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Abstract

The easy oil and gas is gone. Newly discovered fields follow the trend of being smaller and harder to reach, moving to increasingly remote locations with high temperatures. The huge fields of the past are maturing and depleting, which can lead to a narrower window between pore pressure and fracture pressure. Combining this with the recent decline in oil prices, the demand for lower drilling costs and more efficient drilling becomes evident. Managed Pressure Drilling (MPD) offers a solution to this by balancing the downhole pressure and reducing Non-Productive Time (NPT) while drilling. The last couple of years have seen a steady rise in application of this technology.

Although similar to Underbalanced Drilling (UBD) in terms of equipment used, MPD does not welcome influxes to surface while drilling. It is, however, better equipped to deal with any resulting influx than a conventional drilling operation. A literary review of the various methods and applications of the technology is presented, along with the equipment needed and the drilling problems MPD seeks to negate. The main focus is on the Constant Bottomhole Pressure (CBHP) variation of MPD as this is planned for use on Kristin, an HPHT field in the Norwegian Sea. If successful, this would be the world's first application of MPD on a floating drilling vessel in harsh conditions.

Special emphasis is placed on well control, as well as detection and subsequent circulation of kicks. Kick simulations were performed in Drillbench© for a well drilled conventionally on Kristin in 2008, referred to as Well A. The simulation setup was based on 160 bar depletion in the Ile formation, while the Garn formation above was undepleted. The simulations showed that kicks from Garn of 1.6 m^3 and above would fracture the Ile formation for low mud weights. Based on this, it is not recommended to drill conventionally on similar depleted wells, due to the narrow window between pore and fracture pressure. MPD is recommended as an alternative as it is better at detecting and circulating kicks. To be able to compare MPD and conventional mode and conclude which one is best suited for Well A, similar kick simulations are recommended for MPD mode. Such simulations were outside the scope of this thesis.

A comparative risk analysis is made between the conventional method of circulating kicks and the MPD method planned for use on Kristin. The objective is to find out if MPD offers any benefits in terms of added safety or efficiency while dealing with influxes. Based on the analysis, MPD can safely be used when the conventional system acts as a backup. If encountering a large kick in MPD mode, one can always shut-in and circulate it out via the conventional system. However, such a large kick is improbable, as the MPD system is specifically designed to detect kicks early and avoid development of large kicks. The conventional system relies on human interaction, which represents a significant safety concern. The MPD system is almost entirely automatic, eliminating much of the risks associated with human delay and error. Since the MPD system can drill ahead during a small kick without the need for shutting in the well, it saves considerable rig time compared to the conventional system.

Acknowledgement

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Stavanger, 10th of June 2009.

Trygve Birkeland

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1 Introduction

MPD is regarded by many experts as the future solution for drilling in narrow windows between fracture and pore pressure. It also has the potential for detecting kicks earlier and reducing NPT while drilling. Kristin is an extreme HPHT field in the Norwegian Sea which is depleting quickly. MPD is planned on future 8.5” sections on Kristin where the depletion is unevenly distributed. Challenges associated with heave in harsh conditions require a new riser solution to be developed for MPD usage. Simulations are performed to determine if a well can be drilled conventionally with a depletion of 160 bars. MPD is further investigated to evaluate if it offers any benefits in terms of safety and efficiency.

The first five chapters in this thesis are basically a literary review of the most important aspects of MPD. The intent is to educate the reader on the most up-to-date literature available on the topic and clearly explain what separates MPD from conventional drilling. Chapter one gives an introduction into what MPD is all about and the drilling problems it seeks to negate. Different MPD applications are outlined in chapter two. The equipment associated with MPD is described in chapter three, while the phenomenon of kicks is described in chapter four. Chapter five gives a description of the Kristin field and the challenges associated with it.

The last three chapters represent the experimental work of this thesis. Chapters six and seven consist of the simulations and risk analysis, respectively. Finally, summary and conclusions are presented in chapter eight.

1.1 Managed Pressure Drilling

In conventional drilling the bottomhole pressure (BHP) is defined as the sum of hydrostatic head of drilling fluid (MW_{HH}) and the annulus friction pressure when circulating (AFP).

$$BHP_{DYN} = MW_{HH} + AFP \qquad \text{(Eq. 1)}$$

During connections there is no circulation and hence static conditions. AFP can then be assumed to be zero:

$$BHP_{STAT} = MW_{HH} \qquad \text{(Eq. 2)}$$

In order to control the bottomhole pressure in conventional drilling one can change the mud weight, which will influence the hydrostatic head, or one can regulate the AFP by changing the pump rate. The stopping and starting of pumps during pipe connections creates pressure fluctuations in the wellbore which can cause problems when drilling in narrow margins between pore pressure and fracture pressure.

Managed Pressure Drilling (MPD) introduces another variable for controlling bottomhole pressure. In addition to mud weight and annulus friction pressure, backpressure (BP) is applied from surface to maintain overbalance in the well. The formula for bottomhole pressure while circulating thus becomes:

$$BHP_{DYN} = MW_{HH} + AFP + BP \qquad \text{(Eq. 3)}$$

The amount of backpressure while circulating is usually close to zero or relatively low. In static conditions, like when the pumps are shut off for connections, more backpressure is applied from surface to account for the loss of AFP:

$$BHP_{STAT} = MW_{HH} + BP \qquad \text{(Eq. 4)}$$

This facilitates the ability to keep a near constant BHP during the entire drilling operation. This is very beneficial in narrow operating margins where the slightest pressure variation can induce an influx or fracture the formation. In order to keep the BHP constant a closed circulation system is needed, which is different from the conventional open-to-atmosphere system. By keeping the BHP slightly overbalanced, or as near as balanced as possible, the driller can safely drill through narrow operating windows without having to set the casing prematurely.

The International Association of Drilling Contractors (IADC) UBO and MPD Committee defines managed pressure drilling (MPD) as[**1**]:
"*MPD is an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. It is the intention of MPD to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process.*

• *MPD process employs a collection of tools and techniques which may mitigate the risks and costs associated with drilling wells that have narrow downhole environmental limits, by proactively managing the annular hydraulic pressure profile.*

• *MPD may include control of back pressure, fluid density, fluid rheology, annular fluid level, circulating friction, hole geometry or combinations thereof.*

• *MPD may allow faster corrective action to deal with observed pressure variations. The ability to dynamically control annular pressures facilitates drilling of what might otherwise be economically unattainable prospects."*

There seems to be some confusion in the industry about what MPD is and what it is not. This confusion is aided by companies who like to refer to the name of their patented technologies. For simplicity, terms like low-head drilling, near balanced drilling and micro-flux control all fall under the category of MPD in this thesis.

1.2 Underbalanced Drilling

Although similar in many ways, Underbalanced Drilling (UBD) is principally different from MPD. UBD operations are intentionally designed to operate with a bottomhole pressure that is lower than the pore pressure in the formation. The advantages of drilling with a hydrostatic head that is lower than pore pressure are mainly reduced formation damage, increased rate of penetration (ROP), and less potential for lost circulation and differential sticking. Disadvantages include potentially reduced wellbore stability, safety concerns regarding toxic gas in high pressure environments, and increased costs.

Since the bottomhole pressure is lower than the pore pressure, influx of formation fluids into the wellbore is a natural part of the operation. UBD operations are equipped with surface equipment that can handle these influxes. A closed circulation system prevents the wellbore fluids from reaching areas where people and possible ignition sources are present. However, if there is a risk of high release rates of H_2S gas at surface, UBD is not recommended.

Although UBD has been practiced on land for years with good results, the offshore industry has been hesitant to embrace the technology because of the safety concern with inviting influx of formation fluids to the surface and regulations regarding hydrocarbon flaring. The main difference between UBD and MPD is that influx of formation fluid to surface is intentional during UBD, but not during MPD. UBD and MPD can be used in narrow margins where conventional drilling is not possible, as illustrated in Figure 1. UBD is mainly performed to reduce formation damage and increase productivity, while MPD is used to solve purely drilling related challenges and drill more efficiently[**2**].

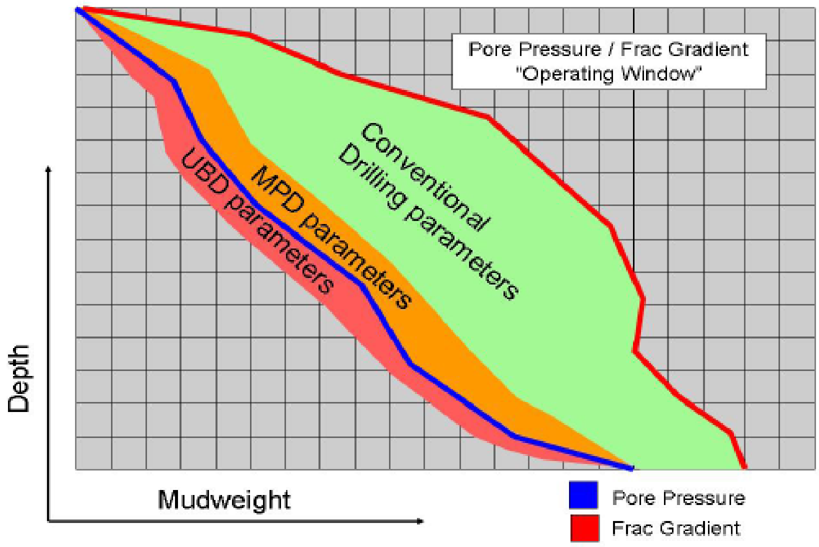

Figure 1 – Pressure gradients for UBD, MPD and conventional drilling**[3]**.

1.3 Historical background

The reservoir pressure and how it is controlled is the determining factor for how a field is operated. It also impacts the construction time and cost, the production and the overall risk associated with the field. The technology for controlling BHP has remained essentially unchanged during the last 100 years. For a US land job performed 15 years ago, it was not uncommon to encounter situations where one had to use a Rotating Control Device (RCD) and a choke to generate backpressure to keep a well in balance. Back then, the technique was not referred to as MPD[4]. In fact, the RCD was used as early as in the 1930s, but then mainly as a diverter for aerated mud drilling, not primarily designed to hold pressure. A description of this device is given in chapter 3.

In 2005, 75% of all US land-based wells drilled at least one section with UBD, MPD, or some kind of compressible fluid, according to Hannegan[**5**]. Ten years earlier, this number was about 10%[**6**]. During the last couple of years, the offshore market has seen an increasing number of uses for MPD technology.

Many offshore oil and gasfields in the world are maturing which leads to increased need for drilling new infill wells as well as exploration wells to increase the reserves. The demand for offshore drilling rigs is increasing the deepwater daily rig rates while the decreasing oil price is pushing for more effective drilling. Offshore MPD can reduce Non-Productive Time (NPT) significantly and reduce drilling costs, while it is also beneficial for drilling difficult wells in mature environments with narrow pressure windows.

1.4 Pressure depletion

Sources for this chapter are [**7**] and [**8**] unless otherwise stated in the text.

Narrow margins between pore pressure and formation fracture pressure are typically encountered in depleted, deepwater, or High Pressure High Temperature (HPHT) fields. In a porous rock like a sandstone reservoir, there is usually water with pore pressure, P_P. When a field gets depleted, the pore pressure drops. The vertical stress in the rock itself will then be reduced by P_P, so that the vertical stress on the rock material is σ_v - P_P. For porous materials without geological stress changes ($\sigma_H = \sigma_h$) Hook's law gives the following equations:

$$s_H - P_P = s_h - P_P = \frac{v}{1-v}\left(s_v - P_P\right) \Rightarrow$$
$$P_F = s_H = s_h = \frac{v}{1-v}\left(s_v - P_P\right) + P_P = \frac{v}{1-v} s_v + \frac{1-2v}{1-v} P_P \qquad \text{(Eq. 5)}$$

Where:

P_F = fracture pressure

P_P = pore pressure

v = Poisson ratio

σ_H = largest horizontal stress

σ_h = smallest horizontal stress

σ_v = vertical stress

Since the Poisson ratio is usually between 0 and 0.5 for reservoir rocks, the term (1-2v)/(1-v) is always positive. Thus if the pore pressure is reduced, the fracture pressure will also decrease.

If a depleted zone has an even and known depletion and if the drilling is limited to this zone, the drilling window can actually increase with depletion. But knowledge about this depletion can be limited and non-depleted shale sections that have a higher pore pressure than expected will decrease the drilling window.

1.5 Drilling problems

Figure 2 shows factors contributing to NPT on gas wells in the Gulf of Mexico.

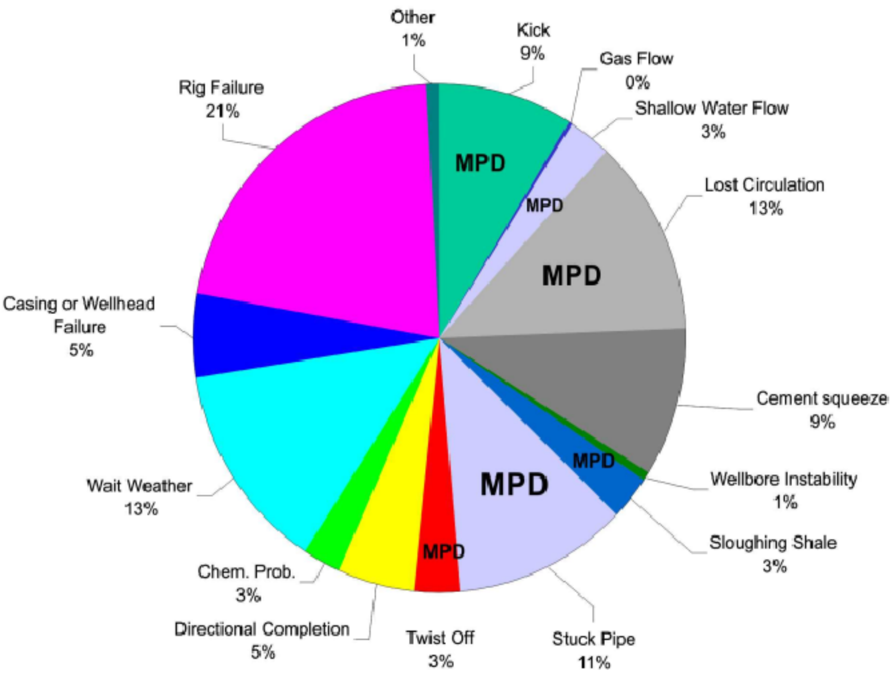

Figure 2 – Problem incidents Gulf of Mexico shelf gas wells**[9]**.

As illustrated in Figure 2, drilling related problems which can be mitigated by MPD include:

- Kick

- Shallow water flow
- Sloughing shale
- Wellbore instability
- Stuck pipe
- Lost circulation
- Twist off

MPD can operate very close to the pore pressure gradient compared to conventional drilling. This reduction in overbalance reduces the differential pressure over the rock that is being drilled. The force holding the rock in place is thus reduced, making it easier to break and transport a chip. Overall, this increases the ROP[**10**].

1.5.1 Stuck pipe

The collapse pressure curve can sometimes be equal to or greater than the pore pressure curve. Under such circumstances, chunks of the formation can slough off and create stuck pipe situations. Another mechanism that contributes to sloughing is the cyclic loading of the wellbore when drilling and making connections. The process of turning the pumps on and off induces fatigue to the in-situ stresses in the formation.

Differential sticking is a common problem that often leads to stuck pipe. This is caused by high differential pressure between the wellbore and the formation. A high overbalance combined with a long openhole section increases the chance of experiencing differential sticking. This is especially critical when the drillstring is stationary without circulating or rotating, e.g. during connections.

1.5.2 Surge and swab

When tripping out of the well too fast, the BHP will be momentarily reduced due to the volume change. This is called a swab effect and can trigger an influx of formation fluids into the wellbore if large enough. When tripping too fast into a well, the opposite happens and the BHP increases. This can fracture the formation in narrow operational windows and is called a surge effect. Harsh weather in the North Sea often result in several meters of rig heave, which can trigger surge and swab effects when drilling from a floating platform. Nygaard *et al.*[**11**] performed theoretical simulations that indicated that such pressure fluctuations could be reduced by automatic control of both the MPD choke and pump rates.

1.5.3 Lost circulation

Lost circulation may occur as a result of pressure fluctuations exceeding the fracture pressure during tripping or connections. Depending on the severity of the loss and the mud used, this can be a costly problem. Loss of mud in the wellbore reduces the hydrostatic mudcolumn which increases the chance of having a kick. By keeping a relatively constant BHP during the entire MPD operation, pressure fluctuations in the wellbore are minimized along with the risk of lost circulation. A mud loss detected at the mud pits under conventional drilling may originate from several sources, including loss from solids, control equipment, surface leaks, or downhole losses. As a consequence, a partial downhole loss may be attributed to another source and therefore go undetected until the situation worsens. MPD utilizes a closed pressure system where a detected loss could only originate from a downhole loss, which makes it possible for earlier identification of a lost circulation event. A remedial operation can hence be performed before the wellbore is beyond repair[**12**].

1.5.4 Ballooning

Another effect of pressure fluctuations at the wellbore is the ballooning effect. When drilling fractured formations in an overbalanced state, the fractures are kept open by the pressure and drilling mud can escape into the fractures. When circulation is stopped during a connection, the BHP falls and the fractures close, forcing the mud back into the wellbore. This influx of mud can often be misinterpreted as a kick and the common cure is to increase the mud weight to regain balanced conditions in the well. As circulation is resumed, the equivalent circulating density (ECD) will increase the BHP which will again lead to opening of fractures and loss of mud. The situation can deteriorate until the BHP exceeds the fracture propagation pressure, which may result in total losses. MPD can reduce this problem by maintaining a relatively constant BHP during both static and dynamic conditions. An Annular-Pressure-While-Drilling (APWD) tool should be run to measure the BHP which can help determine whether the influx is a kick or just flowback from the formation[**13**].

1.5.5 Other issues

On an offshore drilling rig, time is the most important cost contributor. The time consuming process of weighting-up mud is not only costly in itself, but also an indirect cause of many NPT problems. By increasing the mud weight, one increases the overbalance, which increases the risk of fracturing weak formations. When increasing the mud weight, solids are often added to the mud which negatively affect the ROP and increases wear on bit. From Figure 3 it is clear that overbalance is inversely proportional to ROP. By drilling with a near balanced BHP as is done in MPD mode, the ROP will significantly increase. MPD maintains a near constant BHP at bit depth by applying backpressure at the surface. By avoiding the frequent change of mud weight, the problems associated with it diminishes. The result is less formation damage and lost circulation, as well as increased bit life, which leads to less tripping in order to change out the drill bit[**14**].

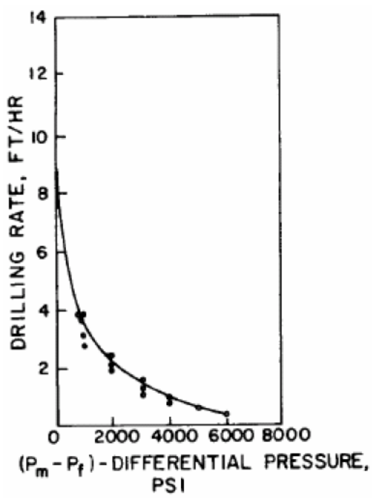

Figure 3 – Relationship of overbalance pressure to ROP**[14]**.

When encountering zones with different pore and fracture gradients, the common solution is to vary the mud weight and set multiple casings in the problem zones. MPD makes it possible to navigate these pressure gradients with fewer casings, which leads to substantial cost savings and increases the hole size achievable at total depth (TD).

While MPD can reduce drilling costs, drilling cost certainty is just as important in today's economic climate. Figure 4 illustrates the cost uncertainty of MPD and conventional drilling. The width of the curve reflects the variation in final drilling costs. The main contributor to cost uncertainty in drilling operations is NPT. The figure shows that MPD has a narrower curve and thus a smaller cost uncertainty compared to conventional drilling, which is natural since MPD addresses many of the issues contributing to NPT[**14**].

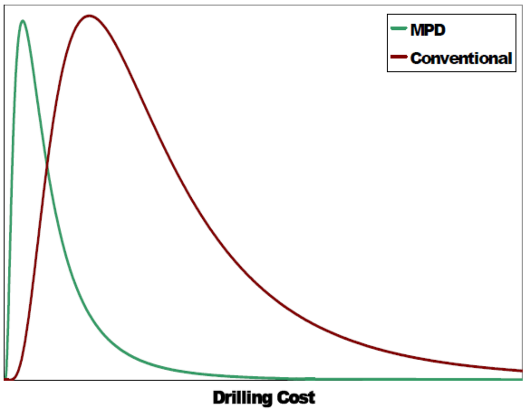

Figure 4 – Cost uncertainty curves for MPD and conventional drilling**[14]**.

As the pressure increases and the temperature drops, the risk of hydrate formation increases which can plug pipes and flowlines. When gas is forced through a valve and then expands as a result of the lower pressure, the gas will cool down because of the Joule-Thompson effect. Due to this thermodynamic phenomenon, hydrates may form downstream of the rig choke when circulating out gas kicks. To prevent this, glycol is injected upstream the choke while circulating out kicks. To monitor if hydrates are forming, pressure and temperature gauges are installed upstream and downstream the choke. Figure 5 shows the relationship between pressure, temperature and hydrate formation for a field in the North Sea.

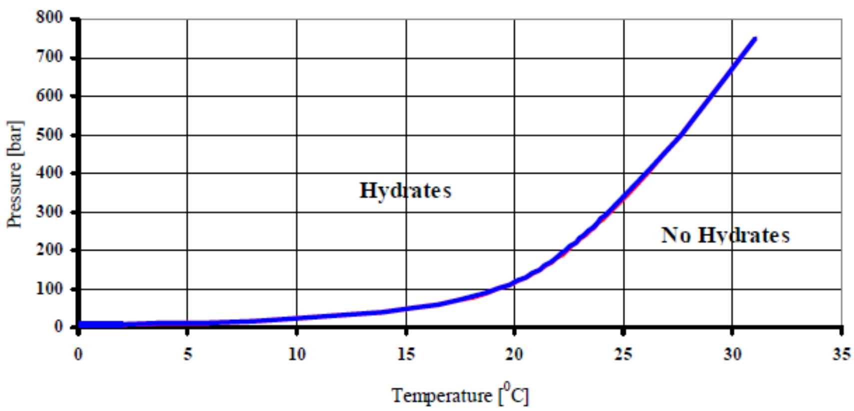

Figure 5 – Hydrate formation curve (courtesy of StatoilHydro).

1.6 Hydraulic parameters

Sources for this chapter are [**3**] and [**15**] unless otherwise stated in the text.

In order to reduce pressure fluctuations during drilling, tripping and connections, it is imperative that one fully understands what dictates the pressure behaviour in the wellbore. Fluid parameters that affect the downhole pressure include rheology, density, and compressibility. ROP, surface backpressure, pump rate, drillstring and hole geometry, pipe rotation, and eccentricity are other hydraulic parameters that govern the pressure in the annulus. All these parameters are interdependent and the relations between them are not always straight forward.

