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# MASTER'S THESIS

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# Master Thesis

***Faculty of Science and Technology***

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*"Riserless Drilling Systems"*

Author: Erlend Jarstø Myhre

## Acknowledgement

*This thesis is the concluding part of my study for MSc degree in Petroleum Engineering at the University of Stavanger, Norway.*

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# Abstract

As the oil and gas recoverables are getting more inaccessible and harder to procure, the worlds demand for petroleum resources are constantly increasing. This entails the oil industry to expose themselves towards more challenging environments for oil and gas exploitation. To enable for this development to be beneficial, or even feasible, the industry is eagerly on the lookout for innovative solutions to counter for the given challenge.

This thesis will elucidate a new drilling technique that mitigates narrow pore-/fracture-pressure windows, wellbore instability, depleted formations, formation damage, excessive casing strings, fatigue life, large water depths and hostile environments. The mitigation of fatigue life on the Gullfaks Satellites (GFS) substructure is one of the main drivers for Statoil to implement this technology in the first instance. The technology, called Riserless Drilling Systems, enables for drilling of the entire well without the need of a large rigid riser. The research focus for this thesis will therefore be to evaluate the methods potential, and to see if it is a viable and adaptive solution for the oil and gas industry.

The research methods used for this thesis are an evaluation of the feasibility studies done by the Riserless Drilling System service providers, company visits, data retrieval from relevant sources and some experimental research through the use of the commercial spreadsheet Microsoft Excel. Through careful evaluation of the developing technology, the author is of the opinion that a Riserless Drilling System is a viable solution for the given purpose based on the performed research. The basis for this lies within the already filed proven RMR® technology, and the comprehensive underlying feasibility studies performed. Hence the author concludes, with reservation regarding pump technology, that the conceptual technology will be suitable for the presented water depths. As the water depth on GFS is not of any concern for this technology, it would be a highly potential candidate for the mitigation of further fatigue development on the wellhead systems.

Disregarded the cost involved in utilizing a Riserless Drilling System, the author is of the perception that further initiative is beneficial due to its many positive aspects. As a direct result of these, the technology will emerge and may with time become the best alternative to drill a well in the future.

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# 1 Introduction

Single- or dual gradient, that's the question: What is all the fuss about this fairly new approach in drilling a well? Can't we just proceed with the already existing and applicable methods which we have always used? And what is actually dual gradient? This is what the industry asks itself during the equipment qualification round when planning the next well. It might not be the actual case, but why should we go the extra mile and expose ourselves to all these new technologies? The answer for this can be directed to this citation:

*"It has been stated many times that all the easy wells have been drilled. It would stand to reason then that only problem wells remain. Even though this last statement is not entirely correct, our industry is facing increasingly costly incidences of pressure-related non-productive time. Problems include narrow pore-/fracture-pressure windows, wellbore instability, depleted formations, formation damage, and excessive casing strings, among others".* **Jerome Schubert**, SPE.

It is important to apply new technologies in the industry to be able to explore and exploit the hydrocarbons that have so far been out of range for the operator. Therefore, it is essential to look into new methods to reach these targets. The main goal of this thesis is to evaluate the implementation of a Riserless Drilling System in the oil and gas industry. Through this research, based on the information given, the author will consider the technology and its viability. The reader will gain a general knowledge of the developing technology and its application areas, as well as its advantages and disadvantages. Also, Statoils main driver to initiate this research was that the technology of concern mitigates wellhead fatigue issues related to the Gullfaks Satellites (GFS). In addition to the mitigation of wellhead fatigue, the technology has several positive aspects in terms of counteracting the above mentioned factors in the citation.

As stated earlier, the reader will get an insight of the technology through the author's ability to elaborate around the subject based on the research methods used. By this, the author hopes to convey a clear message so that the reader can get a perception of what the technology entails. To achieve this, the author wishes at start to address and compare the technology of concern against the conventional methods to prepare the reader for further understanding of the topic.

## 1.1 Conventional Riser Drilling

In Conventional Riser Drilling (CRD) the annular interval is made up by one pressure gradient (density) throughout the whole well, from topside rig to bottom of hole. This is what we call single gradient drilling (SGD), and applies after the blowout preventer (BOP) and riser is set. A BOP is a large device consisting of several hydraulically operated rams that are required for well control. A riser is a large-diameter pipe that acts as a temporary extension of the wellbore and up to surface which enables for fluid return from the wellbore annulus. Further explanation of the two will follow later in the thesis.

When drilling conventional the well is open to the atmosphere. In such a system the only ways to manipulate the bottom hole pressure (BHP) is by adjusting the pump rate, or by circulating a different MW into the well. By adjusting the pump rate one can manipulate the frictional pressure loss in the well. The frictional pressure loss is dependent on the length of the well, formation, viscosity and rheology. Low pump rate creates low frictional pressure loss, and high pump rate creates a high frictional pressure loss. Furthermore, since the mud column is the primary well barrier in CRD, the hydrostatic head provided by the drilling fluid must be higher than the formation pressure. While circulating, the BHP is defined by the hydrostatic column provided by the MW and the frictional pressure created by annular flow. This frictional pressure addition is called the equivalent circulation density (ECD), and occurs only when circulating. During any drilling operation the BHP must stay within the drilling window at all times. This means staying above the pore pressure, and below the fracture pressure;

**Drilling window:**

$$P_{Pore} < BHP < P_{Frac} \tag{1}$$

**Dynamic BHP:**

$$BHP_{DYN} = P_{MW} + P_{ECD} \tag{2}$$

**Static BHP:**

$$BHP_{STAT} = P_{MW} \tag{3}$$

One can see from the equations above that the BHP varies in magnitude equal to the ECD contribution. This pressure fluctuation occurs every time the pumps stop, or when a connection is made. If the ECD contribution is too big compared to the drilling window, the well can experience influx/collapse or loss/fracturing between static and dynamic conditions.

## 1.2 Riserless Drilling Systems

This sub-chapter is meant as a light introduction to the reader, thus the details will be kept at a basis level. To clarify once again for the reader, this technology is still on the development phase and has not yet been field tested. Nevertheless, the concept builds on field proven technology and it’s just a matter of time before the technology is commercial available.

In contradiction to SGD, the Riserless Drilling System makes use of the dual gradient principle by eliminating the riser. This means that the hydrostatic column that makes up the BHP consists of two different gradients, seawater gradient and drilling fluid, which together have to accomplish the same BHP as for CRD. This implies that for dual gradient drilling (DGD) the drilling fluid, which has its peak at the mudline, must be composed by a heavier mud weight to achieve this. The mudline is the reference point of where the seafloor begins. The Riserless Drilling System is not the sole user of this principle. There exist several other dual gradient solutions that include a riser which enables alteration of the liquid column to compensate for insufficient mud weight. For additional information about these, the reader is advised to consult the master thesis *“Dual Gradient Drilling”* [4]. To clarify the principles mode of operation, an illustration is presented below.

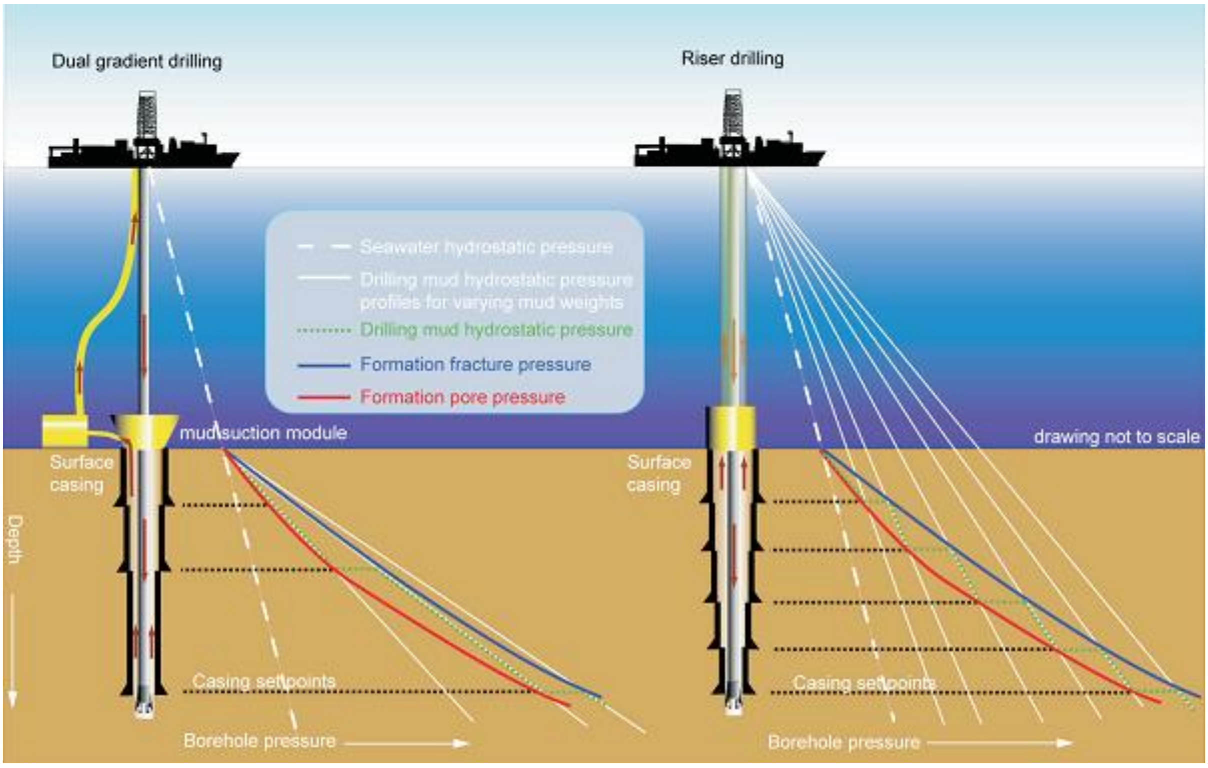



**Figure 1** *Principal drawing of the progression of pressure gradients along the well. Figure is taken from [5].*

Depicted in Figure 1, the pore, frac and mud pressure gradients are referenced to the rig for SGD. For DGD, the mud gradient is referenced to the mudline. This will enlarge the margins between the fracture pressure and pore pressure. Furthermore, by establishing the mud gradient at the seafloor, with water as the overburden hydrostatic column, the “slope” of which the gradient “enters” the drilling window at mudline will be more in compliance with the pore- and fracture limits. This results in deeper casing setting depths which again lead to less casing strings, and larger production capacity due to greater pipe dimensions at bottom of well.

As described in the name, Riserless Drilling System, the technology does not include a riser at all. The replacing conduit system for mud return to rig topside is now a subsea mud funnel, suction hose, pump module and a mud return line. This mud return system will accumulate and pump the annular returns from the mudline and up to the rig mud system, eliminating the need for a riser. This provides great advantages to the drilling operation which will be further explained later in the thesis.

The reason why this method has not been implemented earlier is that the industry has not managed to justify its use due to unattractive economics. Operators have now recently started to show interests in this emerging technology on the basis of its great potential.

## 2 Top Hole Drilling

Top hole drilling is the first operation when drilling a well. It consists of drilling the two first sections and to set the coherent casing strings for the particular intervals. From the first exploration well being drilled in the North Sea, Q3 1966, and up to 1985, a marine drilling riser was used to achieve this. After a “shallow gas” incident on the rig West Vanguard during operations on the Haltenbanken field in 1985, the marine drilling riser was abolished from top hole drilling on the Norwegian Continental Shelf (NCS) [6]. Shallow gas is defined by NORSOK D-010 [7] as *“free gas or gas in solution that exists in permeable formation which is penetrated before the surface casing and BOP has been installed”.* An influx occurred when the bit entered a shallow gas pocket, and rose upwards inside the riser. Since no BOP is installed during top hole drilling, the gas was able to reach the rig and develop into a topside blowout. Now, all top hole sections are drilled riserless in the NCS, and a marine drilling riser is connected together with a BOP after the wellhead is installed. Being absent of a riser during top hole drilling have resulted in a “Pump and Dump” practice. This have caused large amount of drilling fluid disposal to seabed environment. As an alternative to the “Pump and Dump” method, a Riserless Mud Recovery system has been developed to overcome this challenge. This development will be further described later in this chapter.

As supplementary information to the reader a marine drilling riser is a large-diameter pipe that acts as a temporary extension of the wellbore and up to surface, connecting the surface drilling facility to the subsea BOP [8]. It is connected to the surface tension system on the rig, and runs all the way down to the BOP. Between the riser and BOP exists a Lower Marine Riser Package (LMRP) that is basically a connector platform that is used to easily connect or disconnect from the BOP. The drill string is conveyed on the inside of the riser which then transforms the riser into an annular return conduit for the drilling fluid. It is also equipped with kill and choke-lines for well control, as well as hydraulic pod lines for control of subsea equipment.

**Figure 2** *Marine Drilling Riser with buoyancy elements. Figure is taken from Flotec.*

## 2.1 Conventional Top Hole Drilling

The source for this subchapter is [9] unless stated otherwise. When drilling conventionally the top hole sections are drilled without a marine drilling riser in place. Before drilling the top hole sections, a temporary guide base is conveyed on guide lines down to seabed. A guide rope is then used to lead the drill pipe down for entering through the guide base. The first removal of rock and other sediments are called spudding of well, and are done by the drill bit. Drill bit dimensions and casing size is case specific, but typical scenarios are 36” hole for a 30” conductor casing, and 26” hole for a 20” surface casing. The 26” hole for surface casing is usually drilled with a smaller pilot hole, and then open up afterwards using an under-reamer. This is done to delimit the gas flow if a shallow gas pocket is hit. During the top hole drilling operation the drilling fluid and cuttings are circulated out and disposed on the seabed. This solution limits the use of advanced drilling fluids and has environmental concerns regarding polluting discharges to the seabed area. This is also the case for the cementing operation for the two first sections. It is of utmost importance that the conductor casing is vertical aligned (<1-2 degrees) and cemented properly to avoid additional stresses to the wellhead, BOP and riser. This is especially important in deep water due to weak surrounding formations. Further procedures for the top hole operation are to cement the wellhead in place together with the 20” surface casing and convey the BOP and marine drilling riser. When a marine drilling riser and BOP are in place, the rest of the well can be drilled and cased using advanced fluids which can now be diverted back to the drilling vessel for cleaning and re-use through the riser conduit. The schematic below shows a typical top hole drilling procedure.

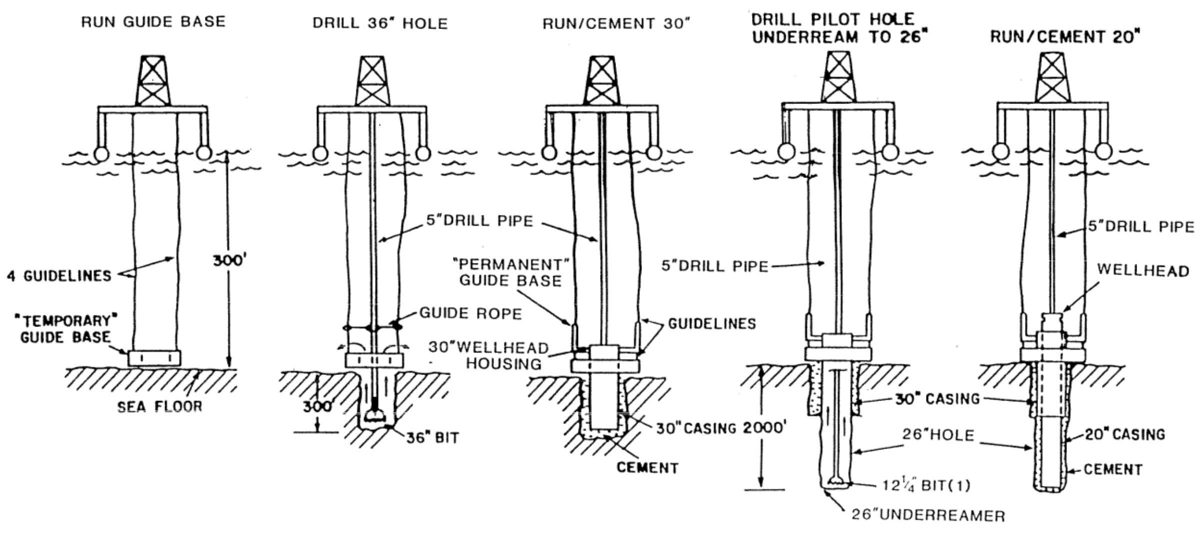



**Figure 3** *Schematic illustration of top hole drilling. Figure is taken from [9].*

Also a concern regarding cuttings discharge around the borehole is that the large amounts of disposed cuttings are destructive for the cementing and completion of subsea template and wellhead. To counter for this issue a Cuttings Transport System was developed to transport the cuttings away form the drill site.

## 2.2 Cuttings Transport Systems

This subchapter is inspired by reference [10] and [11]. A Cuttings Transport System (CTS) is implemented when the accumulation of cuttings around the drill site are becoming troublesome for further drilling activities and installation of subsea equipment. To enable for this solution either a subsea pump is installed or a topside supported injector principal is used. Both methods have the same goal, to transport the cuttings away from the interest point. The two main service providers for this technology are IKM [10] Testing and AGR Group [12]. Below is an illustration of IKMs CTS setup on seabed.

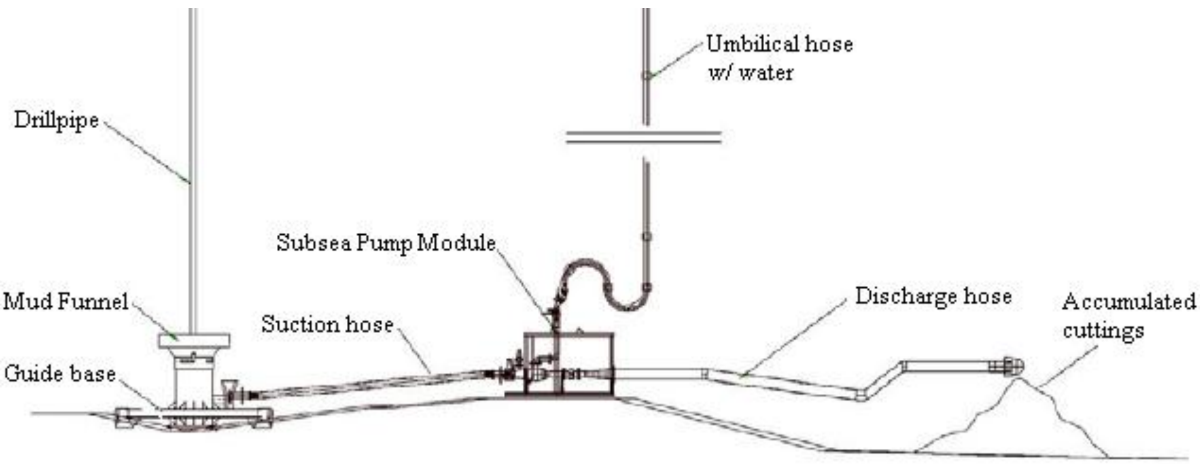



**Figure 4** *Cuttings Transport System schematic for IKMs injector technology. Figure is taken from IKM.*

Both systems use a mud funnel that is placed on top of the guide base. Inside the mud funnel an interface is formed between the seawater and the drilling fluid. The interface behaviour between the two is governed by density and surface tension, and the position of this is controlled by the pump modules suction rate. The mud funnel accumulates the mud coming from the annular outlet of the well, and redirects it out through a suction hose that is coupled to the pumping device. From the pump, the drilling fluid and cuttings are transported inside a discharge hose to a designated area on the seabed. The fluid and cuttings can be transported as far as 2000 m away from the drill site using AGRs system, and 400 m using IKMs system.

The difference in transported distance is due to the two service provider's inequality in pump technology. AGR use an electrical powered subsea pump technology, whilst IKM uses injector pump technology. The electrical powered pump from AGR is a disc pump using the centrifugal principal. The disc pump will be thoroughly explained later in this thesis under the sub-chapter "Pump Technology". IKM on the other hand pumps water down an umbilical hose from the rig, into an ejector device on seabed. When water is injected into the ejector, a venturi effect occurs as the water passes the suction hose inlet. A venturi effect is a reduction in fluid pressure as a result of fluid flow through a constricted section of pipe. The differential pressure created by the motive fluid (water) sucks the inlet fluid (drilling fluid) into the system and carries it through the discharge hose to the preferred location. Both systems need to uphold a critical velocity to avoid particle settlement in the discharge hose. Favourable operation depths for the two systems are around 300 m, but can be applicable down to 500 m. Cameras are used on top of the Mud Funnel for additional visual control.

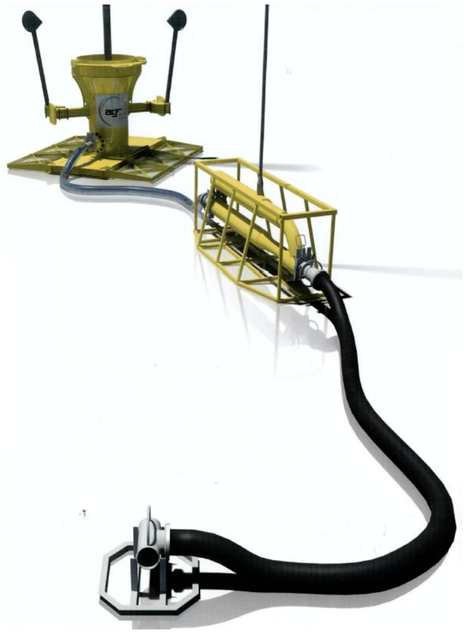


**Figure 5** *Cutting Transportation System drawing of AGRs technology. Figure is taken from AGR*

Below shows a model of conventional deposition of solids on seabed performed by the Department of Petroleum Resources [13] (DPR). This clearly indicates how accumulated cuttings around the wellbore can complicate further drilling and deployment of equipment.

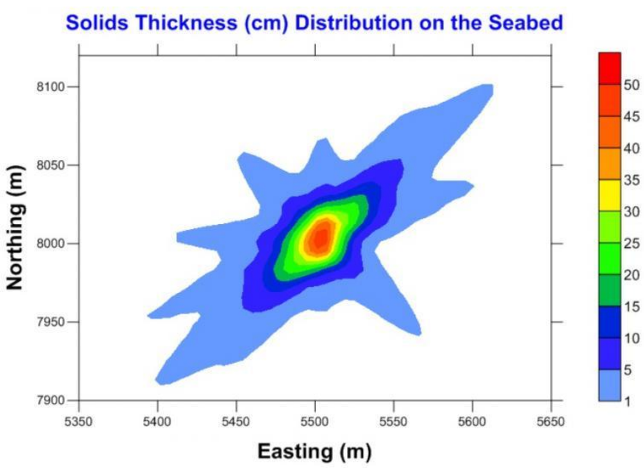



**Figure 6** *Deposition and accumulation of solids on seabed. Source: fluid-dynamix.com*

## 2.3 Riserless Mud Recovery

References used are [14] and [15]. Riserless Mud Recovery (RMR®) is developed by AGR and is a continuation of their CTS technology. Instead of transporting the drilling fluids and cuttings for discharge to seabed, there is now implemented a return hose from the pump that is connected back to the drilling facility. Through this mud return line (MRL), the drilling fluid and cuttings can now be retrieved to surface. This concept enables for the use of engineered fluids with the possibility to recover and re-use the drilling fluid under top hole drilling. It also reduces the environmental impact regarding cuttings discharge and the release of chemicals to the surroundings in sensitive areas. Since the first RMR® operation in 2004 on the Troll field, the technology has been used on more than 130 wells. Below shows a typical RMR® arrangement on seabed with mud funnel, suction hose, pump module and mud return line.

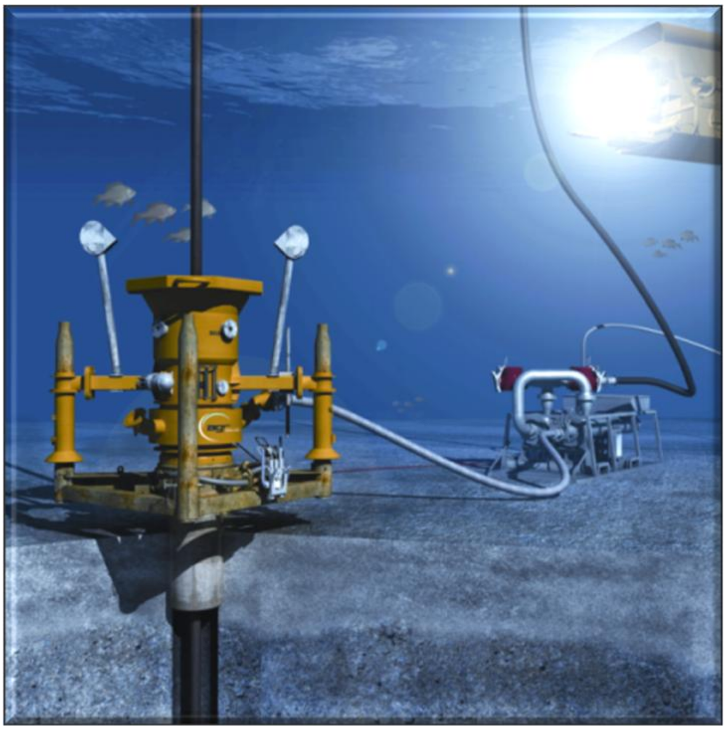
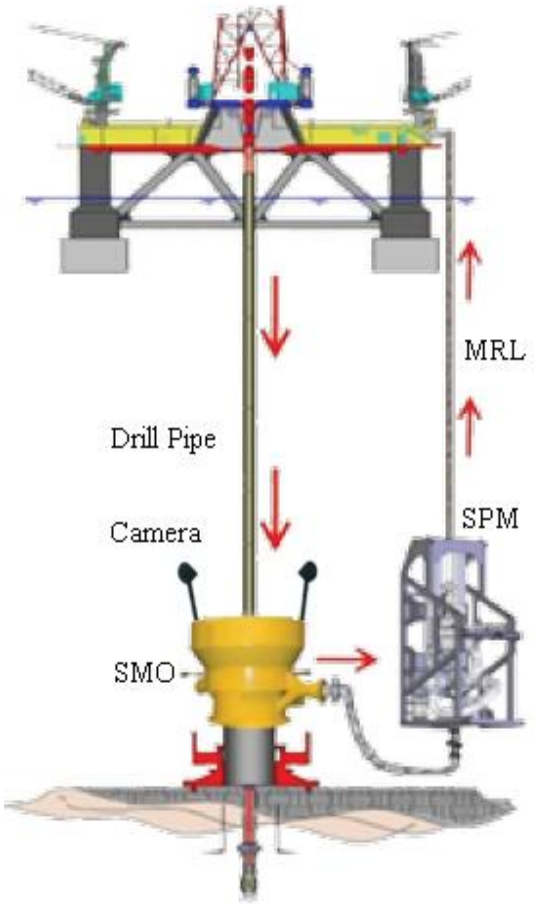


**Figure 7** *Subsea arrangement of the RMR® system. Figure is taken from AGR.*

The deployment of the system is performed by a special designed winch that lowers the subsea pump module (SPM), together with an umbilical down to seabed. The umbilical consists of a bundle of electric cables for power supply, and the MRL. A suction module (SMO) is installed on the guide base and lowered to the designated location. This is the same as the earlier presented mud funnel. This module will act as the interface sustainer between the well and the seawater column. A remotely operated vehicle (ROV) will take care of the subsea hook-up between the two installations. When drilling, the mud will be pumped down the drill pipe and up through the annulus. When the mud level increases in the SMO, a differential pressure will be recognized by a pressure sensor. This sensor, together with a PID-controller, will regulate the speed of the pump motor to maintain a constant pressure in the SMO. Additional cameras are installed on the SMO to assist visual control for the RMR® operator, and as a redundancy for the interface management. Since the SPM is pumping the returns back to surface, the hydrostatic head will be the seawater gradient down to the interface between mud and seawater in the SMO. From the SMO and down, normal conditions will apply where the hydrostatic head is created by the mud column. When circulating, an additional pressure will occur in the annulus due to the frictional resistance between the annular wall and pumping fluid.




