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Automatic Well Control Simulations

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Preface

This Master Thesis was written during the spring of 2012 in accordance with the course TPG4910 Drilling Technology at the Norwegian University of Science and Technology (NTNU), Department of Petroleum Engineering and Applied Geophysics.

I would like to thank supervisor John-Morten Godhavn for his support and guidance throughout the writing of this report. I would also like to thank SPT Group for guidance regarding simulations performed. In addition I express my gratitude to everyone providing me with information and help.

I hereby declare that this Master Thesis has been written by me and in accordance to NTNU's regulations.

Trondheim, May 2012

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Abstract

Every year kick incidents occur, maybe best remembered by the Macondo blowout in April 2010 resulting in devastating oil spills throughout the Gulf of Mexico. Well control is one of the most important factors in any drilling operation, preventing disastrous blowouts where people and the environment will be affected. The development of new technologies has increased significantly, lowering the risks of blowouts, mostly because of the reliability of blowout preventers. Better hardware systems have been developed and better materials has increased the performance during critical parts of an operation.

There are several causes why we encounter kicks; not keeping the hole full, lost circulation, swabbing, underbalanced pressures, trapped fluids/pressures and mechanical failures. Before an actual kick, there are warning signs that might occur and knowing how to interpret positive indicators of kick is very important. Pit gain, increase in return flow rate and abnormalities in drillpipe pressure are all signs that formation fluid has entered the well.

When experiencing a kick, procedures to reduce the danger and the non productive time have to be started. Firstly the well has to be shut in by either the hard shut-in method or the soft shut-in method. Then the influx has to be circulated out of the well by the use of either the Driller's Method or the Wait and Weight Method.

To better understand and visualize the behavior of formation fluid entering the well, the simulation program Drillbench Kick has been used. The soft shut-in has been compared against the hard shut-in and the Driller's Method has been run against the Wait & Weight Method. The simulations have been performed with both oil based mud and water based mud.

Sammendrag

Hvert år opplever vi kick situasjoner, kanskje best husket ved Macondo ulykken i april 2010 som resulterte i ødeleggende oljeutslipp i Mexicogulfen. Brønnkontroll er en av de viktigste faktorene i enhver boreoperasjon som forhindrer katastrofale utblåsninger hvor mennesker og miljø blir berørt. Utviklingen av nye teknologier har skutt fart, og dette har senket risikoen ved boreoperasjoner.

Det er flere årsaker til at vi støter på kick; brønnhullet er ikke holdt fullt, tapt sirkulasjon, underbalansert trykk, fanget væske/trykk og mekaniske feil. Før et kick oppstår er det flere varselsignaler som kan oppstå og korrekt tolkning av disse signalene er viktig. Økt mud-tank volum, økning i tilbakestrøm og unormale borerørstrykk er alle tegn på at formasjonsvæske har trengt inn i brønnen.

Det er prosedyrer for håndtering av kick som oppstår som reduserer både farer og ikke-produktive-tiden som oppstår. Brønnen blir stengt inne av enten hard- eller soft shut-in metoden. Etter dette blir gassen sirkulert ut av brønnen ved hjelp av Driller's Metoden eller Wait and Weight Metoden.

For å bedre forstå hva som skjer når formasjonsvæske trenger inn i brønnen har simuleringsprogrammet Drillbench Kick blitt brukt. De forskjellige metodene har blitt sammenlignet med hverandre og både oljebasert- og vannbasert mud har blitt brukt.

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1 Introduction

The demand for energy is constantly increasing, forcing the petroleum industry to come up with innovative solutions to find and produce the remaining resources. The industry is forced to work in remote locations where high pressure and temperature reservoirs, deep water, narrow pressure margins and harsh weather are factors that hamper the operations.

The awareness regarding well control in the drilling industry has always been one of the main focus areas. If formation fluid enter the well it can lead to disastrous blowouts where people on rigs can be injured, or in a worst case scenario; killed. The environment can also be harmed due to oil spills. Moving drilling locations to remote areas around the world demands the wells to be drilled in the safest possible way.

The development of new technologies has increased significantly, lowering the risks of blowouts. This is most because of the reliability of the blowout preventers. Better hardware systems have been developed and better materials has increased the performance during critical parts of an operations. The downtime due to equipment failure has, because of this, been reduced.

Even though the industry is changing, we have to be aware of the dangers we may encounter. Having the knowledge, but also be able to understand signs and warnings from the well while drilling can help in preventing blowouts, thus protecting both environment and personnel on the rig.

The report will look at the theory about well control; what is causing a kick to occur and how the signs can be interpreted and understood. A kick simulator has been used to illustrate and understand how different methods change the well condition prior to the kick and during the closing and circulation. In the first part of the simulation the soft shut-in method has been tested against the hard shut-in method. Then the two most common circulation methods, Driller's- and Wait & Weight Method, have been simulated. It has been used both oil based mud and water based mud to also understand how this affect the well control procedure.

2 Well Control Theory

Primary well control

Primary well control is defined as the prevention of formation fluid flow by maintaining a hydrostatic pressure equal to or greater than the pressure of the fluids in the formation, but less than formation fracture pressure. It is very important to make sure that primary well control is preserved at all times. This includes:

- Drilling fluids with adequate density are used
- Active system volumes are continuously monitored
- Changes are detected immediately and correct actions are being performed

Secondary well control

If the pressure of our drilling fluid fails to prevent formation fluid to enter the wellbore, the well will flow. By the use of a blowout preventer, (BOP), we can prevent the fluids from escaping the well.

Hydrostatic pressure

The hydrostatic pressure depends on the density and vertical height of the fluid.

Equation 1: Hydrostatic Pressure

$$P_{hydrostatic} = Depth(TVD) * Density$$

Circulation pressure

Circulation pressure is given by the rig pump and represents the total pressure required to transfer mud from the pump, through the surface lines, the drillstring, the bottomhole assembly,(BHA), the bit nozzles and up through the annulus back to the surface.

The annular pressure, or friction loss, helps in preserving the pressure on the exposed formation and causes a slight increase in the total pressure as long as the pump is circulating mud. This in turn leads to an increase in the bottomhole pressure, (BHP), above the static BHP. We can call this increase annular pressure loss, (APL).

Equation 2: Circulating Pressure

$$P_{circulating,bottomhole} = P_{hydrostatic} + APL$$

Bottomhole pressure

BHP is the sum of all pressures being exerted on a well by drilling personnel operations. This means the sum of hydrostatic pressures, APL plus any surface applied backpressures.

Equivalent circulating density

The Equivalent Circulating Density, (ECD), can be explained as an increase in pressure that occurs only when the mud is being circulated in the well. Due to the friction in the annulus, the BHP will be higher than when the mud is not being circulated.

Equation 3: Equivalent Circulating Density

$$ECD = Mud\ Weight + \frac{APL}{0{,}052 * TVD}$$

There are several factors affecting ECD

- As the depth of the hole increases the total friction loss in the wellbore increase, hence greater ECD on the bottom of the wellbore.
- Similar to the depth; the greater the circulation rate, the greater the frictional loss resulting in greater ECD.
- A heavy mud weight will provide more resistance.
- The amount of solids in the drilling fluid will increase the ECD.
- The rheology of the mud also affects the ECD. If the viscosity or gel strength is too high, the drilling fluid will increase its resistance to flow. This leads to a higher frictional loss increasing the ECD.
- The higher the flow area, the easier the mud will flow. If the annular clearance is small, the ECD will increase.

(C.T.C Drilling and Well Control Department)

Formation pressure

'Formation pressure, or pore pressure, is said to be normal when it is caused by the hydrostatic head of the subsurface water contained in the formations and there is pore to pore pressure communication with the atmosphere', (Aberdeen Drilling Schools & Well Control Training Centre, 2002).

By dividing this pressure with the true vertical depth, we find the average pressure gradient of the formation fluid. The North Sea area pore pressure averages 0.452 psi/ft, while in the Gulf of Mexico the pore pressure averages at 0.465 psi/ft.

Normal formation pressure

Normal formation pressure is the hydrostatic pressure of water extending from the surface to the subsurface formation. The hydrostatic pressure is affected by different factors. Increasing the dissolved solids (salt) increases the formation pressure gradient whilst an increase in the level of gases in solution will decrease the pressure gradient. The temperature also affects the hydrostatic pressure gradient, as a higher temperature will expand the fluid reducing the gradient.

Abnormal pressure

Abnormal pressure can be defined by every pressure which does not conform to the definition of normal pressure. There are several causes why experience abnormal pressures.

Under-compaction in shale's: if the balance between the rate of compaction and fluid expulsion is disturbed so the fluid removal is slowed down, the pressure will increase. This will result in a much higher porosity than expected for the depth of shale burial in that area.

Salt is totally impermeable to fluids and behave plastically. Its pressure transmission properties are more like fluids than solids and therefore it exerts pressure equal to the overburden load in all directions. Fluids from any underlying formation can't escape, so the formation becomes over pressured.

Formation slippage may bring permeable formation laterally against an impermeable formation preventing flow of fluids. This may allow fluids to flow from a deeper permeable formation to a shallower. If the shallower formation is sealed then it will be pressurized from the deeper zone.

Other causes which can cause abnormal pressure are mineralization, tectonic causes, diapirism and the reservoir structure.

Formation fracture pressure

It is necessary to have some knowledge about the formation fracture pressure so we can drill a well safely. The maximum volume of any uncontrolled influx from formation depends on the fracture pressure of the exposed formation.

If the wellbore pressure is equal to or greater than the fracture pressure, the formation will break down, mud will be lost, hydrostatic pressure will be reduced and we lose primary control. Fracture pressure is related to the weight of the formation matrix and the fluids occupying the pore space within the matrix, above the zone of interest. These two factors are known as the overburden pressure.

If we assume an average density of a thick sedimentary sequence to be equivalent of 19.2 ppg, then the overburden gradient is given by:

$$0.052 * 19.2 = 1.0\frac{psi}{ft}$$

Onshore the overburden gradient can be assumed close to 1.0 psi/ft, but when we are offshore we need to take into account the sea. As we see from Figure 1, the total overburden pressure will be considerably lower for an offshore rig. This makes surface casing sets very vulnerable, and the reason for never shutting in shallow gas kicks. (Aberdeen Drilling Schools & Well Control Training Centre, 2002)

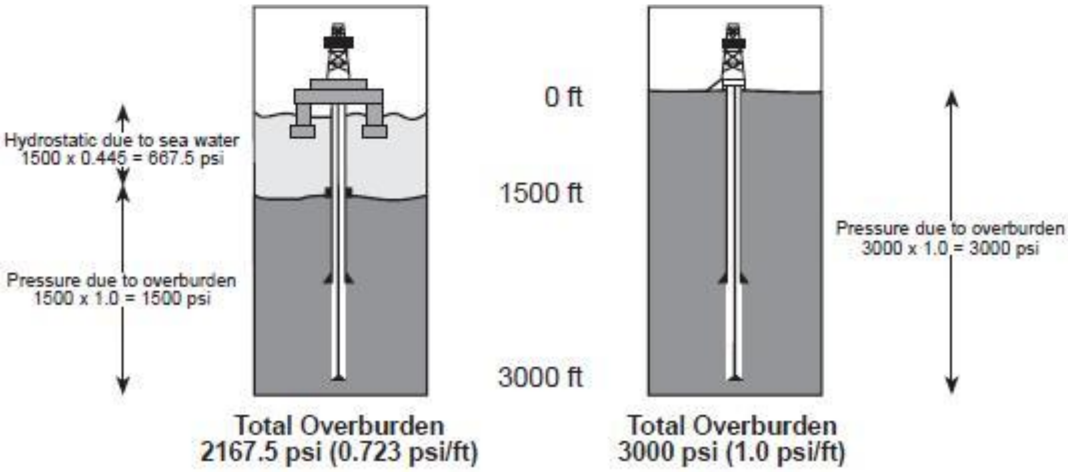

Figure 1: Fracture Gradient Comparisons, (Aberdeen Drilling Schools & Well Control Training Centre, 2002)

3 Causes of Kicks

A kick can be defined as an unwanted influx, or flow, of formation fluid into the well. When the flow is uncontrolled during completion, workover or production operations, the control of the well is threatened. If the kick is not handled correctly, it can lead to a blowout endangering rig personnel and the environment. (Chevron Petroleum Technology Company, 1994)

The main causes of kicks are:

- Not keeping the hole full
- Swabbing
- Underbalanced pressure
- Lost circulation
- Shallow gas sands
- Excessive drilling rate in gas bearing sands
- Human error

3.1 Not keeping the hole full

As the fluid level in the borehole decrease, the hydrostatic pressure will sink and reduce the BHP. As the drill pipe and drill collars are pulled out of the hole, a mud volume equal to the steel must be added to keep the hole full. If this operation fails, the mud column will be reduced. If the BHP is reduced below the formation pressure a kick may occur if there's a permeable formation in the borehole.

If the mud volume required is less than the steel removed then either

1. Formation fluid must have entered the hole
2. Gas is already in the annulus and is migrating and expanding

The steel volume of a drill collar can be up to ten times the volume of a drill pipe, thus increasing the needed mud volume and the potential mud column fall significantly.

There are two possible ways to monitor the mud volume during tripping:

1. Continuous monitoring the hole fill volume by an automated measuring system
2. Continuously circulating on the trip tank

The trip tank can be set to continuous gravity feed or pump feed. By using this method, the hole will be full at all times, and the volumes that have been used can be accurately maintained. The biggest problem is that there isn't enough mud to permit a full trip without refilling. The drill crew will therefore need strict routines checking the mud level and refilling when needed. (C.T.C Drilling and Well Control Department)

3.2 Swabbing

As the drillpipe is pulled out of the hole, the upward motion of the bit and bottomhole assembly can decrease the BHP resulting in a kick.

There are several factors contributing to swabbing:

- Pipe pulling speed; the faster the string is pulled out of the hole, the greater the pressure drop will be.
- Small annular clearance will result in a greater pressure loss compared to a larger clearance.
- High mud viscosity or gel strength creates a thick flowing mud resulting in greater pressure loss
- Balled up bit or stabilizers; the BHA is surrounded by clay or sticky shale which is increasing the diameter of the bit or stabilizers making them act as pistons when they are pulled out of the hole.

However, there are procedures that may reduce the likelihood of swabbing. These include:

1. Circulating the hole before tripping
2. Noting the pressure and position of tight-spots from previous trips
3. Control the pipe-pulling speed

The only reliable method of detecting a swabbed kick is proper hole fill procedures, carefully monitoring of the trip volumes are essential. (C.T.C Drilling and Well Control Department)

3.3 Underbalanced pressure

The mud column is providing the hydrostatic pressure in the wellbore and this is the primary means of preventing a kick. We can experience insufficient mud weight when encountering an unexpected high-pressure zone, but the mud can also have been diluted at either the surface or in the well. Fluids flowing from the formation may change the properties of our drilling fluid. Comparing the ingoing mud with the returning mud can help prevent dilution.

As said earlier, we can also encounter abnormal pressure zones. If a zone has a higher formation pressure above the normal gradient for the area to be penetrated, light drilling fluid weight can cause a kick. Signs of high formation pressure may be seen in the form of 'sloughing' or 'heaving' shale's, excess hole fill, and elliptical hole sections or tight spots. (C.T.C Drilling and Well Control Department)

3.4 Lost circulation

Kick can occur when we experience lost circulation. The pressure in the well may become larger than the fracture pressure of the formation, due to a too high mud density, and the drilling fluid will flow into the exposed formation. We may also experience lost circulation when we have a too high surge pressure. As the drillstring is moved into the borehole, the BHP will increase and in combination with the hydrostatic pressure, the fracture pressure can be exceeded. (Chevron Petroleum Technology Company, 1994)

Other reasons for lost circulation can be naturally fractured or pressured depleted zones, annulus plugging due to BHA, packing-off or sloughing shale's or excessive circulation breaking pressure when mud gel strength is too high, see Figure 2.

The best way to handle this type of kick is to fill the annulus with lighter fluids to maintain the best possible hydrostatic pressure in the well. Since the mud, in most cases, only drops a few hundred feet, the addition of fluid will reduce the underbalanced pressure in the well to a minimum. If flow still exists, it is at a reduced rate, giving more time for emergency procedures or well control measures. (C.T.C Drilling and Well Control Department)

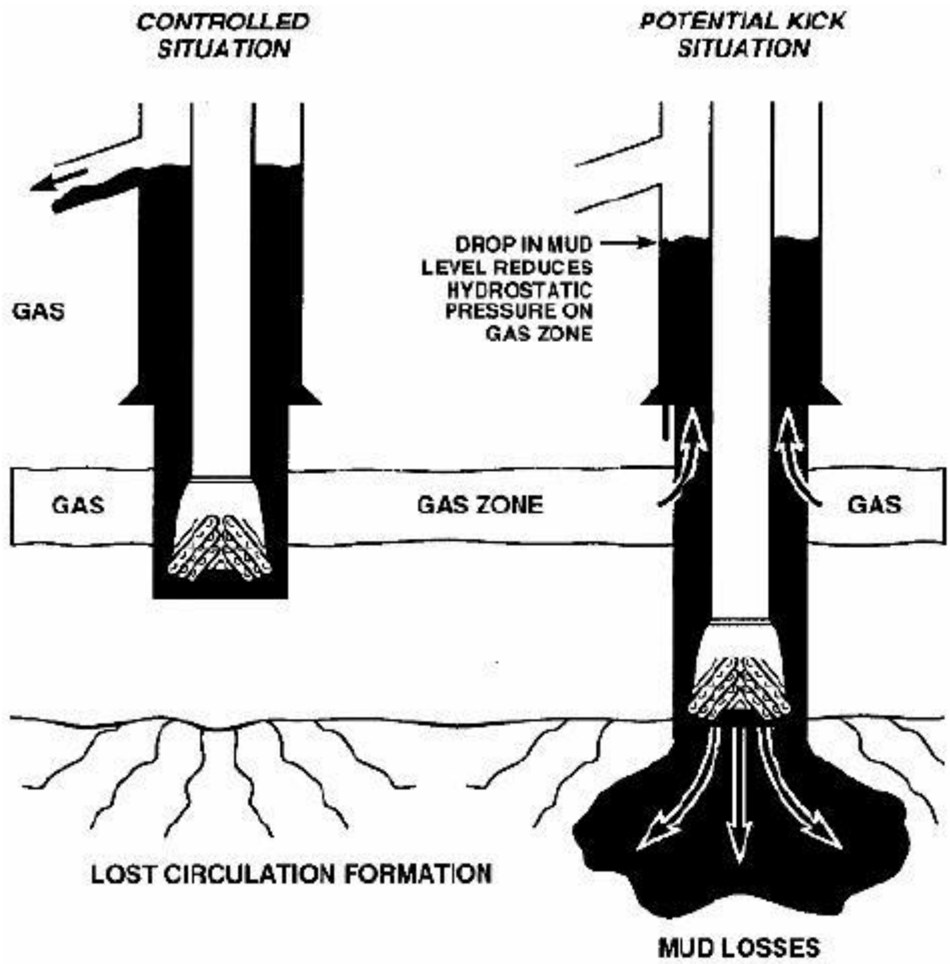

Figure 2: Lost Circulation, (C.T.C Drilling and Well Control Department)

3.5 Excessive drilling rate

As a gas bearing formation is drilled, possible breakout of formation fluid will cause cuttings in the mud, explained in chapter 4.1. If a fast rate of penetration is made in such a formation, the percentage of formation fluid is likewise increased and problems may result.

3.6 Trapped fluids

As work sometimes is being done on wells that are or were being produced, reservoir fluids may be trapped below tools. When determining the reservoir pressure and required fluid density, production data, flowing pressures and shut-in pressures are invaluable.

Reservoir fluids can also be trapped in the tubing string. We can shut them off in several ways, including the surface production tree or by setting a plug in the tubing nipple. This trapped volume can be quite large, depending on where the tubing has been set.

We can also have fluids trapped below the production packer in the tailpipe annulus. Usually, this doesn't get noticed until the packer is removed.

Minimizing the distance between perforations and the downhole tools will greatly reduce the risk of trapped fluids.

3.7 Mechanical failures

On the surface we have Christmas trees, tubing heads and blowout preventers protecting the rig and the personnel from kick turning into blowouts. Downhole equipments are of same importance, helping in the prevention of kicks to occur. As these are installed based on the well condition at the time, they will be exposed to various well conditions and the equipment will be weakened as time goes by, resulting in unwanted trapped fluids and pressures.

A packer or tubing failure can cause fluid to be trapped inside the casing, Figure 3 a, resulting in extremely high pressures. These types of failure are typically detected by analyzing production data and regularly inspections of the casing and tubing pressures. There are also problems when formation fluids are highly corrosive. This can weaken, or worst case scenario, create holes in the casing. We can then experience crossflow between two zones, Figure 3 b, or trapped fluids as previously discussed.

We can also experience failures in liner laps, Figure 3 c. Liner laps are usually sealed off from the well with cement. The small clearance area between the liner and the casing can make the bonding of cement difficult to obtain, and there often exists a communication channel. Failures of liner laps have a high potential risk, as the leak can enter the well several hundred feet above the interval depth, hence requiring an abnormally high killing fluid weight.

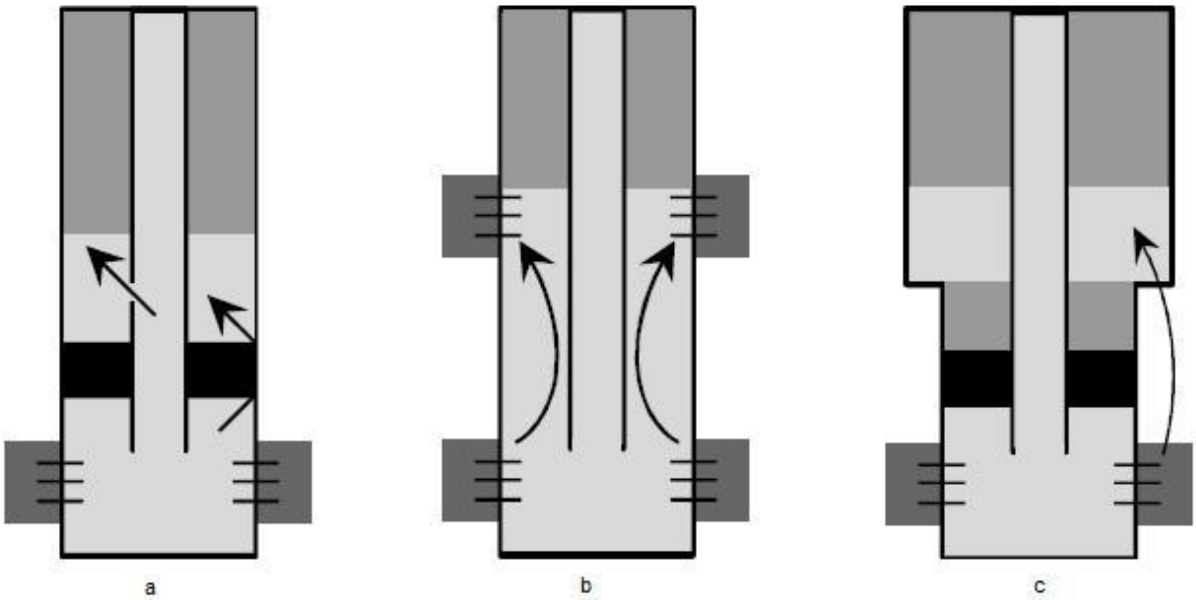

Figure 3: Mechanical failures, (Chevron Petroleum Technology Company, 1994)

4 Kick Indicators

(Chevron Petroleum Technology Company, 1994)

At the presence of a kick, there are a number of warning signs and indications which will alert the driller of what's going on. As detection of these signals can prevent a disastrous blowout, it is important that all crew members understands and act accordingly to the situation.

4.1 Possible indicators of a kick

Precede a kick there are normally one or more warning signs. Experiencing any of these signals, the well should be checked.

Gas/Oil/Water cuttings

Gas, water or oil cuttings in the circulated drilling fluid are a good warning signal. The gas cuttings will appear foamy, while oil cuttings will lead to sheen of oil across the rig tank. For water, the fluid weight will become lighter and the chloride concentration will change.

Incorrect fill-up volumes

As discussed earlier, when removing the drillpipe from the well, equal volume of mud need to replace the steel removed. This also applies when we run into the well, only difference is now to monitor the returning mud volume.

Decrease in pump pressure

Pump pressure is as defined in Equation 2, a function between hydrostatic pressure and APL. If an influx enters the well, the hydrostatic pressure will decrease, hence the pump pressure decreases and the pump speed increases.

Increase in flow line temperature

Temperature gradients in the transition between normal and abnormal pressure zones can often increase around twice the rate of the normal temperature gradient. An increase in the flow line temperature can indicate the top of an over pressured section. (C.T.C Drilling and Well Control Department)

4.2 Positive indicators of a kick

When recognizing positive kick indicators, actions must be taken to control the well.

Pit gain

As the influx from the formation enters the well, it leads to an expulsion of mud resulting in an increase of the surface volume which we can think of as a close circulating system. It can be very hard to detect an increase of the volume, as other factors can hide the change. Surface additions and withdrawals must be done with the driller's knowledge. Also the

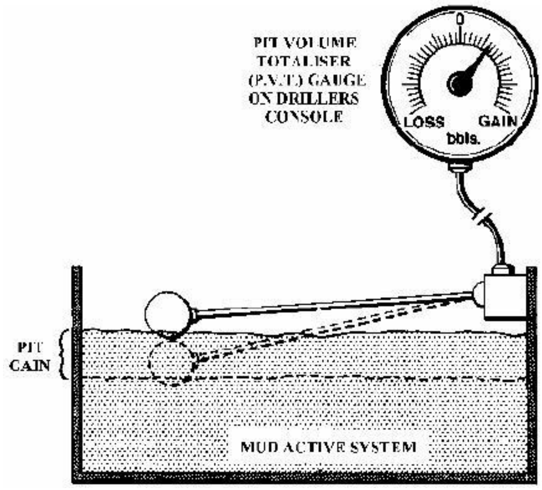

Figure 4: Pit gain (C.T.C Drilling and Well Control Department)

addition of materials, i.e. barite, can change the total mud volume.

