University of Stavanger

Faculty of Science and Technology

MASTER'S THESIS

Study program: Master's Programme in Offshore Technology Specialization: Subsea Technology	Spring semester, 2013 Open
Author: Nisit Rungrujirat	…………………………………………… (Writer's signature)

Faculty supervisor: Prof. Dr. Arnfinn Nergaard (UiS)

External supervisor(s): Harald Syse (Reelwell AS)

Title of thesis:

Basic Design of Subsea BOP Stack with RCD for Riserless Drilling

Credits (ECTS): 30

Key words: BOP stack Riserless Reelwell Drilling method	Pages: 71 + enclosure: 85 Stavanger June 17th, 2013

Abstract

Reelwell Riserless drilling concept has been proposed to overcome the economic challenge of drilling through the thick salt layer. The concept shall bases on RDM method, which is a new drilling method with the concentric drill string other special design tool such as Rotating control devices and Double float valve. The concentric drill string consists of outer conventional pipe joints an inner string specially designed for RDM that shall allow the "return" through the inner pipe. This shall eliminate the need of marine riser, which results in significant cost savings by exclusion of riser related costs and enables us to use smaller rigs with much lower day rate for ultra deep-water drilling operations. There would also be a considerable mud cost reduction and rig space saving as there is no riser to be filled up with drilling mud.

The study has reviewed the conventional drilling procedure, the case study's working condition and defined the Basic Design of Subsea BOP stack with Rotating control device for Reelwell-Riserless drilling, to achieve reasonable reliability and performance to mitigate risk in the operation. The BOP control system is also reviewed and proposed a new technology to improve its efficiency in the new working environment.

Acknowledgements

First of all, I would like to express my sincere appreciation to my supervisor, Professor Arnfinn Nergaard for his support and guidance during the work.

My gratitude also goes to Reelwell AS, Stavanger, Norway for granting me office space and all other necessary information to facilitate the successful execution of this task.

I am grateful to my classmates and friends in Stavanger who have made my M.Sc. study an exciting and enjoyable time.

Finally, my endless thanks go for my family for their support and encouragement in the hard time.

Table of Contents

List of Figures

List of Tables

1 Project Background

Since the Lula pre-salt discovery in 2006, Santos basin became an influential stage of large oil field discoveries. However the pre-salt plays represent thick salt layer below the ultra deep-water depth is a highly challenge for the drilling activities in the area. The salt layer allows very low penetration rate drilling while the ultra deep water requires a large capacity drilling rig that comes along with very high cost.

Reelwell Riserless drilling concept has been proposed to overcome the economic challenge of drilling through the thick salt layer. The concept shall bases on RDM method, which is a new drilling method with the concentric drill string (Figure 1), and other special design tool such as Rotating control devices and Double float valve. The concentric drill string consists of outer conventional pipe joints an inner string specially designed for RDM that shall allow the "return" through the inner pipe. This shall eliminate the need of marine riser and results in significant cost savings by exclusion of riser related costs and enables us to use smaller rigs, which day rate are much lower, for ultra deep-water drilling operations. There would also be a considerable mud cost reduction and rig space saving as there is no riser to be filled up with drilling mud. Relaxation of station keeping is another benefit of Riserless operation. (Mirrajabi, M., A. I. Nergaard, et al., 2009).

However to apply this technology to a new environmental condition, several components are need to be reviewed, redesigned and/or qualified. Subsea BOP stack and the drilling well control system are a key barrier in the drilling activities to achieve a reasonable reliability and acceptable risk in this new environmental condition, they are also needed to be reviewed/redesigned and qualified.

1.1 Pre-salt: the new major plays in offshore Brazil

The Pre-salt layer is a geological formation on the continental shelves off the coast of Brazil (and also in Africa) that bears the petroleum traps under its huge thick salt layer (up to 2000m thick). Brazilian pre-salt province located in the South Atlantic Ocean that extends over 800 km along the Brazilian coast – from the state of Santa Catarina coast to the coast of Espirito Santo – up to 200 km wide, cover both Campos and Santos Basin and include several recently major discoveries such as Lula (Tupi), Jupiter, Sugar and etc.

Exploration and development of this pre-salt layer is in its infancy with only a handful of wells drilled so far. Having reservoirs buried below as much as 2000 meter of salt, the pre-salt play presents a multifaceted deep-water scenario that is bringing new challenges to Brazilian exploration and production.

Reservoirs in this domain are complex heterogeneous layered carbonates, which makes accurate reservoir characterization very challenging. Drilling these wells was proved extremely difficult with low penetration rates. The tendency for borehole deviation while drilling in salt elevates the importance of precise directional control. Flow assurance related to paraffin deposition, hydrate and scaling control is also a challenge. In addition, the pre-salt environment is corrosive with significant amounts of carbon dioxide (CO_2) and hydrogen sulfide (H2S) present. This places a high demand on special cement and metallurgy throughout the drilling and completion process. (Halliburton, 2013)

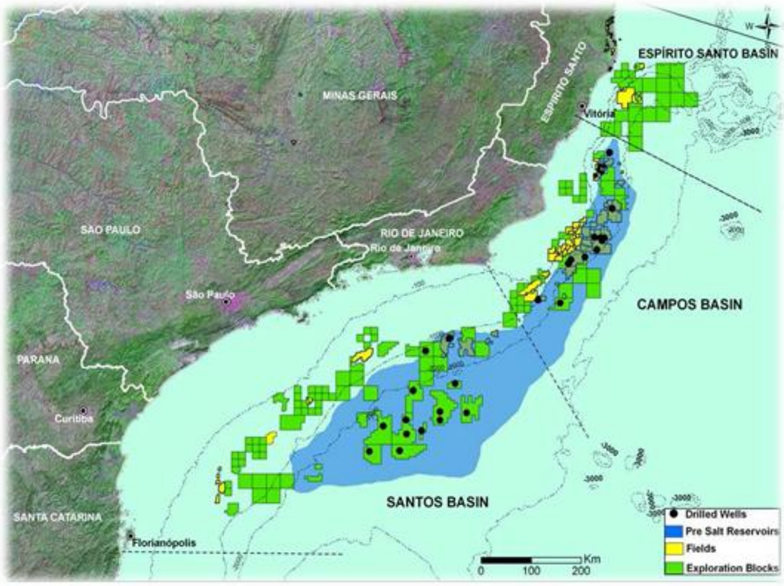


Figure 1 Santos and Campos Basin offshore Brazil, Pre-salt layer plays (Newswires, 2009)

1.2 Project objective

This study shall define the Basic Design of Subsea BOP stack, with Rotating control device for Reelwell-Riserless drilling, to achieve reasonable reliability and performance to mitigate risk in this new environmental condition. The objectives of the study are defined as follow:

- Review the conventional drilling operation
- Review the case study's working condition
- Identify BOP stack schematic, functions and components requirement
- Identify existing technology and, if need, propose conceptual specification for new technology to meet the requirement or improvement of the BOP stack
- Review the BOP control system and if need, propose conceptual specification for new technology to meet the requirement or improvement of the BOP control system
- Identify the BOP operating pressure requirement

1.3 The case study definition

<u>The description</u>

The case study is a part of a feasibility study of "Reelwell" to drill "Riserless" in the second section of developing wells, which is the salt section, in the Brazilian pre-salt area. Water depth of the area is approximately 2000m. The drilling programs are divided into 3 sections as shown in Figure 2 and plan to perform on batch base. When a unit completes the assigned section, it will move to another location and start operation for the next well.

A top-hole-drilling unit shall operate first section, included riserless drill in top-hole section until reach the top of salt layer at approximately 1000 m vertical depth below seabed, then install surface casing, cement shoe and casing deployment valve. By the end of the first section, The 22” cement shoe must be set and cemented hundreds of meters into the salt section with the 18 ¾” 15 k wellhead housing landed and locked into a 36” conductor housing. The Casing Flapper Valve must be installed and closed.

The second section, the case study, shall be drilled by RDM - Riserless drilling unit from the top of salt section down to the 200 meter above the bottom of the salt section, approximately 3000m from seabed (5000m from Mean Sea Level) and prepare the well for the third section. By the end of the operation, the 13 3/8” casing must be set to 200 m above the bottom of the salt section, landed and sealed off in the 18 ¾” 15 k WH. The well must be filled with mud and the casing flapper valve closed.

The conventional rig with marine riser shall drill the third section in the reservoir formation, install casing and make the well ready to completion and/or production. This is not included in the study.

Objective of the case study

The project aim to improve cost effectiveness of the drilling operation in the pre-salt target by utilizing the Reelwell Riserless concept which enable smaller rig (3rd or 4th Generation) to operate in the regime which normally need larger and much more expensive one (5th or 6th Generation)

Time frame of the case study

2013: Feasibility study and conceptual design

2014: Detail engineering

2015: Demonstration and qualification

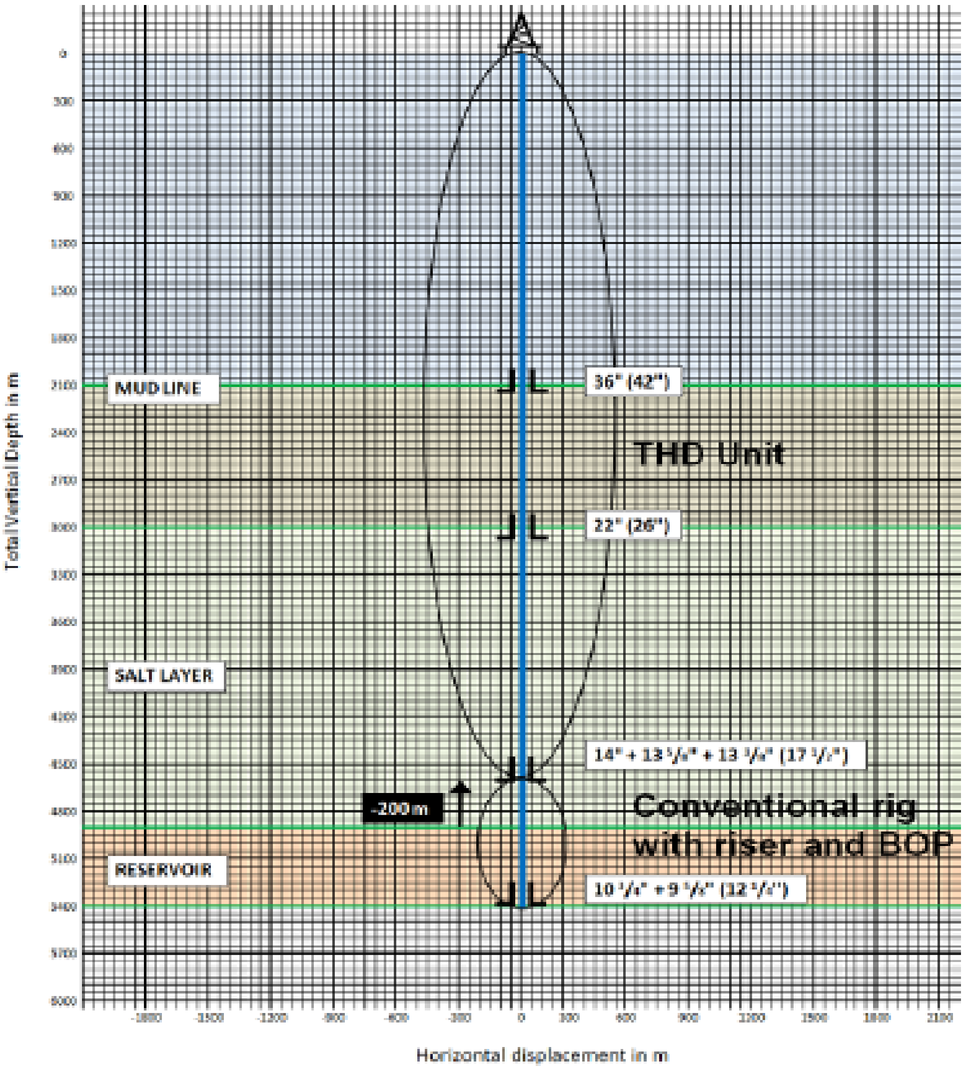


Figure 2 the Base case’s drilling program (Courtesy of Petro Bras)

2 State-of-Art

2.1 Conventional subsea drilling

Heriot-Watt IPE (2006) has described the operations and equipment that used to drill a subsea well are almost identical to those used for a land well. But subsea drilling, from a mobile drilling unit such as Drillship or Semi-Submersible, always bears the possibility that, at some point during the drilling operation, the vessel will have to disconnect from the well or move off the location due to bad weather. A hydraulic latch between the marine riser and the BOP stack ensures that it is possible to close in the well, disconnect the marine riser from the top of the BOP stack and move the rig off location safely at any stage during the drilling operation. Then the wellhead and the BOP equipment are the primary barrier, in the event of a kick, instead of the fluid column, which have been circulated back to the vessel.

Below is an outline the operations and equipment used when drilling and completing a well from a floating vessel, using a subsea wellhead system as described by Heriot-Watt IPE, (2006) based on a common scheme in the North Sea (30", 18 5/8", 13 3/8", 9 5/8" and 7").

There are two types of guidance system used to run subsea wellhead equipment to the seabed when drilling from a mobile drilling unit. The guideline-less system allows the equipment to be run and be retrieved remotely without the use of divers or fixed guideline, which is very preferable in the deep water (>1500ft). However following description shall base on more common guideline system.

1) Towing onto the location, positioning and running Temporary guide base

The rig is towed onto the location indicated in advance by a survey vessel, and held in position by using anchors or by using dynamic positioning techniques and a final check is made with an ROV prior to running the equipment.

If needed, the Temporary Guide base (TGB) shall be the first piece of equipment to be lowered to the seabed. The TGB is run on drill pipe and latched into the base.

2) Drilling, Running and Cementing the Conductor (30" casing)

If the seabed is soft seabed, the 30" casing can be "jetted" into position. A jetting bit with a stabilizer on drill pipe is run down inside the 30" casing and suspended from the casing running tool. The jetting bit should be spaced out such that it lies about 2ft. from the open-ended shoe joint. The 30" housing is locked onto the Permanent Guide Base (PGB), and the running tool made up as before. The whole assembly is then lowered to the seabed. Seawater is pumped, through the jetting assembly, to wash away the formation until the PGB is a few feet from the mud line.

Otherwise, a 36" hole is drilled without riser or BOP to a depth of 100-200ft. below the seabed, typically with seawater and leaves the cutting settling onto the seabed. Then the 30" casing and casing head housing is run to the seabed with the PGB. Drill pipe for cementing the casing is run down inside the casing and wellhead and made up to the underside of the 30" running tool. Then the casing is cemented by circulating down the drill pipe and out through the casing shoe until cement returns are observed. The cement is displaced to just above the shoe.

The 30" casing is a major load bearing element in the wellhead system, and it is essential that the 30" is cemented all the way up to the seabed. If cement is not observed at the seabed a top-up cementation, via a stinger through the PGB, will be performed.

3) Drilling the 26" Hole

The 26" hole is drilled riserless with seawater to 1000-2000 ft without BOP and circulation back to the rig.