**Figur 8** *RMR® Setup. Figure is taken from AGR.*

**Dynamic BHP:**

$$BHP_{DYN} = (P_{WATER})_{h(water)} + (P_{MW} + P_{ECD})_{h(well)} \qquad (4)$$

**Static BHP:**

$$BHP_{STAT} = (P_{WATER})_{h(water)} + (P_{MW})_{h(well)} \qquad (5)$$

It is also important to consider the maximum setting depth for the SPM depending on the pressure rating of the MRL. Since the MRL is a low pressure hose, the specific gravity of the drilling fluid and ECD inside the MRL are the contributing factors that limit its setting depth. For deeper water scenarios, several SPMs can be set in series upward along the MRL, or in series on seabed, to be able to pump the returns to surface in a sufficient manner.

### 2.3.1 Advantages

**Engineered Mud**

One of the most important advantages with RMR® top hole drilling is that it enables for the use of engineered mud instead of seawater. Using a weighted inhibited drilling mud results in better fluid loss control, reduces chemical reaction with clay, improves setting depth for casing and mitigates geohazard occurrences like shallow water flow, formation instability and shallow gas zones. Regarding chemical reaction with clay, one can increase the salinity of the drilling mud to reduce the chemical reaction potential between the mud and the formation [16]. This will mitigate the clay from swelling up and cause borehole instability. Since 90 % of wells drilled consist of shales, the use of engineered mud is clearly beneficial. Furthermore, it also maintains a thin protective layer of filter cake on the bore hole wall that hinders fluid loss to formation. Concerning the shallow water flow, it is the most significant shallow hazard problem in water depths less than 1000 ft [17]. The phenomenon occurs when drilling through over-pressured water sands at very shallow depths below seafloor. The overpressured water will start to flow into the well and generate large washouts and may cause loss of well. Using an engineered mud will, if designed right, keep the well in overbalance and oppose the ingress of water. One can also use polymer additives in the drilling mud as a preventive measure to shallow water flow. Shallow gas is as mentioned earlier in this thesis free gas or gas in solution that exists in permeable formation, and is kept back by sufficient mud weight. As a result of having a more gauge and stable bore hole, casing setting depths are greatly improved.

**Fluid Return**

Instead of the conventional Pump and Dump method, cuttings and drilling fluids are transported back to the drilling facility. This leaves no cutting accumulation around the well bore that can complicate further equipment installations. It's also more environmental friendly. Furthermore, the mud volume control is enhanced due to real-time visual monitoring of the well. Top hole mud-log data and cutting analysis are also possible when having fluid return.

**Equipment Stability**

A more gauged and stable top hole results in a better cementing job for the conductor and surface casing. This is due to a more exact volume of cement being pumped into the well for proper mounting of casing. Also, a gauged hole results in a more evenly placed cement layer around the metal pipe. Since the conductor and surface casing are to be the anchor and foundation for the wellhead, it is clearly that a solid cement job of these will contribute in a better stability for overlying subsea equipment. Confer reference paper [18], a shortfall of cement between the two casing strings can cause failure of wellhead integrity due to high cyclic loading. The best load path for external loads is when the load is obtained and shared between conductor and surface casing. This is achieved with a proper cement job where the whole annulus is filled with cement. Without exact volume calculations, such accurate displacement is hard to accomplish. Even with visual confirmation of full cement returns at wellhead, the effective cement level can drop if fragments of unstable formation break off.

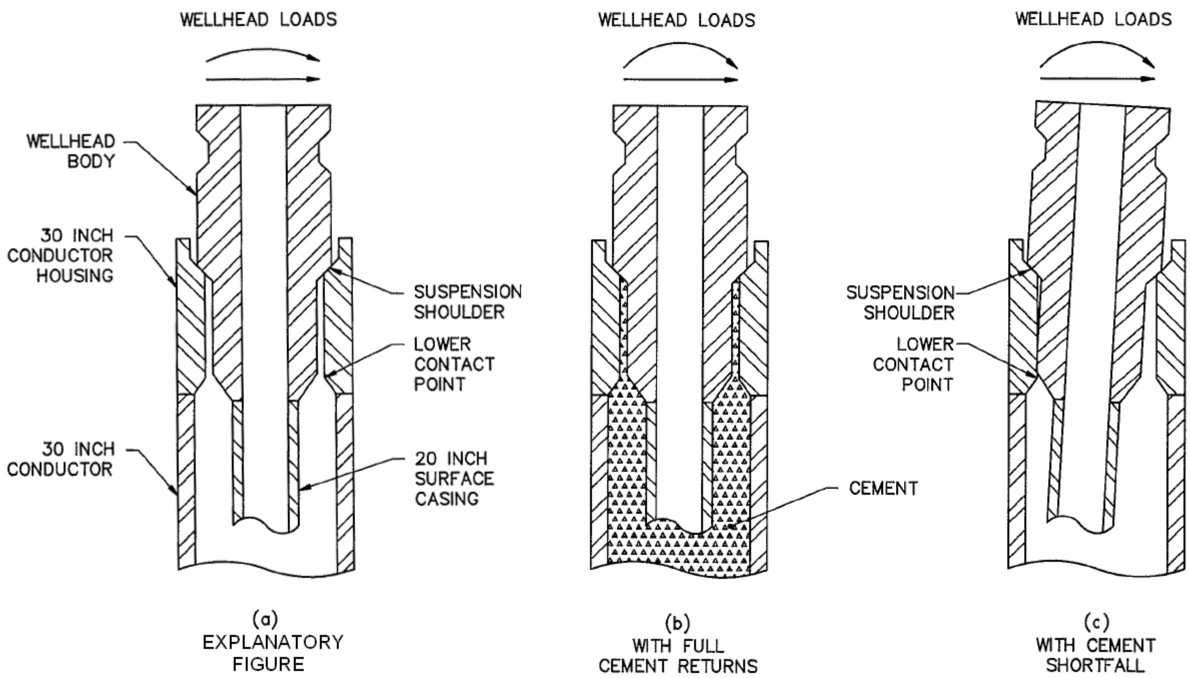



**Figure 9** *Effect of cement shortfall around wellhead. Figure is taken from [18].*

As depicted in Figure 9, a shortfall of cement due to a poor cement job can result in an unstable and wobbly wellhead and surface casing configuration. The absence of cement between the 30” conductor housing and the 20“ surface casing on schematic (c) will allow more deviation of the wellhead body and enhance the fatigue loading.

### 2.3.2 Disadvatages

**Logistics**

When new technology and methods are implemented, logistics related to these can be a challenge. Depending on rig facility and location, transportation and storage of the system can in some cases be troublesome or even not applicable. The use of RMR® can be justified with respect to logistics due to the re-use of drilling mud. The “Pump and Dump” method requires a lot of accessible drilling fluid that have to be brought to the drilling facility by ship transportation from land.

**Deployment**

Seen from the conventional side, deployment of new technologies within the normal operating procedures can create extra time spent on the operation. It requires adaptations and additional runs regarding hoisting and lowering of equipment to seabed. By having more equipment involved in the process, the overall operation becomes more critical with respect to equipment reliability, thus leave more potential for failure.

**Gumbo**

Gumbo is a generic term for soft, sticky, swelling clay formations that are frequently encountered in surface holes offshore, or in sedimentary basins onshore near seas [8]. This can cause clogging of equipment, e.g. hoses and pump, and are therefore not preferred through the return system. The creeping nature of the gumbo results in accumulation of the substance in the mud funnel. If observed, it should be dumped to sea by turning of the subsea pump while rig pump continues circulation. This applies when using a water based mud (WBM).

# 3 Riserless Drilling Systems

The main focus of this thesis is to evaluate the implementation and adaptation of a Riserless Drilling System for commercial use in the offshore industry. This involves the elimination of a marine drilling riser, even after the BOP is in place. To be able to achieve this very unusual approach of drilling a well, modifications to the conventional equipment and development of new and innovative technology has to take place. In this context, a feasibility study was therefore performed by two individual service companies to evaluate the possibility for such a system. The involved companies were Ocean Riser Systems and AGR Group. The feasibility study was initially to investigate if a Riserless Drilling System could be implemented on the Gullfaks Satellites (Gullveig, Gullfaks South and Rimfaks). The motivation behind the study was to come up with a system that eliminates the use of a marine drilling riser to minimise the lateral forces acting on the subsea wellhead systems to avoid future wellhead fatigue. Prerequisites given by Statoil were deployment and operation from an anchored, single activity semi-submersible rig with minimal deviation from conventional operations.

Furthermore, this concept might also be a solution regarding deep water and ultra deep water drilling in the future. Since the drilling activity is forced more out on larger water depths, CRD is getting troublesome for the operator due to logistics and the acting forces on both topside and subsea equipment. If this system were to be implemented and proven functional for normal water depths, it could be modified and enlarged to deal with extreme water depths.

## *3.1 Ocean Riser Systems*

Ocean Riser Systems AS (ORS) [19] was founded in 2002 and is a service provider within MPD technologies, subsea drilling and well intervention. ORS have a total of 14 employees. The largest shareholders in ORS are Energy Capital Management, Viking Venture and Aker Capital. The company have their head office at Lysaker, outside Oslo, Norway.

## 3.2 AGR Group

The company started out as AGR Services AS [12] in 1987. It later changed the name into AGR Group AS and has now over 1,800 employees worldwide. AGR Group is a supplier within services and technologies to the international oil and gas industry with a total of three operating divisions: AGR Petroleum Services, Drilling Services and Field Operations. The company have their head office at Straume, outside Bergen, Norway.

## 3.3 System Description and Equipment

Since the two conducted feasibility studies are similar to a certain extent, a general equipment presentation of the two proposed solutions will follow. The major differences will be stated in the text if needed. Primarily the differences lie in subsea hook-up and some equipment solutions. Since the Riserless Drilling System is abbreviated by AGR as a registered trademark, RDS®**,** it will be referred to as RD (Riserless Drilling System) further in this thesis.

The RD technology is largely based on the previous presented RMR® technology. As a continuation of the top hole drilling system, the RD can be used throughout the whole drilling operation for an entire well. This dual gradient approach calls for several measures regarding operational procedures and implementation of new technology. Dual gradient means that the BHP is made up by two fluid densities, in this case seawater and drilling fluid. With some fundamental modifications to the RMR® equipment, full well control can be obtained even absent of a marine drilling riser. The main components enclosing a Riserless Drilling System are:

- Lower Marine Riser Package with kill / choke lines and pod lines
- Mud funnel with level control system
- Subsea pumping module with launch system and return hoses
- BOP stack
- Control system

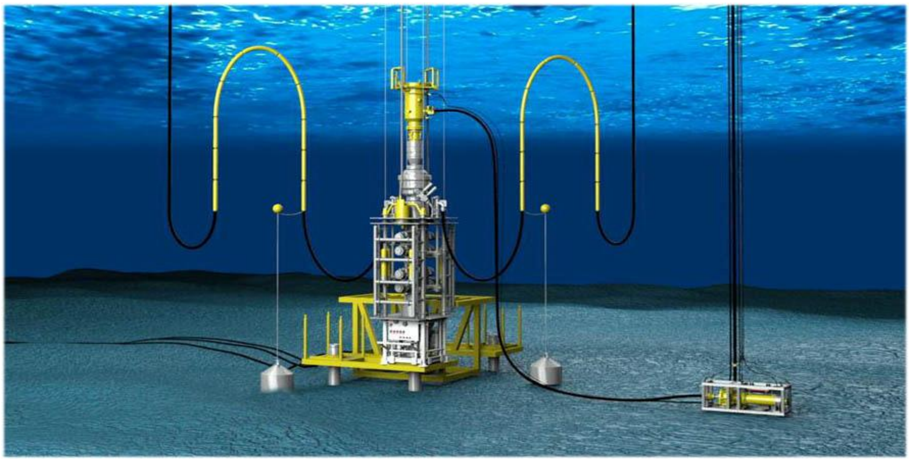


**Figure 10** *ORS Riserless Drilling arrangement Figure is taken from ORS.*

The figure above shows the thought RD arrangement on seabed as presented by ORS. As an addition to the former introduced mud funnel in RMR® top hole drilling, this system is much more complex and requires several extra components. To better understand the setup and functionality of each component, a schematic overview is presented in the subsequent figure. Furthermore, a more detailed equipment description will follow underneath to explain the individual components in a more detailed manner. The upcoming equipment description is interpreted based on reference [20, 21].

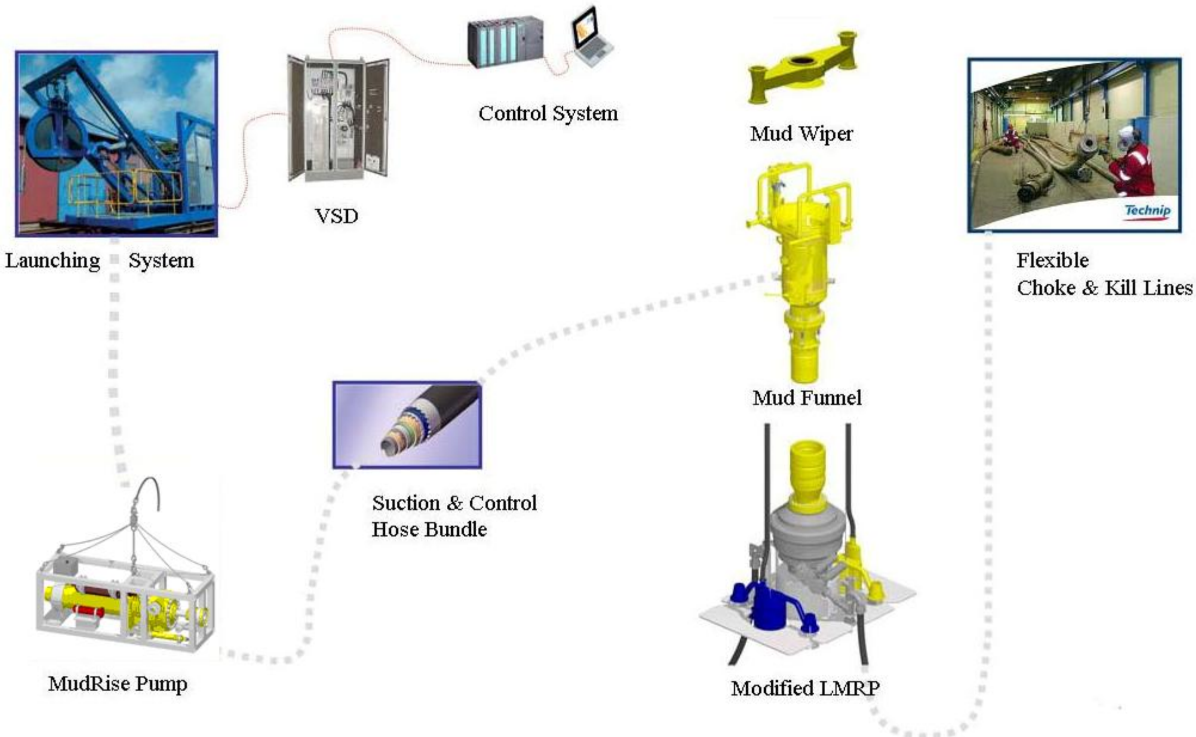



**Figure 11** *ORS Riserless Drilling System Components. Figure is taken from ORS.*

### 3.3.1 Universal Wiper Element

The wiper element is located on top of the mud funnel and consists of several rubber elements that seals and wipes off mud that surrounds the drill pipe when tripping out of the well. A total of 10 U-shaped rubber plates facing each other are stacked upwards in the element, and makes up one wiper insert. Each wiper element can have several wiper inserts depending on the individual tubular size to be run. The range in tubular size to be run through the wiper element can vary from 5" to 22". Together with a zero discharge pump system, the wiper element allows the use of OBM. It also acts as a tubular restraining frame and is lowered down diagonally on two guide lines from the moonpool winch. The tubular restraining frame is hinged to enable for replacement without pulling the tubular. To protect the guide lines, plastic polyoxymethylene is used on the funnel guides to avoid excessive wear from pipe loading when used as a tubular restraining frame. The universal wiper element is not yet System Integration Tested. This component is distinctive for the ORS design.

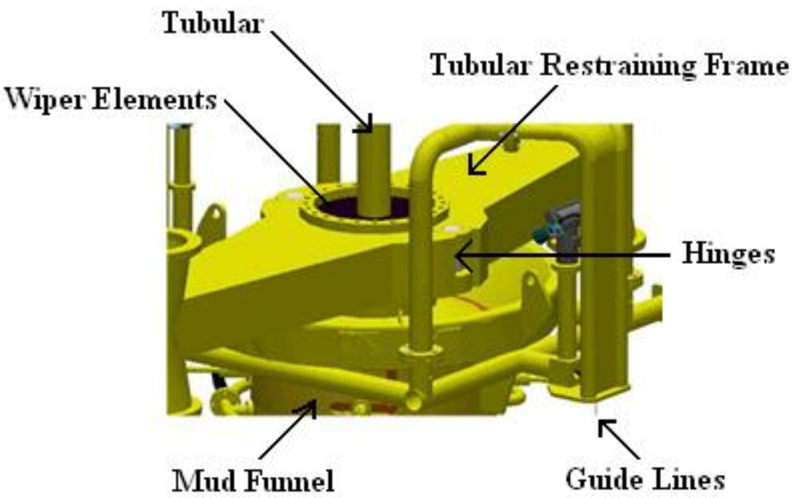



**Figure 12** *The Universal Wiper Element located on top of the Mud Funnel. Figure is taken from ORS.*

### 3.3.2 Zero Discharge System

When drilling with OBM, a zero discharge system has to be added. This system consists of an additional centrifugal pump that is mounted on the main pump module. A 2" hose is then connected to the mud funnel. The pump is on/off operated, and when activated creates an underflow of seawater above the mud/seawater interface. This will create a constantly pull of seawater downwards through the restricted area, see Figure 13. The underflow created in the funnel captures contaminants above the interface as seawater flows towards the zero discharge suction hose inlet inside the mud funnel. From the suction hose it gets transported to the zero discharge pump and lifted up to the rigs mud system. Figure 13 below shows an illustration of the zero discharge arrangement when installed on top of the mud funnel. This component is distinctive for ORS design.

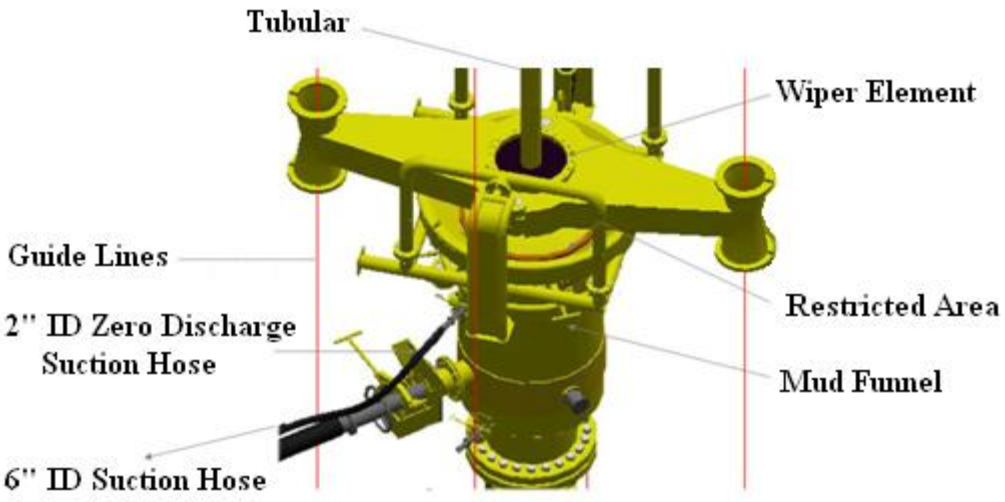



**Figure 13** *Zero Discharge Arrangement on top of Mud Funnel. Figure is taken from ORS.*

### 3.3.3 Mud Funnel

The Mud Funnel is located above the Lower Marine Riser Package (LMRP) and is a part of the volume control system. The mud funnel, also called “the bucket”, is equipped with a level sensor, cameras and lights which give the operator the ability to monitor and regulate the level manually, or automatically. Visual monitoring is used as additional safety in case the automatic level control system fails. The automatic control and display software will use algorithms for gain and loss detection. The mud/seawater interface is controlled at all times, ensuring full volume control and hindering of mud spill to the surroundings. When the mud/seawater interface moves upwards in the bucket, the level control sensor signals to the subsea pump which increases the pumps rotation per minute (RPM). The level control sensor measures the pressure inside and outside of the mud funnel to determine the change in hydrostatic pressure. The flow rate in the suction hose between the mud funnel and subsea pump increases and holds the interface at a preferable constant level. Distinctive for ORS design there will be a 2” re-circulation hose running from surface and down to the mud funnel which enables for mud replenishment to keep the mud level constant during tripping in/out of well. The re-circulation hose can also flush/clean the suction/discharge hose with clean mud.

AGR's pump allows backflow through the pump to refill mud in the mud funnel or flush the system to avoid clogging. To provide connection and disconnection of the mud funnel from the LMRP, a mud funnel mandrel is located at the bottom of the module. The mandrel will be of the same type as a standard 30" housing profile for a marine drilling riser using a H4 connector. As depicted in the next coming figures there are some deviations in design between the two service providers. The functionality is the same, but they are equipped differently. The thought solution presented by ORS is to include a zero discharge system and a re-circulation line for mud replenishment. AGR have developed a large spill tray that can capture excessive mud that might overflow the bucket. This is not depicted here, but consists mainly of an outer shell that encloses the mud funnel.


**Figure 14** *ORS Mud Funnel design. Figure is taken from ORS.*

The presented figure below show AGRs mud funnel from an RMR® setup, thus this unit would require some modifications. Amongst these, the wellhead adapter would be replaced with a H4 connector for LMRP connection.


**Figure 15** *AGR Mud Funnel design used for RMR® operations. Figure is taken from AGR.*

To be able to connect and disconnect the mud funnel from the LMRP, a connector has to be installed. Both service providers propose an 18-3/4" H4 connector profile that enables for this. The connector depicted below is a VetcoGray 18-3/4" E H-4 connector. Instead of being mounted at the bottom of a riser, it is mounted at the bottom of the mud funnel. When the connector is guided on top of the LMRP latch mandrel, a circumferential dog ring will lock into the locking grooves of the mandrel profile. A metal gasket with VX/VT (gas/liquid) seal profile will ensure proper metal-to-metal sealing between the connector and LMRP.

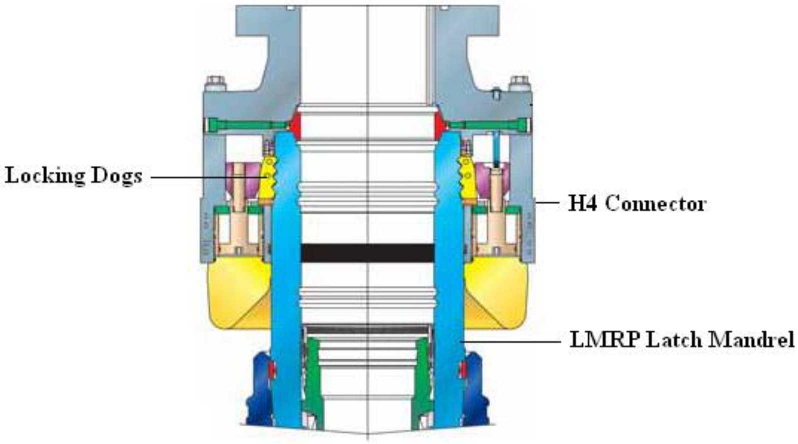



**Figure 16** *VetcoGray H-4 connector cross-sectional drawing. Figure is taken from VetcoGray [22].*

Figure 17 below shows a detailed preview of the locking mechanism. A piston moves inside a sealed hydraulic chamber which is pressurized hydraulically from surface. When the piston moves downwards, the locking dogs are forced into the locking grooves of the mandrel profile. When hydraulic pressure is applied from the low side of the piston, the piston is lifted and the dog ring is released. The connector can also be mechanically released by overpull.

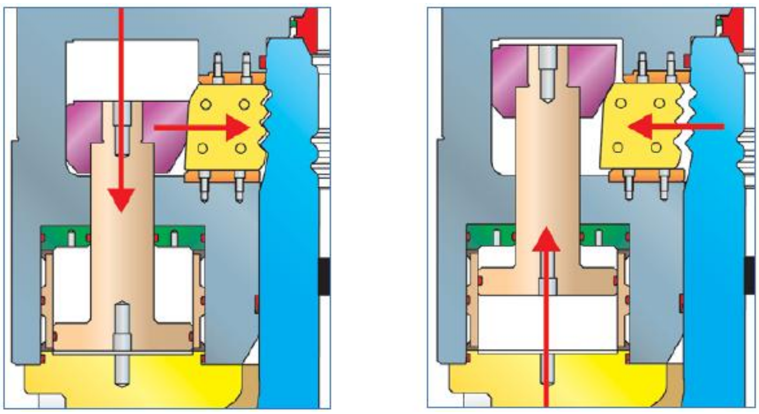


**Figure 17** *Magnified preview of the hydraulic control chamber for dog ring operation Left picture is locked position, whilst right picture is released position. Figure is taken from VetcoGray [22].*

### 3.3.4 Subsea Pump and Mud Recovery System

When drilling riserless, the conventional fluid conduit conveyed by the riser is absent. To enable for fluid recovery, the replacing elements to achieve circulation to surface are now the suction hose, subsea pump and mud return line. Both service providers have evaluated several solutions of subsea arrangement regarding hose/pod line layout and placement of subsea pump, but have come up with two different solutions for implementation on GFS. The pump has been discussed to be placed on top of the LMRP, hang freely in the umbilical or stationed on the seafloor adjacent to the subsea stack. ORS have recommended a solution where the pump is placed on the seafloor adjacent from the subsea stack. If subsidence of pump into the unconsolidated mudline is a problem, it will be equipped with mud mats to distribute the weight on the seafloor. With this solution a suction hose will connect the mud funnel to the inlet of the subsea pump. Figure 18 below shows ORS pump module as intended.