Visual observations of the mud pit level with regular recordings are a valuable tool to keep control. On floating drilling rigs the heave motion produce problems regarding accurate measurements. Here, use of several floats or other sensors can help and reduce the problems. Figure 4 shows an example of how pit gain may be monitored. (C.T.C Drilling and Well Control Department)

Increase in return flow rate

As mentioned, we think of the circulating system as a closed system; same amount of mud that goes into the well should come out of the well. As an influx enters the well, the volume of the return flow rate will increase.

Drillpipe pressure

Due to fluids inside the drillpipe, there will be a hydrostatic pressure which should remain constant as the pumps are shut off. The pressure will be positive if we have lighter mud inside, and heavier mud outside of the drillpipe. As we initiate circulation, the different fluid densities and friction will cause a change in the density. The pressure should be decreased by the lighter fluids being pumped down while the heavier mud is being pushed out. To use the drillpipe pressure as a kick indicator can be difficult, but if experiencing abnormalities the driller should stop and check that everything is as it should be. (Erikson, 2011)

5 Minimizing the influx

Early recognition and action upon a kick will minimize the flow of formation fluid into the well. This in turn leads to a lower casing pressure both when the well is shut-in and when the kick is circulated out.

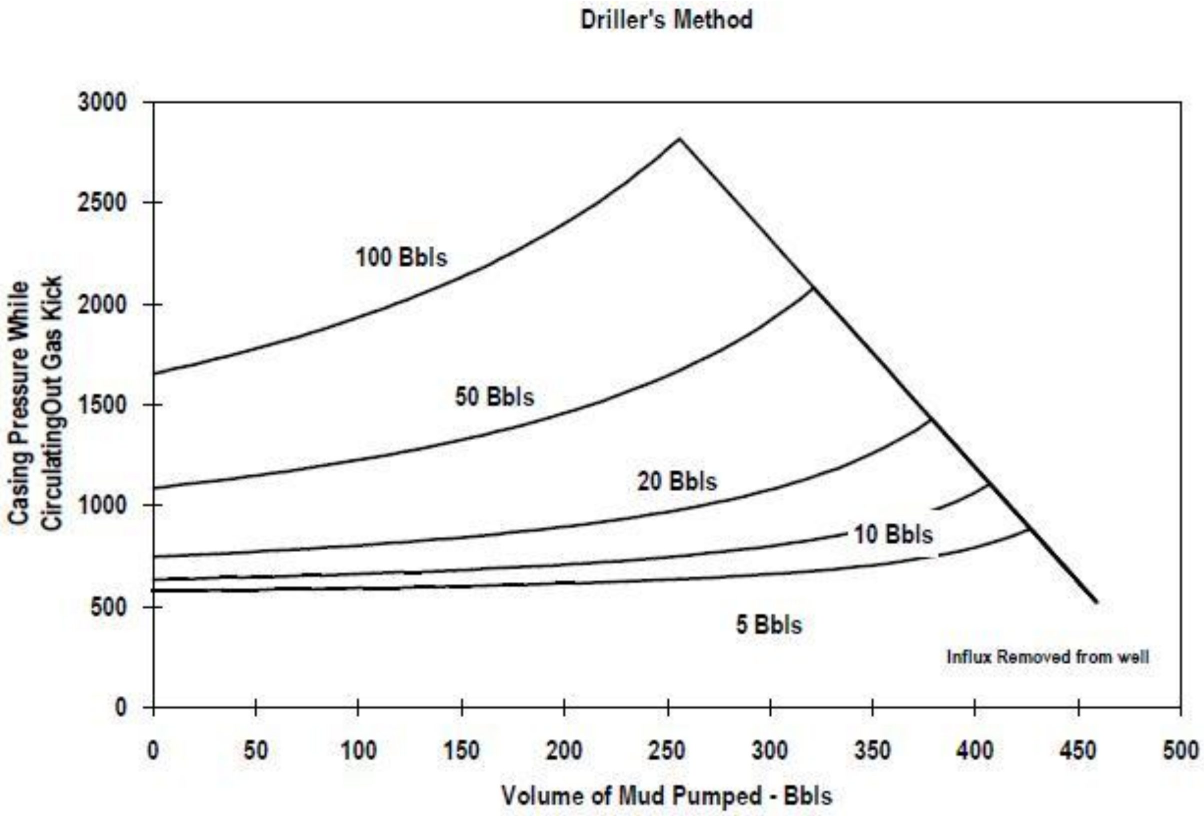

Figure 5: Effect of influx volume on casing pressure, (Chevron Petroleum Technology Company, 1994)

As seen from Figure 5, a large influx will lead to a high casing pressure both at shut-in and when circulating.

Another factor affecting the casing pressure is the type of influx flowing into our well. Gas is much lighter than i.e. saltwater, and a kick that is pure gas will, in comparison with oil or saltwater, create a much higher casing pressure. Well geometry is also a factor, as a kick in a 5 ½" production casing will result in a higher casing pressure than for a 7" production casing. A kick of the same volume will have a greater height in the 5 ½" production casing.

Obviously a great formation pressure will produce a high casing pressure. The higher the formation pressure, the higher the casing pressure, initial shut-in tubing pressure and fluid densities will be. The last factor affecting the casing pressure is the fluid density. A light fluid density will create a higher pressure than a heavier fluid, even thought the killing fluid density required is the same.

For the drilling crew, they can only control the size of an influx. So proper training in detecting warning signals, understanding and recognition of positive indicators and correct shut-in procedures will greatly affect the minimization of the influx. (Chevron Petroleum Technology Company, 1994)

6 Shut-In Procedures

When a positive indicator of a kick is observed, and a flow check verifies that the well is flowing, it should be shut in immediately. If only the surface casing has been set, the kick should be diverted rather than attempting shut-in.

Early recognition of warning signals and a quick shut-in is the key to effective well control. Acting fast and correct minimizes the volume of formation fluid entering the wellbore and the drilling fluid expelled from the annulus.

The size and severity of the kick depends upon:

- The degree of under balance
- The formation permeability
- The length of time the well remains under balance

(C.T.C Drilling and Well Control Department)

Different contractors and operators have procedures for how to handle kicks by the use of either a soft shut-in or hard shut-in.

6.1 Soft Shut-In

When using the soft shut-in procedure, a choke is left open at all times except during a well control operation. The choke line valves are set up so that the flow path is open through the choking system, with the exception of one choke line valve near the BOP. When the soft shut-in procedure has been chosen, the choke line valve is opened. The BOP is then closed and finally the choke is closed. By doing so, we can control and monitor the casing pressure build up while closing in the well. This is of great importance when formation fracturing and broaching to the surface is likely to happen if the well has been closed in without regarding the possibility of excessive initial closing pressure.

6.2 Hard Shut-In

When using the hard shut-in method, the choke remains closed at all times other than during a well control operation. Except for the choke(s) and a choke line valve located near the BOP, choke line valves are aligned to allow flow through the choking system. The BOP is closed and the casing pressured is measured. If this can’t be measured at the wellhead, the choke line valve is opened with the choke or a nearby high pressure valve remaining closed so the pressure can be measured at the choke manifold. The hard shut-in procedure closes the well at the shortest amount of time, reducing the flow of formation fluid into the well. Limitation is defined by the well conditions; the maximum allowable casing pressure is greater than the anticipated initial close in pressure and a well fracture isn’t expected to broach the surface on initial closure.

(Aberdeen Drilling Schools & Well Control Training Centre, 2002)

7 Mud

In the start, mud was originally designed to remove the drilled cuttings away from the well to the surface, but as the drilling industry has modified, the drilling fluid has now several important tasks.

When making the hole, drilling fluids assists by removing the cuttings, cool and lubricate the bit and drillstring, and it also helps in transmitting power to the bit nozzles or turbines. When it comes to hole preservation, it supports and stabilizes the borehole wall. Other areas where the drilling fluids help to reach the objective are;

- Produces sufficient pressure within the borehole to prevent the inflow of formation fluids
- Supports the pipe and casing weight
- Serves as a medium for formation logging

Even though drilling fluids is designed to help drill the holes, it might sometimes cause problems. It is important that the mud don't corrode the bit, drillstring, casing or surface equipment, damage the productivity of our reservoir or pollute the environment. (EP Learning and Development, 1998)

The most common drilling fluids used today are Oil Based Mud, (OBM), and Water Based Mud, (WBM).

OBM is suitable when drilling slim and deviated holes, depleted zones and water sensitive formation. There are two different types of OBM:

- Pure oil base fluid
- Invert oil emulsion fluids, (IOEM)

Pure oil base fluid contains less than 3% volume water. The water is considered inescapable contaminant, and by adding chemicals the wanted drilling fluids properties is obtained. Invert oil emulsion fluids has 5 – 40% volume water. The water is replacing expensive oil and becomes a part of the drilling fluid properties. (EP Learning and Development, 1998)

WBM is basic water where clay and other chemicals are added to obtain wanted properties, i.e. viscosity control, shale stability, enhance drilling ROP, and cooling and lubrication of the system. The most common additive is bentonite.

Well control considerations

When a substance is dissolved in a solvent, it is called solute and it may be solid, liquid or gas. Due to its polar orientation, water is a good solvent. Ionic compounds are highly soluble in water due to the attractive forces between oppositely charged ions are being weakened by polar water. The same ionic compounds are not soluble in non-polar liquids like oil. (Skalle, 2009)

We experience several advantages when drilling with OBM compared to other drilling fluids. It can withstand high temperatures, it doesn't react with clay causing clay instability, the mud cake created is thin, preventing stuck pipe, and it is a good lubricant, hence reducing the drilling torque. (Erikson, 2011)

When experiencing kick while using OBM, it may be difficult to detect due to the serious problems created by gas solubility in mud. Instead of migrating towards the surface, as we see happens for WBM, the gas may dissolve into the solution. Unless the formation becomes considerably underbalanced when using OBM, there might not be any changes in the pit level until the gas influx has been pumped a considerably height up the annulus, see Figure 6. Here the hydrostatic pressure will decrease and fall below the bubble point for the gas. This leads to a rapid expansion of the gas, and the mud flow will increase. This can, in some cases, unload the annulus resulting in full pits and a high annular pressure.

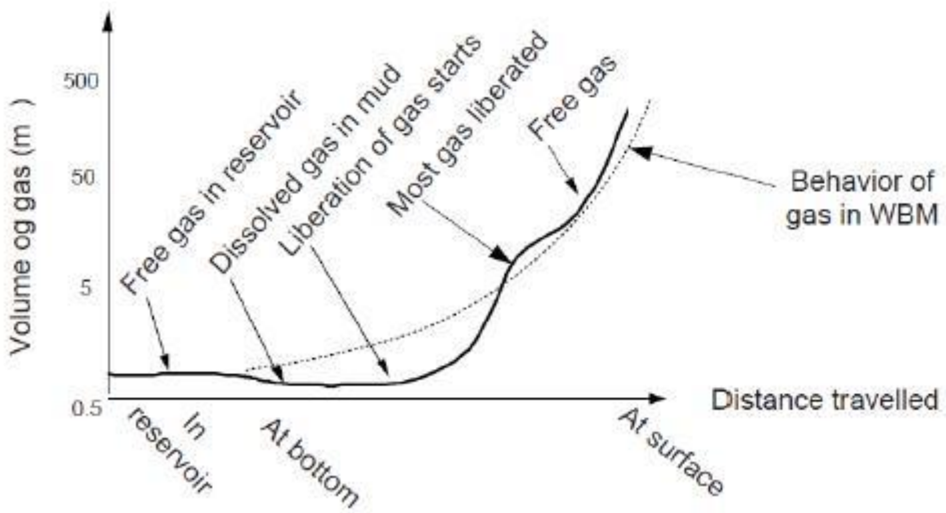

Figure 6: Volumetric behavior of methane dissolved in OBM, (Skalle, 2009)

8 Kill Methods

The purpose of the various kill methods is to circulate out any formation fluids from the wellbore, and replace existing mud with a heavier kill mud which won't allow any further influx from the formation. This must be done with minimum damage to the well. If this operation is successful, the well may be re-opened and the work can continue.

As the well has been shut-in the pressures in the well will be in balance, providing no equipment failure. The hydrostatic pressure has been reduced, but surface applied pressure on the annulus and on the drillpipe makes up for the losses. We can use this information to determine the formation pressure and therefore the weight of our kill mud required to balance and kill the well.

Equation 4: Formation Pressure from the Drillpipe

$$P_{formation} = P_{hydrostatic} + Shut\ in\ Drillpipe\ Pressure$$

Equation 5: Formation Pressure from the Annulus

$$P_{formation} = P_{hydrostatic} + \ Shut\ in\ Casing\ Pressure$$

As the mud in the annulus contains a mixture of mud, cuttings and formation fluid, it will be impossible to be able to determine the formation pressure from Equation 5. But since the drillpipe has clean mud with known density the formation pressure can be calculated.

The kill mud has to produce a hydrostatic pressure equal to the formation pressure over a length equal to the TVD of the hole. We can also describe the kill mud weight as the original mud weight increased by an amount that will provide a hydrostatic pressure equal to the amount of the shut in drillpipe pressure, (SIDPP), over the vertical length of the hole, see Equation 6.

Equation 6: Kill Mud Weight

$$\rho_{Kill\ Mud}[ppg] = \frac{SIDPP\ [psi]}{TVD[ft] * 0.052} + \rho_{Original\ Mud}[ppg]$$

In the next two chapters, two kill methods will be discussed; Driller's Method and Wait & Weight Method, (W&W Method). Both of these methods keep a constant BHP, and they only differ in the process of pumping the kill mud down into the well. (Aberdeen Drilling Schools & Well Control Training Centre, 2002)

8.1 Driller's Method

The Driller's Method obtains well control with two separate circulations. The kick is circulated out of the hole using the existing mud weight, before circulating the well with the heavier kill mud. It is considered to be the simplest killing method, since it deals separately with the removal of the kick and the addition of kill mud. It also requires less arithmetic.

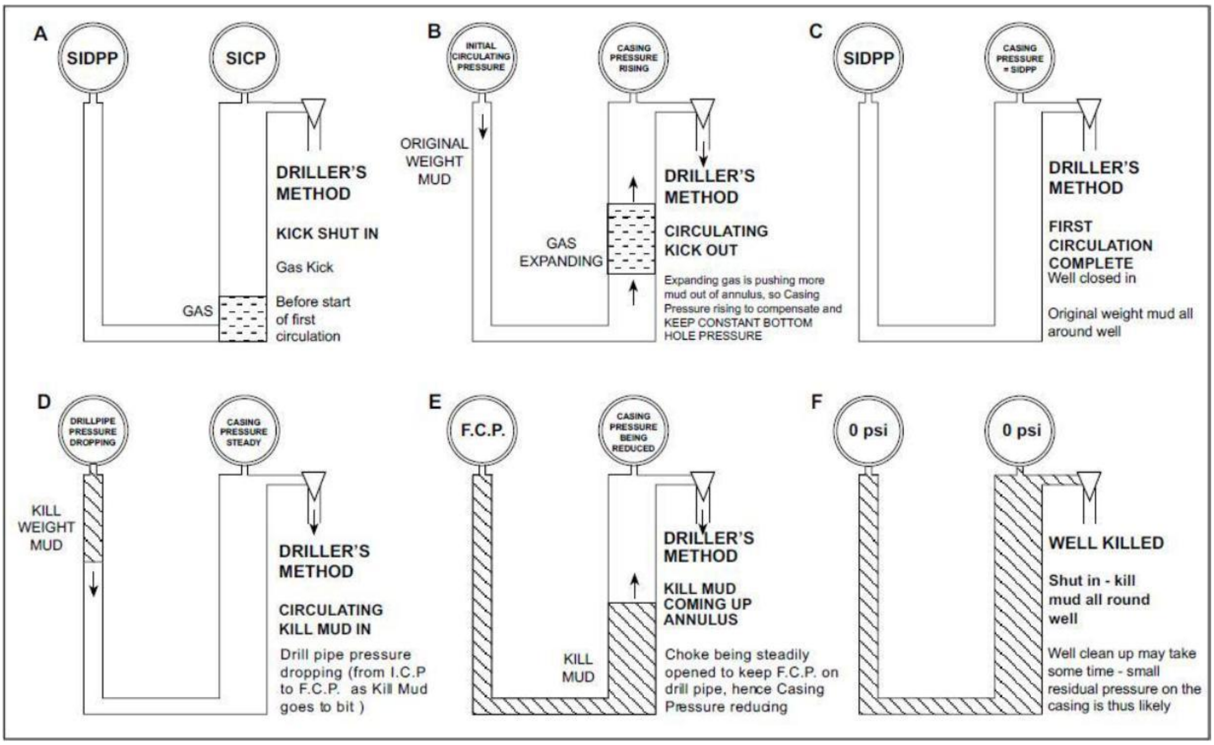

Figure 7: Driller's Method, (Aberdeen Drilling Schools & Well Control Training Centre, 2002)

Figure 7 and the following steps describe the Driller's Method in detail:

1. When the kick is detected, the well is shut in.
2. The Shut-in Drillpipe Pressure, (SIDPP), and the Shut-in Casing Pressure, (SICP), are both recorded before the pumps are started. As the decreasing well pressure can lead cause more influx from the formation, this operation can be difficult. The choke needs to be opened slowly so the flow rate steadily reaches the Slow Circulation Rate, (SCR).
3. The gas is being circulated out of the well, and the choke pressure should be equal to SICP at the start. As the gas expands towards the surface, the SICP value will reach its top value just before the kick reaches the surface, before decreasing to a value equal to SIDPP.
4. By using Equation 6, the kill weight mud is calculated.
5. As the drillpipe is filled with kill weight mud, SIDPP is reduced to zero. As the heavier mud will increase the friction pressure, the Initial Circulation Pressure, (ICP), will decrease to Final Circulation Pressure, (FCP).
6. When the well has been filled with the heavy mud, the well is closed and SIDPP and SICP are controlled. If the well is killed, these values should be zero. If not, then:

a. There may be trapped pressure in the well
b. There may be an additional influx remaining in the well
c. There may not be dense enough kill weight fluid in the well

(Erikson, 2011)

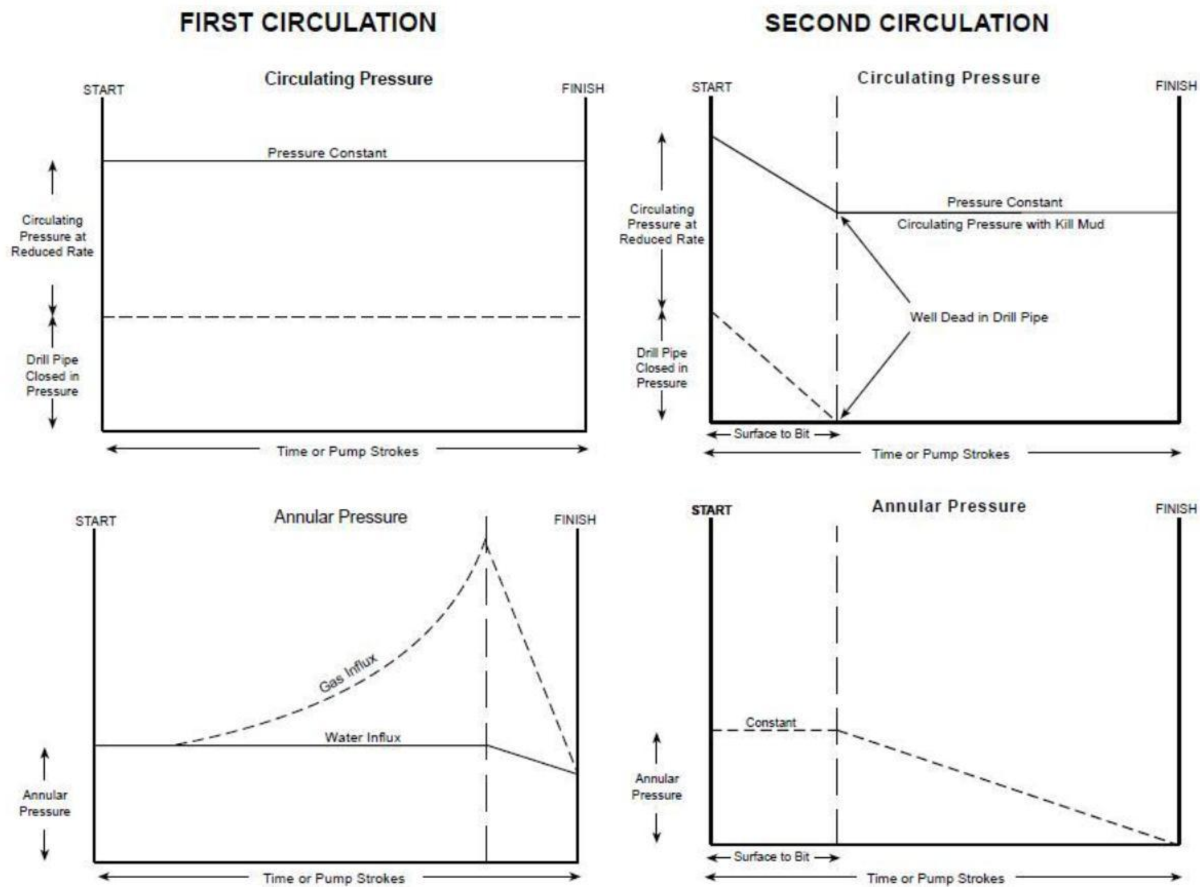

Figure 8: Circulating out kick, Driller's Method, (Aberdeen Drilling Schools & Well Control Training Centre, 2002)

The circulating and annular pressure has been illustrated in Figure 8. For the first circulation, we can see the circulating pressure is constant, before it decreases and stabilize at the FCP. The reason for this is that the heavier kill mud is replacing the lighter. The FCP is obtained as the kill mud reaches the bit.

For the annular pressure, the gas is expanding as it travels towards the surface, hence the pressure is increased. As the gas is circulated out of the well at the surface the pressure decreases. When the kill mud is circulated into the well, the annular pressure is constant until the mud reaches the bit. As the mud travels from the bit to the surface, the pressure will decrease as the choke is opened to maintain FCP.

(Aberdeen Drilling Schools & Well Control Training Centre, 2002)

8.2 Wait & Weight Method

The Wait & Weight Method, (W&W Method), is also known as the Engineers Method. Compared to the Driller's Method, the W&W Method, in theory, only needs one circulation to kill the well. As the well has been shut-in and the pressure is stabilized, the SIDPP is used to calculate the kill weight mud.

As the mud is being pumped down the string, the choke is adjusted to reduce the drillpipe pressure. The static head of mud is balancing the formation pressure when the mud reaches the bit. When finalizing the circulation, the influx, drillpipe content and kill mud is being circulated to the surface, the drillpipe pressure is kept constant at the circulation pressure by choke adjustments.

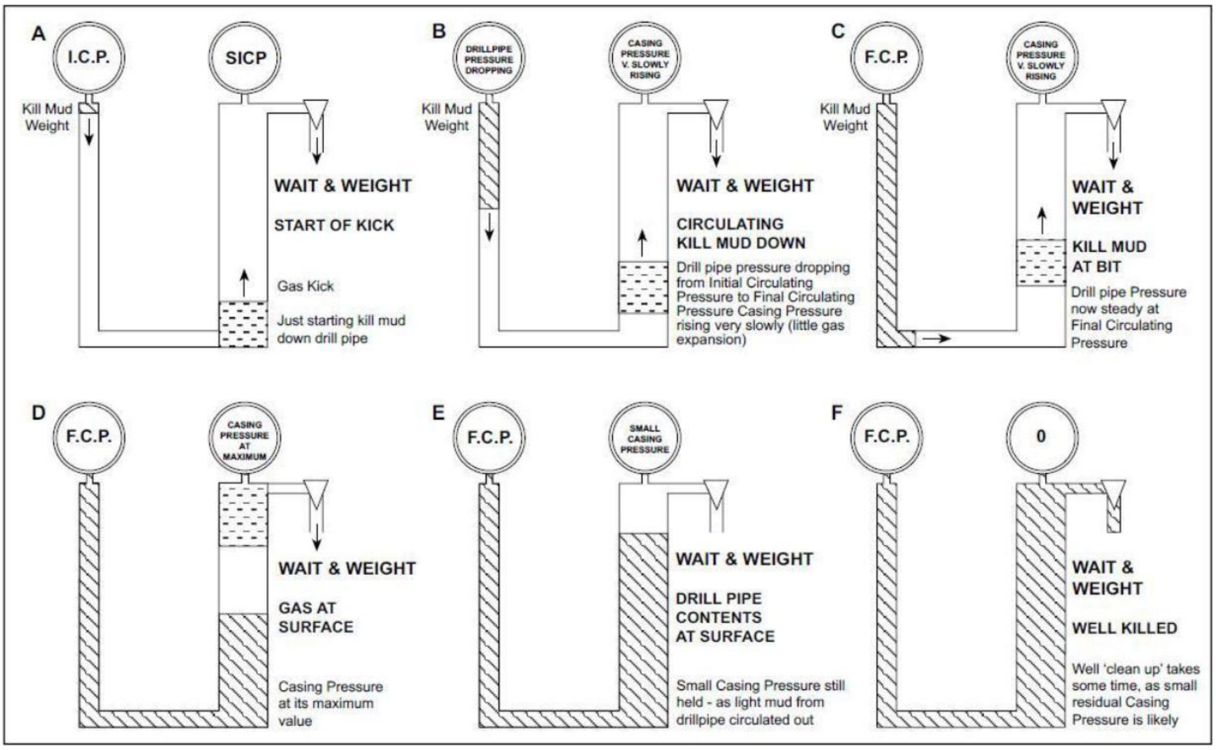

Figure 9: Wait and Weight Method, (Aberdeen Drilling Schools & Well Control Training Centre, 2002)

Figure 9 and the follow steps describe the W&W Method in detail:

1. The kick is detected and the well is shut in.
2. After determining the SIDPP and SICP, the kill mud weight should be calculated using Equation 6. As the calculations are being made, gas might migrate up the annulus causing an increase in the SICP, so attention needs to be paid to the monitors.
3. When the kill mud is ready to be circulated, the pumps are brought up to speed reaching SCR, while the choke is being opened so that the casing pressure is maintained constant.
4. When the kill weight mud reaches the bit, the drillpipe pressure is equal to the FCP.
5. The kill weight mud is circulated to the surface while keeping a constant FCP.