If shallow gas hazard is present, a riser and diverter system to divert gas up to the surface is normally installed. Then first drilling a small diameter (12 1/4") pilot hole and logging the open formations to ensure that there is no free hydrocarbon left in the formation. Then the diverter and riser are removed, and the 26” hole is drilled conventionally without circulation back to the rig, and in this case the drilled cuttings are deposited on the seabed. Alternatively the hole can be open to 26” by running an under- reamer down through the diverter assembly. However, the diverter assembly still have to be removed before running the 18 5/8” casing.

4) Running 18 5/8" casing, install 18 3/4" high pressure wellhead housing and cement

Having drilled the 26" hole, the required length of 185/8" casing string with 183/4" high-pressure wellhead housing on top is made up. This Wellhead housing is where the BOP and subsequently Xmas tree will latch and seal. The 13 3/8”, 9 5/8” and 7” casing hangers are also land and seal inside this high-pressure housing.

The running tool is then made up into the 183/4" housing, lowered the drill pipe until the 183/4" housing lands and locks in place in the 30" housing on the seabed. The casing annulus is circulated and cemented, then the drill pipe and tool are recovered.

5) Installing the BOP

Since the 171/2" hole section will be drilled to considerable depth, a subsea BOP stack and marine riser will generally be required at this stage in the operation. The BOP stack, LMRP, riser and choke and kill lines are run in one operation. Once the BOP stack is landed and latched onto the 18 3/4" housing, the required tension is set on the marine riser tensioners and the flow line is hooked up. Then the BOP stack is pressure tested.

6) Drilling the 17 1/2" Hole

From this section, the 171/2" hole, the drill bit can be rotated either from a surface-located mechanical motor or by a downhole mud motor. The hole is drilled into subsurface formations as high-pressure drilling fluid (mud) is pumped, through the drill string, to circulate downward and lift the drilling cuttings upward, through the casing annulus. Once the drilling fluid and cuttings reach the drilling rig, the cuttings are removed by vibrating shale shakers and the drilling fluid is processed and chemically treated to sustain continuous recirculation. Efficient processing and proper treatment are important because they limit the quantity of drilling fluid required and the volume of waste generated.

7) Clean Circulation

When the casing point has been reached the hole is circulated clean and the drilling assembly recovered in preparation for running the 13 $^{3}/_{8}$" casing.

8) Running the 13 $^{3}/_{8}$" Casing

The wear bushing sitting inside the 18 $^{3}/_{4}$" housing is removed. The 13$^{3}/_{8}$" casing is run into the hole through the BOP stack and riser assembly. The 13$^{3}/_{8}$" casing hanger is run together with a seal assembly (or pack-off), which is used to seal off the 18$^{5}/_{8}$"x 13$^{3}/_{8}$" annulus after the cement job is complete. The entire assembly is run in the hole on a casing hanger running tool and casing or drill pipes. The system is designed such that the casing can be run, landed, cemented and the seal assembly energized, all in one trip.

9) Cementing the 13 $^{3}/_{8}$" Casing

Having landed the casing hanger in the 18$^{3}/_{4}$" housing, the cement is pumped and displaced down the running string. The running string may be either casing joints, extending back to the rig, or drill pipe. In the case of drill pipe, a special cement plug retainer is connected to the underside of the casing hanger running tool and the cement operation is conducted in a similar fashion to a liner cementing. At the end of the cement job, the running string is rotated to the right. This releases the running tool while simultaneously energizing the pack-off assembly on the outside of the hanger.

10) Cement integrity test

When the BOP is in place and the pack-off is set, it can be pressure tested, and then the running tool can be picked up and pulled back to the surface. Since the casing is an integral part of the BOP system, it is vital that the annulus between successive casings is properly sealed off. It is good practice to flush the wellhead area prior to pulling the running string back to the surface. A wear bushing is installed, above the 13$^{3}/_{8}$" hanger, to protect the sealing surfaces during the next drilling phase.

11) Drilling the 12 $^{1}/_{4}$" Hole

The 12 ¼" bit and BHA are made up and run to just above the cement inside the 13 $^{3}/_{8}$" casing. Prior to drilling out of the shoe the casing is pressure tested. To ensure that it is safe to drill ahead, a leak-off test is performed immediately after drilling out of the casing shoe. The next section of hole (12 ¼") is drilled to the required depth and cleaned out. Then the 9 $^{5}/_{8}$" casing is run and cemented. Exactly the same procedures are used for the 9 $^{5}/_{8}$" casing, as for the 13 $^{3}/_{8}$" casing string. If necessary, drilling can continue to greater depths by drilling an 8 ½" hole and running and cementing 7" casing.

12) Preparing the well for completion

The well is now ready for completion. There are a number of alternative ways in which the operation may proceed. These routes are dependent on the way in which the well is to be perforated and cleaned up.

The production casing must be cleaned up, and displace the drilling fluid to clean brine after the drilling operation is complete and before any production tubing is run in the hole.

13) Completion

Then the tubing string is made up and run in hole. The tubing hanger is attached to the top of the string, and the entire assembly is run through the drilling riser and BOP, and landed, locked in place with the wellhead and set the Packers. The pressure integrity of the tubing string, tubing hanger to wellhead seals and the production packer are then tested. The BOP and drilling riser can be removed after having the subsurface valve and wireline plug installed in place and tested. The Xmas tree is then installed in place, tested the function, perforation and cleaning up the well to ready to production.

2.2 Well control barrier Philosophy

2.2.1 Barrier element

Norsok standard D010 (2004) define a Well barrier element as object that alone cannot prevent flow from one side to the other side of itself. The Examples of recognized barrier elements related to drilling operation such as

- BOP arrangements
- Properly cemented casing
- Cement plugs
- Mechanically/hydraulically operated plugs/packers
- Lubricators
- Seal assembly of casing/production tubing
- Wellhead systems

The various valves of a BOP or X-mas tree valve are considered to be barrier elements and will together with the well anchorage form one barrier. The shear ram is regarded as a barrier element which increases the accessibility of the secondary barrier, e.g. in those cases where a pipe ram is leaking or where the drill string is out of the hole.

2.2.2 Well control barrier and the requirement

Norsok standard D010 (2004) define a Well control barrier as an envelope of one or several dependent barrier element preventing Fluid or gases from flowing unintentionally from the formation, into another formation or to the surface.

In Norway, the following primary requirement were required by the regulation, Norsok standard D010 (2004), for well control barrier should be achieve:

- During drilling and well intervention activities at least two independent and tested barriers should be in place after setting the surface casing.
- A barrier shall be present in the event of possible cross flow between different pressure regimes in the formation.
- It should be possible to activate the two barriers independently.
- Systems shall prevent failure or individual accidents to simultaneously eliminate both

barriers.

- The barriers should be independent of each other without any barrier element in common.
- The defined well barriers should allow for immediate re-establishment when lost.
- In the event of a barrier failure, immediate compensating measures shall be taken in order to keep adequate safety level, until two independent and tested barriers have been restored.
- No activities for any other purpose than re-establishing two barriers shall be carried out in the well.
- To the extent possible the barriers shall be tested in the direction of flow. The position/status of the well barriers should be known at all times.
- If two tested barriers cannot be achieved, efforts shall be made to ensure that the total level of risk is not increased.

If the ordinary 2 - barrier concept is being compromised (e.g.: for deep water, under-balanced drilling), a non-conformance handling for validation of the integrity for well control must be provided/documented. Under the condition that the total safety level is maintained compatible with a 2-barrier solution, there may be a trade-off between the actual availability of the barriers in question, and operational precautions.

The barrier requirement for the specific drilling operations, such as over balance case, under balance case, are also specified the barrier requirement, see more detail in Norsok standard D010 (2004).

2.3 Blowout preventer (BOP)

This Section provides technical overview of the blowout preventer and also related international regulations.

2.3.1 The BOP Stack

The BOP stack serves as a secondary means of well control. When the primary barrier fail (Mud column), a formation influx occurs during drilling, one or more BOPs are activated to seal the annulus, or wellbore, to “shut in” the well. Denser or heavier mud is then circulated into the wellbore to re-establish primary well control. Mud is pumped down the drill string, up the annulus, out the choke line at the base of the BOP stack, and then up the high-pressure lines on the riser and through the choke manifold until the downhole pressure is controlled and the influx is circulated out of the well. Once this “kill weight” mud extends from the bottom of the well to the top, the well is back in balance and has been “killed.” With the integrity of the well re-established, operations may resume. (Transocean, 2011)

There are two basic types of blowout preventers (BOPs) — ram and annular — that come in a variety of styles, sizes, and pressure ratings.

An “annular BOP” is a sealing element resembles a large rubber doughnut, as shown in figure 3, that is mechanically squeezed inward to seal on either pipe (drill collar, drill pipe, casing, or tubing) or the open hole(but not considered as a reliable one). It could seal on variety of pipe size in one. Most blowout preventer (BOP) stacks contain at least one annular BOP at the top of the BOP stack, and one or more ram-type preventers below.

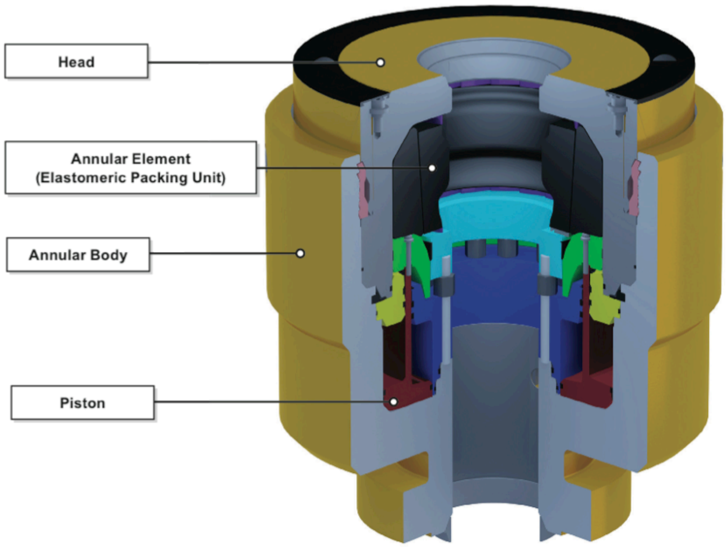


Figure 3 An annulus BOP (Transocean, 2011)

A "RAM BOP" consists of two halves of a cover for the well that are split down the middle. When activated, Large-diameter hydraulic cylinders, normally retracted, force the two halves of the cover together in the middle to seal the wellbore. These covers are constructed of steel for strength and fitted with elastomer components on the sealing surfaces. The halves of the covers, formally called ram blocks, are available in a variety of configurations. (Schlumberger, 2013-1)

- Blind Ram is flat at the mating surfaces to enable them to seal over an open wellbore.
- Pipe Ram has a circular cutout in the middle that corresponds to the diameter of the pipe in the hole to seal the well when pipe is in the hole.
- Shear-Blind Ram is fitted with a tool steel-cutting surface to enable the ram BOPs to completely shear through drill pipe, and seal the wellbore.

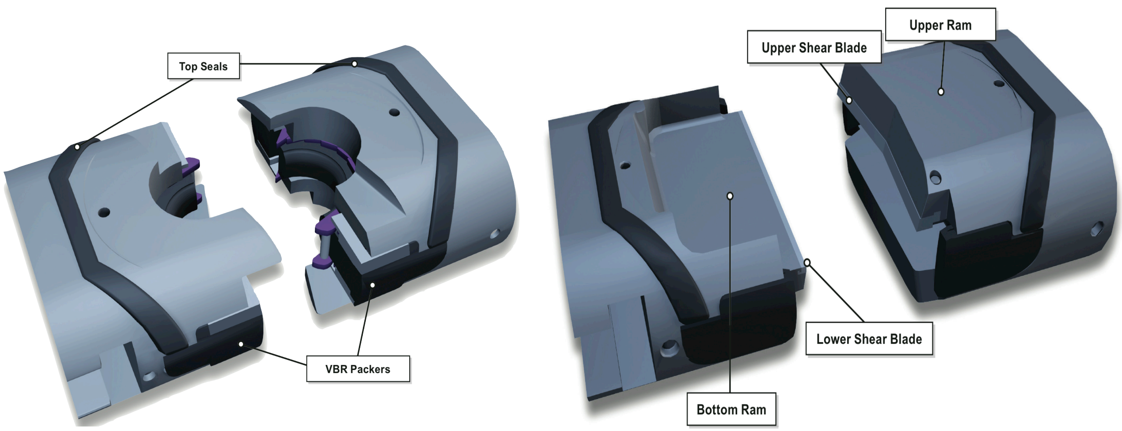


Figure 4 Variable bore ram (left) and Blind shear ram (right)

A "BOP stack" is comprised of several individual blowout preventers serving various functions that are assembled or "stacked" together, with at least one annular BOP on top of several ram BOPs. These various BOPs can seal around the drill pipe, casing, or tubing; close over an open wellbore; or cut through the drill pipe with steel shearing blades. The various ram blocks can be changed in the ram preventers, enabling the well team to optimize BOP configuration for the particular hole section or operation in progress. An example of a BOP stack from Transocean's "Deepwater Horizon" is shown its cutaway view and its component of the assembly in figure 5 and 6 accordingly. (Schlumberger, 2013-1)