1.6.1 Rheology

Most drilling fluids have a non-zero yield point. When fluid flow is initiated, or just before it stops, there is a sudden pressure increase or decrease in the wellbore, as Figure 6 illustrates. Moving the pipe up or down also triggers pressure fluctuations, regardless of speed. These pressure fluctuations must be taken into account when making connections and when tripping.

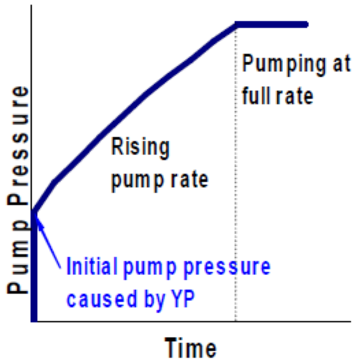

Figure 6 – Effect of yield point on pump pressure[15].

1.6.2 Pump rate and cuttings

For low pump rates, the dominating factor is the concentration of cuttings. The BHP will decrease until the pump rate reaches a value where the annular friction takes over as the dominating factor. When this happens, the BHP will increase with the pump rate. As the pump rate increases the hole cleaning capabilities become better and the concentration of cuttings decreases. This is illustrated in Figure 7. If the ROP is zero and no cuttings are present, the BHP will increase with the pump rate no matter what the pump rate is. The transition from laminar to turbulent flow will cause a small but sharp pressure increase, which can be seen between 420 and 450 gpm in the figure. As a result of this, hole cleaning problems and cuttings accumulation might arise with insufficient pump rates. When operating in narrow margins in MPD mode it can be tempting to reduce the ECD by lowering the pump rate. As one is operating closer to the pore pressure than in conventional drilling, the ROP might also be higher than usual, leading to increased cuttings. The combination of reduced circulation rate and increased ROP increases the chance of encountering stuck pipe or twist-off situations.

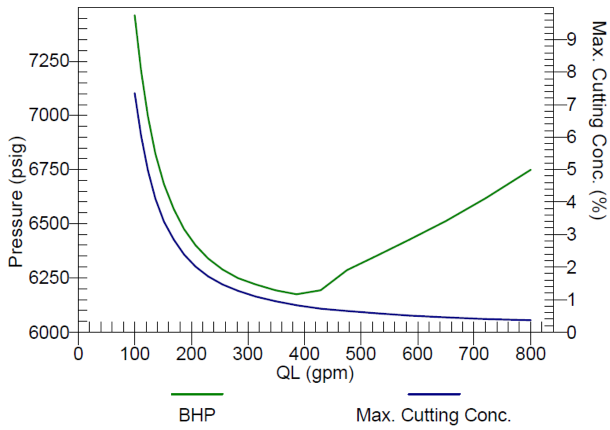

Figure 7 – Effect of pump rate on BHP and cuttings concentration**[15]**.

1.6.3 Other parameters

Rotation of the drillstring will lower the torque and drag, but increase the fluid velocity and the ECD. However, it will also help transport the cuttings to surface, which will lower the ECD. The transport of cuttings is most often the dominating factor, but this depends on ROP and cuttings size. The eccentricity of the pipe can also have a small effect on the BHP by introducing uneven hole cleaning in the wellbore. While water based mud (WBM) is regarded as fairly incompressible, synthetic/oil-based mud (SOBM) is compressible. Deep HPHT wells might enhance the compressibility. In certain conditions the density downhole might be slightly higher than the density measured in the pits.

As previously mentioned, the purpose of a CBHP operation is to keep the pressure relatively constant at bottom. But this may limit the length of open hole section that can be drilled. In order to clarify this problem, consider Figure 8, which shows that the slope of wellbore pressure is different when drilling and when making a connection. When drilling in an open hole, the pressure increases with depth because of frictional pressure drop. During connections, surface backpressure is applied, resulting in wellbore pressure decreasing with depth.

In the CBHP variation of MPD it is only possible to keep the pressure constant at one specific point in the well. Normally this point is chosen to be at bottom of the section being drilled, at the drill bit. This is the case in the operating window to the left in Figure 8. Here it is not possible to drill much deeper without risking that the annular pressure during connection (blue curve) exceeds the formation fracture pressure limit of the window. If the point of constant pressure was moved from the bottom to somewhere higher in the openhole section, one would be able to drill a longer section without fracturing the formation, as illustrated to the right in Figure 8. The pressure will no longer be constant at the bottom, but a wider operating window can be achieved[**3**]. Another side effect from keeping only the BHP constant is that the pressure above is changing between drilling and connections. This cyclic loading may weaken the formation which can lead to well stability issues.

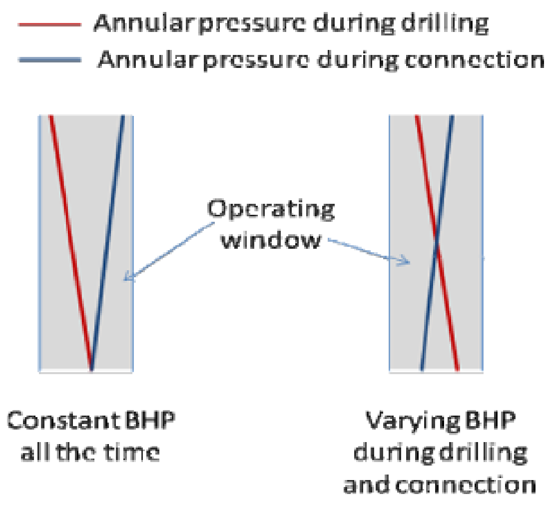

Figure 8 – Point of constant pressure during drilling and connection**[3]**.

The well geometry plays a part in how much of the well is affected by applying backpressure at the surface. If the well is static and completely horizontal at some section, the pressure in this section would be constant as the TVD is the same. Consequently, addition of backpressure at surface would result in the same pressure increase in each part of the horizontal section. However, if the well is vertical, the pressure will be different as the TVD is not constant along the wellpath. This is only true when the well is static, like during connections. If there is circulation, the friction loss will depend primarily on the well length and secondary on the geometry[**15**].

1.7 Drilling fluids

1.7.1 ULIF

A leakoff test (LOT) is usually performed to identify the fracture pressure of a formation. The formation is pressurized until the fluid enters the formation or creates a fracture. If this pressure is exceeded during normal operations, one usually experiences partial losses to the formation. These losses can be stopped if treated early, and if successful, this indicates that the LOT has been increased. An ultralow invasion-drilling fluid (ULIF) has been developed that increases the LOT and thus the pressure window available by creating a barrier at the wellbore wall. This barrier has a very low permeability that hinders fluid invasion and pressure transmission into the formation[**12**].

1.7.2 Stress Cage Fluids

Designer drilling fluids with Loss Prevention Material (LM) have been developed and tested to strengthen the formation up to 30 bars with regards to the fracture gradient. The specially selected and designed LM props fractures and seals them against wellbore pressure. The combination of these two functions creates additional tangential stresses or hoop stresses around the wellbore, which increases the fracture pressure gradient. Fluids that have such materials are known as Stress Cage fluids.

1.7.3 Balanced mud pill

To be able to trip out during MPD in HPHT wells, the well can be displaced with weighted mud to bring the well into hydrostatic overbalance and then trip out conventionally without using backpressure. This might expose the reservoir to excessive over-pressure. An alternative is to use light mud with heavier weighted mud above it. To avoid the heavy mud contaminating the light mud, a balanced mud pill (BMP) can be used to separate the two mud systems. Ronæs *et al.*[**16**] describes the development and testing of such a pill and Syltøy *et al.*[**17**] wrote about the successful use of such a pill on a North Sea HPHT field.

2 Variations of MPD

2.1 Controllers

Unless otherwise stated, the references for the following chapter are [**35**], [**36**], and [**11**].

In order to automatically control the choke opening in an MPD system, one must have a controller. In a dynamic system, the controller automatically adjusts the input parameters to obtain a given output. Different controllers exist for different applications.

2.1.1 PID control

A PID (Proportional-Integral-Derivative) controller can be found in many applications and is most suitable for linear systems, but can also be used for non-linear systems. A challenge with the linear PID controller is to find the correct control parameters. As drilling is non-linear the PID controller needs to be re-tuned each time a dynamic well property changes, like fluid rheology or temperature. Tuning is time-consuming, and poor tuning leads to oscillations and slow response times. A transient flow model may be used to auto-tune the parameters. A diagram of the PID controller is shown in Figure 9.

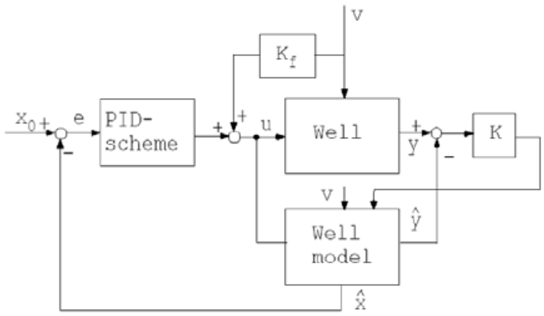

Figure 9 – PID control scheme**[36]**.

2.1.2 MPC

An MPC (Model Predictive Control) is non-linear and uses a model to predict the future behaviour of the system. The model must be able to describe the behaviour of the non-linear two-phase fluid flow in the well. An algorithm tries to minimize the error between the setpoint and the future predicted measurement. Based on the results from the algorithm, the optimal control setting is chosen. MPC does not require re-tuning and a diagram of the control method is shown in Figure 10.

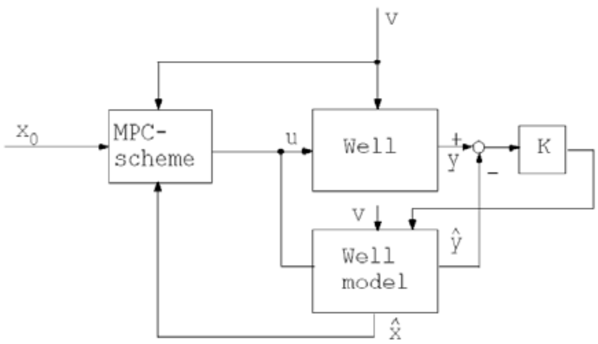

Figure 10 – MPC scheme**[36]**.

Iversen *et al*.[**37**] performed a well control study of the Kristin field, where MPD simulations with PID choke control and CCS provided 3 to 4 bar improvement on pressure control. They also recommended that simulations using MPC choke control should be performed.

2.2 Different types of MPD

MPD can be divided into two main categories[**38**]:

Reactive MPD – Conventional drilling practices are performed, but the rig has an RCD, choke and float valves in case of surprise change in pressure regime.

Proactive MPD: **-** The casing and fluid programs are designed from the start to take full advantage of the ability to more precisely control the pressure variations in the well. This category is also known as "walk the line".

While reactive MPD has been practiced for years on problem wells, it is only during the last couple of years that proactive MPD operations have received significant attention. A further distinction between different types of proactive MPD techniques practiced offshore follows in the next subchapters.

2.2.1 Constant Bottomhole Pressure (CBHP)

Drilling narrow margins between pore pressure and fracture requires close control of the BHP. This can be achieved by using a light fluid which in static conditions may be slightly underbalanced compared to the pore pressure. The purpose of this is to avoid fracturing the formation during circulation, when balance is achieved by controlling the equivalent circulating density (ECD). To avoid influx of formation fluid during connections, backpressure is applied at surface to maintain more balanced conditions in the wellbore than during conventional drilling, which often is significantly overbalanced. A manual, automatic, or semi-automatic choke is used to control the backpressure. In order to keep the BHP constant the driller can alter the fluid density and rheology, the hole geometry, annular fluid level, hydraulic pressure, and surface backpressure. The choke and backpressure pump can be controlled by a computer running a hydraulic model in real-time This method is also known as ECD-management[**6**].

2.2.2 Pressurized Mud Cap Drilling (PCMD)

PCMD is best suited when there is a high risk of lost circulation, like many places in the Asia Pacific region where cavernous voids encountered during drilling result in huge fluid losses. An RCD is used to seal off the annulus, but pressures above the operating limit of the RCD can be experienced. To avoid this problem, a light and expendable fluid, like seawater with the appropriate additives, is used to drill the problem zone. This increases ROP, while the drilling fluid along with the cuttings will be forced into the lost circulation zone. By adding a predetermined column height of heavy mud in the annulus in addition to surface backpressure no fluid is returned to surface from the annulus. Well control is thus maintained even if substantial fluid losses occur. A typical PMCD application can be seen in Figure 11. It can be discussed whether this technique is a proactive or reactive one, as wells often are drilled conventionally until the problem zone is encountered, thus placing it in the latter category[**38**],[**6**].

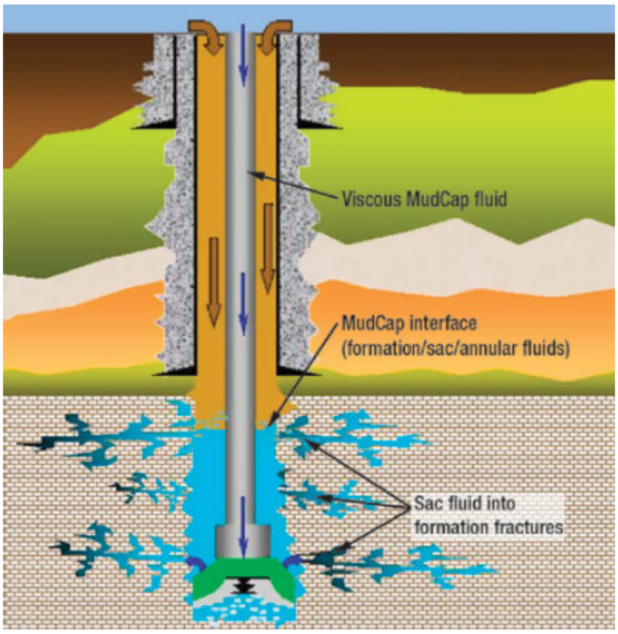

Figure 11 – Pressurized Mudcap Drilling**[6]**.

2.2.3 Dual Gradient Drilling (DG)

Mainly applicable in deepwater wells, an inert gas or other light fluid is injected into the riser at a predetermined depth to reduce the hydrostatic mudcolumn and hence reduce BHP. The well is "tricked" into thinking that the riser is shorter than it actually is and will now have two pressure gradients, one before the injection point and one after. This variation of MPD is illustrated in Figure 12.

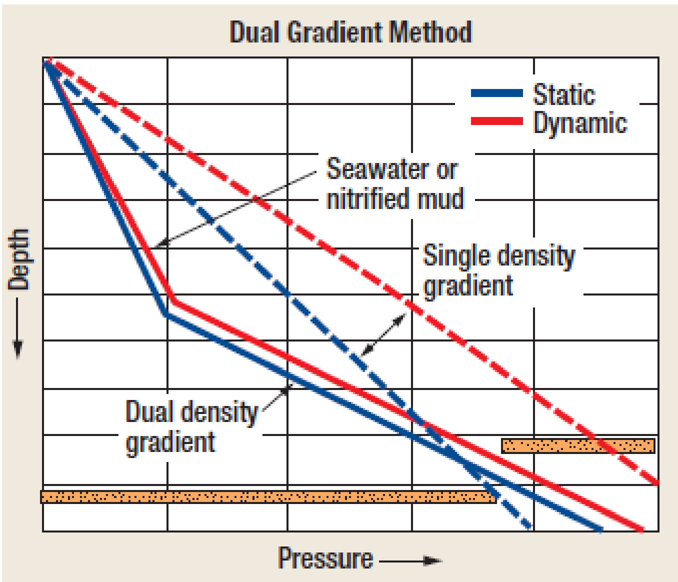

Figure 12 – The dual gradient variation of MPD**[39]**.

2.2.4 Health, Safety and Environment MPD (HSE)

By having a closed, pressurized mud return system compared to a conventional one which is exposed to atmospheric pressure, HSE issues will be improved. A closed system prevents personnel from being exposed to potentially dangerous gases like H_2S and also removes the danger of a flash fire at the surface. This is especially important in HPHT fields where small gas influx at reservoir depth can become several hundreds of magnitudes larger at surface.

2.2.5 Riserless MPD

An ROV (Remotely Operated Vehicle) is used in conjunction with a subsea RCD to control backpressure. Since there is no riser, the cuttings and well fluids will be discharged to seabed. Because of environmental concerns the drilling fluid used should be seawater. This technique is mainly applicable on top holes which are thought to have shallow water flow or similar hazards.

2.2.6 Zero Discharge Riserless MPD

This variation of MPD is similar to riserless MPD but it has a subsea pump that transports cuttings to surface, facilitating zero discharge to sea[**40**].

2.2.7 Reverse circulation (RC)

Hitherto, this technique has mainly been used on land drilling operations but it may be applicable offshore as well. As the name implies, the drilling fluid is circulated in reverse up the drillpipe. The drill bit nozzles can be removed to facilitate this, thus making the bit act like a choke. The drilling fluid is heavy and free of cuttings providing overbalance. It is thought that this technique may be applicable to minimize cuttings in short horizontal intervals.

3 MPD equipment

The source for this chapter is [**18**] unless otherwise stated in the text.

Since much of the MPD equipment and technology is based on UBD technology, there has been some confusion and scepticism regarding the use of MPD offshore. The truth is that MPD technology can enhance safety and well control issues if properly applied. In non-reservoir sections, simpler equipment can be used for MPD without sacrificing the overall safety of the operation. Compare this with the fully underbalanced equipment needed for UBD and the cost savings become apparent. Though several different setups exist for different applications, the core equipment package of a MPD operation is similar.

3.1 Rotating Control Device (RCD)

A Rotating Control Device (RCD) is used to divert the flow to the choke manifold and seal off the annulus. This provides a closed circulation system which prevents sour gas from reaching the rig floor while the BOP is closing during a kick. Depending on MPD variation and rig type, the RCD can be placed either at surface or subsea. Other names for the RCD are rotating control diverter or rotating control head. The RCD can be divided into two different categories, passive rotating devices and active rotating annular preventers.

The passive system, which can be seen in Figure 13, uses an undersized stripping rubber that forms a seal against the drillstring under zero pressure. The seal is made stronger by exposing it to annular pressure. The pipe can rotate and move vertically through the RCD while it continuously maintains a seal. Depending on rotation RPM and surface pressure, the RCD rubber element needs to be periodically replaced due to wear. Spiral drill collars are difficult to seal against and drill pipes with grooves can damage the RCD stripper rubber so both should be avoided during an MPD operation. The passive system is the most common in use[**19**].

The active rotating annular preventer uses hydraulic power to form a seal against the drillpipe. This system is larger and requires more vertical space. The packer element needs less replacing than its passive counterpart.

Figure 13 – Rotating Control Device (courtesy of Smith Services).

3.2 MPD Choke

An MPD choke manifold is used to control the annular backpressure by regulating the opening of the choke. In order to maintain backpressure, a sufficient mud volume must flow through an open choke. If this flow decreases, the choke opening decreases to maintain the same pressure. The opposite happens for increasing flow. If there is no flow, the choke needs to close quickly in order to trap the pressure. The choke needs to be fast, accurate and highly reliable with a closing time not exceeding 30 seconds. Preferably, there should be two chokes coupled in parallel for redundancy in case one of them gets plugged. Chokes are available from 5000 to 20000 psi operating pressure, depending on type and application. A dedicated backpressure pump should be available to generate the necessary backpressure during connections or if the rig pumps should fail. One of the rig pumps can alternatively be used. The choke can either be controlled manually or fully automatic.

3.2.1 Degrees of automation

When making connections, the choke needs to be gradually closed while the rig pump rate is gradually reduced. As the choke closes, the backpressure imposed on the annulus increases along with the BHP. The reduction of the pump rate counteracts this by reducing the ECD along with the BHP. The purpose is to reduce BHP fluctuations and keep it as constant as possible. Figure 14 shows an example of how such a procedure would look like. If the choke is controlled manually, keeping the BHP constant can be difficult to achieve and require well trained personnel. It also represents a safety concern as the risk of human error is ever present.

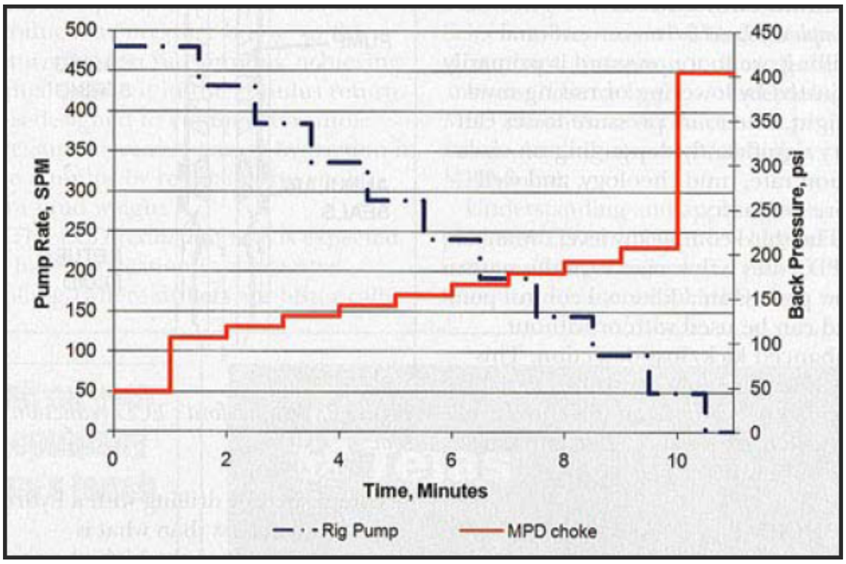

Figure 14 – Plot of backpressure and pump rate for manual MPD connections**[20]**.

Fully automatic mode incorporates a Programmable Logic Controller (PLC) which automatically controls the choke opening to setpoints computed by a dynamic hydraulic flow model. Both the choke and the pump rate can be automatically controlled by the system, or just the choke, depending on the system. The dynamic hydraulic flow model runs in real time, continuously updating the calculations as new measurements become available. The new calculations lead to new setpoints for the choke opening. This way the BHP is kept relatively constant. Bjørkevoll *et al*.[**21**] describe such a model that was used on an MPD application in the North Sea.

It is vital that the model is calibrated with measured BHP to ensure accuracy. Downhole pressure measurements are usually sent via mud pulse telemetry to the surface for interpretation. Depending on well length and pump rate, the delay can be significant. This induces input lag to the hydraulic modelling which can result in inaccuracy in the output. An alternative is to use wired pipe or similar technologies, which dramatically increase the speed and bandwidth available for downhole measurements, though at a higher cost. Sometimes, unwanted events can occur that even the most advanced control system cannot handle, like a drillstring washout. Such events may require human intervention. The ability to keep a relatively constant BHP will also be limited by computing power.