6. After the kill mud has performed a circulation, the pumps are stopped and the well is shut in. Now, both the casing and drillpipe pressure should be zero. In not, the mud density was too low and another calculation and circulation has to be done.

(Aberdeen Drilling Schools & Well Control Training Centre, 2002)

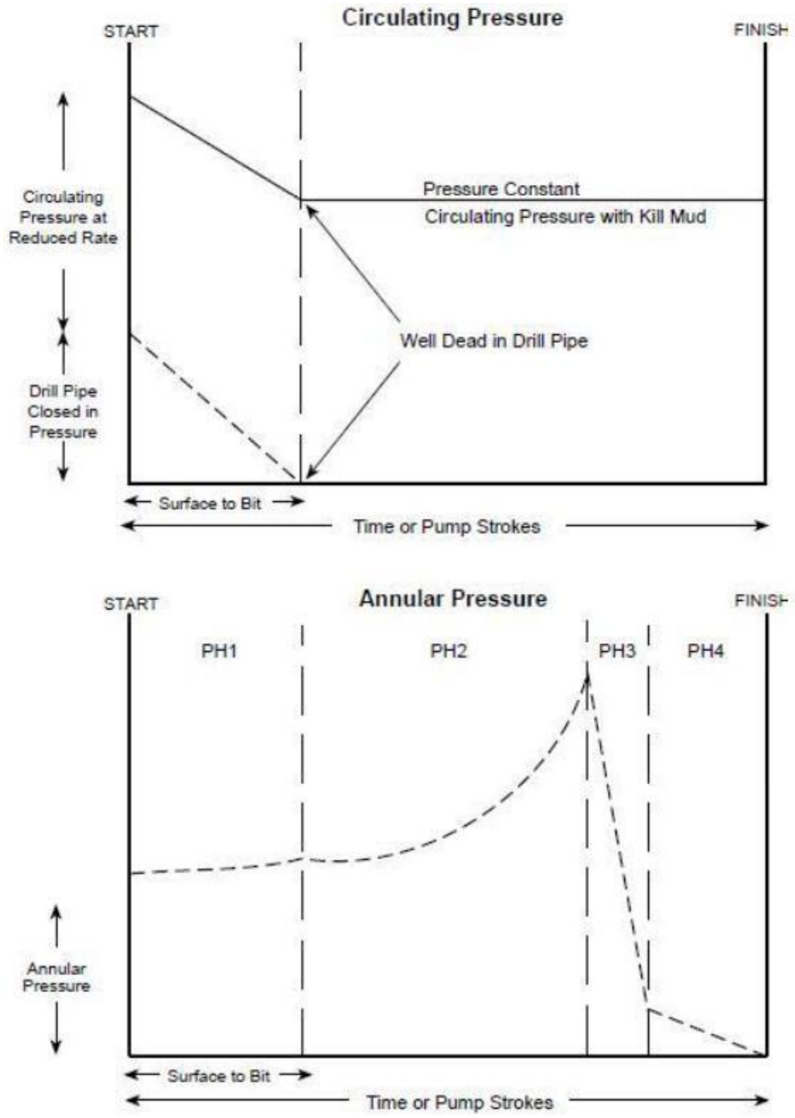

Figure 10: Circulating out kick by the Wait & Weight Method, (Aberdeen Drilling Schools & Well Control Training Centre, 2002)

Also for the W&W Method, Figure 10 shows the circulating and annular pressure when the kick is being circulated out of the well. As the kill mud is entering the drillstring, the circulating pressure is decreasing until it reaches the bit. It is then kept constant as long as the pump rate is constant.

For the annulus, the pressure is increasing to a maximum during phase 1 and 2. As mentioned before, the pressure will be greatest as the influx reaches the surface due to expansion. As the kick is being circulated out of the hole the pressure decreases. The annular pressure won't reach zero until all of the lighter mud has been replaced by the kill weight mud.

Comparison of the two methods will be discussed by showing to theory and results in chapter 12.

9 Kick tolerance

'Kick tolerance may be defined as the maximum kick size which can be tolerated without fracturing the previous casing shoe. Kick tolerance may also be defined in the terms of the maximum allowable pore pressure at next true depth, (TD), or maximum allowable mud weight which can be tolerated without fracturing the previous casing shoe.' (Rabia, 2001)

There are several variables affecting the kick tolerance;

- Formation strength, fracture pressure or fracture gradient
- Mud density or gradient
- Gas influx density or gradient
- Formation pore pressure, gradient or SIDPP
- Drill string and wellbore geometries

Listed in Table 1 is typical kick tolerance values shown. If the well cannot handle a kick size defined by the volumes specified, the last casing shoe has to set deeper. (Aberdeen Drilling Schools & Well Control Training Centre, 2002)

Hole size (inch)	Kick volume (bbl)
6" and smaller	10-25
8,5"	25-50
12,25"	50-100
17,5"	100-150
23"	250

Table 1: Typical values of kick tolerance, (Rabia, 2001)

10 Simulation

As projects in the oil industry is heading towards deeper wells, higher temperatures and pressures, remote locations etc. it becomes more crucial to be able to foresee unwanted incidents that may occur during operations. When using a simulator in the well planning phase, it can help us eliminate unwanted well situations by analyzing and evaluate different scenarios.

10.1 Drillbench kick

The simulator used is made by the SPT Group. The software program is applicable for all conventional drilling operations and has several individual applications focusing on the challenges encountered regarding the different operations.

'The Dynamic Well Control application in Drillbench is a unique tool for engineering, decision making support and risk evaluation. The software is based on the R&D activities in multiphase flow modeling, laboratory and full scale experiments, and extensive verification. The simulator uses advanced mathematical models to simulate the flow process in the well.' (SPT Group, 2012)

Key features;

- Well control procedures
- Kick tolerance studies
- Casing design
- Design of surface equipment
- Effect of well geometry, mud density etc.
- Horizontal kicks
- Well kill operations

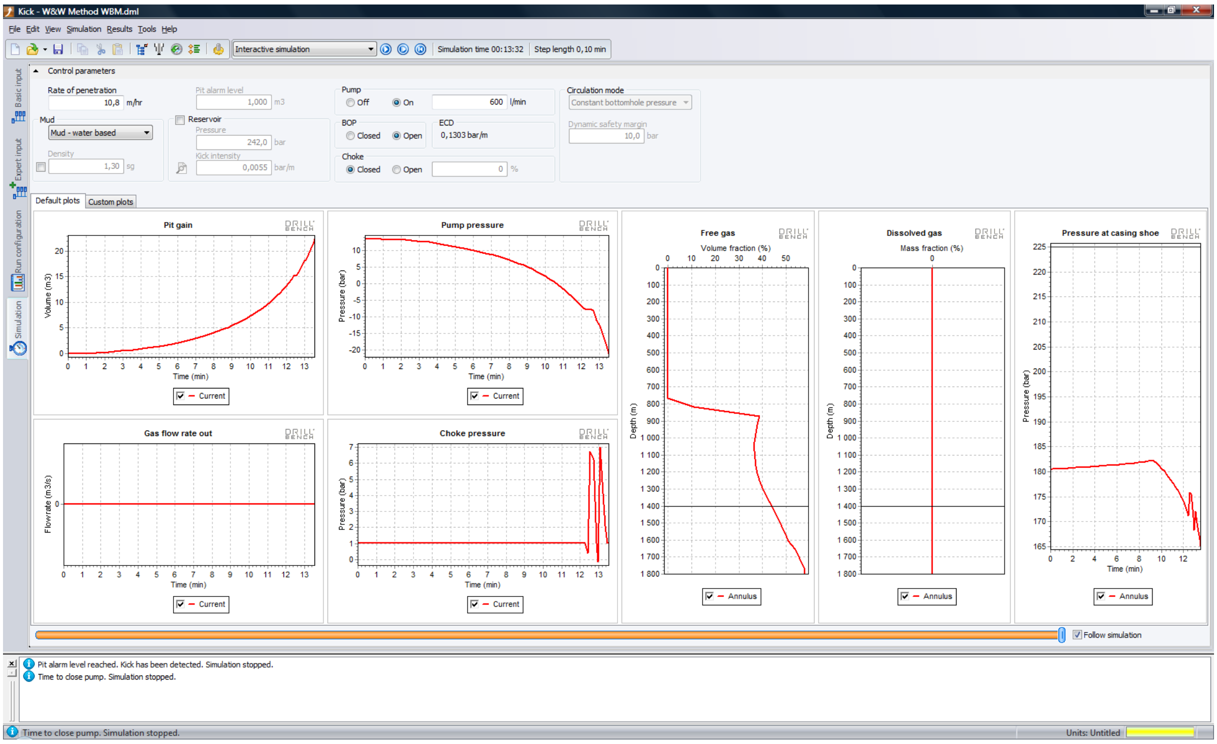

Figure 11: User simulation interface, Kick module, (SPT Group, 2012)

As shown in Figure 11, the simulator offers a user-friendly graphical interface, where the process can be monitored and actions can be done anytime during the simulation. (SPT Group, 2012)

10.2 Simulation process

The simulator has built-in samples which have been used for the simulations, see Appendix, 1. Input parameters in simulator. Different simulations have been done for both OBM and WBM. The differences between soft- and hard shut-in have been examined and then both Driller's Method and W&W Method have been simulated.

When simulating the shut-in process, the procedure of the kick simulation is as followed:

1. Start drilling
2. When kick is detected shut of the pump
3. Continue simulation. The simulation runs until the program register that the pump is shut down.
4. Hard shut-in: Close BOP. The simulation runs until the program register that the BOP is closed.
   Soft shut-in: Open the choke and close the BOP. Close choke.
5. Simulate until influx ends
6. Open pump and choke
7. Circulate the gas out of the well

When simulating the circulation methods, the simulator do the whole procedure automatically.

W&W Method:

1. Pre-kick circulation period
2. Taking in kick
3. Turning off pump
4. Closing BOP
5. Shut in time
6. Opening choke
7. Turning on pump
8. Circulating out kick

Driller’s Method

1. Pre-kick circulation
2. Taking in kick
3. Turning off pump
4. Closing BOP
5. Shut in time
6. Opening choke
7. Turning on pump
8. Circulating out kick
9. Circulating kill mud

11 Results

When simulating soft- and hard shut-in, parameters shown in Table 2 have been used:

Rate of penetration	10,8 m/hr
Pit alarm level	1,00 m^3
Pump rate	3000 l/min
Circulation rate	600 l/min
Circulation mode	Constant bottomhole pressure
Dynamic safety margin	10,00 bar

Table 2: Simulation parameters, soft- & hard shut-in

11.1 Soft Shut-In

11.1.1 OBM

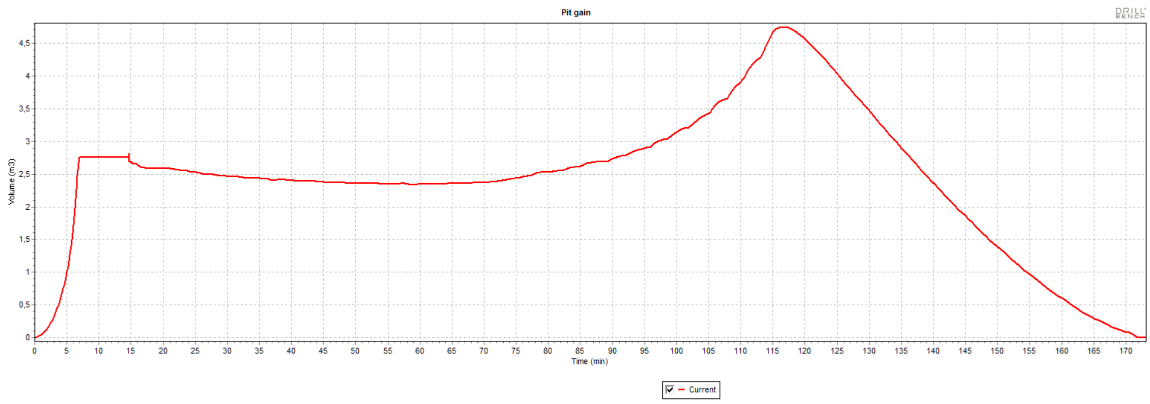

Figure 12: Pit gain

Figure 12 shows the pit gain. Since the choke is open when we close the BOP, a small portion of the drilling fluid will flow into the chokeline. We can see from the graph as the pump starts again, we have a small increase in the pit gain due to this mud volume. The gas will be compressed because of the hydrostatic pressure and some will be solved into the mud; we will therefore experience a decrease in the pit gain. As the pressure is sinking, the gas will expand hence more mud will be expelled from the well. The pit gain reaches a maximum value of 4,756m^3. The kick is circulated out after 2 hours and 53 minutes.

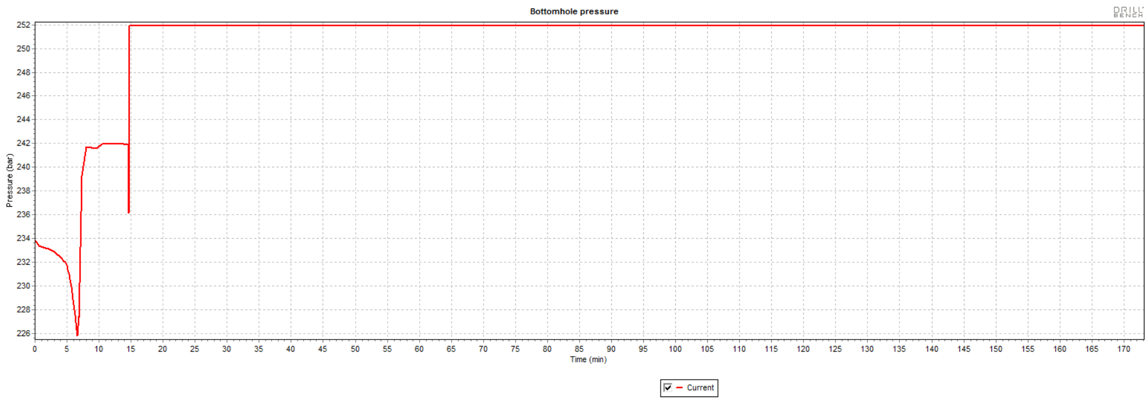

Figure 13: Bottomhole pressure

In Figure 13 the bottomhole pressure is illustrated. Due to the soft shut-in, the pressure will, after the kick is taken, vary before increasing as the well is shut in. To make sure we won't experience more influx from the formation, the pressure is increased during the shut-in time of the well. During this period the pressure increases to 241,925 bars, and when the circulation starts the pressure is increased to 251,914 bars.

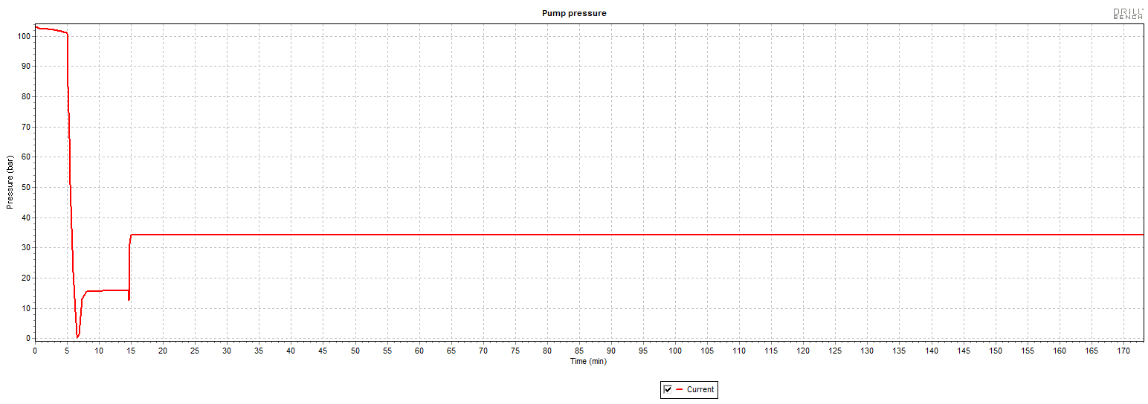

Figure 14: Pump pressure

The pump pressure is shown in **Feil! Fant ikke referansekilden.**. It is illustrating the force needed to make sure the mud is flowing through the well at wanted rate. When the gas enters the well the pressure will decrease; the gas is lighter then the mud expelled from the well, hence it will be easier for the pumps to maintain flow rate. When the gas is being circulated out of the well, the pressure is constant at a value of 34,230 bars.

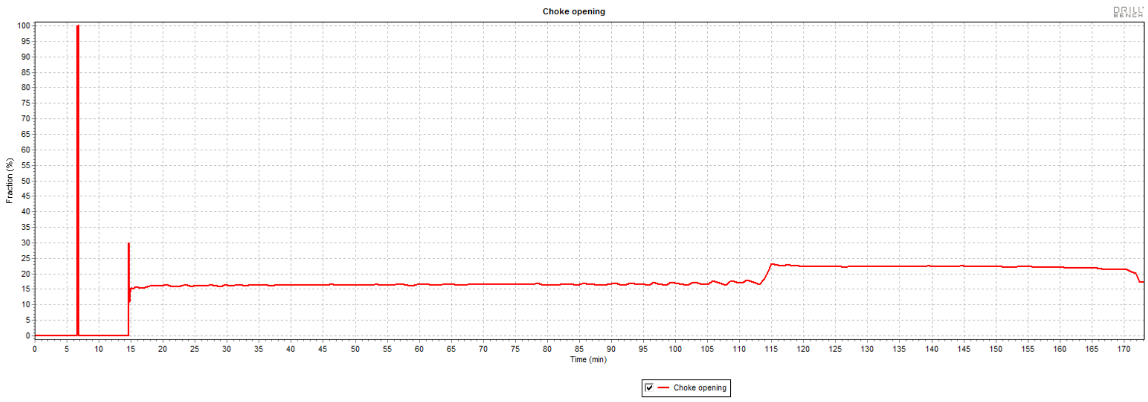

Figure 15: Choke opening

For the soft shut-in method, the coke is open when the BOP is closed. It is then closed to obtain a higher well pressure than formation pressure stopping formation fluid from entering the well. The choke opening varies to keep the bottomhole pressure constant during the circulation, Figure 15.

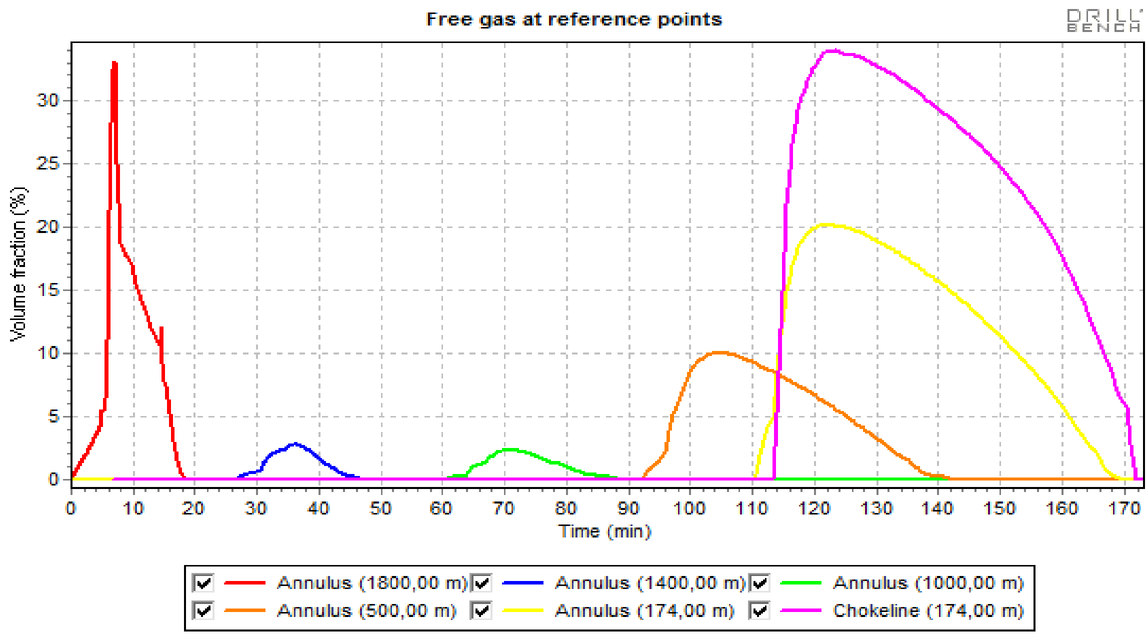

Figure 16: Free gas

To see how the gas behaves during its travel towards the surface, the illustration in Figure 16 have been used. 5 different reference points have been chosen; 1800m, 1400m, 1000m, 500m and 174m. At 1800 m we are at the bottom of the well, so here we can see how the gas flows freely into the well before it is affected by the pressure and type of mud. When the influx is stopped the pressure compresses the gas, and since we have OBM some of the gas will also mix into the mud. Due to this, the volume fraction decreases. When the gas reaches its bubble point, the gas will free itself from the mud increasing the free gas fraction. The hydrostatic pressure is decreasing at the same time, and the gas will expand the closer it gets to the surface. In Figure 17 below, the dissolved gas mass fraction is shown.

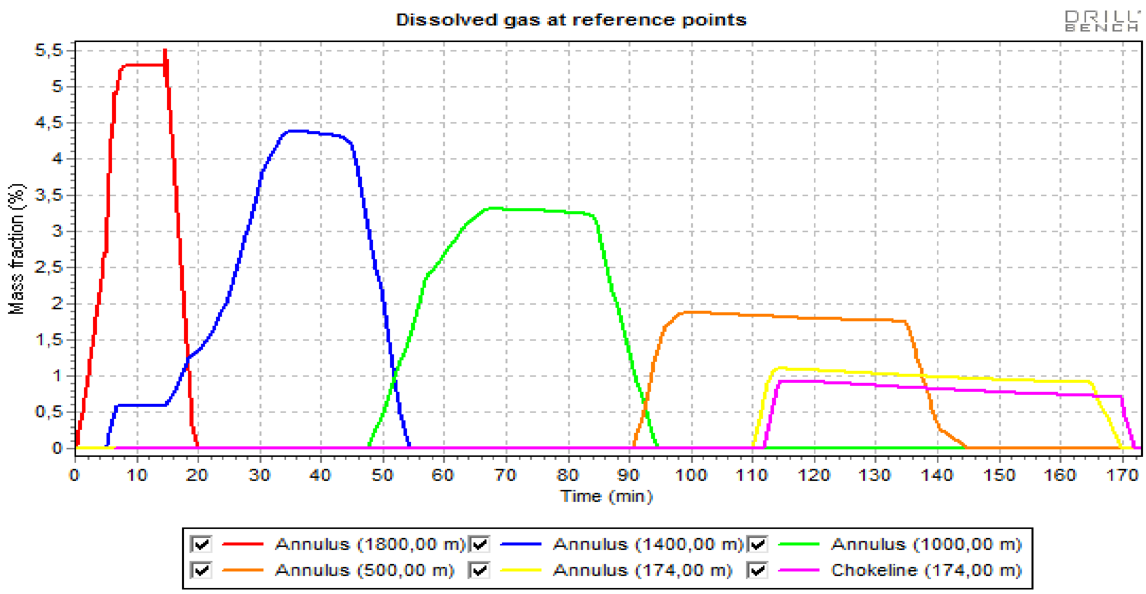

Figure 17: Dissolved gas

11.1.2 WBM

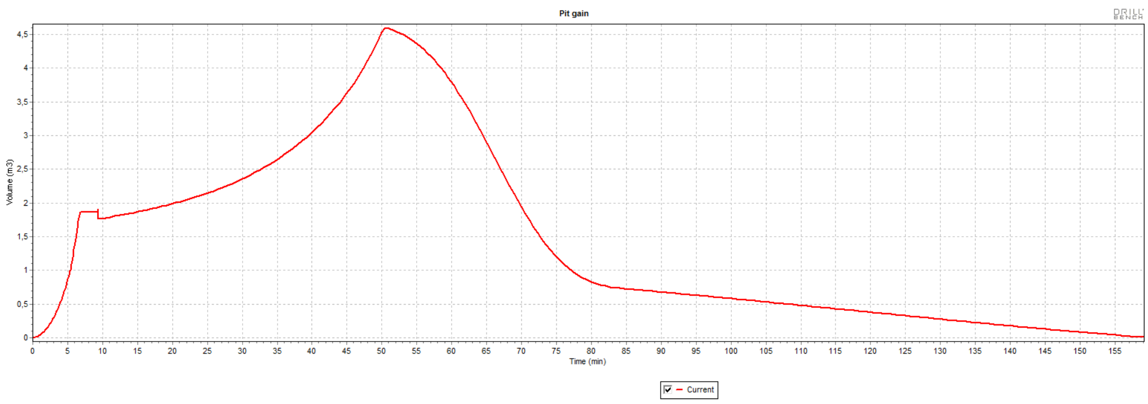

Figure 18: Pit gain

Figure 18 illustrates the pit gain when we use WBM. We can clearly see the same trends and behavior as we did when we were using OBM. In comparison when we used OBM, we see that after we start to circulate the kick, the pit gain doesn't decrease. This is due to the fact that the gas isn't soluble with the WBM and is free at all times. We experience a maximum pit gain of 4,599m^3, and the gas is circulated out after 2 hours and 39 minutes.