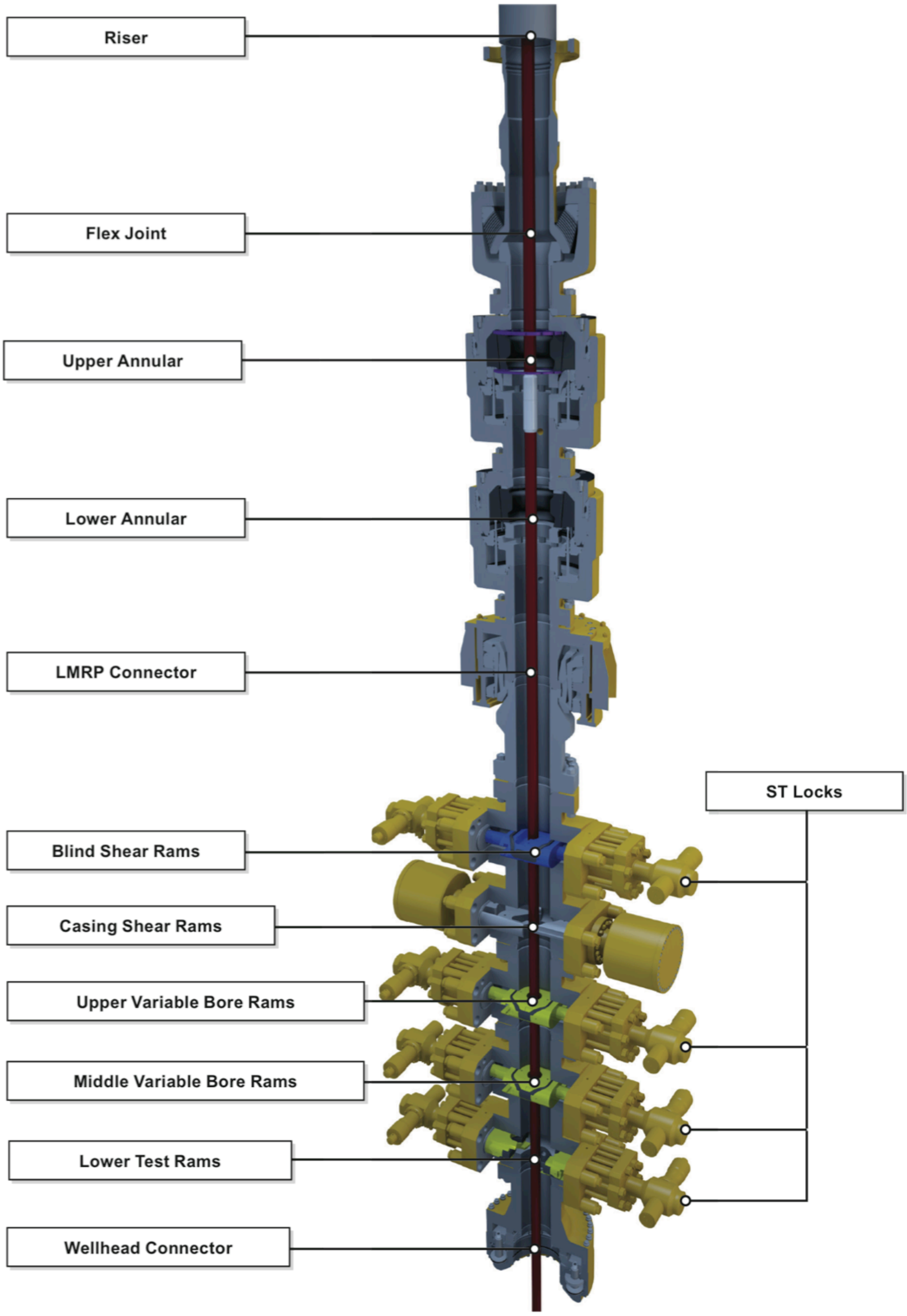


Figure 5 Cutaway view of Deepwater Horizon BOP stack (Transocean, 2011)

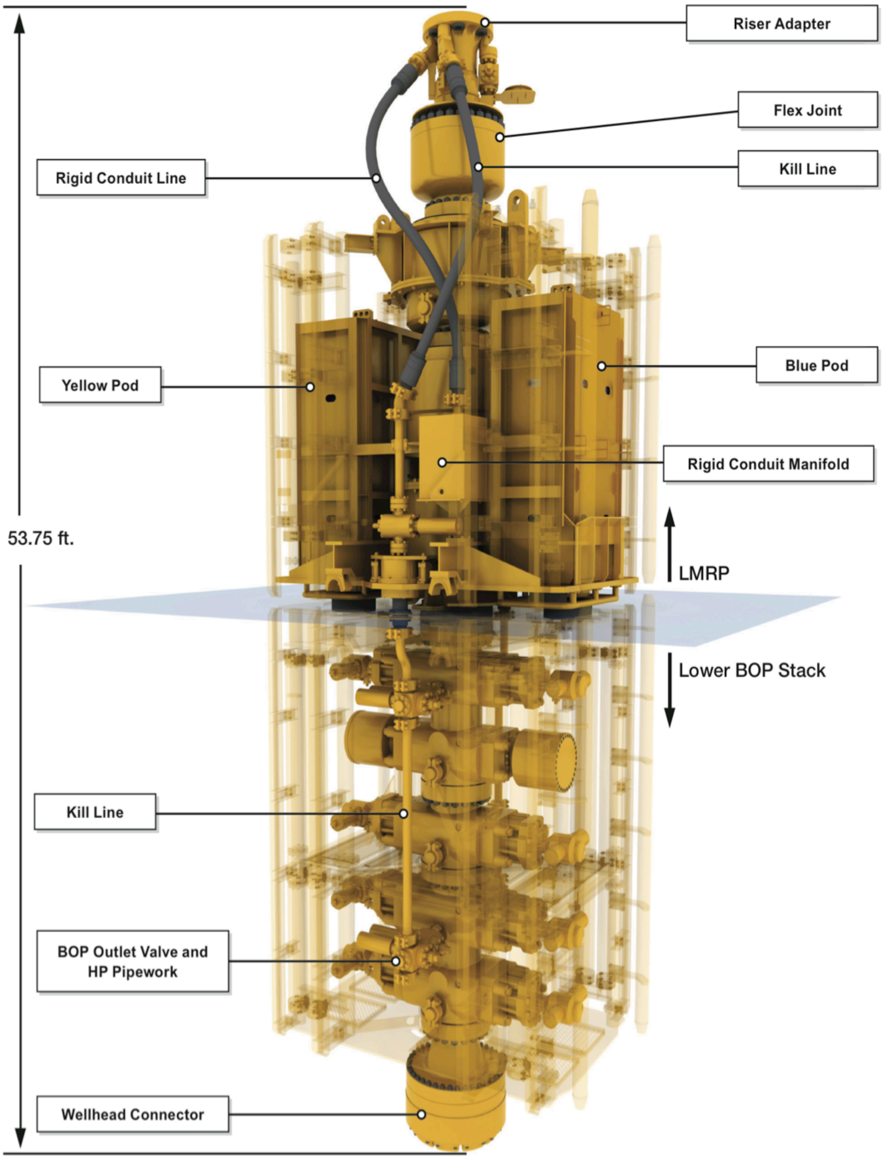


Figure 6 Deepwater Horizon BOP Stack (Transocean, 2011)

2.3.2 The BOPs Primary functions

The main key function of the BOP is Prevention of blowouts and well leaks. The Norwegian Oil Industry Association (OLF) (2004) has defined the BOP primary function in OLF guideline 070 as:

1) Seal around drill pipe

This function is the most common used can be achieved either by pipe ram BOP or Annular BOP. Pipe ram get advantage such that it could be activated faster and the drill pipe could hang on it. However it was designed for a specific or a few pipe sizes. The annular BOP is more flexible but was consider less effective to maintain the seal and could not hang off the pipe.

2) Seal an open hole

To achieve this function, it is need either Blind ram or blind shear ram, which is integrated with the shear function. Considering these alternative are depend on the size of pipe. Normally blind shear ram is available on the smaller size.

If a leak should occur there will be a possibility to run pipe in the hole and close the annular around the pipe. The blind shear ram may then be opened and the pipe stripped further in so the pipe rams may also be used.

3) Shear drill pipe and seal off well

If the drill pipe has to be sheared before the well can be sealed off. Historically this has been an event where the well has blown out through the drill string and stabbing the top drive and/or the Kelly valve on the drill floor has failed. It is not industry practice to test on a regular basis the function of the shear ram with pipe in the BOP. It is considered a destructive test. Factory acceptance testing is performed for the BOP to shear a pipe. The blind shear ram or the set of blind and shear ram is the tool for the function. In order to minimize size and weight of the BOP stack, the integrated type is preferred unless the drill string dimension exceed it limitation.

2.3.3 The BOPs Operational function

In addition to the primary function as discussed above, API RP53 also recommended the operational requirement for the floating drilling unit that the BOP arrangement should provide means to:

- Close in on the drill string and on casing or liner and allow circulation
- Close and seal on open hole and allow volumetric well control operations
- Strip the drill string using the annular BOP(s)
- Hang off the drill pipe on a ram BOP and control the wellbore
- Shear logging cable or the drill pipe and seal the wellbore
- Disconnect the riser from the BOP stack
- Circulate the well after drill pipe disconnect.
- Circulate across the BOP stack to remove trapped gas

Moreover, there are some routine operational tasks that require BOPs, such as casing pressure and formation strength tests (BP, 2010)

2.3.4 The BOPs control system function

Nergaard (2005) defines the BOPs control system basic function as a system to control the BOP stack to achieve the corresponded safety and emergency case as follow:

1) Passive secondary well barrier after Mud Column: the primary function must be available but not yet activated in the time of drilling.
2) Active to control the well in case that the primary barrier fails i.e. Kick
3) Active to hang off the drill string for bad weather, the pipe is usually landed on the wear bushing in the wellhead. (Some close a ram below the running tool for

centralizing) The running tool retrieved and the BSR are closed to act as an additional barrier. (This is one of the reasons BSR are on top)

4) Active in BO scenario – Shear, Seal, Regain Control. With kill and choke line and manifold installation, pumping the heavier mud down after the blowout or kick through the kill line and let gas or oil bleed out through the choke line. The challenge is that how many out let does it need for a stack. Increasing of the
5) Active in loss of position – Emergency riser disconnect
6) Active in loss of Primary Control i.e. Acoustic emergency function, ROV intervention

2.3.5 BOP control system – MUX E/H

Currently, most of the subsea BOP stacks are implementing the multiplex Electro-Hydraulic system (MUX E/H system), which obtain hydraulic/electrical power and signal from shared lines within the umbilical. The simplified system of the MUX E/H is as shown in figure 7. The demand on the subsea control system is initiated at the surface. The demand signal is multiplexed down the control umbilical to the subsea control system. There, the signal is decoded, confirmed, and performed. For a demand that requires a BOP Ram to close, for example, the multiplex signal would be received at the subsea control pod and decoded. The decoded signal would cause a solenoid to be opened electrically which would send a hydraulic pilot signal to the proper hydraulic valve. This pilot signal would cause the hydraulic valve to shift and send stored and pressurized hydraulic fluid from the accumulator either from subsea or surface to the BOP to be closed. (Shanks, E., Dykes, A., et al., 2003).

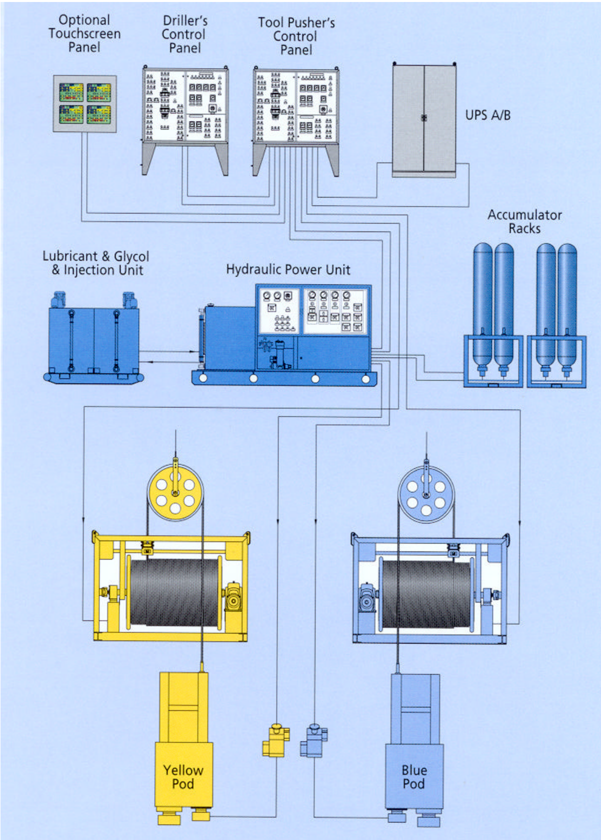


Figure 7 Simplified schematic of Multiplex Electro-Hydraulic system (MUX E/H) (Shanks, E., Dykes, A., et al., 2003)

The system umbilical allows Subsea Control Modules (SCM) to be connected in parallel. Redundancy can easily be provided for increased availability, in the evident of an individual line becoming faulty. But there are also weaknesses in the system relating to susceptibility to hydraulic fluid cleanliness, materials compatibility, hydrostatic effects in deeper waters, and limitations over long distance tiebacks and the costs of the long distance MUX E/H umbilical can be very expensive. (Theobald and Lindsey-Curran, 2005)

The critical components of the subsea control system are as following:

a) Two remote control panels

Most of the demands are initiated at the control panel on the surface, then decoded and multiplex down via the control umbilical to subsea control module. Each one clearly showing 'open' and 'closed' positions for all subsea functions. One panel must be located near the driller's position. The other will be located at a safe distance from the substructure and adjacent to the escape route from the drilling unit, or in the tool pusher's office. A meter for indicating control fluid flow should be located on each remote control panel. And the panels should be connected to the control manifold in such a way that all functions can be operated independently from each panel. (Wipertrip.com, 2010)

b) Subsea control module (SCM)

The SCM or control pods are used commonly to provide well control function for the operation according to the electrical power, communication signals and hydraulic power supplier from the surface. Normally each subsea BOP system has two complete control pods. Each pod is capable of performing all necessary functions on the BOP to provide 100% redundant. For the normal operation with marine riser, these pods are normally mounted on the LMRP. While these systems may be considered redundant, any major problem associated with one pod will cause the system to be retrieved to the surface for repair. (Shanks, E., Dykes, A., et al., 2003)

c) Accumulator rack

Accumulators as used in the oil industry generally comprise 3 basic types, the bladder, diaphragm, and the hydro-pneumatic piston type as shown in figure 8. The first being the most widely used in BOP control systems. The working principle is relatively simple, yet effective as shown in figure 9; hydraulic fluid is stored under pressure and available for discharge to provide the necessary power fluid to actuate BOP control functions on demand. Energy storage is provided by the compressibility of the nitrogen pre-charge gas contained within the bladder or chamber. Upon discharging of the bottle during actuation of a control function, work is done by the gas as it expands and forces the hydraulic fluid out under pressure into the hydraulic circuitry of the control system.