3.3 Continuous Circulation System (CCS)

A system has been developed as shown in Figure 15 that makes it possible to circulate while making pipe connections. The CCS needs to be calibrated and tuned to the rig once it has been installed. When dealing with HPHT wells, downhole temperature changes can be large and unpredictable. Mud that remains static in the borehole can be heated above the temperatures it was designed for. The temperature changes affect the mud properties and make it harder to interpret the trends in other parameters. Thus it will become more difficult to accurately control the choke to compensate for downhole pressure fluctuations. By maintaining circulation when making connections, the fluid is not as affected by the temperature changes, providing easier choke control. Since there is continuous circulation, the ECD will be ever present, minimizing pressure fluctuations during connections. Continuous circulation also improves hole cleaning and minimizes connection gas. This can lead to a larger drilling window as the mud weight can be lowered down to equivalent initial pore pressure. Although the CCS is highly advantageous when drilling wells with narrow pressure margins, the associated installation costs often prevents its usage[**22**].

Figure 15 – The main unit of the Continuous Circulation System**[23]**.

3.4 Non-return valves

To prevent flow up the drill string and keep a positive backpressure during tripping, non-return valves (NRVs) or floats are installed in the Bottom Hole Assembly (BHA), normally above the mud motor. Without these, backpressure applied at the surface might lead to drilling fluid flowing back up the drill pipe, carrying cuttings that can plug the MWD or blow out the drill pipe. Two floats are usually installed for redundancy and sometimes even three are used. If a float valve needs replacing, the entire drill string needs to be tripped. To avoid this, wireline retrievable floats are recommended.

3.5 *Other equipment*

When using traditional mud motors to drill oriented, the string is not rotated and cuttings may fall out of suspension and rest on the low side of the hole. As a result of this, the ECD will be lower. But when rotary mode is initiated, the cuttings will get suspended and ECD will dramatically increase. This causes rapid pressure fluctuations which may lead to formation fracturing in narrow drilling windows even in MPD mode. By using a Rotary Steerable System, rotation is maintained both in steering mode and neutral mode thus providing a more constant ECD[**24**].

3.5.1 Downhole Deployment Valve (DDV)

The purpose of the DDV is to isolate the surface from well pressure when removing or running in the drillstring. The DDV is installed as a part of the casing string and is controlled from surface. When the bit is just above the DDV in a tripping out procedure, the valve will close and the pressure above is bled off facilitating the safe removal of the drillstring. This operation is done in reverse when running in the drillstring, allowing deployment of long complex assemblies through the BOP without the need for a snubbing unit.

3.5.2 Pressure-While-Drilling Tools

It is important to have knowledge of the pore pressure during drilling in narrow margins. A Formation-Pressure-While-Drilling (FPWD) tool should be included in the BHA to be able to take formation pressure tests without stopping circulation or performing a trip. Similarly, an APWD tool should also be used to keep track of the bottomhole pressure. These pressures need to be calibrated with the hydraulic model to ensure accuracy in the pressure predictions made by the simulator.

3.5.3 ECD Reduction Tool (ECDRT)

A tool is currently being developed that can reduce the ECD in the wellbore by as much as 10 bar. The ECD reduction tool (ECDRT) can be installed high up in the vertical section of the drillstring with a short trip and requires very little rig-up time. A schematic of the ECDRT can be seen in Figure 16. The return fluid receives energy from a pump that is powered by a turbine motor. The tool does not rotate with the drillstring and has annular seals to ensure that the flow passes through the tool. The tool is activated by fluid flow and deactivated when the flow stops. It can handle densities up to 1.8 SG, including cuttings, and run inside 9 5/8” to 13-3/8” casings. This may limit its applications in deepwater HPHT fields like Kristin, which can require heavier mud weights. According to Bansal *et al*.[**25**] tests indicated that cuttings flowed smoothly through the tool and no interruption to mud pulse telemetry was observed. Wells with narrow margins between pore and fracture pressure can benefit from this tool as the operational window is expanded. As the tool is still in undergoing development and testing, further improvements are possible.

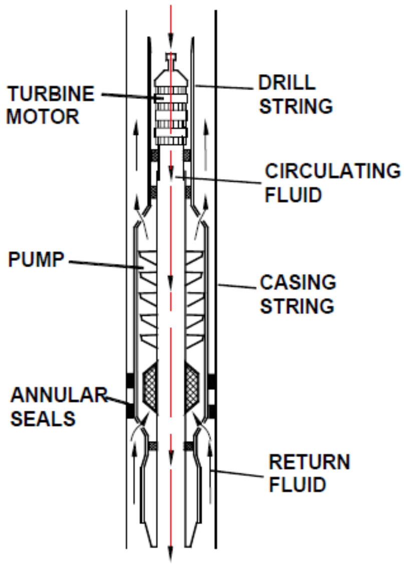

Figure 16 – Schematic of the ECDRT**[25]**.

3.5.4 Pressure relief valves

To prevent overpressure incidents in the flowlines, there should be pressure relief valves installed that automatically triggers when encountering a certain pressure. These can be made to automatically reset when the pressure drops below the set-point. The relief valve upstream of the choke manifold can be controlled automatically by the choke control software, continuously updating the set-point pressure. This has already been done on the Kvitebjørn field in the North Sea[**17**].

3.5.5 Continuous Circulation Valve (CCV)

A valve has been developed that enables continuous circulation even during connections. The 3-way valve is installed on top of each stand of drill pipe. It has a sideport that can be connected to a hose to maintain circulation during connections. It can either be open at top and closed at the side inlet or closed at top and open at the side inlet. By keeping a constant circulation, the pressure fluctuations down hole are minimized[**26**].

3.5.6 Coriolis flowmeter

A coriolis flowmeter can measure mass flow, volumetric flow, density and temperature. Drilling fluids that include cuttings create problems for other flowmeters, but the coriolis flowmeter can handle it. Used in combination with a control system, the coriolis flowmeter can detect mud losses of less than 0.5 bbl. By oscillating a flow tube and measuring the time it takes to complete one oscillation, the coriolis flowmeter can measure density quickly and accurately. A coriolis flowmeter is shown in Figure 17.

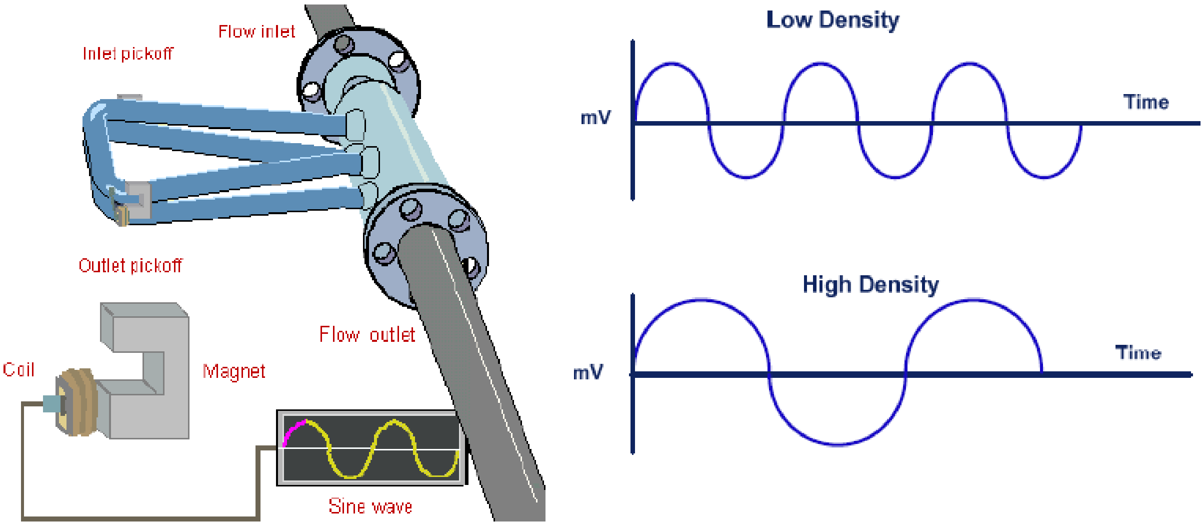

Figure 17 – Coriolis flowmeter with oscillation period**[18]**.

3.5.7 Accuracy

As a system becomes more automated, more instrumentation is added and the complexity increases. Less human intervention demands higher reliability from sensors and measurements. The accuracy of the choke control depends on the accuracy of the hydraulic model. In any computer simulation, poor input equals poor output. It is vital that measurements that are used as input values in the hydraulic model are as accurate as possible. The pump rate is an important parameter and is often given in strokes per minute (SPM) or revolutions per minute (RPM). For low flowrates these measurements can be inaccurate, so a mass flowmeter should be located upstream of the rig pumps to ensure accuracy. The mud density is another critical parameter which can give big errors if measured incorrectly.

3.5.8 Human competency

All of the above equipment and technology is useless without humans that can operate it. As the equipment complexity increases, so does the need for proper training. Increased automation can reduce the risk of human error, but only to a certain degree. Real time decisions still need to be taken. In HPHT wells with narrow pressure margins one small mistake can be catastrophic. A highly motivated and skilled rig crew is essential[**17**].

4 What is a kick?

A kick is defined as having an influx of reservoir fluids into the wellbore while drilling. This can occur in two ways. An underbalanced kick is when the pressure of the hydrostatic mud column is lower than the formation pore pressure. An induced kick is when dynamic or transient effects lower the BHP below the pore pressure. Surge and swab are examples of such effects. If a kick is not controlled, it can lead to a blowout which can jeopardize the rig crew and the rig itself.

The maximum kick influx volume that can safely be shut-in and circulated out of the well without breaking down the formation at the open hole weak point is defined as the kick tolerance. The kick tolerance is primarily a function of well design.

When encountering a kick in a conventional drilling operation, the pump is shut down, rotation is stopped, and the BOP's are closed. Depending on the circulation method, the mud in the annulus along with the influx is circulated through the rig choke, often with a heavier mud weight and a slower pump rate. The slower pump rate is used to decrease the annular friction pressure. After the fluid passes through the choke, it enters the mud gas separator (MGS) and finally the mud pits.

The influx will not stop until the wellbore pressure at the point of influx is equal to the formation pressure or pore pressure. This gives:

$$BHP = P_P = SIDPP + P_{HDP} = SICP + P_{HAN} + P_{HKICK} \qquad \text{(Eq. 6)}$$

Where:

P_P = Pore pressure

SIDPP = Shut-in drillpipe pressure

SICP = Shut-in casing pressure

P_{HDP} = Hydrostatic pressure of mudcolumn in drillpipe

P_{HAN} = Hydrostatic pressure of mudcolumn in annulus

P_{HKICK} = Hydrostatic pressure of kickcolumn in annulus

While MPD does not invite influx of hydrocarbons to the surface as UBD does, it is better equipped to deal with such influxes than conventional drilling. A small influx can be safely diverted via the RCD to the MPD choke manifold. Here it can pass through the MGS and finally the mud pits. This procedure can be done without shutting down the pump or closing the BOP, which saves considerable rig time. This is all possible because MPD can detect kicks earlier than most conventional systems.

4.1 Kick indicators

Indications of influx or kick warnings include:

- Drilling break
- Increase in flow rate
- Decrease in circulating pressure
- Increase in pump rate
- Increase in pit volume (also known as pit gain)
- Gas cut mud
- Increase in torque, drag and fill
- Hole taking less mud than calculated
- Well flows with pumps off

- Decrease in BHP

A drilling break is defined as a sudden change in ROP when drilling with constant parameters. This may indicate a kick and for safety reasons the drilling is halted and the well is checked for flow to verify the kick. This may give the kick additional time to grow in size. Some HPHT-fields do not use flowchecking for this reason. Flow measurements give the quickest indication of a kick.

When an influx occurs during drilling with SOBM, the influx gas will go into solution and migrate upwards since it has a lower density. Depending on the kick intensity, the density of the mudcolumn might decrease which in turn decreases the BHP. If an APWD tool is used, it can measure the BHP and detect this pressure decrease. For floating drilling rigs, rig heave represents a problem for detecting kicks. The heave along with the compensation mechanism in the telescopic riser joint create fluctuations in returned mud flow. This makes it harder to distinguish genuine influx situations from normal situations when reading the flowrate.

The above kick indicators all apply for conventional drilling. For MPD the closed circulation system and the increased ability to keep a constant BHP facilitate detection of very small pressure fluctuations. The primary indicator on Kristin is choke pressure. If this increases or decreases within a certain predefined limit (5 bars on the Kristin field), a kick or a lost circulation event might be in progress. The secondary indicator is to compare the flowrate change in against the flowrate change out. In situations where the conventional drilling system acts as a backup to the MPD system, the traditional kick indicators mentioned above for the conventional system also apply for the MPD system.

4.2 Fingerprinting

To be able to determine when an actual influx is occurring during conventional drilling, it is important to have data and measurements for normal changes in down hole pressures and surface mud volumes for comparison. The process of measuring and documenting this is called fingerprinting. The data recorded during any given operation is the fingerprint for the next time the same operation is performed. Examples of fingerprints taken before drilling the 8.5” section:

- Surge and swab pressures when breaking circulation
- Mud compression factor
- Drill string rotational effects on ECD
- Rig pitch, heave and roll impact on instrument readings
- Response time of pressure transmission from choke gauge to drill pipe gauge
- Mud expansion due to temperature effects
- Flowback during connections and when shutting off pumps.
- Pressure build-up during shut-in
- Background gas readings

By comparing the suspected influx to the fingerprints one can determine quickly and accurately if the influx is indeed an actual influx[**27**].

4.3 Shut-in procedures

4.3.1 Hard shut-in procedure

During a hard shut-in, the pumps are stopped and the annulus is checked for flow for maximum 15 minutes. If there is flow in annulus, the well is shut in by closing the annular BOP while the rig choke is closed. This produces a water hammering effect which gives a pressure spike downhole. In narrow margins the bottomhole pressure must be kept relatively constant so this pressure spike is unwanted. The hard shut-in method shall be used on the Kristin field, but without the flowcheck. To still be able to determine if there is an influx, fingerprints are used[**27**].

4.3.2 Soft shut-in procedure

The soft shut-in procedure is similar to the hard shut-in, but when closing the annular BOP, the choke is first opened and then gradually closed after the BOP has been closed. This should reduce the pressure spike, but can also result in more influx since the choke is kept open for a certain period of time. The added influx volume will increase the shut-in pressure[**28**].

4.3.3 MPD shut-in procedures

Carlsen *et al*.[**29**] describe the dynamic shut-in procedure (DSI) that can be used for MPD applications with an RCD, an MPD choke manifold, a backpressure pump, and an automatic coordinated control system. When an influx occurs in the wellbore, the flowrate through the choke increases. This increases the frictional pressure over the choke which again increases the BHP. The automatic control system tries to keep the BHP constant at the predetermined setpoint by opening the choke. This will cause further influx and further flow through the choke. The control system will now recognize this as a kick and regulate the choke opening to the previous setpoint which will increase the BHP and reduce the influx. If the well still is flowing, the BHP can be increased by increasing the backpressure pumprate or closing the choke further. Carlsen *et al*. performed simulations comparing the DSI to a standard shut-in procedure. During the standard shut-in procedure the pumps are shut down, a flowcheck is performed, and if pit gain is still increasing the choke is closed. Results concluded that less formation influx was received when using the DSI. This can be explained by less variation in BHP during the kick and the subsequent displacement of the kick when using the DSI, since the pumps are never shut off. When performing a flowcheck during the standard shut-in, the kick is allowed more time to grow in size resulting in larger pressures when circulating out. Figure 18 shows the variations in BHP using the DSI versus the standard shut-in procedure and also the circulation of the influx. Notice the sharp pressure drop when turning off the pumps, which will result in more influx from the formation, as illustrated in Figure 19.

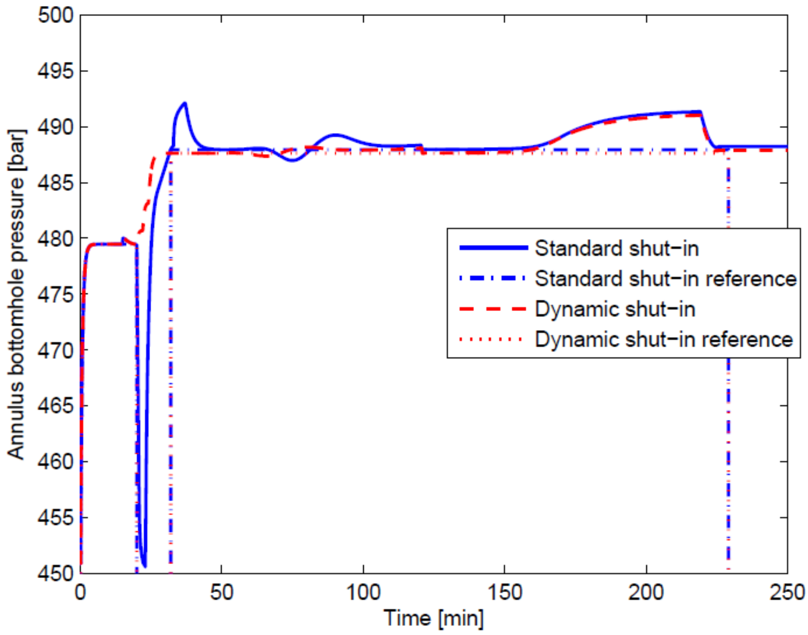

Figure 18 – BHP using the DSI and the standard shut-in method[**29**].

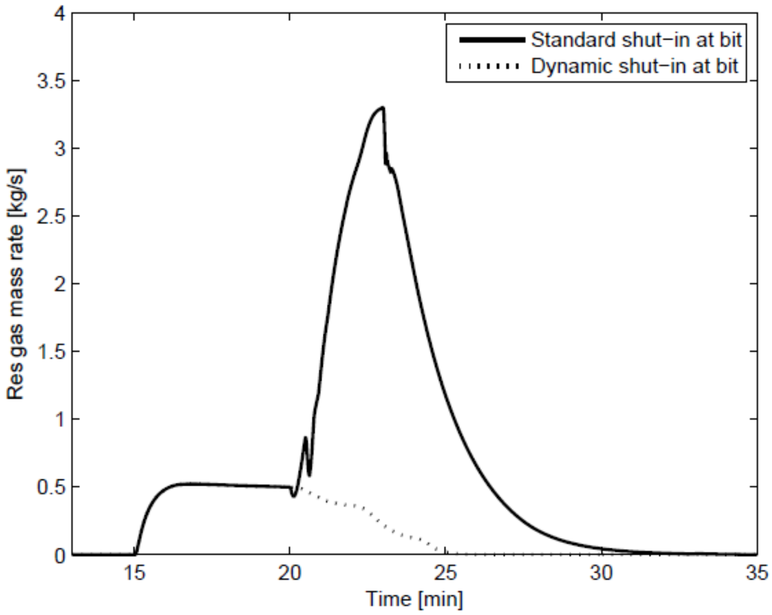

Figure 19 – Reservoir gas mass rate using standard shut-in and the DSI[**29**].

4.4 Thermal expansion

When drilling HPHT wells, significant temperature changes can be observed when going from a circulating state to a non-circulating state. As cold mud is circulated down the drillstring, it will cool the lower part of the well, while hot mud from bottom will heat the upper part of the well. When circulation is stopped, the well temperature will gradually approach the geothermal gradient of the surrounding formation. Now the drilling fluid in the upper part will be cooled and the fluid in the lower part will be heated. If the overall temperature in the fluid is increasing, it will experience thermal expansion. An oil based mud will have a larger thermal expansion than water based mud. A pit gain will be experienced at the surface and if the well is shut in, there will be a pressure build-up. The effect of thermal expansion is important to be aware of and simulations to account for this should be included in the planning and execution phase[**30**].

4.5 Circulation methods

Several different methods exist for circulating out a kick. Only the two chosen methods for the Kristin field will be described here.

The Driller's method (DM) consists of two circulations. The first is performed with the mud already in the well while the second is done with a heavier mud if the first circulation was insufficient to balance the formation pressure. By keeping the circulating drill pipe pressure constant, the BHP is kept constant. The DM requires less calculation than some other methods like the Wait and Weight method. Since circulation is maintained from the start, the DM is the preferred choice in complicated deviated wells, deepwater wells, and wells with hole stability issues[**31**].

If the influx is larger than 4 m^3 bullheading is recommended as the kill method on Kristin. The kill mud is pumped into the annulus at a pressure that often exceeds the fracture pressure of the weakest formation, forcing the fluids out of the wellbore. This can severely damage the reservoir and further aid the development of an underground blowout. Other circumstances where bullheading is recommended on an HPHT well include[**27**]:

- Lost circulation during circulation of kick
- If unacceptable values of H_2S gas is present

- Drill string is plugged or twisted off
- Drill sting is not at TD
- When time is critical, like emergency disconnect during a storm.

Short open hole sections with high permeability are better suited for bullheading than long intervals with low permeability.

4.6 Kill methods

When a kick is shut in and the hole does not hold, an underground cross-flow between reservoirs can occur. In order to restore control of the well, the well may have to be killed. Sandwich kill or dynamic kill can have some success in such circumstances according to Ng[**32**].

To sandwich kill is to bullhead kill fluid from both above and below the loss zone. Dynamic kill is more complex. A relief well is drilled to intersect the flowing well as close as possible to the zone of influx. In order to kill the well, salt water can be pumped at high rates up the annulus of the flowing well, creating sufficient frictional pressures to stop the influx. When control is established with the light fluid, a heavier mud capable of providing static overbalance is pumped into the relief well. Dynamic kill is also highly advantageous in depleted wells with narrow pressure margins, as it can be used without necessarily fracturing the formation. The high-performance equipment required to provide sufficient pump rates and the availability of kill fluid can limit this technique[**33**].

4.7 Well control aspects of MPD

MPD can act as a safety device, because it offers:

- Earlier kick detection
- Better control of BHP during well control events
- Quick reduction of BHP if lost circulation occurs
- Increase of backpressure while the BOP is closing

When drilling with synthetic/oil-based mud (SOBM) a gas kick can be hard to detect. This is because gas is soluble in SOBM but not in water based mud (WBM). As the gas can stay in solution, the kick may not be detected until the gas bubble is close to surface. However, the gas is not instantly dissolved in the mud; it takes some time. During this time interval, SOBM behaves similarly to WBM with regards to kick detection.

When a gas kick is circulated out it will eventually be reduced to atmospheric pressure. The composition, initial temperature, and final temperature of the gas will dictate how much the gas will expand during this process. Approximately 99 percent of the expansion occurs during the last 1000-2000 psi[**34**]. When using a floating drilling rig, the BOP is located subsea. If a kick occurs when using SOBM, the influx might not be detected before the gas breaks out of solution or boils out in the riser. It will then be too late to divert all of the influx from the riser. In conventional drilling, the diverter system which is located under the rotary table should be used to divert the gas away from the rig in an emergency situation. This risks spilling SOBM on the rig floor and maybe to sea, since the slip joint might leak.