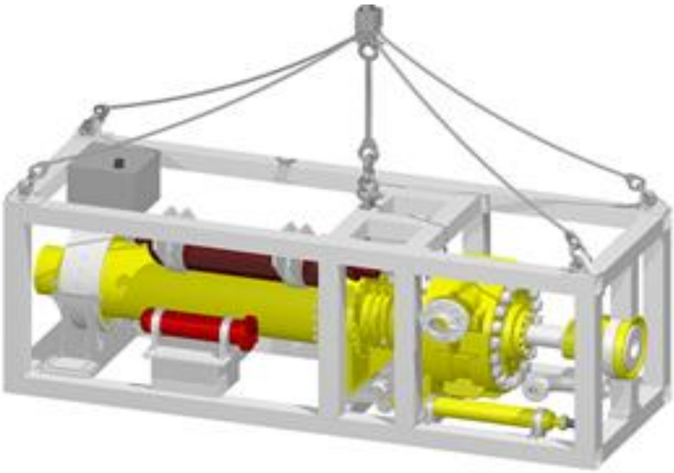


**Figure 18** *ORSs Subsea Mudrise Pump System. The module will be placed on seafloor and equipped with mud mats if needed. Figure is taken from ORS.*

AGR on the other hand recommends that the pump is mounted directly on top of the LMRP. By combining the subsea pump and the mud funnel, the suction hose can be eliminated. This is quite beneficial because the suction hose can collapse if the suction pressure gets too big and cause a halt in the operation. It also results in a tidier subsea configuration with less individual parts at seabed. Both companies recommend a pliant wave configuration (see Figure 21) for the hoses and pod lines that space out from the subsea installation. Furthermore, as mentioned earlier, the pump is automatically controlled by a level control sensor and a PID-controller for both cases. A topside Variable Speed Drive (VSD) regulates the subsea pumps power supply accordingly. The visual monitoring and control by camera is meant as redundancy measures only. The disc pump, which will be thoroughly explained later, creates enough head to lift the hydrostatic fluid column in the MRL up to surface. The MRL is a 6” ID discharge hose that consists of 15 m flexible hose sections. It is made of nitrile butadiene rubber (NBR), reinforced with high tensile textile cords with embedded steel helix and antistatic wire. From top of the MRL, the returns will be tied back to the rig flow line and processed through the shakers as normal. Figure 19 shows AGR’s field proven modified SPM which allows the mud funnel to be placed in the center.

**Figure 19** *AGRs Subsea Pump Module. The pump has a U-shape to allow room for the mud funnel and passage of tubular in the center. Picture is taken from AGR.*

### 3.3.5 Lower Marine Riser Package

The LMRP is located above the BOP, and acts as the junction point between the BOP and the mud funnel. The LMRP is equipped with connection points for flexible kill and choke hoses (k/c hoses), pod lines, mud funnel latch mandrel, annular preventer and gas relief valves for trapped gas. Some fundamental changes with the modified LMRP compared to conventional LMRP is the removal of the riser adapter and lower flex joint. Also the hydraulically operated mud funnel latch mechanism differs from conventional setup. The LMRP is together with the mud funnel, a part of the fluid recovery system. The figure below is a proposal from ORS on how the modified LMRP could look like. The mud funnel hydraulic latch mandrel will act as the connection point for the H4 connector on the mud funnel. The hydraulic pod lines for well control will be unchanged, but instead of going along the riser to surface, they will space out from the installation with a pliant wave configuration. The k/c hoses will have similar arrangement as the pod lines, but hang downwards from a gooseneck for better load handling of the heave motion of the rig. The gooseneck connection can be operated by ROV if replacement of hose is necessary. The flexible k/c hoses are quite extraordinary compared to CRD and will be further explained in the upcoming subchapter.

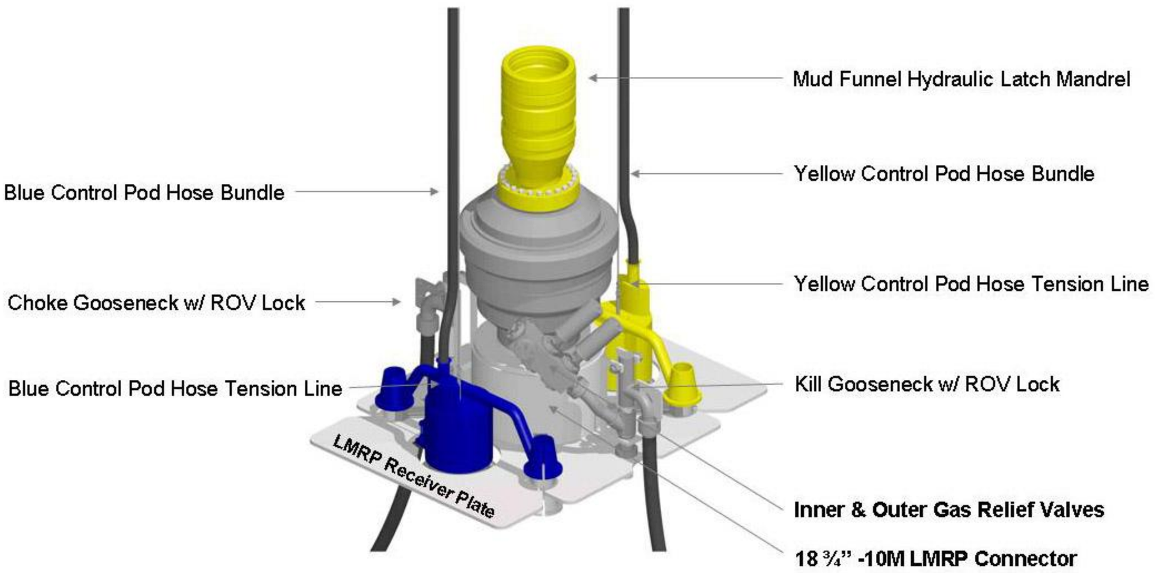



**Figure 20** *Modified "Built for Purpose" Lower Marine Riser Package schematic. Figure is taken from ORS.*

### 3.3.6 Flexible Kill and Choke Hoses

When absent of a marine drilling riser, new flexible kill and choke hoses have to be adopted. Conventionally the k/c lines are clamped and integral alongside a rigid riser stretching from BOP and up to the surface drilling facility. Now they have to be replaced with flexible k/c hoses that have to hang separately down to seabed without the protective housing of a marine drilling riser. This also applies for the hydraulically operated pod lines that control BOP and other subsea equipment. The k/c hoses proposed are standard 38 m long Coflexip® sections that are commonly used on floaters as moonpool drape hoses. These are expensive high pressure hoses, and together with the storage and deployment adaptations constitute 1/3 of the total equipment costs. The lowermost portion of the hose will have a pliant wave configuration; see Figure 21, which is maintained by buoyancy elements to compensate for the heave movements created by the rig. It is also suggested to introduce a clump weight for seafloor anchoring that will contribute in stabilizing the vertical section of the hoses. An advantage of having flexible hoses is that they are more accessible and easier to replace in case of a damaged section. Also a major advantage is that the flexible k/c and pod lines can stay connected even after an Emergency Quick Disconnect (EQD) due to its additional length. This maintains full well control despite rig being moved off well center. A disadvantage on the other hand is the need for reinforced equipment both topside and subsea due to the extensive weight of the heavy Coflexip® hoses. For the GFS case a total length of 190 m is required for 135 m water depth. Since the hose weigh 83,16 kg/m, one length will have a weight of 15,8 tons in air, and 11,6 tons if immersed in water. Every operation needs two of these lengths, kill and choke hose, thus the load will be significant in the hose connection point topside. A detailed engineering design should therefore be conducted regarding reinforcement of supporting equipment. As an alternative to the flexible k/c hoses a continuous reel-dispensed coil have been proposed by the companies Deepflex Inc. [23] and Technip UK Ltd. [24]. Due to uncertainties regarding approval and qualification testing of these reel-dispensed coils, they have not been further evaluated at this stage.

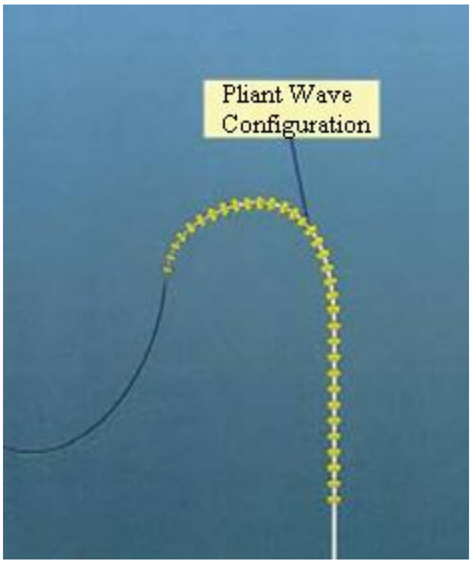



**Figure 21** *Pliant Wave Configuration of k/c hoses achieved by buoyancy elements. Figure is taken from ORS.*

### 3.3.7 Blow Out Preventer

The BOP is located above XT/wellhead and is a secondary barrier element. The proposed BOP for RD is a conventional 18 ¾″ BOP stack with four rams. Also included in the well control package is an 18 ¾″ annular preventer in the LMRP. The BOP ram configuration will consist of shear/blind ram, fixed ram for drillpipe (5”) and two variable bore pipe rams for the variety of tubular sizes applied. For workover activities, a reconfiguration of the BOP stack should be performed to include casing rams to be able to cut the casing string. This configuration is not an absolute requirement, but necessary to achieve full safety level. A five ram BOP stack will hence induce a much larger load on the underlying equipment such as christmas tree (XT) and wellhead. This is due to the additional ram weight and the corresponding stack mounted accumulators. The accumulators enable closure of BOP even when disconnected from the rig. As an additional redundancy to BOP control, an acoustic control system will back up the primary BOP control system. The BOP will be conveyed on drill pipe, contrary to the conventional riser BOP deployment.

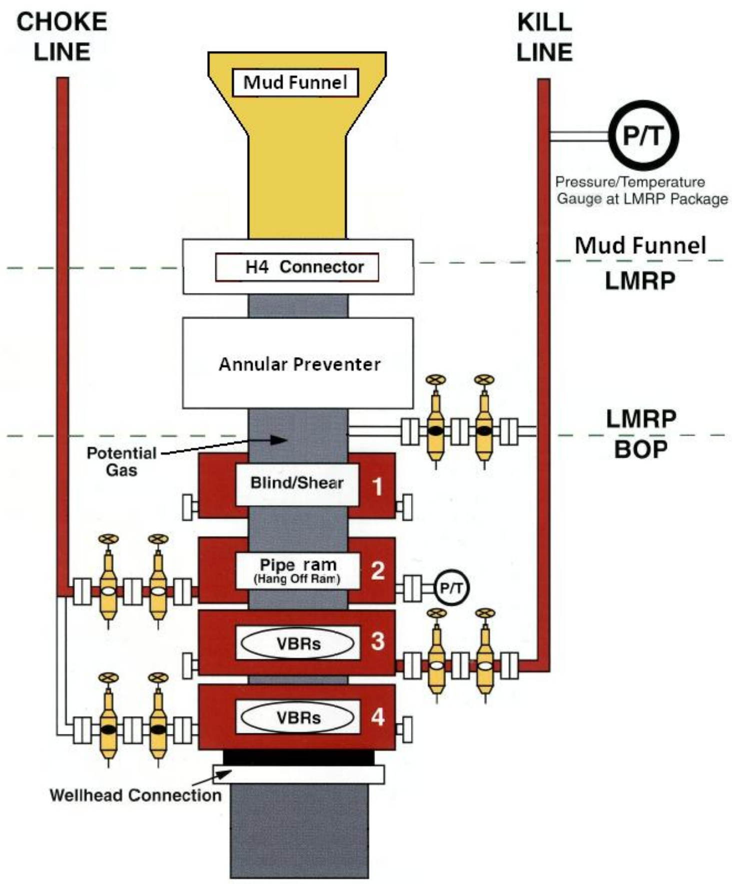



**Figure 22** *The subsea arrangement of an 18 ¾" BOP stack with four rams, LMRP and Mud Funnel. Figure is taken from reference [25] and modified.*

Different rams are installed in the BOP to obtain several closing possibilities depending on the well control scenario.

**Pipe ram** is designed to close and provide good seal around one particular diameter or sized pipe [25]. The ram is equipped with a self-feeding rubber packer that seals for pressure and flow in the annulus. It is very important that the tool joint of the pipe is clear of the closing area which the pipe ram is closing around. This is due to the tool joint having a bigger OD than the pipe itself, thus crushing the joint or damaging the pipe ram resulting in insufficient sealing of the annulus.

**Blind ram** consist of a large packer element that is capable of closing the entire hole when absent of a tubular through the BOP. The sealing ability should be tested to withstand full pressure rating which can occur in the well.

**Shear ram** have special shear blades that are able to cut through tubular goods. These are tubulars like normal tubing, drillpipe, collars etc. Hydraulic boosters may be necessary for additional force to be able to cut through strong goods.

**Blind/shear ram** is a combination of the two last mentioned rams above. This type of ram can cut the tubular and blind the whole closing area if required in one go. This is beneficial since the operator saves time by using one set of rams to perform the job of two rams. Quick response and time saving is essential in well control situations.

**Variable bore ram** is able to seal around several sizes of pipe. The packer element contains steel reinforced inserts which provides support for the rubber sealing element when activated. This ram can serve as both primary and secondary ram for any given pipe. Referring to [25], the VBRs performed comparably to pipe ram packers in standard fatigue tests.

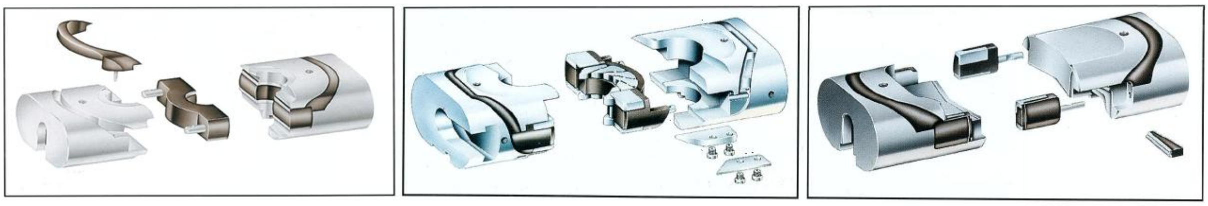


**Figure 23** *Pipe ram, variable bore ram and blind/shear ram blocks used in the BOP stack. Figure is taken from reference [25].*

### 3.3.8 Basement Deck

The basement deck is a new tailor made component specially design for the Riserless Drilling Systems k/c hoses. Two basement decks are proposed to be located underneath the rig main deck that will serve and support the k/c hoses. Each deck is equipped with a parking stab and a flexible jumper connection. The parking stab will act as a hang off point for made up hoses prior to installation. The flexible jumper connection provides a mechanical connection to the existing rig hard pipe systems. When the LMRP is ready for deployment, the awaiting hoses can be picked up from the basement deck and connected as intended using the rigs winch system. If the rig is to be moved, the prepared underlying u-shaped hose length can be hoisted up in the derrick to avoid complications with the rigs pontoons. The basement deck is a special and expensive proposal, but might be a necessity for RD on deeper water. This solution is distinctive for ORS design. AGR has not yet planned the operational deployment of the k/c hoses on a detailed level, but confer reference [15] the lines will be made up while running the BOP. For GFS the total k/c length equals five hose sections for each line resulting in a total of ten connection points. It will therefore not lead to any particular, noticeable difference in time spent for the two procedures. This depends on whether or not the rig is capable of running single or dual activities. The prerequisites given by Statoil for this case was a single activity rig, thus an evaluation of the two has to be performed to determine best practice.

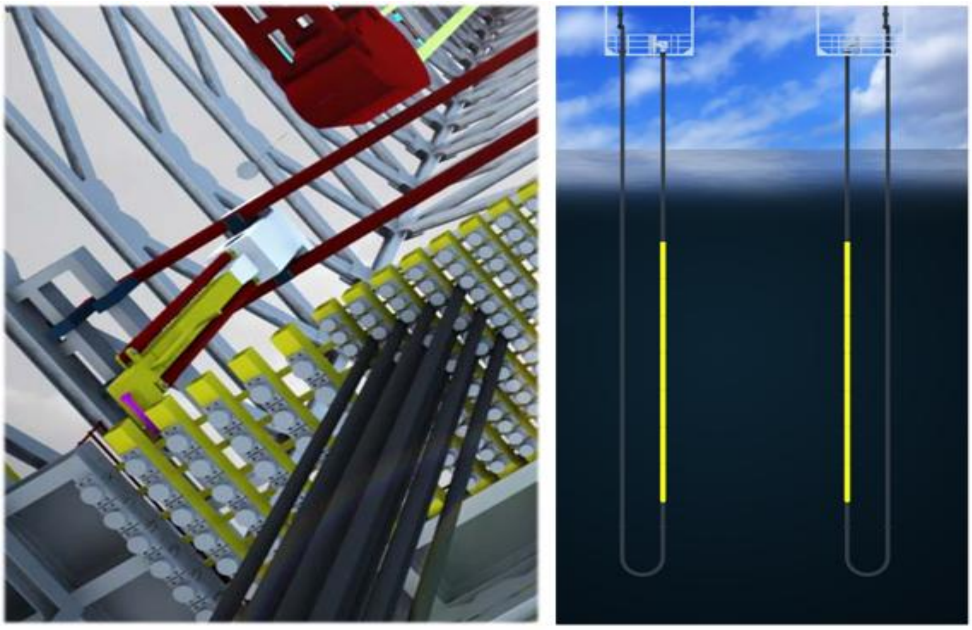


**Figure 24** *The picture to the right shows the pre-built k/c hoses hanging from ORSs proposed basement deck. The picture to the left shows the k/c hose "stands" hanging from the finger table. Figure is taken from ORS.*

### 3.3.9 Launching System

Both systems will use a dedicated umbilical winch for deployment of the pump and auxiliary lines. The auxiliary lines will be spooled on drums that will be run in and out by electric power. It is important that inspections are made to evaluate the structural integrity of the selected area on the rig. This is due to the heavy load the launching system and the lowering/hoisting activities will induce during operations. Dependent of the rig used, the location of the umbilical winch can vary. If a standalone subsea pump adjacent to the subsea stack were to be used, the best practice for deployment of the system would preferably be launching of umbilical's and pump "over the side" of the rig, and run the BOP stack, LMRP and mud funnel through the moon pool from the derrick tower. A moon pool is the opening in the floor beneath the platform which gives access to the water below by aligning the drillfloor above the relevant slot. This allows for simultaneously deployment of the two separate units which will save rig time. If a secondary moon pool (dual activity rig) exists and is available, this could be used instead of the dedicated umbilical winch for pump deployment. For the case where the pump is integral on top of the LMRP, only deployment through one moon pool is necessary. For both cases the MRL and auxiliary lines should be launched from the side of rig to achieve a natural distance to the stack and avoid entanglement with drillpipe and other equipment. Figure 25 below shows the umbilical winch for pump and auxiliary line deployment.

**Figure 25** *Dedicated umbilical winch. Figure taken from ORS.*

### *3.3.10 Control System Container*

The control container contains power supply for the entire system. For more than three pumps, an additional power container is needed for sufficient power supply. Also in the control container, there is a control room with a PC that controls the subsea pump. Together with a Programmable Logic Controller (PLC) the PC will be the controlling device of the entire system. The level control system has four main tasks; mud level measurement, automatic level control, kick/loss detection (volume control) and logging related to mud level measurements. Telemetry cables are located inside the umbilical for data transfer between the subsea differential pressure sensor on the mud funnel, and the PLC. The sensor will provide redundant level measurements that the PLC will use to manage the subsea pump's RPM through the VSD. This ensures that the interface between the drilling mud and the seawater is kept within the bounds of the funnel.

The block diagram below shows an overview of the action sequence architecture for the given control system. A data engine (computer) will be the interface for manual and automatic control. The PLC will use the pre-programmed conditions set by the operator to obtain the setpoint in the mud funnel. The setpoint is the preferable level height that is wanted in the mud funnel. If the levels vary from this value, adjustments will be made by the PLC to counteract for the changes and maintain the selected mud/seawater interface level. A constantly feed of data is sent to the PLC from the subsea instrumentation for verification of the changes made to the system.

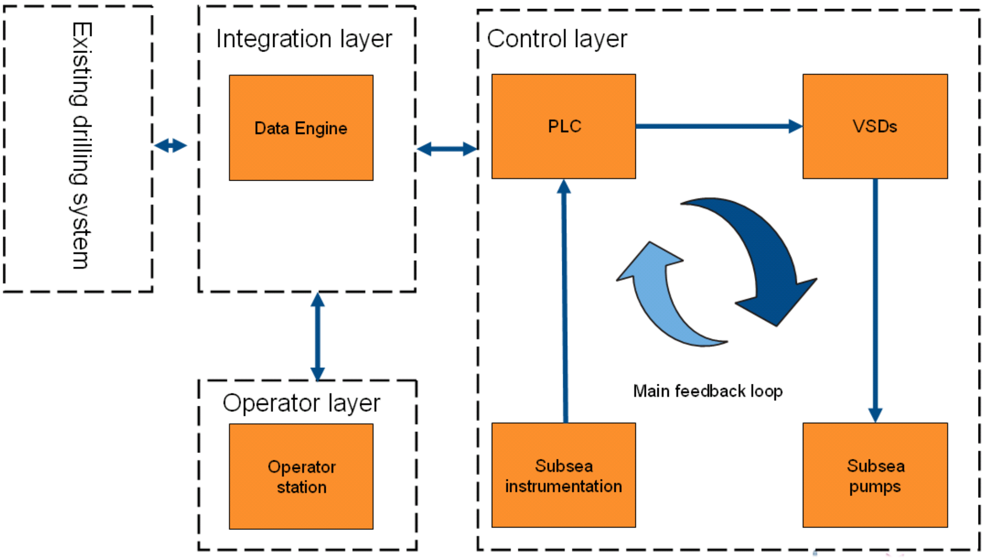



**Figure 26** *Action sequence architecture for the Control System. Figure is taken from ORS.*

The outer boundary limits (High High and Low Low) for a given setpoint in the mud funnel is an indication of the level being outside its normal "band". If so, alarms will notify the operator so that remedial action can be taken. This might involve emergency procedures entailing BOP closure if normal level is not established after the performed measures. The alarm boundaries are defined in the figure below.

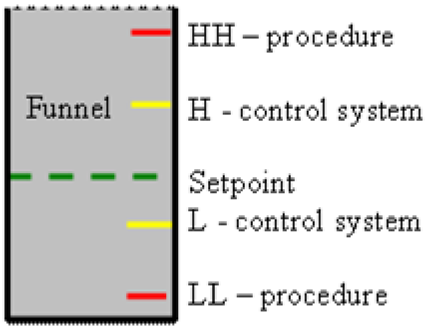



**Figure 27** *Level Control System alarm boundaries. Figure is taken from ORS.*

To understand the PLCs mode of operation, a more detailed description is required. In simple terms a PLC is a digital computer used for automation of electromechanical processes according to reference [26]. It uses a ladder-style logic circuit principle, which allows the programmer to create several switches that are on/off operated, or adjustable switches that regulates depending on the magnitude of the input signal. The PLC monitors its connection inputs, and sends out a signal through the output based on its configuration. A pre-configured circuit form will determine the output and make changes to the system based on the input. Figure 28 below is an example of how a circuit is programmed to perform a specific task. If the High Level signal from the sensor is activated, the switch controlling the VSD will enhance pump RPM based on the magnitude of the digital signal. If Low Level is reached, the circuit is cut and the VSD stops the pump. The level control system is configured to maintain a constant level (± 20 cm from setpoint), thus this process will continue during the whole operation.

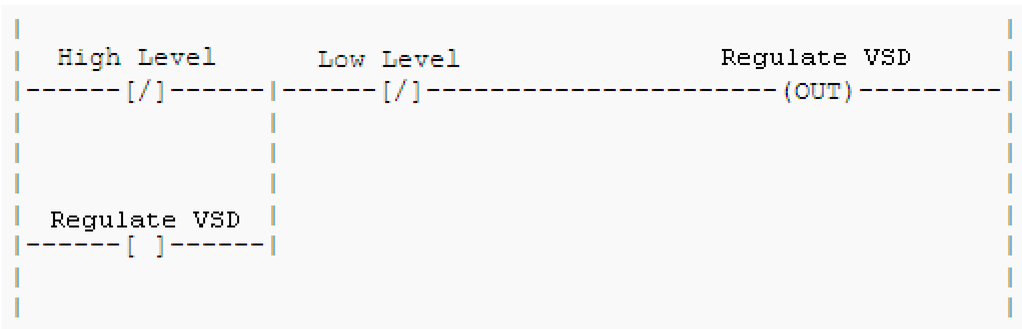



**Figure 28** *Simplified circuit form for VSD control.*

Since most modern PLCs have an implemented PID-controller, the level adjusting process is conducted in a steady manner. The PID-controller is an electronic control unit that is used to regulate electrical and mechanical devices in the industry [27]. It uses mathematical algorithms, a so called “three-term control”; **P**roportional, **I**ntegral and **D**erivative values, hence the name. By utilizing the three parameters above, the controller regulates the process based on the error magnitude from setpoint. The error magnitude is the difference between measured value, and the desired setpoint. **P** depends on the present value. If the measured value deviates from the desired value, the proportional term will change the output proportional to the current error value. **I** depend on the accumulation of past errors. By integrating the magnitude of the error over time, it finds the integral gain (accumulated offset) and adds this to the controller output. **D** predicts future errors. It calculates the slope gradient of the error magnitude over time to slow the rate of change of the controller output. This is done to smooth the output and get a more stable process. The weighted sum of the **P-I-D** terms will constitute the output signal that regulates the process. In RD this process is the control of the VSD that regulates the pump RPM. The input is error magnitude of mud/seawater interface from desired setpoint, and the output is the compensatory measures for VSD adjustments. Figure 29 below shows the tuning parameters in block form for a PID-controller.

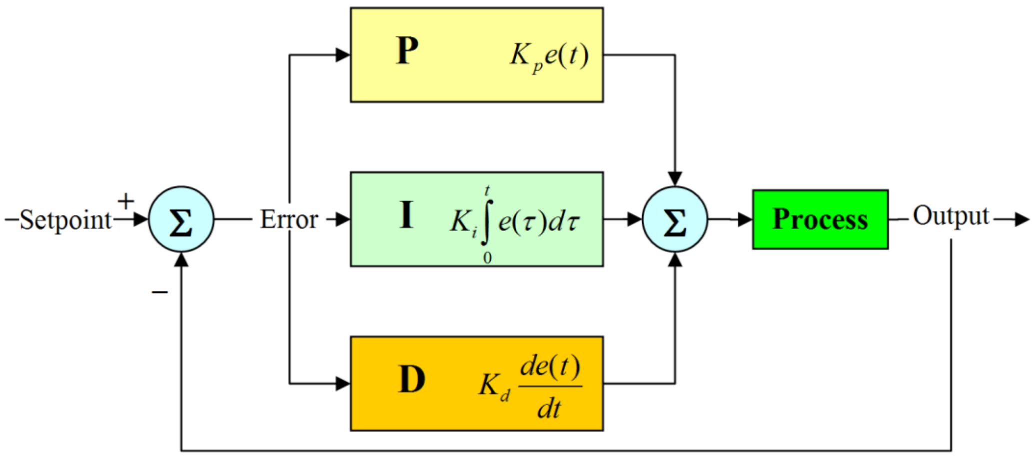



**Figure 29** *Block diagram of a PID-controller. Figure is taken from [27].*

## 3.4 Advantages

All the topics mentioned below have been, or will be discussed later in the thesis. But for the sake of clarity and orderliness of the thesis they will be presented shortly in this section.