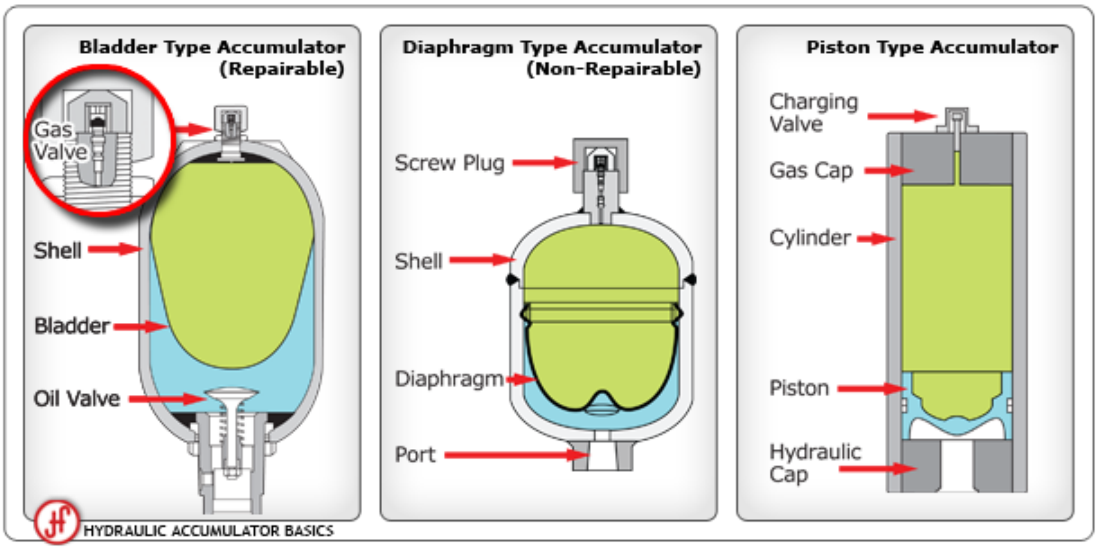


Figure 8 Basic types of the accumulator from left to right: Bladder, Diaphragm and Piston (John Henry Foster Co., 2012)

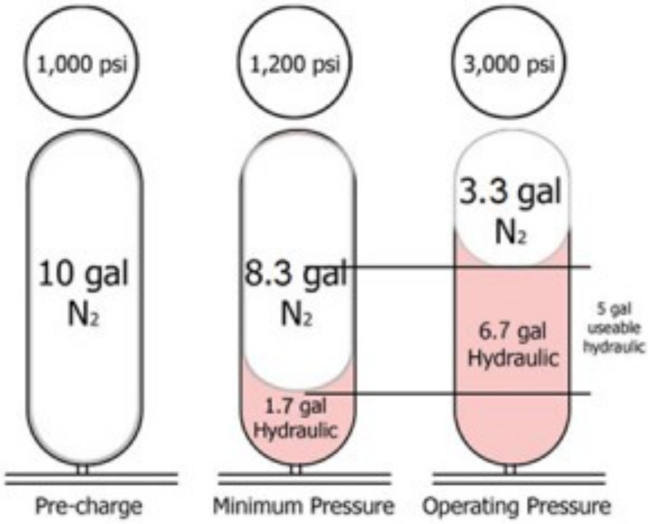


Figure 9 Accumulator in Pre-charge, minimum pressure and operating pressure (courtesy of www.drillingformulas.com)

The system could be rated working pressure of 3000 and 5000 psi. A system rated working pressure of 3000psi is still in use in relatively shallow water drilling but becoming increasingly rare, with most rigs now utilizing the enhanced efficiencies and higher differential pressures of the 5000psi system pressure (McCurdy, P. J. A. 2009).

The accumulator's capacity is normally specified by standards, specifications and regulations as the minimum Functional volume requirement that, without recharging it should be adequate to operate the defined activities.

Moreover the hydraulic fluid reservoir usable capacity of the return-to-reservoir hydraulic control system shall be at least twice the stored hydraulic fluid capacity of the accumulator system. Offshore rig control systems shall have an audible and visible alarm to indicate low fluid level in each of the applicable individual reservoirs. The alarm shall sound and illuminate at the power unit, driller’s control station and a minimum of one auxiliary remote panel, if equipped (API spec 16D, 2004)

d) Stack mounted (subsea) accumulator unit

For MUX E/H system and pilot-operated system, some accumulators may be mounted on the BOP stack for quicker response of the functions, the secondary emergency control function (such as dead-man shear) and operation via an acoustic control. The accumulator bottles on the BOP stack should be fitted with non-return valves to prevent accidental dumping and should be of sufficient capacity for an activation of each of the emergency control functions plus 50%. (Wipertrip.com, 2010)

e) Surface supporting system

The system must also complete with the following equipment to provided required power and signal for subsea equipment. They must be located in a safe area away from the drilling floor and the spider-deck. (Wipertrip.com, 2010)

- A soluble oil/water reservoir
- Automatic proportioning equipment for soluble oil
- A control manifold
- A electrically driven triplex charging pump
- Two air-driven pumps for charging the accumulators
- Regulator, which will not "fail open", causing loss of operating pressure.

f) An secondary control system

This included an acoustic control system and other emergency control sequence. An acoustic control system provides secondary control system in the event that the BOP functions are inoperable due to a failure of the primary control system. Emergency control sequence such as Automatic mode function (or Deadman), when is armed, provides an emergency back-up control sequence to close in a subsea well in the event of the complete loss of operation control of the BOP’s, or for a planned or unplanned disconnect of the Lower Marine Riser Package (LMRP) from the BOP Stack. (Wipertrip.com, 2010)

These secondary control systems require sufficient hydraulic power (pressure and volume) stored in the stack accumulators to operate the sequence which is normally included closing at least one blind-shear ram (or one casing shear ram and one blind ram in case of casing), and open one hydraulic connector. This emergency sequences requirement could be various, depend on risk, availability, local regulation and requirement of the operator.

g) A dual hydraulic or electro-hydraulic cable and/or hose system

Providing the interconnections between the surface and subsea equipment with 100% redundancy of control for all functions of the BOP stack.

The nature of the interconnection is depended on type of the control system. For the direct hydraulic and pilot-operated hydraulic systems, integrated multiple hose bundles are commonly used. For MUX E/H systems the electrical interconnections may be combined into integrated 'umbilical' cable bundles. Alternatively the hydraulic hose can be handled separately.

As a general rule, the original total lengths of the flexible control cables and hoses should be 90 m (300 feet) greater than the maximum water depth for which the system is designed. (Wipertrip.com, 2010)

2.3.6 Code of regulation for the BOPs

Bureau of Safety and Environmental Enforcement (BSEE) (2011), the authorization regulated US outer continental shelf, and Norsok - D001 (2012), the Norwegian regulation, require the subsea BOP system to be installed prior to drill below surface and intermediate casing. Although Norsok – D001 tend to be more stringent, both of them share several similar requirements.

a) The BOPs

Prior to drill below The BOP stack component shall consist at least a wellhead connector, four remote controlled BOPs included at least two pipe rams, one blind-shear ram and one annular type.

It shall be verified that the BOP system can shear and seal the relevant tubular with adequate weight and grade of the following:

- Drill pipe
- Production tubing
- Landing string and/or shear subs
- Wire line
- Coiled tubing

In addition, Norsok - D001 (2012) requires DP operated vessel to be equipped with another shear ram that can shear casings and drill pipe tool joints or other heavy walled pipe with expected maximum wellhead pressure, shall be installed. Consideration of other configurations, arrangements and shear capacities shall be based on operational requirements and a risk assessment.

b) Control components

The control component of the stack must consist of

- An accumulator system which shall provide sufficient capacity to supply 1.5 times the volume of fluid necessary to close and hold closed all BOP equipment units with a minimum pressure of 200 psi above the pre-charge pressure without assistance from a charging system.
- A subsea accumulator closing unit or a suitable alternate to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface.
- An operable dual-pod control systems necessary to ensure proper and independent operation of the BOP system functions

- A backup to the primary accumulator-charging system, which shall be automatic, supplied by a power source independent from the power source to the primary accumulator-charging system, and possess sufficient capability to close all BOP components and hold them closed.
- At least 2 operable remote BOP control station, one on the drilling floor, the others shall be in readily accessible locations away from the drilling floor.
- An ROV intervention control panel
- Locking devices installed on the ram-type preventers

c) Choke and kill line

Each of the choke and kill outlets on the BOP stack shall be fitted with two full-opening gate valves arranged in series and installed close to the BOP. The valves shall be protected against damage from external loads. The size of the choke and kill outlets/inlets and piping shall be adequate for the maximum expected circulation rate when in use during operation and in well control situations.

Norsok-D001 (2012) requires at least 2 choke and kill outlet with all of these gate valves to be controlled remotely with hydraulic. In contrast, BSEE (2011) requires only one choke and kill line and also require only one of those gate valves to be controlled remotely. The valves shall be of the "fail assist" closing type, and shall be capable of closing under dynamic flow conditions, preferable sequenced with the outer valves closing prior the inner valves. For valves requiring hydraulic assist for closing, activation should be automatic when loss of surface control and/or hydraulic fluid.

d) Choke manifold

A choke manifold suitable for the anticipated pressures to which it may be subjected, method of well control, be employed, surrounding environment, and corrosiveness, volume, and abrasiveness of fluids and shall have a rated working pressure at least as great as the rated working pressure of the ram-type BOP's.

Valves, pipes, flexible steel hoses, and other fittings upstream of, and including, the choke manifold with pressure ratings at least as great as the rated working pressure of the ram-type BOP's.

e) LMRP

The LMRP shall be connected to the BOP stack by means of a remotely controlled hydraulic connector. The LMRP shall incorporate the dis-connectable choke and kill stabs and the pods for the BOP control system and alternative ROV stabs.

It shall be documented and verified that the LMRP can be safely disconnected and reconnected (without having to pull same to surface) at a given angle without equipment damage. Testing of BOPs at the surface shall be possible with the LMRP connected to the BOP and the control system connected.

2.4 Rotating control device (RCD)

RCD is a tool developed to create a pressure-tight barrier in the wellbore annulus that enables return fluids containing and/or diverting. It was estimated that about 75% of the working rigs in the US and Canada use a rotating control head in each well's drilling program for one reason or another.

Rotating control device is installed on top of the annular BOP or ram BOP to seal rotating drill tools and influent division when operating non-balance drilling such as Underbalance drilling and Manage pressure drilling. When it is used together with hydraulic BOP, drilling tools check valve, oil and gas division equipment and non-killing drilling pressure device, it can operate with pressure drilling and non-killing drilling. It plays a vital part in special operations such as liberating low-pressure oil and gas layer, leakage proof drilling, air drilling and non-killing well repair. Beside non-balance drilling operation, there are also other applications of RCD, such as to provide real time data for better well control and facilitate close-loop drilling that benefit to safety and environment.

A Rotating Control Device consists of rotating assembly, shell, and hydraulic power unit. Rotating assembly consists of rotating bushing assembly, central tube, spherical rubbers and bearing room; shell consists of shell, hydraulic clamp and cylinder, rotating assembly and shell are connected by clamp; hydraulic power unit consists of power unit and hoses. Example of a rotating control device is shown in figure 10.

By rotating power bushing assembly on the rotating control device, Kelly rotates running shell, central tube, spherical rubbers and drill stem. Spherical rubbers seal the drill column by its flexibility and well pressure assisting seal. Dynamic sealing between central tube and rotating assembly is achieved by up and down dynamic sealing assembly.

Hydraulic power unit is used to control open and close of hydraulic clamp, and to provide lubricant to cool down spare parts in rotating assembly and dynamic sealing assembly; to provide circulate liquid to cool down up dynamic sealing assembly. (Shanghai Sunry Petroleum Equipment Co. Ltd.,2009)

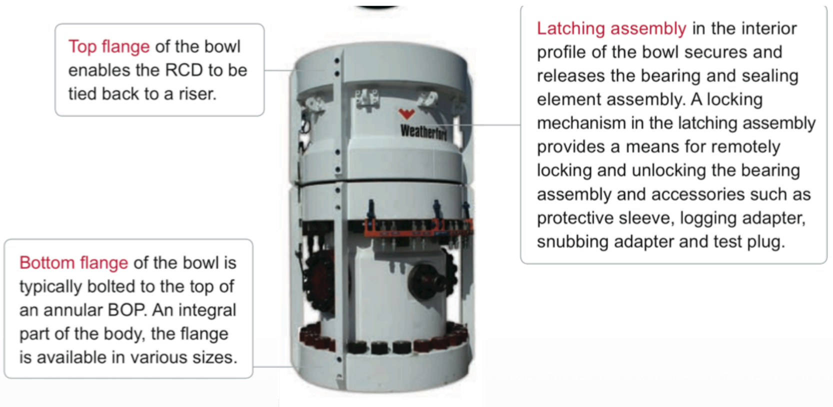


Figure 10 Example of a RCD for Subsea application (Courtesy of Weatherford)

2.5 Salt Section

Salt structure associated with oil and gas reservoir is found in several form, as salt tectonics structures, undeformed bedded sedimentary salt, and as mixed domains. Because of viscous behavior at modest stresses and temperatures, salt can be tectonically mobilized solely because of density differences between salt (2.16 g/cm^3 for pure NaCl) and other sediments (2.3 – 2.6 g/cm^3)

Natural "salt" deposits are usually pure NaCl (halite) crystals of 1 – 20 mm mean grain diameter with 0-15% insoluble materials such as shale beds or inter-crystalline clay ("chaotic salt"). Deep bedded salts (>2000 m depth) and all diapiric or tectonically mobilized salts have undergone recrystallization. Non-salt mineral content is lower and the crystalline fabric more uniform, with crystals of 5 mm to 10-20 mm. Other halides may exist in beds of limited thickness and extent. Sylvite (KCl) behaves similarly to halite, but there can be beds, streaks or mixtures of carnallite, bischofite, tachyhydrite, polyhalite, and other rare halides. When encountered, they can present particular difficulties in drilling

Salt rocks are viscous and flow slowly at all non-zero shear stress states; one may assume isotropic stresses, which are found in viscous rocks and very soft mud. Because salt is a viscous liquid, the term under-balance is used herein to mean a mud pressure less than the vertical stress.

Under stress, sedimented granular salt continues to compact, expelling brine, until porosity is totally occluded (φ < 2-4%). Even after this, particularly with high stresses and temperatures, salt continues to compact until a brine-filled porosity of 0.3-1.5% remains. This consists of thin, dendritic voids at grain boundaries, but for practical purposes, salt permeability can be taken as zero. Flow through salt in engineering time scales (<100 years) occurs in non-salt lithologies or through introduced flaws (e.g. hydraulic fracture). Therefore the concept of pressure as a state descriptor is not useful.

In perspective of drilling activities, salt does not present as serious problems as fractured shale, but there are challenges such as washouts, rapid borehole closure, mud weight control issues, and casing placement decisions. Subsalt overpressure or pressure reversion may exist, and extensive rubble or sheared zones are common underneath salt tongues or adjacent to diapirs. It may be difficult to decide where salt ends and non- salt sediments start: salt-infilled rubble zones and salt with 30-40% non-salt shale and sand inclusions can exist within salt beds, or at the boundaries of salt structures. However, most drilling problems within salt are managed relatively easily by considering salt properties during planning and drilling.

Salt is essentially impermeable, so the effect of drilling fluid density (mud weight, MW) on rate of penetration is small. MW management can be used to control closure rate while sustaining reasonable penetration rates. However, high MW carries risks of lost circulation in non-salt zones, and this risk must be properly managed through knowledge of stresses.

When an offshore deep-water borehole is full of a drilling fluid and penetrates a large sequence of salt, it is not possible to equilibrate the stresses by drilling mud pressure at both the top and bottom of the salt. Suppose one wishes to balance the stress while drilling at the base of the salt to avoid all creep, there would be a surplus pressure at the top of the salt sequence. But, if it is necessary to stay below the fracture pressure in the soft sediments at the top of the salt, there would be underbalance at the salt base, and creep closure would be an issue, especially with high T cases. It is best, in most circumstances, to place a casing shoe into the salt as far below the salt top as possible.