Depending on the gas expansion factor, the gas may expand violently close to surface, endangering the rig crew and equipment. Even if the kick is detected and circulated through the rig choke, the mud flow rates might be large enough to wash out the choke and associated equipment. High pressure kicks can reduce the hydrostatic mud column to a degree where the well starts to unload. This means that the mud column in the well is replaced by reservoir fluid. The circulation rate should be as low as possible to help the choke operator to make to correct adjustments.

A drilled kick will boil out shallower than a swabbed kick because it will have a lower gas to oil ratio (GOR). The circulation ratio while drilling is usually higher than the kick rate which leads to the reduced GOR. Swabbing normally occurs when tripping, which is not normally done while circulating, leading to a high GOR. This also means that a gas condensate kick will boil out at a shallower depth than a methane gas kick.

The longer it takes before the well is shut in during a kick, the larger the risk of an uncontrolled blowout. That is why kick detection is so important. In HPHT wells this safety aspect become even more critical as gas expansion factors can be extreme. Thus, MPD would contribute to increased safety and increased well control.

During normal connections air can come into the drillpipe. By introducing air into the mudcolumn, the compressibility of the system can be altered such that the pressure transmission speed to bottom is lowered. This can make it harder to regulate the BHP accurately with the use of backpressure from the MPD choke. By using the CCS system, this effect can be minimized as less air is allowed into the system during connections.

5 About the Kristin field

Sources for this chapter are [**8**], [**17**] and [**41**] unless otherwise stated in the text.

Kristin is a gas condensate field located on Haltenbanken, 190 km offshore Norway in the Norwegian Sea. The formations containing hydrocarbons are Tofte, Ile and Garn. The shale formation Not separates Garn and Ile.

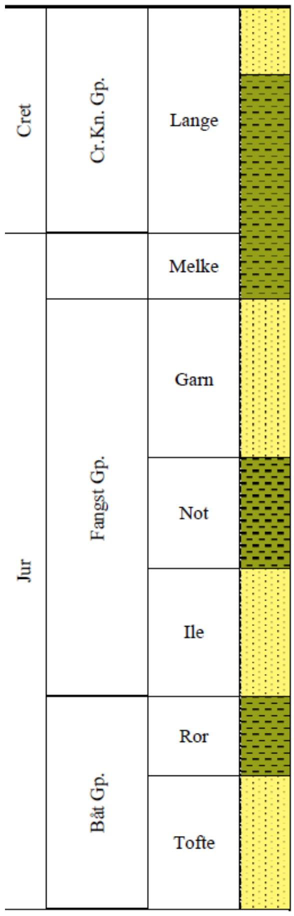

Figure 20 – Geology of the Kristin field (courtesy of StatoilHydro).

With a temperature of 172°C and a shut in wellhead pressure (SIWHP) of 740 bar it is classified as an HPHT field by NORSOK D-010[**42**]. The pore pressure was initially 1.97 SG and the fracture pressure 2.14 SG. As the field was depleted the fracture pressure decreased, resulting in a narrower drilling window. As a result, a CBHP variation of MPD is planned on future 8 ½" sections, which are the most challenging sections with regards to operational window. However, at some point the wells will reach the drillable depletion limit, where the drilling window is too small to continue drilling. Expandable liners can then be used to isolate higher or lower pressure zones, extending the potential length of the well.

Two semi submersible rigs are planned for drilling on Kristin. West Alpha is mostly used to drill the top holes and Scarabeo 5 is used to drill the reservoir sections and complete the wells. Offshore MPD from a floating drilling installation in harsh weather has not been done till date, at least not in an HPHT environment. Kristin is the most extreme field on the Norwegian continental shelf and was also the first subsea HPHT field developed in the world. This provides additional technical challenges that will have to be solved by developing and implementing new technology.

In conventional drilling mode the riser does not experience large pressures since the BOP is located beneath it. The exception is during a shallow gas kick, but the pressure in such an event rarely exceeds 7 bars. The slip joint packer system and the diverter system are the weak points in the riser and are rated from 17 to 34 bars. The riser itself is a very solid structure built to withstand rough weather conditions and heavy tensional loads. By removing the weak pressure points, the full internal pressure capacity of the riser can be utilized for MPD applications. In MPD mode, the riser should be able to handle a continuous surface backpressure of 50 bars during normal operations. In addition, it should be able to function at its highest pressure capacity during an underbalanced situation.

5.1 Riser Pressure Control

In order to use a conventional riser under pressure in harsh offshore environments, a solution for Riser Pressure Control (RPC) had to be developed. The equipment associated with RPC should be able to pass through the rotary table and be as rig independent as possible.

In order to replace the weak point associated with the slip joint packer, a Multi-part Sliding Joint (MPSJ) is being developed. This is used to connect the RCD to the upper flex joint, as seen to the right in Figure 21. Without the MPSJ, rig heave would lead to eccentric motion of the drillstring that would quickly wear out the rubber element in the RCD. The MPSJ centralises drill pipe in RCD and prevents spill from a leaking RCD. If the RCD is removed the MPSJ facilitates return of fluid to the diverter and conventional drilling mode. A modified Lower Marine Riser Package (LMRP) connector or hydraulic connector is used to remotely connect the rest of the RPC equipment to the riser, avoiding hazardous work over the moonpool. The MPSJ and the RPC equipment can be run through the rotary table. The working pressure is now limited to 130 bars by the lower flex joint.

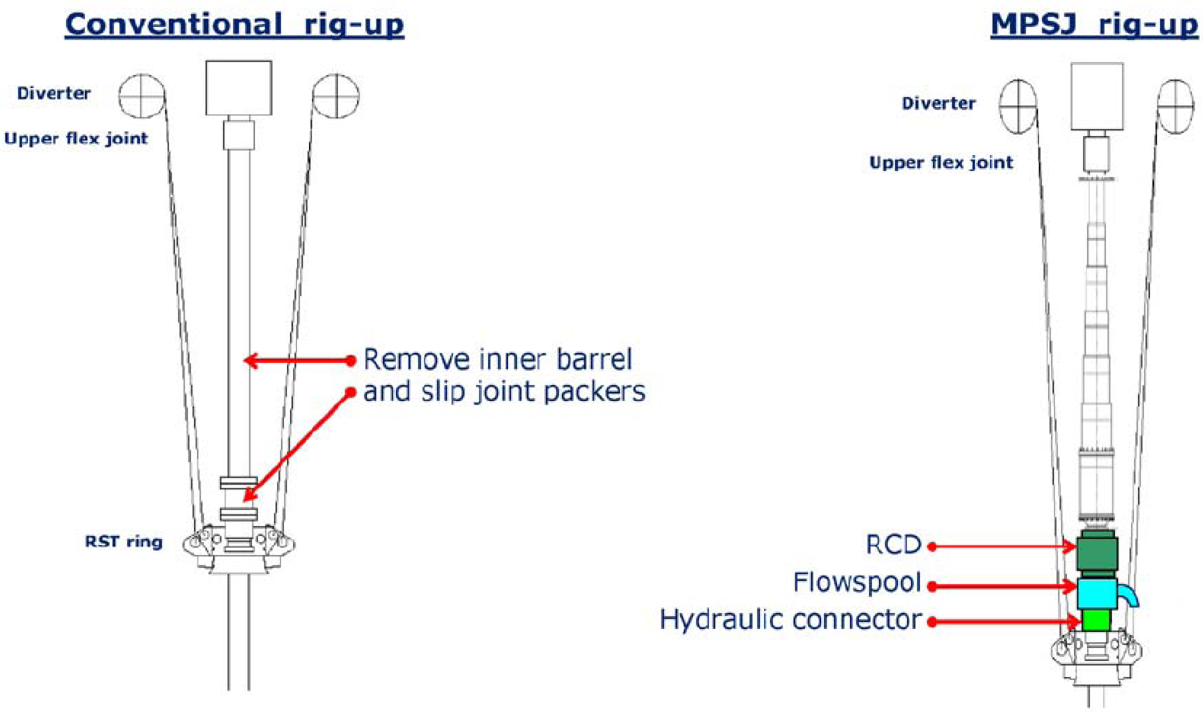

Figure 21 – Comparison of conventional rig-up and MPSJ rig-up**[8]**.

Since the rig used is a semisubmersible, there will be rig heave from the waves. To account for surge and swab effects an APWD tool will be used to monitor the BHP while ECD simulations are continuously run on the rig. The static mud weight on Kristin will always be above initial reservoir pore pressure. Due to this, it was not deemed necessary to route the return mud flow through the MGS.

Two MPD chokes will be run in parallel to allow for redundancy if one is blocked. A block diagram of the equipment can be seen in Figure 22.

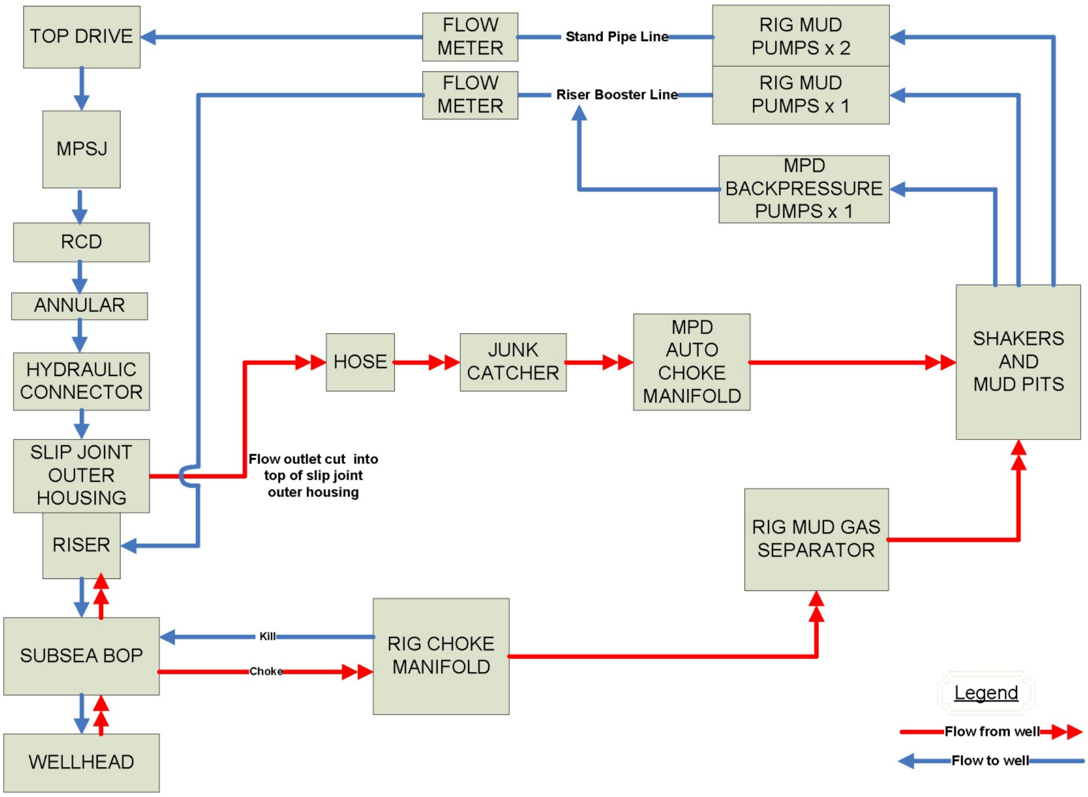

Figure 22 – Kristin MPD Block Diagram**[43]**.

The RCD planned for usage on Kristin is rated to 5000 psi in static conditions and 2500 psi when rotating. The diverter is rated to only 500 psi. The gas expansion factor on Kristin is approximately 305, which means that 1 m^3 of influx at bottomhole will generate 305 m^3 at surface. If the gas from a kick boils out in the riser, this will be a potentially dangerous situation in conventional mode. Since the RCD has a pressure rating ten times higher than the diverter and since MPD uses a closed system, the gas can be diverted in a much safer way in MPD mode. Additionally, since MPD has the potential to detect kicks earlier than conventional, the kick size will be smaller, leading to reduced pressure effects during circulation.

5.2 Reservoir Drilling Fluids

Three different fluids have been used for drilling the reservoir sections on the Kristin development wells:

- Cesium-/potassium formate brine (Cs/K)
- Invert emulsion HPHT oil based mud with Micronized Barite Slurries (MBS)
- Invert emulsion HPHT oil based mud (OBM)

The Cs/K system had several advantages over the oil based fluids. Since it is a brine, gas kicks can be detected sooner because of the low gas solubility. Screen plugging would be reduced because of low solids content. Barite is not used as weight material in brine so sag issues are eliminated. It also has a low viscosity which gives less ECD effects. During drilling however, severe lost circulation, shale washouts, and foaming issues were encountered when using the brine. Foaming led to increased loss and gain which could be misinterpreted as a kick. These factors along with the very high cost associated with the system led to the use of alternative fluids. Experience from the Kvitebjørn field, where a similar fluid system was used on an MPD well, showed that the Cs/K is extremely incompressible. This results in almost instantaneous pressure transmissions downhole when regulating the surface backpressure, which causes unwanted oscillations in BHP. The choke controller needs extra tuning to account for this effect.

Because of the risk related to screen-plugging when using the OBM system, a fluid with micronized barite slurries was used. The MBS fluid provided slightly less ECD than the OBM but plugged bit nozzles were frequently encountered during drilling. In order to change mud weight, the MBS along with the Cs/K fluid had to be weighted with a spike fluid. This spike fluid takes up a larger volume than the barite used to weight the OBM.

The OBM has a higher ECD than the Cs/K which means that the riser margin could not be maintained during drilling. When it became necessary to wait on weather and trip out, the mud weight was changed to include riser margin. Some sag issues were encountered when using this mud, but proper circulation restored the situation. Overall this fluid proved to be the best choice for drilling the reservoir section of deviated HPHT wells on the Kristin field.

Kick detection is more difficult when using a SOBM compared to a WBM. The gas from a kick will dissolve in the oil and dampen the effect of increased flow rate and pit gain seen on surface. However, once detected, small kicks are easier to control in oil based mud since the dissolved gas will limit the pressure increase seen on surface. Very large kicks behave similarly for both SOBM and WBM[**44**].

6 Simulations

6.1 *About the software*

Drillbench© is a drilling software package developed by Scandpower, with different modules for different purposes. The Hydraulics© module was used to compute the expected ECD and fluid density sensitivity analysis. The Pressmod© module was used to give a dynamic temperature model of the drillstring and annulus. It also helped in validating that the input parameters chosen could be used to drill the respective sections. The Kick© module was used to simulate several kick situations for conventional drilling, and the subsequent circulation of the influx. The kick module is a two phase flow simulator which can simulate kick situations, starting with influx and ending with circulation of the influx. Since it is fully time transient, the entire process can be visualized, and interactive actions can be taken at any time. This facilitates simulation of specific procedures like extended shut-in, altering the mud weight and so on. The graphical user interface of the software is easy and intuitive, as illustrated by Figure 23, which shows a simulation in Kick©. It does, however, ignore the effect of cuttings. As described in chapter 1.6.2, cuttings can have a significant effect on ECD. Initially, the kick module was chosen for simulations including both conventional mode and MPD mode. However, it soon became apparent that simulation of MPD mode was not possible with this software so another option needed to be considered. The International Research Institute of Stavanger (IRIS) provided an in-house developed simulator called WemodforMatlab based on the Matlab programming language. This simulator proved to be too complex for the author of this thesis and simulations for MPD could not be done as a result.

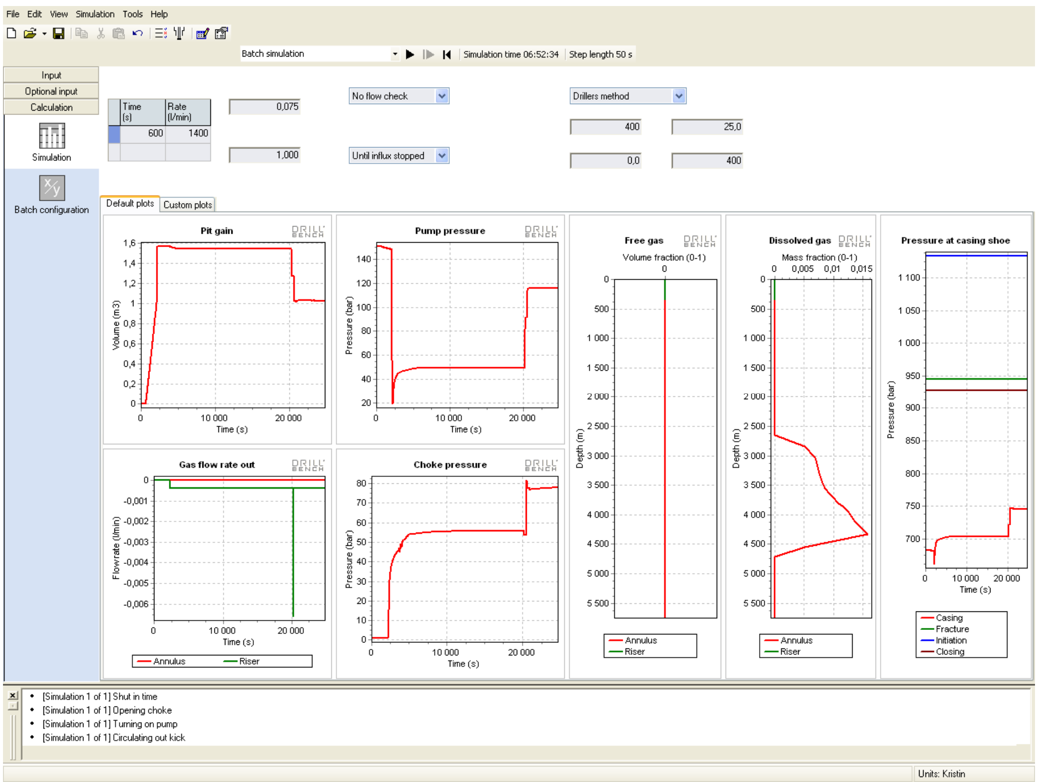

Figure 23 – Graphical user interface of the Kick-module in Drillbench©.

6.2 Base case description

The following simulations are all performed on a development well that was drilled on Kristin in 2008, hereby referred to as Well A. The wellpath is shown in Figure 24. The reservoirs Garn and Ile are separated by a shale formation called Not (Figure 20). Ile has better permeability than Garn and will experience a more rapid pressure decline. In addition, the Ile formation is vertically heterogeneous, which results in variable depletion depending on sand layer. The worst case scenario is that the initial pore pressure in Ile is heavily depleted while Garn remains undepleted. The fracture pressure would also be depleted in Ile, with an expected depletion constant of 0.55. This means for 1 bar depletion in pore pressure in Ile, the fracture pressure would be depleted 0.55 bar. When drilling into Ile, the mud weight needs to be reduced to avoid fracturing the formation. This reduction in mud weight might lead to an influx from undepleted zones in Garn; in other words a kick situation. This is the main scenario investigated in this thesis.

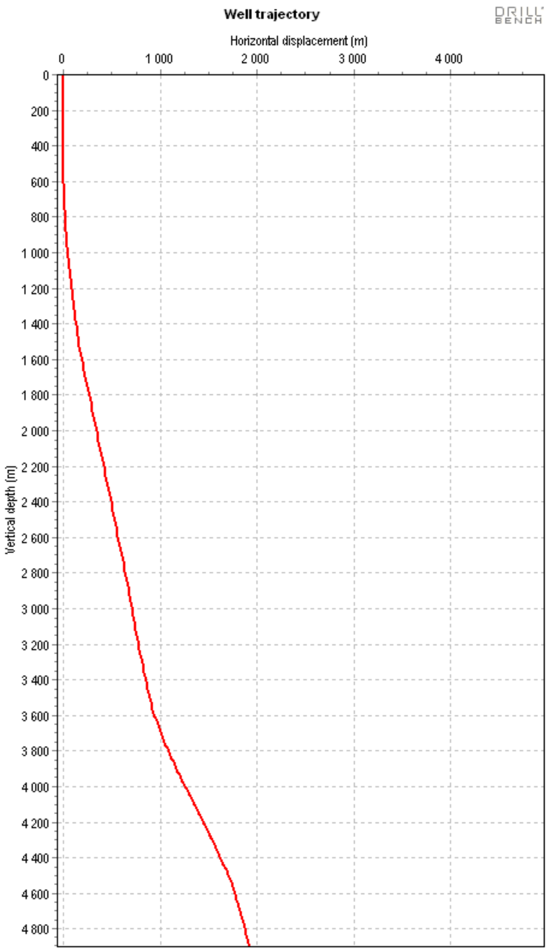

Figure 24 – 2D wellpath of Well A.

6.3 Scenario

Ile is depleted by 160 bar, while Garn remains undepleted. The bit is at the top of Ile and drilling is performed conventionally (without MPD). These simulations will help in concluding if similar wells can be drilled conventionally on Kristin with a 160 bar depletion or if MPD should be considered.

In Figure 25 below, the pore and fracture pressure gradients are plotted. The pore pressure values are actual measurements from Well A, taken from the StatoilHydro DBR (Daily Drilling Report) Database and corrected for depletion. The fracture gradient is a prediction taken from an offset well in the same area, corrected for depletion in the Ile formation. The figure shows a narrow margin between pore pressure in Garn and fracture pressure in the depleted Ile formation, illustrated by a blue rectangle. When a kick occurs, the well is normally shut in until the static well pressure equalizes the pressure from the influx zone and the influx stops. In order to stop the influx, the wellbore pressure must balance the highest pore pressure in Garn, which is 894 bar or 1.954 SG at 4678 mTVD.

