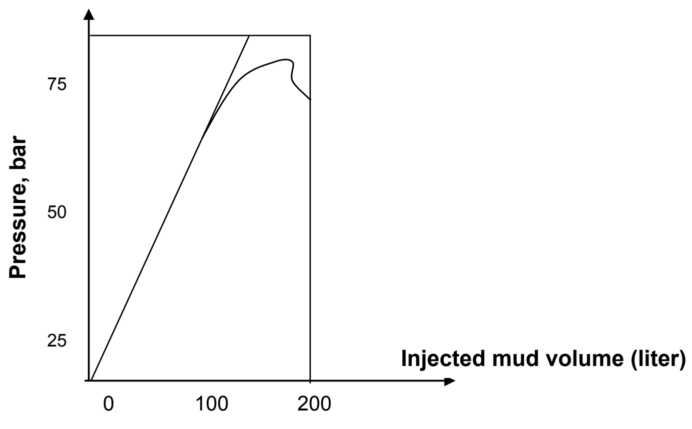


Figure 1-9: Pump pressure variation during LOT.

1.10 Fracture pressure from field data

a) In two wells, 34/10-11 and B-103, at a depth of 2 200 m (7 218 ft) the pore pressure gradient is 1.53 and 1.3 respectively (see Figures 1.10-1 and 1.10-2. The formation overburden density is also seen here. Find the fracture gradient for the two wells at this depth (use Eaton method). The Poisson number μ is given in Figure 1.10-3 (use Gulf Coast data).

b) Apply data from well 34/10-11 and its leak-off data for the 20″ and 16″ casings in Figure 1.10-4 and 1.10-5 respectively, to estimate fracture gradient at respective casing shoe depths.

c) Evaluate the oil company's selection of casing setting depths in well 34/10-11. They are shown in Figure 1.10-1. Select the trip margin as defined by the difference between mud density and pore pressure in Figure 1.10-1, and use a kick margin of 0.05 kg/l.

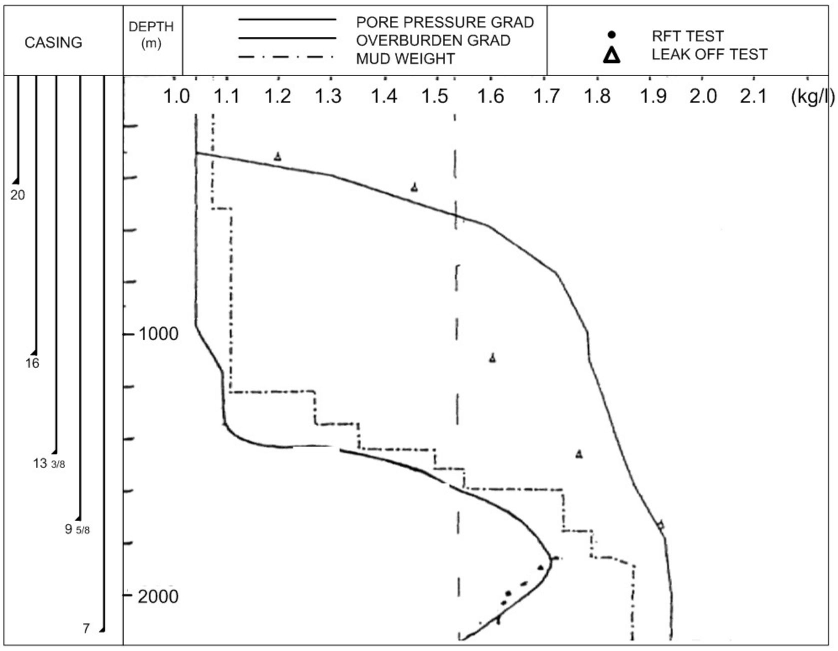


Figure 1-10.1: Well 34/10-11.

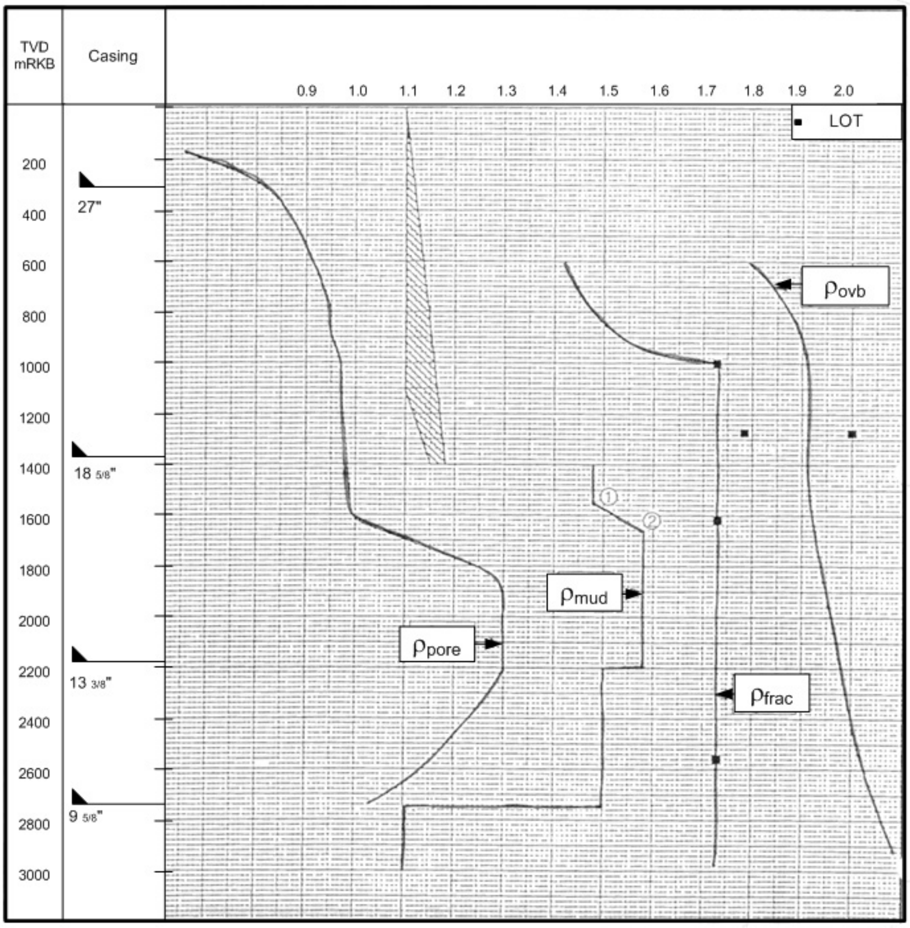


Figure 1-10.2: Well B-103. Pressure prognosis.

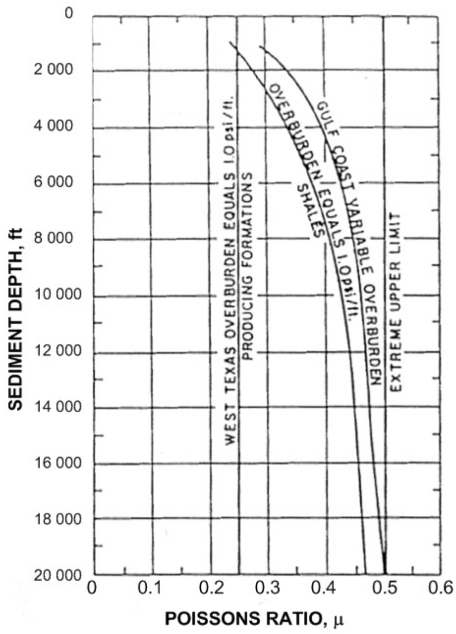


Figure 1-10.3: Typical offshore Poisson's ratios.

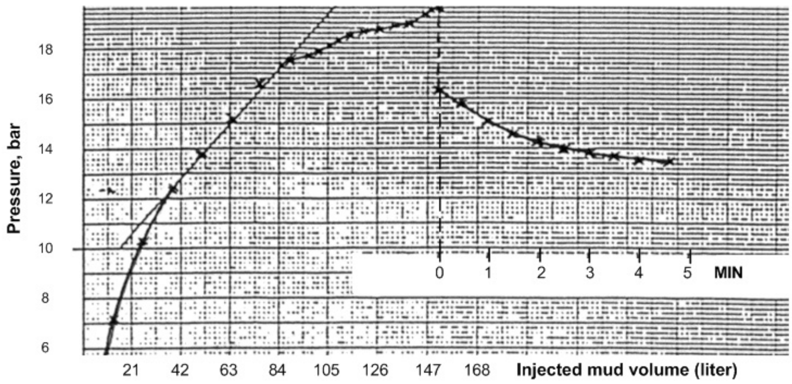


Figure 1-10.4: Leak-off test below the 20" casing shoe. Well 34/10-11.

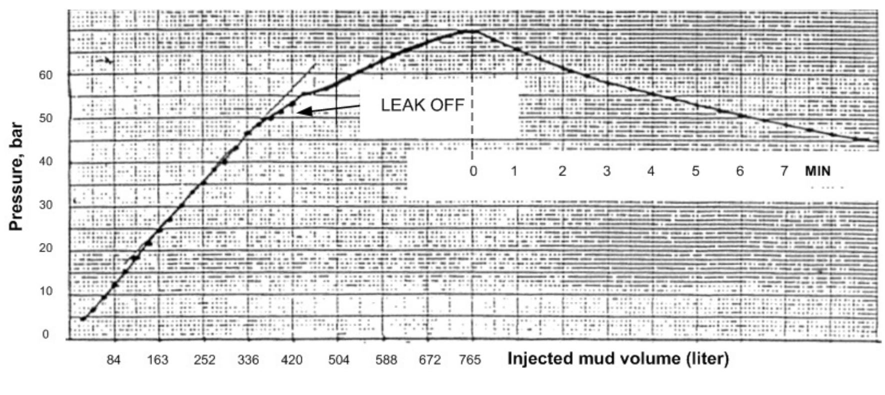


Figure 1-10.5: Leak-off test below the 16" casing shoe. Well 34/10-11.

2 Killing operation

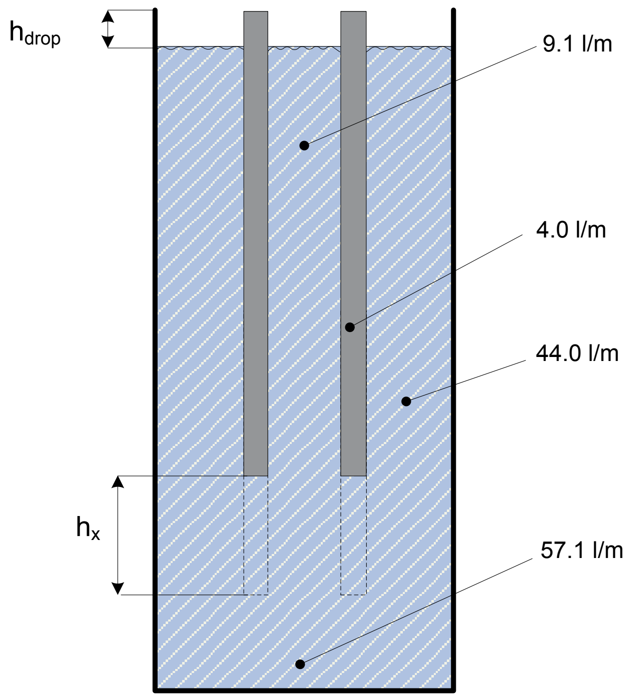
2.1 Preparing for kick

a) How is primary well control maintained in a well?

b) Mention 6 examples of how primary well control may be lost.

c) When pulling out of the casing, it was not being re-filled with mud. See data and figure below:

- DP capacity: Cap_{dp} = 9.10 l/m
- Steel displacement: Cap_{steel} = 4.0 l/m
- Length of one stand: L_{dp} = 27 m
- Annular capacity between casing and DP: Cap_{csg} = 44 l/m
- Casing capacity: Cap_{well} = 44 + 4 + 9.1 = 57.1 l/m
- Mud weight: ρ_{mud} = 1.52 kg/l
- Pore pressure at 2 900 m (total depth): p_{pore} = is 420 bar.



How many meters of drill pipe may be pulled dry (no mud left inside when the tool joint connection is broken) before the well is becoming underbalanced?

d) How is it possible to record the SIDPP when a flapper valve is installed in the drill string above the bit?
e) Explain how a 4 way (# of ports)/3 position type valve inside the subsea BOP-pod is operated in order to close one of the BOP?
f) Mention two reasons why the circulation rate needs to be "slow" when circulating out a kick.
g) Select 4 situations from the list below where new "slow circulation pressure" must be taken during drilling:

1. Each shift
2. After change of bit nozzles
3. After change of bottom hole assembly
4. Before and after LOT
5. After change of mud weight
6. After increased ROP

h) Give a short explanation of why the shut-in choke (or casing) pressure (SICP) normally is higher than the standpipe pressure after a kick has been encountered.

2.2 Safety margin

a) A vertical exploration well is drilled at 2 300 m from a semi-submersible drilling rig. All depths are referred to rotary kelly bushing (RKB) level. The following data are given:

- Air gap: 25 m
- Sea bottom 500 m
- 9 5/8″ casing shoe depth: 2 200 m
- Mud density: 1.25 kg/l
- Pore pressure @ 2 300 m: 1.15 kg/l (also ref. to RKB)

A Leak Off Test to 63 bar surface pressure was taken at the 9 5/8″ shoe with 1.20 kg/l mud weight. Is the present mud weight sufficiently high to maintain the Riser Margin?

b) Define and estimate kick tolerance and present a supportive or illustrating sketch on basis of the parameters listed below.

$\rho_{pore\ at\ final\ TVD}$	= 1.42 kg / l
ρ_{gas}	= 0.35 kg / l (assume constant during killing)
TVD_{csg}	= 1 200 m
Final TVD	= 2 100 m
ρ_{mud}	= 1.3 kg / l
Cap_{ann}	= 25 l/m
p_{LO} (ρ_{mud} = 1.1 kg/l)	= 62 bar

c) How large a kick can be taken before MAASP is surpassed at time of influx? Gas is weightless and concentrated at the bottom of the well at time of influx.

d) Refer to table 1below, for details of an exploration well. Estimate the following factors: MAASP, Riser Margin and Kick Tolerance

e) What is the useful information you get out of MAASP and Kick Tolerance at shut-in during drilling? How are the two SMS different?

f) What is Kick Margin and why is it applied?

g) Explain the negative effect of spending too long time on shutting-in the kick.

2.3 Conventional. Drillers

Given the kick data in the table below (right well), answer the following questions:

a) What is the density of the influx described in Table 2-3 below?

TVD / MD	= 2500 m / 3 500 m
TVD_{csg} / MD_{csg}	= 1500 m / 1 510 m
Water depth	= 500 m
SCP	= p_{sirc} @ $_{30\ spm}$ = 52 bar when circulated through the riser
SCP	= p_{sirc} @ $_{30\ spm}$ = 62 bar when circulated through the choke line
ρ_{Mud}	= 1.50 kg/l
p_{SIDP}	= 20 bar
p_{SIC}	= 30 bar
V_{kick}	= 2.3 m^3
Cap_{pump}	= 20 l/stroke
Cap_{Ann}	= 20.0 l/m (assumed constant throughout the annulus)
$Cap_{ch.line}$	= 5.0 l/m
Cap_{HWDP}	= 5.0 l/m
Cap_{DS}	=10.0 l /m (0.01 m^3 / m)
$p_{LO\ at\ shoe}$	= 45 bar
$ax^2 + bx + c = 0$	
$x = -b +/- (b^2 - 4ac)^{0.5} / 2a$	

Table 2-3: Data

In all tasks assume the gas is ideal and that it follows the mud.

b) Standard Driller's method (the effect of friction in annulus is ignored). Assume L_{DC} = 0. Make a plot of SPP vs. strokes during the process of filling the drill string (DS) with kill mud.

2.4 Kill sheet. W&W. Conventional. Fracturing

This exercise of killing is conventional since the additional pressure loss in the annulus is negligible, due to the combined effect of shallow ocean depth and two choke lines are applied. Both are 4″When a critical situation occurs it is important that all known data are pre-entered into the kill sheet (Figure 2-3.1). If a kick is encountered the remaining data in the kill sheet can then be quickly entered and estimated. The following operational data are given:

DP:	5″ · 4.127″	Pump capacity:	19.57 l/stroke
DC:	6.5″ · 2.5″, 150 m	Choke line ID:	3″
Bit:	8.5″	Casing:	9 5/8″, @ 3 470 m TVD

After having cemented the casing, a leak-off test with mud of density 1.61 kg/l resulted in a surface leak-off pressure of 42.6 bars. The mud density was then increased to 1.67 kg/l. The following circulation at reduced pump speeds gave these results:

Pump Speed (SPM)	Up choke line (bar)
20	23
25	28
30	37

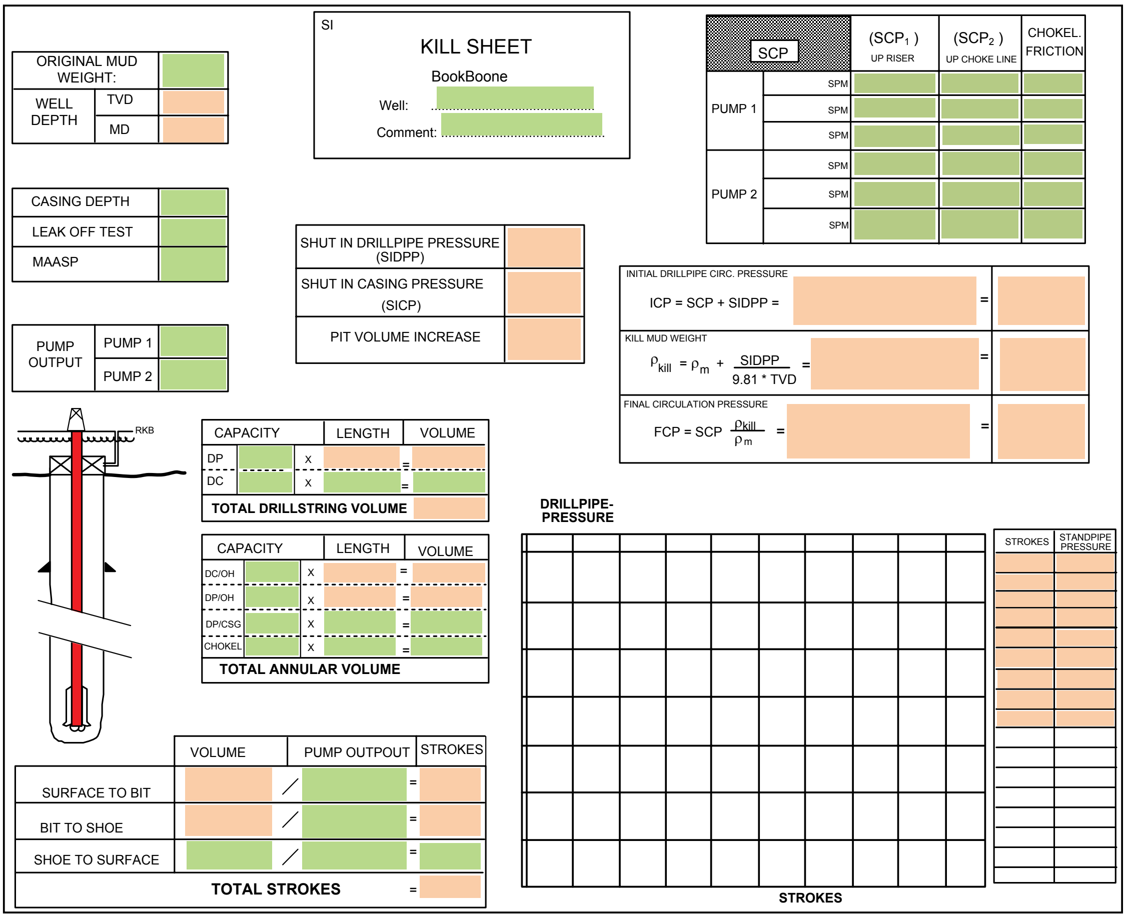


Figure 2-3.1: Typical one page kill sheet. Green indicates info that can be inserted each morning (before kick), orange boxes are entered after a kick has been shut-in.

When drilling further the wellbore inclination was increased to 45° (see Figure 2-3.2). At 4 215 mMD a kick was encountered, the well was closed-in and the following data were recorded:

Increase in V_{pit}:	1.7 m^3
SIDPP:	22 bar
SICP:	32 bar

Circulate out the kick by means of the W&W method. Choose the pump speed of 25 SPM when circulating out the kick.

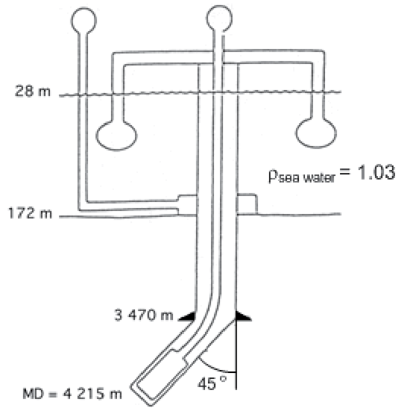


Figure 2-3.2: Vertical projection of the well.

Capacities:

DP:	9.16 l/m
DC:	3.17 l/m
DC/OH:	15.2 l/m
DP/OH:	23.3 l/m
DP/casing:	24.9 l/m
Choke line:	4.56 l/m

a) Complete the kill sheet. Selected SCS = 20 SPM
b) What is the height of the influx in the annulus, and what is its density (type of fluid)?
c) Sea depth is 205 m and RKB-elevation above sea level is 28 m. What should the riser margin be?
d) While waiting to initiate the killing procedure the SIDPP and SICP increase another 30 bar during the first half hour after closing the BOP. What is the buoyant velocity of the gas kick?

2.5 Engineer's method. Conventional. Pressure in 3 points of time

In this task it would be useful to present the results in a depth-pressure graph. This will improve the understanding of the dynamics of a killing operation.

The well data and the kick data experienced during drilling from a fixed platform into a high pressure zone are given here:

TVD	=	1 500 m
SCP = p_{sirc} @ $_{30\ spm}$	=	42 bar
ρ_{mud}	=	1.36 kg/l
p_{SIDP}	=	20 bar
p_{SIC}	=	30 bar
V_{kick}	=	1.5 m^3
$Cap_{\ pump}$	=	20 l/stroke
$Cap_{\ DC\text{-}OH}$	=	14.0 l/m (DC is100 m long)
$Cap_{\ Dp\text{-}well}$	=	20.0 l /m (0.02 m^3 / m)
$Cap_{\ DS}$	=	10.0 l /m (0.01 m^3 / m)
$p_{\ LO\ at\ shoe}$	=	45 bar
$TVD_{\ csg}$	=	900 m
$ax^2 + bx + c$	=	0
x	=	$\left(-b \pm \sqrt{b^2 - 4ac}\right)/2a$

During killing assume the kick consists of ideal gas (weightless, Z and T = const.), gas appears as one bubble and travels along with the mud. The hydrostatic column of the mixed fluid/gas in the annulus together with the surface choke pressure is balancing the pore pressure. The hydraulic friction during killing is distributed like this in the circulating system:

Through drill pipe:	50%	(evenly distributed along the pipe)
Through bit:	50%	
Through annulus:	0%	

Your task is to investigate how the well behaves in 3 specific points of time, and estimate 2 different drill string pressure and 2 different annular pressures for each of the 3 time points at the positions as stated below:

- Drill string pressure: At the bottom (just above the bit) and at the surface (SPP)
- Annular pressure: At bottom of the well and at the surface (the choke pressure)

The 3 specific points of time are:

1. Time of stabilized shut in pressure
2. Pump has just reached the speed of slow circulating rate (SCR), but gas is practically still at the bottom of the well
3. Top of gas has reached casing shoe

2.6 Driller's. Conventional. Pressure in 6 points of time

This task is similar to the previous one, but now the friction in the annulus has to be accounted for. Your task is to investigate how the well behaves in 6 specific time points, and for each display four resulting pressures into a depth-pressure graph:

- Drill string pressure: At bottom (above bit) and surface (stand pipe pressure)
- Annular pressure: At bottom and surface (choke pressure)

The well data and the kick data experienced during drilling from a fixed platform into a high pressure zones are given here:

TVD	=	1 500 m
SCP = p_{sirc} @ $_{30\ spm}$	=	62 bar
ρ_{mud}	=	1.36 kg/l
p_{SIDP}	=	20 bar
p_{SIC}	=	40 bar
V_{kick}	=	1.050 m^3
Cap $_{DC\text{-}OH}$	=	14.0 l/m (DC is 200 m long)
Cap $_{Dp\text{-}well}$	=	20.0 l /m
p $_{LO\ at\ shoe}$	=	45 bar
TVD $_{csg}$	=	1 200 m
$ax^2 + bx + c$	=	0
x	=	$\left(-b \pm \sqrt{b^2 - 4ac}\right)/2a$

Assume ideal gas (weightless, Z and T = const.), gas appears as one bubble and travels along with the mud. The friction is distributed as follows, and should be included in the evaluation.