This shows that a high creep rate potential exists and it is difficult to balance the rock stresses in deep-water conditions (leaving aside technologies such as sea-floor booster pumps or gas lift). Thus, closure rate potential must be evaluated to see if borehole closure is a potential problem. (Dusseault, M. B., V. Maury, et al., 2004)

3 Reelwell Drilling Method

3.1 Reelwell Drilling Method - basic system

The Reelwell Drilling Method (RDM) is based on the use of a Dual Drill String where the drilling fluid flows to the bit via the drill string annulus, and the return flow to surface is through an inner string. As shown in figure 11, RDM system consists of:

- The **Dual Drill String (DDS)** is a closed loop flow circulation system. Cuttings are transported to the surface by drilling fluid travelling up the central pipe of the dual string, leaving the wellbore annulus free of cuttings.
- The **Top Drive Adapter (TDA)** is a dual conduit swivel that allows rotation of the drill string with the top drive. The TDA route the discharge drilling fluid from the top drive to the DDS annulus and the return flow is taken of the TDA housing.
- The **Dual Float Valve (DFV)** contains double barriers on both channels and facilitates controlled pressure drilling and pressureless pipe connections. Two or more of the DFV can be mounted in series in the DDS for redundancy.
- The **Flow Control Unit (FCU)** is a control valve arrangement where all the active drilling fluid is routed through. The purpose is to assure constant down-hole pressure during drilling and pipe connection. The unit is equipped with pressure and flow sensors both on the drilling fluid inlet and return lines. The Reelwell control panel is fully integrated with the well control and monitoring system of the drilling facility.

These components make the difference from conventional drilling in the circulation flow path of the drilling fluid. For conventional drilling the fluid returns up wellbore annulus, whereas in RDM the drilling, with help of RCD, fluid returns to surface through the inner pipe of the DDS. RDM is based on pumping the drilling fluid into the DDS annulus via the TDA and down to the DFV at the top of the conventional Bottom Hole Assembly (BHA). From the DFV the cuttings are transported back to surface inside the inner string, so that the hole remains clean at all times.

The system requires a lower drilling fluid circulation volume to remove cuttings approximately 50% of the volume used by conventional drilling. Typical flow rates for RDM are 600-1200 l/min. Less active drilling fluid volume and flow rate reduces the consumption of chemicals and load on treatment facilities, leading to a more cost efficient and environmentally friendly system.

Moreover the Reelwell Multi Gradient Drilling System allows for use of a high density passive fluid in the wellbore annulus and a lighter active circulating fluid - “heavy over light”. (Reelwell AS, 2011)

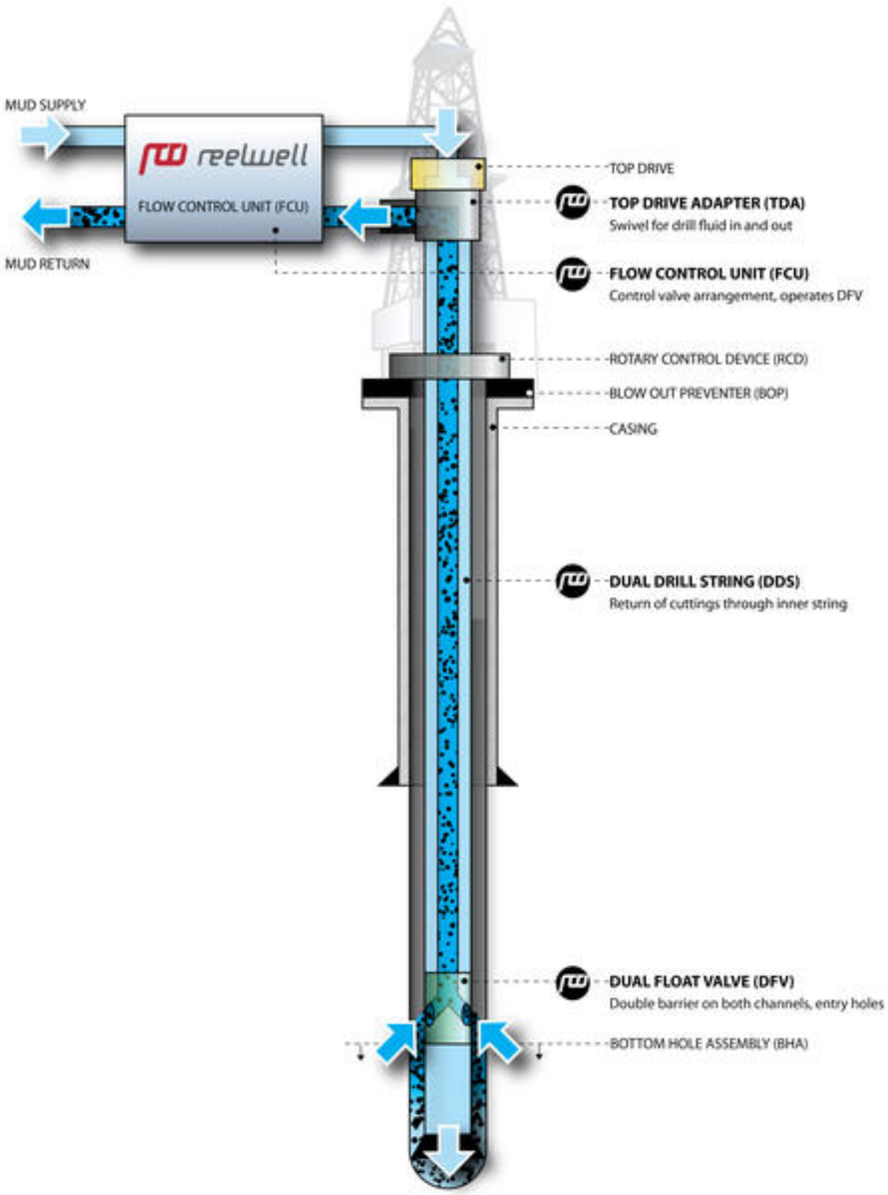


Figure 11 Reelwell Drilling Method (RDM) configuration (Reelwell AS, 2011)

3.2 Reelwell Drilling Method – Riserless concept

Reelwell - Riserless is a developing concept with support from Shell, Total, Statoil, Petrobras, RWE, Innovation Norway, and the Norwegian Research Council. Figure 12 shows the component of the Reelwell - Riserless concept.

With RDM, the cuttings are transported to surface inside the dual drill string, thus the riser is not necessary for subsea drilling operation. This shall enables drilling operations in ultra deep waters from 3rd and 4th generation drilling units due to the reduced weight related to omitting the riser and dramatically reducing fluid volumes.

Moreover from a safety perspective, the system will enable improved safety related to the ability to performing Managed Pressure Drilling and Under Balanced Drilling operations with no pressurized equipment on surface. The potential hazard of drilling with a riser is eliminated since the return flow is inside a closed loop high-pressure system with RDM-R. (Reelwell AS, 2011)

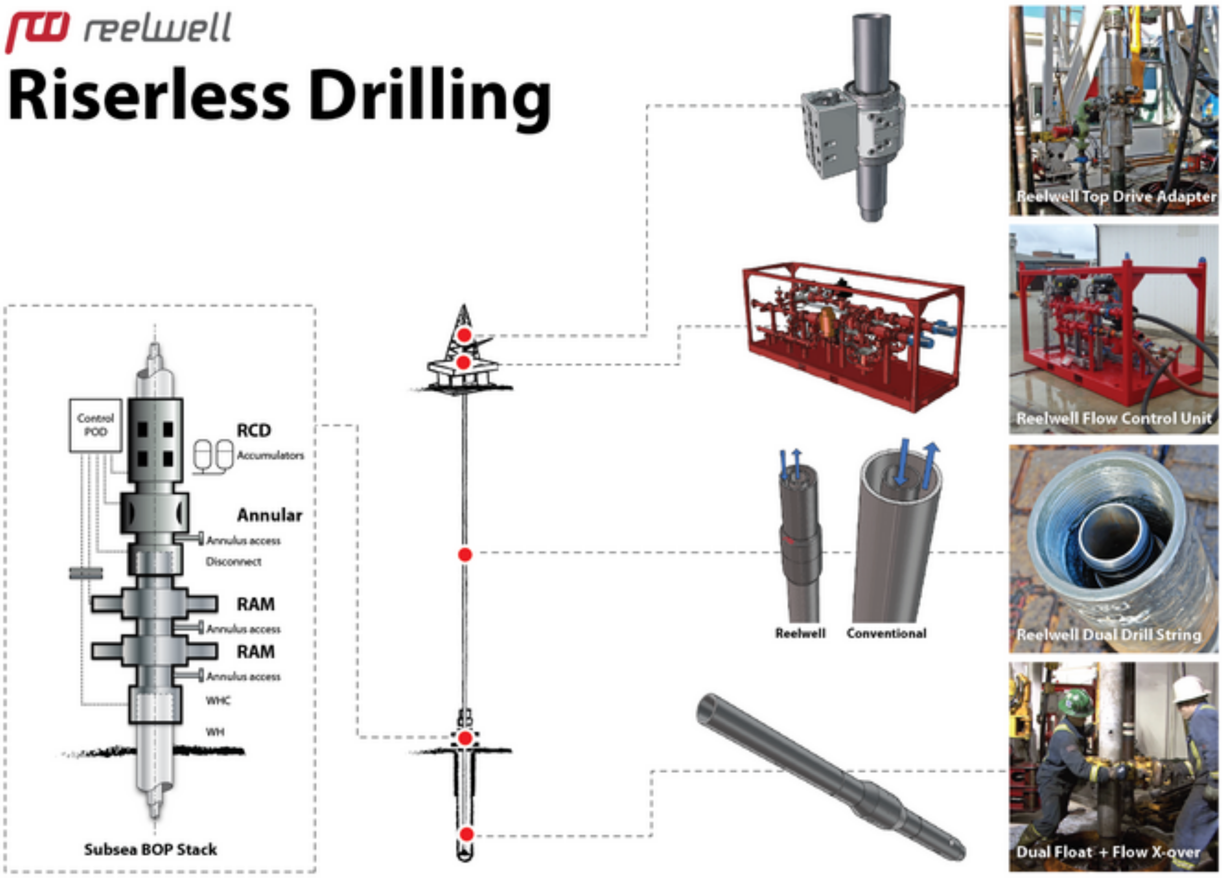


Figure 12 RDM-Riserless system (Reelwell AS, 2011)

4 Riserless drilling in salt section

This study is a conceptual study where most of the information is roughly provided, and scope is broad. Some procedures and parameters are worth for the dedicated studies when more information is available; for example, mud selection, mud weight control and field geography. Therefore to achieve the objective of the conceptual design, following working procedure and parameter are established and discussed for the benefit of the conceptual design.

4.1 Assumption

4.1.1 Salt section characteristic

The subsurface character is one of the most important information to design a drilling operation, but it can be known only if the well or well nearby is drilled, which is not available yet. Therefore, the study have to assume subsurface formation according to an exploration well No.1 in Santos basin, which is in the same area, should present similar characteristic, and information is available. Figure 13 show the salt section of the exploration well No.1 in Santos basin, which is assumed to be similar to the case.

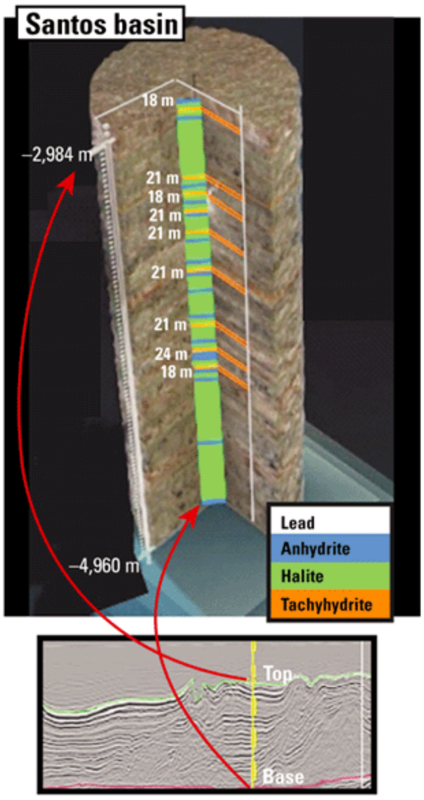


Figure 13 Salt section in Well No.1 Santos basin (Poiate, Edgard J., Costa, A. Maia, and Falcão, Jose L., 2006)

From figure 13, the salts section is 2 km thick approximately with pure evaporite section, mainly consists of thick (more than 100m) halite (NaCl) layer, and some thin (around 20 m or less) Anhydrite and Tachyhydrite layer in between. There is not any shale or carbonate component in the operating section.

4.1.2 The dual drill string

The drill string is another vital component for the drilling operation including RDM operation; therefore its information is required to design the system and equipment. As its function to transmit rotation and drill mud under pressure to bit, the drill string and its tool joints must be design for both. For the mechanical purpose, the string must be able to withstand axial force, due to weight carried, radial forces, from well bore pressure, and cyclic stress reversals, due to bending. In the perspective of the fluid dynamic, it must facilitate an acceptable pressure loss in the drill string and an acceptable fluid velocity at the operating flow rate. Moreover, the operation handling must be considered.

Despite of its critical for the study, the dual drill string is still under developing by another study. Therefore, the company provides a base case's parameter as shown in Table1. In order to minimize the weight per length and pressure loss while maintain a reasonable strength and handling equipment compatibility, the outer string of the dual drill string is divided into 2 sections as shown in figure 14. The aluminum section, because of it lighter makes up most of the string length with larger diameter to optimize pressure loss and weight. The steel section with smaller diameter shall be in the tool joint and pipe handling area for approximately 3 m each drill strand, to maintain the handling capability and tool joint strength. The inner string is made of aluminum included its tool joints. The material grade specifications for the pipes are "S135" for the steel section and "S2014" for the aluminum section. Appendix C.2 provides further information of the S2014 aluminum alloy.