### 3.4.1 Wellhead Fatigue

This point is the main goal for the implementation of a riserless system on GFS. Since the satellites production initialisation around year 2000, numerous connections days have been spent on the wellheads. Connection days means days were a riser is mounted on the subsea structure, e.g. during drilling, completion, workovers etc. This has resulted in uncertainties regarding the wellheads integrity due to riser loads and the possible presence of hotspots around the upper area of the wellhead system. A stress-reduction alternative was therefore sought to mitigate the majority of loads induced while doing well surgery. A riserless system is much gentler to the subsea structure as there is no firm transfer of forces from the rig. Rig movement will therefore have little to say regarding induced loads on the wellhead system.

### 3.4.2 Reduced Mud Volume Required

Especially for large water depths, this paragraph is particular beneficial. A typical 18 ¾ " riser has a significantly larger volume than a 6" MRL. This will require a large amount of inactive drilling fluid to be available on the rig as 150 % kill mud of the entire well volume has to be present topside during drilling according to NORSOK D-010 [7].

### 3.4.3 Elimination of Riser

By eliminating the riser, no inspection would be required of the large and hard manoeuvrable pipe. Based on working environments, extensive analysis's has to be performed to determine its integrity for further operations. The flexible k/c hoses would also have to be inspected and evaluated for further use, but due to less induced loads the time interval between tests might increase. Being absent of a riser will also mitigate fatigue on both subsea structure and the conduit itself. Also pipe handling on rig would be positively affected due to less logistical concerns, easier lifting operations and the possibility of readily available conduit stands and k/c hoses in the finger table.

### 3.4.4 Lighter Drilling Vessels

Since less weight in terms of drilling equipment is required during RD, an older generation drilling vessel can be applied. The weight savings can be related to less storage and handling systems needed for conduits, less amount of drilling fluid required on the rig to maintain the specified volume requirements, elimination of casing strings, easier station keeping and less heave compensating measures to name a few. A Riserless Drilling System would consequently result in some deck space requirements as well, but not to the same extent as for a rigid riser system for large water depths. The size of the drilling vessel is of course dependent on the amount of simultaneous operations required, but for a single activity rig this system would be beneficial in terms of weight, storage, pipe handling and mooring. Hence a lighter drilling vessel can be used to drill a well, especially in large water depths.

### 3.4.5 Time and Cost Saving

This is a very broad topic which can be debated in several ways. If a Riserless Drilling System were to be used for the top hole as well, in addition to post BOP, the time and cost for this operation could be performed with positive results. The use of engineered mud for top hole drilling will, as mentioned earlier, mitigates geohazard occurrences that would otherwise make a halt in the operation, or in a worst case scenario result in loss of well. Also the procurement of a riser system and inspections related to these would cease, and the heave compensative measures could be reduced to a minimum due to the pliant wave configuration. Due to an increase of operability in the drilling window as a result of the effective mud weight (EMW) in the well (combination of seawater and mud column), fewer casing set points are required. This saves time spent on the operation and increases productivity as the drainage dimension gets enhanced (larger tubulars to bottom). Furthermore, the less use of inactive drilling mud would be beneficial regarding the drilling expenses associated with the well. Also wellhead issues related to fatigue would be highly improved, which could otherwise result in the need for wellhead replacement or permanent plug and abandonment (PP&A) of well. A Riserless Drilling System can also operate in worse weather conditions than a conventional riser system, resulting in reduced wait-on-weather-time.

### 3.4.6 Fluid Volume Control

With less total drilling fluid in circulation, a better volume control is achieved. Volume measurements for a Riserless Drilling System would be more precise in terms of the level sensor in the mud funnel, more stable level readings of fluid returns as it is unaffected of heave motion, and monitoring of the subsea pump RPM. Also particle settlement in a conventional riser system due to a decrease in fluid velocity as a result of diameter enlargement, could promote imprecision's regarding fluid volume control.

### 3.4.7 Riser Margin

A riser margin is the additional mud density required to keep the well in overbalance after riser disconnect. Since for a Riserless Drilling System where the riser is absent, this principle applies at all time. The hydrostatic column consists of seawater down to the mudline, and drilling fluid from the mudline down to the bottom of the well. By having a heavier drilling fluid with an incorporated riser margin, the operability within the drilling window gets enhanced since the driller can stay closer to the pore pressure, in addition to have a better pressure gradient slope while drilling as a result of the EMW. Furthermore when using a Riserless Drilling System, the BHP will not get affected if a disconnect is required as the conditions are equal before and after. This is a major advantage in terms of well control.

## 3.5 Disadvantages

### 3.5.1 Emissions

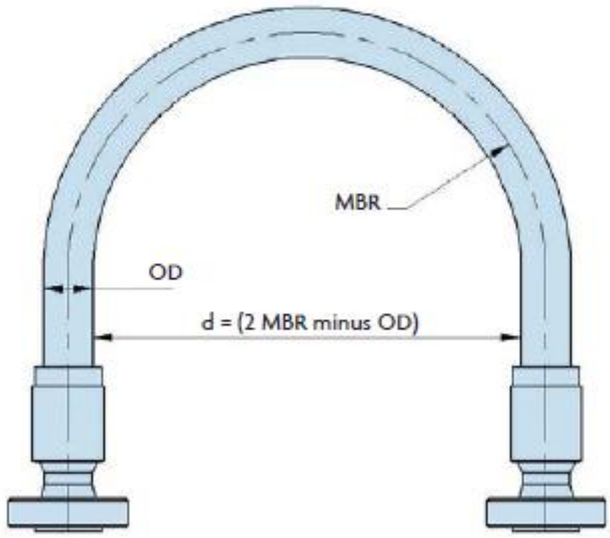
With a riser system the conduit stretches all the way to surface without leaving any contact point for seawater and drilling fluid to encounter. For RD on the other hand, there exists a mud/seawater interface in the mud funnel which keeps parted by density and surface tension alone. This might lead to emission of drilling fluid to the surroundings while tripping in and out of the wellbore is performed, a level failure occurs or a too large U-tube is taken. One should never surpass the buckets capacity to obtain a U-tube. A further explanation of what a U-tube is will follow in the next chapter. It is therefore concerns regarding the use of oil based mud (OBM); hence, extra considerations have to be taken into the account when applying an OBM with a Riserless Drilling System. Nonetheless, this can be discouraged by the universal viper element and the zero discharge system.

### 3.5.2 Equipment Dependent

In all drilling operations the progress is dependent on the equipment to work. For a Riserless Drilling System, the inbound components are reliant on each other for the volume control to be sufficiently maintained. A pump stop or deviation in sensor level readings may result in large spills and shut in BOP. These are serious incidents which are both associated with substantial costs and non productive time (NPT). Regarding pump redundancy, it is suggested to include an additional pump in case of pump failure, or if maintenance is required. Cameras are installed on the mud funnel to act as an extra visual confirmation on the mud/seawater interface height.

### 3.5.3 Flexible Hoses

In most cases a rigid pipe is preferred when coming to liquid transportation due to higher pressure ratings. Also, a rigid pipe is usually more resistant to abrasive materials in the liquid flow than flexible hoses consisting of softer materials. The manufacturer, Technip [3], of the Coflexip® flexible hose proposed for the Riserless Drilling System states that this hose can be stronger than the pipe work it is connected to, and thus rarely a "weak point" of the system. Confer same; *"The line is resistant to bending, including frequent or continuous flexure with the imperative condition that the minimum bending radius (MBR) is not exceeded"*. Special concerns must therefore be taken to maintain its integrity regarding configuration and storage. The calculation example below represents the minimum distance, *d*, between the two surfaces before being affected of the bending radius.




**Example:**

$MBR = 12 * ID \;\; (rule\ of\ thumb)$

$d = 2 * MBR - OD$

$d = (2 * 12 * 6'' - 7{,}5'') * 0{,}0254$

$\Rightarrow d \approx \underline{3{,}47m}$

| | |
|---|---|
| Inner Diameter (ID): | 6" |
| Outer Diameter (OD): | 7,5" |

**Figure 30** *Required minimum distance before being affected of flexure. Figure is taken from [3].*

Furthermore, corrosion of the armour wires in the hose or ageing of the inner liner can lead to a burst scenario or a high pressure leakage. Thorough routine inspections and testing are therefore a necessity. Also to be noted, the high pressure flexible hoses are as mentioned very expensive, constituting 1/3 of the total equipment costs.

# 4 Challenges Related to the Concept

## 4.1 U-tube Effect

Confer the Schlumberger glossary, U-tube effect is described as follows; *"In a U-tube manometer, the height of one leg of fluid changed by altering the density of some of the fluid in the other leg".* This means that if one of the legs has a heavier static column than the other, it will push the lighter fluid column upwards to counteract for the differential pressure. This pushing effect will continue until the hydrostatic pressure difference between the two equalizes and falls into equilibrium. The schematic drawing to the right shows the U-tube effect for a riserless scenario.

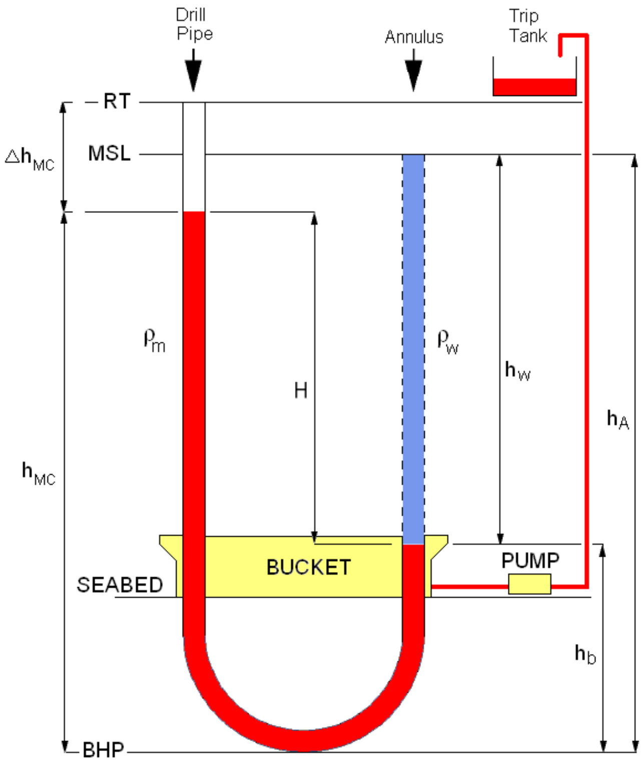



**Figure 31** *Illustration of the U-tube effect*

When drilling riserless the drill pipe will be one leg and the annulus will be the other. Since this system does not have an annular up to the diverter below the rotary table like in CRD operations, one will get a composition of several fluids that will make up the second column. These fluids will be the air gap, water column and annular mud column from bucket and down to bottom of well. As the density of air is 1.22521 kg/m$^3$ at 15°C according to ISA (International Standard Atmosphere), this section can be neglected regarding pressure contribution to the column. The remaining densities in the column will then be the water density and mud density. Hence, the resulting equations for the hydrostatic pressure difference between the two legs are as follows;

Drill pipe column: $$P_{DP} = \rho_m g h_{MC} \quad (6)$$

Annular column: $$P_A = \rho_m g h_b + \rho_w g h_w \quad (7)$$

Differential pressure: $$\Delta P = |P_{DP} - P_A| \quad (8)$$

Furthermore, one can use this differential pressure formula to find the equilibrium point for the heavy mud column by finding the corresponding height to the differential pressure, $\Delta h_{MC}$;

$$\text{Drill pipe equilibrium: } \Delta h_{MC} = \frac{\Delta P}{\rho_m g} \qquad (9)$$

The calculated height $\Delta h_{MC}$ from eq ( 9 ) will be the U-tubing fluid column that will flow into the bucket to equalize for the differential pressure. One can easily convert this height into a volume to evaluate the capacity of the bucket. The U-tube effect will occur every time the rig pumps shut down and circulation is stopped, e.g. when a connection is made. The speed of the U-tubing process will vary depending on hydrostatic pressure difference, mud rheology and frictional pressure loss in annulus when fluid is moving.

Wellbore breathing, also called wellbore ballooning, is also a concern that should be considered when evaluating bucket capacity. This effect is a well known phenomenon within drilling where the mud is lost to the formation during circulation, but returns into the well when circulation stops. This can in some cases be confused with a kick situation, but is easily disproved by logging the mud level change trend. When lost fluid returns to the wellbore, it can enhance the U-tube effect and reduce the bucket capacity further.

When making connections whilst drilling, it is of interest to avoid spill to drill floor. In CRD the annulus is tied back to the rig. By having the inlet/outlet approximately at the same level, the fluid level in the drill pipe can be too high and therefore result in a mud spill. To counter for this undesirable event, a slugging pill can be pumped down the drill pipe to shift the internal level downwards and create an artificial U-tube effect. This enables for a dry connection to be made. In riserless drilling on the other hand, the natural U-tube effect will contribute beneficially regarding spill on drill floor during connections.

If rig pumps are to be stopped, the subsea pump will still run with reduced speed to consume the inflowing U-tube volume in the bucket. Furthermore, regarding AGRs return system capability to resist for excessive U-tubing, the MRL will be equipped with a controllable isolation valve that does not allow fluid to return from the MRL if the subsea pump is stopped. For a worst case scenario, the pump will stop functioning, and a full U-tube will accumulate in the bucket. This must therefore be accounted for when bucket capacity is evaluated.

### *4.1.1 Calculation Example*

The U-tube calculation presented below is for a thought riserless drilling scenario on GFS with a water depth of 135 m. An increase in mud density or water height will consequently lead to a larger U-tube effect. Data for the given case is listed below. Consult Figure 31 for additional explanation of the relevant factors.

| | | |
|---|---|---|
| **Mud Funnel Data** | | |
| Diameter [m] | $d_{MF}$ | 1,15 |
| Wall thickness [m] | $t_{MF}$ | 0,025 |
| Height [m] | $h_{MF}$ | 2 |
| | | |
| **Drill Pipe Data** | | |
| OD [inch] | $d_o$ | 5 |
| ID [inch] | $d_i$ | 4,125 |
| Length of DP in Mud Funnel [m] | $h_{MF}$ | 2 |
| | | |
| **Case Spesific Data** | | |
| Water Depth [m] | $h_w$ | 135 |
| Air Gap (MSL - RT) [m] | $h_{air}$ | 30 |
| Mud Density [s.g] | $\rho_m$ | 1,2 |
| Water Density [s.g] | $\rho_w$ | 1,03 |

***Mud funnel capacity with drill pipe inside:***

$$V_{MF} = \frac{\pi * h_{MF}}{4}\left((d_{MF} - 2t_{MF})^2 - d_0^{\,2}\right) = \underline{1{,}875m^3}$$

***U-tube height inside drill pipe from interface and up:***

$$\Delta P = 0 = \rho_m g h_{MC} - (\rho_m g h_b + \rho_w g h_w) \Rightarrow h_{MC} - h_b = H = h_w \frac{\rho_w}{\rho_m} = \underline{115{,}875m}$$

$$\Rightarrow \Delta h_{MC} = h_w + h_{air} - H = \underline{49{,}125m}$$

***Converting $\Delta h_{MC}$ into volume:***

$$V_{U-tube} = \pi\left(\frac{d_i}{2}\right)^2 \Delta h_{MC} = \underline{0{,}424m^3}$$

***Remaining mud funnel capacity is then:***

$$\Delta V = V_{MF} - V_{U-tube} = \underline{1{,}451m^3} \Rightarrow \frac{\Delta V * 100}{V_{MF}} = \underline{\underline{77{,}39\%}}$$

The calculated bucket capacity shows that it is fully capable of handling a U-tube with 1.2 s.g. mud for the given water depth. This is also a worst case scenario because the Subsea Pump contribution is neglected. In most cases the pump would be running throughout the U-tubing process and consume most of the excessive volume. By performing the calculation example in Excel, one can find that the maximum water depth for this case is 1324 m with a 1.2 s.g mud using the goal seek function, e.g. [Set cell: A1, to value: 0 (remaining capacity), by changing cell: B1].

#### 4.1.2 Equipment that Eliminates the U-tube Effect

If the U-tube effect is getting to severe in large water depths, some remedial actions can be introduced to eliminate the unwanted effect. The upcoming subchapters will give a short description of the available technologies.

##### 4.1.2.1 Drill String Valve

A Drill String Valve (DSV) is a pipe with a coned valve that can be placed just above the BHA to avoid U-tube. When drilling fluid is circulated through the drillpipe, the DSV is held open with the additional pressure created by the rig pumps. A spring in the DSV is adjusted such that when circulation ceases, it closes the valve by spring force. This is a so called pressure balancing principle. The differential pressure required to open the valve is dependent on mud weight, water depth and flow rate. This open/close pressure is carefully calculated and adjusted in workshop on rig prior to deployment in hole. It is important that the spring force is strong enough to overcome the static hydrostatic mud column inside the DP to be able to close. This will then compensates for U-tube imbalance and prevent large volumes of drilling fluid to fill the mud funnel each time a connection is made or circulation is stopped.

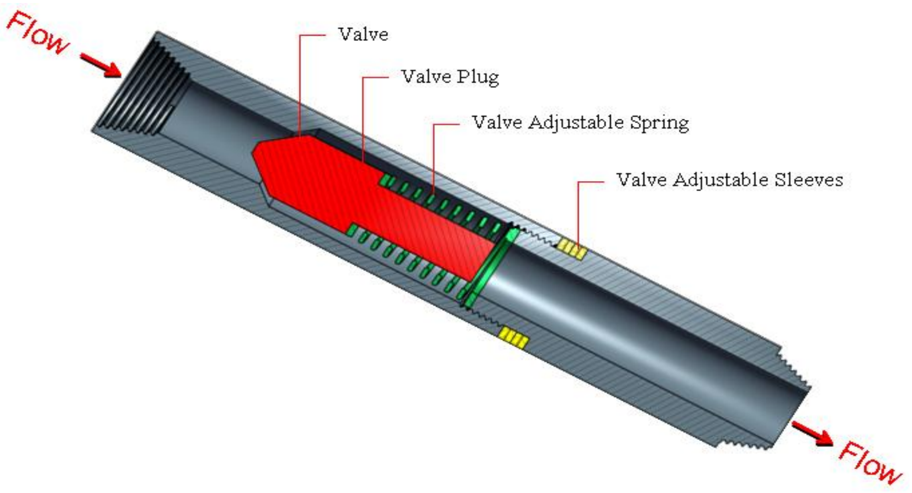



**Figure 32** *Schematic drawing of a Flow Stop Sub. Figure is taken from Baker Hughes [28].*

As depicted in the Figure 32 one can see the valves constituents on a basic level. This is Baker Hughes Flow Stop Sub (FSS) which has the same functionality as a DSV. After a certain pressure build-up, dependent on the spring's tension, the valve plug is forced downwards and enables flow through the cone opening of the valve.

#### *4.1.2.2 Continuous Circulation System*

Another alternative to counteract for U-tubing is to apply a Continuous Circulation System (CCS). This device allows constant circulation even when a connection is made. The CCS is developed by National Oilwell Varco and have been in commercial use since 2005 according to reference [29]. As explained in this paper the connection (tool joint) is enclosed in a pressurized compartment in the CCS with pipe rams similar to conventional BOP pipe rams. The uppermost part of the device is a snubbing and rotating unit that lowers/hoists the drillpipe. The pressure tight chamber can be split in two so that a connection can be made with constant circulation. A wear sub is used for running of drillpipe through the CCS. The wear sub is just an extension pipe that is connected to the topdrive for pipehandling, and enables for tool joint placement inside the CCS. To make a continuous circulation connection, several steps has to be sequentially conducted. Figure 33 below shows an internal view of the CCS to better understand its function. The explanation for the upcoming procedure is partly taken from reference [30].

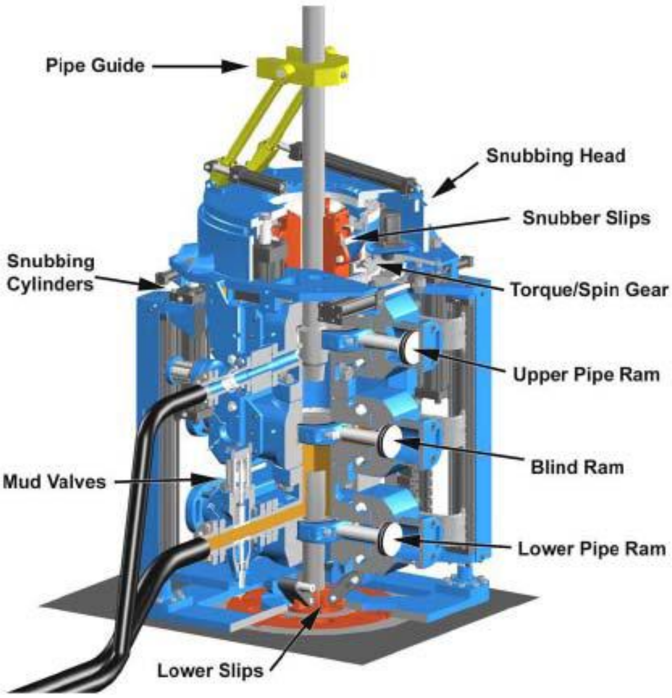



**Figure 33** *Schematic of a Continuous Circulation System unit. Figure is taken from Statoil's archive.*

One starts by inducing drilling fluid at circulation pressure into the chamber to equalize the pressure inside and outside the drillstring. This is done by circulation from rig pump through the lowermost hose, and out through the upper hose back to the mud tank. The connection can then be broken and moved clear the blind ram. When so, the blind ram closes and the chamber is divided into two separately sealed compartments. The wear sub can then be withdrawn by the topdrive to fetch a new stand. The circulation will remain uninterrupted in the lower chamber and down the drillstring due to the constant feed of drilling fluid through the circulation hose. When the new stand is run into the CCS above the blind ram and sealed with the above pipe ram, the upper chamber can be repressurized by circulation through the stand pipe. When the pressure is equalized, the blind ram opens and the connection can be made with continuous circulation. Pressure is then bled off and further drilling is continued. The sequential mechanical operation of a CCS is according to reference [30] approximately 8 minutes, but average connection time will vary from 10 – 20 min for weight to weight (weight on bit), dependent on the rig used. Statoils target regarding conventional connection time is approximately 6 min for slips to slips, and approximately 15 min for weight to weight time.

A CCS is mainly introduced in the drilling operation to achieve better hole cleaning, less particle settlement, eliminate pressure fluctuations against the bore wall, eliminate kicks on connection, constant bottom hole pressure since ECD is maintained, enhance non productive time (NPT) etc. It is therefore not likely that a CCS would be implemented in RD to counteract for U-tube alone, but the use of such a system could be justified if the above mentioned factors where a concern for the drilling activity. In the data excerpt chart below one can see the Rate of Penetration (ROP), Standard Pipe Pressure (SPP), Top Drive System (TDS) RPM and Weight on Bit (WOB) for a typical CCS operation. By having a constant SPP throughout the whole drilling operation, any potential U-tube during connections are eliminated.

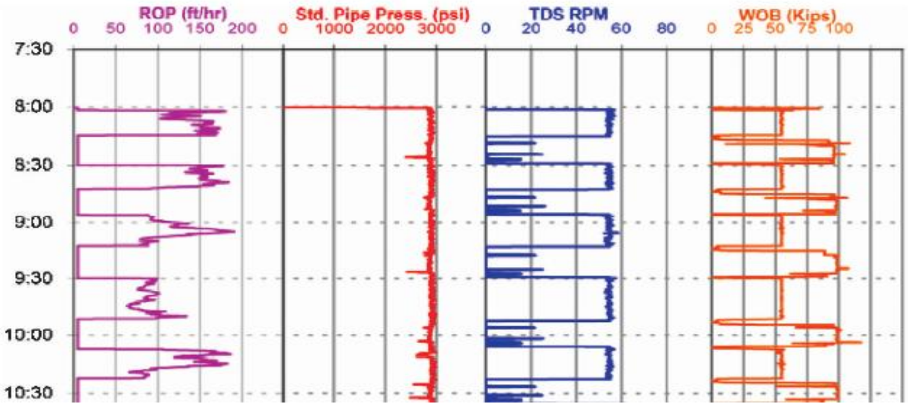



**Figure 34** *Data excerpt chart of CCS drilling. Figure taken from [30].*

## 4.2 Pump Technology

In a riserless operation the pump is the heart of the system. Without this mud lifting device, the returns would not be able to be transported back to the rigs mud facility and shakers. It is therefore set high requirements to the pumps durability and efficiency to maintain a long operating lifetime. The most abrasive pumping technology available as of today is the disc pump [31]. This is the preferred pumping technology for both the involved service providing companies of RD. There is also a diaphragm pump under development for ultra deep water environments, but this will be discussed later in this thesis. The reader should be aware that the involved companies are very reluctant about their pump technology, thus the disc pump will be presented at a general basis throughout this sub-chapter.

### 4.2.1 Disc Pump

This section is to a certain extent influenced by reference [31]. The disc pump history dates back to 1850, but has since then been further developed and reworked to enhance displacement capacity. The pump uses the boundary layer/viscous drag principle, which means that the pumping fluid is displaced through the pump by viscous friction alone. An electric shaft engine rotates a set of parallel discs, and as the discs rotate inside the pump house, they create a large drag effect depending on the spacing between the discs and fluid viscosity. The entered fluid follows the discs surface and the generated kinetic energy displaces the fluid out of the pump unit with a certain velocity. The cavity created by the outgoing fluid induces a vacuum that sucks new fluid in and the process repeats itself. This pumping technique keeps the fluid pulsation-free and laminar throughout the whole pumping process. Also unlike other pumps, the disc pump can endure large particles in the embraced fluid and gets more efficient at higher fluid viscosities due to the amplifying effect of the viscous drag.

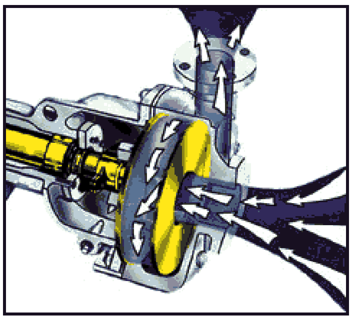


**Figure 35** *Cross-sectional illustration of a disc pump. Figure taken from [32].*

As a further explanation to the phenomena regarding viscous drag, the flow between the parallel discs has different velocities. Due to the frictional force, the fluid velocity near disc surface is considered stationary relative to disc rotation. This is depicted in Figure 36 where the fluids velocity increases towards the center of the gap between the rotating discs. The boundary layer that occurs at disc surface will act as a buffer, protecting the disc material from particle impacts. The robustness of this design results in less maintenance and downtime than for centrifugal and progressive cavity pumps. This is likely to be the contributing factor for its choosing for a riserless system where durability and efficiency is of utmost importance.