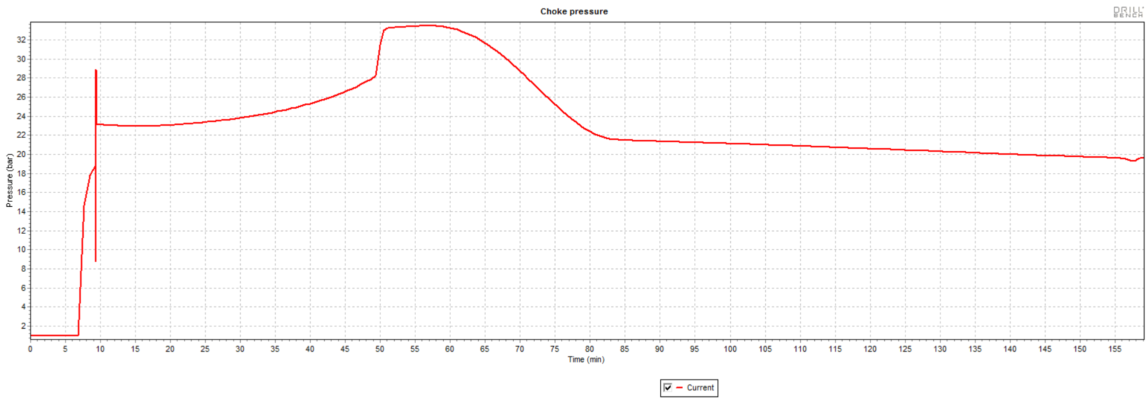

Figure 19: Choke pressure

Figure 19 illustrates the choke pressure. As the gas flows upwards entering the chokeline, the pressure increases until it reaches the surface. Due to the gas expansion the mud above the kick will be expelled from the well, so the choke pressure needs to be increased in order to keep constant bottomhole pressure. Figure 20 below shows the choke opening.

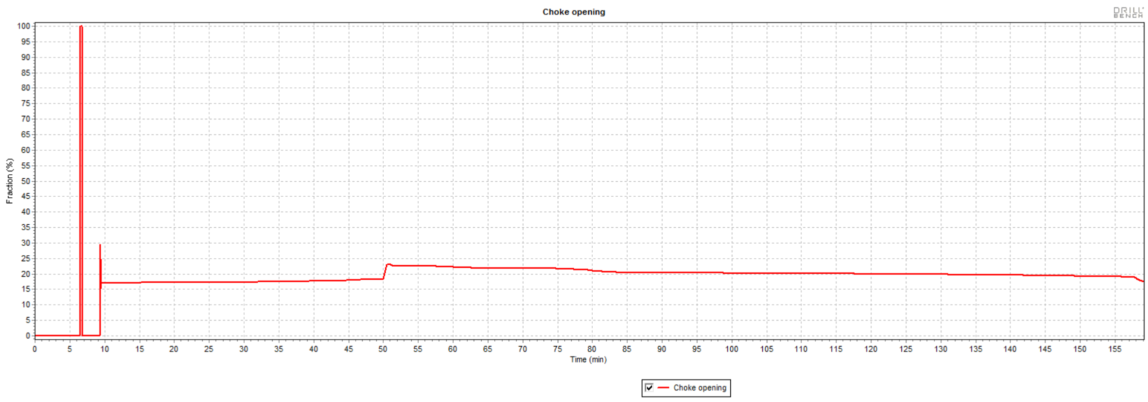

Figure 20: Choke opening

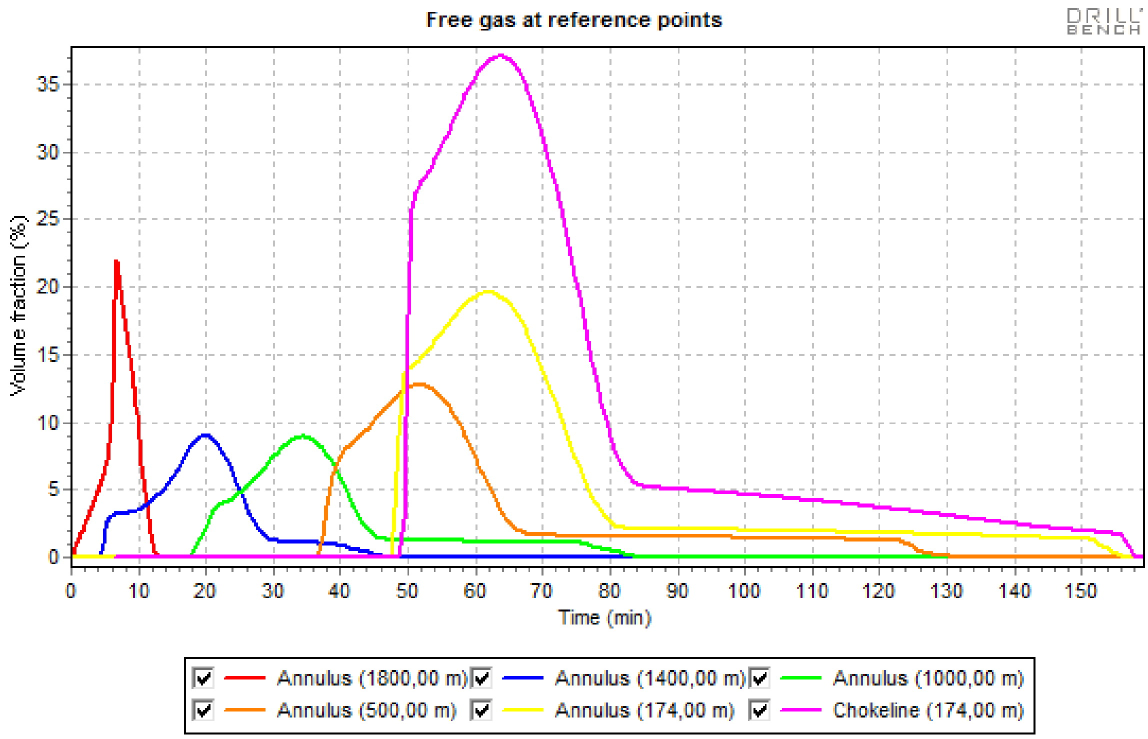

Figure 21: Free gas

Even though we have WBM, we can see the same results for the free gas, Figure 21. Since the gas isn't soluble in WBM, the volume fraction is larger compared to when we have OBM. The pressure is, nevertheless, compressing the gas in the deeper regions, before it expands due to the hydrostatic pressure reduction.

11.2 Hard Shut-In

11.2.1 OBM

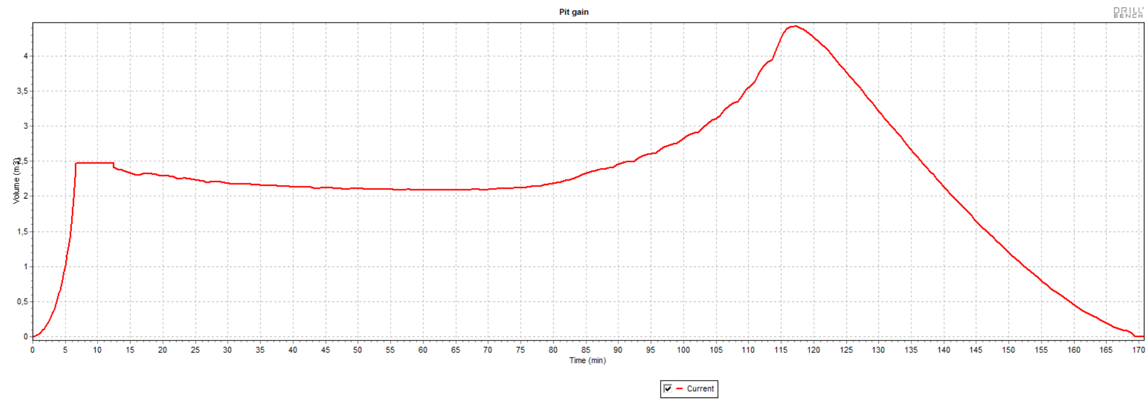

Figure 22: Pit gain

Figure 22 shows the pit gain when we use hard shut-in method. It is very similar to when we used the soft shut-in procedure; the gas is mixing with the OBM, hence decreasing the pit gain before expanding and separating from the drilling fluid. Again we have the maximum pit gain when the gas reaches the surface, 4,413m^3. It takes 2 hours and 51 minutes to circulate the gas out of the well.

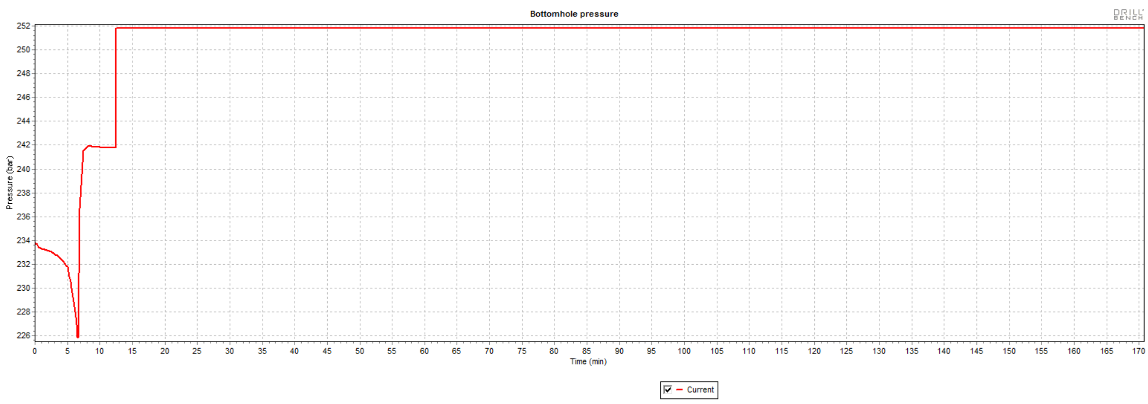

Figure 23: Bottomhole pressure

Figure 23 illustrates the bottomhole pressure. The pressure rises to a value of 242,042 bars during the shut-in time. As the kill mud is being circulated into the well, the pressure increases to 252,004 bars.

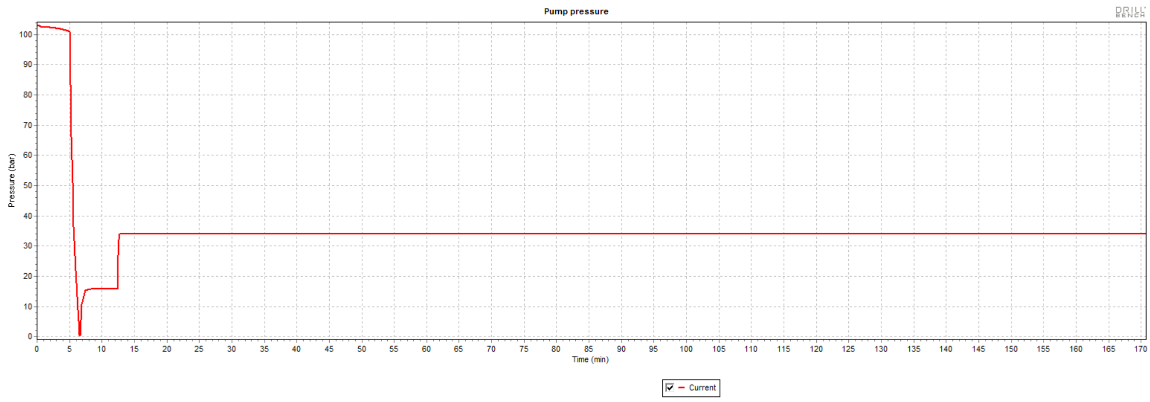

Figure 24: Pump pressure

We see the same trends for hard shut-in as when we used soft shut-in, Figure 24. As the gas is circulated out of the well, the pressure is constant at 34,134 bars.

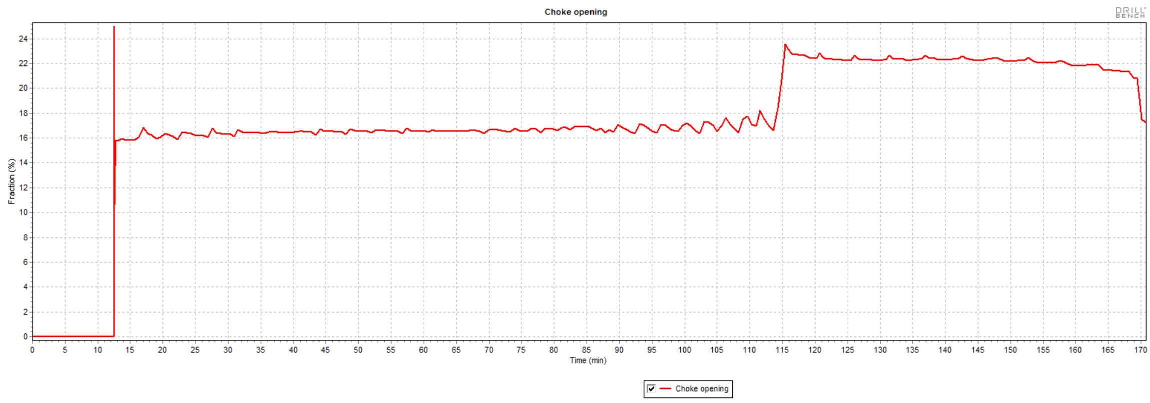

Figure 25: Choke opening

When we use the hard shut-in method, the choke isn't opened until the circulation starts. When it is opened, it stabilizes, but has small high and lows. Since the gas is constantly expanding and separating from the mud, the choke opening varies to keep the bottomhole pressure constant, Figure 25.

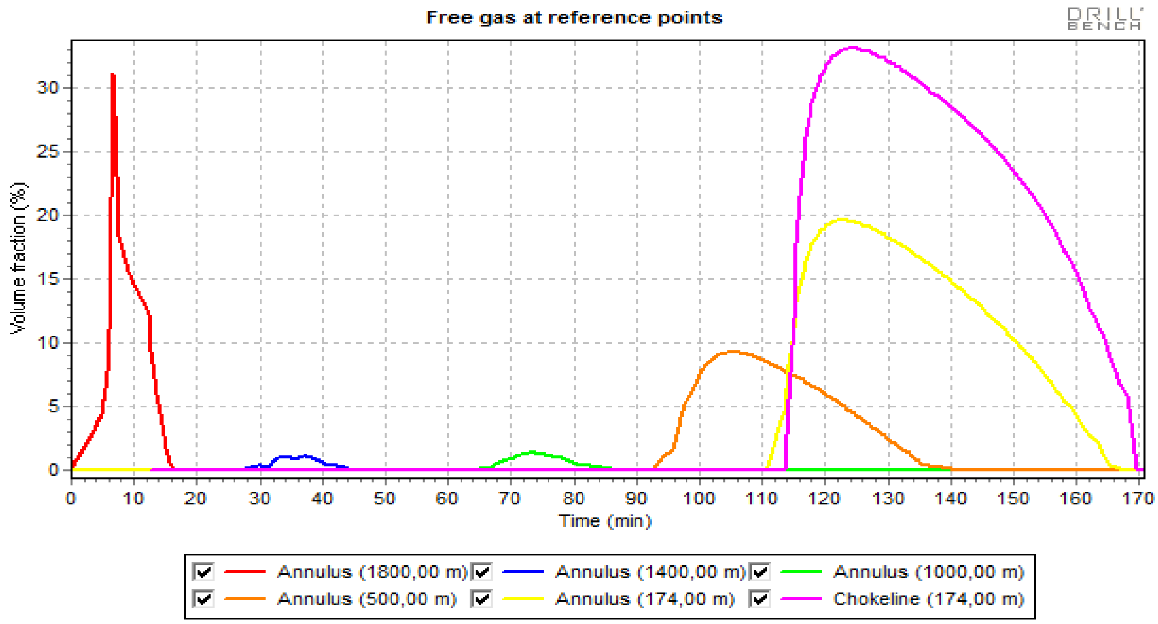

Figure 26: Free gas

When we use the hard shut-in method, we see the free gas volume fraction at 1400m and 1000m are almost zero, Figure 26. The time we have free gas at the bottom is also shorter then when we used the soft shut-in method, resulting in a smaller kick. In Figure 27 below is the dissolved gas shown.

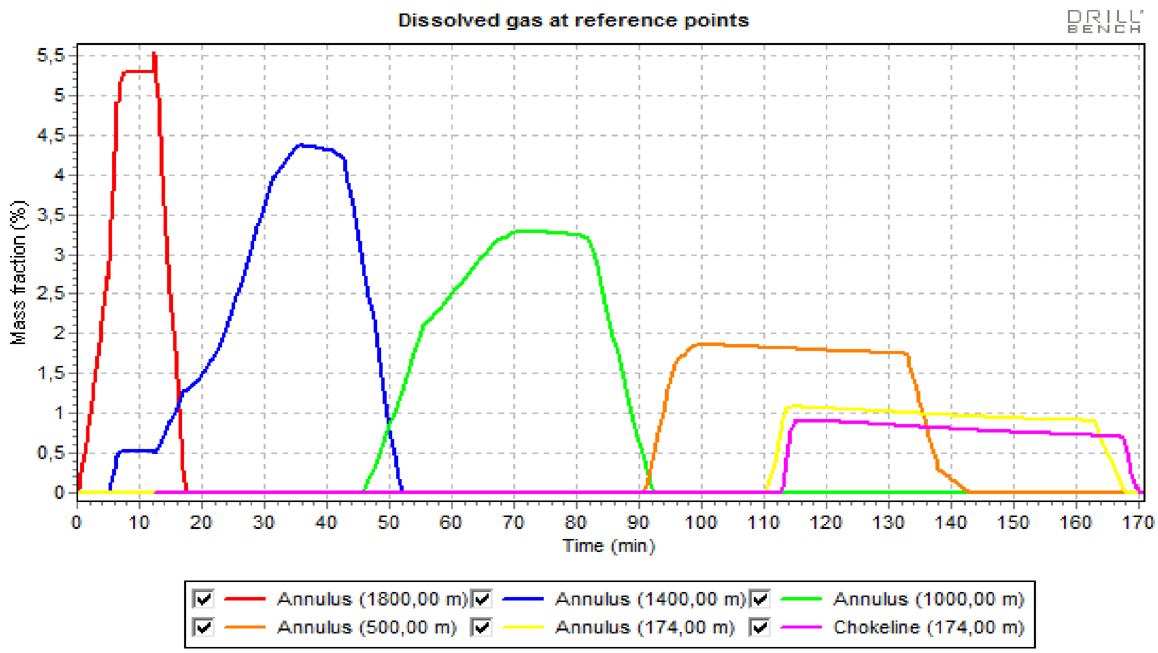

Figure 27: Dissolved gas

11.2.2 WBM

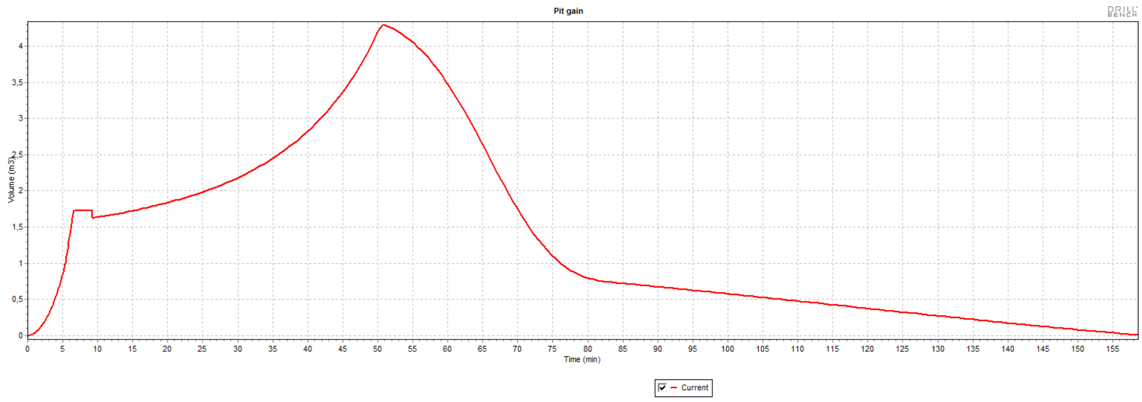

Figure 28: Pit gain

Also for the hard shut-in method, we see similarities between WBM and OBM, Figure 28. The maximum pit gain is 4,287m^3 and the time spent circulating out the gas is 2 hours and 38 minutes.

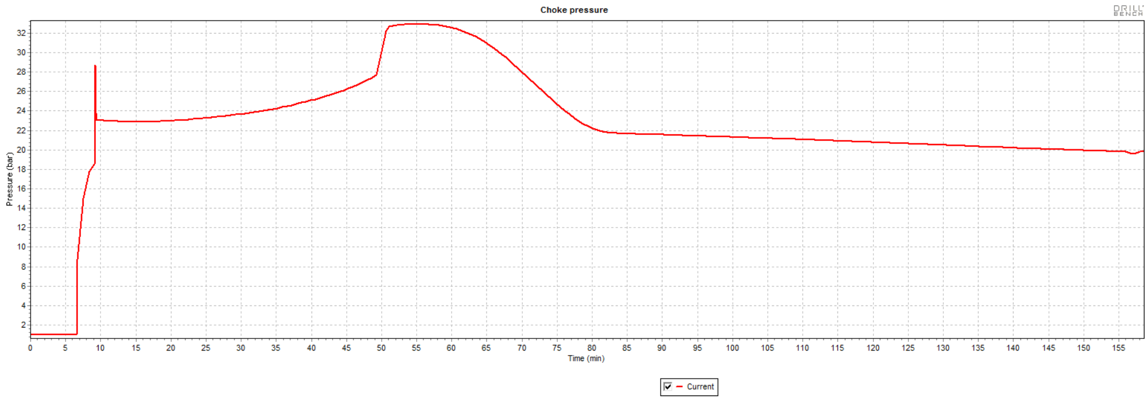

Figure 29: Choke pressure

The choke pressure, Figure 29, increases until the gas reaches the surface. When the gas in the well is reduced, the pressure and opening is reduced until the gas has been fully circulated out. The choke opening is shown in Figure 30 below.

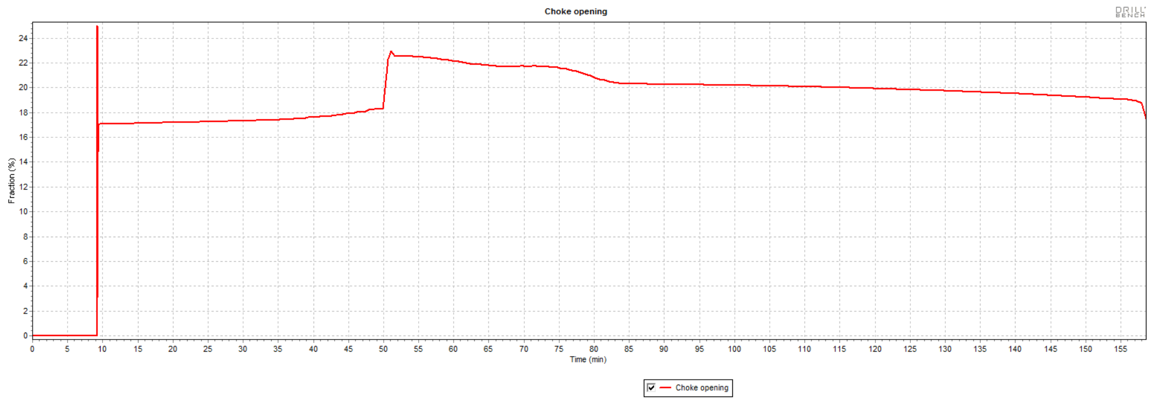

Figure 30: Choke opening

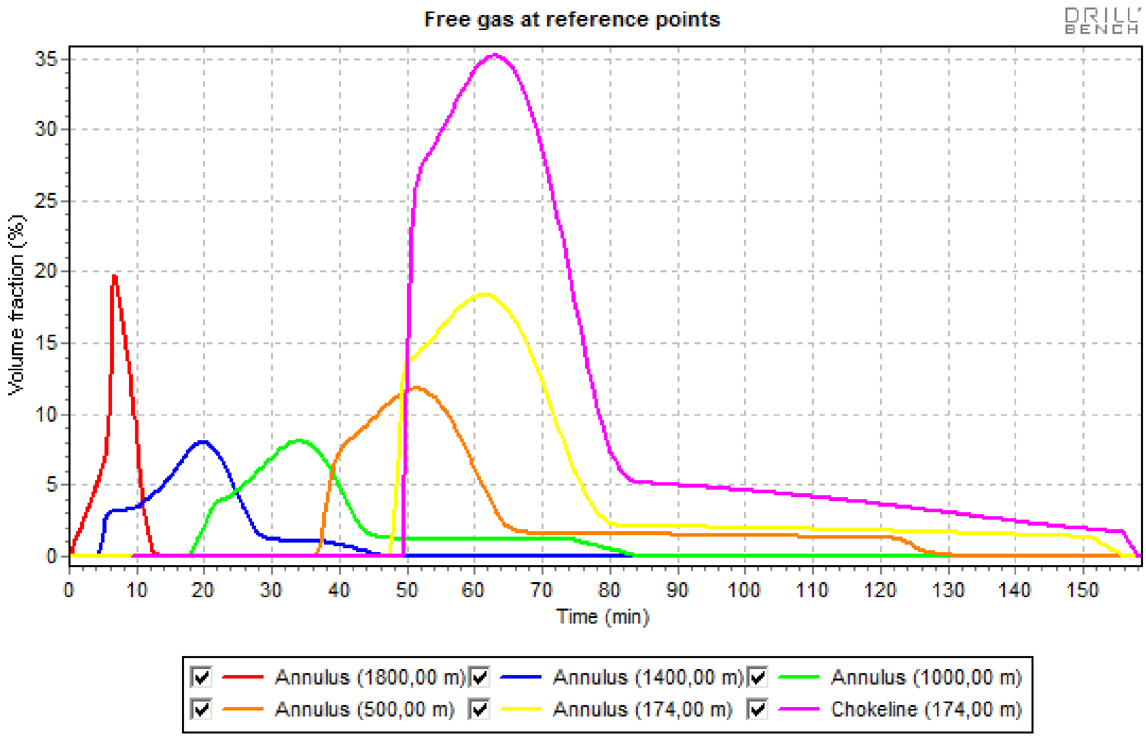

Figure 31: Free gas

Compared to the soft shut-in method the free gas volume fraction in the well is lower when we use the hard shut-in method, Figure 31.