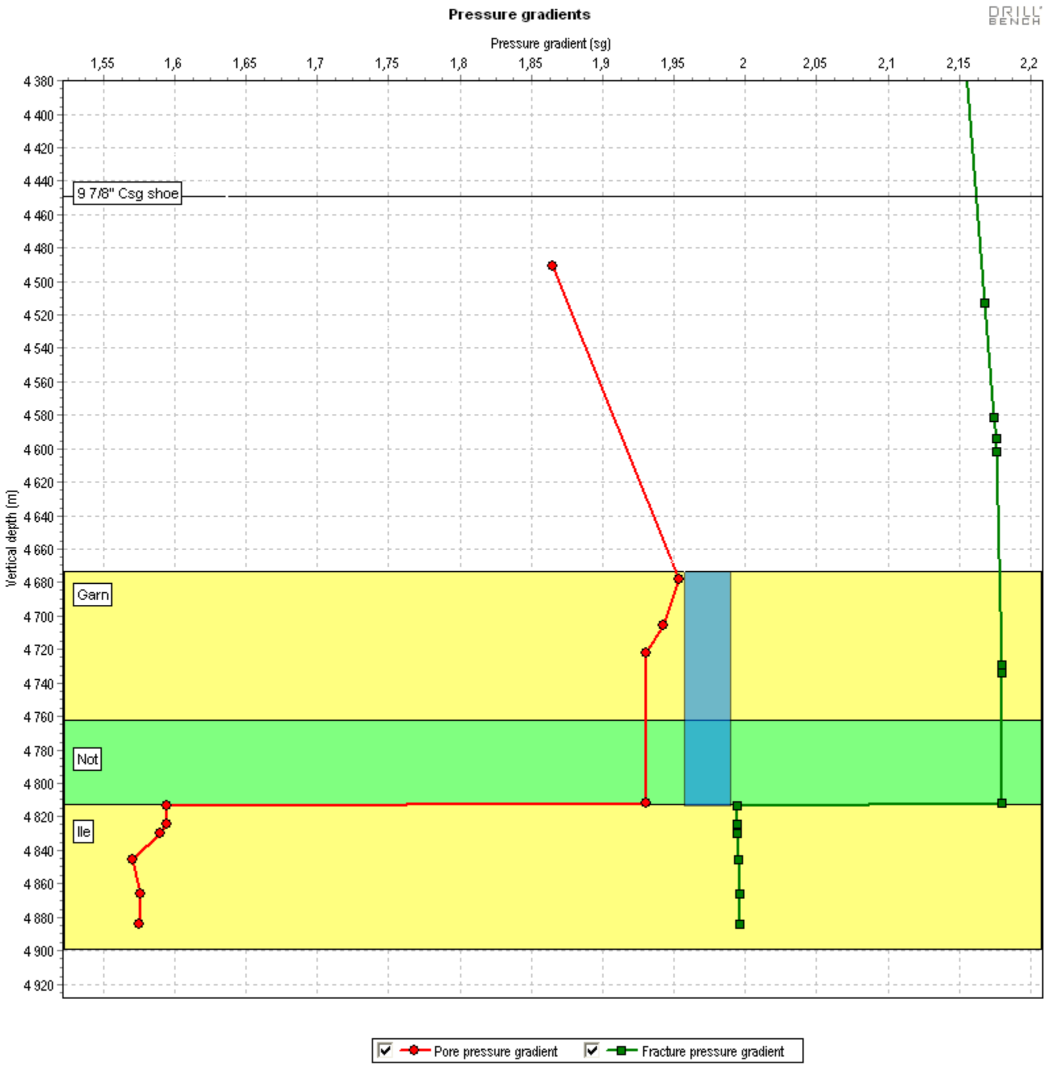

Figure 25 – Pore and fracture pressure gradients corrected for 160 bar depletion in Ile.

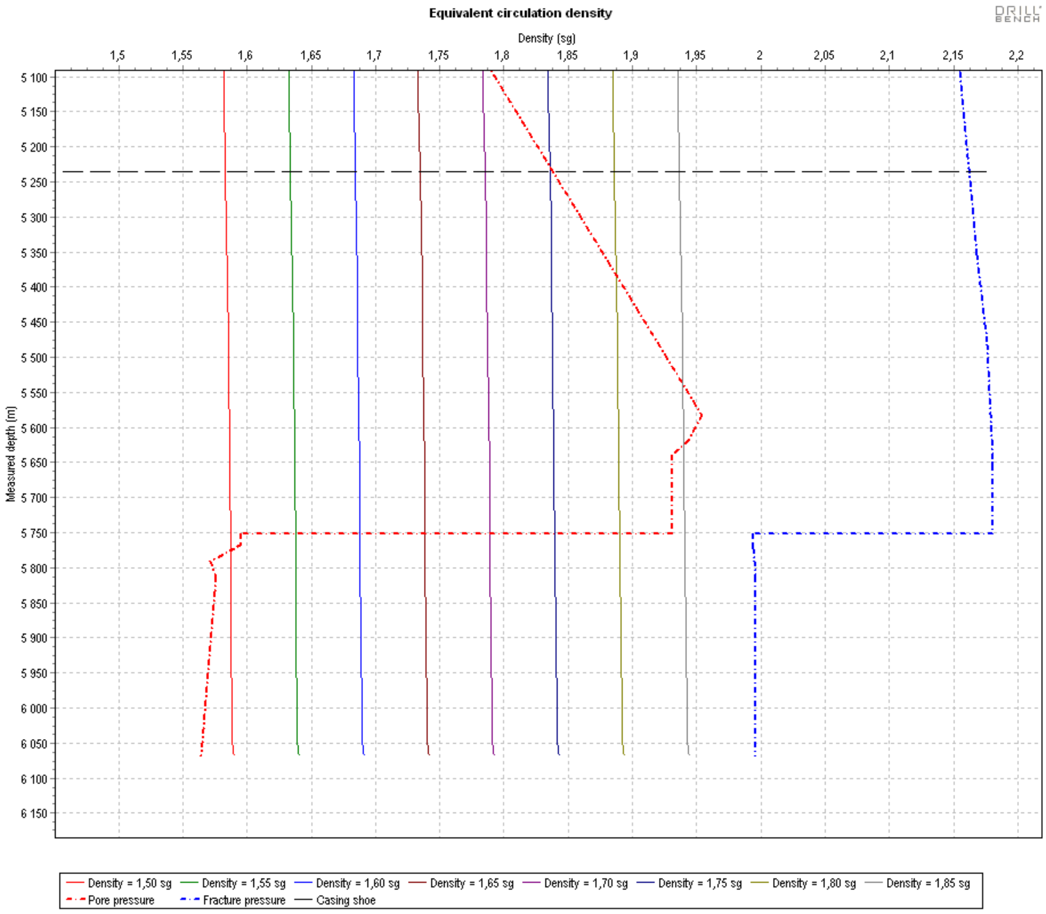

Figure 26 – Mud weight sensitivity analysis plot generated with Hydraulics©.

A mud weight sensitivity analysis was performed in Hydraulics© to evaluate what mud weights to use for simulating drilling of the Ile formation. The plot in Figure 26 illustrates the mud window available for drilling the Ile formation, which starts at 5752 mMd. A mud weight higher than 1.85 SG will provide overbalance versus the influx when circulating, which means there will not be any kick during the simulations. However, operating with a mud weight this close to the fracture gradient is not recommended. Disregarding the pore pressures above Ile, a mud weight lower than 1.50 SG will not be able to generate enough ECD to maintain overbalance in the Ile formation, where the lowest pore pressure is 1.571 SG. This conclusion is further strengthened by using Pressmod© to generate a bottomhole ECD plot while drilling through Ile with a 1.50 SG mud weight, which is shown in Figure 27. This plot only considers the bottomhole ECD and ignores the massive underbalance which occurs in Garn. As seen from the plot, the well is initially at underbalance and slightly overbalanced after 10000 seconds of drilling, which matches well with the plot in Figure 26. This figure also illustrates the problem with unwanted pressure fluctuations during connections. The temporary loss of ECD during a connection leads to a pressure drop, which may lead the well into underbalance. By using MPD one can reduce such pressure fluctuations.

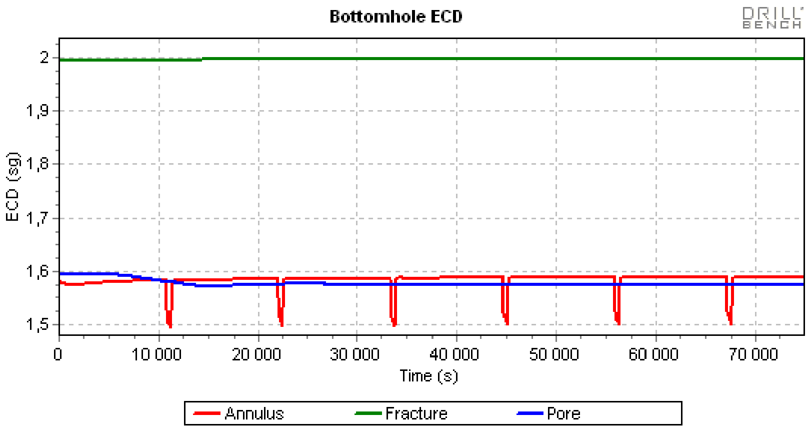

Figure 27 – Bottomhole ECD plot for drilling conventionally through Ile with 1.50 SG mud weight.

Pressmod© was used to generate a temperature profile while drilling through the Ile formation which is shown in Figure 28. The mud weight used was 1.50 SG. The drilling parameters are listed in the Appendix. The rapid change in temperature seen at 400 meters on the annulus line (red line) can be explained by the riser booster rate. Raising the mud weight did not alter the results significantly, so this temperature profile was used for all calculations in Kick.

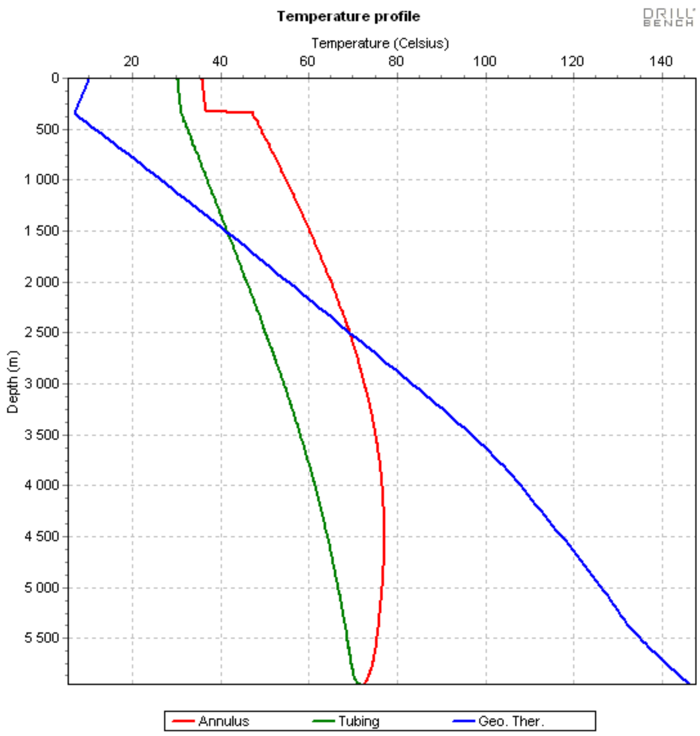

Figure 28 – Temperature profile while drilling through Ile.

6.3.1 Simulation Setup

The following simulations were all done in Kick. Due to the large uncertainty in permeability in the Garn formation, simulations were done with the maximum and minimum values of both permeability and porosity, as shown in Table 1. The term “best case” refers to the values that will generate the least influx, while “worst case” refers to the opposite.

Table 1 - Permeability and porosity for best and worst case scenario.

	Best case	*Worst case*
Permeabiliy [mD]	0,13	2,2
Porosity	0,12	0,15

The oil industry in general is conservative, so the worst case scenario is normally used for design purposes. Sometimes however, it can also be of interest to see what happens in the best case. The best case in this context is when the Garn formation has the lowest permeability and porosity, which will give the lowest influx. The change in porosity from worst case to best case is minor, and so is the impact. But the change in permeability is expected to have a significant effect, based on early simulations.

Inaccurate results occurred when simulating in batch mode, so interactive mode was chosen for simulations. This meant that the Driller’s method of circulating could not be accurately simulated as it consists of two circulations, as described in chapter 4.5. The second circulation, kill mud circulation, was not simulated. Based on test simulations with Driller’s method, the primary circulation is the critical one which generates highest pressures, so avoiding the secondary circulation should not have much impact on the final results. This can be seen in Figure 29.

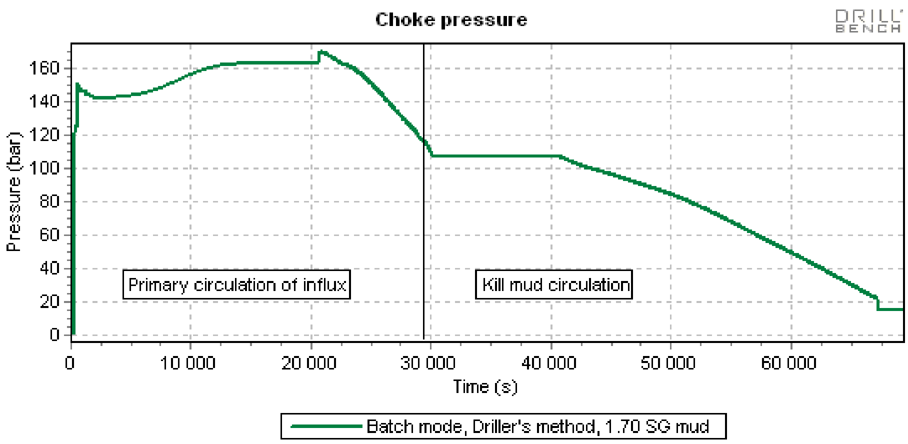

Figure 29 – Typical choke pressure profile while circulating out kick in batch mode.

In order to provide simulation consistency when circulating out the influx, constant bottomhole pressure mode was used. In this mode, the rig choke is regulated automatically to provide a constant BHP. A dynamic safety margin of 25 bars was used in the simulations.

Mud weight and pit alarm were varied in the simulations to generate a larger set of data. An increase in pit gain does not necessarily mean that a kick is in progress; it could be flowback from the reservoir or thermal expansion effects. In reality, background gas fingerprints are used in addition to the pit alarm for kick detection. The minimum pit alarm was set to 1 m^3. This is considered realistic, even though background gas readings are not used in these simulations. The BOP duration of closure time was originally set to 45 seconds which is the time it takes for the preventers on Scarabeo 5 to fully close from an open position. When the kick is detected and the pit alarm is reached, it takes some time before the operator decides to shut down the pump. Likewise, it takes some time for the operator to decide to close the BOP. To account for these human delay factors, an additional time of 45 + 45 seconds was added to the BOP closure time. The new BOP closure time was then 135 seconds.

The following steps were performed for each simulation in interactive mode:

1. Run simulation until pit alarm level is reached. The kick has been detected and the simulation is automatically stopped.
2. Turn off pump and continue simulation until “Pump is off” message is displayed. Simulation automatically stops.
3. Close BOP and continue simulation until “BOP is closed” message is displayed. Simulation automatically stops.
4. Continue simulation until BHP equals pore pressure and the influx has stopped.
5. Open choke and turn on pump. Circulate out influx with 300 lpm. Simulation ends when gas is out.

Special consideration was made to ensure that all input data used in the simulations were as close as possible to the drilled Well A. Such data included wellpath, wellbore and string geometry, surface equipment, mud rheology, drilling parameters, formation data, influx composition, well temperature data and more. Details about the input and simulation parameters can be found in the Appendix.

6.4 Simulation results - Best case

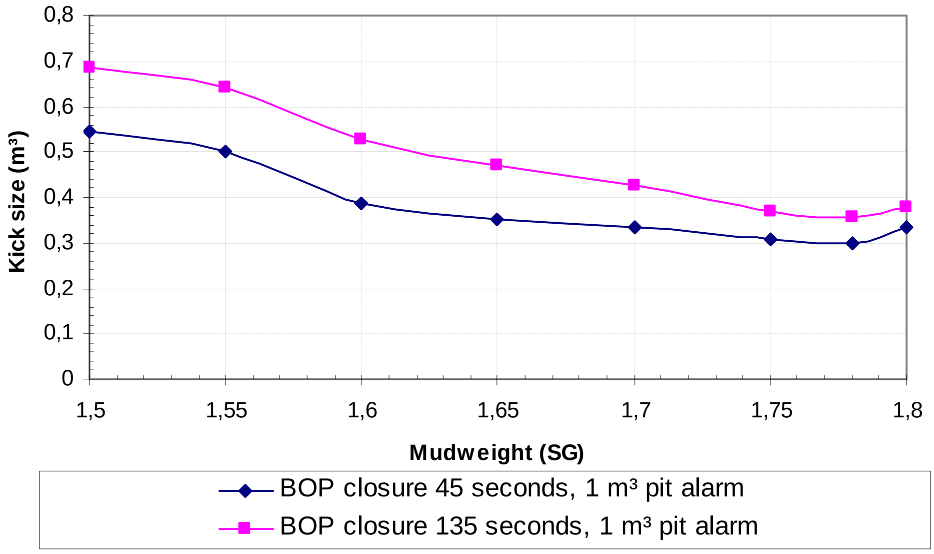

Figure 30 – Kick size vs. mud weight for various durations of BOP closure, best case.

A longer BOP closure time will, of course, provide more influx. The following simulations all use a BOP closure time of 135 seconds, unless stated otherwise. From Figure 30 above, the human delay factor can be seen as the difference between the two curves. The difference seems to decrease with increasing mud weight. The kick size also decreases with increasing mud weight. From this one can argue that the rate of influx is proportional to the underbalance. A large underbalance will give a large influx. When the mud weight approaches 1.8 SG, the underbalance is so slight that there hardly is any influx. For 1.85 SG mud weight, the kick was not detected. This may not be obvious from the above plot, but can be better understood when one considers the kick detection time, as shown in Figure 31.

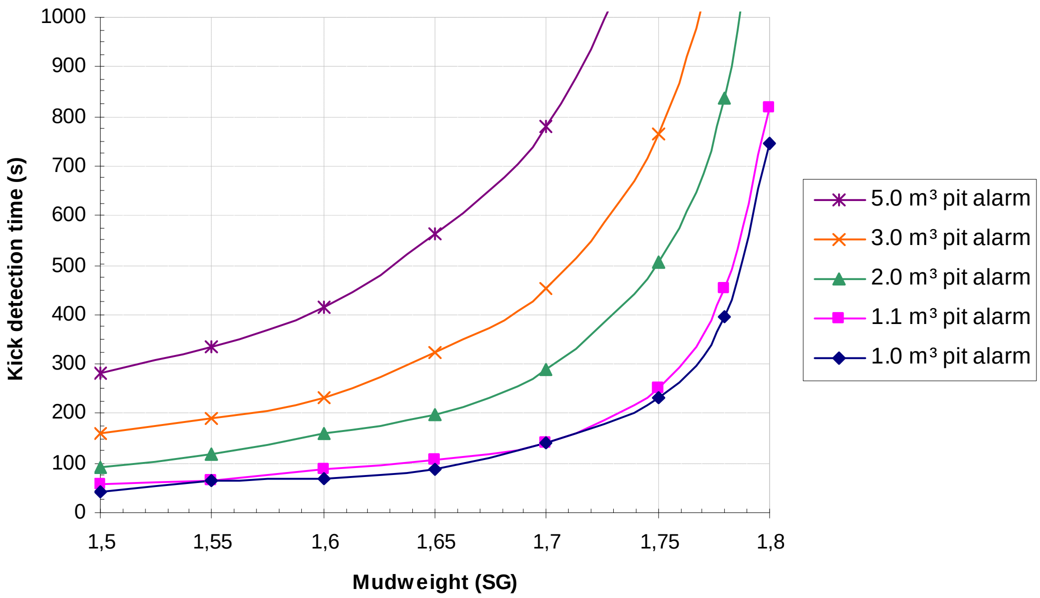

Figure 31 – Kick detection time vs. mud weight for various pit alarm levels, best case.

The kick detection time increases dramatically as the mud weight increases, since the underbalance becomes smaller. A smaller underbalance would give a smaller rate of influx. Another factor to consider is gas solubility. The gas needs some time to dissolve, and when it is dissolved it travels slower up the well, taking longer time to activate the pit alarm. These factors contribute to the exponential shape of the curves. Figure 31 also shows that increasing the pit alarm level would increase the kick detection time. The explanation for this is obvious, as a larger volume would take longer time to fill up.

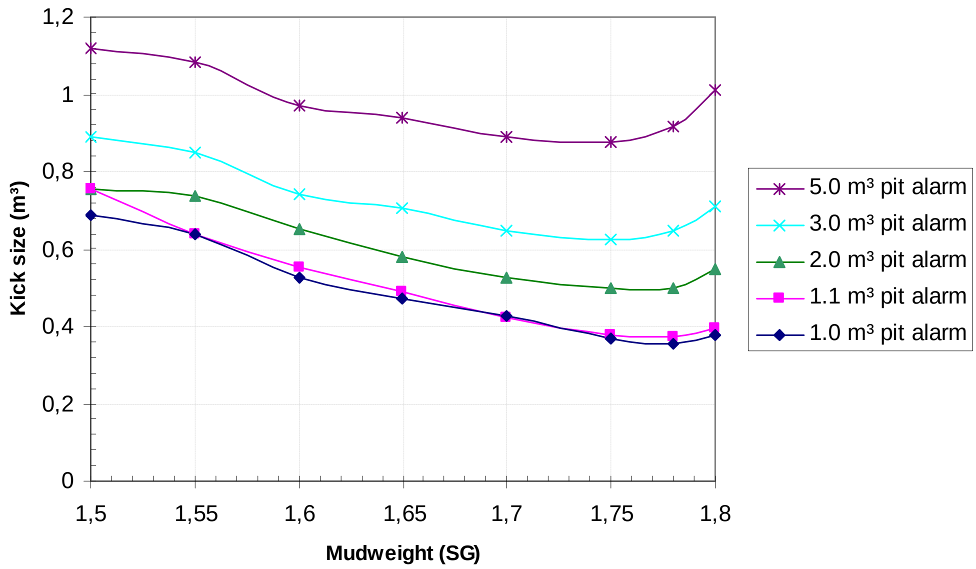

Figure 32 – Kick size vs. mud weight for various pit alarm levels, best case.

Kick size is obviously dependent on the pit alarm level, as it dictates how big influx one should take before the well is shut in. From Figure 32 above one can conclude that kick size increases with increasing pit alarm. The pit alarm is 1 m^3 for the rig used on Kristin, Scarabeo 5. The pit alarm level was varied in the simulations because it was the simplest way to increase the kick size.

None of the simulations for the best case fractured the formation.