Through drill pipe:	30%	(evenly distributed along the pipe)
Through bit:	50%	
Through annulus:	20%	(evenly distributed over total length)

The 6 time points are:

1. Immediately after shut in An additional question here is: Explain why the SICP is exactly 40 bars
2. The pump has reached the speed of SCR, but gas is practically still at the bottom of the well
3. The top of the gas has reached the casing shoe
4. All gas is out of the well and the pump is running at SCR
5. The kill mud has reached 50% down the drill string
6. The pump is turned off in situation 5 and the well is shut in

2.7 Killing. Fracturing. W & W. Conventional

In this exercise a potential problem could be an underground blow out. It is therefore especially important to determine if the formation can withstand the wellbore pressure.

a) During drilling a serious kick results in high danger of blow out. Operational, wellbore geometry and well fluid data are given below. In addition some observations emphasize the severity of the problem: Immediate after the well is closed in, the casing and drill pipe pressure starts to rise slowly. After approximately 30 min. both the pressures starts to decrease!

Mud weight ρ_1:	1.2 kg/l	C_{dp}:	8 l/m
Reduced pump rate:	30 strokes/min	C_{dc}:	4 l/m
Reduced flow rate:	800 l/min	C_{dc-oh}:	29 l/m
Pressure loss at reduced flow rate:			
	60.8 bar	C_{dp-oh}:	100 l/m
SIDPP:	35.1 bar	C_{dp-csg}:	100 l/m
SICP:	45.4 bar	h_w:	3 000 m
V_{kick}:	5.3 m^3	h_{cs}:	1 200 m
$LOT_{1200\ m}$, ρ_0=1.06 kg/l:	62.0 bar	h_{dc}:	150 m

Check MAASP and evaluate the situation before the killing operation is initiated.

b) In order to simulate a dangerous situation, a new situation or case is now presented: The drilling situation is as described above, but now with these changes:

SIDPP = 15 bars, SICP = 20 bars, V_{kick} = 2.3 m^3

Check the pressures at the casing shoe under these assumptions:

- Gas moves like one bubble and at the same speed as the fluid
- Temperature influence is negligible
- Gas density is not negligible. However, assume it is constant while rising through the annulus

Will it be possible to apply the W & W method without fracturing the formation at the casing shoe during killing?

2.8 Killing. Fracturing. W & W. Conventional II

A kick occurs during drilling and results in:

SIDPP = 10 bar
SICP = 22 bar
V_{kick} = 1.5 m^3

The well is further characterized through:

ρ_{mud} = 1.4 kg/1
h_{well} = 2 000 mTVD
h_{csg} = 740 mTVD
SCP = 20 bars at SCR = 30 SPM with a pump that delivers 21 liters pr. stroke

a) Find casing shoe pressure when

- Well is closed in
- Gas reaches the casing shoe

Assume ideal gas (weightless), Z and T = const., gas is one bubble and travels along with the mud, W & W method is used, friction in annulus is negligible, capacity is 0.01 and 0.06 m^3/m in the DS and the ANN respectively.

b) Present pump pressure schedule from the moment the kick is detected until the kill mud has filled the annulus.
c) May friction in the annulus cause any trouble? If yes, how to solve the problem?
d) Why the hurry while initiating the killing procedure?

2.9 Is conventional killing acceptable?

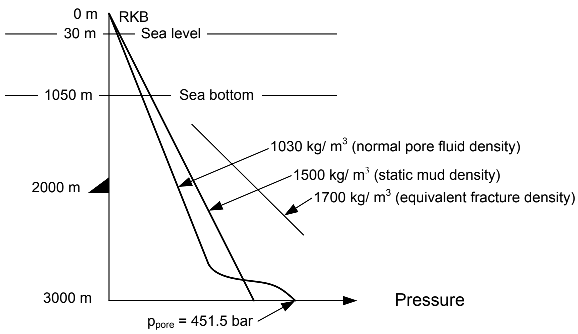


Figure 2-9: The situation.

During drilling at 3 000 m depth a 2 m^3 kick is taken and shut in. Wellbore data are presented in Figure 2-9. The annular capacity is 0.02 m^3/m from bottom to surface. The slow circulating rate has previously been recorded to 110 bars; of these 20 is lost in the annulus, the remaining 90 in the drill string. The 20 bar are subdivided, with 15 in the choke line and the remaining 5 linearly distributed in the annulus below the choke line.

Check if a) Driller's or b) Volumetric method can be applied without fracturing the formation below the casing shoe. Assume ideal, weightless gas which moves as a bubble along with the mud without dissolving. Include no safety margins.

2.10 Killing operation. Modified due to high choke line friction

a) How is primary well control maintained in a well? Mention 4 examples of how primary well control may be lost.
b) What is the modified Driller's method? What is the advantage of the Engineer's method compared to the Driller's method and
c) When is the volumetric method used for controlling a kick?
d) Mention 2 reasons for selecting slow (as compared to fast) circulation rate when circulating out a kick?
e) The distance RKBBOP is 1 000 m. At 2 000 mTVD the 13 3/8″ csg is cemented in place, and the LOT resulted in 45 bar when tested with 1.18 kg/1 mud. Later on, while drilling at 2 900 m TVD a high pressure zone was penetrated and the mud density was increased to 1.32 kg/1. Sunday at 0700, 23.03.2012 Mr. Johnson and his crew enter the drill floor to start a new shift. Drilling depth was now 2 980 m TVD. SCP at SCR was routinely recorded and the results were entered into Table 2-10:

Where	Pressure at pump rate	
	15 SPM	30 SPM
Up riser	20 bar	30 bar
Through choke line	30 bar	45 bar

Table 2-10: Pressure loss in the circulation sytem during slow pump rate.

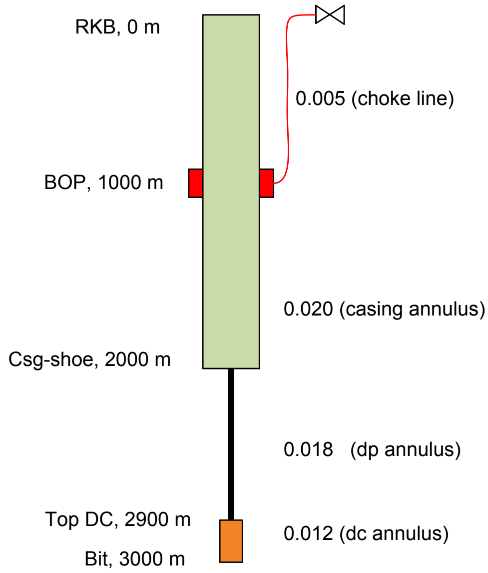


Figure 2-10: Data of exercise 2.10. Capacities to the right.

At 3 000 m depth a kick was encountered and properly shut in. After a few minutes the following stabilized readings were reported:

p_{sidp} = 11 bar, p_{sic} =15 bar, V_{kick} = 0.37 m^3

The well geometry is shown in Figure 2-10, where the capacity in annulus is given in m^3/m. Is it possible to circulate out this kick by standard methods? The row of priority in this exercise is: Driller's, Modified Driller's, other methods.

2.11 Driller's. Modified due to high choke line friction II

A vertical exploration well was drilled at 2 300 m from a semi-submersible drilling rig. The following data are given:

• Air gap:	25 m
• Water depth	500 m
• 9 5/8″ casing shoe depth:	2 200 m
• Mud density:	1.25 kg/liter
• LOT at csg. (1.1 kg/l mud):	63 bar

Capacities:

- 8 ½″ open hole capacity: 36.61 l/m
- DC / open hole capacity: 15.2 l/m (DC length: 100 m)
- DP / open hole capacity: 23.3 l/m
- DP / casing capacity: 23.6 l/m
- 6 ½″ DC capacity: 4.00 l/m
- 5″ DP capacity: 9.10 l/m
- Choke line capacity: 3.2 l/m.

Mud parameters:

- Mud density: 1.25 kg/l
- Mud Pump capacity: 16.0 l/stroke

Slow circulating rates, SCR:

- 20 SPM Up riser / up choke: 15 Bar / 19 bar
- 30 SPM Up riser / up choke: 22 Bar / 30 bar
- 40 SPM Up riser / up choke: 41 Bar / 53 bar

Later, while drilling into a high pressure zone at 3 000 m MD a 2 m^3 kick occurred.

Calculate the following, using 30 SPM SCR while killing the well: knowing that SIDPP and SICP were 28 and 52 respectively. Assume weightless gas. Kill sheet parameters are normally these:

1) MAASP
2) Surface to bit volume
3) Bit to casing shoe
4) Annular volume up to BOP
5) Total annular volume to the choke
6) Kill fluid density
7) Pressure at casing at kill pump rate
    a) In case of conventional operations
    b) In case of modified operation
8) ICP
9) FCP
10) New MAASP

Sketch the drill pipe pressure from the start of the kick till the well is killed, either in a kill sheet or in your own drawing.

2.12 Engineer's. Modified. Pressure at time # 2 and 3

Assume that the situation in Exercise 2.5 took place offshore, and the only difference being:

- Use the modified method
- Friction distribution in annulus is not ignorable:

Through drill pipe:	40%	(evenly distributed over the total length)
Through bit:	40%	
Through annulus:	20%	(evenly distributed over the total length of annulus)

Present your numerical answer at time # 2 (pump has just been started and the SCP recorded).

At time # 3 (top of gas reached casing shoe), present a depth-pressure chart where you compare unmodified and modified solution at time # 3, but only for the annular pressure. Indicate the exact bottomhole pressures in the two cases, but just qualitatively; how the hydrostatic pressure profile through the well looks like.

2.13 Modified. Stop in operation

Make a plot of pump pressure vs. # of pump strokes and insert it in Figure 2-13. Include also a rough sketch of pump and casing pressure before injection of kill mud, with the following information: The kick is detected at minus 3 500 strokes. Use Driller's method. The pump is turned on to kill the well at 3 000 strokes. Assume casing surface pressure reaches a maximum at -500 strokes and that all gas is out of the annulus/ choke line at -250 strokes. Start injection of kill mud at 0 strokes. All depths are related to RKB.

Mud weight, ρ_1:	1.4 kg/1
Reduced pump circulating rate, SCR:	30 spm
Pump flow rate:	800 1/min
Pressure when circulated up riser, SCP_1 :	38 bar
Pressure when circulated up choke line, SCP_1:	53 bar
Well depth, TVD:	3 000 m
Casing shoe depth:	2 000 m
SIDPP:	30 bar
SICP:	37 bar
Cap_{DS}:	10 l/m
p_{LO} at casing shoe with mud of 1 060 kg/l:	115 bar

a) Complete the SPP vs. stroke-chart

b) Verify that the modified method is better suited than the conventional by evaluating situation at time of shut-in.

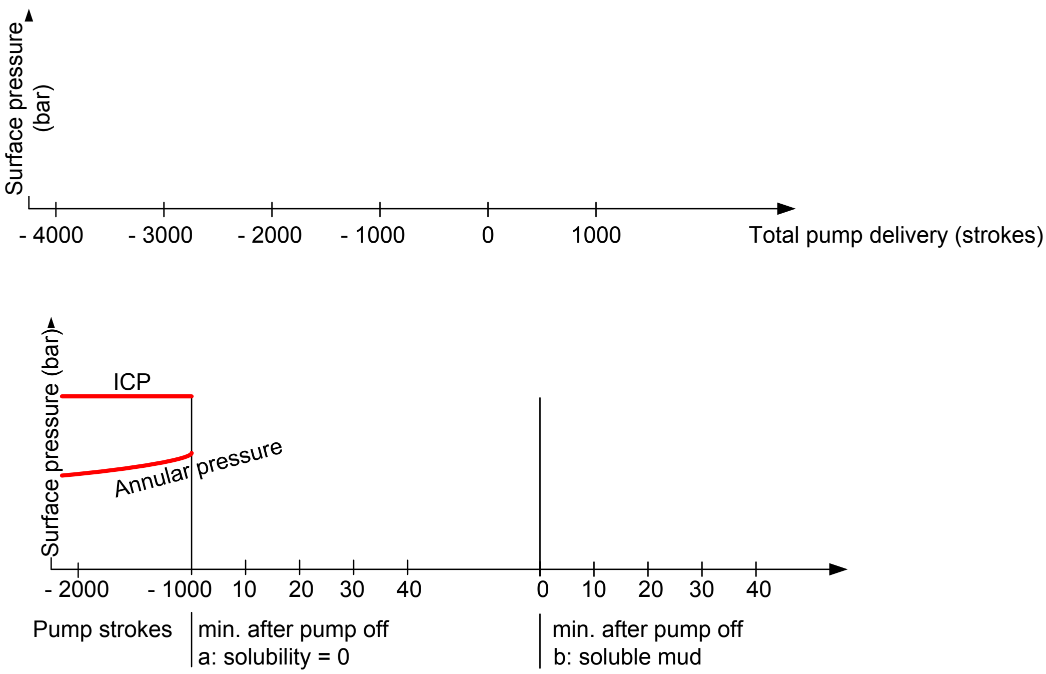


Figure 2-13: Upper graph: Modified killing operation. Lower graph: A stop in the operation.

c) At -1 000 strokes imagine that the pump is turned off and the well is shut-in properly. The wellbore and the kick inside is left alone for 40 minutes for some unknown reason. Indicate in the lower graph of Figure 2-13 how the surface casing and drill pipe pressure will develop during the first minutes, for two alternative mud types:

- WBM: No gas is dissolving in mud
- OBM: Gas dissolving in mud

2.14 Modified. More realistic drill string

a) The data obtained during drilling into a high pressure zone are given as:

TVD	=	3 000 m
$p_{sirc,30\ spm,\ up\ riser}$	=	31 bar
$p_{sirc,30\ spm,\ up\ chokeline}$	=	36 bar
ρ_{mud}	=	1.7 kg/l
p_{SIDP}	=	20 bar
p_{SIC}	=	25 bar
V_{kick}	=	2 m^3
q_{pump}	=	20.0 l/stroke
Cap $_{DP}$	=	15.0 l/m first 1 500 m
Cap $_{DP}$	=	6.0 l/m next 1 500 m
Cap $_{DC-OH}$	=	10.0 l/m 200 m
Cap $_{Dp-well}$	=	30.0 l/m 2 800 m

Present the pump pressure schedule as a function of time (minutes). Take into account the effect a tapered string (different inside diameters) will have on the pump schedule, compared to a slick string. The pressure loss in the drill string is assumed linearly distributed along the two pipe parts and that 50% of the loss occurs in the bit.

b) What is meant by “Modified” in the heading of this exercise?

2.15 Modified. More realistic drill string II

The slow circulation pressure, SCP, was recorded to 42 bars, at slow circulation rate, SCR, of 30 spm. The pump had a capacity of 20.2 l / stroke. A kick was taken and shut in: SIDPP = 30 bars. Mud density was 1.22 kg / l.

Find pump schedule while killing by means of the Driller's method. Figure 2-15 defines the geometry of the well. At 1 000 mTVD the wellbore becomes inclined 60^0, making the well from here twice as long vs. depth. Pressure loss through the bit is 50% of the total at SCR. Assume that the remaining drill pipe frictional pressure loss is linearly distributed with measured depth in each of the three drill pipe sections. The relative pressure loss in the three drill pipe sections are 0.4, 0.4 and 0.2 counting from the surface, respectively. The pressure loss in the annulus is negligible.

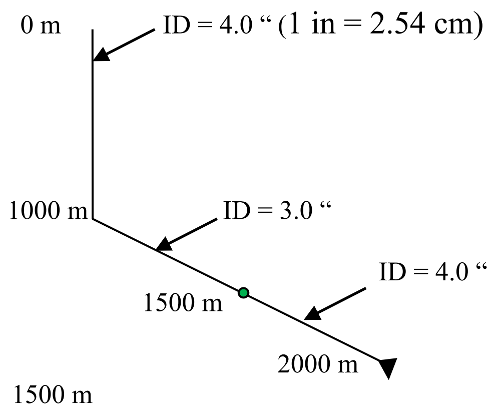


Figure 2-15: Data for exercise 2.14.

2.16 Modified and volumetric

The following information describes a kick situation:

Mud weight, ρ_1:	1.3 kg/1
Well depth, TVD:	3 000 m
SIDPP:	12 bar
SICP:	26 bar
L_{DC}:	200 m
Capacities:	
C_{DP}:	5 1/m
C_{DC}:	2 1/m
$C_{DC/OH}$:	13 1/m
C_{ANN}:	25 1/m
$C_{chokeline}$:	2 1/m
Sea depth:	500 m

a) Previously a LOT has been performed and fracture gradient was determined to 0.14 bar/ m at the casing shoe at 1 000 m depth. At this time the mud density was 1.03 kg/l. What was the pressure at the surface when the formation started to leak?
b) The kick volume was measured to 3 m^3. What does the kick fluid consist of?
c) Circulating pressure at slow circulating rate was 100 bars, measured through the choke line. 40 bar of this pressure was lost in the drill string (including drill collar), 40 in the bit and 20 in the annulus. ¾ of the mentioned 20 bar loss was lost in the choke line and ¼ in the remaining of the annulus. Sketch the dynamic pressure distribution in the drill pipe and the annulus, without calculations, one minute after having turned the pump on (when the flow is in steady state). Please indicate in the graph all your interpretation of the here presented text.
d) During the killing operation the pump breaks down and the well has to be closed. The drill pipe pressure and the casing pressure now read 3 and 29 bar respectively. How would you in detail, point by point, bring the situation under control?

2.17 Volumetric method

After having drilled a vertical depth of 3 000 m it was decided to change the bit. While tripping, the wall started to kick and was properly closed-in. BHA was 500 m above the bottom at shutting-in time. Kick volume was 2.1 m^3.

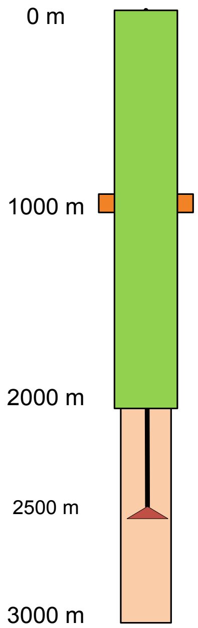
Shut-in pressure read 4.2 bars on both annulus and drill string side. A stripping-in procedure was initiated but was soon interrupted when the mud started leaking from the choke manifold simultaneously as the drill string was reported stuck.

This task was previously (2004) performed in groups of 5 students as a Problem Based Learning (PBL) task. The PBL-procedure is:

Step 1: Define the problem so that all in group members agree and have the same understanding of it
Step 2: Any terms or expressions that needs to be clarified
Step 3: Brain storming session (normally lasting for 10–15 minutes): This always becomes a mixture between good and crazy ideas or explanations. No suggestion is wrong
Step 4: Prioritize suggestions and explanations
Step 5: Learning goals: Must be both specific and general. This is how the students determine what critical knowledge is.
Step 6: Learn: Go out and approach the learning goals individually
Step 7: Solution: Suggest the problems you have been assigned first individually, then in group.

PBL is a technique applied in small and large corporations by engineers. It promotes teamwork and creativity. The real work and the research are like before; it is carried out through Step 6 and 7. The general part in Step 5 will ensure that all teaching goals are fulfilled.

a) Make a group of 3-4 friends. Use the PBL-approach. Through PBL you suggest which topics (Step 6) you want to dig into. Part b), c) and d) are individual PBL tasks.
b) During tripping the well starts flowing and is shut-in. The circulation system is temporarily not functional. The well and kick data are presented in Figure 2-17. Give a rough plot of time vs. casing pressure during killing the well (without pumping).
c) Estimate the choke pressure when the gas has reached the surface. The stagnant rise velocity of the gas is assumed to be 0.3 m/s. All depths are TVD.



Kick volume	2.1 m^3
p_{SIDP}	7 bar
p_{SIG}	7 bar
Capacities:	
Open hole	0.030 m^3/m
Open cased hole	0.030 m^3/m
Ann – DP	0.015 m^3/m
Choke line	0.005 m^3/m
Displacement:	
Drill pipe 0.015 m^3/m	
Mud type:	WBM
Mud density:	1.6 kg/1
Assumption for conventional p-control:	
Gas bubble is at	3000 m at shut in time
Ideal gas, i.e.	Z = 1.0 (constant)
	T = constant
Gas rise velocity:	approx. 500 m/hour
Gas moves as a bubble at:	mud velocity

Figure 2-17: Exercise Data.

d) A gas producing well is planned to be worked over, and need first to be killed. Explain stepwise how to kill such type of wells.

2.18 Comparing 3 Killing methods. Annular friction included.

The situation after a kick was shut in is described in Figure 2-18 for three different killing methods. Show in the graphs how the annular pressure may develop during the killing operation at three different stages in the killing process:

a) At the start of the killing after shut-in
b) When the gas is reaching the casing shoe
c) When gas reaches the surface

The drawn lines should be your answer, accompanied by small comments. No derivations are necessary.

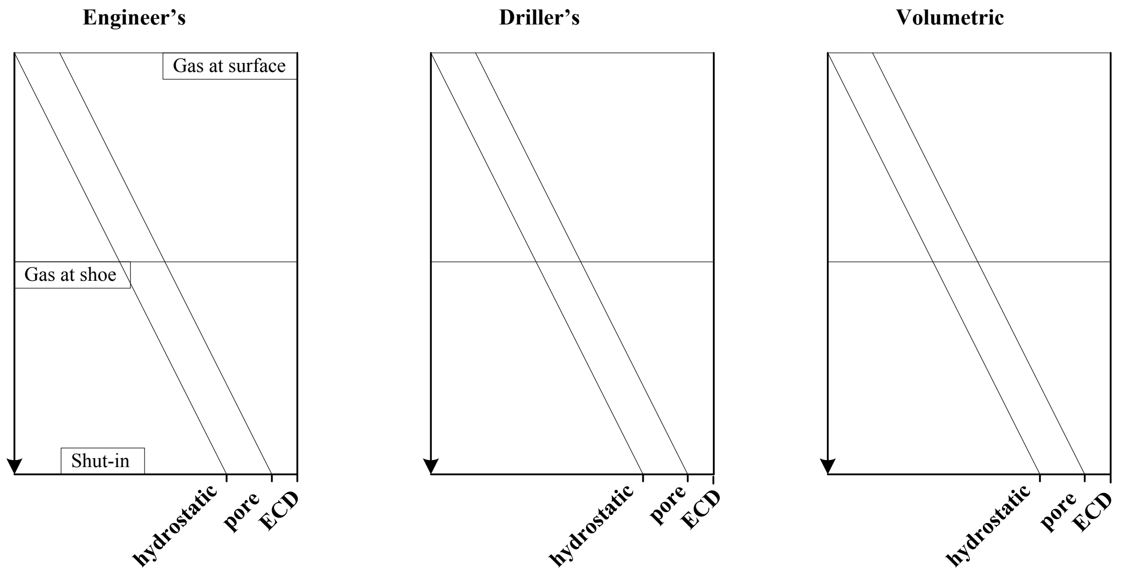


Figure 2-18: Exercise data. The support lines are parallel with the hydrostatic pressure to make it easier for you to draw the missing hydrostatic pressure lines.

Annular friction must be included when circulating.

3 Gas behavior

3.1 Gas transport percolation

At 3 400 meter, a 0.3 m^3 gas kick was shut-in, resulting in 38 bar shut-in casing pressure. The gas started to migrate up the 12¼″ hole, and after 15 minutes, the shut-in casing pressure increased further to 48 bar. The mud weight was 1.75 kg/l.

a) What is the gas migration speed?
b) Technical problems on the rig prevented the pressure to be bled off. What would be the theoretical maximum shut-in casing pressure when the gas reached the surface?
c) Discuss the two constants in the gas velocity equation $v_g = C_1 \cdot v_m + C_2$. Explain why c_1 in the gas velocity equation is equal to approximately 1.2?
d) Prove that $v_g = v^s_g / C_g$ where v^s_g is "superficial" velocity and C_g is the gas fraction.
e) What is meant by axial dispersion during killing?