11.3 Driller's Method

For the Driller's Method, the parameters shown in Table 3: Simulation parameters, Driller's Method have been used:

Pre-kick circulation	10,00 minutes	3000 l/min
Kick intensity	0,01 bar/m	
Pit alarm level	1,00 m^3	
Shut in period	Until influx is stopped	
Circulation rate	600 l/min	
Kill mud circulation rate	600 l/min	
Dynamic safety margin	10,0 bar	
Static safety margin	4,0 bar	

Table 3: Simulation parameters, Driller's Method

11.3.1 OBM

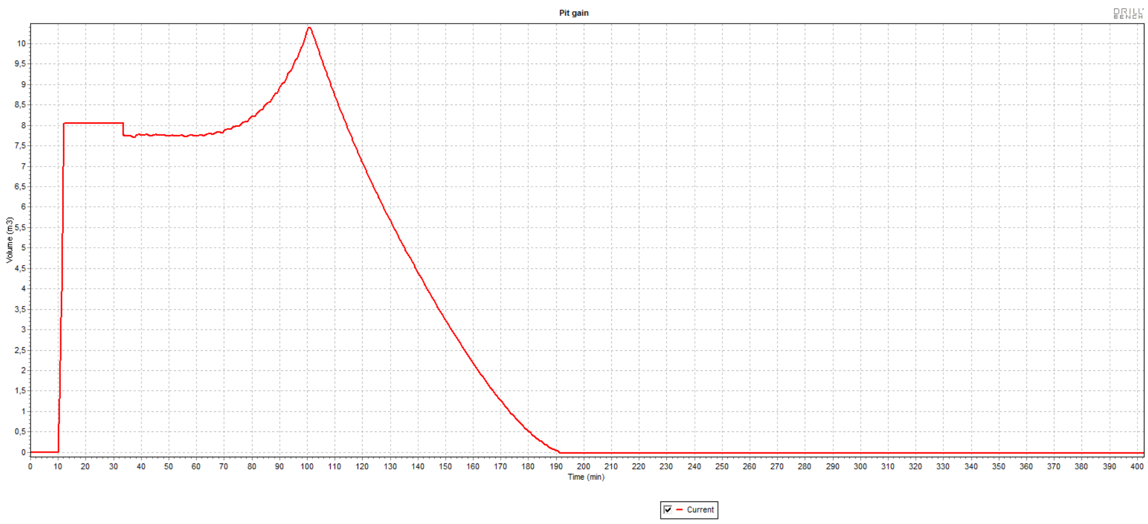

Figure 32: Pit gain

The pit gain is illustrated in Figure 32. In the simulator, a pre-kick circulation time of 10 minutes have been set. When this is finished the kick is taken, increasing the pit gain to 8,004m^3. As explained before, the gas influences the pit gain. After 1 hour and 40 minutes the gas reaches the surface and the pit gain is at a value of 10,399m^3. The gas has been circulated out of the well after 3 hours and 10 minutes. The kill mud has been circulated through the well after 6 hours and 42 minutes.

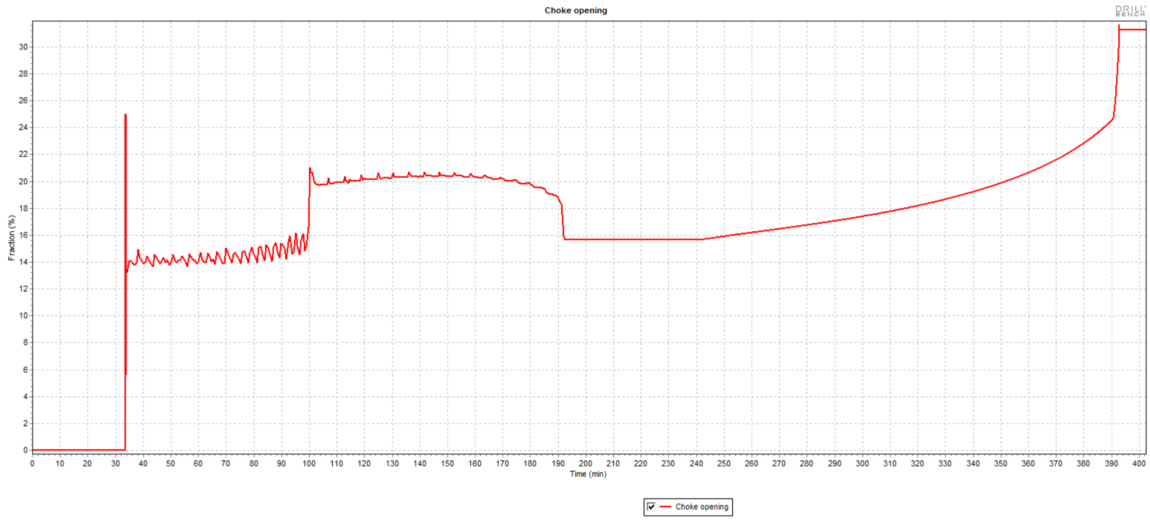

Figure 33: Choke opening

The choke opening is shown in Figure 33. When the gas is being circulated out of the hole, the choke opening increases slightly until the gas reaches the surface. The opening is from here almost stabile until the gas has been circulated out. As the kill mud is pushed down towards the bit, the value is constant at 15,644%. To keep constant bottomhole pressure, the choke is opened as the kill mud is circulated up through the annulus. The heavier mud will increase the hydrostatic pressure, and the counter action is to increase the choke opening to a maximum value of 31,286%.

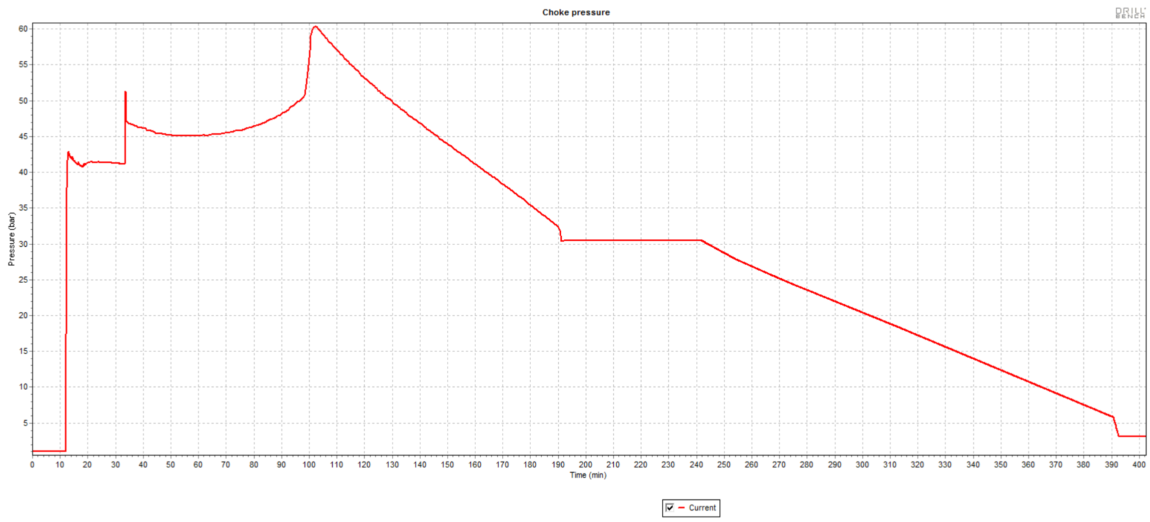

Figure 34: Choke pressure

When the well is closed in, the choke pressure is increased to a value of 42,895 bars, Figure 34. When the circulation is started, the pressure is increasing and reaches a maximum value of 60,338 bars. The pressure is decreasing as the gas is being circulated out, and then stabilizes as the kill mud is circulated down to the bit. Because of the pressure changes in the well described earlier, the choke pressure will continue to decrease until the kill mud has completed one circulation.

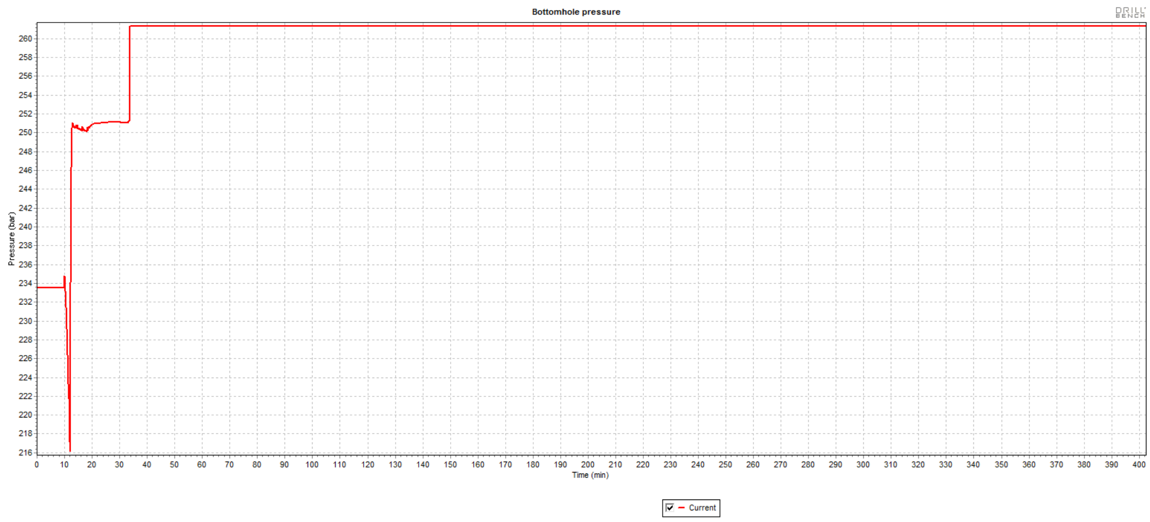

Figure 35: Bottomhole pressure

The bottomhole pressure is shown in Figure 35. After the pre-kick circulation is finished, the pressure drops as the gas enters the well. When the well is shut in the pressure is stabilized at 251,162 bars. When the circulation starts the pressure increases to 261.325 bars. This is the kept constant throughout the circulation of the kill mud.

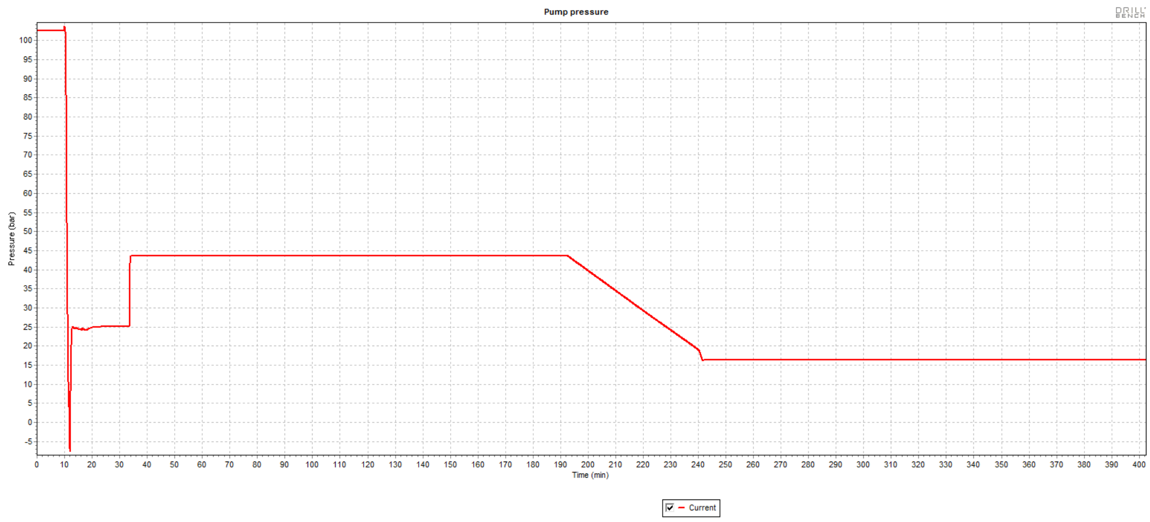

Figure 36: Pump pressure

Figure 36 illustrates the pump pressure. The pressure is constant as the gas is being circulated out, 43,624 bars. After the gas has been circulated out the pump pressure decreases, since the heavier mud is helping the pumps 'pushing' out the lighter drilling mud. The pump pressure is stabilized at 16,415 bars as the kill mud is pumped up the annulus.

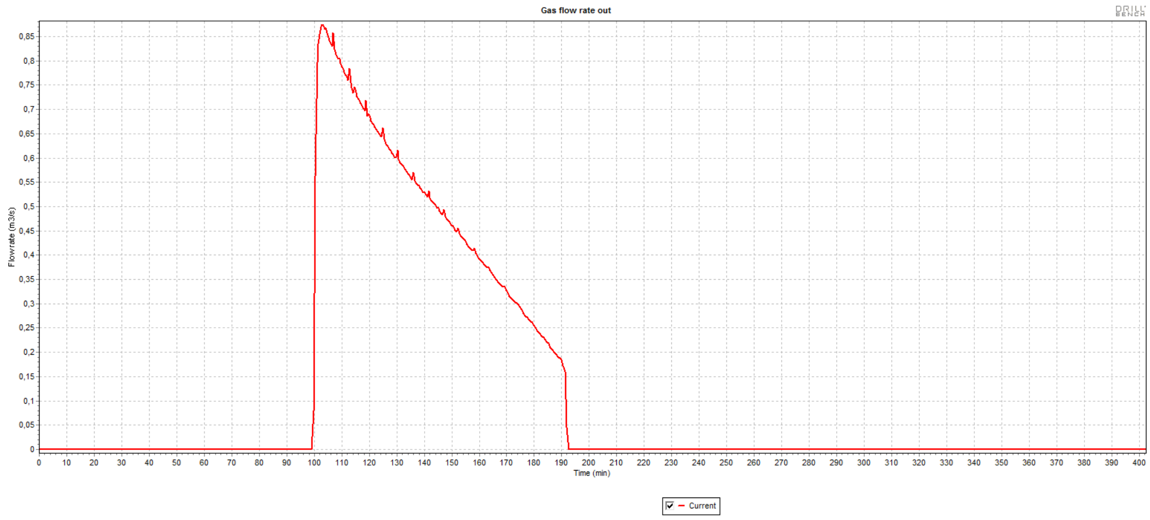

Figure 37: Gas flow rate out

The gas flow rate is shown in Figure 37. After 100 minutes the gas starts to flow out of the well at the surface. The flowrate reaches a maximum value of 0,874m^3/s.

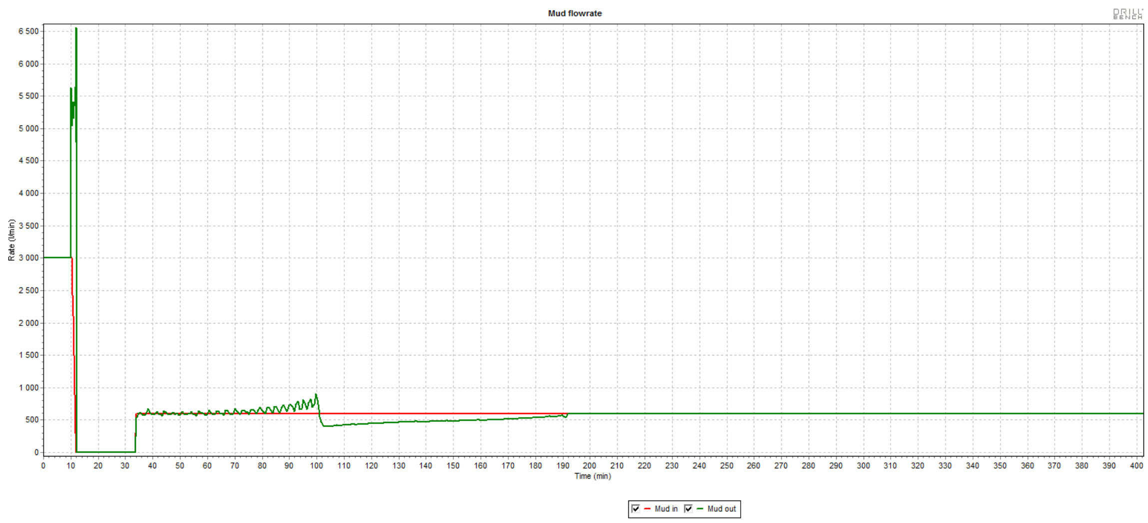

Figure 38: Mud flow rate

When the formation fluid enters the well, we see a large increase in the mud flowrate out of the well before it is closed, Figure 38. When the kick is being circulated, the flowrate out is increasing and above the mudflow in, due to the expansion and separation of the gas from the OBM.

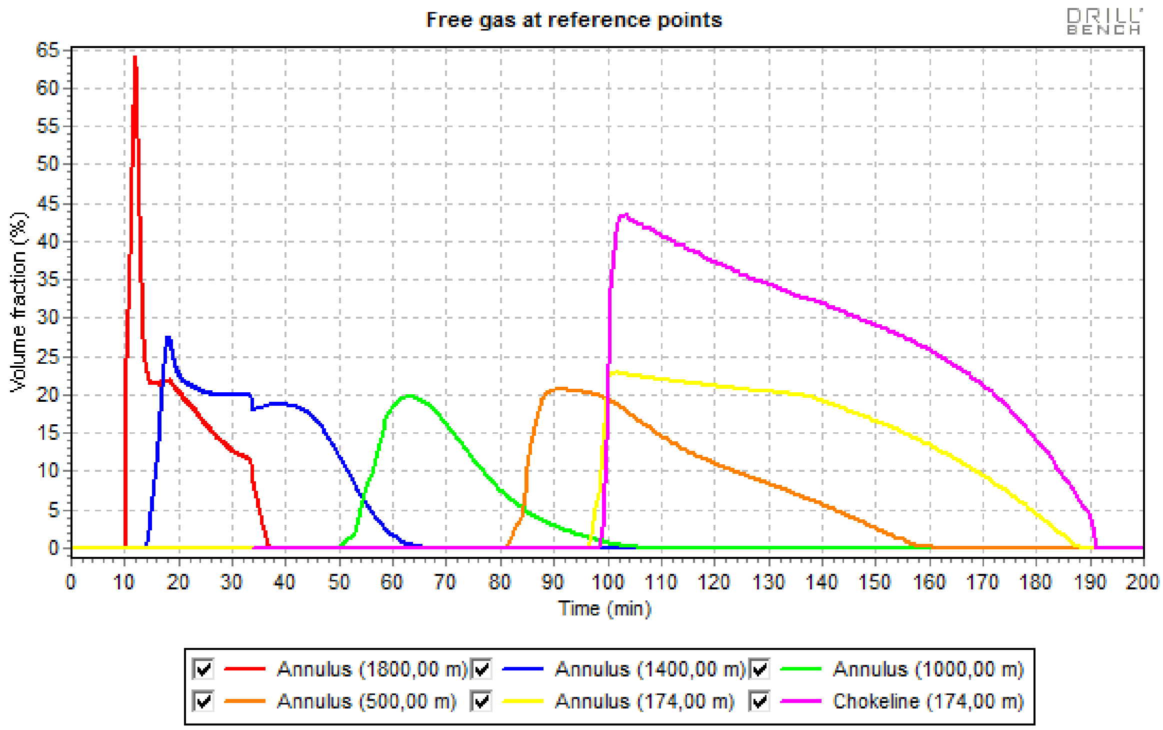

Figure 39: Free gas

The free gas in the well has been illustrated in Figure 39, and the dissolved gas is shown in Figure 40 below.

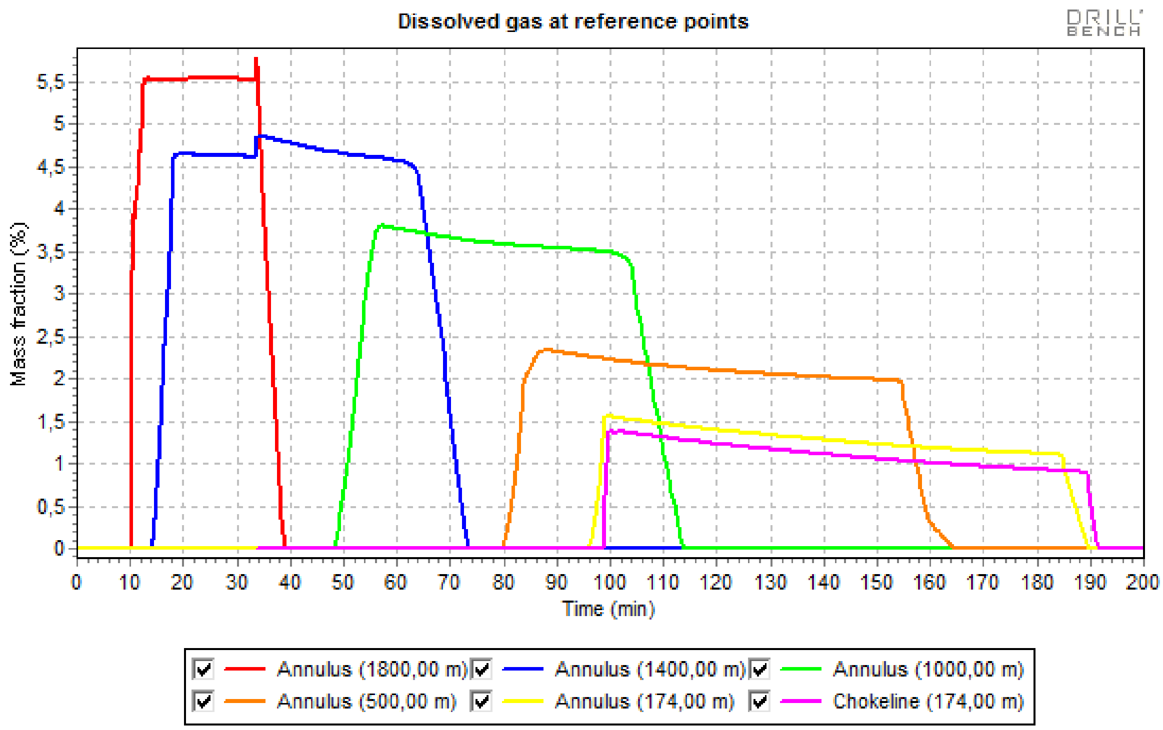

Figure 40: Dissolved gas

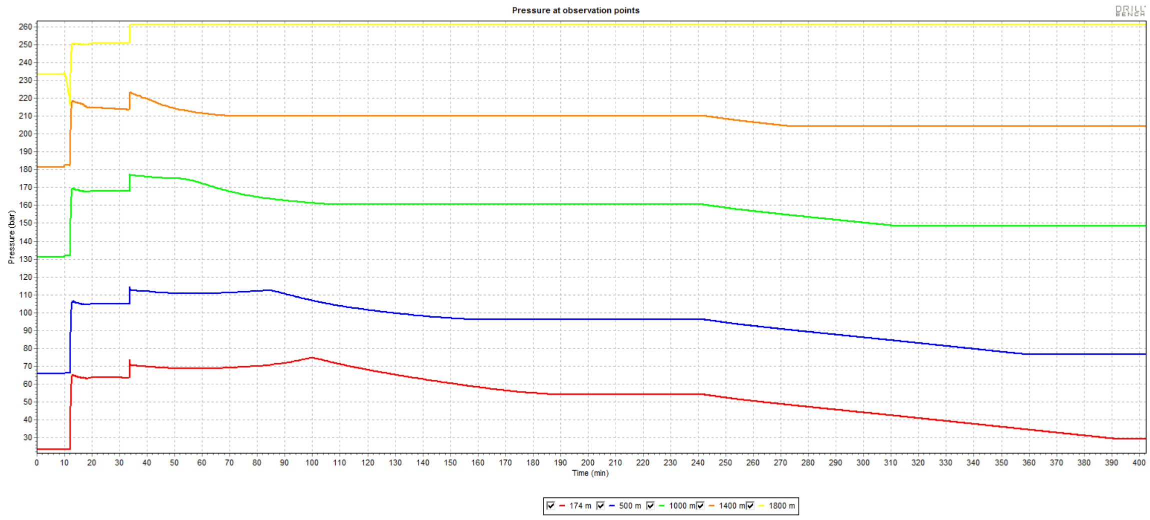

Figure 41: Pressure at observation points

From Figure 41 we can see how the pressure varies in the well at our observation points. The depths of the points are 174m, 500m, 1000m, 1400m and 1800m. At 1800 meters, the pressure is the same as the bottomhole pressure. When the gas has passed our point of interest, the pressures keeps stabile during the circulating of the gas. When the kill mud reaches the bit, the pressures starts to decrease, then once again stabilize as it passes our observation points

11.3.2 WBM

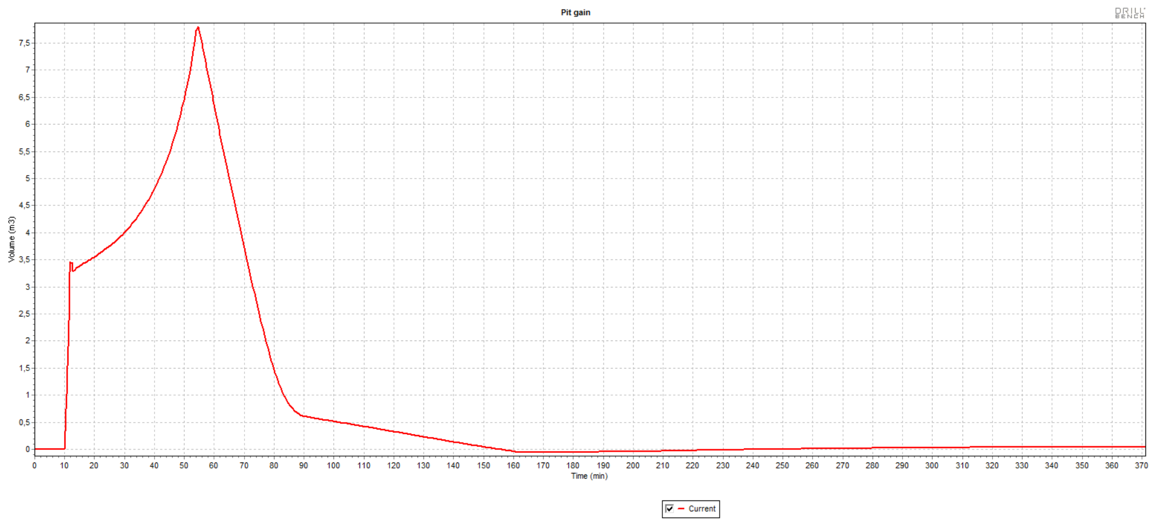

Figure 42: Pit gain

Compared to when using OBM, the shut-in time of the well when using WBM is very short, Figure 42. The pit gain has a value of 3,44m^3 when the well is being shut in. After 54 minutes the gas reaches the surface increasing the pit gain to 7,801m^3. After 2 hours and 35 minutes the gas has been removed from the well. The kill mud has been circulated through the well after 6 hours and 11 minutes.