6.5 *Simulation results – Worst Case*

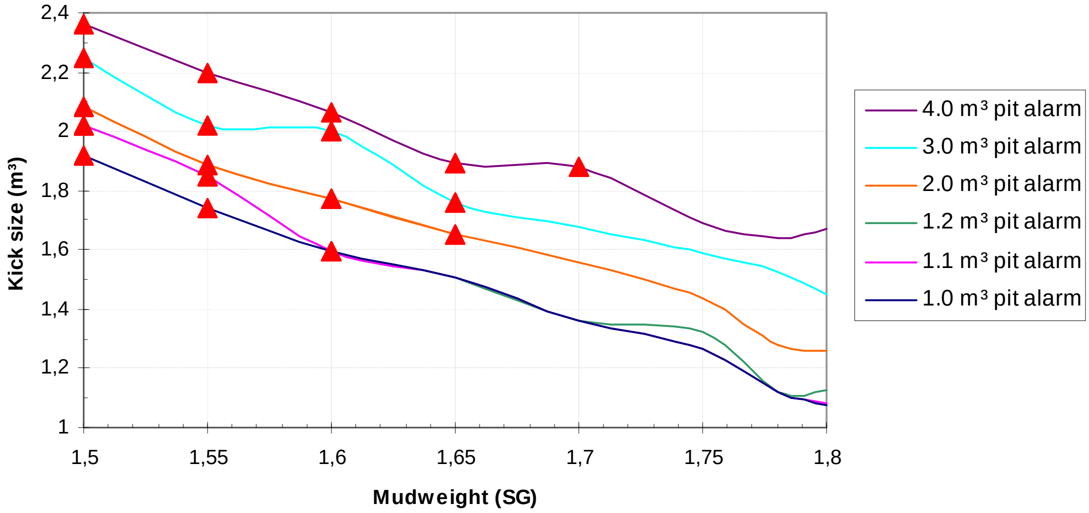

Figure 33 – Kick size vs. mud weight for various pit alarm levels, worst case.

Consider Figure 33, where the red triangles represent values that fractured the formation. According to the simulations, the well also fractured for 1.75 SG mud weight at a pit alarm of 3 and 4 m^3. However, this was confirmed to be a bug in the software, as it did not fracture for 1.73 SG, and those results are not included in the above plot.

The well generally fractures for low mud weights and high kick sizes. The kick tolerance is defined as the influx size the well can circulate out without fracturing. This is dependant on the mud weight used and the degree of underbalance. Due to accuracy limitations of the software, the precise kick tolerance for the various mud weights used could not be found. The results from the above figure should therefore be considered to be rough estimates rather than true values for kick tolerance.

Since the rig used for drilling on Kristin, Scarabeo 5, has a pit alarm of 1 m^3, the focus is on this curve. A mud weight of 1.65 SG and higher can be used in this scenario for conventional drilling. The kick sizes experienced for this curve can be safely handled by a conventional setup. For mud weights over 1.85 SG, the kick will not be detected. However, because of the low fracture gradient, it is not recommended to operate with such high mud weights.

As previously mentioned, these simulations represent the worst case where the entire Garn formation is undepleted. A more realistic scenario is that only some stringers in Garn are undepleted, which would result in a smaller total influx area. This would result in less total influx and less chance of fracturing the formation during shut-in.

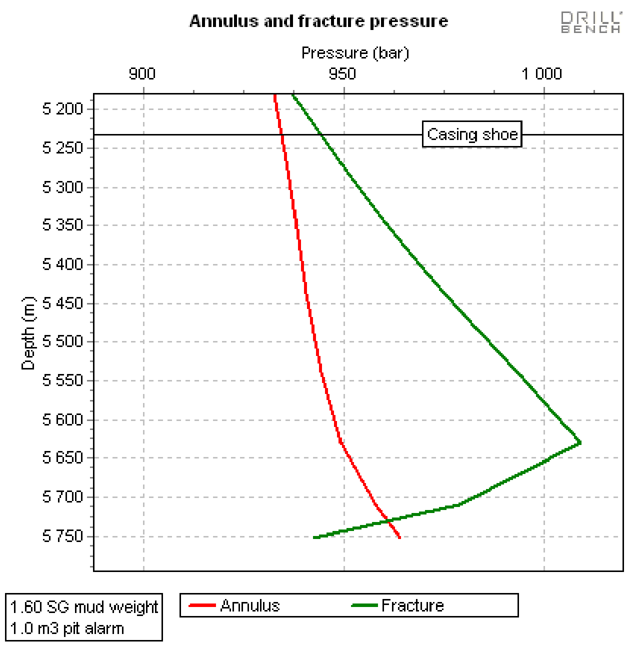

Figure 34 – Annulus and fracture pressure vs. depth, worst case.

Figure 34 shows annulus and fracture pressure plotted against measured depth. For this mud weight (1.60 SG) the well fractures at the bottom of the hole when initiating circulation of the kick. For lower mud weights, the well fractures when shutting in the well, but always at the same place, since the weakest fracture pressure in the well is located at the bottom.

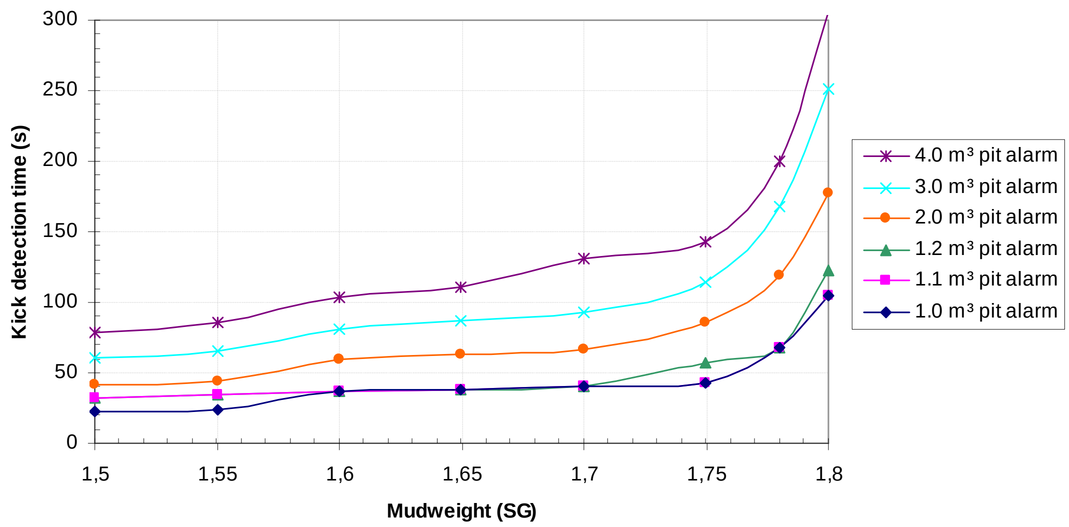

Figure 35 – Kick detection time vs. mud weight for various pit alarm levels, worst case.

If one compares Figure 35 with Figure 31, the trends are similar. The main difference is that the kick detection times are generally lower compared to the best case scenario.

Figure 36 shows the gas flow rates when circulating out the influxes for various pit alarm levels. The behaviour does not seem to be linear, but as expected, the gas flow rate increases with increasing pit alarm level. The highest gas rate, 2.475 MMscf/d, is achieved at the lowest mud weight (1.5 SG) or the maximum underbalance. This amount should not pose any problems for the mud gas separator installed on Scarabeo 5, which can handle a gas rate of 28.24 MMscf/d[**27**].

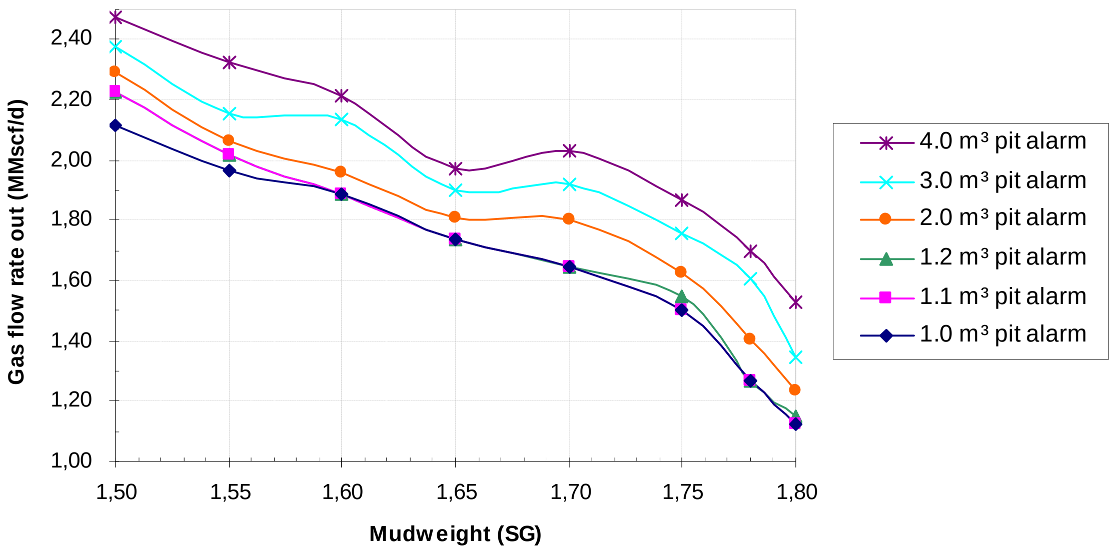

Figure 36 – Gas flow rate out vs. mud weight for various pit alarm levels, worst case.

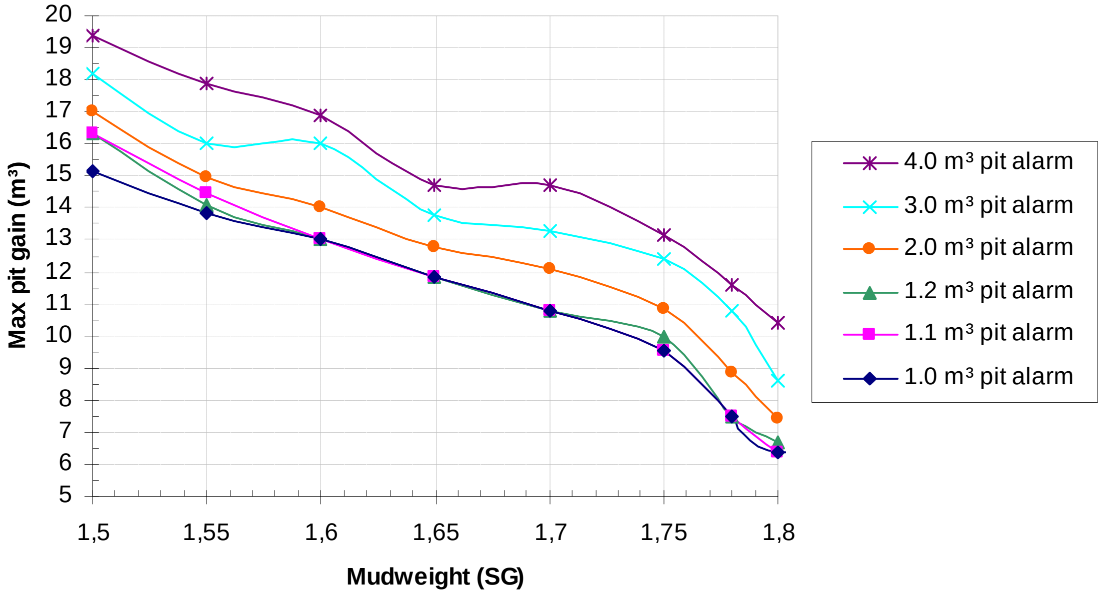

Figure 37 – Max pit gain vs. mud weight for various pit alarm levels, worst case.

Considering Figure 37, the pit gain increases with increasing underbalance, as expected. The plot is very similar to the previous plot, Figure 36.

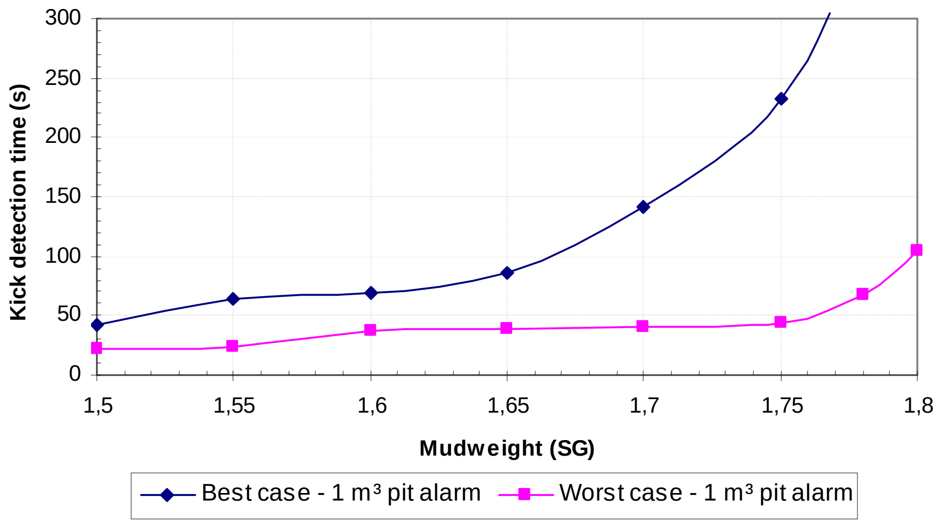

Figure 38 – Comparison of kick detection time vs. mud weight for best and worst case.

Figure 38 shows the difference in kick detection time between the best and worst case scenario. Since the worst case scenario has a higher permeability and porosity, the kick rate from the reservoir will be higher and it will reach the pit alarm sooner than the best case scenario. This difference becomes more pronounced with less underbalance.

When using constant BHP mode in interactive mode, the choke pressure while circulating the kick is computed automatically by the simulator to a keep a constant BHP. The BHP will equal the BHP immediately before starting the circulation of the kick, plus the dynamic safety margin of 25 bar. This can be seen on Figure 39, which shows the pressure profiles when shutting in and circulating a kick in interactive mode (1.7 SG mud weight).

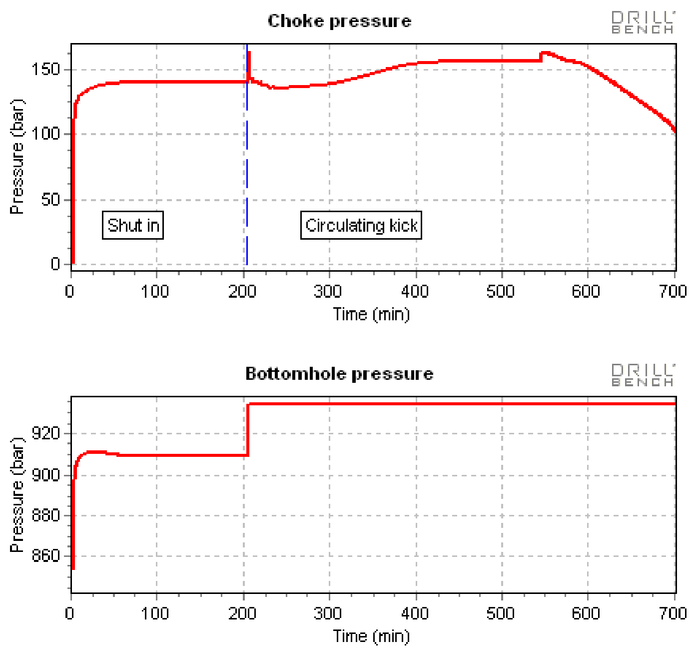

Figure 39 – BHP and choke pressure while circulating out kick, 1 m^3 pit alarm, worst case.

Figure 40 shows choke pressure profiles for three different mud weights. One can see that for the red curve, the largest pressure occurs immediately when starting to circulate the kick. For the blue curve, the largest pressure occurs around 30 000 seconds, which is when the gas bubble reaches the choke. Since the blue curve has a lower mud weight, it experiences a larger underbalance and a greater kick size needs to be circulated out. This results in increased choke pressure.

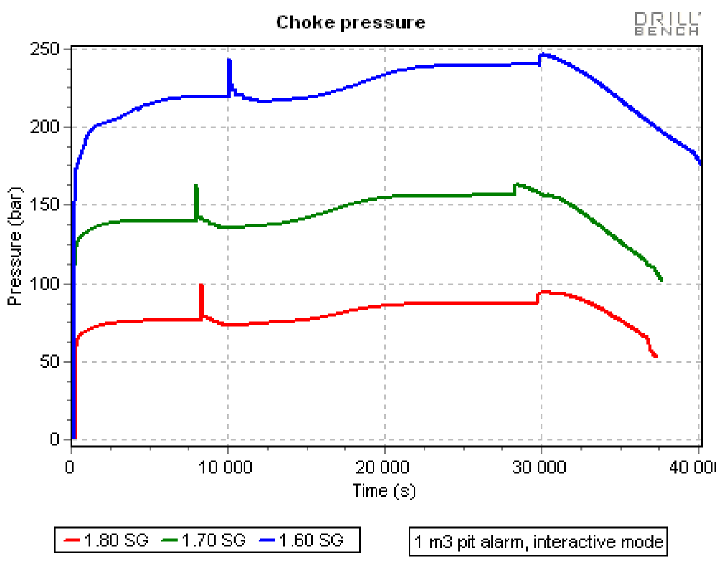

Figure 40 – Choke pressures while circulating out kick for different mud weights, worst case.

According to Ng[**32**], WBM has very different choke pressure profiles compared to OBM. WBM would experience the largest pressure when the gas reaches the choke, while an OBM would experience the largest pressure when starting the kick circulation. As Figure 40 shows, an OBM can experience both scenarios, based on the severity of the kick. This plot shows the importance of performing well control simulations when planning to drill a well. The choke pressures are high because of the underbalance. Larger underbalance will lead to larger choke pressures.

Figure 41 shows a simulation of the Driller's method circulation for 1 m^3 pit alarm. A choke pressure drop after about 20 000 seconds indicates that the influx has reached the choke. The free gas curve shows that the gas boils out just below the BOP before reaching the choke line.

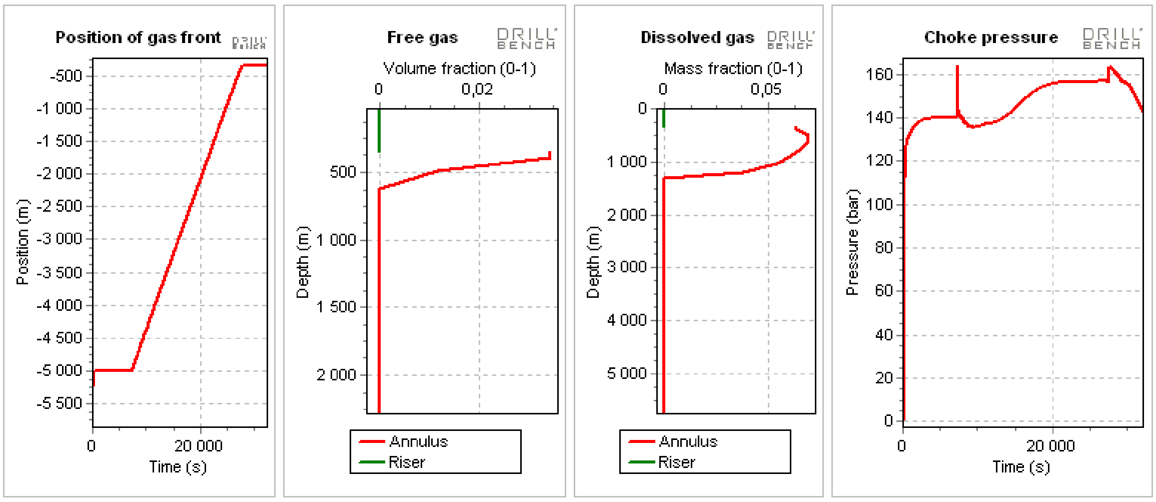

Figure 41 - Surface boil out point, 1.70 SG mud weight (Interactive mode).

If the duration of BOP closure is reduced from 135 seconds (which includes human delay factors) to 45 seconds (no delay factors) the kick size will be less which results in lower surface pressures while circulating the kick out. One would expect the smaller kick to boil out deeper than the larger kick because of the reduced pressure it experiences. However, the smaller size kick does not boil out until downstream of the choke, even though it experiences slightly less pressure while travelling up the wellbore. The smaller kick will more easily dissolve in the mud and have a lower GOR than the larger kick. A lower GOR means that it will boil out shallower than the large kick, thus explaining the behaviour.

7 Risk analysis

In order to evaluate whether circulating out influxes in MPD mode offers any benefits in terms of safety and efficiency over the conventional mode, a comparative risk analysis was performed. First the structure of the analysis is described and a table presenting the modes of failure exclusive for the MPD system is given. A direct comparison between the two systems is then performed based on reliability, kick detection and simulations. Conclusions are summarized in chapter 8.

Quantitative risk analysis (QRA) is also known as probabilistic risk analysis or probabilistic safety analysis. It tries to answer two questions:

1. What are the failure modes or causes of failure?
2. What are the consequences associated with the failure modes?

The modes of failure are quantified by the probability of occurrence while the consequences can be given as a probability distribution over a physical size. Depending on the scope of the analysis, quantifying the probability of a consequence occurring can be a comprehensive task. It may require a complete Fault Tree Analysis, Monte Carlos simulation or similar technique, which is outside the scope of this thesis. Instead a qualitative approach was made to answer the two questions above.

7.1 Analysis structure

The analysis is based on the MPD system and equipment planned for usage on Kristin, illustrated by the block diagram in Figure 22.

Definitions:
System 1 is defined as the conventional mode. Kicks are primarily detected by use of pit gain and the other kick indicators described for the conventional system in chapter 4.1. A flowmeter is not used on Kristin for conventional drilling. The Driller's method is used for circulation of kicks through the rig choke. If flow is detected, the well is shut in using the hard shut-in method without flowchecking.

System 2 is defined as the MPD mode. Detection of kicks is done by methods described in chapter 4.1. Circulation of kicks is performed through the MPD choke and by using the logic in the MPD system. If the MPD system fails during circulation, one automatically switches to System 1 by circulating through the rig choke.

To be on the conservative side and simplify the initial analysis, it can be assumed that the rig choke is as good at keeping the BHP constant during circulation as the MPD choke, which is normally not the case. Furthermore, it can be assumed that the kick volumes are the same for both systems. Figure 42 shows the structure of the risk analysis.

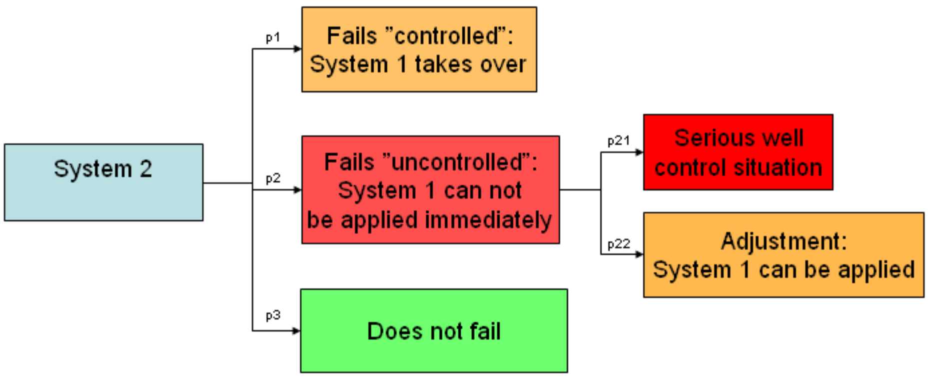

Figure 42 – Structure of the analysis.