3.2 Wellbore pressure during 2-phase flow

At the bottom of a 500 ft deep well gas at a rate of a) 6 000 and b) 1 185 scft/hr, together with 73 gpm of salt water (1.03 kg/l) is being injected simultaneously into an annular return pipe. The back-pressure is, as indicated in Figure 3-2, controlling the gas rate at surface. Assume dispersed bubble flow and assume for convenience that friction and acceleration accounts for a pressure loss equal to 5% of the hydrostatic pressure term. Assume further that:

$$v_g = 1.2\ v_m + 0.8\ \text{(ft/s)}$$

a) Apply the Newton Rapson forward iteration methods to verify that the pressure distribution in the well is in accordance with measured pressure in Figure 3-2.
b) Determine also if the assumption of 5% friction loss was good or not.

The rheology of the polymer-added water is described by the Power law: n = 0.5, K = 0.3 Pas^{-n}. The flow and the geometry data are:

h_2	= 55 ft	=	16.8 m
$q_{g,o}$	= 6 000 ft^3/hr	=	0.0472 m^3/s
q_{liq}	= 73 GPM	=	0.0046 m^3/s
d_i	= 2.50 in	=	0.0635 m
d_o	= 5.43 in	=	0.1379 m

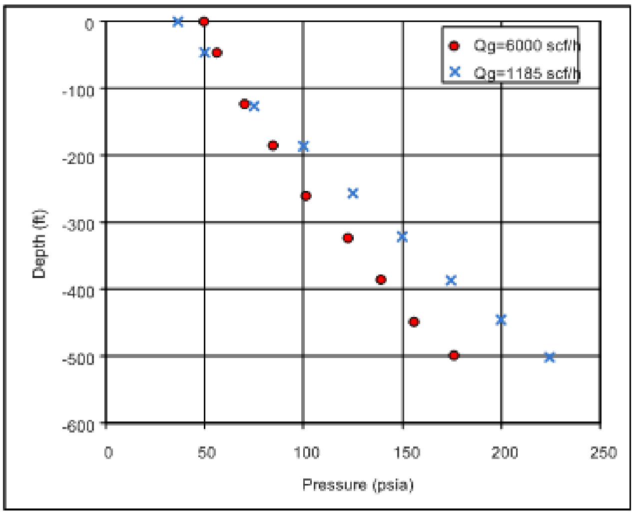


Figure 3-2: Wellbore pressure during two phase flow experiments at UT, Texas, Austin.

3.3 Wellbore pressure during 2-phase flow II

While drilling slightly overbalanced (MPD) with a 12¼″ bit horizontally through a gas reservoir, the ROP was in average equal to 30 m/h, pumping mud at 600 l/min. The reservoir had a porosity of 30%. Assuming these conditions have been stable and constant for several hours. Find v_{mix} at bottom and initial gas concentration while drilling.
Other data as follows;

h_{well} :	1000	m
ρ_{gas} (constant):	0.1	kg/l
ρ_{water} :	1.03	kg/l
p_{pore}	0.11	bar/m
$p_{surface}$	20	bar
$q_{water\ injection}$	1000	l/min.
C_{ann} :	22	l/m
v_g =	$1.2\ v_m + 0.2$	m/s
C_g =	v_g^s / v_g	

$$v_g = \frac{q_g}{A_g + A_l}$$

Your general task is to present a method to determine the surface choke pressure during drilling. Use the Newton-Raphson forward iteration method.

Hint: In order to find the answer we need to guess a surface pressure gradient and find the bottom hole pressure through iteration. q_g is related to standard conditions, i.e. 1 bar. Our first guess of flow rate is **0.5 sm³/m**. If time does not allow you to find the exact answer; just stop when you feel you have shown how to do it.

3.4 Real gas behavior

a) While drilling horizontally through a gas bearing formation the returning total volume at the flow line outlet is:

$$V_{tot,0} = V_{l,0} + V_{g,0}$$

The subscripts l refers to liquid, g to gas and 0 to the surface level.

Derive an expression of density, ρ_0, of the returning fluid at the flow line. Use this expression to derive an expression of the variable density down in the well, $\rho(z)$.

Present the next few principal steps of how to estimate the pressure at depth of interest. The final analytical solution is not required.

b) Case One: 1: Shake a bottle of Pepsi; 2: Open the cork, what happens? Case Two: Repeat 1 and 2 from Case One, but wait for 5 minutes between 1: and 2: What happens?

3.5 Gas solubility

a) The 12¼″ hole section crossed several unstable layers of shale, and WBM had to be replaced by OBM. Just before final depth was being approached (a horizontal well of 5 000 m MD (2 500 m TVD)), the well started to kick. The BOP, located on the sea bottom at 1 600 m sea depth, was closed properly. After closing the BOP, the mud continued to unload from the riser. The mudflow increased, and only 8 minutes after having closed the BOP, gas erupted through the rotary table. The eruption knocked down a pipe tongue which, when hitting the floor, ignited the gas, which exploded. In the explosion one crew member from the logging company was killed and two roughnecks got serious facial burns. The gas flow seized and stopped completely over the next 6 minutes. Give an explanation and a solution to the problem.
b) List situations within the drilling and the completion phase where gas diffusion has importance.
c) Bottle of Pepsi shaken. Then a) open immediately and b) wait for 5 minutes before open. What happens in the two situations?

3.6 Gas solubility

It has been assumed that gas behaves like ideal gas, migrating upwards as one bubble; at the same speed as the drilling fluid and that the solubility of gas in mud can be neglected. This is not true in real cases, and this discrepancy will affect the killing operation. Evaluate therefore the following statements, and, in the case they represent a problem, what is the explanation/solution:

a) The annular surface pressure during killing operations is lower than theoretically calculated in WBM
b) Gas solubility influences the annular pressure during killing operations
c) Gas solubility is a function of salt content of the liquid
d) After drilling into a high-pressure zone with OBM, a 2 m^3 gas kick was encountered and closed in. Due to bad weather conditions all systems were shut down for a period of 6 hours. Assume that the total annular mud volume is 50 m^3.

4 Deep water and cementing issues

4.1 Cold water issues

Below are presented two statements. The task is to explain the problem and suggest possible solutions.

a) Hydrates are forming during drilling operations.
b) The mud develops high gel strength in the choke line since the sea temperatures here are especially low. How high is the pump pressure necessary to break the mud's yield point in a 1000 m long choke line with an ID of 3″ if the gel strength is 10 Pa? This is seen when circulation is initiated to kill the well.

4.2 Deep water shallow formations

During deep water drilling offshore in the Gulf of Mexico, a 15 min. pause in the operation is taken to investigate the two riserless-drilled hole sections. Such checks are taken every 15 m drilled hole. A small flow of mud or dirty water can be detected streaming out of the open well riserless-drilled.

a) Define the problem.
b) Suggest possible solution.
c) Where in the world do we expect to find problems related to shallow water flow (SWF)?
d) Discuss and explain the Daily Drilling Report below. It is a deep water operation at its final stage of a kick killing operation.
e) Why do we need a diverter during offshore drilling?

Displace riser contents w/17.5 PPG mud down c-line @ 100 SPM w/1570 psi. Close 1pr. Close ann. Open upr. Displace gas in stack down c-line, out k-line through choke. Max gas 240 u. Displace 23 bbls seawater down k-line. Open ann. & u-tube water back up k-line w/17.5 ppg mud from riser, while filling riser from trip tank. Pump slug. Check for flow. POOH.

4.3 Cementing best practice

a) Describe Best Practice of top hole drilling.
b) What could be the reason behind all the leaking production wells now a day, on- and offshore?
c) Why does the displacing cement form into distinguished bubbles in the displacement front

4.4 Cementing in general

a) Discuss the objective of the cementing jobs in general and especially for cementing operations of the surface casing (20 inch casing)?
b) Shallow water flow and Gas Migration through cement are problematic processes. Define the problem for each of the processes and suggest solutions respectively.
c) Explain the problems that are stated in the text below. Make sketches.

On April 15th, 1988, the 10¾″ casing had been set at a depth of 1 000 m after a 14½″ hole had been drilled to a depth of 1 003 m with 1.05 kg/l mud without experiencing any problems. The 16″ conductor casing had been set at 40 m and cemented to surface.

The cement company, here called A, cemented the 10¾″ casing with 1170 sacks of "light" cement with 3% salt; slurry weight was 1.2 kg/l. This slurry was followed by 399 sacks of class "H" neat cement; slurry weight 1.7 PPG. Full returns were obtained throughout the job. The plug was bumped with 50 bars, pressured up to 85 bars and held for five minutes. After releasing the pressure, the float held OK. The job was complete at 1400 hours.

At 1800 hours the 16″ conductor casing was cut without incident. At 1900 hours, the welder prepared to cut the 10¾″ casing. Upon lighting the torch, some small gas bubbles, breaking through the cement were ignited, causing slight burns on his face and arms. The escaping gas continued to gain volume, and by 2000 hours cement was being blown from the 16″ conductor casing.

By 0300 hours on April 16th, a well killer from Boots and Coots arrived on location. At this time the well was blowing its maximum amount and the rig motors were shut down. The well was blowing gas, fresh water and sand at least 15 m over the crown block.

By daylight, with the well continuing to blow out of control, preparations were being made to skid the rig in order to facilitate capping the well. Vacuum trucks with 1.2 kg/l mud had been ordered. By 1300 hours the well died. Attempts to fill the hole with 90 m^3 of 1.2 kg/l mud in the 16" conductor casing were made but the hole would not stay full.

At 1600 hours, with the well still dead, Cement company B arrived on location and began cementing operations through a string of 1″ tubing down the 16″ × 10¾″ annulus. The next several days were spent filling up the annulus in stages with some 1300 sacks of cement. Good cement returns were finally achieved with the final 40 sacks.

The ensuing 2 days were spent finishing and cleanup operations around the rig and nippling up a diverter spool and lines on the 10¾″ surface head. The 10¾″ casing was cleaned out down to the float collar and a noise log was run inside the 10¾″ to determine if there was any underground flow. The results of the survey indicated flow between the depths of 350 and 300 m. For this reason the 10¾″ casing was perforated and squeeze cemented to seal off any communications between zones. A casing inspection log was also run and showed no casing damage.

200 sx of class – H cement were squeezed in at 350 m and 600 sxs of cement at 260 m. The cement was then drilled out and the casing cleaned out to the float collar. The casing was pressure tested again, and from this point on normal operations was resumed.

d) Gas Migration through cement is a dangerous phenomenon. Define the problem. Explain how the casing cement sheet can start leaking at any time after its initial set point and during the production phase. Suggest solutions respectively.
e) What factors would you recommend to be taken more seriously by the operator concerning cementing operations through gas bearing formations, and what are your recommendations in this respect.
f) Why do you need a diverter after the BOP is installed?

5 Additional information

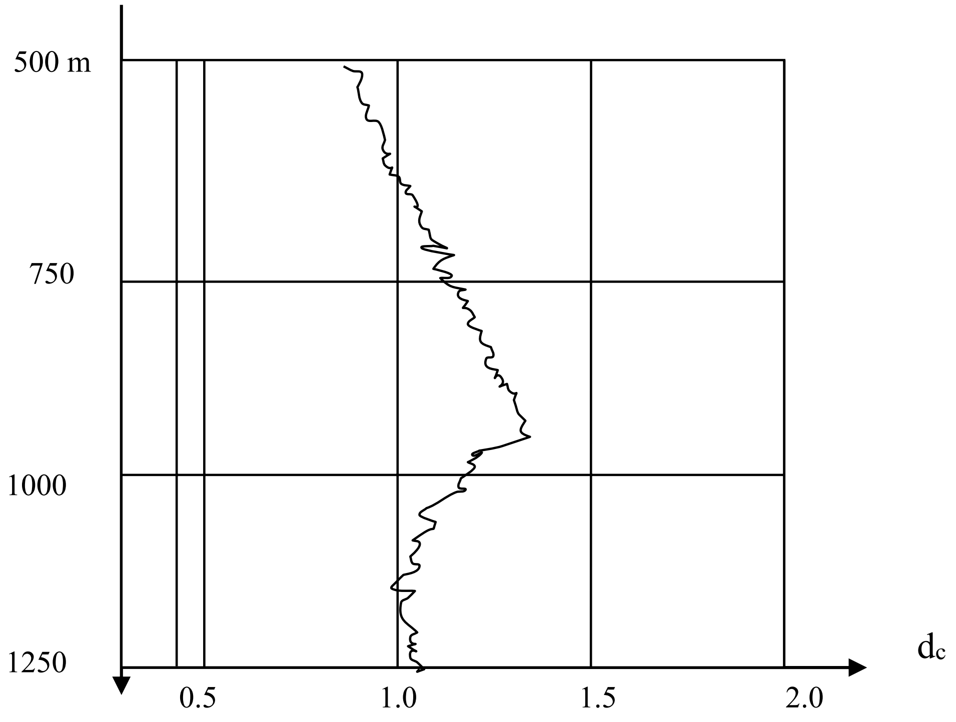


Figure A1: d_c vs depth

$$d = \frac{\log \frac{R_p}{60\,N}}{\log \frac{12\,W}{10^6\,d_b}}$$

$$G_p = G_{ovb} - \left(\left(G_{ovb} - G_{p,n}\right)\left(d_c / d_{c,n}\right)^b\right)$$

$$G_p = G_{ovb} - \left(G_{ovb} - G_{p,n}\right)\left(R / R_n\right)^{1.2}$$

$$G_p = G_{ovb} - \left(G_{ovb} - G_{p,n}\right)\left(\Delta t_n / \Delta t\right)^3$$

$$p_{fr} = \rho_{pore} + \frac{\mu}{1-\mu}\sigma z$$

Solutions – Pressure control

1 Formation pressure – solution

1.1 High pore pressure zone

a) Pore pressure is high (abnormal) whenever it is higher than the hydrostatic water pressure. Equivalent pressure gradients, in terms of density, up to 1.06 kg/l can be defined as normal.

b) Key processes involved in the forming of high pore pressure and its seal are:
- Compaction → porosity reduction
- Digenesis → water rich Smectite transform to Illite, which is more compact.
- Sealing of formations → both the compaction and digenesis will come to a halt after the establishment of impermeable boundaries. They are formed by either shale, salt or faults. Impermeable boundaries will hinder water to escape and thus stopping the compaction. "Rapid" sedimentation of clay increases the probability of the creation of seals. Other forms of high pore pressure are piezometric ground water and charged gas from lower formations.

c) In-situ key parameters characterizing the transition zone:
- Low vertical stress in the matrix → the overburden weight is supported by high pore pressure
- Higher porosity than expected at this depth → correspondingly high water content
- Darcy equation describes the water flow through the seal very well. The permeability is in the range of 10–15 Darcy. The time is in the range of 10 8 years.

d) Key parameters are described briefly below.
- Drilling parameters: ROP decreases with depth due to increased compaction. But in high pressure zones ROP becomes high due to low static and dynamic hold down)
- Logging parameters:
  - o Mud: High gas cont. (from organic material). Low/high T-grad
  - o Cuttings: density, shape
  - o MWD/Logging: Gamma, sonic

e) The equation ROP = K $\cdot\, e^{a_3 D} \cdot e^{a_4 D(ECD-\rho_{pore})}$ (from the SPE-testbook Applied Drilling Engineering) shows that ROP decreases logarithmically with increased overbalance. The constant a_4 varies with type of formation, especially its permeability. ROP is, for constant a_4, related to the magnitude of (p_{mud} – p_{pore}).

f) Hold Down is proportional with bottom hole pressure and expressed by the term $e^{a_3 \cdot D}$, increased HD will lowers ROP.

g) The term K can be used for drillability studies. $e^{a_3 \cdot D}$ can be used to improve the predictivity of ROP. The latter of the three terms can be applied to estimate p_{pore}.

h) Normal pore pressure is defined by the water gradient. Abnormal pressure occurs when the water level is higher; under-compaction occurs during “quick” sedimentation of clay trapping much water; water expulsion, occurs during diagenesis; plate tectonic leads to high stresses and compressed reservoirs. Artesian water erupts after rainfall, causing the water floor to rise.
i) Overburden is compressing the sediments, water is squeezed out and flows slowly up or out sideways. When a seal exist, the leaks are stopped and pressure increases, depending on overburden and tightness of the seal. Latter is defined by Darcy’s law. A final remark; Maximum pore pressure = fracture pressure.

1.2 Sedimentary formation pressure

a) Pore pressure is normal as long as permeability up to surface allows. Due to closures it may go up till fracture. Magnitude between the 2 boundaries is determined by the overburden (up) and Darcy flow (down).
b) Overburden matrix loses porosity in the depths, ρ_{matrix} = 2.7 kg/l
c) Large water depth brings ρ_{frac} and ρ_{pore} relatively closer together
d) Water is trapped and incompressible. Porosity stays at the level it was when trapped
e) 1. Sonic, 1. ROP /d_c, 3. Mud gas content, 4. R, 5. T_{mud}
   ➔ 1. Δt depends on ρ_{fm}, 2. Compressive strength, 3. Drilled out gas content, 4. Salt water content, 5. Salt water heat capacity
f) Yes, especially if a filter is formed, hindering pressure dissipation

1.3 Porosity. Overburden. Sonic log

a) Porosity at specific depth points:
Read first Δt:

500 m : 100

750 m : 75

1 100m : 60, etc

Solve equations with respect to porosity, Ø, and compute

$$\phi_{500} = (100-47)/153 = 0.346$$
$$\phi_{750} = (75-47)/153 = 0.183$$
$$\phi_{1100} = (60-47)/153 = 0.085$$
$$\phi_{1300} = (65-47)/153 = 0.118$$
$$\phi_{1500} = (60-47)/153 = 0.085$$

At 1200 m a high pressure zone is encountered; the porosity will increase again at 1 300 m.

b) Local overburden density can now, with known porosity, be found.

$$\rho_{500} = 2.8\cdot(1-0.346)+1.025\cdot 0.346 = 2.186\ kg/l$$
$$\rho_{750} = 2.8\cdot(1-0.183)+1.025\cdot 0.183 = 2.475\ kg/l$$
$$\rho_{1100} = 2.8\cdot(1-0.085)+1.025\cdot 0.085 = 2.649\ kg/l$$
$$\rho_{1300} = 2.8\cdot(1-0.118)+1.025\cdot 0.118 = 2.591\ kg/l$$

Equivalent density of the overburden is referred to RKB, and its hydrostatic pressure starts from the RKB-level. The answer is depending on the selection of the data points. To obtain a correct answer one need to take the average between the selected data points. In practice a computer program would pick every single data point, and thereby eliminating this type of uncertainty.

$$\rho_{RKB-500} = \frac{0 \cdot 30 + 1.025 \cdot 500}{30 + 500} = 0.967 kg/l \qquad \text{(due to air and seawater)}$$

$$\rho_{RKB-750} = \frac{0.967 \cdot 530 + 2.186 \cdot 250}{530 + 250} = 1.358\ kg/l \qquad \text{(midpoint of 500 m interval)}$$

$$\rho_{RKB-1500} = 1.99\ kg/l$$

1.4 Porosity. Overburden. Sonic

a) In Figure 1-4 we pick out the 600 m sea depth case. It shows the following **average** Δt over the first 400 m below the 600 m deep seabed.

$$\Delta t_{832} = \Delta t_{600-1000} = \frac{\sum_{1}^{n} \Delta t_i}{n} = \frac{130+120+115+110+105+106+92+95+105+100+100+110}{12} = 107\ \mu s/ft$$

Since the distance between every data point is the same, they all obtain the same weight. The next intervals are evaluated similarly and entered into Table 1-4.1.

Equations for the local density: $\rho_i = 2.7 - 2.11 \cdot \phi$

Local porosity is: $\phi_i = 1.288\,(\Delta t - \Delta t_m) / (\Delta t_t - \Delta t_m)$

Depth interval			Selected interval mid points	average Δt in the intervals	local ϕ_i zones	local ρ_i zones
0	-	600	332			
600	***-***	***1000***	***832***	***107***	***0.52***	***1.81***
1000	-	1500	1332	89	0.35	2.10
1500	-	2000	1832	75	0.23	2.32
2000	-	2500	2332	95	0.40	2.03

Table 1-4.1: Sonic data and estimated local density at three simulated sea depths. Results shown only for the 600 m sea depth case.

b) Now we will estimate ρ_{ovb} (referred to RKB) with the influence of 3 different water depths, knowing that overburden is the effect of the cumulative over burden, including air and water:

$$\rho_{ovb} = \frac{\sum(\rho_i \cdot \Delta D)}{\sum \Delta D} \qquad (1)$$

An approximate midpoint is taken as a representative of the average equivalent density as shown in Table 1-4.1. The same midpoint is used for all intervals for the purpose of comparing. See results in Table 1-4.2, which are graphically presented in Figure 1-4.

0 m water depth	600 m water depth	1500 m water depth
$\rho_{32} = 0$	$\rho_{32} = 0$	$\rho_{32} = 0$
$\rho_{332} = (0 \cdot 32 + 1.81 \cdot 300) / 332 = 1.64$	$\rho_{332} = 0.90$	$\rho_{332} = 0.90$
$\rho_{832} = (1.64 \cdot 332 + 1.81 \cdot 300 + 2.1 \cdot 200) / 832 = 1.81$	$\rho_{832} = 1.15$	$\rho_{832} = 0.96$
$\rho_{1332} = (1.81 \cdot 832 + 2.1 \cdot 200 + 2.32 \cdot 300) / 1332 = 1.97$	$\rho_{1332} = 1.39$	$\rho_{1332} = 0.98$
$\rho_{1832} = (1.97 \cdot 1332 + 2.32 \cdot 200 + 2.03 \cdot 300) / 1832 = 2.02$	$\rho_{1832} = 1.61$	$\rho_{1832} = 1.07$
	$\rho_{2332} = 1.80$	$\rho_{2332} = 1.31$

Table 1-4.2: Equivalent overburden (in kg/l) estimated from eqn. (1).

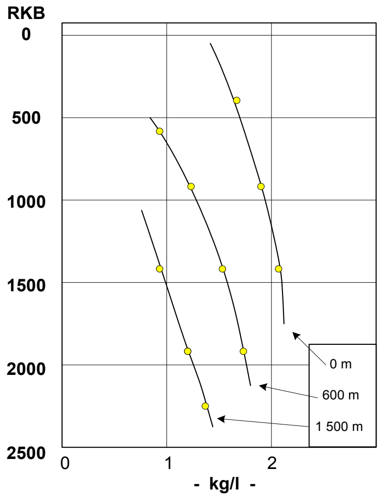


Figure 1- 4: Equivalent overburden density vs. sea depth.

c) Use Eaton's method: $\rho_{pore} = \rho_{ovb} - (\rho_{ovb} - \rho_{p,n})\,(\Delta t/\Delta t_n)^3$. Overburden density assumed 2.0 kg/l.

$$\rho_p = 2 - (2 - 1.025)\left(\frac{60}{85}\right)^3$$

$$= 2 - (0.975)\cdot 0.77^3 = 1.66 kg/l$$

d) $p_{fr} = p_{pore} + \frac{\mu}{1-\mu} \cdot \sigma_z = 407 + \frac{0.25}{0.75} \cdot 77 = 432 bar$

$p_{pore} = 1660 \cdot 9.81 \cdot 2500 = 407 \cdot 10^5\ Pa$

$\sigma_z = p_{ovb} - p_{pore} = (2000 - 1660) \cdot 9.81 \cdot 2500 = 83 \cdot 10^5\ Pa$

1.5 Pore pressure detection.

a)

Method	**Description, pros and cons**
d_c	d_c is similar to the ROP indicator, but the influence on ROP from the most important drilling parameters (WOB and RPM) are accounted for (in a simple manner) + As opposed to ROP it includes the effect of Δ WOB and Δ RPM + Lithology changes are revealed through Gamma Ray. Non-shale areas are ignored - Not available in real time
$c_{gas\ in\ mud}$	Gas will always diffuse into the cap rock over the millions of years. Pore water is drilled out and even swabbed-in during cnx. Gas content in the mud is measured in the possum belly. + Reliable indicator in the overburden. - Dependent on the existence of gas
T_{mud}	High pore pressure zones act as insulators in sedimentary rocks due to the high heat capacity of water + A simple method. Find deviations from the temperature trend vs. depth. - Unreliable. Too dependent on pump flow rate. Have to use a more complex model in real time - Large heat loss in marine riser increases the noise and thus decreases reliability
ROP	Depends on $p_{mud} - p_{pore}$; high differential pressure will statically hold cuttings down + Simpler method than the d_c method
ρ_{shale}	Is a function of porosity, which is high in sealed, under-compacted, high pressure shale

b) The sealing mechanisms have been different. In addition also the compaction/charging-process may have been different.

c) Increase return flow; increased pit volume; pump pressure de- / increases when drilling into over pressure; SIDPP > 0 after shut-in

d) Hold-down effects are varying while drilling in porous formations. Establishing of a filter inside of the formation ahead of the bit is crucial. To establish a filter in front of the bit, average particle size must be 1/3 of average pore size. Both static and dynamic hold-down is affected by the permeability. The permeability which dictates how effective the pressure differences are preserved in the vicinity of the bit tooth action.
e) Clean shale can be found by means of Gamma. Shale must have been exposed to normal (slow) compaction and diagenesis. Pore water reaches equilibrium with surrounding water pressure.
f) Clay, and sometimes filter/filtrate-supported sandstone, can resist the pressure difference between wellbore hydrostatic pressure and pore pressure ahead of the bit (i.e. inside the formation). But only clay is impermeable enough to preserve this pressure difference as a function of depth. If sands are interbedded between tight shale, also the sand layers will contain pore pressure vs. depth information.
g) From data we read at 2 000 m, Δt = 110 as variable and 70 on the trend line (NB, Δt scale is logarithmic).

$$\rho_{pore} = \rho_{ovb} - (\rho_{ovb} - \rho_{pore,n})(\Delta t_n / \Delta t)^3 = 1.75 - (1.75) * 70/110)^3 = 1.54 \text{ kg/l}$$

The graph reads a pore pressure density of 12 PPG = 1.44 kg/l. Conclusion: The two info sources give rather similar answers.