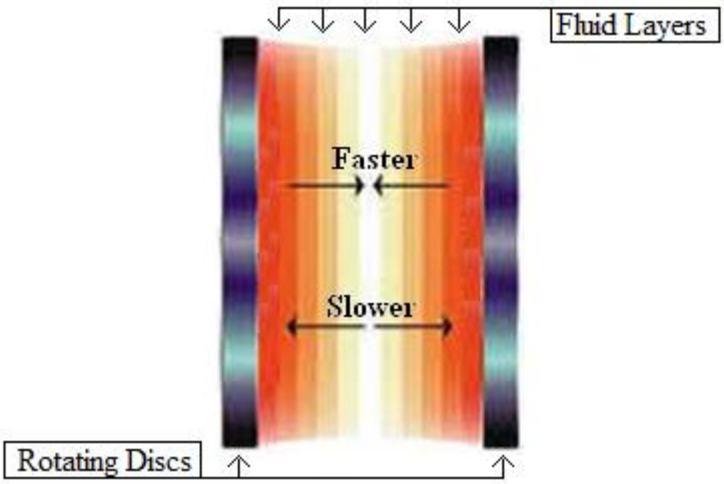



**Figure 36** *Successive layers of fluid between the two rotating discs. Figure taken from [31].*

Furthermore, there are some considerations regarding the bearing and sealing element between the motor compartment and pump house according to ORS [33]. Since the rotating shaft driven by the electric motor goes through the water tight motor compartment to supply the discs with rotational movement, the sealing element has to be of high quality. This mechanical sealing element can cause pump failure when worn more than 10 – 15 %. The pump design is constructed such that if the motor compartment is filled with water, the pump will still function. If the drilling fluid on the other hand were to fill the compartment, it would have devastating consequences for the pump.

Also to be considered are the pumps capability to handle gas content in the drilling fluid. When the gas ratio is larger than 11 %, the disc pump will suffer a decrease in pump efficiency. This would not be a concern due to the well being shut-in long before such high amount of gas reaches the pump.

### 4.2.2 Pump Efficiency

As the service providing companies for the Riserless Drilling System are quite protective of their pump technology, the information basis for further pump efficiency evaluation is rather confined. The pump is the most important unit in RD, but in addition also the bottleneck of the system. It has therefore been a race in the industry to develop the most efficient and viable pump technology for commercial use. In the first instance, ORS and AGR are the delivering providers for the requested pump technology, but a Norwegian company, PG Marine Group [34] from Oslo, is developing a Multi Application Pump Solution Hose Diaphragm Pump (PG-MAPS®) that can be applied on deeper water. This diaphragm pump will be further explained later in this thesis. Also, Hydril [35] and Chevron [36] possesses a positive displacement seawater-driven diaphragm pump for ultra deep water that is currently being fine-tuned to fit a Riserless Drilling System, but will not be further evaluated in this thesis due to Statoils inaccessibility to the pump. Furthermore, due to the current status of the riserless drilling concept, where the pump provided by ORS is still on the development phase, and AGR have a continuation of the already applied RMR® pump technology, this section will adopt the RMR® pump when describing pump efficiency for a Riserless Drilling System.

Pump efficiency is defined as; "The ratio of the power imparted on the fluid by the pump in relation to the power supplied to drive the pump" [37]. The RMR® disc pump has a pump efficiency of 0,47, which means that 53 % of the power induced to the pump is lost in the transmission from electric to mechanical energy. The pump efficiency for a pump is not stationary, but will alter dependent on the amount of discharge running through the pump. The disc pump, which belongs to the centrifugal pump family, has a tendency to increase pump efficiency with higher flow rates. This continues until peak efficiency is achieved, and further increase in flow rate will have a declining effect on the pump efficiency. Due to wear on rotating discs from the constantly abrasive cutting flow, the pump will over time loose some of its efficiency. The pump efficiency should always be defined by the manufacture in form of a pump curve showing head [m] vs. flow rate [lpm], or similar.

The lifting capacity for a pump is directly related to the pumps efficiency and the pumping power. The total energy needed to lift a hydrostatic column is dependent on the differential pressure over the pump, the flow rate the pump is pumping the fluid with, and the efficiency of the pump;

$$P = \frac{\Delta PQ}{\eta} \qquad (10)$$

Where;

*P = power [W]*

*ΔP = differential pressure over pump between outlet and inlet [Pa]*

*Q = flow rate [$m^3/s$]*

*η = pump efficiency in fraction*

**Calculation example:**

| | |
|---|---|
| Water depth: | 135 m |
| Air gap: | 20 m |
| Mud density: | 1400 $kg/m^3$ |
| Seawater density: | 1030 $kg/m^3$ |
| Flow rate: | 4500 l/min |
| Pump efficiency: | 0,47 |
| Gravity: | 9,81 $m/s^2$ |

*Pumping power;*

$$P = \frac{(\rho_m g h_m - \rho_w g h_w) * Q}{\eta} = \frac{(1400 * 9{,}81 * (135 + 20) - 1030 * 9{,}81 * 135) * \frac{4{,}5}{60}}{0{,}47} = \underline{122025W}$$

The total energy needed to lift the drilling fluid from the subsea pump and up to the rigs fluid system is in theory 122,025 kW for the given example. The calculations are based on the pump inlet being positioned at the same level as the mud/seawater interface. The RMR® disc pump provided by AGR is a 300 kW engine pump. This means that it could singly lift the fluid column for this particular case. Nevertheless, AGRs pump modules consists of several pumps in series that work together to provide sufficient hydraulic head to be able to elevate the fluid to surface. These are RMR®600 (2x300kW), RMR®900 (3x300kW) and RMR®1200 (4x300kW). The next coming graph gives a general description of each pumps capacity dependent on the operational configuration. The data used are obtained from AGRs RMR® presentations.

**The example configuration presented in the graph below is composed of:**

- • 20 in. Disc pump
- • 20 m air gap
- • 26 in. hole
- • Rate of Penetration (ROP) - 30 m/h
- • 29 cP - Mud plastic viscosity
- • 40 m of suction line
- • Flow rate - 4500 l/min

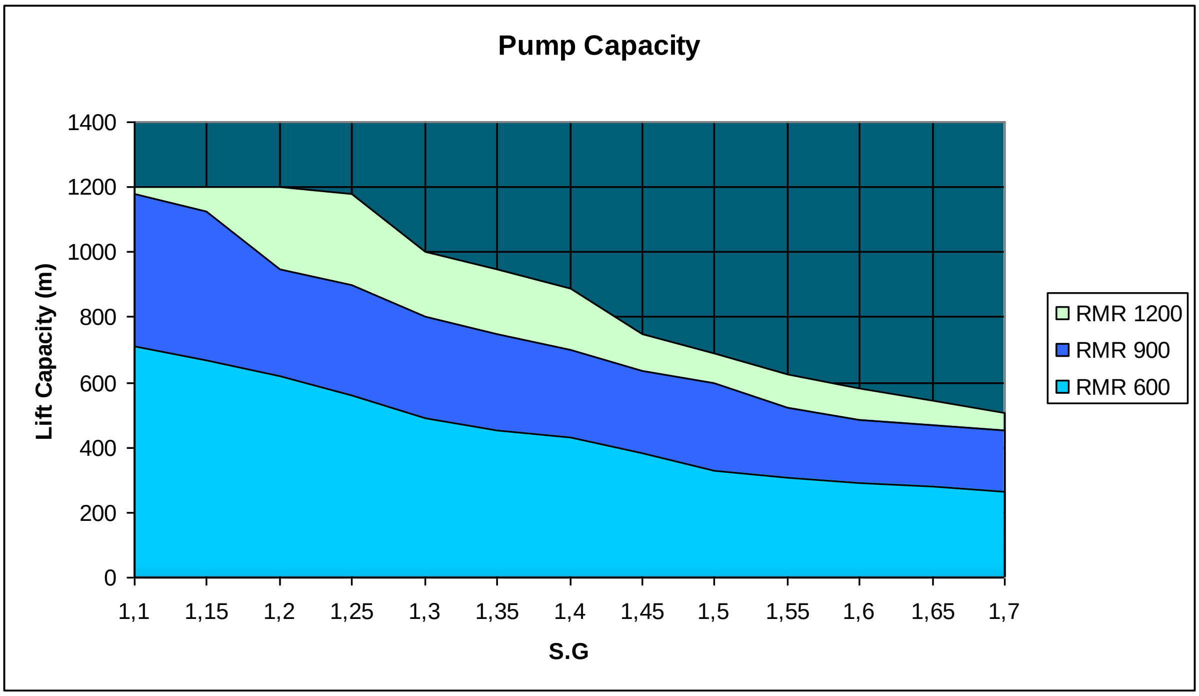



**Figure 37** *Pump efficiency graph for RMR®600, RMR®900 and RMR®1200. For presentation purpose only. Data is taken from AGR.*

One can see from the graph above that the lifting capacity decreases when a heavier mud is pumped. The presented graph is much more exact than the previously given calculation example, and thus not in total compliance due to cuttings content, viscosity and 40 m of suction line which are also taken into the account. With an ROP of 30 m/h the accumulated cuttings content in the drilling fluid will induce a larger hydrostatic pressure acting on the pumps outlet. This will then contribute negatively to the pumps lifting capacity.

## 4.3 Well Control

Well Control is vital for safe well handling. During drilling activities the operator is required to have full control in order for a safe operation to take place. If an undesired event occurs, e.g. a kick is taken or an emergency disconnect is required; proper shut-in procedures must be executed to maintain control of the well. In order to achieve this, primary and secondary barriers need to be in place during all well activities. These well barriers consist of several different barrier elements. A set of well barrier elements is commonly referred to as a well barrier envelope.

The best method of well control regarding kick is to prevent it from happening. Since this is not always possible, the practical goal would be to detect the kick quickly and to control it safely [39]. Primary kick detection methods could be monitoring of pit gain, increase in return rate, interface level increase after stop of rig pump and increased rpm of the subsea pump. If no counteractive device for U-tube is installed, this volume increase has to be taken into the account when evaluating total measured flow rate. Nevertheless, such a device should be mandatory due to the pressure imbalance in the well and the challenge this inflicts on well control. It is preferred to close the BOP when the pressure imbalance equalizes so that unnecessary pressure build-up below BOP does not occur, which may result in formation fracturing and possible fluid loss. A full U-tube can take up to 15-25 min to settle, something that is not acceptable in a well control situation before BOP shut-in. Without pressure disturbance below BOP from the U-tube effect, shut-in pressures due to liquid influx can be recorded and proper well control procedures can be taken. The most commonly used procedures are Driller's Method and Wait & Weight.

**FACTS**

**Well Control**

- **Well Control** as defined by NORSOK D-010 [7];
  *"Collective expression for all measures that can be applied to prevent uncontrolled release of well bore effluents to the external environment or uncontrolled underground flow".*

- **Loss of Well Control** as defined by BOEM [38];
  - *Uncontrolled flow of formation or other fluid*
  - *Flow through a diverter*
  - *Uncontrolled flow resulting from a failure of surface equipment or procedures*

- **Barriers**, NORSOK D-010 [7];
  - **Primary well barrier**;
  *First object that prevents flow from a source*
  - **Secondary well barrier**;
  *Second object that prevents flow from a source*
  - **Common well barrier element**;
  *Barrier element that is shared between the primary and secondary well barrier*

- **Well influx/inflow (kick)**;
  *Unintentional inflow of formation fluid from the formation into the wellbore*

## 4.4 Well Barriers for Riserless Drilling Systems

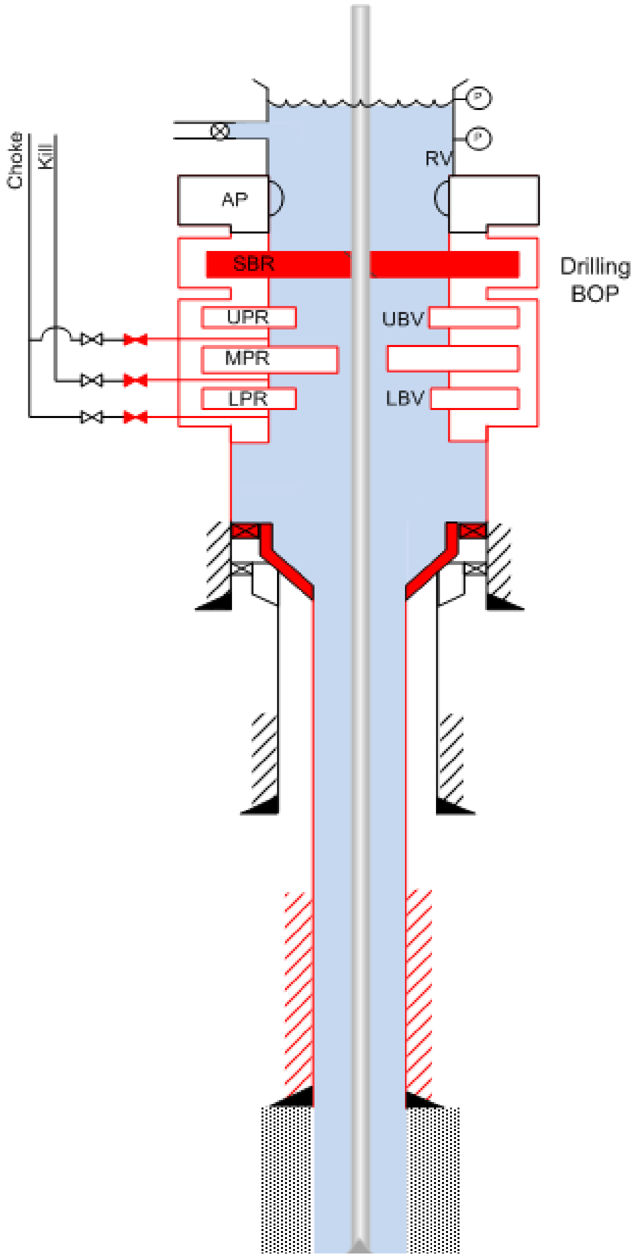



**Figure 38** *Well barrier schematic illustration of drilling with shearable drill string. Figure taken from [2]*

| **Primary well barrier** |
|---|
| **Fluid column** *(mud and seawater)* |
| **Level in Mud Funnel** |
| **Secondary well barrier** |
| **Casing cement** |
| **Casing** |
| **Wellhead** |
| **Drilling BOP** |

**Table 1** *Well barrier elements for drilling operations with shearable drill string*

- SBR Shearing Blind Ram
- UPR Upper Pipe Ram
- MPR Middle Pipe Ram
- LPR Lower Pipe Ram
- UBV Upper Blind Valve
- LBV Lower Blind Valve
- AP Annular Preventer
- RV Relief Valve

**Note:** The well barrier schematics for drilling are quite similar for CRD and drilling with a riserless system. The differences are that in CRD the fluid column consists of mud only, there is no mud funnel and a riser is present. For drilling with RD the fluid column is composed of a seawater column and a mud column. A mud funnel, subsea pump and a MRL have replaced the riser.

### 4.5 Shut-In Procedures

Shut-in procedures for well control situations must be thoroughly implemented and highly practiced within the drill crew. A fast response in a kick situation will result in less shut-in casing pressure and simplify the later procedure of circulating out the kick. In the drilling industry there are mainly two types of shut-in procedures; hard shut-in and soft shut-in. According to Well Control School [40] the main difference between the two is choke valve status on rig manifold during drilling; if it is closed or open. Choke valve on BOP stack is always closed while drilling. Figure 39 below gives a good overview of the shut-in procedures with pipe on bottom. In a shut-in procedure the BOP choke valve will open (1), and the BOP will be closed (2). For hard shut-in this will be the whole procedure since rig choke is already closed. Company personnel should be notified and Shut-In Drill Pipe Pressure (SIDPP) and Shut-In Casing Pressure (SICP) recorded every minute. This is the preferred procedure as it results in less total influx. Soft shut-in is similar, just that the rig choke has to be closed (3) in addition after BOP closure. Monitoring of casing pressure is important to ensure that limitations are not exceeded for the formation or pressure is trapped. This will cause a gradually and softer shut-in, but in addition induce a larger influx volume.

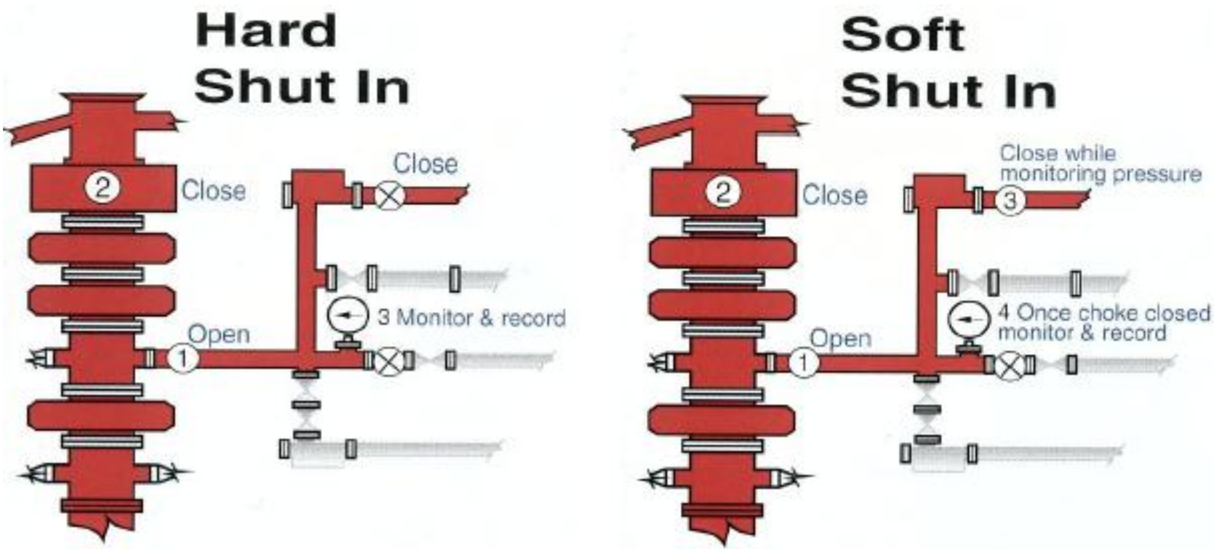



**Figure 39** *Shut-in procedures of BOP and rig manifold. Figure taken from WCS [40]*

To restore drilling operations, conventional well control procedures can be used to circulate out the kick through k/c lines. Since conventional well control procedures are to be used for the Riserless Drilling System, the system is designed so that the pump module will be isolated from the circulation path if the BOP is activated according to ORS [2].

## 4.6 *Friction Loss in Kill and Choke Lines*

Since a heavier mud with riser margin is always present in the borehole, it could be problematic when circulation through choke line is required, e.g. after shut-in of BOP. The extension of the mud column to surface, and the additional ECD in choke line, might lead to fracturing of formation and possibility of loss of primary barrier. This is most likely to be a problem for deepwater wells with long k/c lines. As a countervailing measure to decrease ECD contribution through choke line one can circulate in a less dense and thinner fluid at BOP level. This method have been tested and field proven in Angola, see paper [41]. By circulating a lighter and thinner base fluid into the kill line, the ECD in choke line can be manipulated. When the ECD reducing fluid is circulated into the system, the returning choke flow rate will be a mixture of the Slow Circulating Rate (SCR) (mud flow) and the Additional Flow Rate (AFR) (thin and light fluid). Depending on the flow ratio between the original fluid and the added fluid, AFR/SCR, desirable conditions with less ECD can be achieved. The two AFR ratios used for this case were AFR's 20% and AFR's 40%. Figure 40 below yields the results for the above-mentioned conditions;

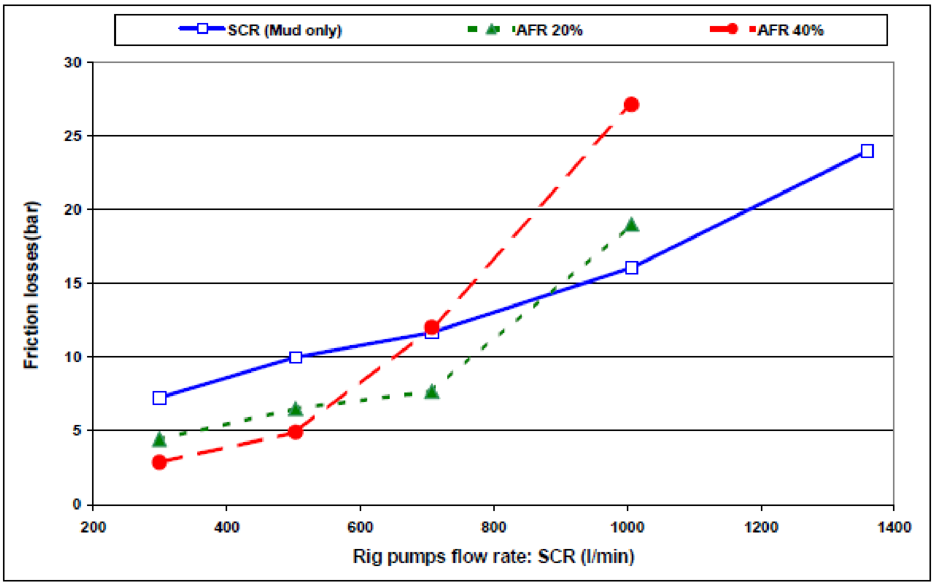



**Figure 40** *Dynamic friction losses inside the choke line. Figure taken from [41]*

When staying under a certain flow rate, the AFR method is clearly preferred in terms of frictional losses in choke line. For high flow rates, turbulent flow can be reached in the choke line, resulting in an increase of friction loss. For further details regarding the well control procedure for the AFR method, consult the reference paper [41].

## 4.7 Riser Margin

With reference to NORSOK D-010 [7], *"The fluid column is not a qualified well barrier when the marine riser has been disconnected"*. To compensate for this in CRD, one can displace the whole well to a higher mud density before riser disconnect, or drill with a "Riser Margin". A riser margin is the additional fluid density required to stay in overbalance, even after the riser is disconnected and the overlying hydrostatic fluid column, from BOP level and upwards, is replaced with seawater. When RD is utilized, the borehole will always have an incorporated riser margin at all times, and the primary barrier will here consist of the hydrostatic water column, mud column with riser margin and the interface in the mud funnel. The figure below represents the pressure profiles for various scenarios during drilling and disconnect of riser for conventional operations. If a riser margin is not included in the drilling fluid, the blue plot would possible fall below the pore pressure and shift the well over to underbalanced conditions. This could lead to an unwanted well control situation, e.g. a kick. The green graph will be the actual case for a Riserless Drilling System at all times.

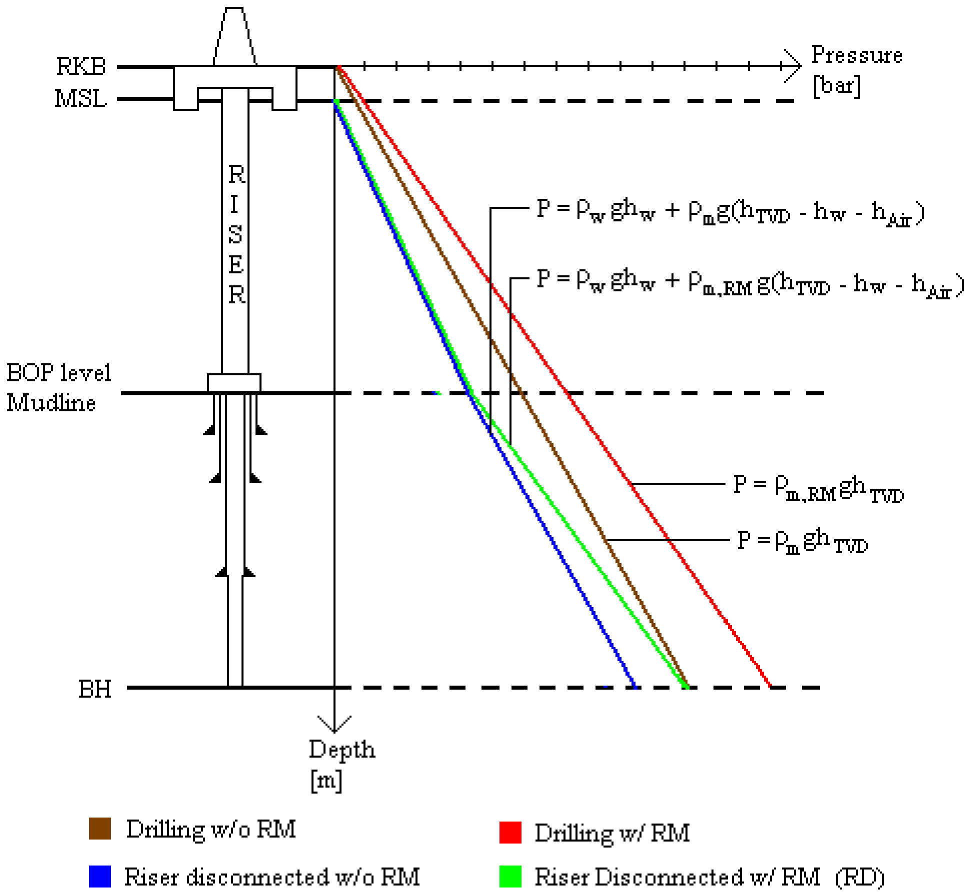



**Figure 41** *Pressure plot for different scenarios during drilling and disconnect of riser. It renders the benefits of including a Riser Margin (RM) in the drilling mud.*

As a comment to the riser margin and disconnection of riser, the pressure below the BOP is equivalent to the fictive mud column to surface after BOP closure. This entails in theory that the BHP is maintained, even without a riser margin in place after disconnect. Nonetheless, having this pressure build-up below BOP is not suffice regarding proper well control, thus a riser margin should be present. This is because the pressure might leak with time and disappear, resulting in an influx and unknown conditions below BOP.