It is assumed that System 2 is used for circulating influxes. There are then three possible outcomes:

- Orange – System 2 fails in a controlled mode, but System 1 can immediately take over.
- Red – System 2 fails in an uncontrolled manner where adjustments are needed before System 1 can take over.
- Green – System 2 does not fail, everything proceeds as intended.

The probabilities for these situations occurring are illustrated by p1, p2, p3, p21 and p22 in Figure 42. To simplify the analysis further, only the components that are exclusive to System 2 when circulating out influxes are evaluated. The causes of failure for the various elements and the associated consequences are analysed qualitatively. The results are presented in tabular form in Table 2 to provide a logical and intuitive understanding for the reader.

Table 2 – Modes of failure for System 2 with consequences[**45**].

Active components when circulating out influx in MPD mode	*Failure mode/cause*	*Fails controlled (conventional system can immediately take over)*	*Consequence*		*Comments*
1. Continuous circulating system (CCS)	Leakage	yes	Direct	1. Lose ECD. 2. Lose data from the PWD sub.	Any variation, increase or decrease in circulation rate will be compensated by the auto-choke. Any resulting BHP variation is dependant on auto-chokes accuracy, reaction time, etc. System accuracy is estimated as being up to +/- 5 bar.
		yes	Indirect	1. Lose ECD. 2. Lose data from the PWD sub.	Circulation re-start effect is based on time dependant temperature dynamics. Min is 0, Max is maximum variations + gel break, Most is mid variations + no gel break. (These numbers are high since auto-choke should compensate for all effects, but these are difficult to model accurately)
	Control system	yes	Direct	1. Lose ECD. 2. Lose data from the PWD sub.	Any variation, increase or decrease in circulation rate will be compensated by the auto-choke. Any resulting BHP variation is dependant on auto-chokes accuracy, reaction time, etc. System accuracy is estimated as being up to +/- 5 bar.

		yes	Indirect	1. Lose ECD. 2. Lose data from the PWD sub.	Circulation re-start effect is based on time dependant temperature dynamics. Min is 0, Max is maximum variations + gel break, Most is mid variations + no gel break. (These numbers are high since auto-choke should compensate for all effects, but these are difficult to model accurately)
	Power failure	yes	Direct	1. Lose ECD. 2. Lose data from the PWD sub.	Any variation, increase or decrease in circulation rate will be compensated by the auto-choke. Any resulting BHP variation is dependant on auto-chokes accuracy, reaction time, etc. System accuracy is estimated as being up to +/- 5 bar.
		yes	Indirect	1. Lose ECD. 2. Lose data from the PWD sub.	Circulation re-start effect is based on time dependant temperature dynamics. Min is 0, Max is maximum variations + gel break, Most is mid variations + no gel break. (These numbers are high since auto-choke should compensate for all effects, but these are difficult to model accurately)
	Mechanical failure	yes	Direct	1. Lose ECD.2. Lose data from the PWD sub.	Any variation, increase or decrease in circulation rate will be compensated by the auto-choke. Any resulting BHP variation is dependant on auto-chokes accuracy, reaction time, etc. System accuracy is estimated as being up to +/- 5 bar.
		yes	Indirect	1. Lose ECD. 2. Lose data from the PWD sub.	Circulation re-start effect is based on time dependant temperature dynamics. Min is 0, Max is maximum variations + gel break, Most is mid variations + no gel break. (These numbers are high since auto-choke should compensate for all effects, but these are difficult to model accurately)

2. MPD choke	Plugging - RCD debris	yes	Direct	Min results from minor plugging of short duration that will not be transmitted downhole. Due to compensation the maximum downhole impact is +/- 5 bar. It is assumed that this type of blocking is partial.	2 chokes are run in parallel for redundancy so if one gets blocked, there should be no problem switching to the other one. Junk catcher installed upstream of MPD choke helps mitigate the plugging problem.
			Indirect		
	Plugging - hydrates	yes	Direct	Annular seal gone. Lose ability to provide backpressure.	2 chokes are run in parallel for redundancy so if one gets blocked, there should be no problem switching to the other one. Junk catcher installed upstream of MPD choke helps mitigate the plugging problem.
			Indirect		
	Plugging - cuttings	yes	Direct	Annular seal gone. Lose ability to provide backpressure.	2 chokes are run in parallel for redundancy so if one gets blocked, there should be no problem switching to the other one. Junk catcher installed upstream of MPD choke helps mitigate the plugging problem.
			Indirect		
	Total blocking of both chokes simultaneously or of common inlet to chokes	yes	Direct	The pressure surge effect from this event is only considered to be the “hammer effect” from the moving fluid since the pumps will be stopped a few seconds after the event occurs	2 chokes are run in parallel for redundancy so if one gets blocked, there should be no problem switching to the other one. Junk catcher installed upstream of MPD choke helps mitigate the plugging problem.
			Indirect	If drilling window is too narrow possible fracture/leak to the formation.	The drilling window needs to be established for each individual well in order to evaluate this risk more accurately
	Choke washout	yes	Direct	Annular seal gone. Lose ability to provide backpressure.	2 chokes are run in parallel for redundancy so if one gets blocked, there should be no problem switching to the other one.
			Indirect		
	Power failure	yes	Direct	Will temporarily not be able to regulate choke opening. Lose ability to provide backpressure	
			Indirect		

3. MPD backpressure pump	Mechanical failure	yes	Direct	Lose ability to provide additional back-pressure.	Any variation, increase or decrease in circulation rate will be compensated by the auto-choke. Any resulting BHP variation is dependant on auto-chokes accuracy, reaction time, etc. System accuracy is estimated as being up to +/- 5 bar.
			Indirect		Circulation re-start effect is based on time dependant temperature dynamics. Min is 0, Max is maximum variations + gel break, Most is mid variations + no gel break. (These numbers are high since auto-choke should compensate for all effects, but these are difficult to model accurately)
	Operator failure	yes	Direct	Lose back-pressure on the well. MPD choke will have to compensate for this lost pressure.	Same pressure effect as above. A potential failure mode is that the backpressure pump by mistake is overridden or not turned on.
			Indirect		Circulation re-start effect is based on time dependant temperature dynamics. Min is 0, Max is maximum variations + gel break, Most is mid variations + no gel break. (These numbers are high since auto-choke should compensate for all effects, but these are difficult to model accurately)
	Software failure	yes	Direct	Lose ability to provide additional back-pressure.	Software is designed to fail AS-IS for the MPD chokes so the back-pressure in the well should be trapped.
			Indirect		
	Power failure	yes	Direct	Lose ability to provide additional back-pressure.	Backup power generators will provide backup power quickly, will lead to some pressure fluctuations
			Indirect		
4. Computer (hardware)	Power failure	yes	Direct	Limited immediate impact, system designed to fail as is.	

			Indirect		May have to stop circulation and secure with well control to reinstate system. Circulation re-start effect is based on time dependant temperature dynamics. Min is 0, Max is maximum variations + gel break, Most is mid variations + no gel break. (These numbers are high since auto-choke should compensate for all effects, but these are difficult to model accurately)
	Mechanical failure	yes	Direct	Limited immediate impact, system designed to fail as is.	
			Indirect		May have to stop circulation and secure with well control to reinstate system. Circulation re-start effect is based on time dependant temperature dynamics. Min is 0, Max is maximum variations + gel break, Most is mid variations + no gel break. (These numbers are high since auto-choke should compensate for all effects, but these are difficult to model accurately)
	Signal failure (to interfaced systems)	yes	Direct	Limited immediate impact, system designed to fail as is.	
			Indirect		May have to stop circulation and secure with well control to reinstate system. Circulation re-start effect is based on time dependant temperature dynamics. Min is 0, Max is maximum variations + gel break, Most is mid variations + no gel break. (These numbers are high since auto-choke should compensate for all effects, but these are difficult to model accurately)
5. Computer (software)	Inaccuracy of software	yes	Direct	Can lead to small pressure fluctuations downhole. May need to reboot system.	Maximum back pressure variations will be pre-set and alarms will be set to go off at the pre-set values. This limits the extent of the inaccuracy.

			Indirect		May have to stop circulation and secure the well using primary well control to reinstate system. Circulation re-start effect is based on time dependant temperature dynamics. Min is 0, Max is maximum variations + gel break, Most is mid variations + no gel break. (These numbers are high since auto-choke should compensate for all effects, but these are difficult to model accurately)
	Logical failure (division by zero. Other exceptions that are thrown by the software.)	yes	Direct	Unexpected error, may need to reboot system	Software is designed to handle all the exceptions that could be thrown so the likelihood of this should be very low.
			Indirect		
6. Multipart sliding joint	Leakage (seal failure)	yes	Direct	Spill OBM to the sea. Environmental damage due to spillage of OBM. Lose pressure integrity.	The compensating measure is to close the rigs annular BOP and displace the OBM in the riser to sea-water to minimize the spillage.
			Indirect		
	Mechanical failure (stress concentration)	yes	Direct	Spill OBM to the sea. Environmental damage due to spillage of OBM. Lose pressure integrity.	FMECA is done during the design phase to minimize the likelihood of this type of failure.
			Indirect		
7. RCD	Unplanned element changeout	yes	Direct	Possible leakage of OBM to the environment.	No immediate impact on BHP. Possible longer term impact on auto-choke accuracy.
			Indirect		
	Catastrophic element failure	yes	Direct	Annular seal gone. Lose ability to provide backpressure. Assumed choke pressure during operation is 20 bar.	Worst case necessitates a stripping operation. In case of problems, one will pump out (trip out while maintaining circulation). Will not drill further when having this kind of failure.
			Indirect		
	Element failure (wear)	yes	Direct	Will have to replace element. Annular seal gone	Any variation, increase or decrease, will be compensated by the auto-choke.
			Indirect		
	Control system failure	yes	Direct	No direct impact as the system will fail as is.	
			Indirect		
	Operator failure	yes	Direct	Annular seal gone. Lose ability to provide backpressure. Assumed choke pressure during operation is 20 bar.	Worst case necessitates a stripping operation. In case of problems, one will pump out (trip out while maintaining circulation). Will not drill further when having this kind of failure.
			Indirect		

8. Hydraulic connector	Leakage	yes	Direct	Spill OBM to the sea. Environmental damage due to spillage of OBM. Lose pressure integrity.	The compensating measure is to close the rigs annular BOP and displace the OBM in the riser to sea-water to minimize the spillage.
			Indirect		
	Mechanical failure (excessive cyclic loading)	yes	Direct	Spill OBM to the sea. Environmental damage due to spillage of OBM. Lose pressure integrity.	FMECA is done during the design phase to minimize the likelihood of this type of failure.
			Indirect		
9. Flowmeter	Inaccuracy	yes	Direct	Provide incorrect input to the hydraulic software controlling the MPD system. Cannot correctly measure the fluid fractions coming out of the well.	Coriolis flowmeters are deemed to be fairly accurate
			Indirect	Inaccurate BHP is maintained.	
	Plugging	yes	Direct	Will cause additional backpressure on the well thereby increasing the BHP.	Depends on choke plugging. If choke opening is smaller than flowmeter opening, the choke will plug first and such the flowmeter will not plug.
			Indirect	Provide incorrect input to the hydraulic software controlling the MPD system. Cannot correctly measure the fluid fractions coming out of the well.	
10. Junk catcher	Plugging	yes	Direct	Will cause additional backpressure on the well thereby increasing the BHP.	
			Indirect		
	Erosional failure	yes	Direct	Spill OBM on the rig. Lose ability of the system to provide back-pressure.	
			Indirect		
11. Hose	Leakage	yes	Direct	Spill OBM to the sea. Environmental damage due to spillage of OBM.	
			Indirect	Lose pressure integrity.	

12. Annular BOP	Leakage	yes	Direct	Spill OBM to the sea. Environmental damage due to spillage of OBM. Lose pressure integrity.	
			Indirect		
	Mechanical failure	yes	Direct	Spill OBM to the sea. Environmental damage due to spillage of OBM. Lose pressure integrity.	
			Indirect		
	Element failure(wear)	yes	Direct	Will have to replace element. Annular seal gone	Any variation, increase or decrease, will be compensated by the auto-choke.
			Indirect		
	Operator failure	yes	Direct	Annular seal gone. Lose ability to provide backpressure. Assumed choke pressure during operation is 20 bar.	Worst case necessitates a stripping operation. In case of problems, one will pump out (trip out while maintaining circulation). Will not drill further when having this kind of failure.
			Indirect		
	Catastrophic element failure	yes	Direct	Annular seal gone. Lose ability to provide backpressure. Assumed choke pressure during operation is 20 bar.	Worst case necessitates a stripping operation. In case of problems, one will pump out (trip out while maintaining circulation). Will not drill further when having this kind of failure.
			Indirect		

Not one of the failure modes fails uncontrolled, so System 1 (conventional system) can always take over. Based on the above table one can conclude that the MPD system can safely be used when the conventional acts as a backup.

7.2 Direct comparison

To compare the two systems directly some new assumptions must be made:

1. The MPD system is assumed to function entirely alone, with no backup system.
2. The conventional system is also assumed to function entirely alone, with no backup system.

The two systems are compared qualitatively based on the following criteria:

1. Reliability
2. Kick detection
3. Simulations

7.2.1 Reliability

Uptime is defined as the state when every component of the respective system is up and running and functions as it should. If at least one component fails, the system is defined as being down. The systems uptime directly reflects the systems reliability.

Table 3 - Wellbore elements involved in circulating out influxes.

Conventional system	**MPD system**
Rig choke manifold	Rig choke manifold
PWD	PWD
Rig pump	Rig pump
Riser	Riser
Wellhead	Wellhead
Mud gas separator	Mud gas separator
Mud pits	Mud pits
Subsea BOP	Subsea BOP
Choke line	Choke line
Kill line	Kill line
Booster line	Booster line
	MPD choke
	MPD backpressure pump
	CCS (Continuous Circulation System)
	Computer (Hardware)
	Computer (Software)
	Multipart sliding joint
	RCD
	Annular BOP
	Hydraulic connector
	Flowmeter
	Hose
	Junk catcher

Table 3 shows the wellbore elements that are involved in circulating out influxes in both conventional mode and MPD mode. All of the elements that are involved in the conventional system are also included in the MPD system. These common elements are of less interest than the elements that are exclusive to the MPD system. The rubber part of the RCD is expected to get worn down and needs replacing from time to time. The MPSJ should reduce the frequency of these replacements by centralizing the drillpipe in the RCD. Although the MPSJ will go through rigorous testing and qualification before usage, no test is perfect. The element is brand new and daily usage over an extended time interval might reveal new reliability issues. Since the MPD choke is run in parallel, issues regarding reliability should be reduced for this element. Even if it fails, it can be replaced without halting the operation by switching to the other MPD choke. The annular BOP is only used when replacing the RCD and is as reliable as conventional annular BOPs. Computer hardware and software will probably suffer the same reliability issues as other computer controlled systems on the rig. The consequences of such events would be limited, as shown in Table 2.

A complete quantitative analysis of the reliability of the various elements with associated failure trees and calculated probabilities is outside the scope of this paper. Instead, a description of how this analysis could have been done if sufficient data was available is given.

The probabilities and frequencies of the listed failure modes in Table 2 are normally estimated based on historic reliability data or observations from similar activities. This may require detailed modelling or access to experimental data. Such data may not always be available and engineers and experts may then come up with a conservative suggestion.

Table 4 – Barriers while drilling the 8.5” section on Kristin.

Conventional system	**MPD system**	
	If static mud weight > pore pressure	If static mud weight < pore pressure
Primary barrier elements (drilling 8.5"):		
Fluid column	Fluid column	RCD 2-3 Non-return valves Drillstring MPD choke manifold Annular BOP Fluid column
Secondary barrier elements (drilling 8.5")		
9 7/8” casing Cement 9 7/8" casing Drilling BOP Wellhead	9 7/8” casing Cement 9 7/8" casing Drilling BOP Wellhead	9 7/8” casing Cement 9 7/8" casing Drilling BOP Wellhead

The well barriers during drilling of the 8.5” section is shown in Table 4. The philosophy on Kristin is to always keep the static mud weight of the fluid column above initial pore pressure. This means that the fluid column always qualifies as a primary barrier. When circulation is lost in conventional mode, the primary barrier is lost. In MPD mode, you still have NRVs inside the drillstring, RCD, annular BOP and choke manifold at top which means that the primary barrier is still in place. The common wellbore elements are all of the secondary barrier elements, which include the 9 7/8” casing, casing cement, drilling BOP, and wellhead.

Table 5 gives an example of how estimated probabilities can be used in a QRA. Here, the probability of direct failure for the auto-choke system is estimated to be 5%. The consequence or impact of this occurrence in terms of pressure is estimated to be +/- 7 bars. If data about the reliability were available, similar calculations could be made for every element in the system.

Table 5 – Example of how probability is incorporated into a QRA.

Mechanism	**Causes**	**Occurrence probability**	**Pressure impact (bar)**	**Comments**
Auto-choke system failure	1. Mechanical, power failure or signal failure	P(direct)) = 5% P(indirect) = 100%	Direct: T(-7,0,7) Indirect: T(2.5,0,2.5)	Limited immediate impact, system designed to fail as is. There are two chokes. If one for some reasons goes out the system will automatically and instantly switch to the other choke. Have hydraulic backup for power and also cable from other platform for redundancy.

Figure 43 shows a risk matrix with risk factors which is a useful tool in a QRA. Consequences are categorized based on impact and severity. The impact could be personal injury, environmental impact like oil spill to sea or chemical spill, economical impact, or company reputation impact. Severity for personal injury could be whether the event leads to a fatality or just basic first aid. The consequence is given a number based on how severe the hazard is. A higher severity gives a higher number. An event occurring once a week has a higher frequency and probability than an event occurring once a year. The risk of any hazard occurring is then quantified by multiplying frequency with the consequence. A higher number means higher risk. The risk numbers are colour coded to illustrate the level of risk. A grey risk is considered intolerable, while a green risk is tolerable.

RISK MATRIX WITH RISK FACTORS

	Consequence					Increasing frequency (probability)				
						5 > 5 years	4 > 1 year	3 > 6 months	2 > 14 days	1 < 14 days
	Personal injury	Oil spill to sea	Chemical Group 1	Economical: Lost rigtime/ equipment	Reputation	Never heard of in the industry	Has occured in Statoil	Occurs several times a year	Occurs several times a month	Occurs once a week
	P	O	C	E	R	Highly unlikely	unlikely	Low likelihood	Possible	Probably
1	Fatality	> 1000 m3	> 1000 m3	> 100 mill. NOK	National impact. National media coverage.	75	150	225	300	375
2	Serious pers. injury w/possible permanent injury	> 100 m3	> 100 m3	> 50 mill. NOK	Considerable impact. Regional media coverage.	25	50	75	100	125
3	Serious pers. injury	> 1 m3	> 10 m3	> 25 mill. NOK	Limited impact. Local media coverage.	10	20	30	40	50
4	Medical treatment	> 0.1 m3	> 1 m3	> 1 mill. NOK	Slight impact. Local public awareness.	5	10	15	20	25
5	First aid	< 0.1 m3	< 1 m3	< 1 mill. NOK	No impact	1	2	3	4	5

All insidents will be approved by B&B/RESU Manager

All insidents will be approved by Asset Manager

Intolerable

Figure 43 – Risk matrix with risk factors (courtesy of StatoilHydro).

A conservative estimation is traditionally applied when quantifying the risk. It should be acknowledged that the true risk of any analysis could be higher or lower.

7.2.2 Kick detection

The method of detecting kicks for the conventional system is described in chapter 4. On Kristin it is similar, only here an APWD tool installed in both conventional and MPD mode. This is used to monitor the BHP, but only when the rig pumps are active as it uses mud pulse telemetry. During connections or when the backpressure pump is on, there is no info from the APWD. Therefore this tool does not give an advantage to either system with regards to kick detection.

For conventional drilling on Scarabeo 5, the pit alarm is set to 1 m^3. A lower pit alarm gives greater sensitivity. This might lead to earlier kick detection but also more false alarms. False alarms lead to NPT and distrust in the alarm system, which can be dangerous when a real kick situation occurs. To reduce the number of false alarms, the system needs to better be able to model and predict variations in pit volume. An example is the pit volume increase when stopping circulation, as shown in Figure 44. The increase can be explained by pipe draining, which is different from rig to rig and hard to accurately model[**46**].

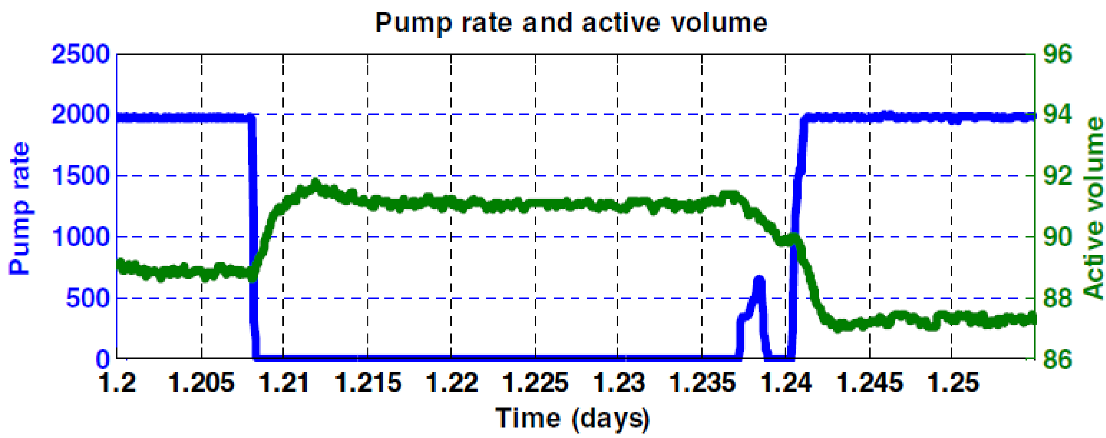

Figure 44 – Pipe draining effect on pit volume[**46**].

As mentioned in chapter 4.1, the MPD system can detect kicks based on the same kick indicators as the conventional system. Since it is a closed system, additional indicators like small variations in choke pressure and flow change in versus flow change out can be used. A coriolis flowmeter installed downstream of the MPD choke can detect small changes in flow out of the well. If flow out deviates from flow in, a kick or loss scenario may be in progress. The coriolis flowmeter is a more accurate kick indicator than the APWD tool and can detect much smaller influxes. The computer controlled choke has setpoints that are automatically computed by a dynamic flow model as described in chapter 3.2.1. This facilitates early detection of kicks, before the gas has dissolved in the mud. Santos *et al*.[**47**] performed tests and field trials which proved that by using MPD it is possible to detect gas kicks early, before the gas has time to dissolve in SOBM. Using a closed loop system and a flowmeter they managed to detect gas kicks in SOBM with less than 0.5 bbl of influx volume.