1.6 Pore pressure, d_c

Task force: Apply all possible warning signs from the well simultaneously, like cuttings density, ROP, d_c, MWD etc. and increase the mud weight accordingly as soon as an increased pore pressure is positively identified. If the well kicks, close it fast in order to minimize annular pressures.

a) To find the d-exponent, solve the R_p eqn. and normalize it

$$Rp = Log (R_p/60RPN) / (log 12 WOB/10^6 d_{bit})$$

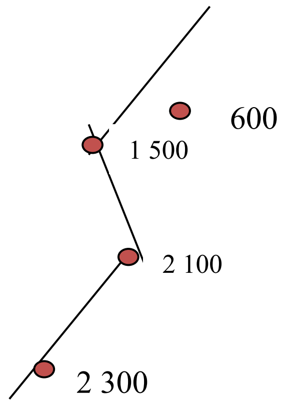
Then solve for each point available, make graph, and establish a normal trend line from 500 m to 1 700 m (drilled with 8.8 PPG mud weight). Instead of calculating the d-exponent in every data point, we pick out 2 points on the established trend line; i.e.;

at 600 m; R_p = 14.0 m/h = 45.9 ft/h,
at 1 500 m; R_p = 12.0 m/h = 39.4 ft/h

d_{600} = log (R_p/60RPM) / log (12WOB / 10^6 d_{bit})

$$d_{600} = \frac{\log\left(45.9/(60\cdot 90)\right)}{\log\left(12\cdot 40\,000/\left(10^6\cdot 17.5\right)\right)} = 1.326$$

$$d_{1500} = \frac{\log\left(39.4/(60\cdot 90)\right)}{\log\left(12\cdot 40\,000/\left(10^6\cdot 17.5\right)\right)} = 1.368$$



And at 2000 m: ROP = 15 m/t = 49.2 ft/h

$$d_{2000} = \frac{\log\left(49.2/(60\cdot 90)\right)}{\log\left(12\cdot 50\,000/\left(10^6\cdot 12.25\right)\right)} = 1.56$$

Likewise at 1 750, 2 100 and 2 300 m (but with different parameters), leading to :

$d_{1750} = 1.53$
$d_{2000} = 1.56$
$d_{2100} = 1.55$
$d_{2300} = 1.56$

b) After mud changed from the normal 8.8 PPG (1.05 kg/l) to 10 PPG at 1 750 m and 13 PPG at 2000 m, the corrected d-exponent becomes (see Figure 1-5):

$d_{c,1750} = 1.53 \cdot 8.8/10 = 1.35$

$$d_{c,2000} = 1.56 \cdot \frac{8.8}{13} = 1.06$$

$$d_{c,2100} = 1.55 \cdot \frac{8.8}{13} = 1.05$$

$d_{c,2300} = d_{c,2000} = 1.06$

c) …The resulting graph:

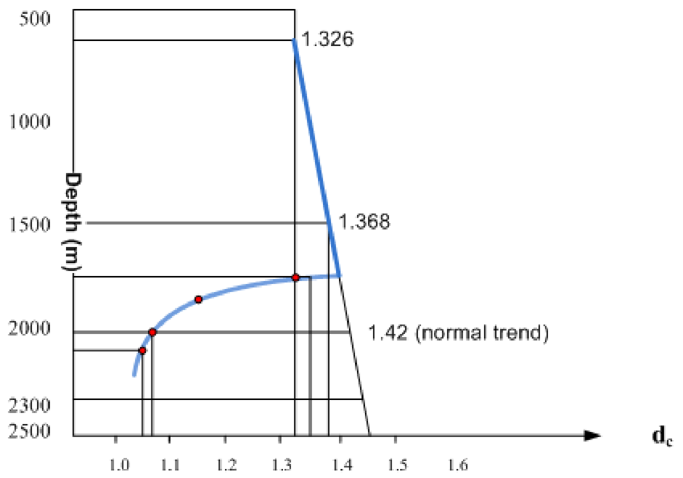


Figure 1-6: Resulting d_c – exponent of exercise 1.5.

Pore pressure at 2 000 m after Eaton's method. $G_{p,normal}$ corresponds to normal pore pressure: 1.03 kg/l (corresponding to 8.8 PPG):

$$G_p = G_o - (G_o - G_{p,n})\left(\frac{d_c}{d_{c,n}}\right)^{1.2} = 2.2 - (2.2 - 1.03)\ (1.05\ /\ 1.42)^{1.2} = 1.386 \text{ kg/l} = 11.8 \text{ PPG}$$

1.7 Pore pressure detection. d_c overlay curve

Overlay curves are constructed through solving Eaton's formula with respect to depth. Let d_c vary:

$$\rho_p = \rho_{ovb} - (\rho_{ovb} - \rho_{p,n})\left(\frac{d_c}{d_{c,n}}\right)^{1.2}$$

$$\frac{d_c^{\,1.2}}{(d_{c,n})^{1.2}} \cdot (\rho_{ovb} - \rho_{p,n}) = \rho_{ovb} - \rho_p$$

$$d_c = \left(\frac{\rho_{ovb} - \rho_p}{\rho_{ovb} - \rho_{p,n}}\right)^{1/1.2} \cdot d_{c,n}$$

By means of this equation the table below presents d_c vs. depth for three different ρ_p. The $d_{c,n}$ is read from Figure 1-7 in the task section.

Interval no	Start of interval	Middle of interval	$\rho_{p,n}$	ρ_o	$d_{c,n}$	Resulting d_c for ρ_p= 1.1	1.2	1.3
1	1 500	1 750	1.03	1.50	1.25	1.12	0.88	0.63
2	2 000	2 250	1.03	1.70	1.30	1.20	1.04	0.87
4	2 500	2 750	1.03	1.85	1.35	1.27	1.13	0.99
6	3 000	3 250	1.03	1.92	1.40	1.33	1.19	1.06
8	3 500	3 750	1.03	1.95	1.45	1.38	1.24	1.11

The result is presented graphically in Figure 1-7:

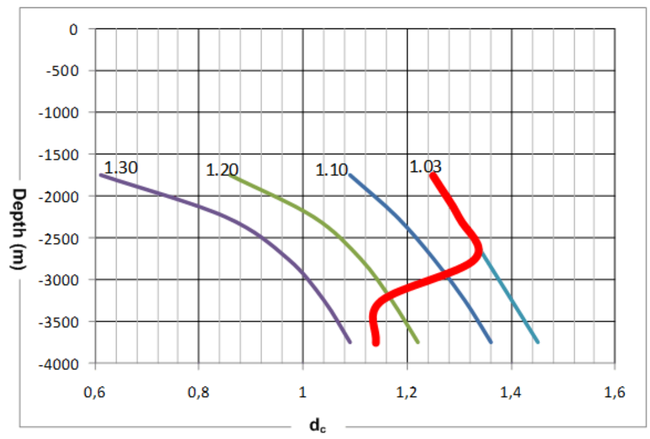


Figure 1-7. Overlay curves on top of field-observed dc exponent (red curve).

1.8 Fracture pressure. Poissn's ratio

a) Fracture pressure is determined by Eaton:

$\rho_{frac} = \rho_{pore} + \tau_3, \tau_3 = \frac{\mu}{1-\mu} \cdot \tau_z$

At shallow depths $\mu = 0.25 \rightarrow \rho_f = \rho_p + \frac{1}{3}\tau_z$

Where $\tau_z = \rho_{ovb} - \rho_{pore} \Rightarrow \rho_f = \rho_p + \frac{1}{3}\rho_{ovb} + \frac{1}{3}\rho_p = \frac{1}{3}(2\rho_p + \rho_{ovb}) \Rightarrow \frac{4}{3}kg/l$

At large depth $\mu \rightarrow 0.5, \rightarrow \tau_3 \rightarrow \tau_2, \rho_f = \rho_{pore} + \rho_{ovb}$

a) Poisson's Ratio $= \frac{\Delta x}{\Delta 2} = 0.5 = \frac{\Delta d}{\Delta h}$

$$V_o = \pi \left(\frac{d}{2}\right)^2 \cdot h$$

After compression the height is reduced to 0.99 h, and the diameter has expanded to d · x, where x is the expansion fraction. Should be 1.005 because then:

$$\mu = \frac{\Delta x}{\Delta z} = \frac{1.005-1}{1-0.99} = \frac{0.005}{0.01} = \underline{\underline{0.5}}$$

The compressed volume is therefore:

$$V_c = \pi \left(\frac{x \cdot d}{2}\right)^2 \cdot 0.99h$$

Letting $V_o = V_c$ we obtain:

$$\pi \left(\frac{xd}{2}\right)^2 \cdot 0.99\,h = \pi \left(\frac{d}{2}\right)^2 \cdot h$$

$$x = \sqrt{\frac{1}{0.99}} = 1.005$$

b) At a low burial depth the sediments are not behaving elastic, not like metamorphic rocks at high depths. At low depths part of the deformation is absorbed by reorientation of the material/reduction of porosity.

1.9 Fracture pressure. LOT

a) It is recommended to make a sketch of the operation and to point out relevant parameters. A pressure vs. TVD-sketch is also recommended. Fracture initiation pressure (leak off), formation breakdown pressure, fracture propagation pressure and minimum horizontal stress can be found.

b) $$\rho_{eq} = \frac{p_{fr}}{gh} = \frac{1\,320 \cdot 9.81 \cdot 2\,400 + 60 \cdot 10^5}{9.81 \cdot 2\,400} = 1575\, kg/m^3$$

c) The slope is an indicator of the compressibility, C, of the

mud + gas in mud
steel wall
formation wall

$$\Delta V = \sum V_i \cdot C_i \cdot \Delta p$$

The 84 l are applied to compress the involved fluid + expand the involved casing, drill string and formation. Assume that 20% of the 84 liters are used for compressing the mud during the leak off test of the 20″ csg. To find the fluid compressibility the total mud volume must first be determined.

$$V_{tot} = V_{209\ m.csg} + V_{463\ m.dp} + V_{90\ m.surf} = 37 + 4 + 1 = 42\ m^3$$

On the straight pressure line from 8.5 (crossing the y-axis) to 17 bars 84 liters (0.084 m^3) are pumped to compress/expend:

$$c = \frac{1}{V} \cdot \frac{\partial V}{\partial p} = \frac{1}{42} \cdot \frac{0.084 \cdot 0.20}{(17 - 8.5) \cdot 10^5} = 4.71 \cdot 10^{-10}\, Pa^{-1}$$

From a chemical handbook we find: $c_{water} = 4.35 \cdot 10^{-10}\ Pa^{-1}$
The 20% assumption of the fluid compression was therefore rather good. Now, with the correct date, we see that the true answer is that it accounts for approximately 18.5% of the total compression.

The practical consequence of large compressibility in the exposed system is that pressure is not immediately transmitted; some of the pressure or energy is spent on compressional work. This means that more fluid is needed before the pressure stabilizes. It will cause no practical problem.

d) $MAASP_{before} = 60 \cdot 10^5 - (1\,320 - 1\,320) 9.81 \cdot 2\,400 = 60 \cdot 10^5\, Pa$
$MAASP_{after} = 60 \cdot 10^5 - (1\,380 - 1\,320) 9.81 \cdot 2\,400 = 50 \cdot 10^5\, Pa$

e)

- Increase cohesion with chemicals
- Wellbore stress augmentation through generation of small fractures
- Increase fracture propagation resistance with filter cake (WBM)
- Need to adjust surface mud cleaning process

1.10 Fracture pressure from field data

a) The most commonly applied formula for estimating fracture pressure is:

$$p_{fr} = p_{pore} + K_i \cdot \sigma_1 \rightarrow \rho_{fr} = \rho_{pore} + K_i \cdot \rho_1 = 1.63 + 0.786(2.0 - 1.63) = 1.899$$

where $K_i = \frac{\mu}{1-\mu}$ and $\sigma_1 = \sigma_2 = p_{ovb} - p_{pore}$

From the Figure 1-10.3 we find at 2 200 m:

$\mu =$ 0.44; Poisson number, resulting in:

$$K_i = \frac{0.44}{1 - 0.44} = 0.786$$

Taking 1 PPG = 0.1198 kg/l and including a Safety margin = 0.5 PPG = 0.06 kg/l we obtain:

Well	Input parameters; read from figures		Estimated	Fracture pressure; read from figures
	ρ_{ovb}	ρ_{pore}	ρ_{frac}	ρ_{rac}
34/10 – 11	2.0	1.53	1.90	1.90
B 103	1.98	1.30	1.84	1.73

b) For 16″ csg, 34/10-11 we obtain: $\rho_{frac} = \frac{P_{leak}}{gh} \frac{169 \cdot 10^5}{9.81 \cdot 1100} = 1\ 566\ kg/m^3$
From Figure 1-10.1 p_{LO} = 50 bar and p_{frac} = 169 bar

c) By including a kick margin of 0.05 kg/l in the fracture data and assuming that the actual mud program include trip margin, the resulting casing program becomes very close to the actual one, as shown in Figure 1-10.2.

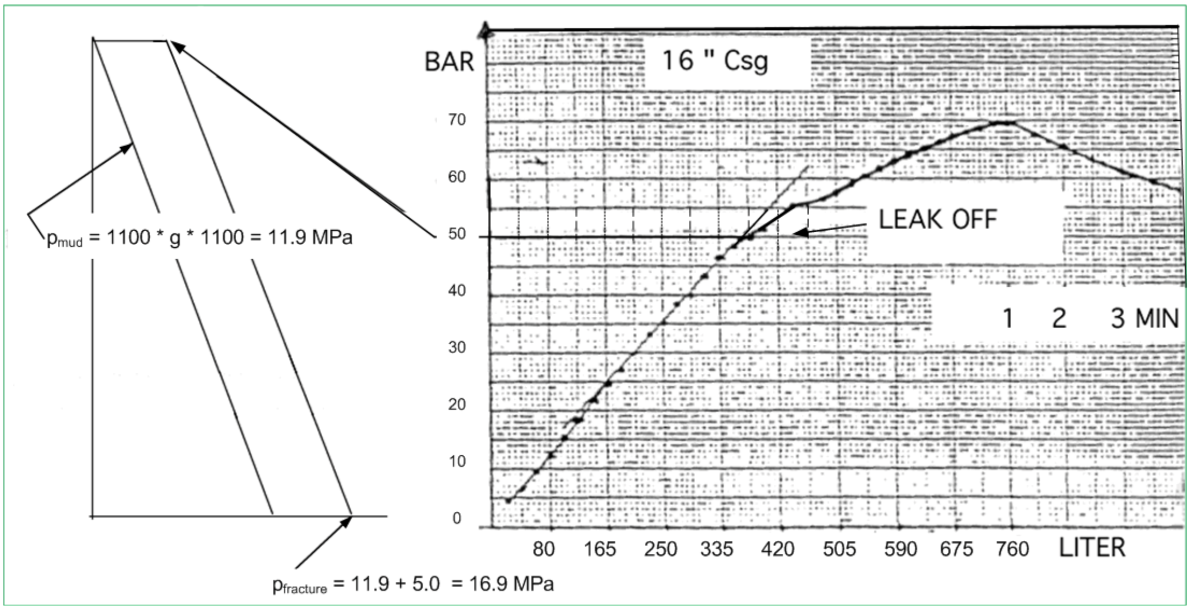


Figure 1-10.1: Relevant LOT parameters.

The observed data and estimated data are summarized here:

Well	MW	Casing size	Shoe depth	ρ_{LO} read from Fig. 1.10-4+5	Estimated ρ_{frac}	r_{frac} read from Fig. 1.10-1
-	kg/l	inch	m	bar	kg/l	kg/l
34/10 – 11	1.07	20	450	17.4	1.47	1.46
34/10 – 11	1.22	16	1100	5.0	1.57	1.61

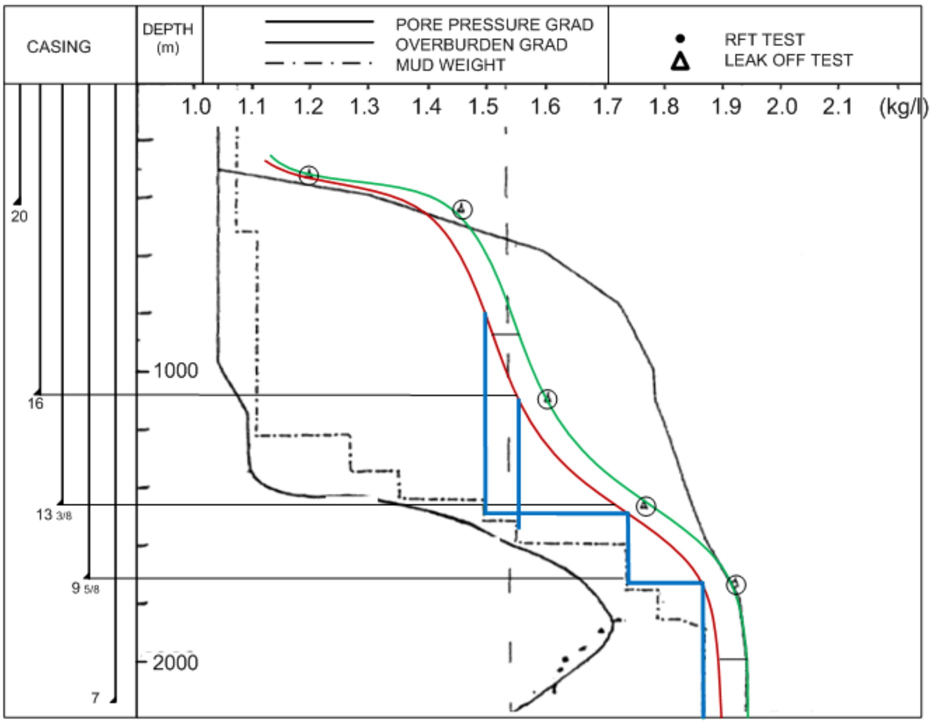


Figure 1-10.2: The real casing program is being reproduced by using the mud pressure (blue line) and fracture pressure minus SM (red curve) as boundaries.

2 Conventional and modified p-control

2.1 Preparing for kick

a) By keeping bottom p > pore p. This is obtained partly by manipulating the surface choke at the choke line outlet, thereby adjusting the SPP.

b) Primary well control can be lost due to:
- High pressure zone not detected
- Mud density too low (gas cut)
- Drilling into neighbor, live well
- Lost circulation due to $p_{well} > p_{fr}$
- Swab during tripping / Not keeping annulus full during tripping
- Emptying riser due to hidden gas (in OBM)

c) …Pulled dry: x is the unknown length of the drill string pulled out

Step 1. Volume displaced = $V_{displaced\ out} = x \cdot Cap_{steel} = x \cdot 4$

Step 2. Dropping level in annulus

$h_{drop} = V_{displaced\ out} / [Cap_{well} - Cap_{steel}] = x \cdot 4 / (57.1 - 4) = 0.075\ x$

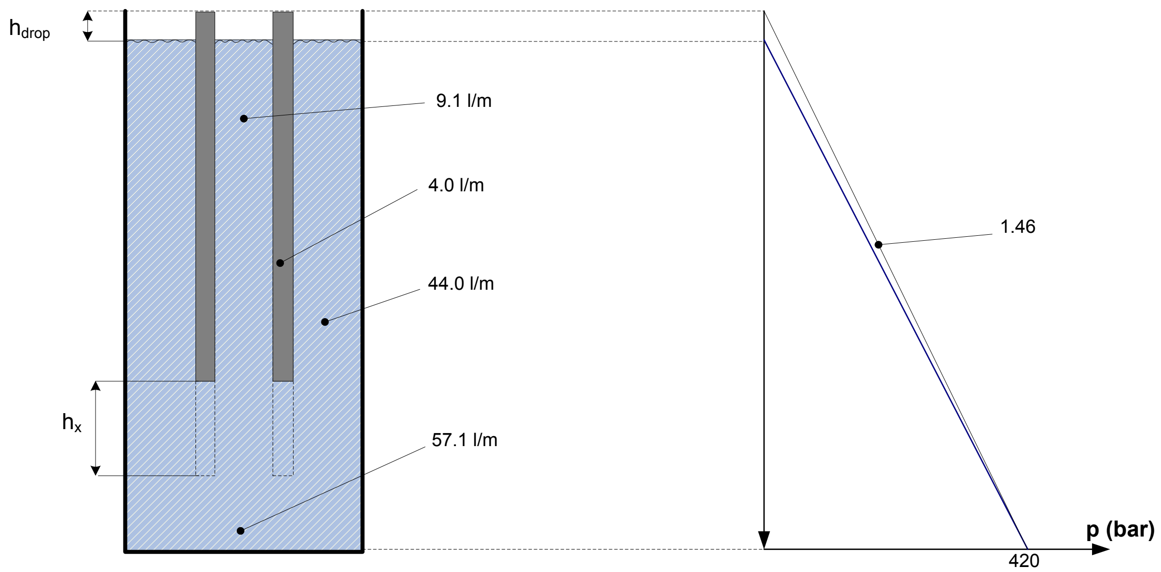
Step 3. Balance between hydrostatic and pore pressure when:

$$\rho_{mud} \cdot g \cdot (h_{well} - h_{bal}) = p_{drop}$$
$$h_{bal} = h_{well} - \frac{p_{pore}}{\rho_{mud} \cdot g} = 2\,900 - 420 \cdot 10^5 / (1520 \cdot 9.81) = 83\ m$$

Step 4: Pulling length x is therefore:

$0.075\ h_x = 83$ m

$h_x = 83/0.075 = 1\ 107$ m



d) Pump until it opens, seen by the sudden increase in the, until now, constant SICP. Or a small hole in the flap would ensure communication. Or use PWD.
e) After pressing "Close upper pipe valve" a pilot signal is activated at the surface and sent through an 1/8″ line to a 4-3 valve (4-openings, 3-positions) in the pod. It opens for and thus routes high pressure oil from the accumulators through a 1″ line to the appropriate side of the selected piston. A shuttle valve makes sure one pod of two is selected (this is one more example of redundancy/high safety level). Make two principle drawing; the control system and a 4/3 control valve. Give name to the relevant equipment parts.
f) Quick changes during choke manipulation is now avoided + pressure is limited by the surface equipment's pressure rating
g) In these cases large wellbore changes leads to changes in friction pressure. Each shift; caused by Δ drilled length; Δ nozzle; Δ BHA, Δ MW etc.
h) Gas is light, has expanded and requires higher back pressure at the surface to balance pore pressure