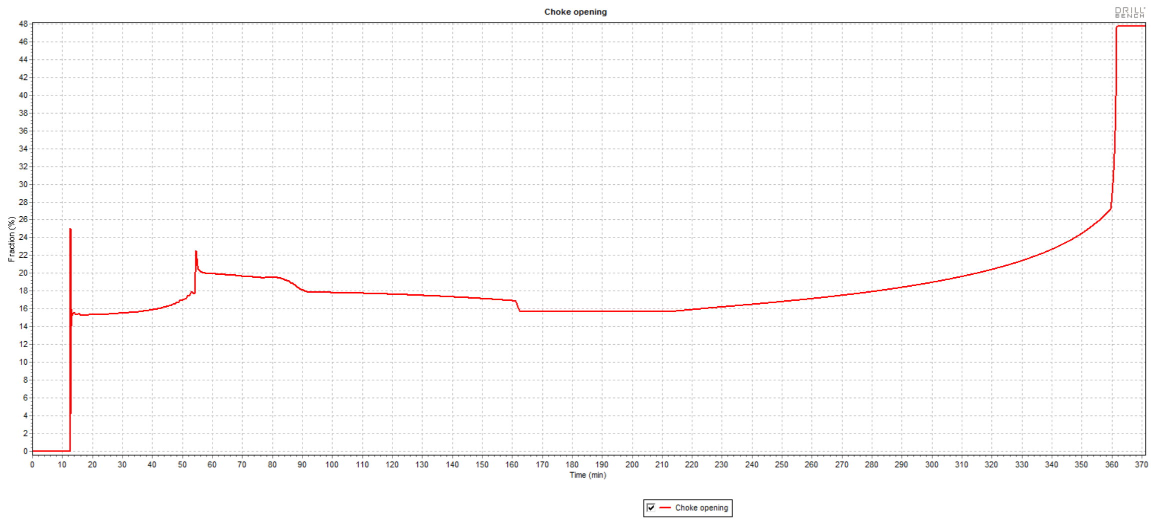

Figure 43: Choke opening

Again, when the gas is being circulated the choke opening increases to keep the bottomhole pressure constant, but after the gas reaches the surface, the opening is reduced more linear than with OBM, Figure 43. It stabilizes at 15,644% and increase to 47,738% as the kill mud reaches the surface.

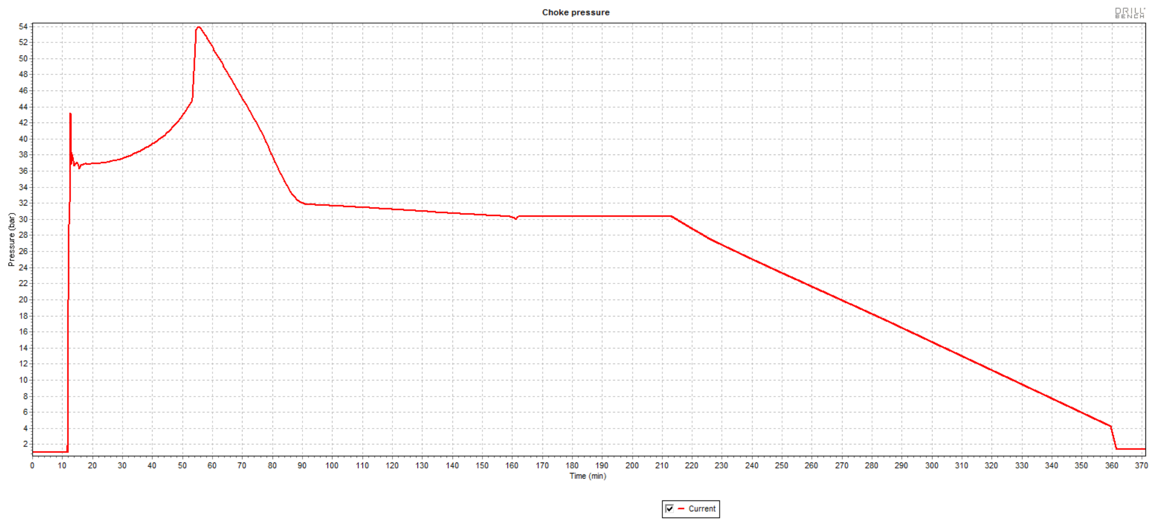

Figure 44: Choke pressure

The choke pressure at closure of the well is 43,224 bars, Figure 44. It increases until the gas reaches the surface, gaining a maximum value of 53,968 bars. From here on it decreases until the kill mud is being pumped into the well. When the kill mud is at the bottom, the choke pressure is reduced due to the choke opening is increased.

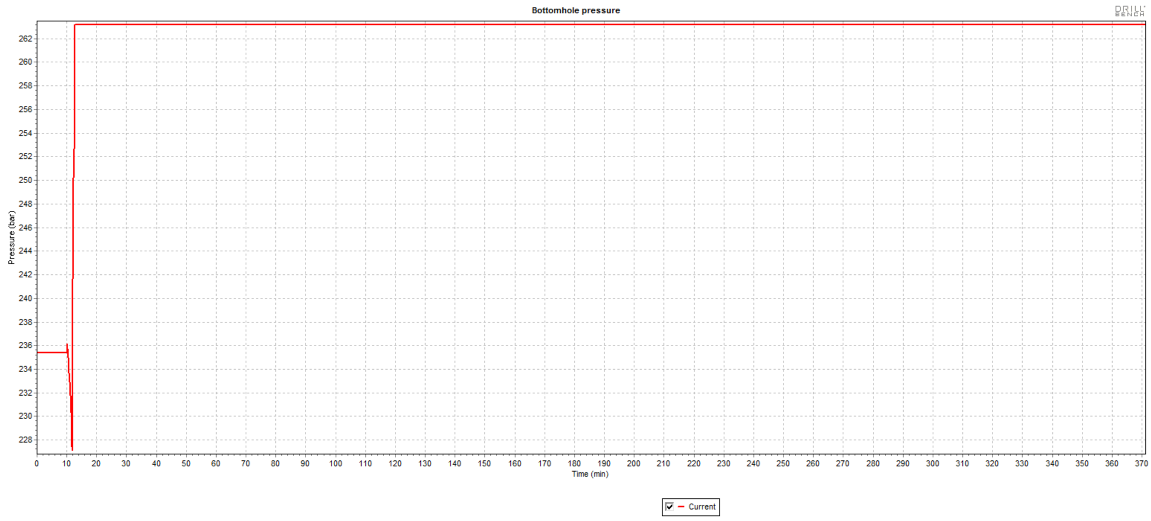

Figure 45: Bottomhole pressure

Due to the short shut-in time when using WBM, the pressure is increasing rapidly after the kick detection, Figure 45. The pressure rises to 252,961 bars during the shut-in time, before stabilizing at 263,181 bars.

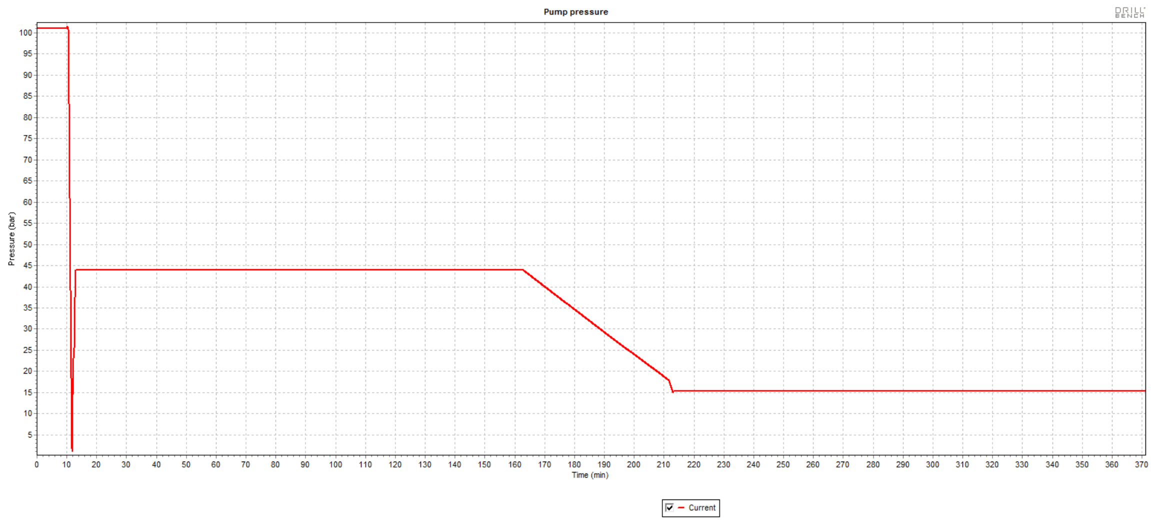

Figure 46: Pump pressure

The pump pressure is very similar when using WBM as it were when we used OBM, Figure 46. When the circulation starts the pressure stabilize at 44,002 bars, before decreasing to 15,260 bars where it is kept constant during until the end of the simulation.

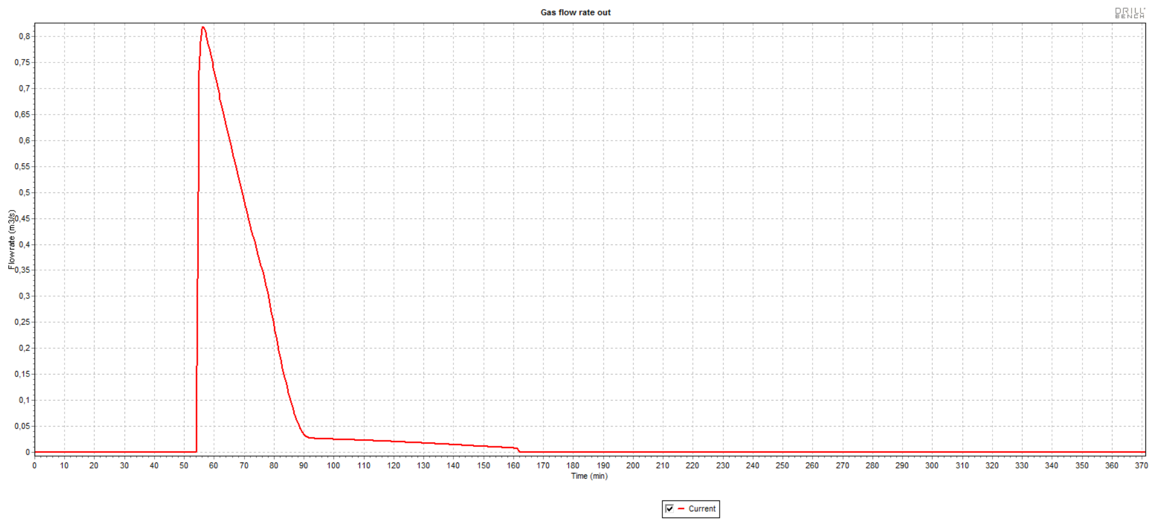

Figure 47: Gas flow rate out

After 54 minutes the gas reaches the surface, flowing out with a maximum value of 0,819m^3/s, Figure 47.

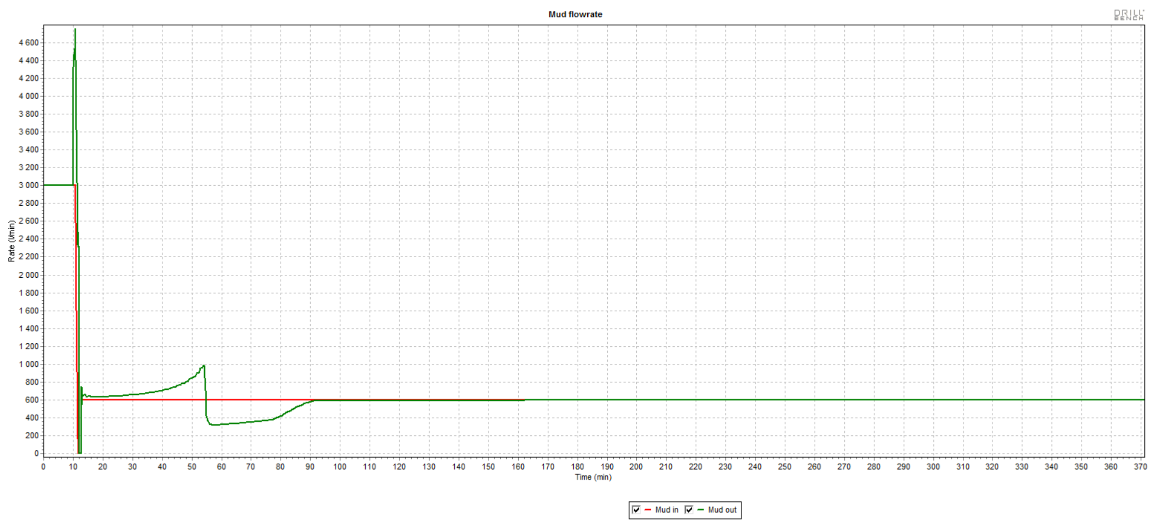

Figure 48: Mud flowrate

From the mud flow rate in Figure 48 we see how the mud rate is in correlation with the gas flow rate. After the kick is being circulated the mud out increases due to the gas expansion. When the gas reaches the surface most of the flow out of the well is the gas, hence the mud flow is reduced until the gas is fully circulated out of the well.

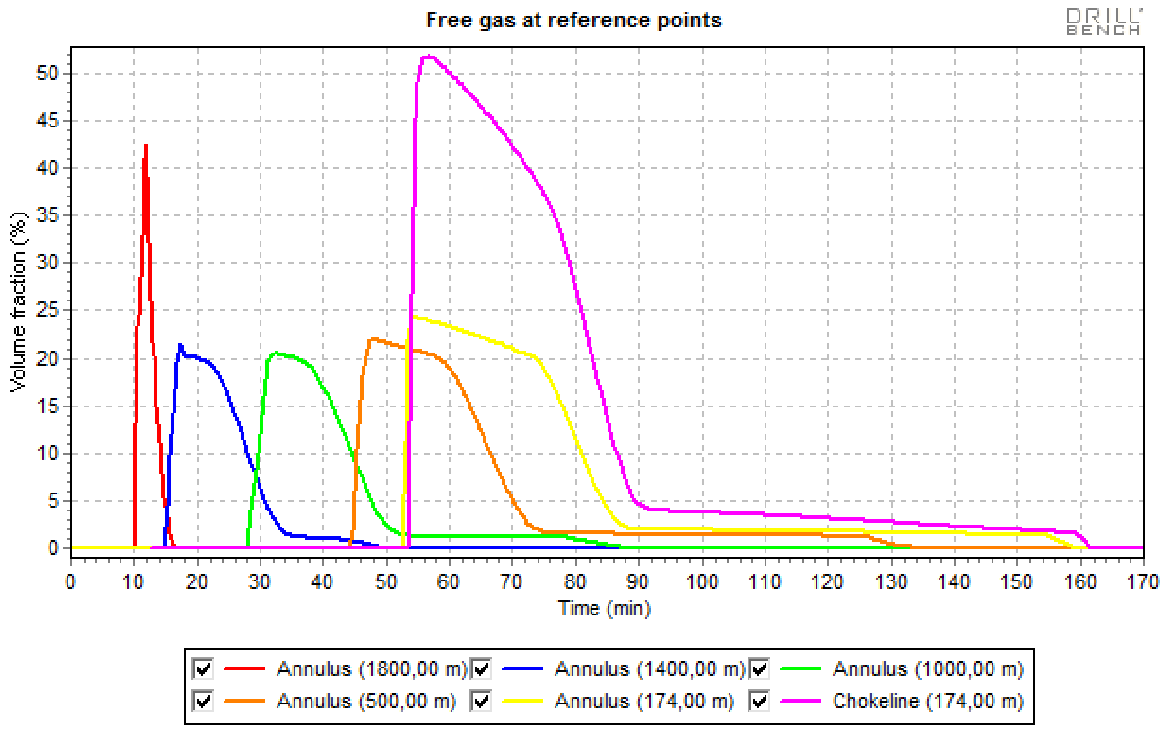

Figure 49: Free gas

The free gas in the well is illustrated in Figure 49.

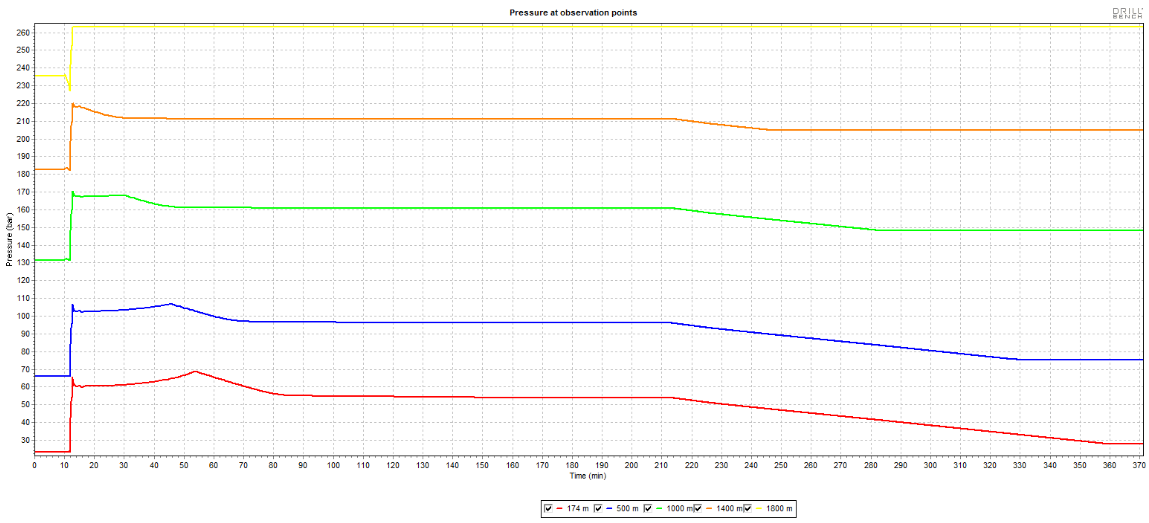

Figure 50: Pressure at observation points

The pressures at our observation points are shown in Figure 50.

11.4 Wait & Weight Method

For the W&W Method, the parameters shown in Table 4 have been used:

Pre-kick circulation	10,00 minutes	3000 l/min
Kick intensity	0,01 bar/m	
Pit alarm level	1,00 m^3	
Shut in period	Until influx is stopped	
Circulation rate	600 l/min	
Static safety margin	10,0 bar	

Table 4: Simulation parameters, W&W Method

11.4.1 OBM

Figure 51: Pit gain

Until the circulation of the kick starts, we have the same results as for the Driller's Method; pit gain has a value of 8,044m^3, Figure 51. The gas is circulated out by circulating the kill mud from the start, and after 1 hours and 41 minutes the gas reaches the surface. The pit gain has now increased to 10,523m^3. The gas has been circulated out after 3 hours and 12 minutes.

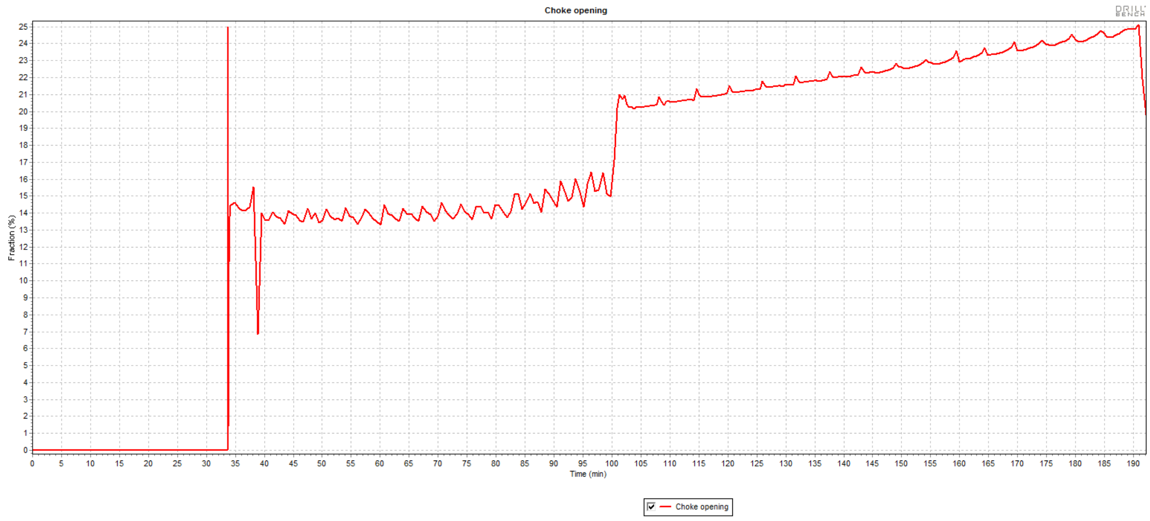

Figure 52: Choke opening

Figure 52 shows the choke opening. The choke remains closed at all times until the kick is due to be circulated out of the well. When the kill mud is being circulated, the choke is opened and stabilizes at an opening value around 14%. We can see again when we have OBM how the choke opening varies during the circulation.

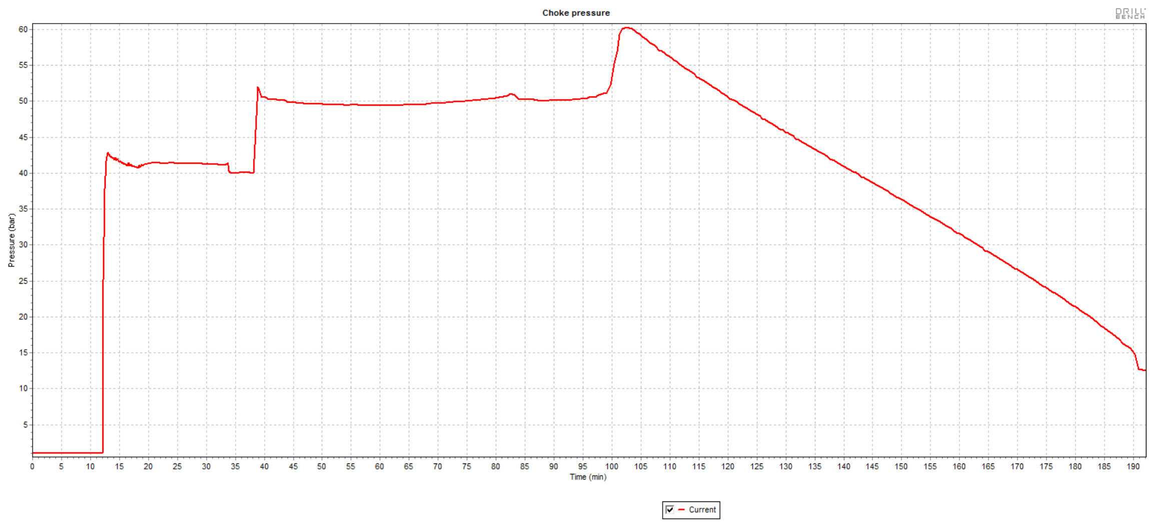

Figure 53: Choke pressure

Figure 53 shows the choke pressure. As the well is shut in, the pressure increases to a value of 42,895 bars. During the close in time the pressure stabilize, before increasing to 52,052 bars when the choke is opened and the kill mud is being circulated. The choke pressure reaches its maximum when the gas reaches the surface, 60,312 bars. From this point, the pressure in the choke reduces until the kick has been circulated out of the well.

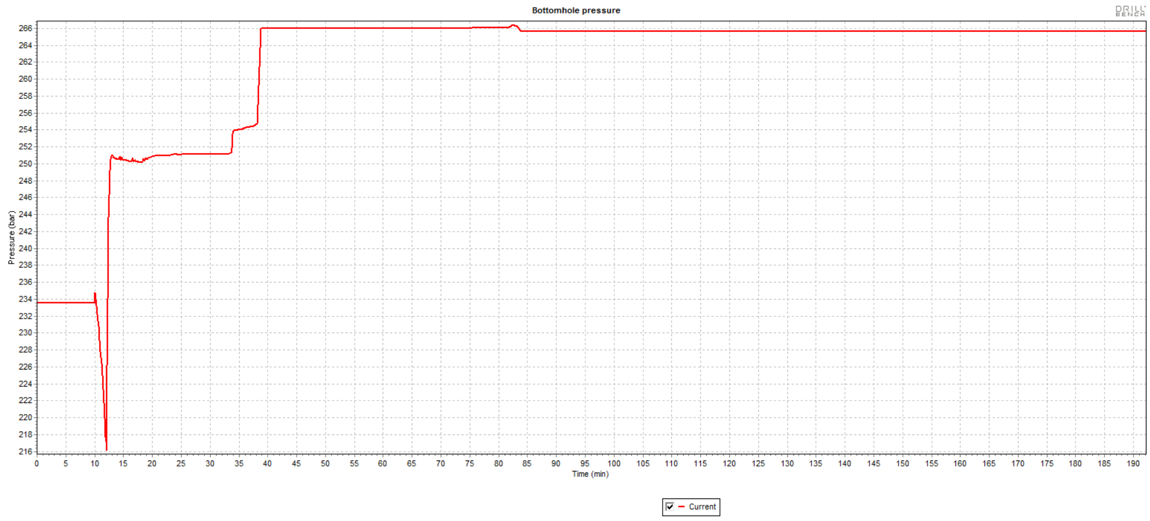

Figure 54: Bottomhole pressure

From Figure 54 we can see the bottomhole pressure development. We see the difference from the Driller's Method when we start the circulation as explained earlier. The pressure is stabile at a value of 266,032 bars until the kill mud reaches the bit and the pressure drops down to 265,616 bars.