**Riser Margin Calculation Example:**

| | |
|---|---|
| Water depth, $h_w$: | 135 m |
| Air gap, $h_{Air}$: | 20 m |
| TVD, $h_{TVD}$: | 2000 m |
| Mud Density, $\rho_m$: | 1,5 s.g. |
| Seawater Density, $\rho_w$: | 1,03 s.g. |

***Differential Pressure for Riser Disconnect:***

$$\Delta P = \rho_m g h_{Air} + (\rho_m - \rho_w) g h_w = 1{,}5 * 0{,}0981 * 20 + (1{,}5 - 1{,}03) * 0{,}0981 * 135 = \underline{9{,}17 bar}$$

***Riser Margin:***

$$\Delta\rho = \frac{\Delta P}{g(h_{TVD} - h_w - h_{Air})} = \frac{9{,}17}{0{,}0981 * (2000 - 135 - 20)} \approx \underline{0{,}051 s.g.}$$

The resulting density to stay in overbalance after riser disconnect for this particular case is;

$$\rho_{RM} = \rho_m + \Delta\rho = 1{,}5 + 0{,}051 = \underline{1{,}551 s.g.}$$

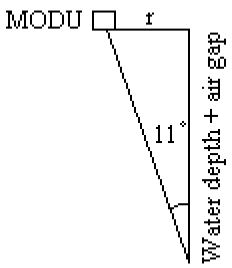
This means that for CRD, an addition of 9,17 bar above preferred density is required during drilling to stay in overbalance in case of a riser disconnect. On larger water depths, the riser margin can become too severe for the formation to handle, resulting in fracturing of formation. This is one of the major benefits in implementing a Riserless Drilling System since the seawater and mud column with riser margin make up the normal drilling state. Although, careful considerations have to be taken when designing the drilling mud to leave room for circulation of mud up the choke line to surface during a well control situation. The additional ECD contribution in the small choke hose, and the extension of the mud column to surface, might fracture the underlying formation.

## 4.8 Emergency Quick Disconnect

In case of an EQD, the immediate response is to shear pipe and close BOP. If time, it is possible to install a hang-off tool, and hang-off in BOP to avoid sharing of drillpipe. As touched upon earlier, full well control can be maintained even after EQD due to k/c and pod lines still being connected. Hence, a slack off on guide & pod tension lines must be carried out to secure an allowance of maximum 11 degree dislocation from well centre. For a conventional setup with a riser in place, an EQD would entail disconnecting the LMRP as well. An EQD is performed in case of drift-off, or if bad weather conditions arises. Figure 42 gives an idea of the thought watch circle the mobile drilling unit (MODU) can have with an 11 degree dislocation from well centre.

*Watch circle radius:*

| | |
|---|---|
| Water depth: | 135 m |
| Air gap: | 20 m |
| Deviation: | 11° |




$$r = (135 + 20) * \tan(11) \approx \underline{30m}$$

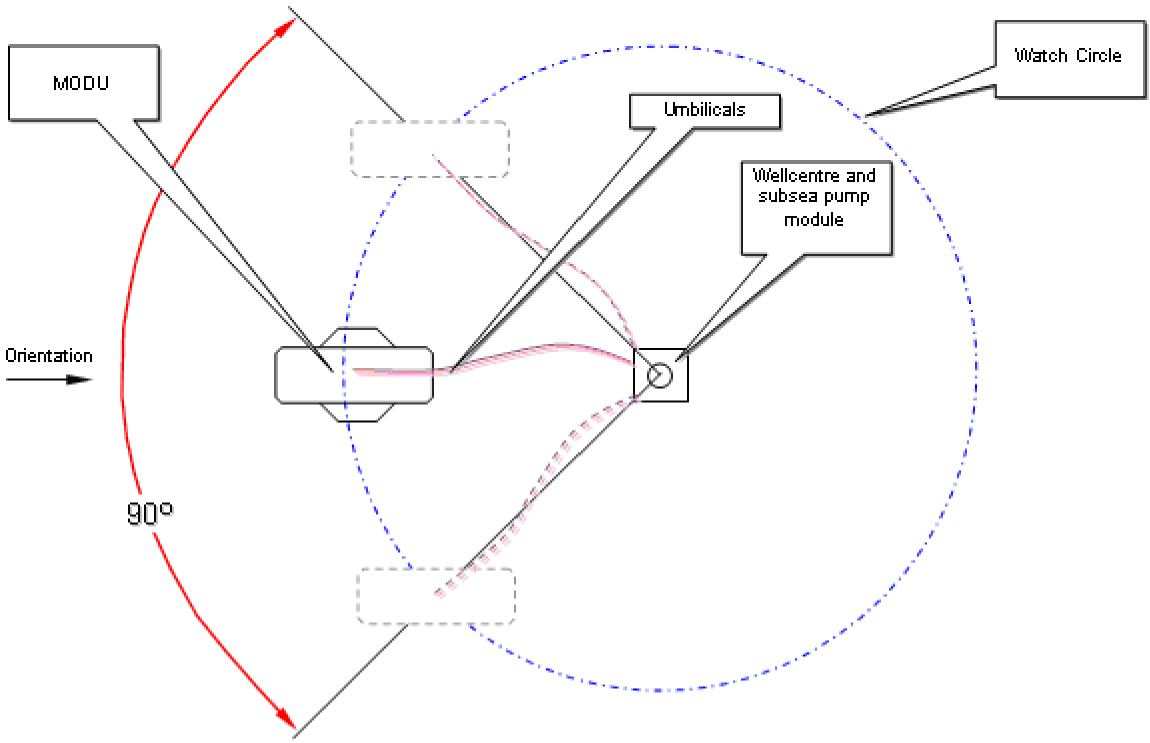



**Figure 42** *MODU watch circle for RD. The circle shows deviation allowance from well centre. Figure is taken from [42].*

As a comment to the MODU watch circle for a Riserless Drilling System, it is also dependent on subsea configuration. The rig should not be dislocated so that the hoses and control lines interferes with the subsea installation and stack. The pliant wave configuration of the umbilical and hoses allows for the rig to deviate off rig centre, but considerations have to be taken into the account with respect to clearances from the subsea equipment and the rig off-set orientation.

A second comment to the EQD procedure for RD is that a riser margin is always present during drilling. For CRD the entire well has to be displaced to mud with incorporated riser margin before disconnect. This is a time consuming process and might not always be applicable if a fast disconnect is required. When hydrocarbon bearing formations are penetrated, the primary compensating measure is to drill with a riser margin. If the water depth is significant, the additional mud weight can cause extra challenges to the drilling operation when drilling through small drilling windows. Exceptions for riser margin are therefore often sought on deep water to be able to drill such wells. For RD an EQD entails disconnect without the need for additional procedures regarding riser margin due to the riser margin already being in place. This is clearly beneficial in a disconnect situation.

## 4.9 Volume Control

Conventionally the volume control is done by measuring the volume in the active mud pits and calculating the volume in the drillstring, riser and hole. The Riserless Drilling System will be equivalent to the conventional system, just that the riser volume has been replaced with the volume in the mud funnel and MRL. Volume control is thus conducted in the same way as for CRD except for the flow check.

### 4.9.1 Flow Check

In suspect of an influx or loss when drilling conventionally, a flow check is taken to determine whether or not volume in is equal to volume out. That can be done either static or dynamically. When taking a static flow check the circulation is stopped and the fluid level in riser or dedicated trip tank is monitored. For dynamic flow checks the rig pump continues to pump, while the return flow is measured by a mass flow meter, also known as a coriolis flow meter. This apparatus measures mass per unit time that passes through a U-shaped pipe based on vibrations.

For a floating drilling facility, the static flow check process can be difficult due to the constant heave motion of the rig. The fluid level will fluctuate together with rig movement and change rapidly because of the risers slip joint relative movement. This can be time consuming, thus leading to a larger influx if a kick was actual happening. For riserless drilling the mud volume will be fixed due to the MRL always being completely filled with mud. Hence, no fluctuation will occur in combination with rig heave. Since this concept is still being in the development phase, proper flow check procedures have not yet been evaluated. It has been mentioned by AGR to observe the mud mirror in the bucket by use of an ROV or by the pre-installed cameras. ORS have also introduced a preferred method of performing a flow check in their feasibility study. By redirecting the pumped returns to a trip tank on the rig, and then use the rigs circulation pump to pump the fluid back to the bucket through the 2” re-circulation hose to refill and maintain the mud/water interface. This closed circulation loop will be closely monitored in the trip tank to determine if there is an influx. A process like this will take time and might result in a larger influx. According to NORSOK D-010 [7], a flow check should last 10 min for normal wells, and 30 min for HTHP wells. Also confer same, flow checks should be performed upon indications of increased return rate, increased volume in surface pits, increased gas content, flow on connections or at specified regular intervals.

The closed circulation loop proposed to perform a flow check is a mixture of the dynamic/static procedures. The well is static up to the mud funnel, but becomes dynamic through the constant re-fill in the mud funnel and the pumping back to surface. The best approach might therefore not be only monitoring of trip tank when a flow check is taken, but to introduce the dynamic procedures for flow check conducted during Managed Pressure Drilling (MPD). Confer the International Association of Drilling Contractors (IADC) [43], MPD is; *"an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore".* The flow check procedure for the abovementioned technology is as follows;

**Dynamic MPD Flow Check**

1. Drillers first action
   - Stop Drilling
   - P/U off bottom
   - Continue rotation and circulation with same parameters
2. Monitor the flow meter readings, pit volumes and system pressures for 15 minutes
3. If pit volumes, flow in and out are constant
   $\Rightarrow$ Downhole conditions are stable
4. If flow check does not confirm stable conditions
   $\Rightarrow$ Follow Flow Path Procedure

This procedure could be adopted for a Riserless Drilling System with some slight modifications. Point 1, bullet 3 would entail circulation from the mud funnel to surface, not the whole well. Furthermore, point 2 regarding pressure monitoring is not an issue for a Riserless Drilling System due to the system being open. Point 4 would imply BOP shut-in procedures if the well was flowing, not a flow path procedure as can be the case for MPD depending on kick size. To adopt this procedure for RD, the Petroleum Safety Authorities (PSA) must be an external risk facilitator in the approval process. Together with Statoil, a HAZOP (HAZard & OPerability analysis) & HAZID (HAZard IDentification) is performed to establish a systematic evaluation and proper risk assessment. A matrix is then made to identify potential hazards, and a new evaluation round takes place where the group together agrees on the preferred procedures.

### 4.9.2 Fluid Volume Requirements

According to NORSOK D-010 [7] and Statoils internal APOS (Arbeids Prosess Orientert Styring) documentation , an addition of minimum 100 % of the entire well volume should be available on the installation during well testing and completion. During drilling, the topside volume requirement are 150 % kill mud of the entire well volume, and sufficient to give 10 bar overbalance. This is because the volume capacity topside should be large enough to handle any loss situation to regain well control. To illustrate the amount of fluid needed, a calculation example is presented below. The calculation focuses on well volume from the BOP stack and up to rotary table since the rest of the well is similar for conventional and riserless.

**Conduit Volume Calculations:**

Fluid required topside to fill the applied conduit for a 100 m section;

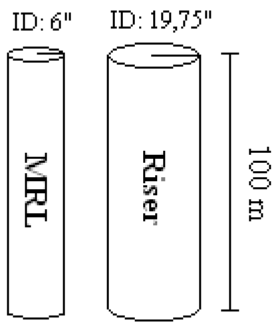
| | |
|---|---|
| Riser ID [inch] | 19,75 |
| Riser length [m] | 100 |
| MRL ID [inch] | 6 |
| MRL lenght [m] | 100 |

**Conventional conduit** *(DP excluded)***:**

$$V_{Riser} = \pi\left(\frac{ID * 0{,}0254}{2}\right)^2 h = \underline{19{,}76 m^3}$$

**RD conduit:**

$$V_{MRL} = \pi\left(\frac{ID * 0{,}0254}{2}\right)^2 h = \underline{1{,}83 m^3}$$




This is a significant difference with a total of 92.6 % saved conduit volume in favour of riserless. For large water depths this volume would be a comprehensive challenge in terms of the readily available fluid required for proper well control. Although well volume below mudline consists of approximately 200 – 1000 m$^3$, dependent on dimensions and depth, the conduit volume savings are highly noticeable in total volume requirements for large water depths.

## 4.10 Approval from Governing Authority

There are strict requirements when adopting a new technology for use in the oil and gas industry, especially on the NCS where standards are highly regulated. All new technologies implemented in the industry need thorough investigation to determine if design and functionality is in sufficient order. The most commonly used standards on the NCS are "Norsk Sokkels Konkurranseposisjon" (NORSOK) [44] and "Det Norske Veritas" (DNV) [45]. These work in accordance with the governing service departments; The Petroleum Safety Authorities (PSA) [46], The Government Pollution Authorities (SFT) [47] and The Government Health Directorate (SHDIR) [48]. The Department of Labour and Social Affairs (ASD) [49] and The Oil and Energy Department (OED) [50] acts as the primary governing authority according to [51].

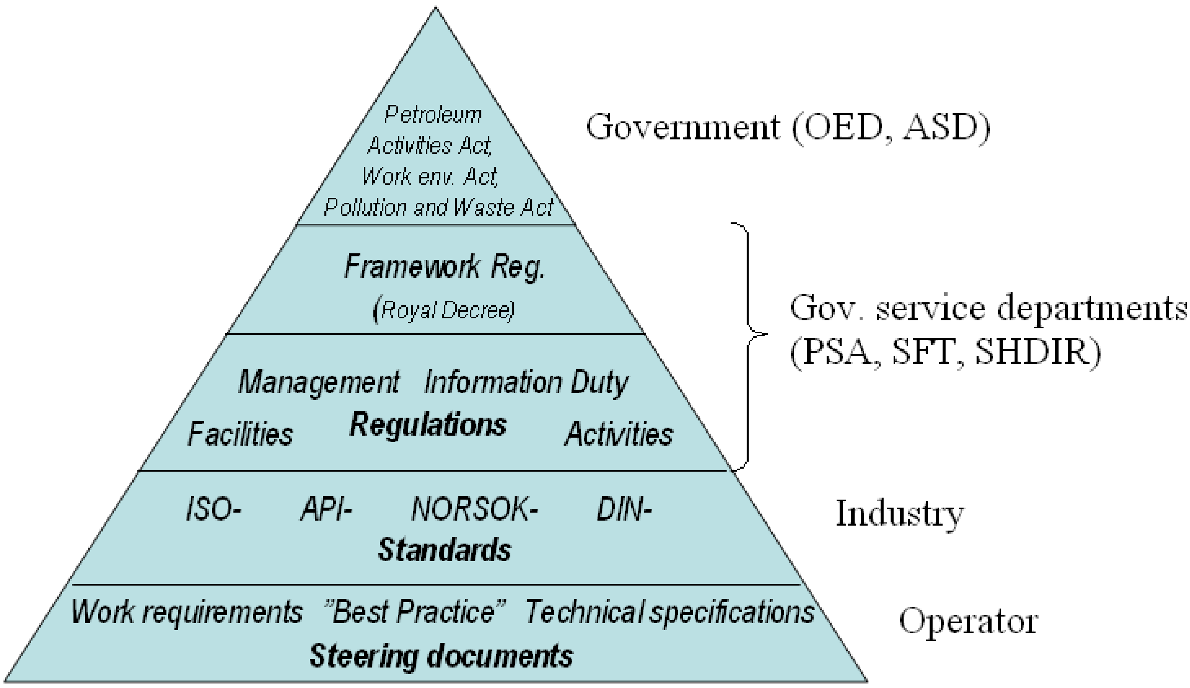



**Figure 43** *Governing authorities' hierarchy of the petroleum industry. Figure is taken from [51].*

Furthermore, the service providers of the Riserless Drilling Systems refer to several standards within NORSOK and DNV. These are to be used in the approval process as a basis for the final qualification of the system. A general description of the relevant standards will follow in the next sections.

#### 4.10.1 NORSOK

*"The NORSOK standards are developed by the Norwegian petroleum industry to ensure adequate safety, value adding and cost effectiveness for petroleum industry developments and operations. Furthermore, NORSOK standards are as far as possible intended to replace oil company specifications and serve as references in the authorities' regulations" [7].*

##### 4.10.1.1 Z-015 'Temporary Equipment'

NORSOK Z-015 describes the minimum technical and safety-related requirements for temporary equipment [52]. This entails equipment that is involved on well activities for a short period of time to perform a small specific job, not for permanent installation. The existing RMR® system developed by AGR is designed after this standard. RD is built much upon the same concept, but implies a more comprehensive investigation due to its greater extent regarding well control and requirements. Nevertheless, some of these experiences can be related to the attainment of RD.

##### 4.10.1.2 D-001 'Drilling Facilities'

NORSOK D-001 describes the design, installation and commissioning principles for a drilling facility. This includes all topside equipment and systems, equipment marking, testing, layout etc. The standard also requires that no single failure during drilling and well activities can lead to significant damage either on personnel, environment or material. Safety systems are therefore to be provided with two independent levels of protection to reduce the probability for common cause failures [53]. This design and redundancy philosophy is important to secure an acceptable safety level on a drilling facility. Even though RD is mostly subsea equipment, an implementation of such a system should be in accordance with this standard.

##### 4.10.1.3 D-010 'Well Integrity in Drilling and Well Operations'

NORSOK D-010 is a very important NORSOK standard, and defines requirements for well integrity and well barrier philosophy. It also includes well design, planning and execution of well operations [7]. Since RD does not have a riser in place during well activities, there will be some differences in accordance to D-010. This includes the preservation of the primary well barrier (fluid column). The primary well barrier for RD is the water column down to the Mud Funnel, and the mud column from that point and down to TVD. As the interface between the two columns has not yet been evaluated with regards to riserless drilling, it should be addressed and discussed with PSA according to reference [2]. Furthermore, fluid and volume control must be maintained through the subsea mud recovery system.

#### 4.10.2 DNV

*"DET NORSKE VERITAS (DNV) is an autonomous and independent foundation with the objectives of safeguarding life, property and the environment, at sea and onshore. DNV undertakes classification, certification, and other verification and consultancy services relating to quality of ships, offshore units and installations, and onshore industries worldwide, and carries out research in relation to these functions" [54].*

##### 4.10.2.1 DNV-RP-A203 'Qualification Procedure for New Technology'

DNV-RP-A203 [55] is a recommended practice (RP) that provides a quality control of components, equipment and assemblies used in the oil and gas industry. This applies especially for new technology to ensure that it is up to standard and reliable for its specific purpose. This standard was the first industry-recommended practice for qualifying new technology. Confer DNV [55]; "*New technology is technology that is not proven. This implies that the application of proven technology in a new environment or an unproven technology in a known environment, are both new technology".*

This implies that even though some of the systems constituents have a track record and have a previously approval, a new general system approval has to be performed based on the relevant standard. As a qualification basis in the approval process, a risk-based approach is used to determine the systems reliability. The outcome will be essential in the further development and realization of the system.

##### 4.10.2.2 DNV-OS-E101 'Drilling Plant'

DNV-OS-E101 [54] is an offshore standard (OS) that provides requirements for the design, materials, construction and commissioning of a drilling and intervention facilities. This standard is to some extent similar to NORSOK D-001. It is enforced to improve safe handling of rig and safeguard personnel. If approved by this standard, the system can be classified as a part of the drilling plant.

# 5 Wellhead Issues Related to Subsea Wells

To uphold structural integrity in subsea wells after continuous operations is a challenge in the offshore industry. Depending on the generic load conditions (normal, extreme, accidental), the structural integrity can be weakened with time. When it comes to structural failure in subsea wells, it can be divided into two failure modes; accidental or fatigue related. Accidental failure can be events like trawling activities, dynamic positioning failure, tear-off or other severe mechanical loads. Fatigue on the other hand is failure by repeated stress in materials. It is fatigue related problems that will be illuminated further in this chapter.

## *5.1 Wellhead Fatigue*

Wellhead fatigue is one of the main drivers for implementation of a riserless system according to Statoil. The field of interest is as mentioned earlier GFS, and the issues related to wellhead fatigue on some particular wells. Wellhead fatigue is defined as cyclic loading on wellhead systems due to dynamic loading from the riser. When doing a workover or a well intervention in a subsea well, a riser has to be run together with a BOP on top of the subsea XT. During operations like this, the rigid riser will inflict large stresses to the subsea equipment, especially on the wellhead. The amount of stress induced depends on weather conditions, ocean currents, weight and dimensions, angles, equipment configuration and the time the riser is connected. Fatigue life will be reduced as a result of constant cyclic loading, and the metallurgy will eventually submit to crack initiation and propagation. As mentioned earlier in the section's Top Hole Drilling and Equipment Stability, the best load path for external loads is when the load is obtained and shared between the conductor and surface casing. If this is not achieved through a proper cement job, hot spots will occur in the metallurgy and the fatigue loading will yield a more rapid propagation resulting in induced cracks. Referring to Figure 9, a shortfall of cement will not lock the wellhead body into the 30 inch conductor housing confer reference [18]. The external loads applied to the wellhead body will therefore be obtained by the wellhead and the surface casing. Full cement return in annulus, between the conductor and surface casing, will result in a load transfer so that the induced load is shared. Hence, a better load path is provided to reduce fatigue loading on the wellhead. This is also in accordance with APOS, saying that; *"the cement heights are often unknown and therefore a conservative assumption is used in fatigue life calculations. Cement level at the most critical level can reduce fatigue life with a factor of 10 versus cement being topped up or* *having cement level lower than -15 m.* The figure below will give a more detailed overview of the load path for a typical wellhead configuration.

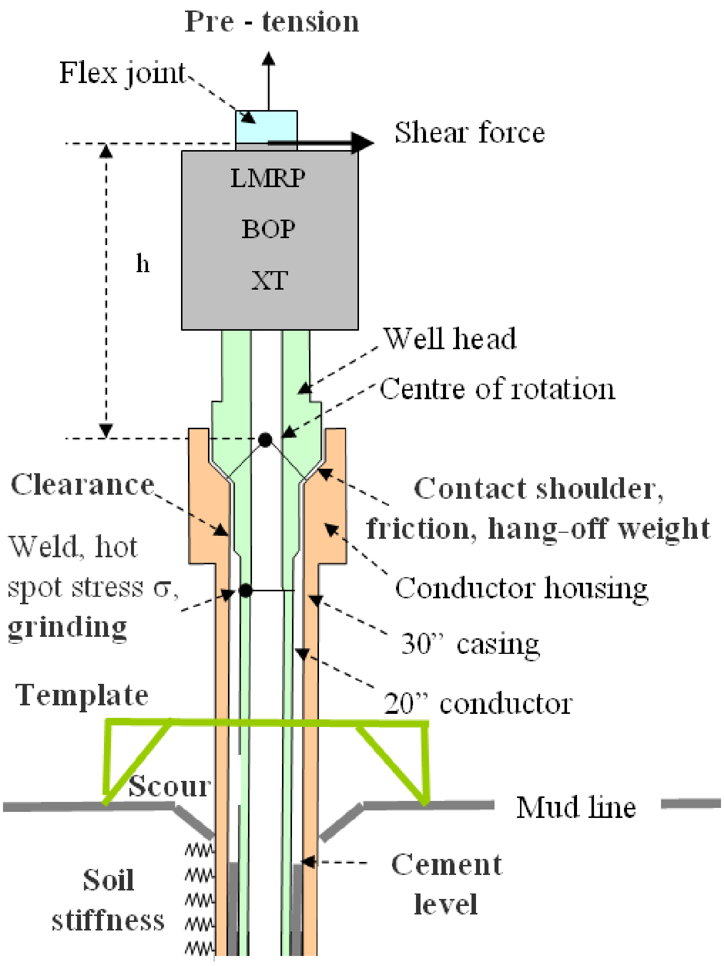



**Figure 44** *Subsea installation configuration for a typical subsea well. Figure is taken from [1].*

As depicted in the figure above, the centre of rotation is located in the wellhead. All movement and induced load will move relatively to this point. When the riser is connected and vertically aligned, the forces are acting vertical on the wellhead. This is not affecting the metallurgy much, and the fatigue life is maintained. However, if the riser were to be slightly tilted or deviated, the tensional force in the riser would induce forces acting in the horizontal direction. This type of load is the contributing factor that will, through cyclic loading, affect the fatigue life of the subsea structure and eventually submit to the stress-strain condition.

To get a proper representation of fatigue life and structural capacity, a fatigue analysis has to be carried out. This analysis encompasses a large number of input parameters that are put into a complex analysis model. Due to the complexity of 3D stress loads and the primary focus of this thesis, the contributing factors will only be discussed briefly in the next coming sections.

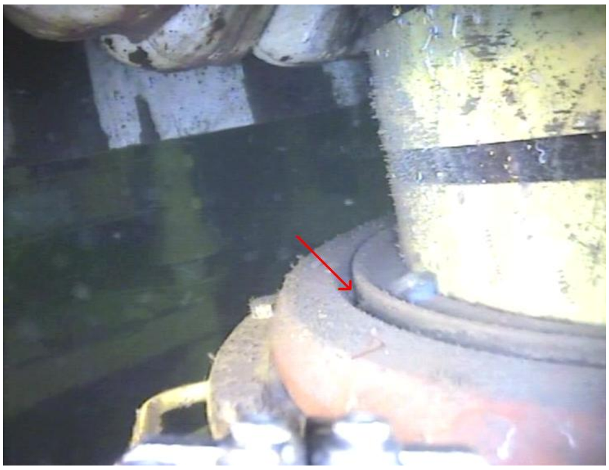


**Figure 45** *Monitoring of relative movement between conductor housing and wellhead landing ring. Figure is taken from [1].*

To record the cyclic loading, one can by the use of an ROV, observe the relative movement between the conductor housing and the wellhead landing ring. By monitoring this movement over time, the recorded clip can be fast-forwarded and used in the fatigue analysis.

### 5.1.1 Weight and Dimensions

Large dimensions and weight have a negative impact on fatigue life. It is therefore desirable to have a small BOP, both in terms of weight and height. A heavy BOP will yield higher loads to the underlying equipment, and a long BOP will contribute to a larger momentum when deviated. Confer APOS; *"As a rule of thumb you can say that BOP installed on a XT versus a BOP installed on a wellhead reduces the fatigue life with a factor of 3-5".* This is a considerable difference when evaluating fatigue life.