2.2 Safety margins

a) Riser Margin requires that there is a pressure balance between the sea column and the heavy mud column on one side and the pore pressure on the other:

$$\rho_{sea} \cdot g\, h_{sea} + \rho_{bal} \cdot g \cdot (h_{well} - h_{above}) = \rho_{pore} \cdot g \cdot h_{well}$$

$$\rho_{bal} = 1\ 199\ \ kg/m^3$$

$$RM = \rho_{bal} - \rho_{kill} = 1199 - 1150 = 49\ kg/m^3$$ (ρ_{kick} and ρ_{pore} are here identical)

$$\rho_{mud} > \rho_{bal}\ which\,is\,then OK$$

b) Kick tolerance is the max kick volume (influx) before fracture is estimated to occur at the casing shoe. Assume that the gas density is constant during travelling to the surface. Check first casing shoe info:

$$\rho_{frac} = 1100 + 62 \cdot 10^5 / (9.81 \cdot 1200) = 1\ 631\ kg/m^3$$

To find acceptable kick volume, set up a pressure balance, starting at the casing shoe, where the gas has arrived. All parameters are defined in the illustrating figure.

$$\rho_{frac} \cdot g \cdot h_{cas} + \rho_{gas} \cdot g \cdot h_{gas} + \rho_{mud} \cdot g(h_{well} - h_{gas}) = p_{pore}$$

$$1\ 627 \cdot 9.81 \cdot 1\ 200 + 350 \cdot 9.81 \cdot h_{gas} + 1\ 300 \cdot 9.81(900 - h_{gas}) = 1\ 420 \cdot 9.81 \cdot 2\ 100$$

$$h_{gas} = 165\ m$$

$$V_{kick\ 1200} = 165 \cdot 0.025 = 3.8\ m^3$$

The gas has a certain length, and even a small density: The gas pressure at the bottom of the gas column is therefore the reference pressure. The kick tolerance becomes:

$$V_{kick\ 2100} \cdot h_1 = V_{kick\ 1200} \cdot h_2$$

$$V_{kick\ 2100} = 3.8\ m^3 \cdot \frac{(1\,200 - 150)}{2\,100} = 2\ m^3$$

c) Kick height at the moment of influx, just when MAASP is reached = h_{kick}

$$p_{mud,cs} = p_{frac}$$
$$p_{frac} = p_{LO} + p_{hydr} \cdot g\ h_{csg} = 62 \cdot 10^5 + 1\,100 \cdot 9.81 \cdot 1\,200 = 191.5 \cdot 10^5$$

To find the mud pressure at the casing shoe we start at the bottom

$$p_{mud,CS} = p_{pore} - p_{gas} - p_{mud}$$
$$p_{pore} = \rho_{pore} \cdot g \cdot h_{well} = 1\,420 \cdot 9.81 \cdot 2\,100 = 293 \cdot 10^5$$
$$p_{gas} = 0$$

$$p_{mud} = \rho_{mud} \cdot g \cdot \left(h_{well} \cdot h_{csg} \cdot h_{gas}\right)$$
$$h_{gas} = \frac{V_{kick}}{Cap_{ann}} = \frac{V_{kick}}{0.014} = 70 \cdot V_{kick}$$
$$p_{mud} = 1300 \cdot 9.81 \cdot (2100 - 1200 - 70 \cdot V_{kick}) = 115 \cdot 10^5 - 9 \cdot 10^5 \cdot V_{kick}$$

Comparing the two, $p_{mud} = p_{frac}$, we find V_{kick}: = 8 m^3

d) There are three negative side effects:
   1. The kick tolerance may be surpassed
   2. The handling of the kick becomes more difficult, especially controlling back pressure while gas is passing the choke
   3. The capacity of the surface degasser may be surpasse

2.3 Conventional. Drillers

a) $h_g = V/Cap = 2300/20 = 115\ m$

$(30-20)\cdot 10^5 = \rho_{mud} g h_g - \rho_g g h_g, \quad \rho_g = 612\ kg/m^3$

$p_{pore} = 1500\cdot 9.81\cdot 2500 + 20\cdot 10^5 = 388\cdot 10^5$

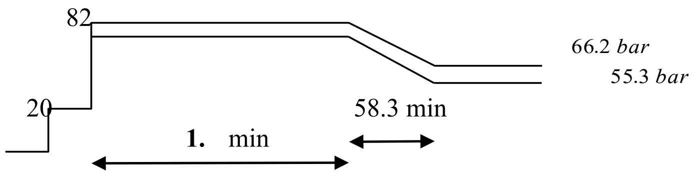
$\rho_{kill} = p_{pore}/(gh) = 1582\ kg/m^3$

V_{DS} = 3500 m · 0.01 = 35 m^3

$Strokes_{DS}$ = V/Cap_{pump} = 35/0.02 = 1750 strokes or 1750 / 30 = 58.3 minutes

ICP = SIDPP + SCP = 20 + 62 = 82 bar

FCP = SCP * ρ_{kill}/ρ_{mud} · = 62 * 1.58 / 1.50 = 66.2 bar



2.4 Kill sheet. W & W. Conventional. Fracturing

a) Some estimation to determine "green" numbers appearing in the kill sheet (Figure 2-4):

$$\rho_e = 1610 + \frac{42.6\cdot 10^5}{3470\cdot 9.81} = 1735 kg/m^3$$

MAASP = (1735-1670) · 3470 · 9.81 = 22.2 · 10^5 Pa or

p_{LO} – (1670-1610) · 3470 · 9.81 = 22.2 · 10^5

Vertical well depth = 3470 + (4215 – 3470) cos 45° = 3996.8 m

And now some of the orange coloured numbers:

ρ_{kill} = 1670 + SIDPP/(9.81 * 3996.8) = 1726 kg/l

Initial circ. pressure: 22 + 23 = 45· 10^5 Pa

Final circ. p: 23 · 1.73 / 1.63 = 23.8 bar

Surface/bit time/strokes:

DP: 9.16 · l/m · 4065 = 37 235 l

DC: 3.167 · l/m · 150 = 475 l => total volume = 37 710 l

Strokes: 37 710 / 19.57 = 1 927 strokes → Time: 1 927 strokes / 20 SPM = 96 min

DC/OH:	15.2 · 150	=	2 280 l
DP/OH:	23.3 · 595	=	13 863 l
DP/csg.:	24.9 ×3270	=	81 423 l
Choke line:	4.56 ×200	=	912 l
Total vol.:		=	98 478 l

Strokes: 9 847 / 19.57 = 5 032 strokes → Time: 5 032 strokes / 20 SPM = 252 min

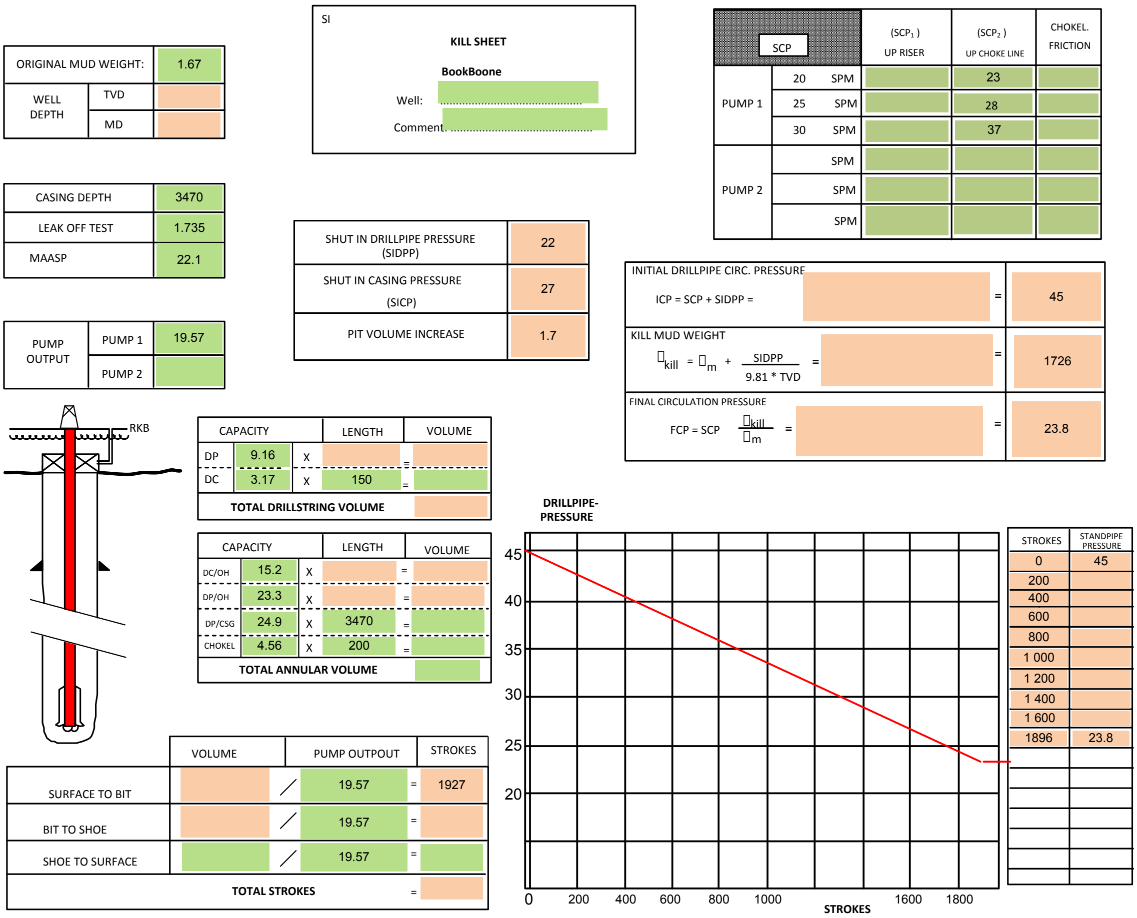


Figure 2-4: Resulting kill sheet.

b) Volume of kick: 1 700 l → $h = 1\,700/15.2 = 111.8\,m$

Vertical height of influx: 111.8 · cos 45 = 79.1 m

Influx density:

$$\rho_{influx} = 1670 - (32 - 22) * 10^5 / (79.1 * 9.81) = 381\ \text{kg/m}^3 \rightarrow \text{compressed gas}$$

c) Density of the mud filling the well from sea bottom must balance the pore pressure (assisted by the sea water column):

$$p_{pore} = 1\ 670 \cdot 3\ 997 \cdot 9.81 + 22 \cdot 10^5 = 676.8 \cdot 10^5 Pa$$

$$p_{pore} = 0 + \rho_{sea} \cdot g \cdot h_{sea} + \rho_{balance} \cdot g(h_{well} - h_{sea} - h_{air})$$

$$\rho_{balannce} = \frac{p_{pore} - h_{seawater} \cdot \rho_{seawater} \cdot 9.81}{(h - h_{seawater} - h_{air}) \cdot 9.81} = 1777\ kg/m^3$$

$\Delta\rho$ = riser margin = 1777 – 1726 = 51 kg/m^3 = 0.05 kg/l

d) Percolation velocity is seen by the increase in surface pressure, the height of mud column it has passed through:

$$h = \frac{\Delta p}{\rho g} = \frac{30 \cdot 10^5}{1670 \cdot 9.81} = 183\ m$$

The vertical rise velocity it therefore: 183 / 30 6.1 m/min = 0.1 m/s

2.5 Engineer's. Conventional. Pressure in 3 points of time

Time # 1(Shut in) at 4 positions:

$$p_{pore} = p_{DP,bottom} = 1\,360 \cdot 9.81 \cdot 1\,500 + 20 \cdot 10^5 = 220 \cdot 10^5\ Pa$$

$$p_{DP,surface} = 20\ bar$$

$$p_{c,bottom} = 220\ bar$$

$$p_{c,top} = 30\ bar$$

Time # 2 (Start pump) at 4 positions:

$p_{DP,bottom} = 220 + 42/2 = 241\ bar$ (50% of the friction is lost in the pipe)

$p_{DP,top} = 20 + 42 = 62\ bar$ (here all the friction is experienced)

$p_{csg,bottom} = 220\ bar$

$p_{csg,top} = 30\ bar$

Time # 3 (Gas at casing shoe) is described graphically in Figure 2-5.1 and 2.5-2:

For this case we need ρ_{kill} and the new friction pressure before the 4 pressures can be estimated

$$\rho_{kill} = \rho_{mud} + \frac{p_{SIDP}}{g \cdot h} = 1\,360 + 20 \cdot \frac{10^5}{9.81 \cdot 1\,500} = 1\,496\ kg/m^3$$

$SCP_2 = 42 \cdot 1.496/1.36 = 46.2$ bar. This happens when kill mud enters the annulus

We need to check where the front of the kill mud is; has it entered the annulus? This we do by comparing the volume of old mud in the drill string with the volume in the annulus below the gas below the casing shoe.

$$V_{DS} = 1500 m \cdot 10 l/m = 15\,000\, l$$

$$V_{ANN-open\ hole} = (600 - 100) \cdot 20 + 100 m \cdot 14 l/m = 11\,400\ l$$

Due to the high drill pipe volume we see that no kill mud enters the annulus before gas reaches the casing shoe. This makes it simpler for us.

The $p_{csg.shoe}$ must balance the pore pressure:

$p_{csg.shoe} + \rho_{mud} \cdot g \cdot (600 - h_{gas}) = p_{pore} + 0$ (no friction in annulus)

$h_{gas,cs} = V_{gas,cs} / Cap_{Dp\text{-}well}$

$V_{gas,cs} \cdot p_{csg.shoe} = V_{kick} \cdot p_{pore}$

$$h_{gas.cs} \cdot Cap_{DB-well} \cdot p_{csg.shoe} = V_{kick} \cdot p_{pore}$$

$$h_{gas.cs} = \frac{1.5 \cdot 220 \cdot 10^5}{0.02 \cdot p_{csg.shoe}} = 1.65 \cdot 10^9 / p_{csg.shoe}$$

$p_{csg.shoe} + 1\,360 \cdot 9.81 \cdot 600 - 1\,360 \cdot 9.81 \cdot 1.65 \cdot 10^9 / p_{csg.shoe} = 220 \cdot 10^5$

$p_{csg.shoe}{}^2 + 8 \cdot 10^6 \cdot p_{csg.shoe} - 2.19 \cdot 10^{13} = 22 \cdot 10^6 \cdot p_{csg.shoe}$

$p_{csg.shoe}{}^2 - 14 \cdot 10^6 \cdot p_{csg.shoe} - 21.9 \cdot 10^{12} = 0$

$$p_{csh.shoe} = 1/2 \cdot (14 \cdot 10^6 \pm \sqrt{(196 + 88) \cdot 10^{12}} = (14 + 17)/2 \cdot 10^9 = 155 \cdot 10^5\ Pa)$$

To find the friction in the drill string we assume a linear increase in friction (until it comes to the bit nozzle at the very end of filling the Drill String). Determine the length filled with kill mud:

$$V_{gas.cs} \cdot 155 = 1.5 \cdot 220 \ \ (1.5 \ \ m^3 \ at \ the \ bottom)$$
$$V_{gas.cs} = 1.5 \cdot 220 / 155 = 2.13 \, m^3$$
$$h_{gas.cs} = V_{gas.cs} \, / \, Cap_{ann} = 2.17 / 0.02 = 109 \, m$$

Volume to be pumped into the annulus before gas reaches casing shoe:

$$V_{ann-openhole} - V_{gas.cs} = 11\,400 - 2\,170 = 9\,230 \ liter$$

Kill mud front has reached this depth inside the drill pipe:

$$h_{kill \ mud \ front} = 1\,500 m \cdot 9\,230 / 15\,000 = 1009 \, m$$

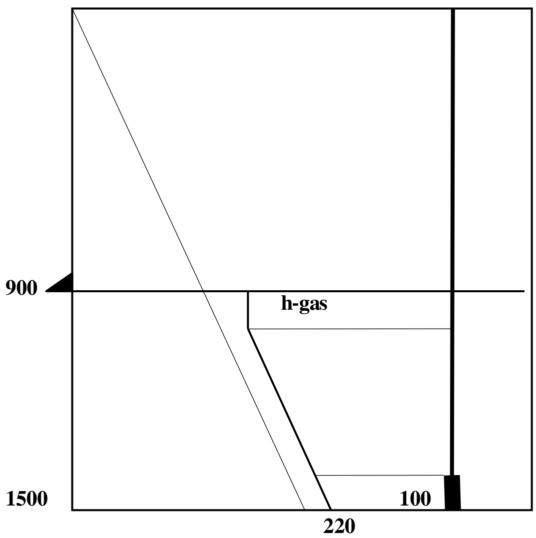


Figure 2-5.1: Situation in #3 in the depth-pressure view.

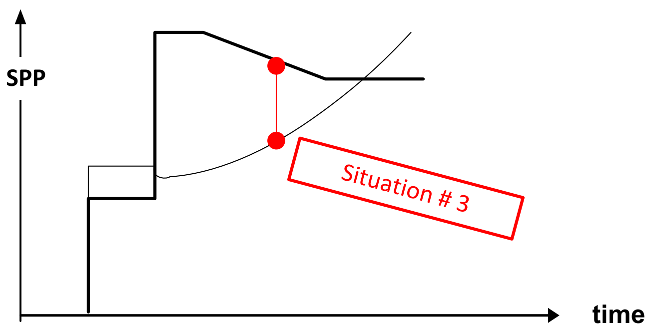


Figure 2-5.2: Situation # 3 in pressure vs. time view.

First now we are ready to estimate all the 4 pressures in time 3:

$$p_{DP,top} = ICP - p_{effect\ of\ killmud} + p_{effect\ of\ increased\ friction} =$$
$$p_{DP,bottom} = 220 + 42 \cdot 0.5 = 241\ bar$$
$$p_{csg,top} = p_{csg.shoe} - p_{hyd,\ csg.shoe} = 155 - 120 = 35\ bar$$
$$p_{csg,bottom} = 220\ bar \text{ (same as ever, when annular friction is ignored)}$$

2.6 Driller's. Conventional. Pressure in 6 points of time

Time # 1: At time of shut-in:

$$p_{1500} = 1360 \cdot 9.81 \cdot 1500 = 200 \cdot 10^5\ Pa$$
$$h_{gas} = \frac{V_{kich}}{Cap_{pc}} = \frac{1050}{14} = 75\ m$$
$$p_{pore} = 200 \cdot 10^5 + 20 \cdot 10^5 = 220 \cdot 10^5\ Pa \quad \text{(hydrostatic + shut-in)}$$

Why is the shut-in pressure (SIC) 40 bars?

$$h_{kick} = \frac{\Delta p}{\rho g} = \frac{(30-20) \cdot 10^5}{1360 \cdot 9.81} = 75\ m$$

$$\Delta p_{ann} = 1360 \cdot 9.81 \cdot 75 = 10 \cdot 10^5 \text{ (additional surface p due to missing hydrostatic p)}$$

Time # 2; Pump has just started:

$$\Delta p_{fric,ann} = 62 \cdot 0.2 = 12.4$$

Pressure increases to 232.4 bar and compresses the gas negligible.

$p_{surfaceDP}$ = 20 + 62 = 82 *bar*
$p_{bottomDP}$ = 62 + 20 + 200 – 62 · 0.3 = 263.4 *bar*

Time # 3: Top of gas reaches casing shoe:

Equivalent circulating density = $1\,360 + \dfrac{12.4 \cdot 10^5}{9.81 \cdot 1\,500} = 1\,444\ kg/m^3$

$$p_x + 1444 \cdot (300 - h_x) \cdot 9.81 = 232.4 \cdot 10^5$$

$$h_x = V_x / 0.02 = 1.050 \cdot 220 \cdot 10^5 / p_x \cdot 0.02 = \frac{33 \cdot 10^8}{p_x}$$

$$V_{kick} \cdot p_{pore} = V_x \cdot p_x \quad \rightarrow \quad V_x = V_{kick} \cdot p_{pore} / p_x = 1.050 \cdot 220 \cdot 10^5 / p_x$$

$$p_{surface,ANN} = 212 \cdot 10^5 - 1\,444 \cdot 1200 \cdot 9.81 = \underline{42\ bar}$$

The pressure is slightly higher than in time # 1 and 2 due to the added friction.
The three other pressures are like in time # 2.

Time # 4: Gas is out:

$p_{surfaceann}$ = *SIDPP* = 20 *bar*

Time # 5: Kill mud has reached 50% down the drill string:

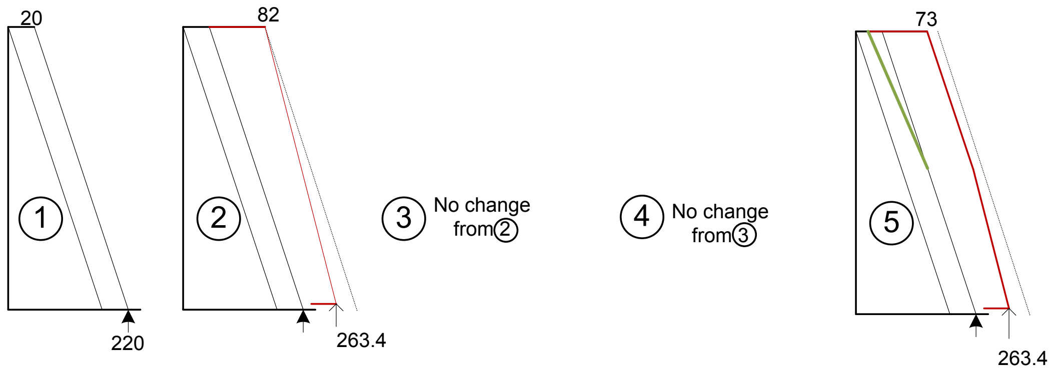
$p_{surface,ann}$ = *SIDPP* = 20 *bar*
Control: $= 232.4 \cdot 10^5 - 1\,444 \cdot 1\,500 \cdot 9.81 = 19.9 \cdot 10^5$

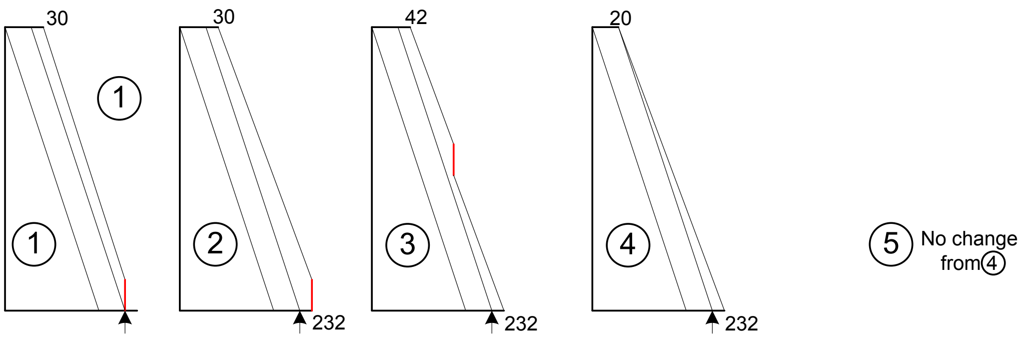
$$\rho_{kill} = 1\,360 + \frac{20 \cdot 10^5}{1\,500 \cdot 9.81} = 1\,496\ kg/m^3$$

SCP_{t4} = 62 · 0.3 · 0.5 · $\dfrac{1496}{1036}$ = 10.23 *bar*
SCP_{t3} = 62 · 0.3 · 0.5 = 9.30 *bar*
Difference = 0.93 *bar*

Friction has increased a little. Half of the SIDPP is now neutralized.

$$p_{surface,dp} = 20 - 10 + 62 + 0.93 = 72.93 \ \ bar$$
$$p_{bottom,dp} = 200 + 20 + 62 - 62 \cdot 0.3 = 263.4 \ \ bar$$





Time # 6: Turn pump off:

$$p_{bottom,both} = 220 bar$$
$$p_{surface,DP} = 10 bar \quad (because\ SIDPP\ is\ now\ reduced\ by\ 50\%)$$
$$p_{surface,ann} = 20 bar$$

2.7 Killing. Fracturing. W&W Conventional

a) Check first if casing shoe can resist the pressure at the moment of close-in:

$$\text{MAASP} = 62 \cdot 10^5 - (1\,200 - 1\,060) \cdot 9.81 \cdot 1\,200 = 45.5 \cdot 10^5$$

Since SICP and MAASP are the same, it shows that the formation is about to be fractured. Fracturing is exactly what happened 30 minutes after shut-in (pressure decrease is observed). If we allow this to develop, or if common killing methods are applied, lost circulation will hinder a successful outcome.