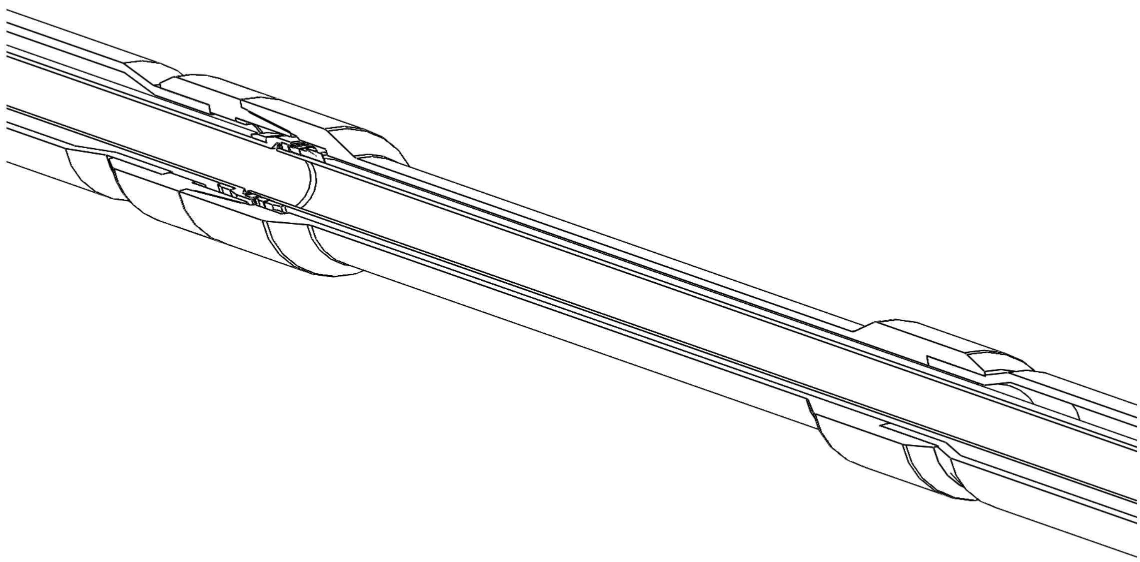


Figure 14 Dual drill string's pipe configuration with Steel handling area in the middle, tool joint on the middle-left and the aluminum pipe on both ends (Courtesy of Reelwell)

Table 1 Dual drill string base case parameter (Reelwell, 2013)

	The parameters	
Outer string	Aluminum section outer diameter	198 mm
	Aluminum section inner diameter	172 mm
	Steel section outer diameter	168 mm (6 $^{5}/_{8}$”)
	Steel section inner diameter	140 mm (5 $^{1}/_{2}$”)
	Tool joint outer diameter (Steel)	203 (8”)
	Tool joint inner diameter (Steel)	127 (5”)
	Pipe (overall) joint length (m/joint)	14
	Steel section length (m/joint)	3
	Pipe weight (kg/m) in air (Al section)	28.5
	Pipe weight (kg/m) in air (Steel section)	40.9
	Max tension load (tons)	300
	Max torques (k ft-lbs)	100
Inner string	Pipe outer diameter	104 mm
	Pipe inner diameter	92 mm
	Tool joint outer diameter	113 mm
	Tool joint inner diameter	92 mm
	Pipe joint length (m/joint)	14
	Pipe weight (kg/m) in air	5.0

4.2 The operation

According to the base case condition, state-of-art review and information about the Riserless concept, the operation step of the Riserless operation could be establish as:

a) *Positioning the rig*

b) *BOP stack and well control equipment installation:* Install the BOP stack, RCD and choke and kill line manifold on top of the in-place wellhead in order to establish a secondary barrier before further drilling.

c) *Run in hole:* Displace the fluid in well, which were left from previous section. Pump in through the drill pipe, which were drop to near bottom. Pressurize RCD seal and let the return coming up, probably, through the kill and choke line to the surface.

d) *Drill out cement shoe:* Cement shoe are drilled out by pumping mud down through the drill pipe.

e) *Formation integrity test:* Formation shall be test for it condition prior to start to drill to prevent unexpected mud loss and kick.

f) *Drill 17 1/2" section:* Drilling with method proposed by Reelwell, the mud was pumped down through the annular of the dual sting drill pipe and return through the inner pipe.

g) *Clean circulation:* Circulate to clean the cutting out of the hole and return through either inner pipe or Kill or choke line.

h) *Run 13 3/8" casing:* Run 13 3/8" casing string included cement shoe into the borehole. Displaced mud returns through the drill pipe. At the top of casing string, connect casing hanger to the drill pipe

i) *Cementing:* Cement is pumped through the drill pipe connected to the casing hanger.

j) *Casing and Cement integrity test*: Pressure test the casing and cement for its integrity to prevent and control any pressured fluid or HC leak.

k) *Circulate in the heavier mud preparing for disconnection:* Displace the fluid in well, which were left from previous section. Pump in through the drill pipe, which were drop to near bottom, and let the return coming up, probably, through the kill and choke line to the surface.

l) *Remove BOP and other well control device:* Disconnect BOP stack including RCD and Kill and Choke line, and then retrieve them up as a reverse installation.

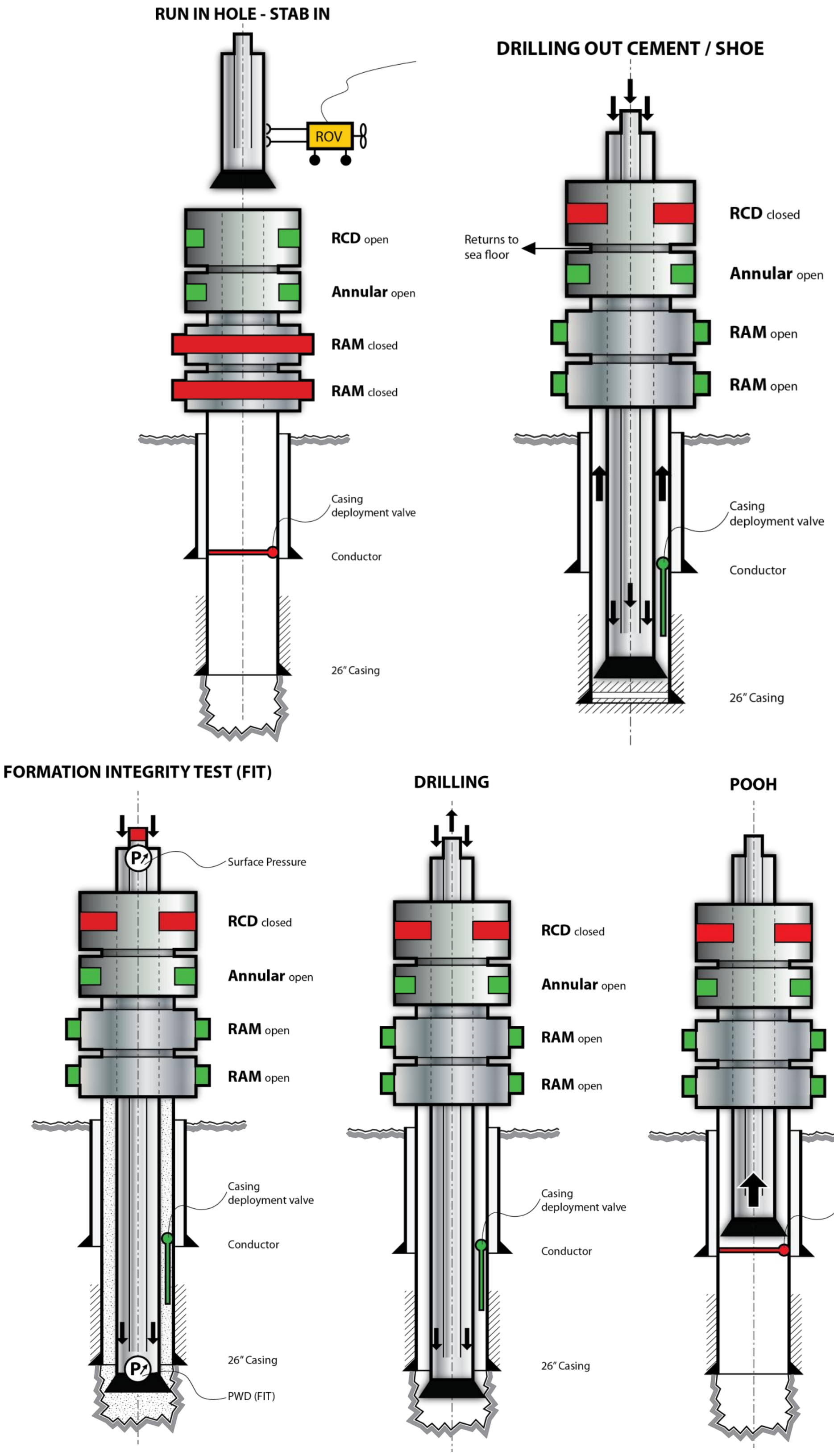


Figure 15 Riserless drilling operation illustration: from top left to bottom right, Run in hole, Drilling out cement shoe, formation integrity test, drilling and Pull out of hole respectively (Reelwell, 2012)

4.3 Mud Selection

4.3.1 Mud weight

Reelwell drilling method, with RCD and a kill line, enable the use of 2 drilling fluid types to optimize the operation benefits as shown in figure 16; a lighter active circulating fluid and a heavier passive well control fluid. The active one is the drilling fluid pumped down the drill string annular to drive and lubricate the drill bit, carry the cutting and return through the inner pipe. The passive one is heavier fluid, injected to the annular between the drill strings and the casing or the hole, with an aim to stabilize the drilled hole such as prevent the formation fluid entering the well, preventing the mud cake forming or salt creeping, depended on the formation character.

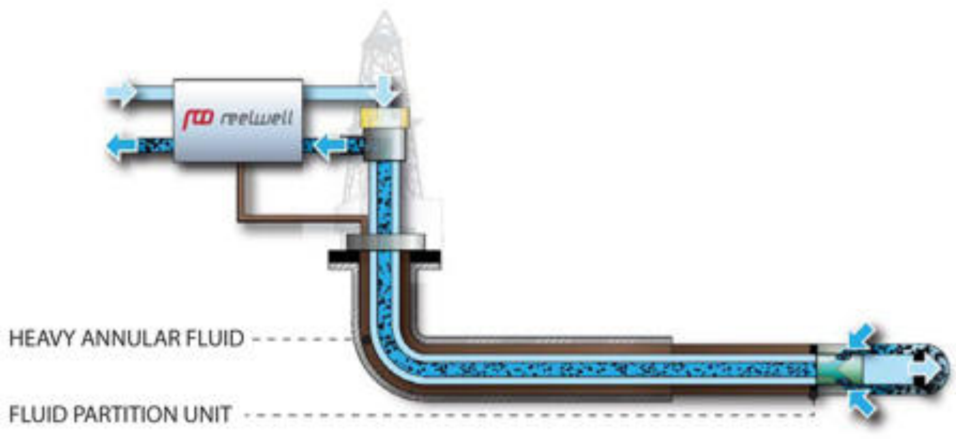


Figure 16 Utilizing of the dual mud system in RDM operation

The active fluid density can be considered from the formation fracture pressure, properties to transmit power to the drill bit and mud motor and the cutting carrying character. For the study, 11 ppg (S.G. = 1.32) active fluid density is given by the company's base case

For the passive well control fluid, Edgard Poiate Jr. et al., (2006), studied an exploration in Santos Basin and showed that the increasing mud weight is an effective strategy to mitigate risk of well closure and pipe struck due to salt creep (figure 17), which is one of the most important threat for the operation. 14 ppg (S.G.= 1.68) mud weight is recommended against salt creep in the Tachyhydrite layers until reach 200 m above the base of the salt, before reaching the rubble zone then set casing to avoid losing circulation in the rubble zone. Based on the same area and formation character with the case study, it is assumed to be applicable for the case study.

Another benefit for the passive well control fluid is the RCD operating pressure, which could be minimized or neutralized by it hydrostatic pressure with help of a choke valve on the well annulus filling line. Although the mud optimization and RCD design are not included in the scope of the study, the discussion shows the benefit and requirement of the dual fluid system, which shall be referred later in the study.

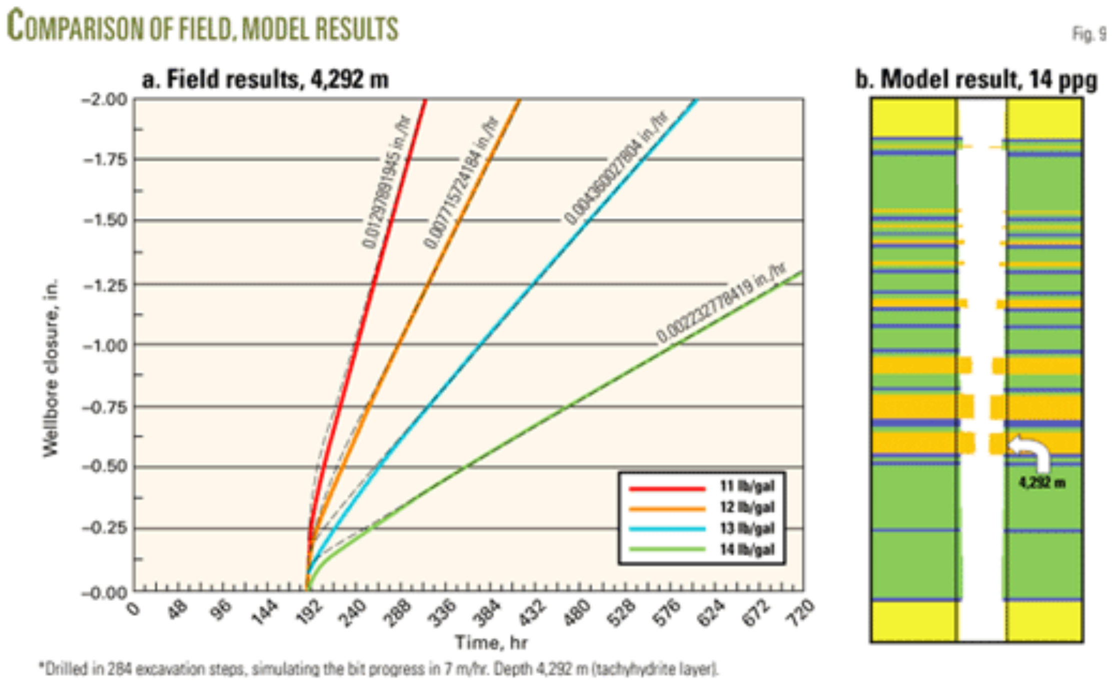


Figure 17 Comparison salt creeping field result by implementation of different mud weight (Poiate, Edgard J. et al., 2006)

4.3.2 Mud type

There are 2 major types of drilling mud widely used in the petroleum industry (excluded water). Water based mud (WBM) is a homogenous blend of water (or sea water) with clay such as Bentonite and other chemical such as NaCl or KCl. These additives are incorporated to create favorable effects such as penetration rate, stability, lubrication, viscosity and etc. NAF is a blending of organic-based fluid, barite, water or brine, and specialty additives. It could be classified into subtype by their base fluid used. Examples of base fluid respected to level of polycyclic aromatic hydrocarbon (PAH), which indicate toxicity, are oil-based mud (OBM), low toxicity mineral-oil-based fluid, enhanced mineral-oil-based fluid, and synthetic-based fluid, from high to low respectively. In general, WBM is more environmental friendly and cheaper.

Mud type selecting become a challenge in the salt rock drilling as there are several concerns from the salt rock such as salt creeping under high temperature or stress, wash out and hole enlargement from non-saturated mud. French S. (2012) has identified and discussed advantage and disadvantage of using those muds in salt section operation in several perspectives, which is summarized in table 2.

- Temperature: figure 18 show the extrapolated for salt section in Santos basin that it tend to be lower than 130C, both WTM and NAF are applicable
- Salt creeping and pipe stuck: as discussed earlier, could be overcome by adjusting mud weight, which is applicable for both of them
- Lost circulation detection in transition zone: not required since the case study is limited its operation in salt section only
- Salt recrystallization: critical, the salt crystal can strike mud system and stop the

operation

- Penetration rate: very important, since high capacity semi-submersible day rate is very high
- Cost of fluid: since the fluid is recyclable and the operation is long term contract, the cost of fluid is not significant in long term
- Cost of transportation: not significant compare to rig rate
- Hole cleaning and cutting carrying capacity: favorable
- Environmental: critical, although there is low risk of blow out, this is still significant

For the well control fluid, WBM present a critical disadvantage as it might wash out the salt section as salt solubility increasing by temperature and crystallize on the surface where the temperature is lower. While NAF drawback about the environment damage is eliminated by the fact that the well control fluid is always close contained, even in the case of emergency disconnect.