Furthermore, the total down-weight is important regarding wellhead loading. It is therefore important with proper pre-tensioning of riser to compensate for unnecessary load on the wellhead. In CRD the riser pre-tension is typically set so that the weight equilibrium is located in the BOP. This gives some weight to the wellhead, and the top of the BOP is tensioned against the riser. Such weight distribution enables for LMRP and BOP separation in case of emergencies. Figure 46 shows a LMRP/BOP stack slightly deviated to

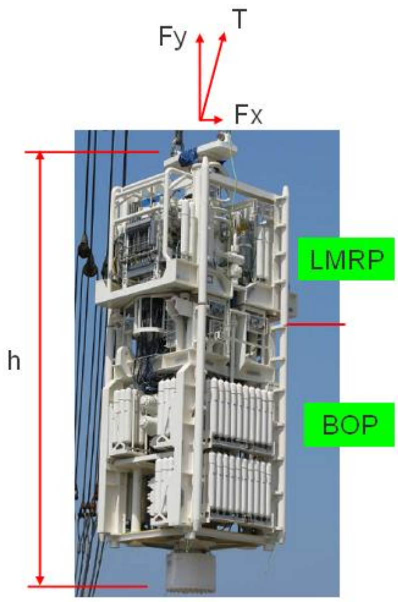



**Figure 46** *LMRP/BOP stack slightly deviated to represent tensional force orientation in two dimensions. Figure is taken from [1].*

illustrate the equivalent forces in two dimensions when tension is applied from the riser. The horizontal force applied on the wellhead from riser tension increases with rig deviation from well centre, but the bending momentum is not proportional with the distance moved. This is due to the flexible riser joint being positioned between the riser and the LMRP. The junction will comply with the bending momentum from the riser and absorb much of the rig displacement due to its low angular stiffness. As the deviation progresses, the tension force is decomposed into a larger force in x-direction, Fx, and to a less force in y-direction, Fy. With heave- and tensional compensation, the weight equilibrium can be maintained to a certain degree, but the increase in horizontal force will remain. Through cyclic loading under these conditions, the structural capacity will encounter a decrease in fatigue life. An example of fatigue life analysis was performed by Statoil to distinguish between the use of a large BOP vs. a small BOP with various tension from riser;

| | Units | Small | Large |
|---|---|---|---|
| BOP + LMRP Water Weight | Tons | 180 | 340 |
| LMRP Water Weight | Tons | 35 | 140 |
| Tension over pull (T) | Tons | 70 | 170 |
| Height (h) | m | 9 | 12 |
| Riser angle | deg | 3 | 3 |
| Bending Moment (Mb) | Tons*m | 33 | 107 |
| Mb^3 | (Tons*m)^3 | 3,58E+04 | 1,22E+06 |
| **Fatigue Life** | **Days** | **200** | **6** |

**Table 2** *Example of fatigue life between small and large BOP Table id taken from [1].*

It is stated from those who performed the calculation example above that it is a very simplified analysis [56]. When estimating fatigue life several factors have to be accounted for. These are stress variations and number of variations induced, own frequency, torque and load, drag factor from ocean currents, inertia between the equipment moving relatively to another etc. In addition, the stresses downwards in the subsea structure have a nonlinear relationship. This makes the calculations extremely hard, if not impossible, to predict since the stress/strain load is not of proportional manner. In the table above, the fatigue life was calculated as follows;

***Bending Momentum:***

$$Mb_S = T\sin(\alpha) * h = 70 * \sin(3) * 9 = \underline{33 ton * m}$$

$$Mb_L = T\sin(\alpha) * h = 170 * \sin(3) * 12 = \underline{107 ton * m}$$

(Statoil uses as a rule of thumb, that; fatigue life is proportional with: $\frac{1}{Mb^3}$ )

***Fatigue Life:***

*$BOP_S$ = 200 days (estimated)*

$$BOP_L = \frac{Mb_S{}^3}{Mb_L{}^3} * BOP_S = \frac{33^3}{107^3} * 200 = \underline{6 days}$$

One can see from the values presented above that fatigue life is drastically reduced when applying a larger BOP. The numbers are meant to emphasize the difference when applying a small vs. a large BOP, and do not reflect the actual relationship due to its simplicity. Nor does the example include the contribution of a slightly deviated stack, only the tensional force in horizontal direction is considered. Nonetheless, for a Riserless Drilling System, these forces will to a great extent vanish since there is no longer a rigid transfer of loads from the rig. Hence no large tension is required, only contribution from the guide wires, flexible k/c hoses and the drill string is experienced. As a result of the implementation of a riserless system, the fatigue life will increase significantly.

### 5.1.2 Riser Loads

Riser loads induced by the moving rig, ocean currents and pre-tension is definitely the major load contributor to the subsea structure. As described in the previous subchapter, the weight of the stack governs the pre-tension applied on the riser. This force, while deviated, contributes to a horizontal force that creates stress variations in the metallurgy during rig heave. Since fatigue life is a function of loads and exposure duration, the cyclic loading will through time initiate crack propagation in the substructure and deprive its integrity. Proper riser handling and monitoring is therefore a necessity to avoid excessive fatigue loading in the connection points, both topside and subsea. According to NORSOK D-010 [7], the riser should have the following; current meter, riser inclination measurement devices along the riser, riser tensioning system and flex joint. The flex joint is, as mentioned earlier, a junction between the LMRP and riser that is more compliant than the riser joints. The flex joints angular stiffness varies with type used, but is also a function of deflection and vessel off-set. An example of flex joint bending stiffness is; 2,5 m flex joint corresponds to the stiffness of 33 m 18 ¾" riser for 1° deviation, confer reference [56]. Bending beyond this off-set angle will yield a different relationship between the two as the relation is not linear. The figure below gives a good representation of the acting forces between the rig and subsea structure.

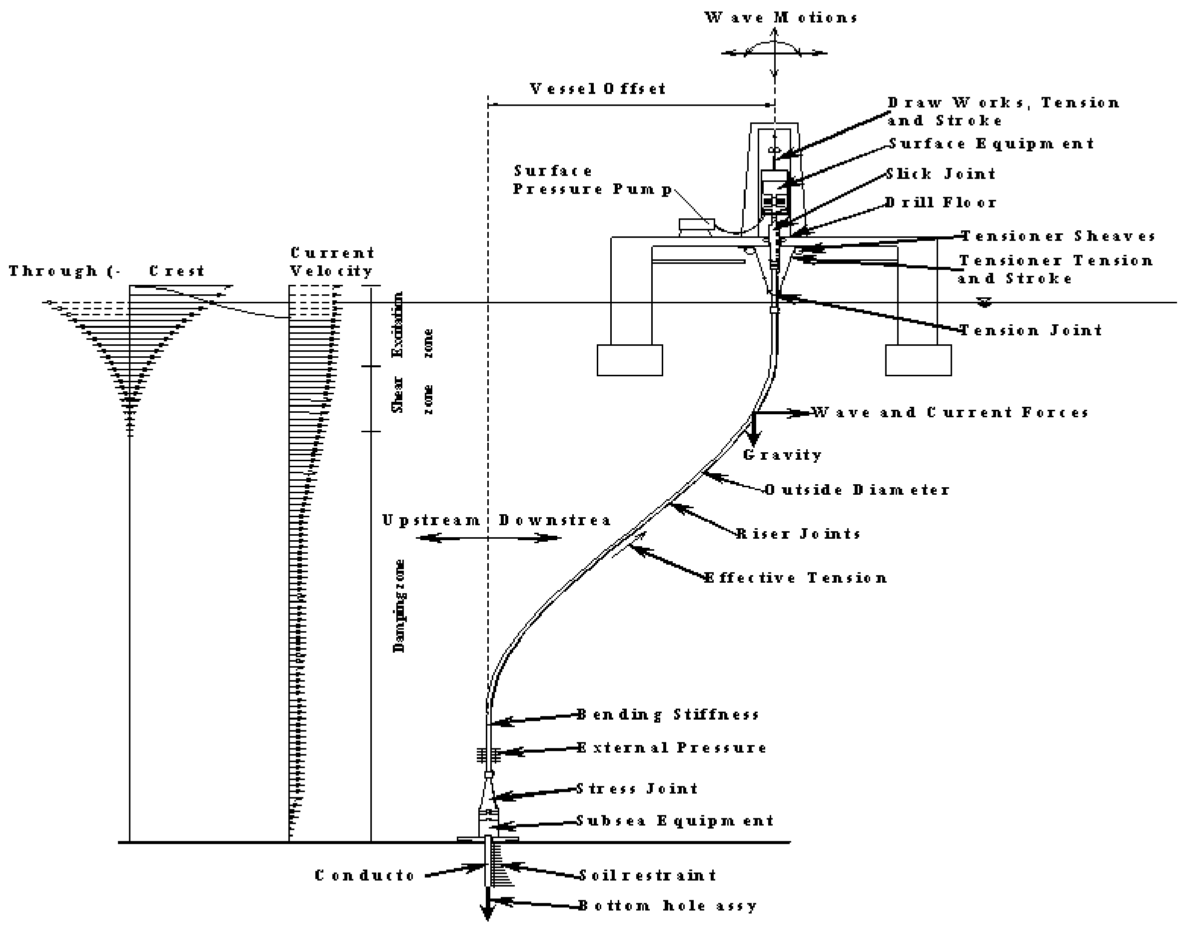



**Figure 47** *Riser geometry for a semisubmersible platform showing the acting forces. Figure is taken from [1].*

The force induced by the riser is dependent on the hydrodynamic drag and heave amplitude. The hydrodynamic drag is the force needed to lead an object with a certain velocity through a medium, in this case water. This effect is a function of the mediums density, drag factor, cross-section against the flow direction and the velocity it travels with. Hence, the induced force on the riser will get contribution from the heave amplitude in z-direction, and ocean currents in the x-y-plane. Also, the slope of the riser determines the magnitude of the contributions as the contact surface changes with the angle. Note that for a riser, which consists of a set of various pipe dimensions, a characteristic cross-section has to be determined. This is found by using the largest outer diameter of the combined pipes. Any calculation example would have to be very simplified, and thereby not render an expedient answer in this context. This topic, due to its complexity, is suitable for a master thesis alone.

Furthermore, the hydrodynamic drag will give inertia to the constantly moving riser. This can affect the fatigue life of the wellhead, both positive and negative. The positive aspect is that the hydrodynamic drag can dampen the rapid movement and reduce the total magnitude of the heave amplitude. This results in less visual movement of the involved components, but might induce larger stress-strain loads in the metallurgy. This because with inertia, the bottom and topside part might fluctuate unsynchronized and create large compression and tensional forces. Also the subsea structure can start to sway in relation to the frequency of the riser, resulting in the same effect as mentioned above. These induced stress variations will, dependent on magnitude and cycles, determine fatigue life.

### *5.1.3 Weather Conditions and Ocean Currents*

In the offshore environments the weather is constantly changing. It is important when connecting and entering a subsea well that a weather window is considered for the whole operation. A pick-up in wind speed and ocean currents will cause the rig/vessel to move more rapidly and lead to motion in the three dimensions. A deviated and tensioned riser combined with rig heave will start to act on the exposed suspension points at seabed, creating a large stress/strain scenario. The heave motion is created by the waves, and will contribute to fatigue depending on wave height and frequency. Under conditions like this, hot spots will occur in the subsea structure due to relative motion between riser/BOP and wellhead. The ocean currents will also act on the elongated riser and reinforce the stress/strain loads. It is therefore desirable to perform operations during summer time when both wave loads and ocean currents are at a minimum.

Figure 48 is a graphical representation of ocean currents from the Snorre field based on metocean (meteorological and oceanographic) measurements. The data set was provided by GM Metocean [57]. The graphs have been obtained from several observation data, showing the mean current velocities against different reference depths. Due to various spread in data, only four depths (data points) where used to represent a net amount of 163 days of simultaneous data collection. The values in between have been interpolated to render a full data series from top to bottom. Each profile is represented as a percentile, meaning that the value of a variable falls below a certain percent of the observation made. E.g., P10 represents 10% of the observations that falls on/below the plotted value. Here we can see that the ocean current is having a descending development down to seabed. The current will therefore have largest impact on the riser closest to MSL, giving high bending momentum at seabed. There is of course a large variation in magnitude in ocean currents throughout the North Sea depending on location, but the graphical representation points out the mean conditions for a particular area. As an additional explanation to the graphs it is reasonable with largest currents at surface due to wind contribution. This is not beneficial in terms of rig displacement and enlargement of horizontal stresses. Furthermore, ocean currents normally decrease with depth, but there could be water layers with altering direction and speed. Close to seabed the bottom friction will ensure a further decrease in flow rate.

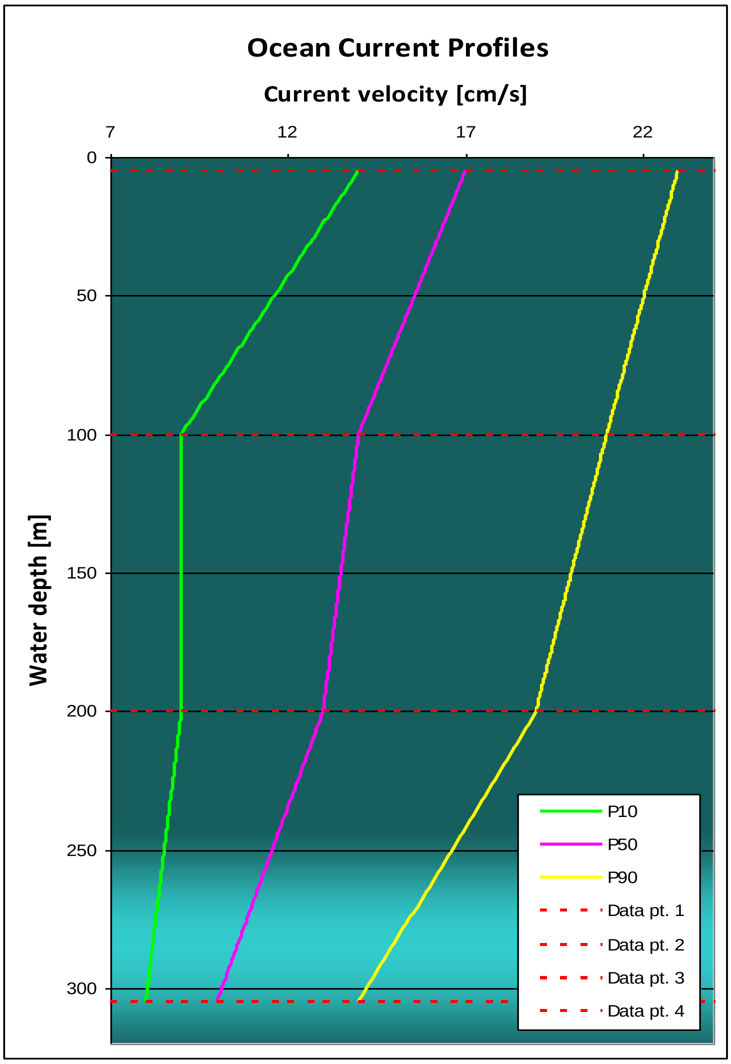



**Figure 48** *Ocean Current Profiles from the Snorre field.*

# 6 Future Applications

The use of a Riserless Drilling System to drill the entire well is quite extraordinary compared to the conventional approach. New possibilities arises with this technology, and as a future application, it might solve the challenging deep water frontiers and possible enable for inclusion of MPD as well. Although RD is a technology in development, the above mentioned applications are considered as a future interest for Statoil when justifying the implementation of this concept.

## 6.1 Large Water Depths

To further elaborate on this subject, a definition of water depths is required. Within the oil and gas industry, water depths are defined as follows;

- Deepwater: + 900 m (3000 ft) [58]
- Ultra deepwater: + 2100 m (7000 ft) [58]
- Hyper deepwater: + 3657 m (12000 ft) [5]

The current water depth well record drilled with a riser is 3051 m, and was performed by Transocean and ChevronTexaco in the Alaminos Canyon field, block 951 in Gulf of Mexico. This was achieved by VetcoGray's HMF™ advanced marine riser systems in Q4 2003. This implies that the existing riser depth capability so far is the record stated above on 3051 m. According to [5], *"Scientific ocean drilling and the energy industry have ultra-deepwater targets of interest beyond the reach of current risers. Research is underway to design risers of even greater depth potential using a combination of metallic and composite materials".* Even though it is possible to stretch the risers potential a little further, alternate technologies should be considered to undertake this challenge. A Riserless Drilling System is not constrained by the length limitations of a riser system; hence it would be optimal in conditions like this. Disregarded pump technology, the elimination of a riser system and implementation of dual gradient drilling would clearly be beneficial for large water depths. This could be a reality with improved pump technology, which is the most imminent bottleneck for this system. A further explanation of future pump technology will follow in the next coming subchapter.

The main inbound factors that differentiate deepwater drilling from drilling in normal water depths are narrow pressure windows, temperature gradients, logistics and costs, strong ocean currents and increased geohazards. A Riserless Drilling System would discourage most of the unwanted effects mentioned above. Since a dual gradient effect is achieved with this system, a favourable situation down hole occurs as less hydrostatic head is present. This enables for better management of the weighted mud within the narrow drilling window. Deepwater drilling windows are narrow due to the overburden sediments are typically weak and over pressured according to [59]. Regarding logistics and costs, the elimination of the riser string and the associated saved mud volume will be substantial for large water depths. Due to a smaller and flexible mud conduit to surface, the ocean currents will not have any major impact on induced load for topside and subsea equipment compared to a riser system. Geohazards are also mitigated for the top hole sections by the use of engineered mud as explained earlier. When in addition several billion barrels are located in these areas, the driving force for the development of a Riserless Drilling System is expedient. The figure below shows a rough overview of the worldwide deepwater reserves as estimated by Quest Offshore in 2009.

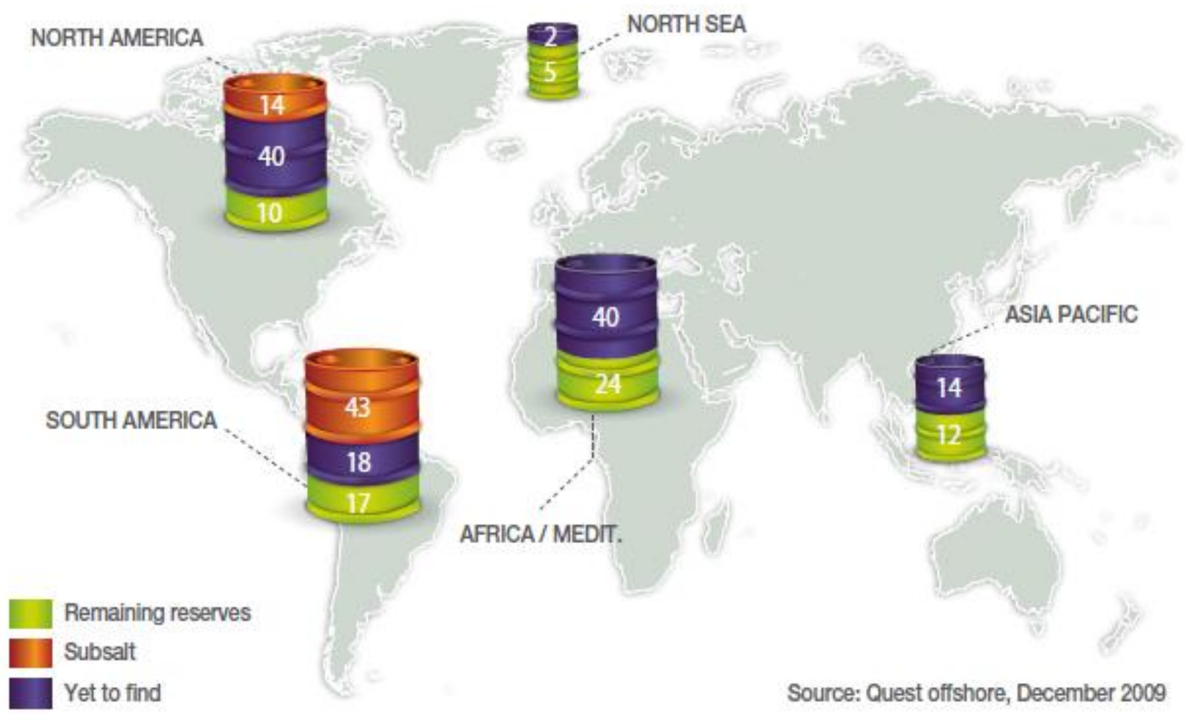



**Figure 49** *Worldwide deepwater reserves (billions of barrels). Figure is taken from* [60].

**Subsalt:** sedimentary systems containing hydrocarbons that are covered over by enormous dome-shaped salt bodies [60].

### 6.1.1 Deep Water Subsea Pump

As the subsea pump is the most essential part of a Riserless Drilling System, and the presented pump capacity for the disc pump is maximum 1200 m for low density drilling fluids, other alternatives has to be evaluated in terms of reaching deeper goals with this technology. A Norwegian company, PG Marine Group [34] from Oslo, has a wide experience within pump technology and areas of use. Most interesting for RD is their Multi Application Pump Solution Hose Diaphragm Pump (PG-MAPS®). This pumping principle is well known in the slurry, waste water, industrial mining and sewage pumping industry. A diaphragm, easier referred to as a membrane, is a flexible divider that parts and isolates between two substances, avoiding direct contact. For this hose diaphragm pump, a non-compressible hydraulic fluid is stationed around the hose which acts as the power transfer from the double-acting actuators. An actuator is a mechanical device for moving or controlling a mechanism or system [61]. A permanent magnet linear electric motor, developed by Techni AS [62], drives the actuator up and down, that again moves the hydraulic fluid which squeezes the diaphragm hoses consecutively. Figure 50 shows the hose diaphragm principle.

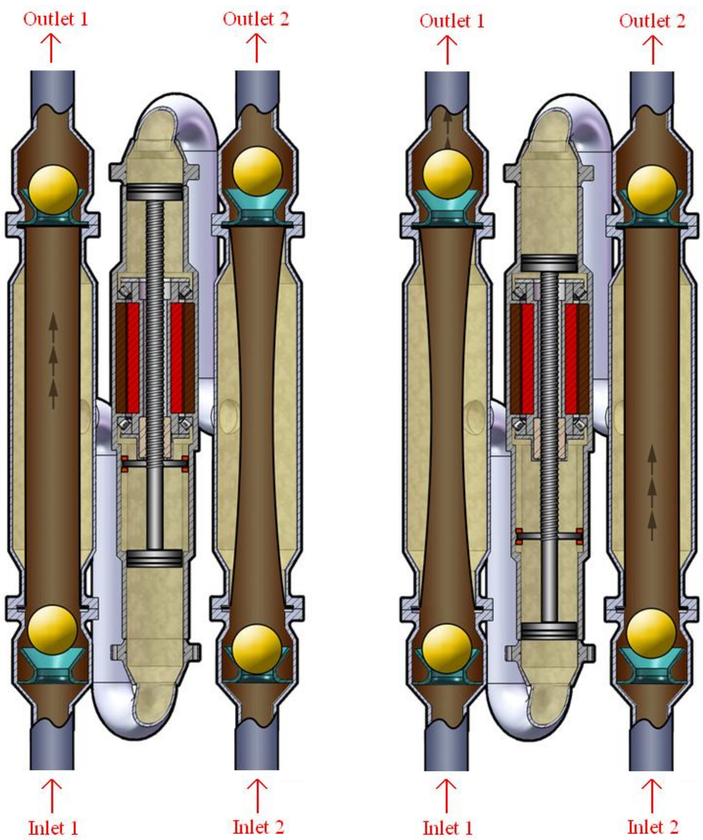



**Figure 50** *PG-MAPS hose diaphragm pump configuration for one* double-acting actuator. *Figure is taken from [34].*

If connected to the mud funnel by the suction hose, this pump would alternate the flow rate through the hoses consecutively, resulting in a continuous flow without pulsations due to the four diaphragm hoses never being squeezed at the same time (shifted 90° apart). The figure above shows the sequence for two hoses only. Ball valves are located in the inlet/outlet seats, opening and closing for flow when the membrane is squeezed. As this is a displacement pump, the pump will lift as long as the applied force is larger than the resistance (hydrostatic head + friction).

This pump is highly applicable for abrasive, acid and viscous media which would be the case when pumping drilling fluids back to the topside mud system. The membrane is made of elastomers, or in some cases polytetrafluoroethylene (PTFE) dependent on the operating temperature. Particle size allowance through the pump is 20-50 mm. Furthermore, due to no rotating parts in the pumping module, the pump is less exposed to wear from any moving parts. Also included in the pump module is a built in redundancy which allows pump continuation with only one double-acting actuator in motion. The pump is equipped with a subsea motor control pod that controls the pumping force, without the need of a VSD.

The pump module comes with two generations of hermetically sealed, leak-free positive displacement pumps, where each pump set can deliver 5000 lpm. The service provider can also dimension and design the pump with several pumping sets to meet the operating demands. It is informed by the supplier that the pump can be applied in deep- to ultra deep waters (2000-2500 m). PG Marine Group and Techni AS were awarded "Spotlight on new Technology" in May 2011 under the annual Offshore Technology Conference in Houston for the PG-MAPS® pump technology.

## 6.2 Managed Pressure Drilling

As mentioned earlier MPD is an "*an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore"*. It does so by annular back-pressure management using a choke manifold and a rotating sealing device that seals of the annulus. MPD may also include manipulation of fluid rheology, annular fluid level alteration in riser, circulating friction pressures and hole geometry, or a combinations of these [63]. This section will focus on applied back-pressure to achieve MPD conditions. By having a sealed annulus, a closed mud system is achieved which can be pressurized through pressure build-up from rig pump circulation, or by applying pressure from the rig choke manifold to compensate for ECD contribution whenever breaking the circulation. For a Riserless Drilling System the relevant annulus is located at seafloor, thus requiring a Subsea Rotating Device (SRD), Chevron [64]. The Riserless Drilling System would then change from being a dual-gradient system, to a RD MPD system. This would then enable for quick pressure adjustments by pressurizing or depressurizing the annulus to keep within the drilling window. The reader should be aware of that MPD utilizes a lower density to provide a larger working window, thus compromising the riser margin.

### 6.2.1 Subsea Rotating Device

The SRD was developed by Chevron to minimize gas ingress into the riser during DGD operations, and to act as a seal between the riser fluid and wellbore fluid. The SRD is designed so that the sealing insert can be retrieved and changed during tripping in and out of the well. The sealing inserts are mounted on bearings so that it rotates together with the drillpipe, avoiding excessive wear of the rubber element. A Riserless Drilling System could possibly benefit from this device in terms of its annular sealing capabilities. The purpose here would be to provide a mechanical interface between the drilling mud in the well, and the surrounding seawater. Similar to DGD with riser, where one can alter the liquid column in the riser to compensate for insufficient mud weight, the BHP can be maintained at all times by adjusting the back-pressure below the SRD. This could be done by adjusting the flow rate out from the subsea pump, whilst maintaining the same circulation rate from rig. The subsea pump will then act as a choke, creating a pressure build-up underneath the SRD. When desired pressure is reached, the pump will return to the same rate as the rig pump. Due to the hydrostatic pressure in the MRL, the choke pressure in the annulus will remain until the flow rate in/out of the well is changed. The sealing capability for Chevron's SRD is 1000 psi (69 bar) differential pressure which is usually sufficient in MPD operations. The optimal solution for a Riserless Drilling System would be to drill the first sections using an open interface (DGD), and switch over to MPD conditions when narrow drilling windows (e.g. depleted zones) are to be drilled. This could be achieved by taking the insert on and off as desired during tripping operations. To be able to trip out of the well, the well must be gradually displaced to overbalanced conditions while the choke pressure is bled off so that the pressure below the SRD is equal to the external seawater gradient. A high density pill can also be used to achieve this. The pressure sensor in the mud funnel would have to be switched between DGD and MPD mode during the different operations. A similar approach has been tested recently by AGR on an RMR® operation using Weatherford's Rotating Control Device (RCD), and proved to be a success. This implies that the concept is applicable, but there is still a long way to go before this is a proven solution for commercial use. Regardless, such a system could revolutionize the entire drilling industry in terms of riserless drilling and the possibility of keeping a constant BHP. It is therefore even more important to implement a fully functional Riserless Drilling System so that this can be achieved. Figure 51 below represents a possible solution that enables for subsea MPD for a Riserless Drilling System.