Three options exist in such critical occasions:

1. Try circulating LCM + different pills like Gunk squeeze, Barite plug etc (expected success ratio: 7/10)
2. Reverse circulation (expected success probability e.g.: 10%. The low probability is caused by the MAASP being so close to SICP)
3. «Bull heading» + LCM or cementing (expected success probability e.g.: 30%, the low probability is caused by the large open hole length)

Bull heading and reverse circulation will, due to the long open section, often cause the casing shoe formation to rupture, causing lost circulation/underground blowout (which is highly probable in this case).

If, after having tried circulating LCM for a while, unsuccessfully, turn off pumps, check if the loss heals itself. It often will with WBM. If not hang DP in BOP, close BOP, pull away and start drilling a relief well.

b) Can Wait & Wait method be applied in the new case?

The difference between MAASP – SICP has now improved by 25.5 bars compared to the previous example. We assume that the annular pressure loss from casing shoe and up hardly can exceed 25.5 bars since the total friction loss in the complete well is 60.8 bars. But how will it be when gas is just below the casing shoe. This is a critical situation and must be checked. The critical situation is described in Figure 2-7: (one could argue that test if the Driller’s method will work, then also W&W will work. However, this is just an exercise)

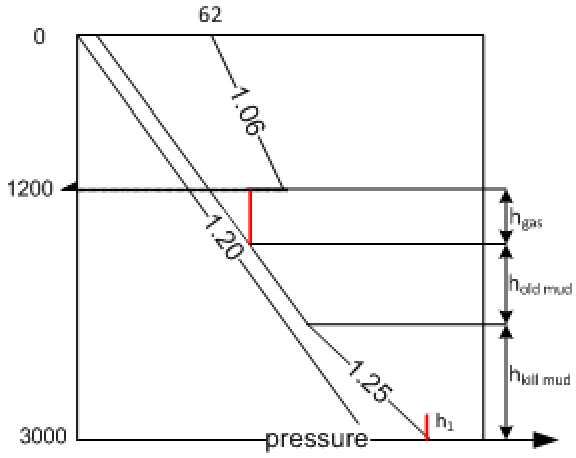


Figure 2-7: Gas reaches casing shoe – W&W method.

The strategy is to compare well bore pressure when the gas passes the casing shoe, with the fracture pressure.

1. Formation pressure:

$$p_{pore} = \rho_1 \cdot g \cdot h_w + p_{sidp} = 1\,200 \cdot 9.81 \cdot 3\,000 + 15 \cdot 10^5 = 368.16 \cdot 10^5$$

New mud to balance pore pressure:

$$\rho_{kill} = p_{pore} / gh_w = 368.16 \cdot 10^5 / 9.81 \cdot 3\,000 = 1251 \ kg/m^3$$

2. Fracture resistance at 1200 m = $62 \cdot 10^5 + 1060 \cdot 9.81 \cdot 1200 = 186.8 \cdot 10^5$
3. Find height of gas when at bottom, h_1

$$V_{kick} = Cap_{dc-w} \cdot h_1$$
$$2.3\ m^3 = 0.029 \cdot h_1 \Rightarrow h_1 = \frac{2.3}{0.029} = 79.3\ m$$

4. Real gas density:

$$V_{kick} = h_1 \cdot Cap_{dc-w} = h_1 \cdot 0.029 = 2.3\ m^3$$
$$\rho_{mud} \cdot g \cdot h_1 - \rho_{kick} \cdot g \cdot h_1 = p_{sic} - p_{SIDP} \quad \rightarrow \quad \rho_{kick} = 557.3\ kg/m^3$$

5. Pressure balance when gas has reached the casing shoe: Start at bottom (p_{pore}) and move up to the casing shoe where the pressure is p_x:

$$p_x = p_{pore} - \rho_{kill} \cdot g \cdot h_{kill\ mud} - \rho_{old\ mud} \cdot g \cdot h_{old\ mud} - \rho_{kick} \cdot g \cdot h_{gas}$$

Height of old mud which is inside the DS at time of shut-in:

$$h_{old\ mud} = h_2 = \frac{V_{ds}}{Cap_{ann}} = 240\ m$$
$$h_{kill\ mud} = 3000 - 1200 - h_{gas} - h_{old\ mud}$$

h_{gas} is found through the law of compressible gas:

$V_{kick} \cdot p_f = V \cdot p_x$ where $V = h_{gas} \cdot Cap_{dp\text{-}w}$

$2.3 \cdot 368.16 \cdot 10^5 = h_{gas}\ 0.1 \cdot p_x$

→ $p_x = 8.47 \cdot 10^8 / h_{gas}$

Combine the two expressions of p_x. Now h_{gas} can be determined.

$$h_{gas} = -147.5 \cdot 10^5 \pm \sqrt{147.5 \cdot 10^5 + 2.3 \cdot 10^{13}} \Big/ (2 \cdot 6795.4) = 55.9\,m$$

6. Finally, inserted to find p_x:

$$p_x = \frac{8.47 \cdot 10^9}{55.9} = 151\ bar$$

If the gas was assumed weightless (worst case), p_x would increase to 151 bars. In other words, the formation will not fracture.

2.8 Killing. Fracturing. W & W. Conventional II

a) $p_{pore} = 1400 \cdot 9.81 \cdot 2000 + 10 \cdot 10^5 = 284.7 \cdot 10^5\ Pa$

$$\rho_{kill} = \frac{p}{gh} = \frac{284.7 \cdot 10^5}{9.81 \cdot 2000} = \underline{1451\,kg/m^3}$$

Casing shoe pressure at time of shut in:

$$p_{740-1} = SICP + p_{hydr}$$
$$p_{740-1} = 22 \cdot 10^5 + 1\,400 \cdot 9.81 \cdot 740 = \underline{18.66\ MPa}$$

Later check gave $p_{740\text{-}1}$ = 12.36 MPa. Casing shoe pressure at time of gas at shoe. At this time also the gas height is unknown; two unknowns require two independent equations:

$$p_{740-2} = p_{hyd,gas} + p_{hydr\ old\ mud} + p_{kill} = p_{mud}$$
$$p_{740-2} + h_3 \cdot 1\,400 \cdot 9.81 + h_2 \cdot 1\,451 \cdot 9.81 = 284.7 \cdot 10^5$$
$$h_3 = \frac{V_{dp}}{C_{ann}} = \frac{0.01 \cdot 2000}{0.06} = 333\,m$$
$$h_2 = 2000 - 740 - h_3 - h_g = 927 - 7.12 \cdot 10^8 / p_{740-2}$$
$$h_g = \frac{V_g}{C_{ann}} = \frac{42.7 \cdot 10^5}{p_{740-2} \cdot 0.06} = \frac{7.12 \cdot 10^8}{p_{740-2}}$$
$$V_g \cdot p_{740-2} = V_{kick} \cdot p_{pore}$$
$$V_g = \frac{V_{kick} \cdot p_{pore}}{p_{740-2}} = \frac{42.7 \cdot 10^6}{p_{740-2}}$$

The final equation becomes: $p_{740-2}{}^2 - 107 \cdot 10^5 \cdot p_{740-2} - 1.013 \cdot 10^{13} = 0$

$$p_{740-2} = 116\,bar$$

b) Surface to bit volume: $0.01 \cdot 2\,000 = 20$ m³

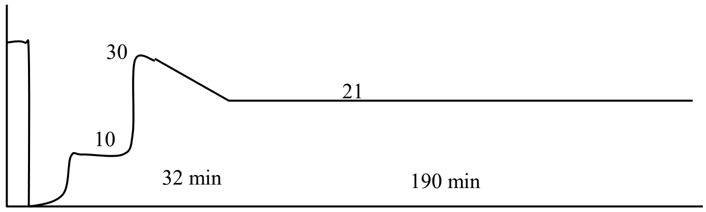
Bottom to surface volume: $0.06 \cdot 2\,000 = 120$ m³

Time of pumping mud from surf-to-bit: $\dfrac{20\ m^3}{\dfrac{21 \cdot 30}{1\,000}} = \dfrac{2\,000}{63} = 32\ \text{min} = 952\ \ strokes$

Time bottom-to-surf: $\dfrac{120}{\dfrac{21}{1000} \cdot 30} = 190$ min = 5 714 strokes

Initial pump pressure: SCP_1 + SIDPP = 20 + 10 = 30 bars

Final pump pressure: SCP · 1 451 / 1 400 = 21 bars



c) Yes, annular pressure increases and the danger of fracture will increase. DP and ANN pressure must then be reduced by the amount of Δp_{ann}.

d) Be quick in order to hinder the pressure to build up when the gas rises without expansion.

2.9 Is conventional killing acceptable?

For both evaluations we need some basic knowledge:

Mud pressure: $p_{3000} = \rho_{mud} \cdot gh = 1\,500 \cdot 9.81 \cdot 3\,000 = 441.45 \cdot 10^5$ Pa

Calculate SIDPP: $p_{sidp} = p_{pore}\ p_{3000} = 451.5\ 441.5 = 10$ bar

Gas height at shut in $h_{kick} = \dfrac{V_{kick}}{Cap_{ann}} = \dfrac{20}{0.02} = 100\,m$

Shoe pressure at shut in: $p_{2000} = 451.5 \cdot 10^5 - (1\,000 - 100) \cdot 9.81 \cdot 1\,500 = 320 \cdot 10^5$ Pa

$p_{fracc,2000} = 1\,700 \cdot 9.81 \cdot 2\,000 = 333.5 \cdot 10^5$ Pa

→ No fracture at shut-in moment, but close enough to suggest lost circulation material (LCM) to be added to the mud.

a) For the Driller's method we need to add frictional pressure at the shoe. This includes friction in the drill string, the choke line and the friction lost between the choke inlet and the casing shoe:

$p_{2000,\ dynamic} = 326 \cdot 10^5 + 15 \cdot 10^5 + 5 \cdot 10^5 \cdot 950/1950 = 344 \cdot 10^5$ Pa

➔ Fracture will occur immediately after start-up of the pump.

b) Now the volumetric method must be tested. Here is no friction. But we now need to check when the gas arrives at the casing shoe. The pressure becomes p_x. Follow the hydrostatic pressure line like in Figure 2-9.

$p_x = 451.5 \cdot 10^5\ (1000\ h_x)\ 9.81 \cdot 1500 = 304.3 \cdot 10^5 + 14\,715\ h_x$

$V_{kick} \cdot 451.5 = V_x \cdot p_x = 0.02 \cdot h_x \cdot p_x$

$$p_x = \frac{2 \cdot 451.5 \cdot 10^5}{0.02 \cdot h_x} = \frac{4.52 \cdot 10^9}{h_x}$$

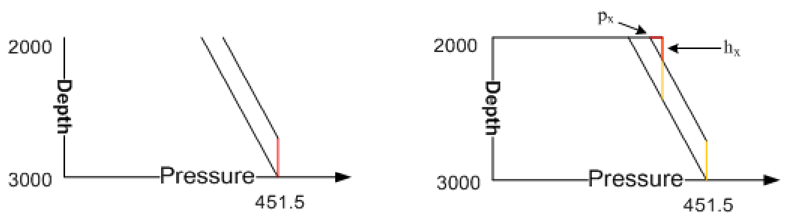


Figure 2-9: The pressure situation during processing the Volumetric method.

Combining the three last equations with respect to h_x, it result I a quadratic equation. Solved:

$$h_x = \frac{-b \pm \sqrt{b^2 - 4ac}}{2a} = \frac{-3 \cdot 10^7 \pm \sqrt{\left(3 \cdot 10^7\right)^2 + 4 \cdot 1.47 \cdot 10^4 \cdot 4.52 \cdot 10^9}}{2 \cdot 1.47 \cdot 10^4} = 140\,m$$

$$p_x = \frac{4.52 \cdot 10^9}{136} = 332 \cdot 10^5\,Pa$$ → Fracture will not occur under these conditions.

If the mud pressure was closer to the fracture pressure as gas passes the casing shoe, the only solution would be the modified method, where 15 bars can be subtracted from the surface pressures.

2.10 Killing operations. Modified due to high choke line friction

a) Primarily by using a mud which results in higher pressure than the pore pressure. Primary well control may be lost by swab pressure, lost circulation, high pressure gas zone & barite sagging.

b) Modified method:
In the modified method the surface pressure is modified at the start of the killing operation. Subtract choke line friction (or annular friction) from shut-in pressures.
Advantage:
Engineer's method: An extra safety factor is brought into the system because the annular pressure will be lower than in the Driller's as soon as kill mud enters the annulus and kill mud is circulated from time zero. As a result the drill pipe or pump pressure is reduced immediately from the initial ICP.

c) Whenever it is not possible to circulate from the bottom. If not circulating from the very bottom there will be a part of the annulus which will be related to uncertainty.

d) To avoid quick changes in the choke pressure/limits in the surface equipment and to minimize annular friction.

e) In Figure 2-10 the surface choke pressure behavior is indicating the importance of friction in the annulus.

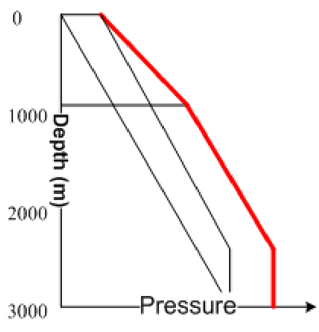


Figure 2-10: Pressure before and after (red) pump-start.

Estimate first two control information:

$p_{pore} = 1320 \cdot 9.81 \cdot 3000 + 11 \cdot 10^5 = 399.5 \cdot 10^5$ Pa

$p_{frac2000} = 1180 \cdot 9.81 \cdot 2000 + 45 \cdot 10^5 = 276.5 \cdot 10^5$ Pa

During killing the well the three critical situations are the first, second and third danger. We start our evaluation with the standard Driller's method, but without neglecting the annulus friction since it is so obviously high.

First danger; the formation may fracture during shut in:

$p_{well,2000}$ at shut in $= 15 \cdot 10^5 + 1320 \cdot 9.81 \cdot 2000 = 274 \cdot 10^5$ Pa
or MAASP $= 17.5 \cdot 10^5$ → Since MAASP > SICP → no fracture

Second danger; start circulating. Will shoe strength be high enough?

We see from the slow rate tests that at 15 SPM the $\Delta p_{chokeline}$ is 10 bars more than up the riser. We assume that the pressure loss in the annulus is 10 bar. We understand immediately from the MAASP-info that the formation will fracture. Just to control:

$$p_{well,\,2000} = p_{well,\,1200} + \Delta p_{ann} = 274 \cdot 10^5 + 10 \cdot 10^5 = 284 \cdot 10^5 \text{ Pa}$$

The well will fracture. Use now the modified method. The pressure will then be reduced by 10 bars, and no fracture.

Third danger; will formation hold when gas reaches casing shoe, after having switched to modified method?
The pressure at the casing shoe when gas is there we call p_x.

$$p_x + (1000\ h_2)\ 1320 \cdot 9.81 = p_{pore}$$
$$p_{pore} \cdot V_{kick} = p_x \cdot V_x$$

The estimation will, in principle, be exactly like in the previous exercise. The casing pressure p_x when the gas is at the casing shoe becomes 210 which shows there will be no fracture. If it was closer the next option is the Modified Engineers. Then it must first be checked if the kill mud is entering the annulus before the gas reaches the casing shoe, in a sufficient manner. Otherwise the Engineer's method would not improve the situation.

Start pump at a slow rate. When SICP starts to increase the control pressure is shifted from annular pressure to the corresponding pump pressure (the SIDPP).

2.11 Driller's. Modified due to choke line friction II

The parameters are easier to estimate when you see the involved factors in a pressure depth view like in Figure 2-11.1. Modified involves reducing the SPP and the choke pressure by the amount corresponding to the choke line friction.

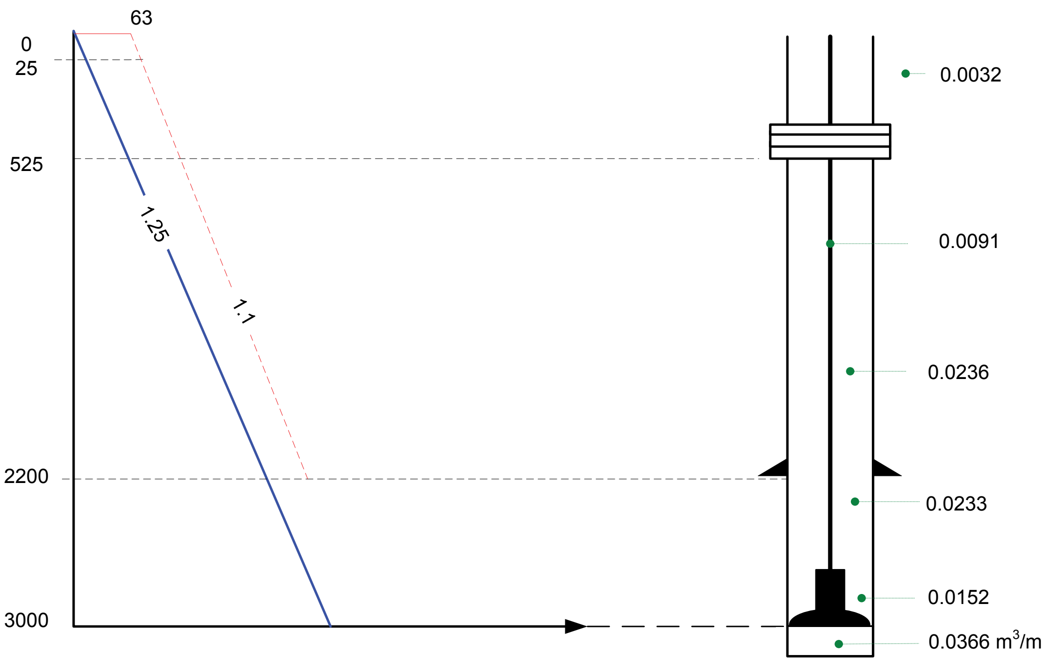


Figure 2-11.1: Data and information in exercise 2-10.1.

1) $MAASP = p_{LO} - (\rho_{now} - \rho_{previous}) \cdot g \cdot h = 63 \cdot 10^5 - (1\,250 - 1\,100) \cdot 9.81 \cdot 2\,200 = 30.6 \cdot 10^5 Pa$

2) $V_{DS} = L_{DP} \cdot Cap_{\Delta p} + L_{DC} \cdot Cap_{DC} = 2\,900 \cdot 0.0091 + 100 \cdot 0.004 = 26.79\, m^3$

3) $V_{ann\,1} = L_1 \cdot Cap_1 + L_2 \cdot Cap_2 = 100 \cdot 0.0152 + 700 \cdot 0.0233 = 17.83\ m^3$

4) $V_{ann\,2} = V_{ann\,1} + L_3 \cdot Cap_3 = 17.83 + (2\,200 - 525) \cdot 0.0236 = 57.36\, m^3$

5) $V_{ann} = V_{ann\,2} + 525 \cdot 0.0032 = 59.04 m^3$

6) $\rho_{kill} = \rho_{mud} + \frac{SIDPP}{g \cdot h} = 1250 + \frac{28 \cdot 10^5}{9.81 \cdot 3\,000} = 1345\, kg/m^3$

7) a) $Initial\ Casing\ Pressure = \rho_{mud} \cdot g \cdot h_{cs} + SICP + \Delta p_{choke\ line} = 1\,250 \cdot 9.81 \cdot 2\,200 + 52 \cdot 10^5 + 8 \cdot 10^5 = 330 \cdot 10^5\ Pa$

b) Answer a) minus 8 bars = 322 bar

8) $ICP = SIDPP + SCP - \Delta p_{choke\ line} = 28 + 30 - 8 = 50\ Bar$

9) $FCP = SCP \cdot \frac{\rho_{kill}}{\rho_{mud}} = 22 \cdot \frac{1.345}{1.25} = 23.7\ Bar$ (see Figure 2-10.2)

10) $MAASP = p_{LO} - (\rho_{kill} - \rho_{mud}) \cdot g \cdot h$

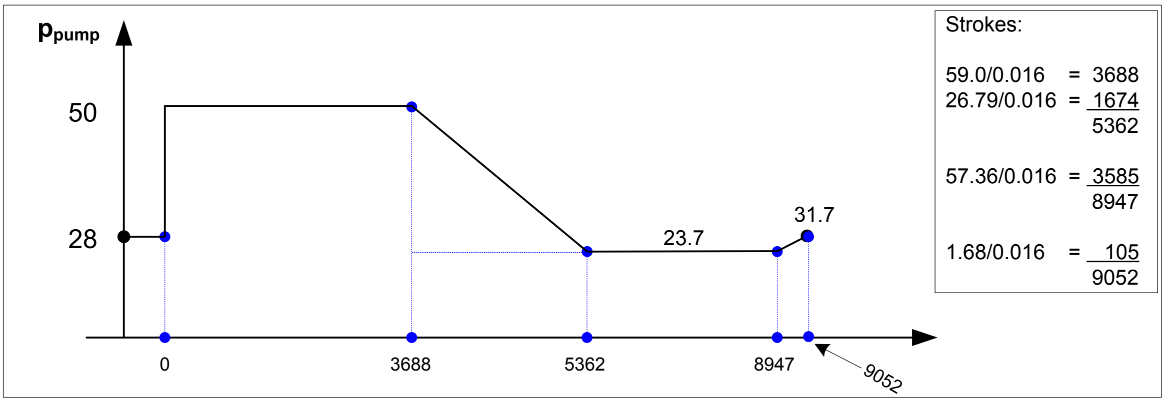


Figure 2-10.2: Pump pressure vs. time.

2.12 Engineer's. Modified. Pressure at time #2 and 3

In the modified method you subtract Δp_{ann} from both sides: $42 \cdot 0.2 = 8.4\, bars$

At time 2: Pump has just been started.

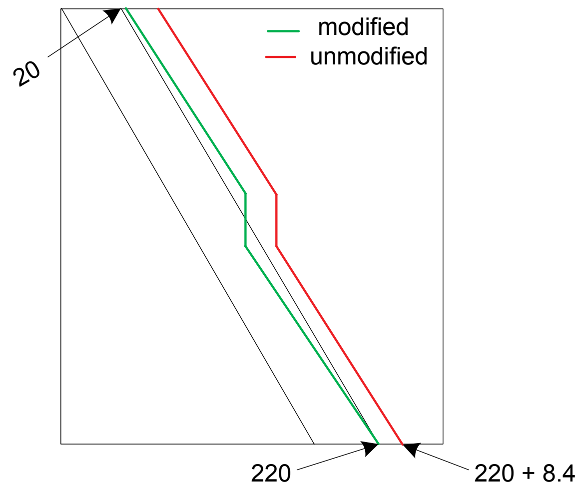
$$p_{dp,bottom} = p_{hydr} + SCP - p_{fric.dp} - \Delta p_{ann}$$
$$p_{dp,bottom} = 220 + 42 - 16.8 - 8.4 = 236.8\ bar$$

$$p_{dp,top} = 20 + 42 - 8.4 = 53.6\ bar$$
$$p_{csg,bottom} = 220 + 8.4 - 8.4 = 220\ bar$$

The annular friction is now neutralized

$$p_{csg,top} = 30 - 8.4 = 21.6\ bar$$

At time 3: Top of gas has reached casing shoe



The modified method creates an annular pressure situation as if the annular friction is zero.