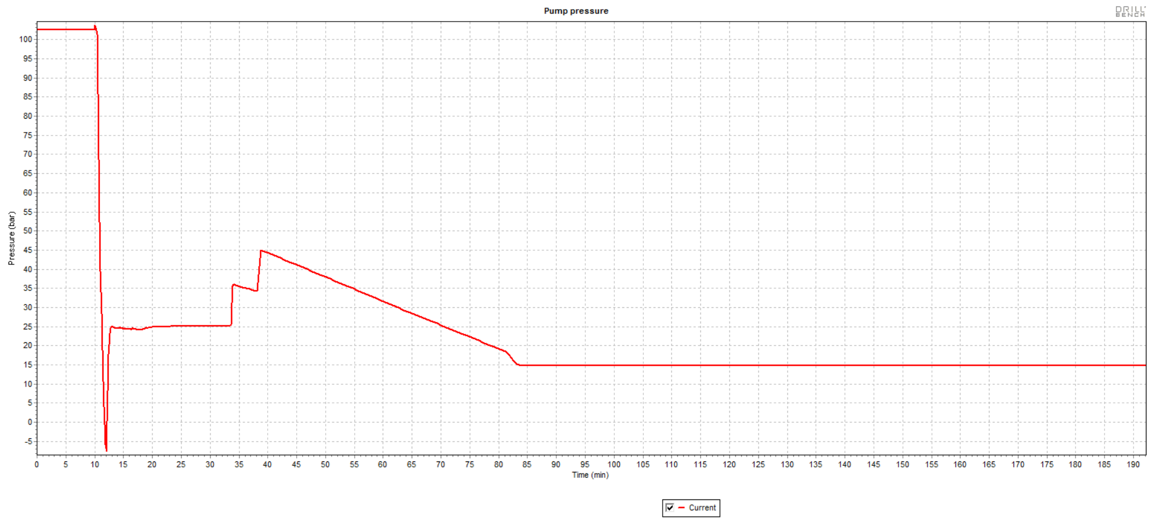

Figure 55: Pump pressure

As the gas flows into the well, the pressure falls to around 25 bars, Figure 55. When the circulation starts, the pump pressure is increased to 45,068 bars. We have a steady decline in the pressure as the kill mud is being circulated down to the bit, before it stabilizes at 14,779 bars.

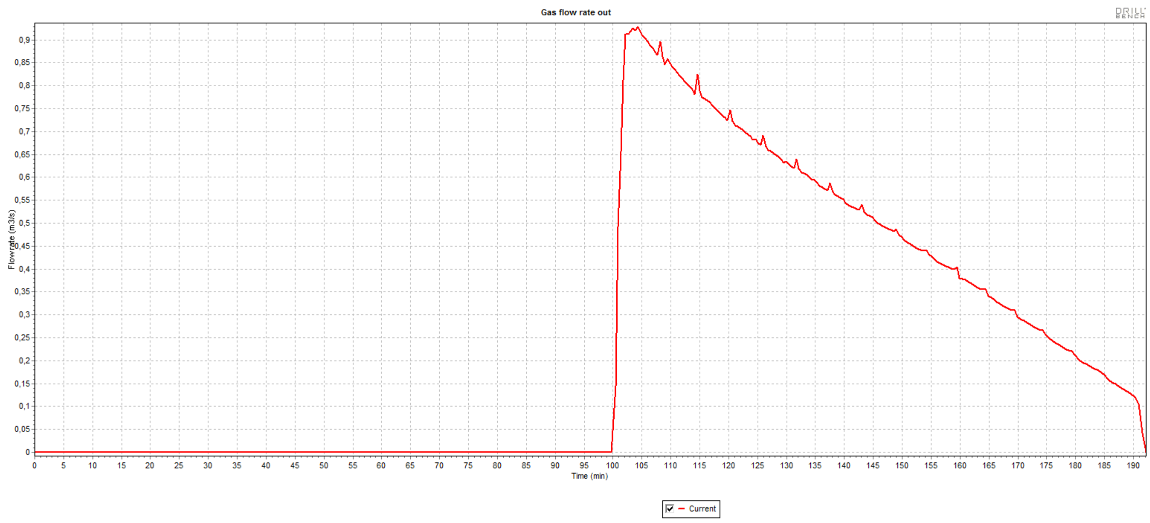

Figure 56: Gas flow rate out

Figure 56 shows the gas flow rate out of the well. The gas starts to flow out of the well after 100 minutes, reaching a maximum flow rate of 0,925m^3/s. We notice the small peaks in the graph; the gas is constantly separated from the mud increasing the flow rate out of the well.

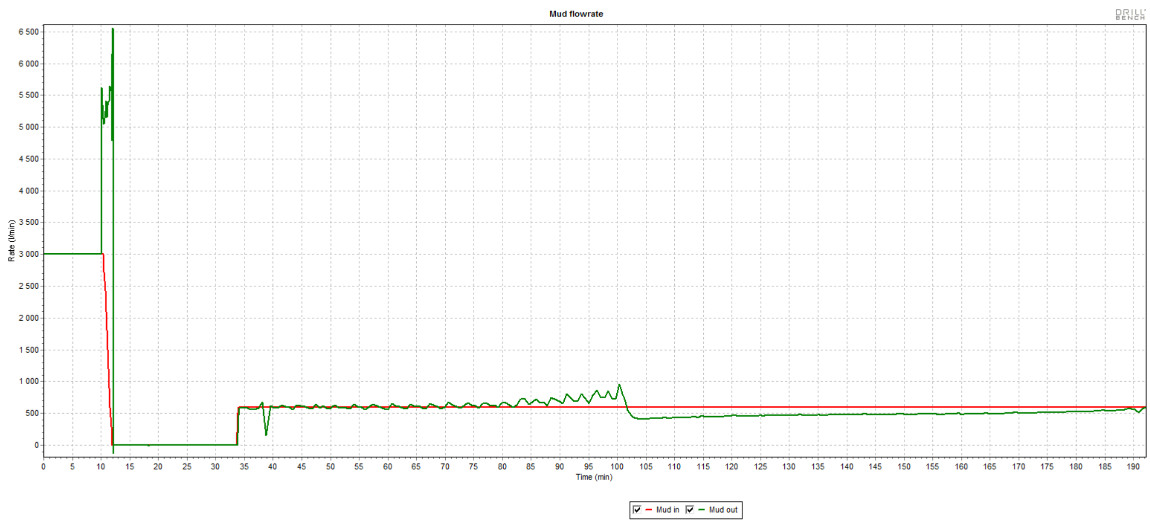

Figure 57: Mud flowrate

From Figure 57, we can see how the mud flowrate increases as the formation fluid flows into the well for a short period before the well is shut in. When the well is opened for circulation, we see the mud flow out is greater than the flow in, as the gas is expanding when travelling towards the surface. As the kick is being circulated out, the mud flowrate falls below the flowrate in, as a percentage of the expelled fluid is gas.

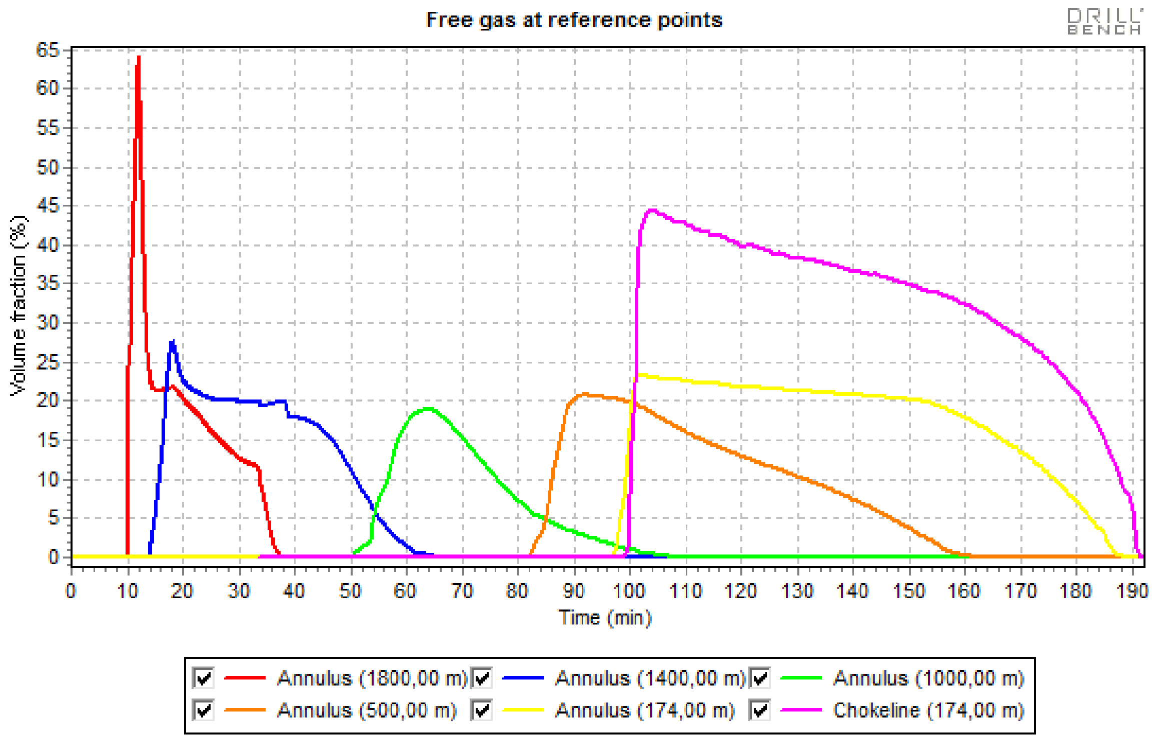

Figure 58: Free gas

The free gas in the well has been illustrated in Figure 58, and the dissolved gas is shown in Figure 59 below.

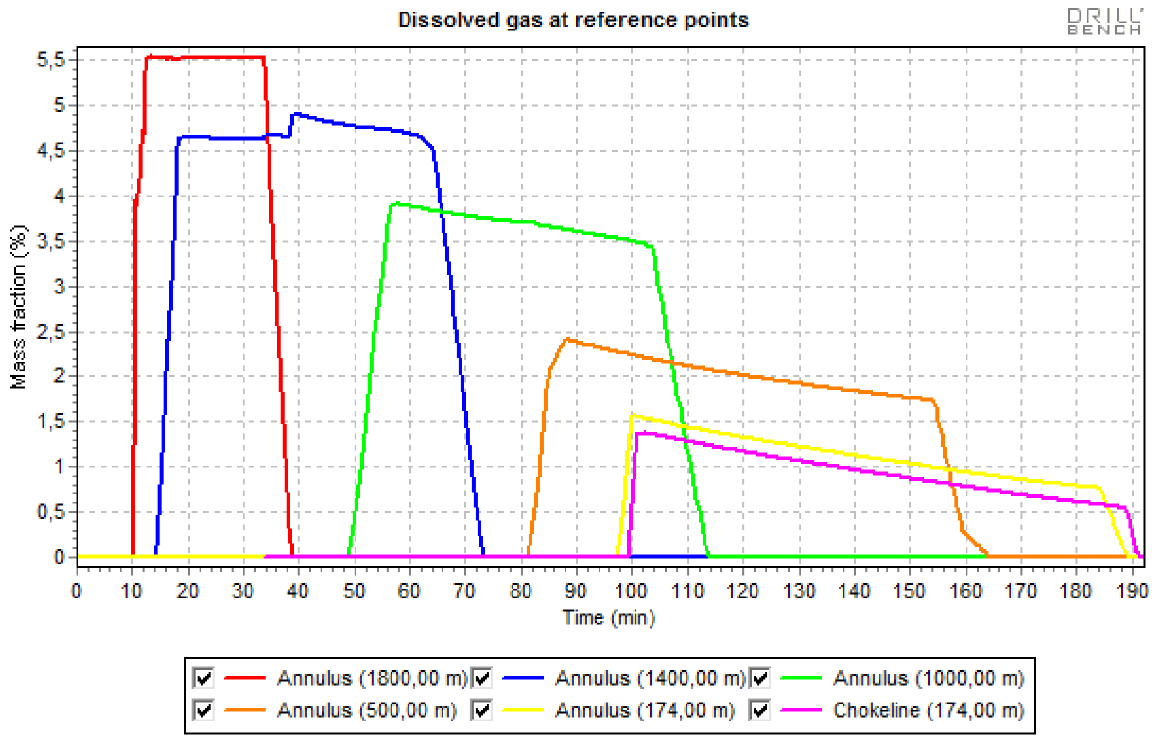

Figure 59: Dissolved gas

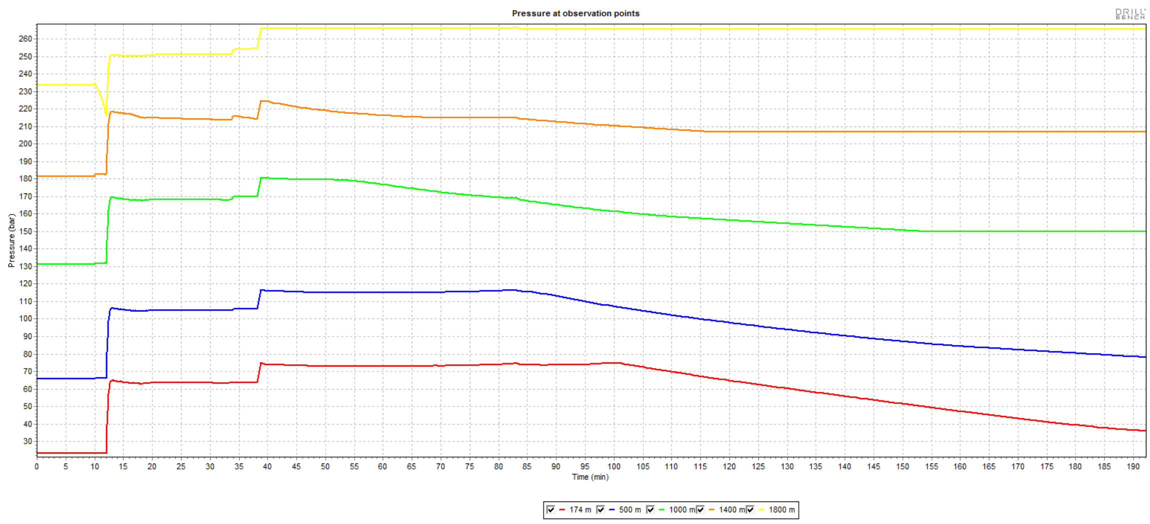

Figure 60: Pressure at observation points

Figure 60 shows pressures at five fixed observation points. As the influx flows in at the bottom of the well, the gas will decrease the pressure at the bottom, but increase the pressure in nearby areas in the well. As the BOP is closed, the pressure throughout the well will stabilize as the influx is stopped due to the pressure increase during the shut-in time. As the well is opened and the kill mud is being circulated, the well pressure increases. When the kill mud reaches the observation points, the pressure at the respective points stabilize.

11.4.2 WBM

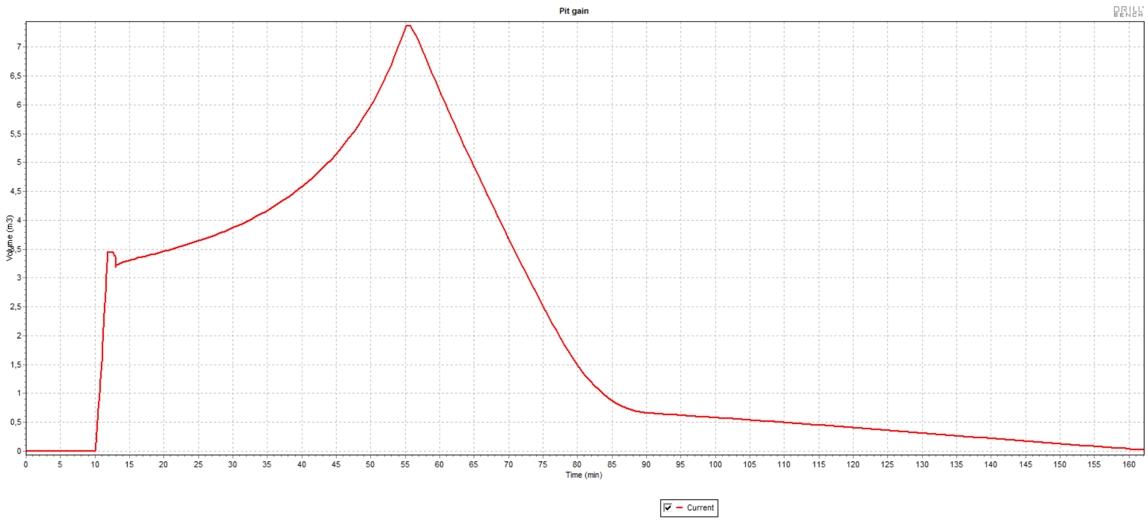

Figure 61: Pit gain

The pit gain at the shut-in time is 3,44m^3, and after 56 minutes the gas reaches the surface at a pit gain value of 7,379m^3. The kick has been circulated out of the well after 2 hours and 42 minutes, Figure 61.

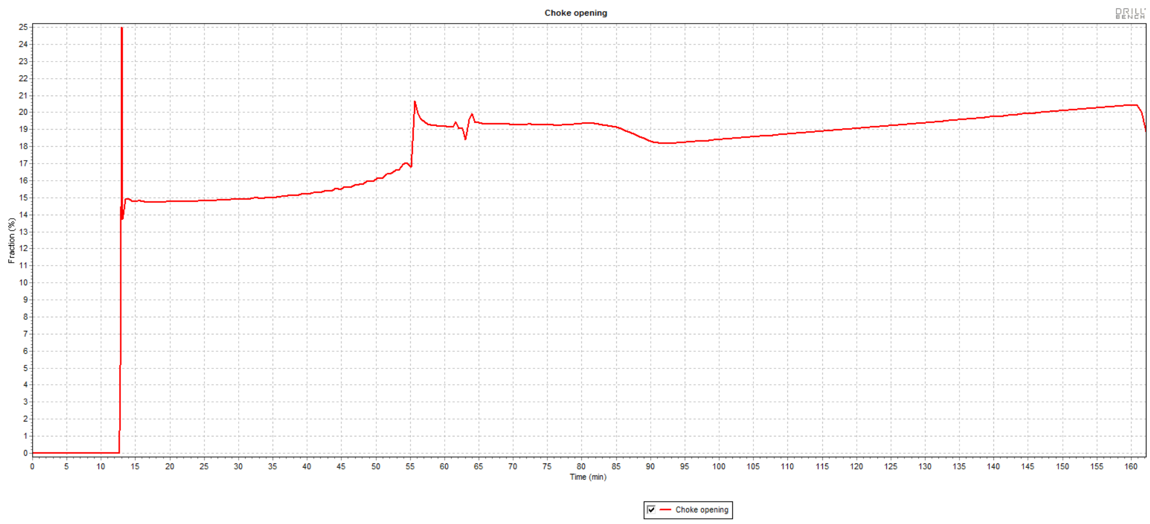

Figure 62: Choke opening

Figure 62 shows the choke opening. As the kill mud is being circulated the choke opening slightly increase from around 15% opening until the gas reaches the surface and it reaches a maximum of 20,673%. As the gas is being pumped out of the well by the kill mud, the choke opening increases until the kick has been circulated out.

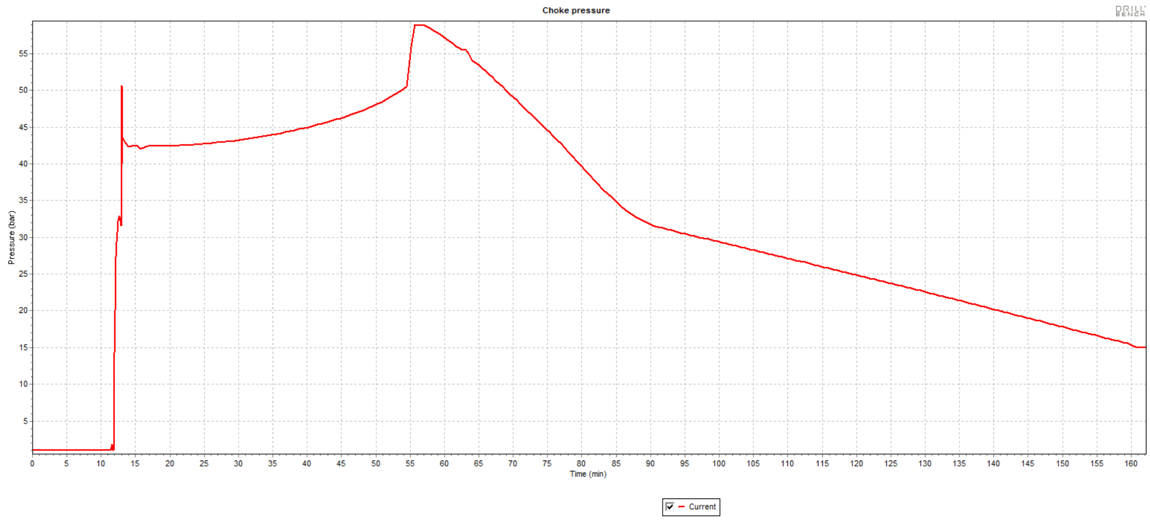

Figure 63: Choke pressure

The choke pressure is shown in Figure 63. As the well is shut in, the pressure increases to a value of 32,877 bars. Due to the short shut-in time of the well, the pressure increases to a value of 50,677 bars as the choke is opened and the pumps start to circulate the kill mud. As the kick reaches the surface, the choke pressure reaches the maximum value of 58,937 bars. The pressure then steadily decreases until the gas has been circulated out of the well.

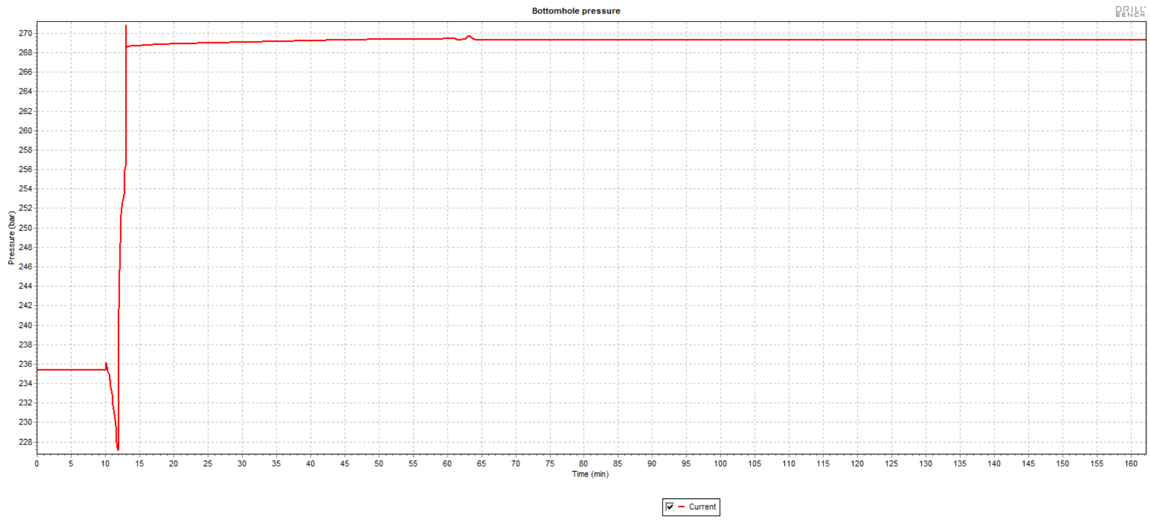

Figure 64: Bottomhole pressure

The pressure rises to 250,339 bars during the shut-in time, before rising to 265,467 bars. As the kill mud is pumped down towards the bit the pressure is slightly increasing, but when it reaches the bottom of the well, the pressure is constant at 266,071 bars, Figure 64.

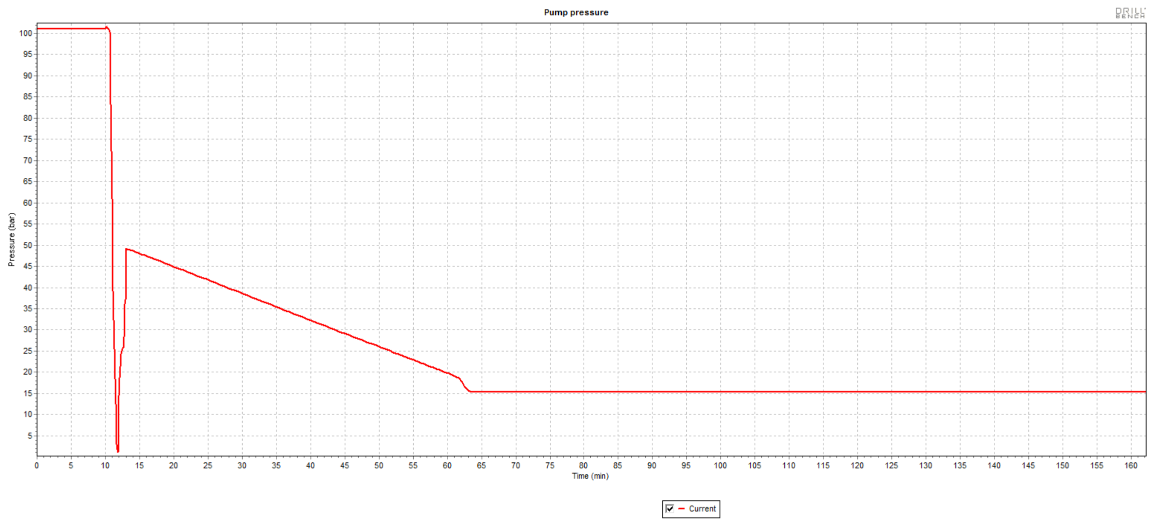

Figure 65: Pump pressure

The pump pressure is shown in Figure 65. As the kill mud circulation starts, the pump pressure reaches a value of 49,176 bars, before decreasing to a stabile value of 15,382 bars.