For the active fluid, the NAF it provides better performance in carrying cutting and increase bit penetration rate. Since there is a low probability of kick and blowout, only the spill case is needed to be concerned as shall be discussed in the next section. Thus, environmental concern become less significant, Moreover NAF also becomes less toxic as advance of technology in refining. As a conclusion, the NAF is recommended for both well control fluid and active fluid.

Table 2 WBM VS NAF advantage and disadvantage (adapted from French S. (2012))

System	Advantage	Disadvantage
Saturated Salt water-based fluid (WBM)	• Struck pipe problem can be overcome • Lost circulation problem in transition zone are easier to detect • Low fluid maintenance cost	• Hole enlargement due to unsaturated fluid and effect of temperature on solubility • Hole cleaning capacity must be supplement during drilling salt • Temperature limitation at 140C due to solubility • Salt recrystallized at surface
Non-Aqueous fluids (NAF)	• Minimize hole enlargement • Carry capacity of fluid is easier to maintain • Higher penetration rate for PDC bit	• Costly if circulation lost • Cost associated with transport • Environmental concern in event of spill or blow-out • Surfactant usage

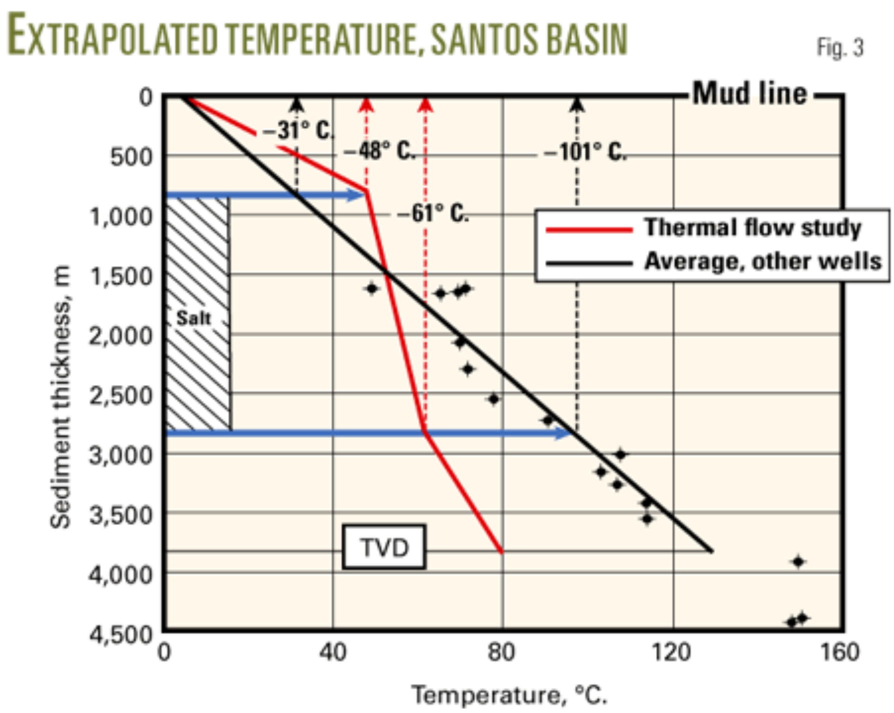


Figure 18 Santos Basin's salt section temperature extrapolated from Thermal flow study (Red) and average from the other wells (Black) (Poiate, Edgard J. et al., 2006)

4.4 Risk of Blowout in salt section

BOP is a secondary well control element especially to control the kick (influx of well fluid into the well) before turning to be a blow out (Well fluid influx at the surface). In order to evaluate the criticality of BOP, Risk assessment is necessary. So this section shall roughly discuss risk of the kick as information for the design.

The existence of the hydrocarbon in the well is an essential requirement of a well kick or blow out. The Reelwell-Riserless operation shall operate in the salt layer only, which is practically zero porosity and impermeable. So the existence of the hydrocarbon in the salt section is practically impossible. Moreover, the layer is a huge 2-km-thick salt layer without any intermediate layer in the section; thus the existence of hydrocarbon trap in the intermediate layer is also practically impossible. If there is any hydrocarbon carbon influx, it shall be very limited volume and inconsequential.

Though fluid flow and pore pressure concepts are not applicable to salt, brine pockets can be encountered, in bedded salts of litho-stratigraphic complexity. Although the case study shall expect to operate in intact salt sequences, where the brine kick is rarely experienced and, if occurs, is small volume and generally inconsequential (Dusseault, M. B., V. Maury, et al., 2004). The information of the formation is still roughly, and the possibility of occurrence is not negligible, and the risk of brine kick should be considered.

4.5 Key Challenge in designing the BOP stack

According to review of the Reelwell-Riserless operation working condition, here are a list of which shall be key challenges to the design of the BOP stack.

a) Safety, performance and cost optimization

Improving cost efficiency of the deep-water drilling is an objective of the project, which is studied. This could be achieved by optimization of the performance and cost. However an incident could lead to a disastrous damage, therefore the safety is also a mandatory concern that should not be compromised.

b) BOP stack weight and size

The bigger and larger BOP shall attract more loads from the wave and current. Consequently the installation tool is needed to be larger and capable for higher tensile, bending and fatigue, especially in the deep-water regime. The BOP installation operation window shall also become narrower.

In conventional drilling, the riser is used as a tool to support and lower subsea BOP to the seabed. It is a large and strong pipe string, thus it can facilitate the installing and retrieving operation of a large and heavy BOP for conventional operation easily. In the riser less operation, regardless of the installation method defined, the stack, including its control system and structure, has to be minimized its weight.

c) Rated working pressure

The BOP's rated working pressure in conventional drilling is normally dictated by the reservior. In riserless drilling, only a section of the well shall be drilled, unrelated to the reservoir. A proper working pressure is a mandatory consideration for the optimal design.

d) BOP shearing, sealing and handling capacity

The RDM technology depend on the dual drill pipe string, which is thicker, more complicated and, for sure, require higher capacity of the BOP to shear and handling. But in the same time, the weight and size must be minimized. Moreover using of the Aluminum material brought up several challenges to the conventional practice of design.

e) Proven technology performance and developing of new technology

The case study operates in the deep-water regime, which limit performance of the mainstream technology currently used in the industry. To improve the operation performance, implementation of new technology should be considered.

5 BOP stack for the Riserless operation

This section shall consider the operating condition and the requirement that the BOP have to anticipate. Related risk, regulation and standard practice shall also be included in the discussion. And the conclusion shall propose a conceptual BOP stack arrangement for the Reelwell-Riserless operation.

5.1 Brazilian Regulation

ANP (The Brazilian National Agency of Petroleum, Natural Gas and Biofuels) is a Federal Administration entity under the Mines and Energy Ministry, responsible to promoting the regulation, contracting and supervision of economics activities related to Oil, Gas and Biofuels industry in Brazil. Under ANP Resolution 43, "Operational Safety of the Management System of Marine Facilities of Drilling and Production of Petroleum and Natural Gas" (SGSO) has been established, and binds any offshore activities in Brazilian continental shelf. (Canto, L. D. S., 2010). The resolution require the concessionaires to:

- Submit the required safety procedure documentation to ANP and are responsible for what is contained in that documentation (*SGSO*)
- Determine that the facility operator has a management system that complies with the SGSO (*ANP Resolution No. 43/2007*)

The regulation does not contain the prescriptive procedure, as ANP consider that it might discourage the creation, or delay the implementation, of new technologies in the field of safety engineering, since the natural tendency of the market, governed by the time and cost optimization, is to obey what was proposed and not overcome it. Therefore, the Technical Regulation of the Management System for Operational Safety applied by the ANP is composed of 17 Safety Management Practices that allow the operator of the concession to correlate them to their own guidelines for the management and safety technologies and methods that best meet each facility. (Morais, C. P., 2011)

5.2 BOP stack working pressure

This section shall define an appropriate stack working pressure, which is an important parameter for further design. First consideration is the well fluid (brine) kick. Although the possibility of the kick is considerable low, it still presents some risk that is still worth to consider. The other is the maximum operating mud pressure.

a) Well fluid kick

Without presence of hydrocarbon in the pocket, the brine pocket pressure can be estimated to be as same attitude as the formation pressure:

$$
\begin{aligned}
P_{formation} &= \rho_{sw} g h_{sw} + \rho_{sedi} g h_{sedi} + \rho_{salt} g h_{salt} \\
&= 9.8 \text{ x } [(1 \text{ x } 2000) + (2.6 \text{ x } 1000) + (2.16 \text{ x } 2000)] \\
&= 87416 \text{ kPa} \quad = \quad 12675 \text{ psi}
\end{aligned}
$$

Because gas does not existed in the brine pocket, the brine and seawater hydrostatic pressure can be deducted for BOP's maximum surface anticipated pressure. Then, the maximum surface pressure that the BOP might anticipate is approximately:

$P_{BOP} = P_{formation} – \rho_{brine} g h_{brine} - \rho_{sw} g h_{sw}$

$= 87416 – 9.8 \times (1.32 \times 3000 + 1.0 \times 2000)$

$= 29008$ kPa = 4206 psi

Where $P_{formation}$ = Formation pressure

P_{BOP} = BOP maximum anticipated surface pressure

ρ = Density

h = Depth

("sw" for seawater, "sedi" for sedimentary, "salt for salt section and "brine" for brine)

b) Operating mud pressure

The other critical scenario of in-bore operating pressure is the working fluid operating pressure as a summation of the effective hydrostatic pressure and the fluid pump-in pressure deducted by friction loss at the defined water depth.

$$P_{operating} = P_{\Delta} + P_{fluid} - p_{loss}$$

Where; $P_{operating}$ = Working fluid effective operating pressure

P_{Δ} = Effective Hydrostatic pressure at the specified depth

$= (SW_{mud} – SW_{seawater}) \times h$ (Pa)

P_{Fluid} = Fluid dynamic pressure at the specified depth (Pa)

p_{loss} = Fluid pressure loss due to friction and other minor loss

$= p_f + p_{joint} + p_{BHA} + p_{bit}$

SW = Specific weight of a fluid (kg/l)

h = Water depth (m)

And from Drilling data handbook (Nguyen, J. and Gabolde, G., 2006), with assumption of Bingham fluid, smooth pipe and turbulent flow regime, the pressure loss in a tubular pipe due to friction could be roughly estimated as:

$$p_f = \frac{Ld^{0.8}Q^{1.8}\mu^{0.2}}{901.63D^{4.8}}$$

And pressure loss in the annular conduit could be roughly estimated as:

$$p_f = \frac{Ld^{0.8}Q^{1.8}\mu^{0.2}}{706.96\,(D_o + D_i)^{1.8}(D_o - D_i)^3}$$

Where; p_f = Pressure loss in the conduit (kPa)

μ = dynamic Viscosity (or Plastic viscosity for Bingham fluid) (cP)

L = Length of the flow path (m)

Q = Flow Volume (liters/min)

d = Fluid density (kg/liter)

D = Inner string's internal diameter (in)

D_o = Annulus outer diameter (External string's outer diameter) (in)

D_i = Annulus inner diameter (Inner string's external diameter) (in)

Appendix "A" show the calculation of the fluid pressure loss, hydrostatic pressure and working fluid operating pressure under the available information. The hydrostatic pressure of seawater is assumed as external pressure for the depth below the seabed as the worst case. The calculation shows the maximum operating pressure of the annular flow at 2000 m depth as 4581 psi.

c) Discussion

From the calculation, the maximum brine surface pressure and the mud operating pressure at the seabed depth are 4206 and 4581 psi accordingly. Therefore, the stack's rated working pressure shall be 5000 psi as the next available standard rating.

The calculation as shown in the appendix also show the maximum working pressure for the annular flow and the inner string flow, which should be checked for the mechanical capability of the assumed pipe parameter such as the yield pressure or collapse pressure. For the annulus, maximum working pressure is 334 bars at the 5000 m depth while the outer pipe is capable of approximately 525 bars. The inner pipe collapse pressure is approximately 380 bars, which is higher than 245.6 bars, the maximum differential pressure between the annular and the inner flow at the surface.

Although the calculations show the result very close to limitation of 5k working pressure, this is the result of the conservative assumptions. There are several studies trying to fine tune the parameter to be less conservative such as larger pipe size, thinner thickness, lower mud weight and lower pressure drop across the BHA and tool joint.

The calculation in the appendix depended on several assumptions, which are needed to review progressively. Among them, there are 2 critical parameters deliver significant effect to this operating pressure and need closely attention. First is the flow rate, which affect the pressure loss to the power of 1.8. The other is the fluid's density, which affect both the effective hydrostatic pressure and the pressure loss.

5.3 Operational requirement

To achieve its primary functional requirement in different scenarios, the arrangement should provide means to satisfy other operational requirement as recommended by API RP53 (1997) for the floating drilling unit that the arrangement should provide means to:

- Close in on the drill string and on casing or liner and allow circulation
- Close and seal on open hole and allow volumetric well control operations

- Strip the drill string using the annular BOP(s)
- Hang off the drill pipe on a ram BOP and control the wellbore
- Shear logging cable or the drill pipe and seal the wellbore
- Disconnect the riser from the BOP stack
- Circulate the well after drill pipe disconnect.
- Circulate across the BOP stack to remove trapped gas

Therefore this section shall review above functional requirements and discuss for effect for each of them to the stack arrangement or control system.

a) Close in on the drill string and on casing or liner and allow circulation

If any scenario might need to close in on the drill string, this can be simply achieved by closing the pipe ram. As the drill pipe still existed, the fluid in the well can be circulated by pumping down through the drill pipe and return in a medium size high-pressure line, normally Choke or Kill lines, connected to the wellhead or stack below the closing BOPs. Although the inner pipe of the dual drill string could be an inherent high-pressure line, which can use to circulate the active fluid, another high-pressure line connected at the wellhead is needed to fill-in the well annulus with well control fluid or return it to surface.

b) Close and seal on open hole and allow volumetric well control operations

The volumetric well control is a method of well control which is required in several case such as when the drill string is out of a well and gas is migrating upward, When the drill string is plugged, When the drill string is a considerable distance off bottom and the kick is below the string, during stripping and/or snubbing operations. Volumetric well control shall keep bottom-hole pressure constant when circulation is not possible and gas is migrating up the hole. Bottom hole pressure is maintained slightly higher than formation pressure while the gas is allowed to expand in a controlled manner as it moves to the surface as shown in figure 19. (Well Control School, 2007).

After closing and sealing on the open hole by the blind ram, Volumetric well control can be accomplished by a set of choke line and choke manifold connected to the wellhead below the BOPs.