2.13 Modified. Stop in operation

a) The resulting pump pressure schedule is shown in Figure 2-13.1:

Pump flow rate (pr. pump stroke): $\frac{pump\ rate}{SCR} = \frac{800\,l}{\min \cdot 30\ stroke/\min} = 26.7\ \ l/stroke$

Strokes to fill the DP: $\frac{3\,000 \cdot 10}{26.7} = 1125\ strokes$

ICP = SIDPP + SCP = 30 + 38 = 68 bar

$$\rho_{kick} = \rho_1 + \frac{SIDPP}{3\,000 \cdot 9.81} = 1\,400 + 102 = 1\,502\ \ kg/m^3 = 1.5\ \ kg/l$$

FCP = $SCP_1 \cdot 1.5/1.4$ = 40.7 bar

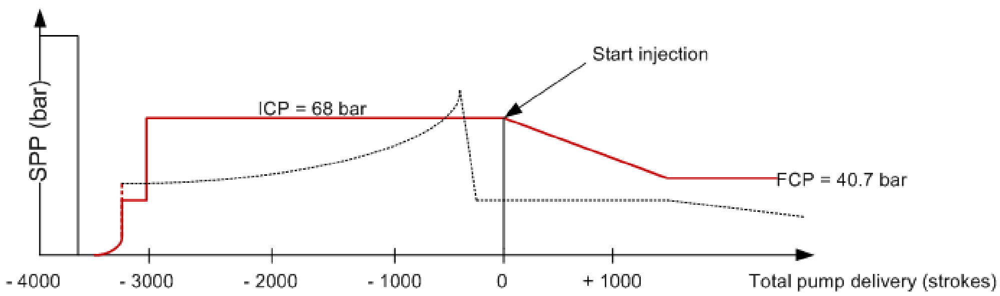


Figure 2-13.1: Pressure variation during killing. Red lines represent DS, black = csg.

b) The crucial question is if the casing shoe will hold. One (of several) ways to check this is through MAASP:

$$MAASP = p_{LO} - (\rho_1 - \rho_{LO})\ g\ h_{csg} = 115 \cdot 10^5\ (1\,400 - 1\,060) \cdot 2\,000 \cdot 9.81 = 48.3 \cdot 10^5$$

This is well above SICP. However, with 15 bar pressure drop in the choke line (53 – 38), the pressure at the casing shoe will increase by 37 + 15 = 52 bars when the pump is started. The formation will fracture at the start of the killing operation if the conventional method was selected.

c) In Figure 2-13.2 the pump was turned off and the well shut in at 1 000 strokes. Gas will rise and bring the pressure up in both the annulus and the drill string (left, assuming no gas dissolves in WBM), unless the gas starts dissolving as it percolates up into new, clean OBM (right). If dissolution dominate4s over rising-pressure effects, pressure will (eventually) decline.

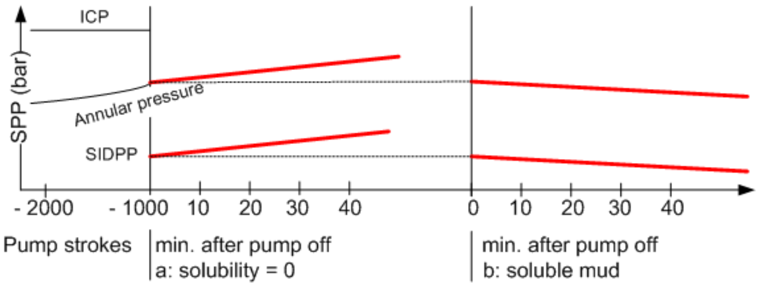


Figure 2-13.2: Pressure evolution (red lines) after pump is shut off and BOP closed at minus 1 000 strokes.

2.14 Modified. More realistic drill string

a) The pump schedule is shown in the resulting table below and in Figure 2-14:

$$p_{initial} = 31 + 20 = 51\ Bar \qquad p_{final} = 31 \cdot \frac{1770}{1700} = 32.3\ Bar \rightarrow \Delta p_{friction} = 1.3\ Bar$$

Assumes that 50% of the friction increases linearly in the two drill string parts and jumps another 50% (0.15 + 0.50 = 0.65 bar) when the kill mud enters the nozzles.

$$\rho_{kill} = 1\,700 + \frac{20 \cdot 10^5}{9.81 \cdot 3\,000} = 1768 = 1.77\ kg/l$$

$$Time\ to\ fill\ the\ upper\ DS = \frac{V}{q} = \frac{l_{DS} \cdot Cap_{DS}}{q_{pump} \cdot SPM} = \frac{1\,500 \cdot 15}{20 \cdot 30} = 37.5\ min$$

$$Time\ to\ fill\ the\ lower\ DS = \frac{V}{q} = \frac{1\,500 \cdot 6}{20 \cdot 30} = 15.0\ min$$

$$Time\ to\ fill\ the\ annulus\ (remove\ gas) = \frac{V}{q} = \frac{10 \cdot 200 + 30 \cdot 2\,800}{20 \cdot 30} = 143.3\ min$$

On bases of input (left), resulting surface pressure variation in the drill string then becomes:

Depth	Start and end pressure	Friction increase	SIDPP reduction	Resulting pressure	Δ time	Resulting time
m	bar	bar	bar	bar	min	min
0	51	0	0	51.0	143.3	143.3
1500		0.325	10	41.325	37.5	180.8
3000		0.65	20	31.65	15.0	195.8
3000+bit	32.3	1.30		32.30	0.0	195.8

Graphically:

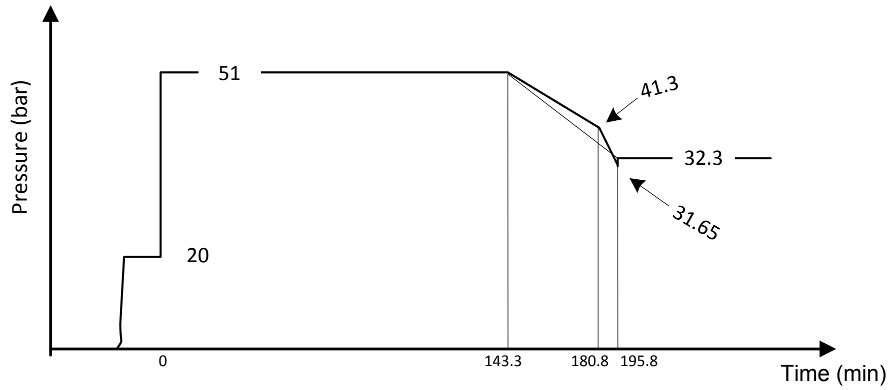


Figure 2-14: Pressure during simplified (one straight line during filling drill string with kill mud) and real drill string geometry.

b) Compared to the standard killing operation, where the friction pressure is the annulus is ignored sincie it is so small, the modified method will neutralize the effect of large annular pressure loss (to avoid fracturing at casing shoe).

2.15 Modified. More realistic drill string II

Need to find friction pressure during killing

$$ICP = 42 + 30 = 72 \text{ bar}$$
$$\rho_{kill} = \rho_1 + SIDPP/(g \cdot h) = 1\,220 + 20 \cdot 10^5 / (9.81 \cdot 1\,500) = 1\,356 \text{ kg/m}^3$$
$$FCP = 42 \cdot 1\,356 / 1\,220 = 46.7 \text{ bar}$$

The added friction after kill mud is in place (assume all, in fact around 90 %) is added in the drill pipe:

$$\Delta p_{friction} = FCP – SCP = 46.7 – 42 = 4.7 \text{ bar}$$

To determine the changing pressure during filling the drill string:

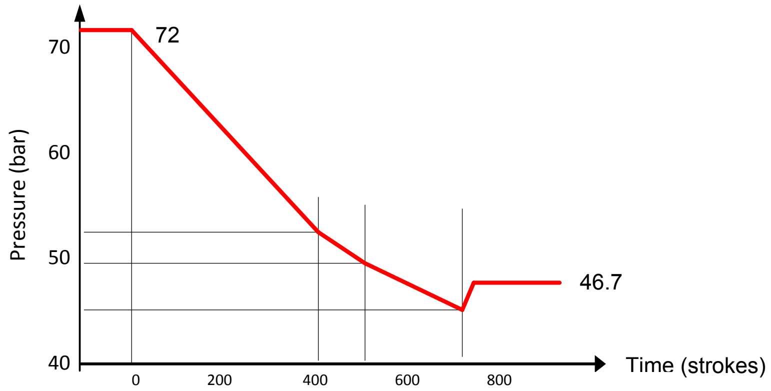
$$SPP = SCR + SIDPP – SIDPP \cdot TVD / TVD_{final} + (FCP – SCP) \cdot (0.5 + 0.5 \text{ at } MD_{final})$$

Control-volume and # of strokes to fill:

$$V_{DP} = \pi r_1^2 \cdot l_1 + \pi r_2^2 \cdot l_2 = (2.0 \cdot 0.0254)^2 \cdot \pi \cdot 1\,500 + (1.5 \cdot 0.0254)^2 \cdot \pi \cdot 500 = 14.44 \text{ m}^3$$
Strokes total DP = V_{DP}/Cap_{pump} = 14 440 / 20.2 = 715 strokes
Strokes at 1000 mMD = 8 100 / 20.2 = 401 strokes
Strokes at 1500 mMD = 401 + 2 290 / 20.2 = 516 strokes
Strokes at 2000 mMD = 516 +4 050 / 20.2 = 716 strokes

In this table the inp0ut is to the left, the estimations in the middle, and the resulting SPP to the right (vs. strokes)

Depth TVD	MD	Strokes	Orig SCP	+ SIDPP	- 30 · TVD/1500	+ 7 · MD/2000 · 0.5 (*)	+7 · 0.5	= SPP
0	0	0	42	30	0	0	0	72
1000	1000	401		30	- 20	+ 0.9 (*0.4)	0	52.9
1250	1500	516		30	- 25	+ 1.9 (*0.8)	0	48.9
1500	2000	716		30	- 30	+ 2.4 (* 1.0)	0	44.4
1500	2000	716		30	- 30	+ 2.4 (* 1.0)	+ 2.4	47.8



2.16 Modified and volumetric

a) Determine the test pressure at surface:

$p_{fr,1000} = \rho_{frac} \cdot h_{csgshoe} = 0.14 \cdot 1\,000 = 140 \text{ bar} = 14 \text{ MPa}$

$p_{LO} = p_{fr} - p_{hyd} = p_{fr} - 1030 \cdot 9.81 \cdot 1\,000 = 3.9 \text{ MPa}$

b) Determine first the height of the gas above the DC, since kick volume is > $V_{ann,dc}$:

$$V_{ann,dc} = Cap_{dc} \cdot h_{dc} = 0.013 \cdot 200 = 2.6 m^3$$

$$h = \frac{V_{kick} - V_{ann,dc}}{Cap_{ann}} = \frac{3-2.6}{0.025} = 16\ m \rightarrow \text{total gas height} = 200 + 16 \text{ m}$$

Influx density: $\rho = \rho_m - \frac{\Delta p}{gh} = 1300 - \frac{(26-12)\cdot 10^5}{9.8(216)} = 670\ kg/m^3$ (Correction: Replace 670 by 640)

The influx consists of compressed gas.

c) Graphical view in Figure 2-16.1.

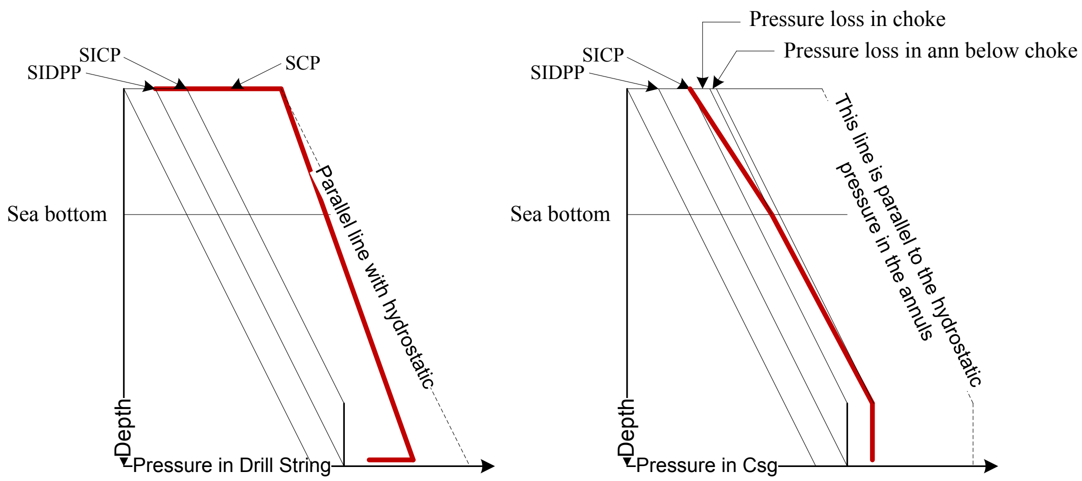


Figure 2-16.1: Pressure in drill string (left) and in annulus (right) just after pump is started.

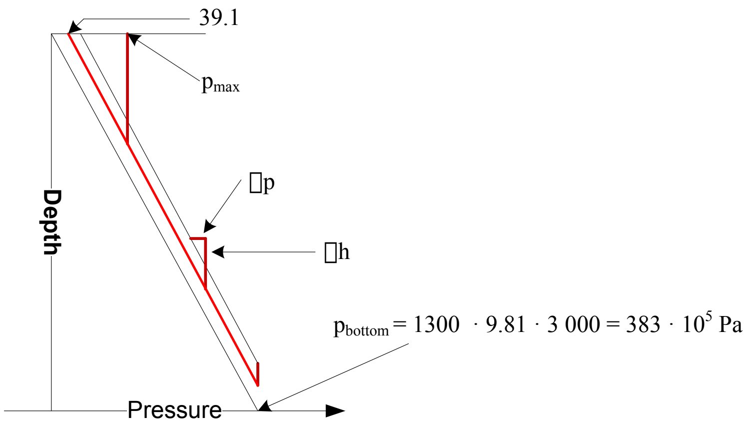


Figure 2-16.2: Pressure evolution in the well during volumetric killing. The hydrostatic line, starting at 29 + 5 + 5.1 at the surface, is the line the bottom of the gas will follow in order to maintain the requirement: keep the bottom hole pressure constant.

c) Volumetric method must be applied to remove the last part of the well in a controlled way:

1. Let p_{csg} increase to 34 bar (29 + 5 for safety)
2. Plan to bleed a volume of 1m³ every time the pressure has increased by Δp
   $\Delta p = \rho g D h = \rho g \,\Delta V/Cap_{ann} = 1300 \cdot 9.81 \cdot (1/\,0.025) = 0.51$ MPa (at every 1 m³ of bled off mud)
3. Check MAASP

4. Let p increase to 34 + 5.1 bar = 39.1 bar
5. Bleed $1m^3$ quickly
6. Repeat until gas is coming through the surface manifold. Close choke
7. Repair pumps
8. Bleed gas till pressure decreases 0.51 MPa
9. After repair is completed, the second half of the volumetric process must be completed. Pump in $1m^3$ mud and let it sink down to the annulus mud level (this will take approximately 10 minutes since the mud level is now so high up in the annulus)
10. Continue till all gas is out. Circulate / condition mud.
11. Increase mud weight before resuming drilling.

2.17 Volumetric method

a) Steps to be critically analyzed.
Here is demonstrated how the task would be approached as a Problem Based Learning (PBL) task:
Step 1: Define the problem so that all group members can agree and have the same understanding of it: A kick was encountered when the drill string was off bottom. At the same time the killing equipment fails.
Step 2: Any terms or expressions that need to be clarified: The Geologist on the team may ask about;
Stripping In: Run drill string through closed BOP into a pressurized well
Stuck String: A sting which is not possible to move either axially or to rotate or both
Step 3: Brain storming session (normally lasting for 10–15 minutes): Normally a heated debate.
Step 4: Prioritize suggestions and explanations may be:
- Swabbed in gas – > expanding gas when it rises in the well – > kick,
- Gas must be below DP since SIDPP = SIC
- Solve both leak and stuck if possible
- Kill well by means of volumetric method

Step 5: Learning goals:
Specific: Swabbing, volumetric method, freeing stuck pipe, repairing leaks
General: Causes of kick, killing methods, well problems during killing operations
Step 6: Learn: Go out and approach the learning goals individually

Step 7: Solution: Suggest the problems you have been assigned first individually. Come together and share and discuss to formulate a common agreeable solution:

Isolate leaking manifold and start repairing it: Depending on the point of leakage we can isolate the leaking point through suitable choice of valves and reinforced hoses. Then start bleeding out the gas by means of the volumetric method. A more detailed, practical approach is shown below:

- Bleeding strategy; let out 1 m^3 of mud through new choke each time pressure has increased estimated amount, after letting pressure initially increase additionally 3 bars for safety reasons.
- Before we start the practical killing procedure, we check two issues:

Issue 1: Find the gradient of the influx through this relation (see Figure 2-17):

Height of gas: $h = \frac{V_{kick}}{Cap_{OH}} = \frac{2.1}{0.03} = 70\ m$

This 70 m column of gas produces a shut in pressure of 7 bars. We assume only the gas height is causing this pressure, since the well was in overbalance at the start of the tripping operation.

The pressure gradient ρ_{influx} can be found:

$$(\rho_{mud} - \rho_{influx}) \cdot g \cdot h = p_{SIDP}$$

$$\rho_{influx} = \rho_{mud} - \frac{p_{SIDP}}{g \cdot h} = 1\,600 - 7 \cdot \frac{10^5}{9.81 \cdot 70} = 580\ kg/m^3$$

Obviously compressed gas.

Issue 2: Find the relationship between the pressure increase, $\Delta p_{increase}$, and the volume of mud to be released, 1 m^3.

This is achieved through; $\Delta p_{increase} = \rho g \Delta h$, as shown in Figure 2-17.1:

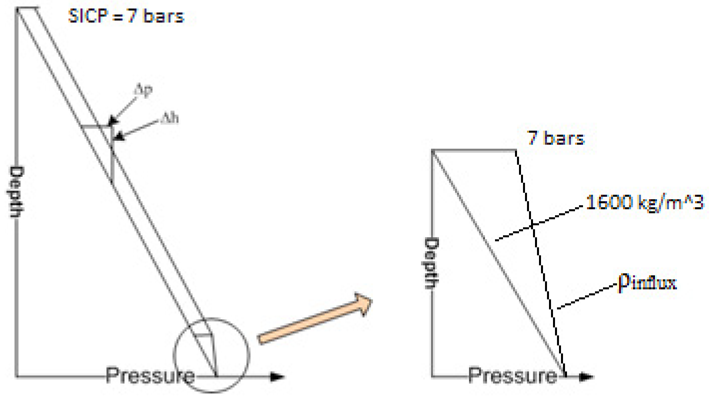


Figure 2-17.1: Relation between Δp-increase and gas height increase Δh. Detailed relation to the right.

We have two different capacities in the string; Capacity at the bottom, the open hole, and the one around the drill pipe. The main schedule becomes:

Parameter →	Capacity	Initial Δh	Δp increase
Units →	m^3/m	m	bars
Open hole	0.030	70/2.1 = 33.3	5.2
DP-Csg Ann	0.015	66.7	10.4

- After the gas has been let out at the surface, and a heavy slug placed in the well, the time has come to jar loose the drill string. After the string has been freed, RIH, and after the kill mud has been circulated from the bottom (add a safety factor to mud density to compensate for swabbing), the well is killed.

  A previous group of participants suggested (under step 3) to jar loose and try to strip the drill string into the closed pressurized well. When planning to run the drill string back in hole (RIH) into a pressurized, closed well, the pressure increase caused by increased steel volume must be bled off. And the MAASP must be continuously supervised.

  Another group suggested to Bullhead the gas kick back into the formation; The gas kick can be pushed or squeezed back into the gas bearing zone, if the formation is sufficiently permeable. A limitation of this method is the danger of fracturing the formation below the shoe; the bullhead pressure must be less than the MAASP pressure. Normally bullheading is limited to killing of producing wells.

b) Assume gas is swabbed in and will stay as free un-dissolved gas as it starts rising. The casing pressure profile during a volumetric killing procedure takes the form as in Figure 2-17.2 at the initial period of the killing procedure:

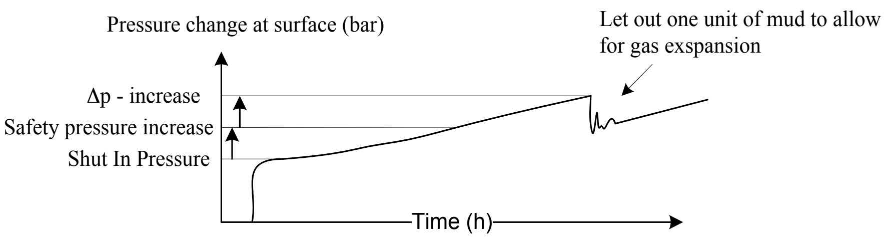


Figure 2-17.2: SPP vs. time during initial stage of volumetric method. This step repeats itself until gas reaches surface.

c) Assuming no gas dissolves, the surface pressure becomes, when the gas reaches the surface:

$$p_{surface} = p_{bottom} - \rho_g g h_x - \rho_{mud}\,(3\,000\text{-}h_x)g$$
$$h_x = V_{surface} / Cap_{surface}$$
$$V_{surface} \cdot p_{surface} = p_{bottom} \cdot V_{kick}$$
$$p_{bottom} = \rho_{mud} \cdot g \cdot h_{well} + p_{SIDP}$$

Solving these equations results in:

$$p_{surface} = 60 \cdot 10^5 \text{ Pa}$$
$$V_{surface} = 16 \text{ m}^3$$

From bottom to top the gas bubble spend: 3 000 m / 500 m/h = 6 h
or, if using alternative info: 3 000 m / 0.3 m/s = 30 000 s = 8.33 h

d) Replace gas with water through the "lubricate & bleed" techniques. Kill the now shut-in water filled well through standard killing methods

2.18 Comparing 3 killing methods. Annular friction included

The graphs in Figure 2-18 speak for themselves.

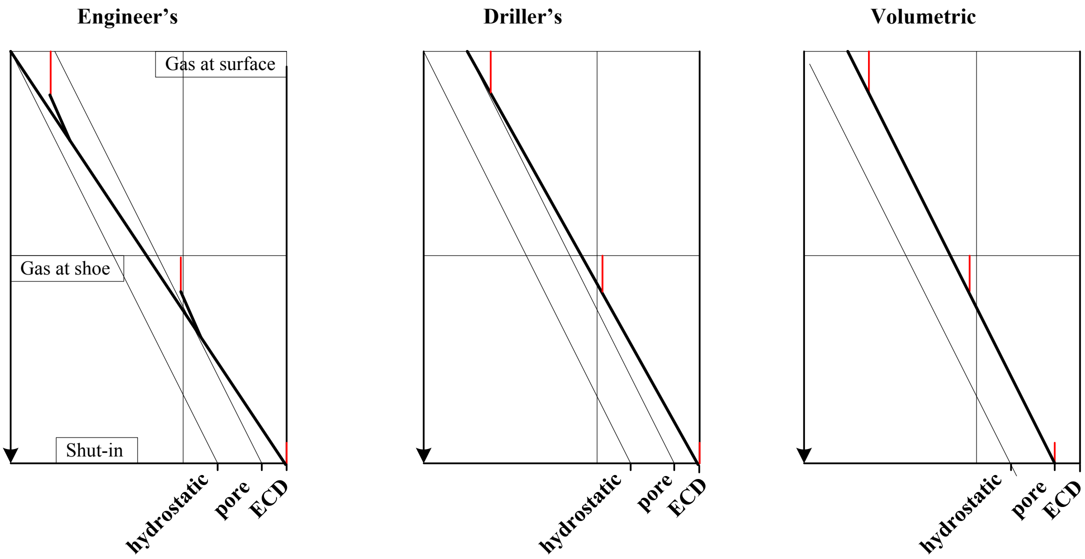


Figure 2-18: A gas kick killed by 3 different methods. When open-hole-length is as large as here the Engineer's method results in the very lowest annular pressure when the gas passes by the casing shoe.