Some MPD techniques have reported a kick detection resolution of 1 bbls pit gain. If this could be achieved consistently on a floating vessel it would be a big improvement from the 10 bbls or more which can occur on these rigs during conventional drilling[**48**].

Failure in MPD system that can lead to long detection times:

- Computer software failure
- Computer hardware failure
- If the choke washes out or plugs it might be a false alarm.

The variation in choke pressure is used as the primary indicator of kicks. Therefore, if the computer software or hardware that regulates the choke opening temporarily fails or acts inaccurately, it will be hard to detect a kick early. One will then need to rely on the other kick indicators like pit alarm and flowmeter measurements. Still, it should not take longer to detect a kick than it would for a conventional system. If the choke washes out, the backpressure is essentially gone. This could lead to underbalance in narrow operating conditions and a subsequent kick. However, since there are two chokes running in parallel, the chance of both washing out is minimal. If the choke plugs, one might think that the plugged choke indicates a kick which would cause a false alarm. A false alarm in MPD mode would be less severe than in conventional mode, since MPD will continue drilling whilst simultaneously circulating out the kick, as opposed to closing the subsea BOP in conventional mode.

7.2.3 Simulations

Simulations for MPD could not be done directly with the Drillbench Kick-software. To still be able to illustrate some of the potential benefits of MPD some assumptions and simplifications can be made. It is well known that MPD can detect kicks earlier than conventional drilling. Assume that MPD is twice as good as detecting kicks as a conventional system. If the conventional system can detect kicks by using a pit alarm of 1 m3, the MPD system can do the same with a pit alarm 0.5 m3. A further assumption is that since the MPD system is automatic, there will not be any human delay factors and the BOP closure time will be only 45 seconds. This is a conservative assumption as the MPD system in reality will use the MPD choke to impose backpressure on the influx zone and stop the influx, which is much quicker than closing the BOP. By simulating this scenario in Kick, you get the following results.

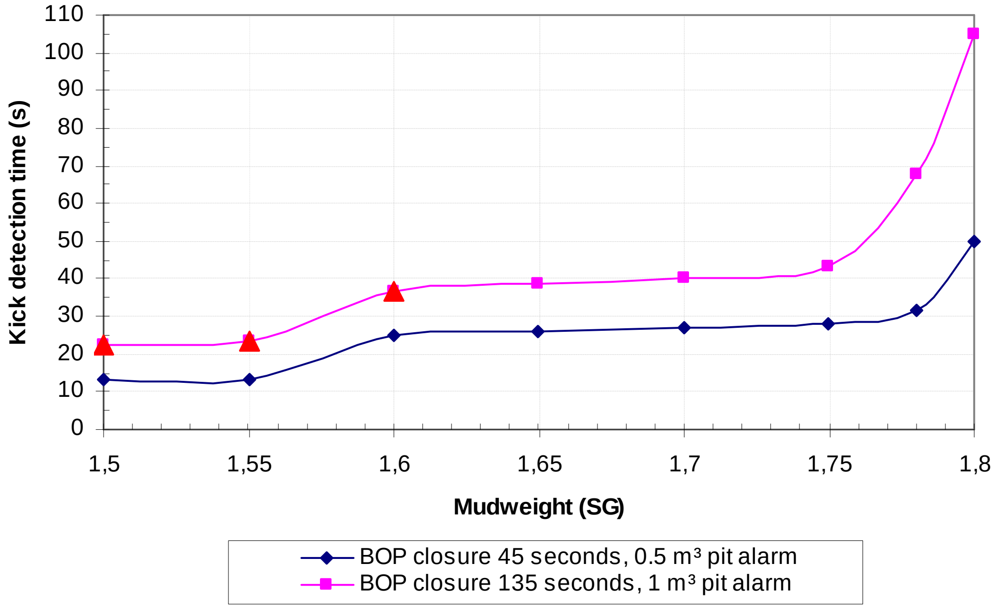

Figure 45 – Kick detection time for different BOP closure times.

Figure 45 shows the kick detection times for the different BOP closure times while Figure 46 shows the kick sizes. The pink curve represents the longest BOP closure time which incorporates human delay factors. This curve fractures for mud weights up to 1.6 SG and represents the conventional system. The dark blue curve represents the MPD system which is automatic, and therefore detects kicks earlier and does not fracture. The difference in kick detection is not that big, but it is a conservative estimate. The main contributor to the difference in detection time is the longer BOP closure time rather than the slightly larger pit alarm. Since the blue curve can be considered conservative, the conclusion is that the MPD system could be used without fracturing, while the conventional system would fracture.

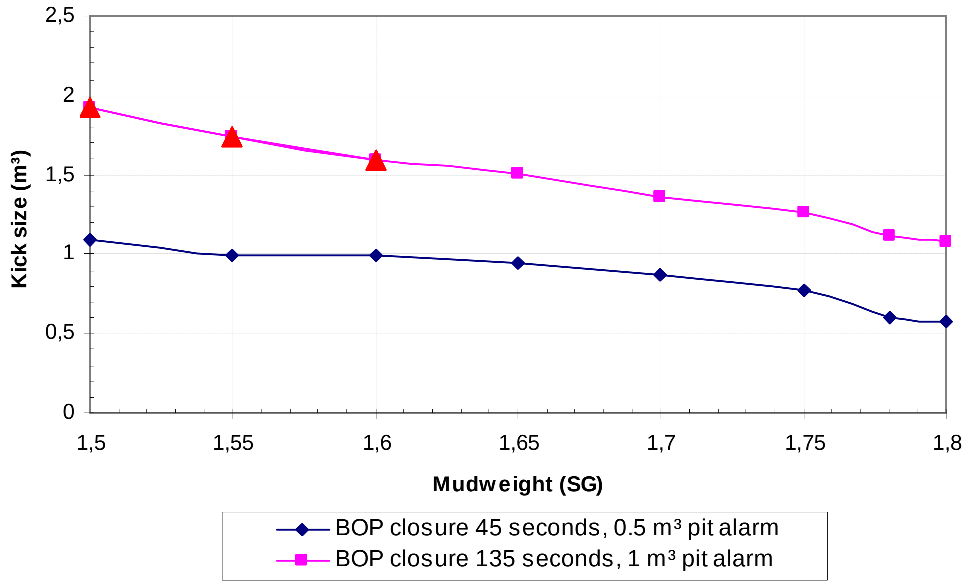

Figure 46 – Kick size for different BOP closure times.

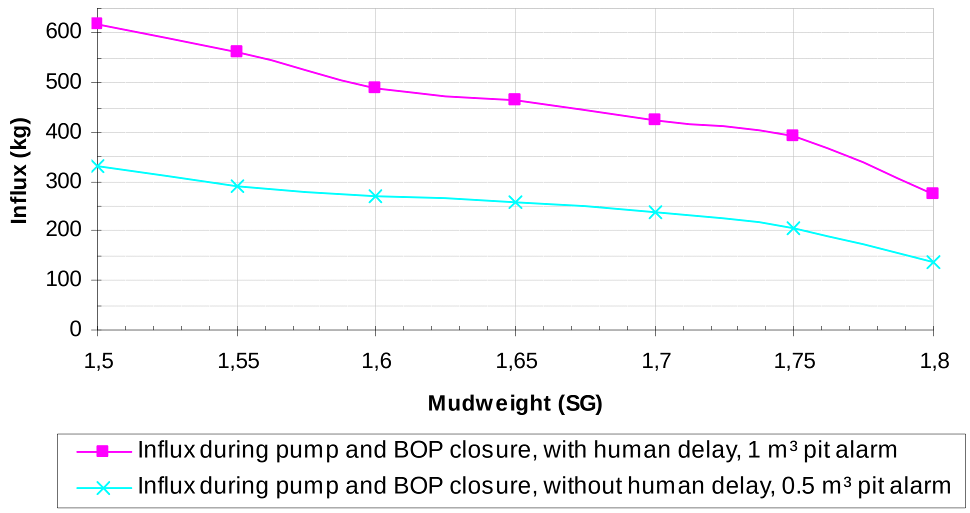

Figure 47 – Mass influx from kick detection until BOP closure.

Figure 47 shows the mass influx which occurs from the time the kick is detected until the BOP is closed. The larger the underbalance, the larger the difference between the two curves. This figure clearly illustrates the importance of acting quickly during a kick situation. For 1.5 SG mud weight, the human delay factors result in almost twice the influx than would have occurred without them. The curves follows the same trend as Figure 46.

Any influx of reservoir fluids in conventional drilling is defined as a kick, but what is a kick in MPD mode? MPD is tooled up to handle small influxes while drilling without the need to shut in the well. These small influxes are automatically circulated out while drilling. On the Kvitebjørn field, a kick in MPD mode is defined to be influx greater than 1 m^3. If the influx is of this magnitude, the well is shut in and the kick is circulated conventionally through the rig choke. A kick situation in MPD occurs if the influx is greater than a certain pre-defined amount which varies from rig to rig. Since the MPD system is designed to automatically detect and circulate out small kicks, the likelihood of a large kick occurring is inherently low.

Normally, the volume of influx that can safely be circulated out in MPD mode will be limited by the equipment pressure rating, the MPD system, qualified personnel on board the rig and the accuracy and reliability of the hydraulic model. Equipment limitations include the capacity of the MGS and the pressure rating of the surface equipment such as RCD, riser, MPD choke manifold, and associated pipes. The RCD is the lowest rated element with 2500 psi in dynamic conditions and 5000 psi in static conditions. MPD simulations need to be carried out to find out what size of influx generates 2500 psi. This size would then be the maximum size that can be circulated out by the MPD system on Kristin. Larger kicks need to be circulated out via the rig choke and routed through the MGS which is only connected to the conventional system. As previously mentioned, the capacity of the MGS on Scarabeo 5 is 28.24 MMscf/d. The highest gas rate achieved during the simulations in chapter six was 2.475 MMscf/d for a kick size of 2.364 m^3. This means that the gas separator can handle rather larger kicks.

In chapter 4.3.3, simulations performed by Carlsen *et al.* concluded that the DSI was far superior to the standard shut-in method with regards to kick size. The main reason for this was the flowcheck performed using the standard method which resulted in far more influx. During conventional drilling on Kristin, flowcheck is not performed. This makes it safer, but positive detection of kicks is harder without the flowcheck. MPD would be an even safer alternative, as it can detect smaller kicks than conventional and has a closed circulating system.

8 Summary and conclusions

Kick simulations were performed for drilling conventionally into a 160 bar depleted Ile formation while receving a kick in the undepleted Garn formation. The simulations were performed on Well A which was drilled on the Kristin field in 2008. The simulations were divided into two parts, a best case and a worst case, depending on permeability and porosity. The intent was to determine if a similar well could be safely drilled conventionally on Kristin with the given depletion.

It is important to remember that reality cannot be 100% accurately modelled, no matter how much work one puts in. The simulations and the numbers presented should under no circumstance be considered as the absolute truth. As all other simulations, these have a certain uncertainty accredited to them, depending on input parameters and software limitations. The results should therefore only be used for guidance.

Based on the simulation results:

- None of the simulations for the best case fractured the formation.
- The well fractured for the worst case for mud weights of 1.70 SG and below when using a pit alarm of 4 m^3.
- The well fractured for the worst case for mud weights of 1.65 SG and below when using a pit alarm of 2-3 m^3.
- The well fractured for the worst case for mud weights of 1.60 SG and below when using a pit alarm of 1-1.2 m^3.
- For a detected influx, the gas boiled out either right below the BOP or in the chokeline.
- Human delays when shutting down the pump and closing the BOP have a large impact on kick size.
- While it is possible to drill conventionally with a depletion of 160 bars in Ile, it is not recommended as long as the Garn formation is undepleted. Using a low mud weight close to the pore pressure in Ile will create a massive underbalance and subsequent influx from Garn which will be sufficient to fracture the formation. To avoid fracturing the formation, the only option is to operate with mud weights very close to the fracture pressure in Ile, effectively minimizing the underbalance and influx in Garn. However, operating this close to the fracture pressure during conventional drilling is not recommended. Although one would try to keep a constant BHP in such a situation, there will always be some pressure fluctuations which risk fracturing the formation. This could then lead to a lost circulation event and a subsequent kick.

A comparative risk analysis was performed in order to evaluate whether circulating out influxes in MPD mode offers any benefits in terms of safety and efficiency over the conventional mode.

Based on the risk analysis:

- MPD can safely be used in situations where a conventional system acts as a backup.
- MPD can detect kicks earlier and is better at circulating out influxes than the conventional system.
- The conventional system relies on human interaction which represents a significant safety concern. The MPD system is almost entirely automatic, eliminating much of the risks associated with human delay and error.
- If encountering a large kick in MPD mode, one can always shut-in and circulate out via the conventional system. However, such a large kick is improbable, as the MPD system is specifically designed to detect kicks early and avoid development of large kicks.
- Since the MPD system can drill ahead during a small kick without the need for shutting in the well, it saves considerable rig time compared to the conventional system.

Recommendations:

- MPD should be considered as an option on Kristin for drilling wells with similar scenario as Well A. The ability to minimize pressure fluctuations and keep a relatively constant BHP is necessary to successfully drill such a well. The added safety of a closed circulation system and the potential for earlier discovery of kicks favours MPD over the conventional system for this particular well.
- Similar kick simulations should be performed for MPD by software able to simulate two-phase flow and fully automatic MPD mode with associated equipment. This would conclude if MPD offers the expected benefits regarding safety and efficiency for this particular well.
- Simulations investigating the effect of air that comes into the MPD system during connections should be performed. Such air is expected to reduce the compressibility of the mud column, making it harder to control the BHP with choke backpressure.
- Flowchecks should be avoided when circulating out kicks. Checking for flow will give the kick an opportunity to grow in size. Alternate means of detecting and confirming a kick, like extensive use of fingerprints should be used instead.
- Complete QRA for the MPD system to be used on Kristin should be done in order to quantify the risk.

Abbreviations & nomenclature

AFP	Annulus Friction Pressure
APWD	Annular Pressure While Drilling
BBLS	Barrels
BHA	Bottom Hole Assembly
BHP	Bottomhole Pressure
BOP	Blowout Preventer
BP	Backpressure
CBHP	Constant Bottomhole Pressure
CCS	Continuous Circulation System
CMC	Controlled Mud Cap Drilling
Cs/K	Cesium-/potassium formate brine
DAPC	Dynamic Annular Pressure Control
DDV	Downhole Deployment Valve
DG	Dual Gradient Drilling
DM	Drillers method
DSI	Dynamic Shut-in Procedure
ECD	Equivalent Circulating Density
ECDRT	ECD reduction tool
EMW	Equivalent/effective Mud Weight
ESD	Equivalent Static Density
FMECA	Failure Mode, Effects and Criticality Analysis
FPWD	Formation Pressure While Drilling
GOR	Gas Oil Ratio
GPM	Gallons per minute
HPHT	High Pressure High Temperature
HSE	Health, Safety and Environment MPD
IADC	International Association of Drilling Contractors
LMRP	Lower Marine Riser Package
LM	Loss Prevention Material
LPM	Liters per minute
MBS	Invert emulsion HPHT oil based mud with Micronized Barite Slurries
MGS	Mud gas separator
MPC	Model Predictive Control
MPD	Managed Pressure Drilling
MPSJ	Multi-Part Sliding Joint
$MW_{\_HH}$	Mud weight hydrostatic head
NPT	Non- Productive Time
OBM	Invert emulsion HPHT oil based mud
P_F	Fracture pressure
$P_{\_HAN}$	Hydrostatic pressure of mudcolumn in annulus
$P_{\_HDP}$	Hydrostatic pressure of mudcolumn in drillpipe
$P_{\_HKICK}$	Hydrostatic pressure of kickcolumn in annulus
PCMD	Pressurized Mud Cap Drilling
PID	Proportional-Intergral-Derivative
PLC	Programmable Logic Controller
P_P	Pore pressure
PWD	Pressure While Drilling
QRA	Quantitative risk analysis
RC	Reverse Circulation
RCD	Rotating Control Device
ROP	Rate of penetration
ROV	Remotely Operated Vehicle

RPC	Riser Pressure Control
SG	Specific Gravity
SICP	Shut-in casing pressure
SIDPP	Shut-in drillpipe pressure
SIWHP	Shut-in wellhead pressure
SOBM	Synthetic/oil-based mud
SPM	Strokes per minute
SPP	Stand Pipe Pressure
TD	Total Depth
UBD	Underbalanced Drilling
UBO	Underbalanced Operations
v	Poisson ratio
WBM	Water Based Mud
σ_H	Largest horizontal stress
σ_h	Smallest horizontal stress
σ_v	Vertical stress

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Appendix

Input parameters for kick simulations:
All depths are measured depth with reference to rotary table.

Table 6 – Drilling parameters used in simulations.

Drilling parameters		
Mud weight	1.5 - 1.8	S.G.
Pump rate	1400	l/min
Rotation speed	120	rpm
Torque	20000	Nm
Rate of penetration	10	m/hr
Riser booster pump rate	500	l/min

Table 7 – Mud properties used in simulations.

Mud properties		
Base oil density	0,78	S.G.
Water density	1,00	S.G.
Solids density	4,20	S.G.
Density	1.5-1.8	S.G.
Reference temperature	15	C
Oil/water ratio	80/20	
Thermal conductivity	0,55	W/m*K
Specific heat capacity	2100	J/kg*k
Static viscosity	0,04	Pa*s

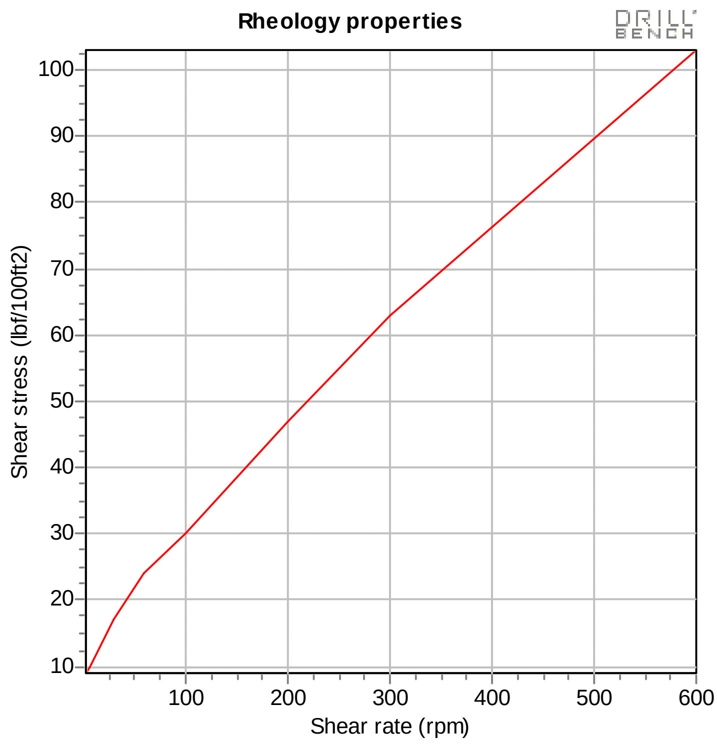

Figure 48 – Mud rheology used in simulations.

Table 8 – String geometry used in simulations.

String geometry				
Component	Type	Section length (m)	Inner diameter (in)	Outer diameter (in)
PD675	Motor	3,77	2,63	6,75
Telescope	Mwd	7,53	5,11	6,75
Ecoscope	Mwd	8,5	2,81	6,75
NM Stab	Stabilizer	1,5	2,88	6,75
NM HWDP	Drillpipe	18	3	5
HWDP	Drillpipe	27	3	5
Jar	Custom	9,5	2,75	6,5
HWDP	Drillpipe	70	3	5
Dart Sub	Custom	0,65	3	6,5
HWDP	Drillpipe	10	3	5
X-over	Custom	1	2,81	6,25
Dp (19.5#)	Drillpipe	5584,4	4,276	5
DP (32.6#)	Drillpipe	10	3,75	5
Bit diameter (in)	Total nozzle area (in2)			
8,5	0,52			

Table 9 – Wellbore geometry used in simulations.

Wellbore geometry			
Riser	Length (m)	Inner diameter (in)	Outer diameter (in)
21" Riser	340	19,764	21
	Hanger depth (m)	Setting depth (m)	Inner diameter (in)
30" X-80	341	430,7	28
20" P110 133.0 lbs/ft	340	1414,7	18,543
14" P110 96,9 lbs/ft	340	645	12,441
13 3/8" Q125 72.0 lbs/ft	645	2398	12,250
10 3/4" C110 85.3 lbs/ft	340	427,5	9,126
9 7/8" SM125S 66.4 lbs/ft	427,5	2703,3	8,504
9 7/8" Q-125 66.4 lbs/ft	2703,3	5236,1	8,504
Open hole length (m)	Diameter (in)		
567,9	8,5		

Kristin MPD system:

Table 10 – Kristin MPD system components

Kristin MPD system components		
	Component type	Manufacturer
MPD choke manifold	Geobalance	Halliburton
Backpressure pump	Geobalance	Halliburton
Software	Geobalance	Halliburton
Hardware	Geobalance	Halliburton
Continuous Circulation System (CCS)		National Oilwell Varco
Multi-part sliding joint		StatoilHydro
Annular BOP	10 K	Shaffer
RCD	Hold 2500	Smith

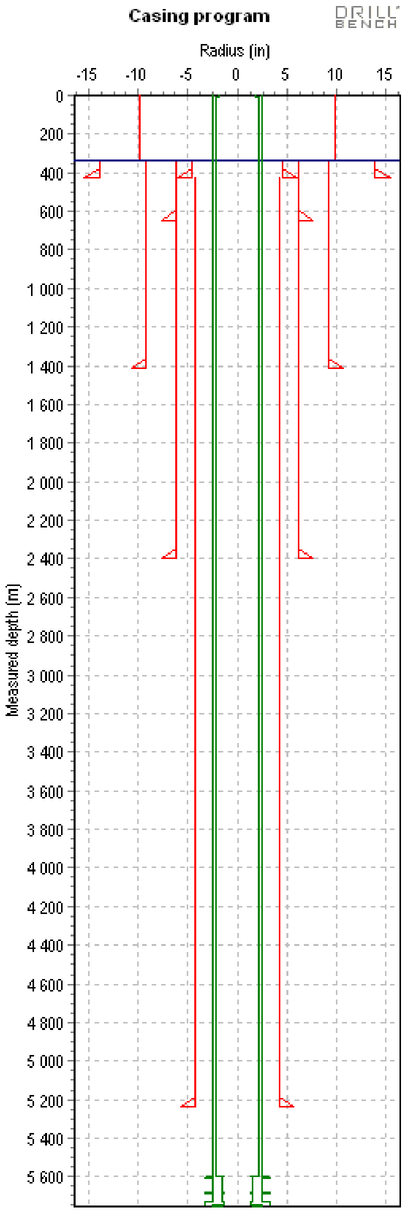

Figure 49 – Casing program for Well A.