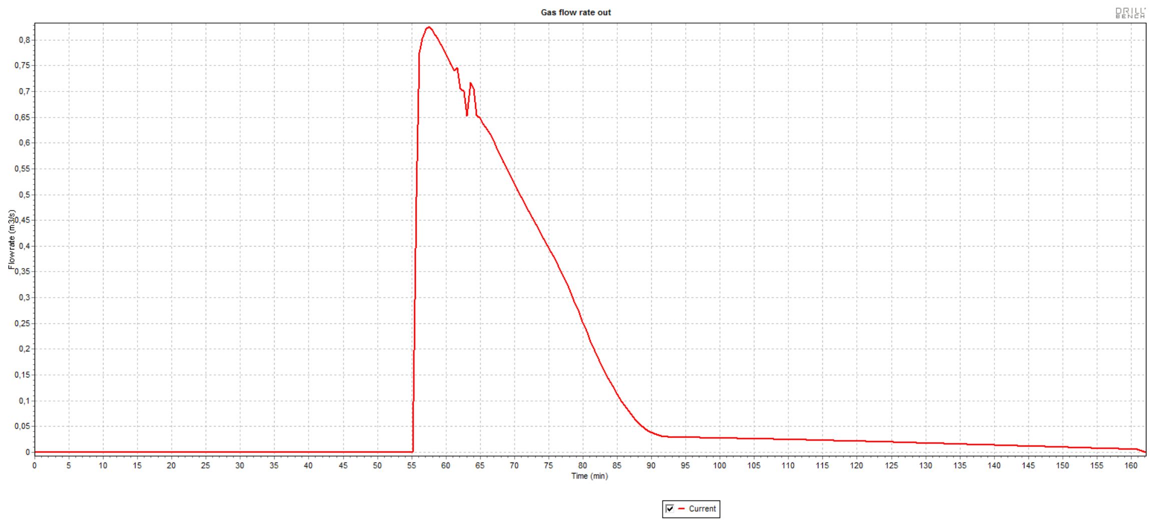

Figure 66: Gas flowrate

Figure 66 illustrates the gas flow rate out of the well. After 56 minutes, the gas starts to flow out of the well, with a maximum rate of 0,826m^3/s.

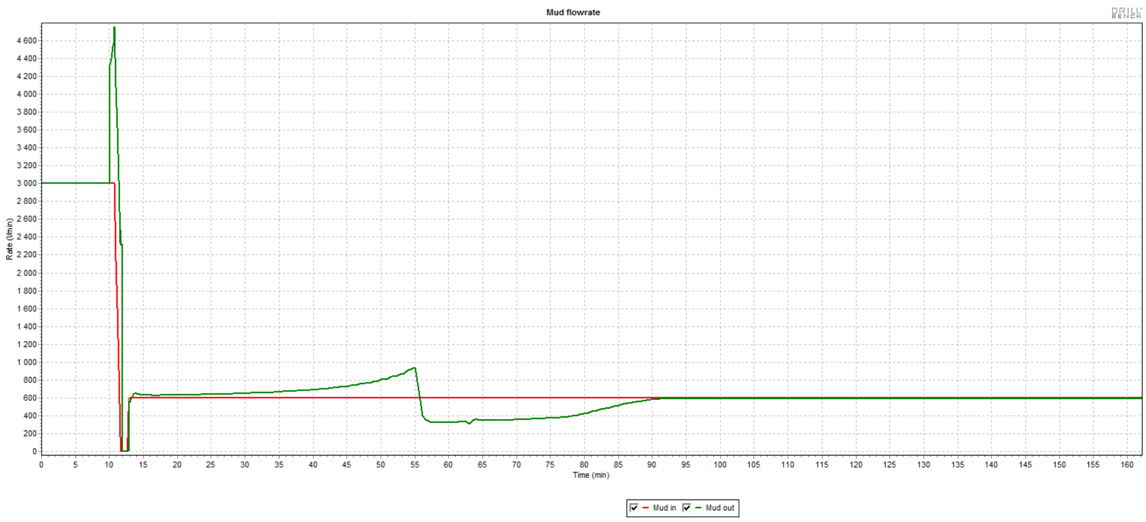

Figure 67: Mud flowrate

After 10 minutes, the mud flowrate out increases as the kick enters the well, Figure 67. When the well is opened after the shut-in time the mud rate increases as the gas expands due to the pressure reduction in the annulus. The flow rate is reduced as the gas reaches the surface.

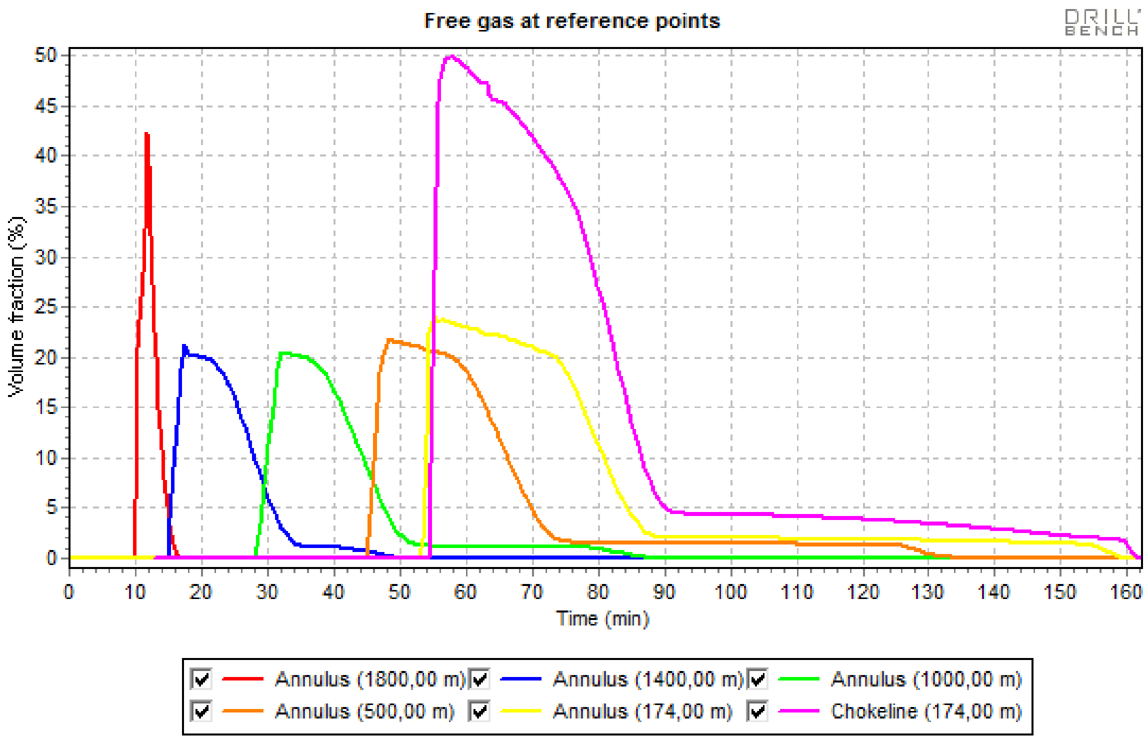

Figure 68: Free gas

The free gas in the well is illustrated in Figure 68.

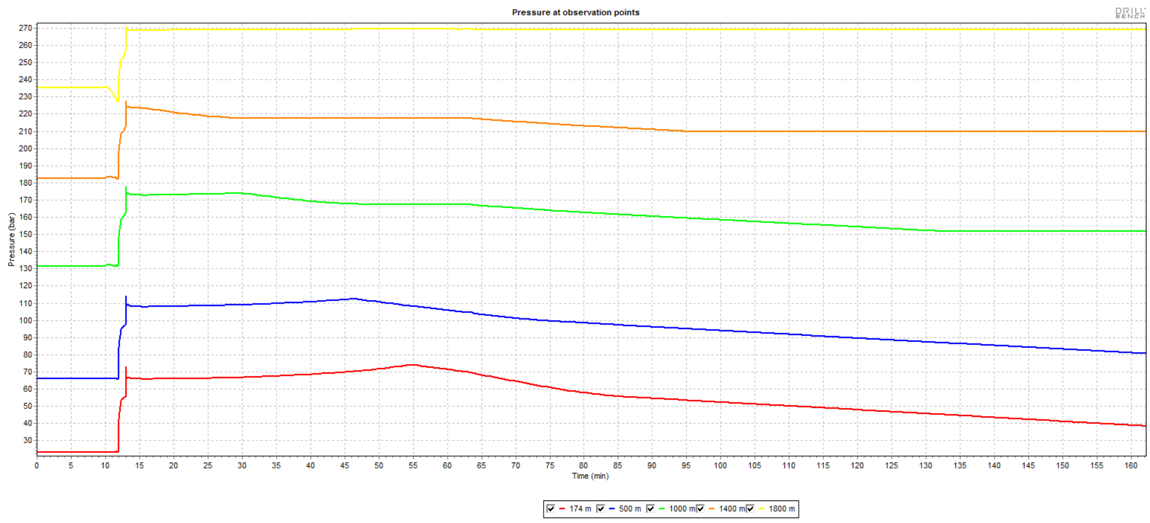

Figure 69: Pressure at observation points

Figure 69 shows us again the pressures at our observation points. When we experience the kick, the pressure at 174 meters is not affected, but as the well is shut-in the pressure at all of our observation point's increase. As we saw when we used OBM, also here the pressure stabilizes after the kill mud has past our points of interests.

12 Discussion

12.1 Soft vs. Hard shut-in

In Table 5 and Table 6 results from the simulation is shown.

	Soft shut-in	Hard shut-in
Max pit gain [m^3]	4,756	4,413
Max bottomhole pressure [bar]	251,914	251,818
Max pressure casing shoe [bar]	207,636	206,895
Total influx [kg]	871,977	805,084
Total simulation time	2 hours & 53 minutes	2 hours & 51 minutes

Table 5: Soft vs. Hard shut in, OBM

	Soft shut-in	Hard shut-in
Max pit gain [m^3]	4,599	4,287
Max bottomhole pressure [bar]	252,342	252,536
Max pressure casing shoe [bar]	205,175	205,068
Total influx [kg]	375,297	345,701
Total simulation time	2 hours & 39 minutes	2 hours & 38 minutes

Table 6: Soft vs. Hard shut-in, WBM

Before choosing which shut-in method to use, there are different issues and problems one needs to be aware of. Both contractors and operators may have different procedures dealing with kicks, and it is important before any drilling operation to have a clear set of rules and procedures if anything happens.

Creating an underground blowout due to a pressure pulse, or water hammer, is one of the main concerns when using the hard shut-in method. When the well is shut-in, the rapid closure of the pipes can generate a pressure wave which propagates through liquids in pipes and pipe networks.

Rapid closure of the BOP in a flowing well causes a pressure wave propagating down the well. The pressure rise, ΔP, when instant closure causes the flow to stop is:

Equation 7: Pressure rise

$$\Delta P = \rho * c * u_1$$

Where ρ is the mud density, c is the wave speed and u_1 is the initial mud velocity. Obviously, if the choke is open, the pressure jump is reduced. Though in reality, the BOP isn't closed immediately; it is expected that the pressure wave amplitude will be reduced significantly if the effective BOP closing time exceeds the travelling wave round trip. This is due to the upward reflected pressure wave and can be assumed applicable for most field situations. However, there is a chance to obtain BOP closure where the effective pressure drop occurs on a short time scale compared to the wave round trip, so if this is the case there will be produced a water hammer pulse.

Because of this, some operators choose to use the soft shut-in method. The major disadvantage with the soft shut-in method is the time spent closing in the kick. This in turn will lead to a larger influx volume entering the well. Due to this, we might end up with a higher casing pressure than with the hard shut-in method. The soft shut-in method is also more complex due to the requirement of ensuring valve alignment before closing BOP. (Jardine, Johnson, White, & Stibbs, 1993)

From the simulation results we can clearly see differences between the soft- and hard shut-in method. The soft shut-in allows more influx into the well since the choke is open when the BOP is closed, allowing more gas to flow into the annulus before the well pressure is above the reservoir pressure. The soft shut-in results, due to the higher reservoir influx, in both higher choke pressure and casing shoe pressure.

Looking at the results, we can also draw conclusions regarding the use of OBM or WBM. As described in chapter 7, the two types will react different when formation fluid enters the well. The total pit gain is of much larger size when using OBM for both the shut-in methods. This can be explained by the solubility of gas into the drilling mud. As the gas is mixed with the mud, the volume is 'hidden' until the bubble point for the gas is reached. It will then separate, and make an impact on the measurements on the surface. But again, described in chapter 7, the OBM can withstand high temperatures, it doesn't react with clay causing clay instability, the mud cake created is thin thus preventing stuck pipe, and it is a good lubricant, hence reducing the drilling torque.

These results all favor the hard shut-in; the formation is exposed to lower net pressure, we experience less influx volume, the annular pressure is lower and the safety towards personnel and equipment is maintained without risk to the well.

12.2 Driller's Method vs. W&W Method

In Table 7 and Table 8 results from the simulation is shown.

W&W Method	WBM	OBM
Max pit gain [m^3]	7,379	10,523
Max bottomhole pressure [bar]	270,833	266,426
Max pressure casing shoe [bar]	227,506	224,878
Total influx [kg]	758,129	2095,111
Total simulation time	2 hours & 42 minutes	3 hours & 12 minutes
Calculated simulation time	3 hours & 26 minutes	3 hours & 54 minutes

Table 7: W&W Method results

Driller's Method	WBM	OBM
Max pit gain [m^3]	7,801	10,399
Max bottomhole pressure [bar]	263,180	261,324
Max pressure casing shoe [bar]	220,081	223,462
Total influx [kg]	758,129	2095,111
Total simulation time	6 hours & 11 minutes	6 hours & 42 minutes

Table 8: Driller's Method results

Comment to the simulator: This is an ideal environment where nothing goes wrong, and the simulation procedures start without any pauses or human errors.

Comment to the W&W Method results: The simulator stops simulating as soon as the gas has been circulated out of the hole. The calculated simulation time has been found by extracting the mud front position graph till it reaches the surface. The graph is linear since we have a constant pump rate, but a small deviation from the 'true' simulation time must be taken into consideration.

There are still discussions regarding which of the circulation methods are best. The basic principle for both of the methods is to keep a constant bottomhole pressure while circulating out the gas. Regarding the oil industry, organizations or companies can adapt one of the well control methods, leading to a well known understanding of procedures, avoiding confusions that may lead to catastrophic events.

There are several situations we may encounter when drilling wells and the circulation methods have both advantages and disadvantages regarding the type and geometry of the well.

When drilling, we may come across areas with significant hole instability problems. The drillstring can get stuck if it is left standing still with no mud circulation due to pack-off problems. If it is decided to use the W&W Method, the time spent mixing the kill mud may cause problems due to the non-circulation time. For the Driller's Method this problem is solved as the circulation starts as soon as the SIDPP or SICP are stabilized, reducing the non-circulation time to a minimum.

When drilling deepwater wells, the low temperature increase the possibility of hydrates forming in the BOP's or choke/kill lines. Again we see how the non-circulating time when using the W&W Method can cause problems due to more favorable hydrate forming conditions.

When the gas reaches the surface the casing pressure is at its maximum. At the same time, the gas flow rate out of the well peaks. When using W&W Method, the maximum casing pressure and gas flow rate will be lower, compared to the Driller's Method, as long as the kill mud enters the annulus before the gas reaches the surface.

From Table 7 and Table 8 we can see the most significant difference between the two methods is the simulation time. The Driller's Method has two separate circulations, compared to the W&W Method which only needs, in theory, one circulation. Other factors need to be evaluated though; the time to mix the sufficient kill weight mud may not reduce the circulation time as wanted. Another thing to keep in mind regarding W&W Method is that one circulation might not be enough. There can be gas remaining in high pockets of the well and poor hole cleaning together with bad mud properties can cause problems.

When we use the W&W Method in the simulator, we experience a higher bottomhole pressure for both OBM and WBM. If the pressure exceeds the fracture pressure it can cause damage to the formation and loss of mud hence reducing the hydrostatic pressure and loss of primary well control.

When the gas reaches the casing shoe, this often tends to maximize the pressure at this point. When circulating the gas the hydrostatic pressure in the well will decrease due to the gas expansion, and to keep constant bottomhole pressure the casing pressure will increase to balance the hydrostatic pressure loss. When the gas passes the casing shoe, the hydrostatic pressure in the open hole will increase because new mud is being pumped into the annulus and the casing shoe pressure will be reduced. As the circulation continues and the gas is over the shoe, the pressure will be kept at the same value since the hydrostatic pressure in the open hole is constant.

The casing shoe pressure can be reduced when using the W&W Method if the kill mud enters the annulus before the top of the bubble is at the shoe. If this is to happen, the drillstring volume has to be less than the open-hole volume minus the bubble size at the shoe.

Another factor affecting the shoe pressure is gas migration. While waiting for the kill mud to be mixed, the gas might migrate upwards in the annulus. When controlling bottomhole pressure before pumping, applications of surface pressure safety factors can be used. These procedures can exceed the benefit an early kill mud delivery to an open hole is intended to provide.

The results obtained have shown both advantages and disadvantages with shut-in- and circulation methods. By the use of simulators we can gain knowledge of dangers and outcomes before they happen. It is important to use these types of tool in the training of rig personnel, both before and as they are working on rigs. Well control is of great importance, and the new drilling era the oil industry is heading towards need more advanced techniques and higher competence regarding well control situations. Even though these are well documented facts, the use of standard well control preparations, i.e. kill sheets and SCR's, must be continued by the rig crew during drilling operations. Clear instructions and procedures about which methods to use before a drilling operation begins is a must. Together with good communication and understanding between the crew members and involved parties regarding procedures and routines the drilling operations will favor everybody.

(Roy, Nini, Sonnemann, & Gillis, 2007)

Nomenclature

APL	-	Annular Pressure Loss
BHA	-	Bottomhole Assembly
BHP	-	Bottomhole pressure
BOP	-	Blowout Preventer
ECD	-	Equivalent Circulating Density
FCP	-	Final Circulation Pressure
ICP	-	Initial Circulation Pressure
ID	-	Inner Diameter
IOEM	-	Invert Oil Emulsion Fluids
OBM	-	Oil Based Mud
OD	-	Outer Diameter
SCR	-	Slow Circulation Rate
SICP	-	Shut In Casing Pressure
SIDPP	-	Shut In Drillpipe Pressure
TD	-	True Depth
TVD	-	True Vertical Depth
WBM	-	Water Based Mud
W&W	-	Wait and Weight

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Appendix

1. Input parameters in simulator

Soft- & hard shut-in, WBM

Survey section			
MD [m]	**Inclination [deg]**	**Azimuth [deg]**	**Vertical depth [m]**
0	0	0	0
1000	10,00	0	994,931
1100	20,00	0	1091,401
1500	10,00	0	1477,281
1700	5,00	0	1675,507

Riser			
	Length[m]	**ID [in]**	**OD [in]**
21” Riser	174,00	19,00	21,00

Casing program				
	Hanger depth [m]	**Setting depth [m]**	**ID [in]**	**OD [in]**
13 5/8 Q125 88.2 lbs/ft	174,00	1400,00	12,374	13,626

String				
Component	**Type**	**Section length [m]**	**ID [in]**	**OD [in]**
DC 8” NC 56-80	Drill collar	175,00	3,000	8,000
DP 6 5/8”	Drill pipe	1625,00	5,965	6,626

Bit	OD [in]	Bit nozzles [1/32 in]
12 ¼ TriCone	12,252	3*18 + 1*16

Surface equipment				
	Length [m]	**ID [in]**	**Duration of closure [min]**	**Pressure after choke [bar]**
Chokeline	174,00	3,642	0,17	1
	Liquid pump rate change [USGal/min^2]	**Volumetric output [l/stroke]**	**Delay until pump shutdown [min]**	
Pump	792,20	15,00	0,17	
	Duration of closure [min]	**Delay until BOP closure [min]**		
BOP	0,25	0,17		

Fracture pressure					
Measured depth [m]	Vertical depth [m]	Fracture pressure gradient [bar/m]	Fracture pressure [bar]	Initiation pressure [bar]	Closing pressure [bar]
1400,00	1379,21	0,1624	225,0	247,2	188,8

	Base oil density [sg]	Solids density [sg]	Density [sg]	Oil/water ratio
OBM	0,875	4,2001	1,30	0/100

Lithology					
	Top [m]	Bottom [m]	Flow model	Top pressure [bar]	Temperature [Kelvin]
Reservoir	1800,00	1810,00	Reservoir model	242,0	330,85

Soft- & hard shut-in, OBM

Survey section			
MD [m]	Inclination [deg]	Azimuth [deg]	Vertical depth [m]
0	0	0	0
1000	10,00	0	994,931
1100	20,00	0	1091,401
1500	10,00	0	1477,281
1700	5,00	0	1675,507

Riser			
	Length[m]	ID [in]	OD [in]
21" Riser	174,00	19,00	21,00

Casing program				
	Hanger depth [m]	Setting depth [m]	ID [in]	OD [in]
13 3/8 P110 61.0 lbs/ft	174,00	1400,00	12,516	13,374

String				
Component	Type	Section length [m]	ID [in]	OD [in]
DC 8" NC 56-80	Drill collar	175,00	3,000	8,000
DP 6 5/8"	Drill pipe	1625,00	5,902	6,626

Bit	OD [in]	Bit nozzles [1/32 in]
12 ¼ TriCone	12,252	3*18 + 1*16

Surface equipment				
	Length [m]	ID [in]	Duration of closure [min]	Pressure after choke [bar]
Chokeline	174,00	3,642	0,17	1
	Liquid pump rate change [USGal/min^2]	Volumetric output [l/stroke]	Delay until pump shutdown [min]	
Pump	528,77	15,00	0,17	
	Duration of closure [min]	Delay until BOP closure [min]		
BOP	0,25	0,17		

Fracture pressure					
Measured depth [m]	Vertical depth [m]	Fracture pressure gradient [bar/m]	Fracture pressure [bar]	Initiation pressure [bar]	Closing pressure [bar]
1400,00	1379,21	0,1697	235,0	247,2	188,8

	Base oil density [sg]	Solids density [sg]	Density [sg]	Oil/water ratio
OBM	0,875	4,2001	1,30	80/20

Lithology					
	Top [m]	Bottom [m]	Flow model	Top pressure [bar]	Temperature [Kelvin]
Reservoir	1800,00	1810,00	Reservoir model	242,0	330,85

Driller's Method & W&W Method, OBM

Survey section			
MD [m]	Inclination [deg]	Azimuth [deg]	Vertical depth [m]
0	0	0	0
1000	10,00	0	994,931
1100	20,00	0	1091,401
1500	10,00	0	1477,281
1700	5,00	0	1675,507

Riser			
	Length[m]	ID [in]	OD [in]
21" Riser	174,00	19,00	21,00

Casing program				
	Hanger depth [m]	**Setting depth [m]**	**ID [in]**	**OD [in]**
13 3/8 P110 61.0 lbs/ft	174,00	1400,00	12,516	13,374

String				
Component	**Type**	**Section length [m]**	**ID [in]**	**OD [in]**
DC 8" NC 56-80	Drill collar	175,00	3,000	8,000
DP 6 5/8"	Drill pipe	1625,00	5,902	6,626

Bit	OD [in]	Bit nozzles [1/32 in]
12 ¼ TriCone	12,252	3*18 + 1*16

Surface equipment				
	Length [m]	**ID [in]**	**Duration of closure [min]**	**Pressure after choke [bar]**
Chokeline	174,00	3,642	0,17	1
	Liquid pump rate change [USGal/min^2]	**Volumetric output [l/stroke]**	**Delay until pump shutdown [min]**	
Pump	528,77	15,00	0,17	
	Duration of closure [min]	**Delay until BOP closure [min]**		
BOP	0,25	0,17		

Fracture pressure					
Measured depth [m]	**Vertical depth [m]**	**Fracture pressure gradient [bar/m]**	**Fracture pressure [bar]**	**Initiation pressure [bar]**	**Closing pressure [bar]**
1400,00	1379,21	0,1697	235,0	247,2	188,8

	Base oil density [sg]	Solids density [sg]	Density [sg]	Oil/water ratio
OBM	0,875	4,2001	1,30	80/20

Lithology					
	Top [m]	**Bottom [m]**	**Flow model**	**Top pressure [bar]**	**Temperature [Kelvin]**
Reservoir	1800,00	1810,00	Reservoir model	242,0	330,85

Driller's method & W&W Method, WBM

Survey section			
MD [m]	**Inclination [deg]**	**Azimuth [deg]**	**Vertical depth [m]**
0	0	0	0
1000	10,00	0	994,931
1100	20,00	0	1091,401
1500	10,00	0	1477,281
1700	5,00	0	1675,507

Riser			
	Length[m]	**ID [in]**	**OD [in]**
21" Riser	174,00	19,00	21,00

Casing program				
	Hanger depth [m]	**Setting depth [m]**	**ID [in]**	**OD [in]**
13 5/8 Q125 88,2 lbs/ft	174,00	1400,00	12,374	13,626

String				
Component	**Type**	**Section length [m]**	**ID [in]**	**OD [in]**
DC 8" NC 56-80	Drill collar	175,00	3,000	8,000
DP 6 5/8"	Drill pipe	1625,00	5,965	6,626

Bit	OD [in]	Bit nozzles [1/32 in]
12 ¼ TriCone	12,252	3*18 + 1*16

Surface equipment				
	Length [m]	**ID [in]**	**Duration of closure [min]**	**Pressure after choke [bar]**
Chokeline	174,00	3,642	0,17	1
	Liquid pump rate change [USGal/min^2]	**Volumetric output [l/stroke]**	**Delay until pump shutdown [min]**	
Pump	792,20	15,00	0,17	
	Duration of closure [min]	**Delay until BOP closure [min]**		
BOP	0,25	0,17		

Fracture pressure					
Measured depth [m]	**Vertical depth [m]**	**Fracture pressure gradient [bar/m]**	**Fracture pressure [bar]**	**Initiation pressure [bar]**	**Closing pressure [bar]**
1400,00	1379,21	0,1624	228,0	247,2	188,8

	Base oil density [sg]	Solids density [sg]	Density [sg]	Oil/water ratio
WBM	0,875	4,2001	1,30	0/100

Lithology					
	Top [m]	**Bottom [m]**	**Flow model**	**Top pressure [bar]**	**Temperature [Kelvin]**
Reservoir	1800,00	1810,00	Reservoir model	242,0	330,85