3 More realistic gas behavior

3.1 Gas transport and percolation

a) 10 bar increase corresponds to $h = (p_{new} – SICP) / (rg) = 10 \cdot 10^5 / (9.81 \cdot 1750) = 58.25$ m
Speed = 58.25 /15 min = 3.9 m/min = 233 m/h

b) No expansion: gas (and gas volume) retains its original bottom pressure and brings it upwards:
$\rho \cdot g \cdot h = 1750 \cdot 9.81 \cdot 3400 = 621 \cdot 10^5\ Pa$

c) Both for dispersed and slug flow we have:

$$v_{g,b} = 12v_m + v_{g,b,st}$$
$$v_{g,s} = 12v_m + v_{g,s,st}$$

where $v_g = \dfrac{q_g}{A_g + A_l}$ and $C_g = \dfrac{A_g}{A_g + A_l}$

The constant 1.2 is close to being a universal quantity equal to 1.2 for all practical purposes, independent of viscosity, flow regime, pipe dimension and inclination

The main reason for the 20% faster gas flow is caused by the coinciding velocity and concentration profile. The concentration profile is explained by means of the Bernoulli's equation: The velocity is high in the middle and accordingly low pressure, sucking gas bubbles into the core flow. Surplus diffusion towards the center is also taking place due to the wall effect. And what is concentrated in the center of the pipe is transported at higher velocity.

d)

$$v_g = \frac{q_g}{A_g} = \frac{q_g}{A_g} \cdot \frac{A_g + A_l}{A_g + A_l} = \frac{q_g}{A_g + A_c} \cdot \frac{1}{A_g/A} = \frac{v_g^S}{C_g}$$

e) Axial dispersion is the mixing of the displacing fluid with the displaced fluid. This process is taking place for one reason:

1. The flow in the pipe-center is moving much faster than the flow along the wall, and thus "shooting" through the displaced fluid, or stretching the mass volume.
2. When gas is involved, one additional but minor effect is involved:
   The front velocity is higher than deeper down because of the addition of gas expansion due to buoyancy, towards lower pressure.

3.2 Wellbore pressure during 2-phase flow

The Newton forward iteration method in brief: Guess a fluid gradient near the surface between ρ_{mud} and ρ_{gas}, depending on their relative amount, estimate pressure at depth 1 and 2 and find the pressure gradient between surface and depth 2. Apply the gradient to depth 2 as the depth 1 gradient, and recalculate pressure at depth 1 and 2. Compare gradients of depth 1 and 2 until no substantial difference exists. Go to next depth and do the same.

a) To give an estimate of the pressure at 55 ft depth an iteration procedure is suggested. Here, to demonstrate manually, we take the full interval of 55 ft since pressure is known here. Normally, in a data-program, we would have selected much smaller depth increment, typically 3 ft, to increase the accuracy. The index convention are:

0 = atmospheric condition
1 = first number, surface conditions (situation # 1)
2 = second number, surface conditions (situation # 2)
g = gas
l = liquid, sometimes also liq
m = mixture, sometimes also mix

The flow area and the surface pressure are needed:

$$A = \frac{\pi}{4}\left((0.1379)^2 - (0.0635)^2\right) = 0.01177 m^2$$

$p_1 = p_{separator}$ = 53.6 psi = $3.70 \cdot 10^5$ Pa (what looks like 50 in the figure is in fact 53.6)

Estimating initial conditions based on surface measurements:

$$q_{g1} = \frac{q_{go} \cdot p_o}{p_1} = \frac{0.0472 \cdot 1.014 \cdot 10^5}{3.70 \cdot 10^5} = 0.013\ m^3/s$$

$$v_{ml} = \frac{q_{g1} + q_{liq}}{A'} = \frac{0.013 + 0.0046}{0.01177} = 1.495 \cdot m/s$$

$$v_{g1}^S = \frac{q_{g1}}{A} = \frac{0.013}{0.01177} = 1.105\ m/s$$

$v_{g1} = 1.2\ v_{ml} + 0.8 \cdot 0.3048$ (m/s) $= 1.2 \cdot 1.495 + 0.8 \cdot 0.3048 = 2.038$ m/s

$$C_{g1} = \frac{v_{g1}^s}{v_{g1}} = \frac{1.105}{2.038} = 0.542$$

$\rho_{mix} = (1 - C_{g1}) \cdot \rho_{liq} = (1 - 0.542) \cdot 1\,000 = 458$ kg/m^3

$G_1 = g \cdot \rho_{mix} \cdot 1.05 = 9.81 \cdot 458 \cdot 1.05 = 0.047 \cdot 10^5$ Pa/m

Iteration is in accordance with Newton-Rapson forward iteration method, and starts with

$$p_{2.1} = p_1 + G_1 \cdot h_2 = 3.70 \cdot 10^5 + 0.047 \cdot 10^5 \cdot 16.8 = 4.49 \cdot 10^5 \text{ Pa}$$

and results finally in

$$p_{2,n} = 4.49 \cdot 10^5 \text{ Pa} = 65.1 \text{ psi. at 55 ft depth.}$$

From the measured data at 55 ft we read 64.3 psi. Our result is 1.2% higher. To improve procedure of calculation the depth interval could be made shorter.

b) Now we will check the friction in the flow system. Only the two most important forms, hydraulic friction (by far the most important) and acceleration are included:

Acceleration pressure: $G_{acc} = \rho_{m2.2} \cdot \dfrac{(v_{m1} - v_{m2.2})^2}{2h_2} = 490 \cdot \dfrac{(1.495 - 1.325)^2}{2 \cdot 16.8} = 0.42\ Pa/m$

Friction term: $N_{\text{Re}-ann} = \dfrac{v_m^{2-n} \cdot (d_o - d_i)^n \cdot \rho_m}{k\left[\dfrac{2n+1}{3n}\right]^n \cdot 12^{n-1}} = \dfrac{1.325^{2-0.5}\ (0.1379 - 0.0635)^{0.5}}{0.3\left[\dfrac{2 \cdot 0.5 + 1}{3 \cdot 0.5}\right]^{0.5} \cdot 12^{0.5-1}} \cdot 1000 = 2 \cdot 10^6$

$N_{re\text{-}ann}$ indicate turbulent flow. Later checking of $N_{Re\text{-}ann}$ finds that 4 200 is the answer.

$$a = \frac{(\log n) + 3.93}{50} = \frac{(\log 0.5) + 3.93}{50} = 0.0726$$

$$b = \frac{(1.74 - \log n)}{7} = \frac{(1.74 - \log 0.5)}{7} = 0.292$$

$$f_{M.turb} = a \cdot N_{Re\text{-}ann}^{-b} = 0.0726 \cdot 4\,200^{-0.292} = 0.0064$$

$$G_{fric} = \frac{2 \cdot f_{m.turb} \cdot v_m^2 \cdot \rho_m}{d_h}$$

d_h: hydraulic diameter:

$$d_h = 4 \cdot \frac{Flow\ area}{Wetted\ periphery} = 4 \cdot \frac{A}{\pi(d_i + d_0)} = 0.0744\ m$$

Alternatively, and more commonly:

$$d_h = d_o - d_i = 0.1379 - 0.0635 = 0.0744\ m$$

$$G_{fric} = \frac{2 \cdot f_{m.turb} \cdot v_m^2 \cdot \rho_m}{d_h} = 2 \cdot 0.0064 \cdot 1.325^2 \cdot 490 = 150 \text{ Pa/m}$$

$$G_{fric} + G_{acc} = 150 + 0.42 = 150 \text{ Pa/m}$$

To make it simple we take the hydrostatic pressure of the mixture, based on the average gas concentration at bottom and surface, to be around 250 kg/m³ · 9.81 = 2 450 Pa/m.

Now we check how large the friction is relative to the hydrostatic: (150 / 2 450) · 100% = 6%

The assumption of 5% was therefore a good guess under these assumptions.

3.3 Wellbore pressure during 2-phase flow II

Solution to Wellbore pressure during p II

Initial gas production $q_{gas,o} = ROP \cdot A = \frac{50 * \quad 3.14 \cdot (12.25 \cdot 0.0254)^2}{60 \cdot 60 \quad \cdot 4} = 0.0139 * 0.076 =$ $0.00106\ m^3/_s$

$q_{mud} = 30\ SPM \cdot 20\ l/stroke\ /(1000 \cdot 60) = 0.01\ m^3/_s$

Initial mixture velocity at bottom: $v_{mix,0} = (q_{gas,0} + q_{mud})/ A = 0.00106$? $0.01) / 0.076 = 0.146$ m/s

In order to find $c_{g,0}$ we need to guess a pressure gradient and later improve it though iteration. Q_g is related to standard conditions, i.e. 1 bar. Our first guess of flow rate is 0.5 sm³/m.

$$\rho = \rho_w \left(1 - C_g\right) + \rho_g C_g$$

$$C_g = v_g^s / v_g = \frac{q_g}{A \cdot \left(1.2\, v_m + 0.2\right)}$$

$$\mathrm{v_m} = \frac{\mathrm{q_g} + \mathrm{q_l}}{\mathrm{A}}$$

$$\frac{A \cdot h}{h} = \frac{cap_{ann}}{h} = A_{ann} = \underline{0.022 m^2}$$

$$q_l = 1000/1000 \cdot 60 = 0.0167 m^3 / s$$

First guess leads to these parameters:

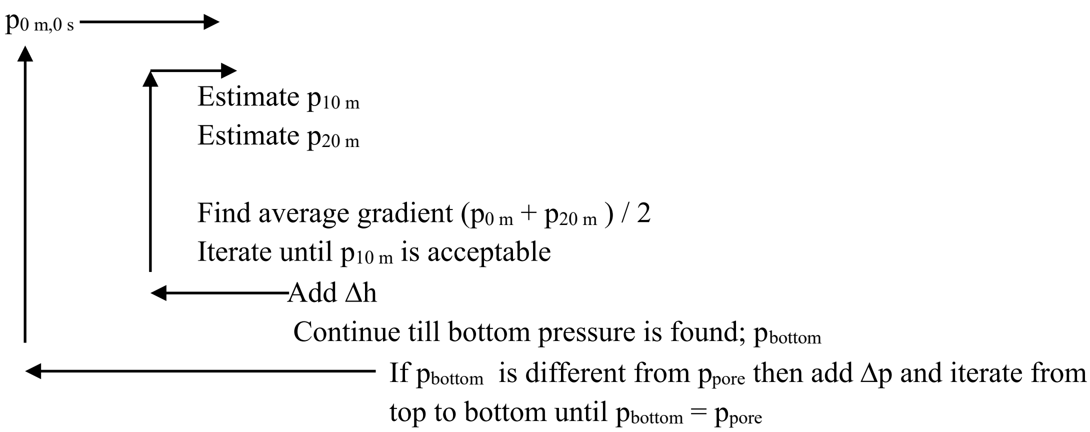
$$C_g = \frac{q_g / p_s}{1.2\left(q_g / p_s + q_l\right) + 0.2 \cdot 0.022} = \frac{0.5/20}{1.2(0.5/20 + 0.0167) + 0.0044} = \frac{0.025}{0.0544} = 0.46$$

$$\rho_1 = 1030(1 - 0.46) + 100 \cdot 0.046 = 603 kg/m^3$$

$$p_1 = \rho_1 \cdot g \cdot \Delta h + p_s = 603 \cdot 100 \cdot 9.81 + 20 \cdot 10^5 = 25.9 \cdot 10^5$$

One step further gives a new gradient (i.e. density) ρ_2
When $\{(\rho_1 + \rho_2)/2 - \rho_1\} < \varepsilon$ by gradually changing q_g, we have found the correct answer.

You must assume a p_{surf} from a guessed average reduced mixture density, e.g. 1.2 kg /l. This gives a p_{surf} of 40 bar. On basis of this assumption C_{gas} is estimated, and it is possible to estimate the initial mixture density at the surface and accordingly the initial pressure at surface; $p_{0\,m,0}$



3.4 Real gas behavior

$V_{tot,0} = V_{l,0} + V_{g.0}$

$V_{l,0} = m_l / \rho_l = V_{tot,0} - V_{g,0}$

$m_l = \rho_l (V_{tot,0} - V_{g,0}$

$\rho_0 = m_l / V_{tot,0} = \rho_l (1 - V_{g,0} / V_{tot,0})$

Here $V_{g,0} / V_{tot,0}) = c_{g,0}$

Density variation down the wellbore becomes

$$\rho(z) = \rho_l\,(1 - c_{g,0}(z) = \rho_l\,(1 - c_{g,0} \cdot p_0 / p(z))$$
$$\rho(z) = \rho_l - \rho_l \,.c_{g,0} \cdot p_0 / p(z)$$

Multiplying by g · dz we obtain the incremental pressure change. By integrating from 0 to z the pressure is given by:

$$p(z) = g \cdot \int [\rho_l - \rho_l \cdot c_{g,0} \cdot p_0 / p(z)]\, dz$$

3.5 Gas solubility

a) Gas kick: The gas was already inside the riser when closing the BOP. It should have been diverted at surface (routinely done today). In an oil based mud the solubility is of great importance for small gas kicks. The complete gas volume can be dissolved in the mud and break out of the solution at a higher level in the annulus as the pressure decreases. Please verify these problems during the planning phase. In such cases it is difficult to detect the gas before it is too late to shut-in, like in this case. In the case of larger gas kicks not all gas can be dissolved and is therefore free, and easier to detect.

The solution to the problem is to always close the gas diverter to divert the gas, simultaneously while closing the BOP for deep water drilling operations.

b)

Situations involving gas diffusion	Role
1. Gas kicks may dissolve downhole 2. Gas may diffuse into the mud from a gas zone 3. While cementing through a gas zone, gas will dissolve in the filtrates from the cement slurry and later be sucked into the hydrating cement. 4. Gas will diffuse into the cap rock layers over millions of years and dissolve in the pore water.	1. More gas at surface than V_{kick} predicts. 2. After circulation a lot of gas will be liberated at surface. 3. Water is consumed during the hydration phase. Gas may liberate when inside the weak, hydrating cement and gas migration through the cement can be initialized. 4. When pore water is being mixed into the mud during drilling and is brought to the surface by the mud, gas can be detected if sensitive instruments are installed.

c) Case 1: High pressure (2 bars) escape and Pepsi and releases CO_2 flow rigorously out of the bottle
Case 2: The released CO_2 has re-dissolved. Only a faint pff is observed

3.6 Gas solubility

Assuming WBM and negligible gas solubility, surface pressure will, as gas arrives at the surface be lower than expected for two reasons:

1) The constant C, in the gas velocity equation is close to 1.2., practically independent of viscosity, flow regime, pipe dimension, and inclination angle. The main reason for gas to flow 20% quicker than the theoretical mean flow is caused by the fact that the velocity profile and the concentration profile coincide. Gas in the center of the pipe, travels faster than gas at its periphery.
2) The displacement front of the gas is shooting through the displacing fluid and resulting in axial dispersion. Additionally, the gas velocity at the tail of the bubble is slower than at the front of the bubble because of continuous fragmentation in the rear (wake of the bubble); every time a TJ is passed fragmentation will occur. And at the bottom the gas is more compressed and the buoyancy effect is lower. Velocity of a dispersed bubble is lower than a gas slug due to higher flow resistance (higher specific area).

For these two reasons the gas is therefore stretched out.

In case of OBM, much of the gas will be dissolved, and therefore the surface pressure increase becomes lower, as shown in Figure 3-6. The dissolved gas will exhibit a much lower, negligible volume, since the gas molecules have lost their kinetic energy while in the liquid state.

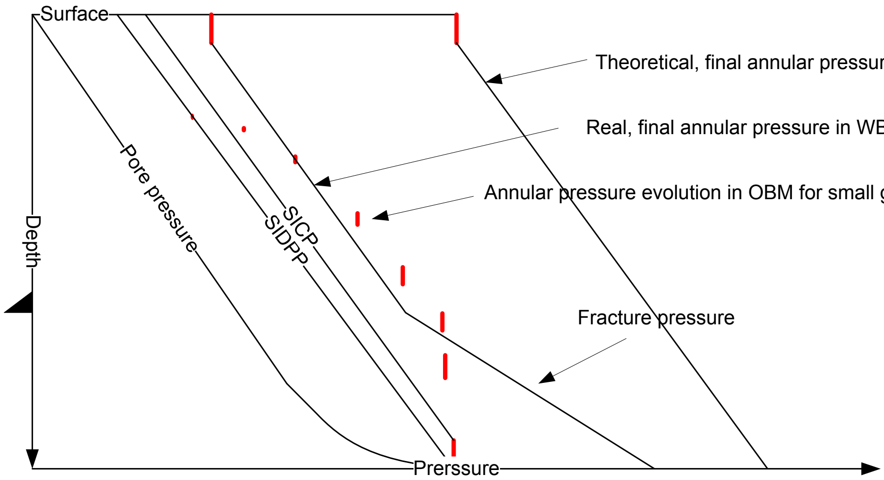


Figure 3-6. Pressure evolution of shut-in gas in OBM (red, left) and in WBM (black).

The free gas will travel upwards due to buoyancy and dissolve in the mud. The initial free gas volume will therefore reduce, and pressure in the bubble will decrease as indicated in Figure 3-6 by small vertical, red lines or bars (vs. time).

When gas is dissolved we assume that the mud density is not influenced by the dissolved gas (negligible amount of mass).

Gas solubility: In water based mud gas solubility is negligible. In Oil based mud the solubility is especially important for small gas kicks. The complete gas volume can be dissolved in the mud, and later go out of solution when circulated to a higher position in the annulus. It is thus difficult to detect small gas kicks before they flash out of the mud close to surface. For larger kicks the surface pressure is easier to interpret, but is different (lower) than for WBM.

d) Salt content: At high salt concentration, much of the water dipoles are bound in relatively rigid layers around salt ions and thus inaccessible for gas to be dissolved in. The part of the water which is still free and "active" will dissolve the same amount of gas pr. unit water volume.
e) 2 m^3 of gas entering a well drilled with OBM. The volume becomes 50 m^3. The 2 m^3 represents 4% of the annular OBM-volume. OBM have normally a high YP and may therefore hold up to 5% gas in the form of dispersed gas bubbles (in addition to the dissolved volume). The gas may thus disappear completely.

4 Deep water and cementing issues

4.1 Cold water issues

a) Hydrates

Due to the low seafloor temperature and the high hydrostatic pressure, the formation of hydrates sediments below deep water can create problems in the drilling operation. They will thaw and cause the formation to destabilize if drilled through. Freed gas can create gas blowouts.

The formation of deep water hydrates in the cold regions of the well can plug the choke and kill lines, BOPs and riser. Gas migrating from the reservoir along the outside of the surface casing and along wit h the mud inside the wellbore can form hydrates both outside of the BOP and on the inside of the wellhead. The formation of hydrate consumes water and will thus dehydrate the drilling fluids.

Recommended solutions are:

- Use hydrate simulators and modeling programs to predict the problem.
- Select the right mud system; WBM or Synthetic BM.
- Chemical inhibitors should be added to the drilling fluids.
- Add thermodynamic inhibitors (salt, glycol) to change equilibrium and conditions to hydrate formations.
- Add kinetic inhibitors (polymers, poly-butylene glycol) to retard the formation of the hydrates.
- Reduce non-circulation time to a minimum to keep the high mud temperature.
- The Driller's method minimizes cooling of mud/gas mixture during kicks.
- Inject methanol into the BOP and wellhead connector.
- Add wellhead features to prevent gas slipping around the BOP and well head connector (mud mat).

b) Gel strength

High gel strength develops at low temperature. Differential pressure in a 1 000 m long choke-line of ID = 3″ = 0.0762 m if gel strength is 10 Pa:

$$\Delta p \cdot A_{cross} = \tau_y \cdot A_{along}$$

$$\Delta p \cdot \frac{\pi}{4} \cdot ID^2 = 10 \cdot \pi \cdot ID \cdot 1000$$

$$\Delta p = \frac{4 \cdot 10}{0.0762} \cdot 1000 = 5.25 \cdot 10^5\ Pa$$

The pressure increase will be added to the annulus pressure. To experience a pressure increase of 10 bars, the YP or gel strength has to be 25 Pa: $\Delta p = 4 \cdot YP \cdot L/d = 4 \cdot 25 \cdot 1\,000 / 0.1 = 10 \cdot 10^5$ Pa.

Viscosity-increase in the choke and kill (C&K) lines due to low temperature can mask the shut-in casing pressure (SICP). This effect increases with the use of synthetic mud (higher viscosity at low temperature). Kick detection may become difficult, as the well may flow during flow checks, but no shut-in casing pressure is seen. In order to reduce the viscosity problem the C&K lines can be filled with an anti-freeze fluid. Always consider the effects of mud solids settling in the C&K line and the resulting plugging or loss of hydrostatic pressure. In deeper water, the gel strength can be high also in the drill pipe, especially with synthetic mud. Slow rotation of the drill pipe can be used to reduce the mud gel strength when breaking circulation.

4.2 Deep water shallow formations

a) SWF = shallow water flow. Water starts flowing from pressurized sands. While flowing; it slowly erodes the sand zone, the cement behind the casing and the water may even find its way up to the surface through the weak, shallow formations. This may cause both the casing and fixed platforms to collapse.
Water filled shallow sands are not easy to predict, nor to detect or control. Unlike trapped gas, they will not give clear spots on the seismic surveys. Normally the upper sections are drilled riserless with no return to the rig and flow must be detected by means of ROV or video surveillance. The shallow water problem can be of a very local nature and safe areas can be found 50–100 meters to the sides.

b) Solution: Kill dynamically and drill further with heavy mud and set casing and cement in place when at TVD. Drill pilot hole without riser. Drill extremely carefully with sonar and regular checks. Avoid such areas when detected through radar surveys (mud volcanoes).
New casing program to seal off the SWF problem using the 20" casing and an external casing packer (ECP). Water zone requires sometimes an additional casing string. This adds complexity in the drilling operation. Top-hole drill-in casing is a potential solution to handle shallow water flows. This method allows the casing to be cemented in place in case of shallow water problems. No time is needed for retrieving the drill string and running casing. Use high quality cement and cement techniques.

c) Shallow water flow is occurring where the settling rate of clay has been high. We find these high rates in conjunction with large river systems like offshore Brazil, in the GoM etc. Here the probability of finding high pressure closures of water sands is high.

d) After a killing operation is completed the BOP need to be cleaned of trapped gas.

Step 1:	Clean out the trapped pockets of gas in the BOP
Step 2.	Exchange the old, original mud in the riser (could still be free / dissolved gas there)

If step 1 is not completed, gas will rise up through the marine riser after opening the BOP, expand and partly empty the riser, which, in worst case could lead to collapsed riser. And the gas could ignite.

If Step 2 is not performed, the hydrostatic pressure may be too low when the BOP is opened, and a new kick may arise from the formation exposed to an underbalanced wellbore.
Typical abbreviations in daily drilling reports:

ann	= annulus
lpr	= lower pipe ram
slug	= small volume of heavier mud
u	= unit (gas unit)
upr	= upper pipe ram
stack	= all the individual preventers
u-tube	= here: use riser and kill line as a U-tube

e) Gas may be hidden in the riser, above the closed BOP, especially if OBM is used.

4.3 Cementing Operations

a) Objective:
- Protect and support the casing
- Prevent the movement of fluid through the annular space outside the casing
- Stop the movement of fluid into vugular or fractured formations
- Close off an abandoned portion of the well

b) Squeeze cement (not part of the required knowledge in this course)
- Set the bottom retainer plug just under the zone of interest for squeeze cement
- Perforate casing at this zone
- Set the top retainer plug above the zone.
- Pump HCl + HF – if needed
- Fracture zone of interest – if needed
- Pump high hydraulic pressure cement through DP
- Wait minimum 24 hours
- Conduct cement evaluation
- Take decision if it is ok or not

c) This is an old story and the kick during cementing took most people by surprise at that distant time. However, today such cases are happening more rarely, but when they do, they take us by surprise. The phenomenon is called Gas Migration in cement. Please learn from the history.

d) Gas Migration: Cement shrinks and sucks water and gas from the surroundings. Gas has buoyancy and may break through the cement, erode it, and after ample time, cause a continuous flow of gas to the surface
Solution: Avoid suction of gas by
Replace shrinking material (cement) by other non-shrinking materials
Use dispersed nitrogen in the cement slurry
Displace gas from near well bore formation before cementing (has never been done)
Always use best practice cementing technique.

e) There are 4 factors that could result in serious consequences (leaking cement) if not handled properly.
   1. Water may be lost from the cement slurry when it is in place in the permeable wellbore due to high hydrostatic pressure of the slurry compared to the pressure in the permeable sedimentary formation
   2. Cement slurry pressure will reduce during the hydration phase and may suck fluids and gas from the surroundings
   3. Displacement of the mud by the cement will lead to some amount of leftover mud along the wall (axial dispersion), especially in the upper parts of the displaced wellbore
   4. Bonding to the wall is poor. The main reasons behind this problem are; remaining filter cake, stresses provoked by shrinkage, temperature differences and/or pressure fluctuations during later operations

   Preventive countermeasures
   1. Remove cake/mud. Reduce permeability in cement (e.g. micro silica)
   2. Minimize axial dispersion by pumping in turbulence, and pump in excess of theoretically necessary volume.
   3. Use elastic cement

f) To handle eventual gas in the riser after BOP closure.