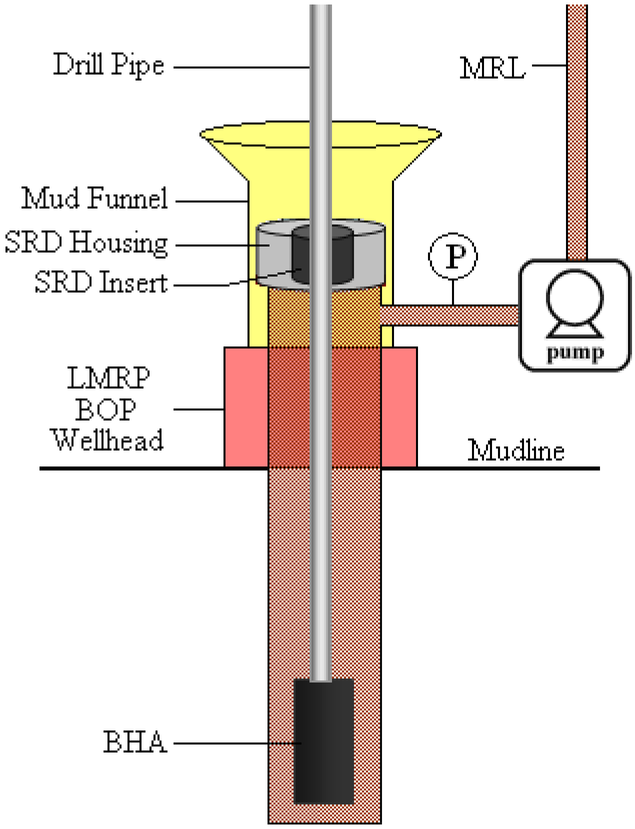



**Figure 51** *A possible configuration of the combination of RD and MPD in the future.*

# 7 Simulations

Throughout this thesis the EMW and the dual gradient effect have been mentioned several times. To get a better understanding of the EMW as it descends in the wellbore, an explanation of the effect followed by three drilling windows with various water depths will be graphically presented to assist the reader.

Since the mud gradient is established at seafloor in DGD, with water as the overburden hydrostatic column, the EMW will be a ratio of the fixed seawater depth together with an incremental of the mud hydrostatic with depth below mudline. This will impart in an un-natural gradient (curved line) which changes as a result of the increasing wellbore depth. This “curve effect” will have largest impact in the beginning when the ratio is greatest, and converge more and more towards the conventional “straight” gradient as drilling progresses.

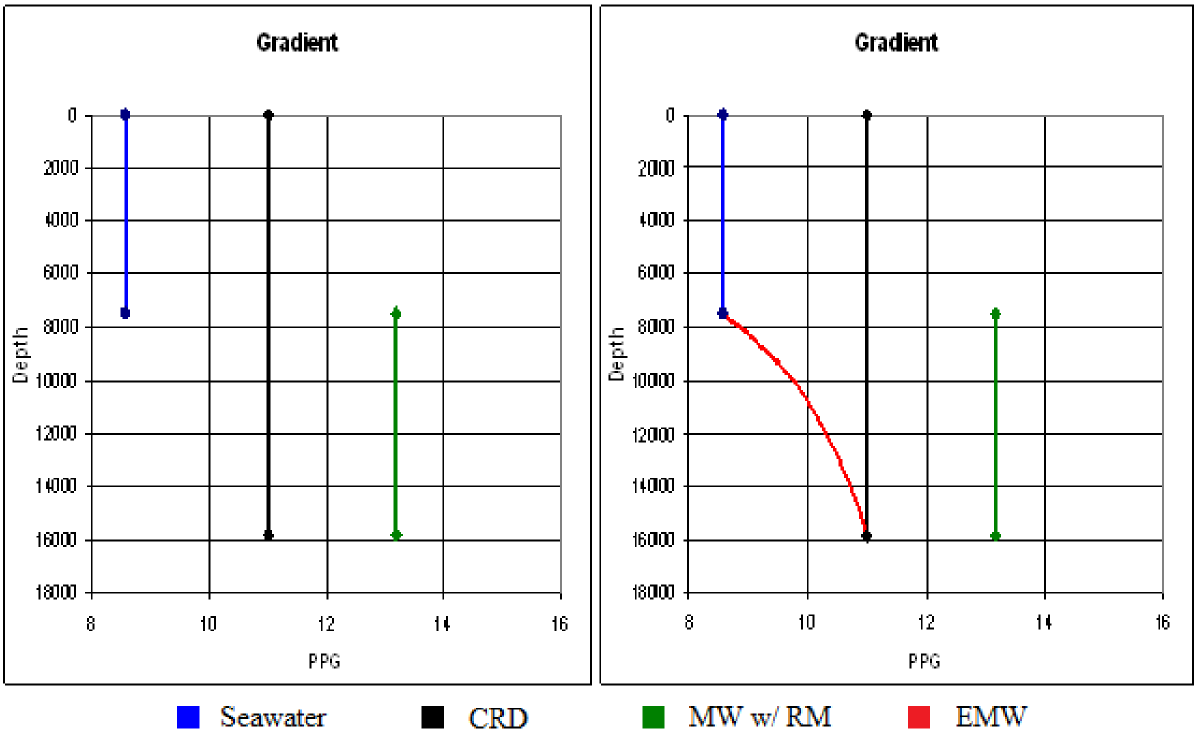



**Figure 52** *Illustration of the Effective Mud Weight (EMW) while descending. Figure taken from [65].*

As depicted in the figure above the EMW is a ratio between the seawater and the mud weight with riser margin (MW w/ RM). The combination of the two gradients result in a seemingly lower EMW than the actual mud weight is at the particular depth. By having a curved slope, the un-natural graph is more in compliance with the pore- and fracture limits as it moves within the drilling window.

The equation for the EMW is as follows;

$$EMW = \frac{\rho_{SW} D_{SW} + \rho_{MW}(TVD - D_{SW} - h_{Airgap})}{TVD} \tag{10}$$

Where;
$\rho_{SW}$ = *density of seawater*
$\rho_{MW}$ = *density of mud weight*
$D_{SW}$ = *water depth*
$TVD$ = *true vertical depth*
$h_{Airgap}$ = *height air gap*

One can see from the equation that the $\rho_{SW}$ ratio will have less impact with increasing depth below mudline. As the $\rho_{MW}$ ratio increases with depth, this term will dominate the equation and thus converge the EMW towards single gradient conditions.

The reader should be aware of that the upcoming graphical presentations are not realistic in terms of casing setting depths. The proposed mud weights and casing points are limited by the drilling window only, and no considerations towards the formation has been accounted for. The graphs are under static conditions, thus the ECD contribution must be considered when going over to dynamic conditions. Furthermore, the riser margin should be included during CRD. Although the graphs are not in exact accordance with an actual drilling program, they are meant to point out the advantages of having a dual gradient system in terms of casing set points.

## 7.1 Gullfaks Satellites

The shallow water depth at GFS results in a small dual gradient effect. With a 134 m water column, the curve converges quickly (around 2000 m) towards the straight CRD graph. However, even for this case RD is beneficial in terms of casing setting depths. For the use of a single gradient system during CRD, a casing shoe must be placed around 2000 m before allowing a higher density into the well. Most likely for this case, both methods would have ended up with the same casing dimension at bottom due to the long RD sections need for being cased off. This graph is only to illustrate that even for wide drilling windows and shallow water depths, the dual gradient system is in theory advantageous compared to a single gradient system.

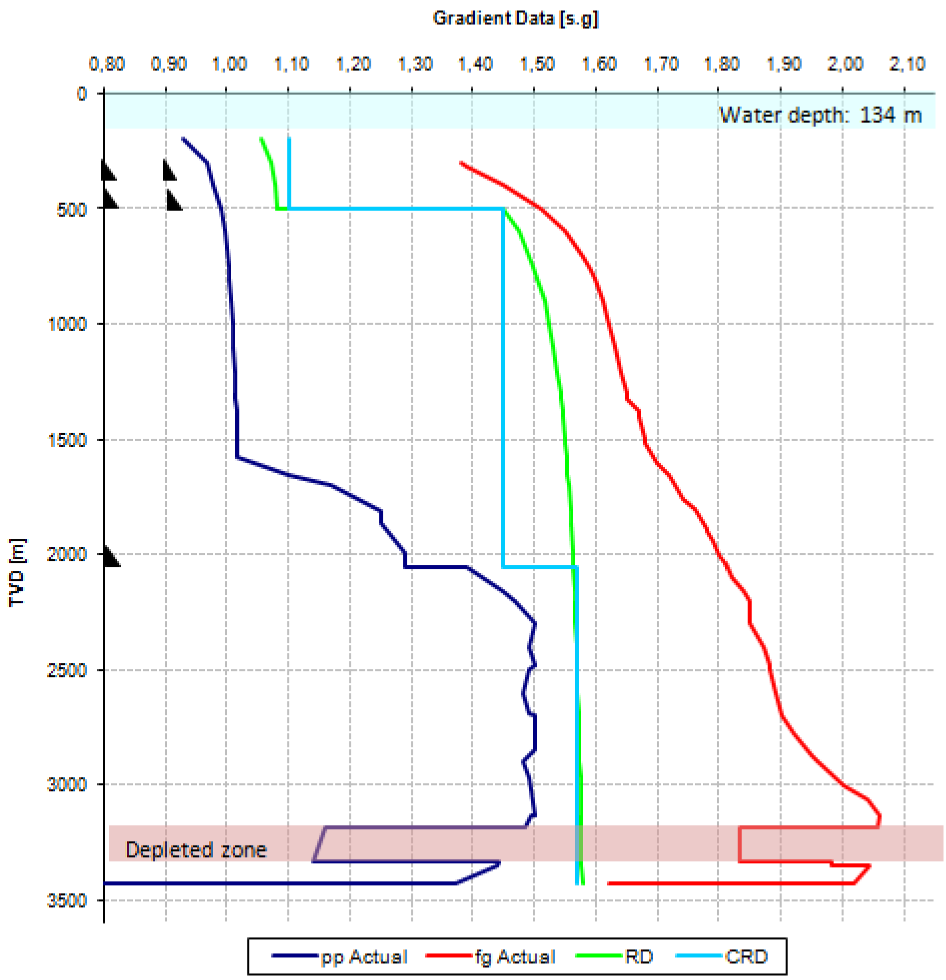



**Figure 53** *Drilling window for GFS showing a proposed drilling program for CRD and RD.*

The lowermost part of the drilling window indicates a depleted zone. This entails a narrowing of the drilling window which complicates further drilling. With a clearance of approximately 14 points (0,14 s.g.), neither CRD or RD would not have had difficulties passing through the narrow window. For CRD an addition of 2,2 points (0,022 s.g.) riser margin should be taken into the account, which leaves enough room for ECD contributions. For larger water depths the riser margin would become to severe, thus not allowing CRD to pass in terms of staying in overbalance during riser loss (riser disconnect). A riserless approach on the contrary doesn't need to take this into the account as the riser margin makes up its normal drilling state. Furthermore, if the ECD contribution is too large, a CCS or MPD compensation should be applied to pass through narrow windows with small pressure variation tolerances.

## *7.2 Gulf of Mexico - Well 1*

Gulf of Mexico (GOM) is known for its large water depths. The case below is taken from a well on the Krakatoa field in GOM which Statoil holds 90% interest in. With 634 m water depth the dual gradient effect is clearly visible throughout the whole well. The largest curve effect is experienced in the beginning, enabling for long sections to be drilled whilst staying between the pore-pressure (PP) and fracture-gradient (FG). As CRD requires in theory a minimum of seven casing points to reach bottom, RD could achieve the same with a minimum of 4 casing points. Several casing points would of course be needed due to formation instabilities and ECD contributions, but theoretically a larger casing dimension would reach bottom. This had resulted in a larger productivity which would be financially beneficial in the GOM where high rates are expected.

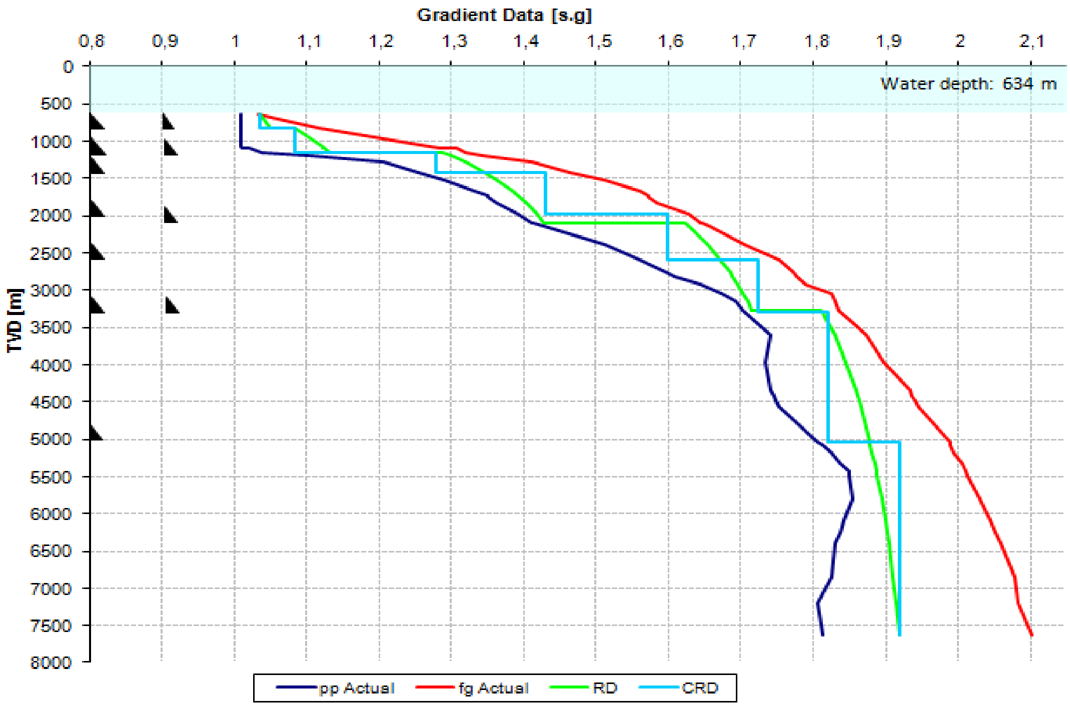



**Figure 54** *Clearly showing the effect of dual gradient in terms of compatibility within the drilling window.*

## 7.3 Gulf of Mexico - Well 2

As the last graphical presentation, an ultra deep water well in the GOM was chosen. With a staggering water depth of 2414 m the curved dual gradient effect is clearly evident. The large water column results in an almost parallel movement in between the PP and FG.

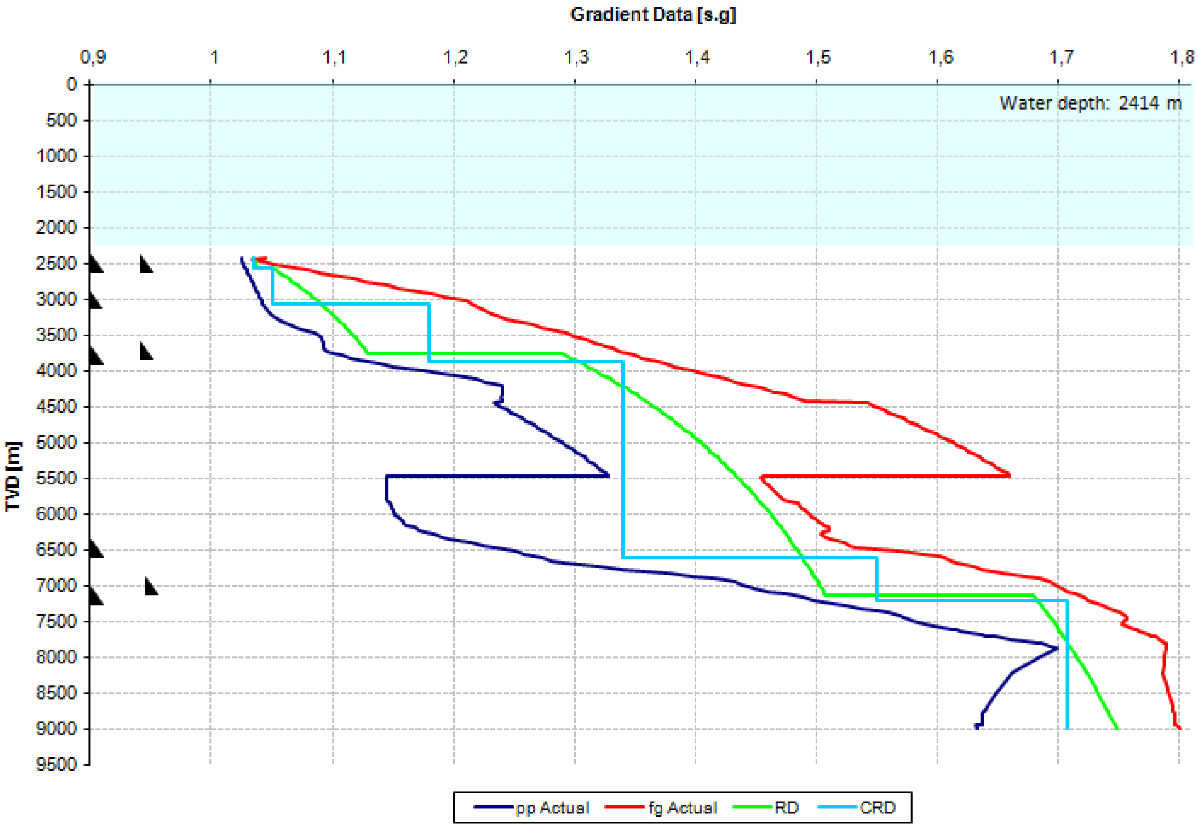



**Figure 55** *Ultra deep water and the advantageous use of a dual gradient approach.*

Furthermore, the reader should be aware of that the riser margin would have to be excluded from CRD to make it even possible to drill. This is normal in the GOM where exceptions are sought for water depths larger than 1000 m. A riser loss during drilling of the last section (7300 m) would result in a 160 bar pressure difference at mudline. This would require 34 points (0,34 s.g.) in additional mud weight to stay in overbalance after a riser disconnect. Thus, this well could not be drilled using CRD with a riser margin. Furthermore, CRD in general only allows for shorter sections to be drilled before requiring a new casing point. As casing strings are associated with large costs in terms of time spent, steel material and cementation, a less need for such operations are clearly preferable. A RD approach would satisfy this requirement, while maintaining better well control due to the preservation of the riser margin.

# 8 Conclusion

Drilling an entire well without the need of a marine drilling riser is an exciting thought. By doing so, the drilling operation will not be limited by the water depth and the restrictions a long rigid riser implies. This is very much beneficial in large water depths where CRD is becoming insufficient and not applicable. Efforts are being made to enable for riser level alteration by partly evacuating the conduit (nitrogen and mud interface), but this does not resolve the large stresses that are transferred from the rig and ocean currents to the subsea structure. It is also quite expensive in terms of additional equipment and modifications. Further commitment to a Riserless Drilling System is thus justified in terms of opening up opportunities for exploration in deeper water, mitigation of fatigue related issues, provides the dual gradient effect which is associated with less casing points, and preserves the riser margin independently of the water depth.

Regarding wellhead fatigue on GFS, the implementation of a Riserless Drilling System will virtually eliminate further fatigue loading during future connection days. The removal of a marine drilling riser will consequently result in elimination of the heave loads that would otherwise been transferred from the rig. This would also mitigate the horizontal stresses induced on the wellhead due to no pre-tension of the riser is needed, nor any contribution from ocean currents is experienced. As a result of this, further fatigue analyses would be greatly simplified since the riser's load conditions are removed from the equation, hence extend the lifetime of the subsea wellhead systems.

After careful evaluation of the developing technology the author has come to the conclusion that a Riserless Drilling System is a viable alternative to drill a well. Although no field trials have yet been performed to date, nor any published papers concerning same exists, the already present and proven RMR® technology is a good basis and argument for further continuation of the concept. The RMR® technology has been utilized since 2003, and has through this time proven to be very reliable and robust. As this technology is in the possession of AGR, the technology gaps for them is of minor extent compared to ORS in terms of developing and succeeding with a Riserless Drilling System. ORS have not yet System Integration Tested the pump system, mud funnel, wiper element or zero discharge system. The subsea pump module also remains to be fully built which is estimated to be completed around Q4, 2011. On the contrary, ORS have some useful solutions that the author considers a necessity for the Riserless Drilling System to achieve its full potential. This will be further elaborated under the upcoming recommendation section. The differences in total cost between the two service providers have deliberately been excluded from the thesis due to internal reasons, but to the readers enlightenment the proposed expenses are approximately equal. This point can therefore not be used in the determination phase when acquiring the best applicable solution. The decision must thus be taken on the basis of the provider's deliverability, functionality, experience and credibility.

## 8.1 Discussion and Recommendations

Based on the available information the author is of the perception that both systems are applicable. Thus the author will reserve the right to give recommendations on the basis of functionality, regardless of ownership rights. This is to apply the technology in the best way possible to achieve a more viable and reliable system.

### 8.1.1 Equipment

Both suppliers provide similar equipment and solutions, but the most obvious inequality is the pump design and configuration. AGR used a subsea stand-alone pump module during RMR® operations, but chose to re-design the pump to make it integral with the LMRP and the mud funnel. This is according to the author's opinion the best alternative since it result in the system being resistant towards suction hose collapse if the suction pressure becomes too severe. This is because the suction hose can be replaced with a rigid pipe that has larger collapse pressure rating. Also, by integrating the pump with the stack, less deployment operations are required and the Riserless Drilling System becomes one unit. Hence, a tidier subsea configuration is achieved without the need for ROV hook-ups. Integrating the pump may become a challenge when several pumps are required due to weight and space restrictions. An additional pump for redundancy should be included in the pumping module either whether one goes for a stand alone or an integral pump.

The arrangement of the hoses and umbilical's subsea is very important in terms of interference and entanglement with drillpipe and subsea stack. If the pump module is decided to be an integral part of the mud funnel, all the flexible hoses can be arranged together in a bundle to form a single retention of hoses to ease the maintenance of the pliant wave configuration. The preservation of the pliant wave configuration should be achieved by introducing a clump weight, either anchored to the seafloor or hanging freely at the end, to stabilize the vertical section of the hose bundle. If anchored, the device should be designed so that it released the bundle to avoid tear off in case of large rig movement.

ORS's wiper element and zero discharge system should be an absolute requirement when operating with an OBM. This is beneficial in terms of restricting the drillpipe to the center of the bucket, and capturing of contaminants to avoid spill to sea. In this case two pressure sensors should be included in the bucket for redundancy as level control by visual confirmation is strongly impaired. Introducing the 2" re-circulation hose is also considered a necessity by the author to enable for the proposed flow check procedure.

Introducing a basement deck to make up and store k/c hoses prior to installation is an expensive solution which requires additional rig modifications. It might also not be applicable in many cases due to rig specifics. One should rather consider other options like using the finger table for single section (38 m) hang-off, and make up the k/c hoses during deployment.

The proposed drill string valve should be included in the system as a part of the standard equipment. This differential pressure valve which is located in the drillstring prevents U-tube entirely. It is a small and convenient device that simplifies the well hydraulics, making it much easier to manage with little work associated. It needs to be adjusted during trips, but this is considered minimal effort for the advantages it brings. This device becomes more important as the operating water depth increases due to the larger U-tube effect.

### 8.1.2 Well Control

As stated earlier the Riserless Drilling System will not be a part of the well control equipment. During well control situations conventional well control procedures will apply, although the system should be able to detect kicks by performing a flow check in advance. It is therefore recommended to include the 2" re-circulation hose to assist in flow check procedures by enable for mud replenishment.

As the interface between the two columns has not yet been evaluated with regards to riserless drilling, it should be addressed and discussed with PSA. This interface, together with the water column and mud column, makes up the primary barrier in the well. Furthermore, according to NORSOK D-010 [7]; "*The fluid column is not a qualified well barrier when the marine riser has been disconnected"*. This needs to be sorted out with PSA before applying a Riserless Drilling System.

### 8.1.3 Further Work

Statoil must take a decision in the first instance of whether or not to implement the Riserless Drilling System on GFS to mitigate further wellhead fatigue. If they decide to follow through with this alternative solution, the service providing company should be chosen. Proper procedures in terms of flow check and deployment must then be established to achieve best practice. Furthermore, the system must get an approval from governing authorities and be field tested.

Further work should also be done with regards to pump technology, as this is the bottle neck of the system. The proposed PG-MAPS® diaphragm pump is an interesting technology that might enable for larger water depths than presented by the Riserless Drilling System service providers. A more thorough investigation should therefore be conducted to determine the pumps functionality and viability.

It is recommended that a DGD approach is established and proven before embarking on introducing a subsea sealing element to enable for MPD operations. Nevertheless, this step is an important milestone in the attainment of achieving optimal performance by expanding its application areas.

## Abbreviations

| | |
|---|---|
| AGR | Arve Gunnar Reidar |
| APOS | Arbeids Prosess Orientert Styring |
| ASD | Arbeids- og Sosialdepartementet |
| BHA | Bottom Hole Assembly |
| BOEM | Bureau of Ocean Energy Management’ |
| BOP | Blow Out Preventer |
| CCS | Continuous Circulation System |
| CRD | Conventional Riser Drilling |
| CTS | Cuttings Transport System |
| DGD | Dual Gradient Drilling |
| DP | Drill Pipe |
| DSV | Drill String Valve |
| ECD | Equivalent Circulation Density |
| EMW | Effective Mud Weight |
| FG | Fracture Gradient |
| FSS | Flow Stop Sub |
| GFS | Gullfaks Satellites |
| GOM | Gulf of Mexico |
| HPHT | High Pressure High Temperature |
| IADC | International Association of Drilling Contractors |
| IKM | Instrumentering Kalibrering Måleteknisk |
| k/c | Kill and Choke |
| MPD | Managed Pressure Drilling |
| MRL | Mud Return Line |
| MSL | Mean Sea Level |
| MWDP | Maximum Well Design Pressure |
| NCS | Norwegian Continental Shelf |
| NPT | Non Productive Time |
| OBM | Oil Based Mud |
| OED | Olje- og Energi Departementet |

| | |
|---|---|
| ORS | Ocean Riser Systems |
| PID | Proportional–Integral–Derivative |
| PLC | Programmable Logic Controller |
| PP | Pore Pressure |
| PPG | Parts Per Gallon |
| PTFE | Polytetrafluoroethylene |
| Ptil | Petroleumstilsynet |
| RD | Riserless Drilling |
| RM | Riser Margin |
| RMR | Riserless Mud Recovery |
| ROV | Remotely Operated Vehicle |
| RPM | Rotation Per Minute |
| SFT | Statens Forurensnings Tilsyn |
| SGD | Single Gradient Drilling |
| SHDIR | Statens Helse Direktorat |
| SICP | Shut-In Casing Pressure |
| SIDPP | Shut-In Drill Pipe Pressure |
| SPM | Subsea Pump Module |
| TVD | True Vertical Depth |
| VBR | Variable Bore Rams |
| VSD | Variable Speed Drive |
| WBM | Water Base Mud |
| XT | Christmas Tree |

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