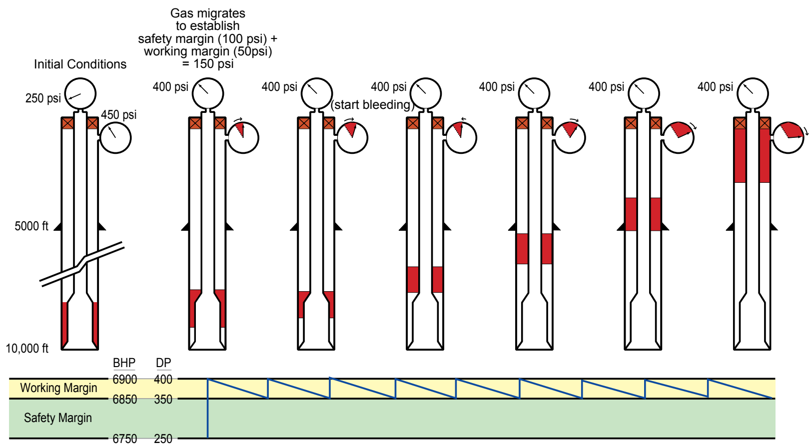


Figure 19 Volumetric well control operation (Gas bleeding) (Well Control School, 2007).

c) Strip the drill string

In some scenarios, the pipe might need to strip through the BOP. Stripping in is the way to run the pipe to the bottom safely when the weight of the drill stem is sufficient to overcome the force of well pressure and when the well is shut in on a kick in order to gain complete well control. Stripping out is the process of removing the drill stem from a well under pressure. Figure 20 show the equipment required for the operation, an annular BOP to seal off the pressure, choke line, a dedicated and precise fluid discharge system from the wellhead to control fluid volume in the well and a fast response BOP control system.

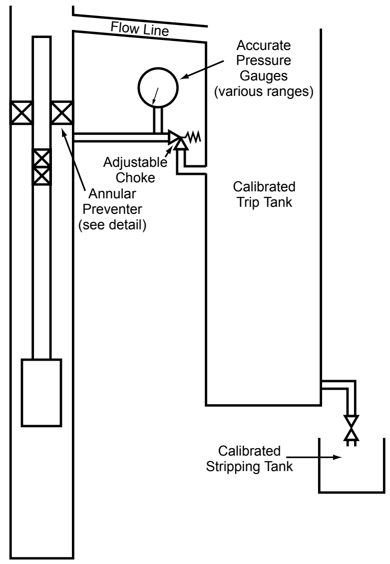


Figure 20 Equipment required for stripping operation (Well Control School, 2007).

d) Hang off the drill pipe

During the operation, the drill pipe might have to be hung temporary to wait for weather or prepare for the emergency disconnection. Therefore, a pipe ram BOP is required to seal and hang the drill pipe when needed. As the drill string is designed as 2 sections separately, the variable bore ram is required for the operation.

The variable bore ram is needed to cover the range of the dual string pipe's diameter, which vary between 6 5/8” (steel section) and 7.8” (Aluminium section), but this range is out of the available range of the variable bore ram available which 7 5/8” is maximum (Variable Bore Ram, Inc., 2013). Therefore either a smaller pipe diameter design or a study to build a larger capacity is mandatory to cover the gap.

For the hang off function, a pipe ram was designed to seal a well under a particular load such as an 18 ¾” “Hydril Pressure Control CompactTM Ram Blowout Preventer” capable to do so under the weight of 60000lbs. Although the Variable bore ram will generally sacrifice its hang off weight capacity for the ability to seal on a wider range of pipe, Montgomery, M. E., (1995) corporate with the suppliers, proved that the variable bore ram if need, could be improved the hang-off capacity up to 60000lbs, the maximum hang-off test capacity. This should be a confirmation that the Variable bore ram is capable to hang off the dual string pipe, which at its maximum length of 5000 m, weight in water approximately 110000 kg (24000lbs).

e) Shear logging cable or the drill pipe and seal the wellbore

In the operation, there are chances that the operation has to stop and disconnect the drill pipe, for example, Rig loss of position or Fire on the rig. Shear function is required to deliver quick drill pipe disconnection and seal function is required to keep the well under control during the disconnection. An integrated Blind shear ram is the most common solutions and most effective solution to deliver these functions. However the dual drill string poses several complexities to the shear and seal function; thus this shall be discussed as a dedicated topic later.

In addition to shearing the drill pipe, casing shearing is another critical function that should be considered. It is a regulatory requirement in some stringent areas such as Norwegian continental shelf. But the regulation in the area does not prescript the requirement. The risk of blow out in the operation is practically negligible. The surface conditions that risk the rig to be disconnected such as severe weather are less consequential and more likely predictable, especially in the short operation such as the casing installation. Therefore, absence of the casing shearing function is considered acceptable.

f) Disconnect the riser from the BOP stack

The marine riser is not used in the operation, thus the requirement is not applicable.

g) Circulate the well after drill pipe disconnect

After shearing and sealing the well for the emergency disconnection, the well needs a couple of high-pressure lines to circulate and gain control of the well. This couple must be connected to the stack below the lowermost BOP to allow circulation if the lowermost BOP has been closed.

Alternatively, the well could also leave it in place waiting for the conventional rig. This could become the option because the conventional rig with marine riser will come and drill on the same well in the reservoir formation. The justification to choose any of them is the quantitative risk assessment and cost-benefit evaluation with more information such as Rig day-rate and cost of the line. Therefore, the study shall continue as if the alternative is not economical.

h) Circulate across the BOP stack to remove trapped gas

This function need other connecting point of choke and kill line along the BOP stack beside the ones in the lowermost. One of choke or kill line is recommended to be install in between Pipe rams and sealing Blind (-Shear) ram.

5.4 Shear and seal function for the dual drill string

Shear and seal functions are mandatory functions of the BOP stack. Blind shear ram is preferable equipment for the function, but there is some limitation on using it. This section shall further discuss on the benefit of using Blind shear ram over a set of blind and shear ram, its complexity, capability and the requirement to use blind shear ram.

a) Benefit of blind-shear ram BOP

Using the blind shear ram is preferred over a combination of blind ram and shear ram as it weighs much less. For example, an 18 ¾" bore size with 5000 psi pressure rating, the blind shear ram weigh approximately 13 tons less excluding the support structure and associated control system. Moreover, every ram in the stack comes with its maintenance burden, using the integrated ram can minimize the excessive maintenance and improve reliability of the stack in the operation. On the other hand, without the constraint of fold-over mechanism required by the blind-shear ram, the dedicated shear ram usually possess higher capability to shear thicker and/or larger pipe such as the super shear ram that can shear the casing and tool joint.

b) Complexity of the dual drill string

The following feature of the dual drill pipe could cause complexity to the shearing capacity consideration.

- The pipe in pipe feature: Normally the BOP manufacturer defines the geometric feasibility to shear on the basis of single wall pipe. The exact effect of the inner pipe to the feasibility is still unknown.
- Using of Aluminum material: Aluminum is material mostly used in this dual drill pipe. But the equations provided by the suppliers for finding force required to shear a pipe are based on steel's properties, which present several different characters from the aluminum such as linear behavior, yield characteristic, elongation and hardness.
- Tool joint and upset area: The internal upset and tool joint could cause the shear function unsuccessful and could damage the shear blades. Avoiding shearing in the upset is recommended (West Engineering Services, 2004). The dual drill pipe features with 1 tool joint and 2 upset area to connect between the aluminum and steel. These joints made up a significant length and could cause problems if the emergency occur.

c) The consideration of the blind-shear ram capability

To determine the capability of a blind-shear ram BOP, the following conditions must be considered:

- The pipe must be geometric feasible to shear for the ram. Table 7 in appendix B.1 show an example from a part of the Cameron engineering bulletin EB702D (Cameron Drilling systems, 2007) that define the "geometric shearable" diameter and wall thickness of the steel pipe for the specified ram.
- Sufficient shearing force: Distortion energy method is a common method used to calculate the force required to shear for generic case. However, the theory does not take the ram configuration designed to reduce pressure requirement into account. Thus, the formula provided by the supplier is preferred to calculate pressure required to shear steel pipe by the ram.

In order to simplification, the feasibility to shear of the dual drill pipe is conservatively assumed wall thickness of the drill pipe equal to the summation of the inner and outer. Appendix B.1 has shown the preliminary selection of the Blind shear ram that Cameron 18 ¾” -5M/10M TL BOP with Double V shear ram (DVS) is feasible to shear the pipe. Appendix B.2 has shown the calculation of the shear force required according to the Distortion energy theory for both steel section and aluminum section. The result indicates that the steel section is the critical section and requires higher force to shear. Appendix B.3 has shown the calculation of operating pressure required to shear the steel section according to the formula provided by Supplier (Cameron Drilling systems, 2007). The operating pressure for the example ram is at least 1027 psi.

d) Discussion

The selection of the Blind shear ram is based on an unproven assumption as stated. A further study to prove the assumption and the selection must be commenced before the implementation. As the DVS Ram provided the capability to shear the thickest pipe among the blind shear ram. If it is proved incapable, a combination of a shear ram and a blind ram is the alternative with advantages and disadvantages as discussed earlier.

5.5 The RCD requirement

The RCD is another vital equipment for the operation, the key design parameter are discussed as followed:

5.5.1 Pressure rating

For an RCD, there is no designated rated working pressure since the maximum internal pressure that the equipment is designed to contain and/or control depends on the operation (Cantu, J. A., J. May, et al.,2004).

- Maximum movement pressure (Stripping or tripping): condition whether the stripping-in or tripping-out must be cease, pipe rotation may continue to avoid sticking while taking control the well
- Maximum rotating pressure: if this pressure is exceeded, rotation should stop and the annular BOP should be closed until the well become under controlled
- Static test pressure: Maximum pressure rate established by the supplier for the selected RCD, every operation included connection pressure test should be less than this pressure

Unlike the BOP, RCD is the equipment used to facilitate the operation. Thus among the pressure discussed above, only the first is the one that are needed to defined for the conceptual design. The latter could be defined as a consequence of the first with proper margin, normally recommended by the manufacturer. Appendix B.4 has shown the calculation of the operating pressure including the well annular pressure at a range of depth with the assumption that well control fluid density is 1.68 kg/l (14 ppg) and trying to keep the bottom hole pressure at the inlet of the inner pipe constant.

Figure 21 and 22 plot the absolute pressure of every section in the well bore including the inner pipe, pipe annular and well annular by calculation for operating scenario at 2001 and 5000m depth below sea level from Appendix B.4, given that depth of 2000m represent the pressure above the stack and 2001m represent the pressure in the wellbore (below the stack). Shifting of the well control fluid pressure between 2000 and 2001 m depth indicates a pressure adjustment, either by choking or adjusting well control fluid density, is required to make the bottom hole pressure constant. According to the calculation, the well control fluid density can be to be reduced as less as 1.53 kg/l in order to mitigate this shifting, though the well closure rate is still a concern to consider.

The RCD operating pressure (Movement) could be found from the different between the well control fluid pressure and seawater hydrostatic pressure at depth 2001 m below sea level, which are 10080 and 5580 kPa for 2001 and 5000m operating depth accordingly. As the maximum case is at 2001m, just below the stack with main contribution from the active fluid pressure requirement to return to surface, the different cannot be neutralized or lower by increasing or decreasing well control fluid density. On another hand, decreasing well control fluid density below 1.53 kg/l tend to make the situation complicated as it will need additional pressure rather than the hydrostatic in case of 2001m and might need larger RCD operating requirement for the case of 5000m.

As the conclusion, the RCD must allow stripping in or tripping out at the different pressure across the SCD (maximum movement pressure) more than 10080 kPa (101 bar, 1465 psi) with a proper margin recommended by the supplier. The pressure for the other operating condition could be established under recommendation from the supplier based on this condition.

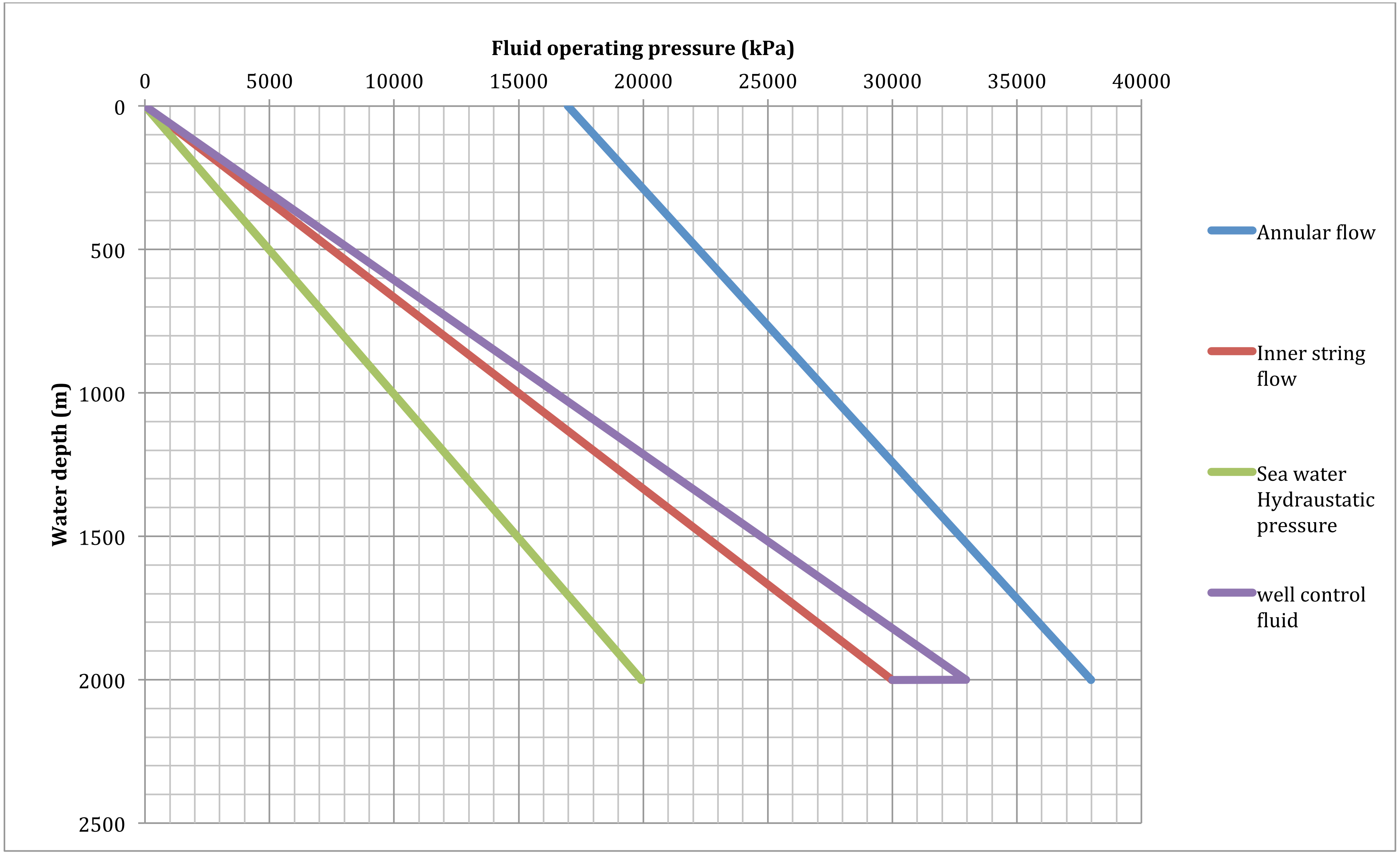


Figure 21 Fluid pressures for the operation at 2001 m depth below the sea level

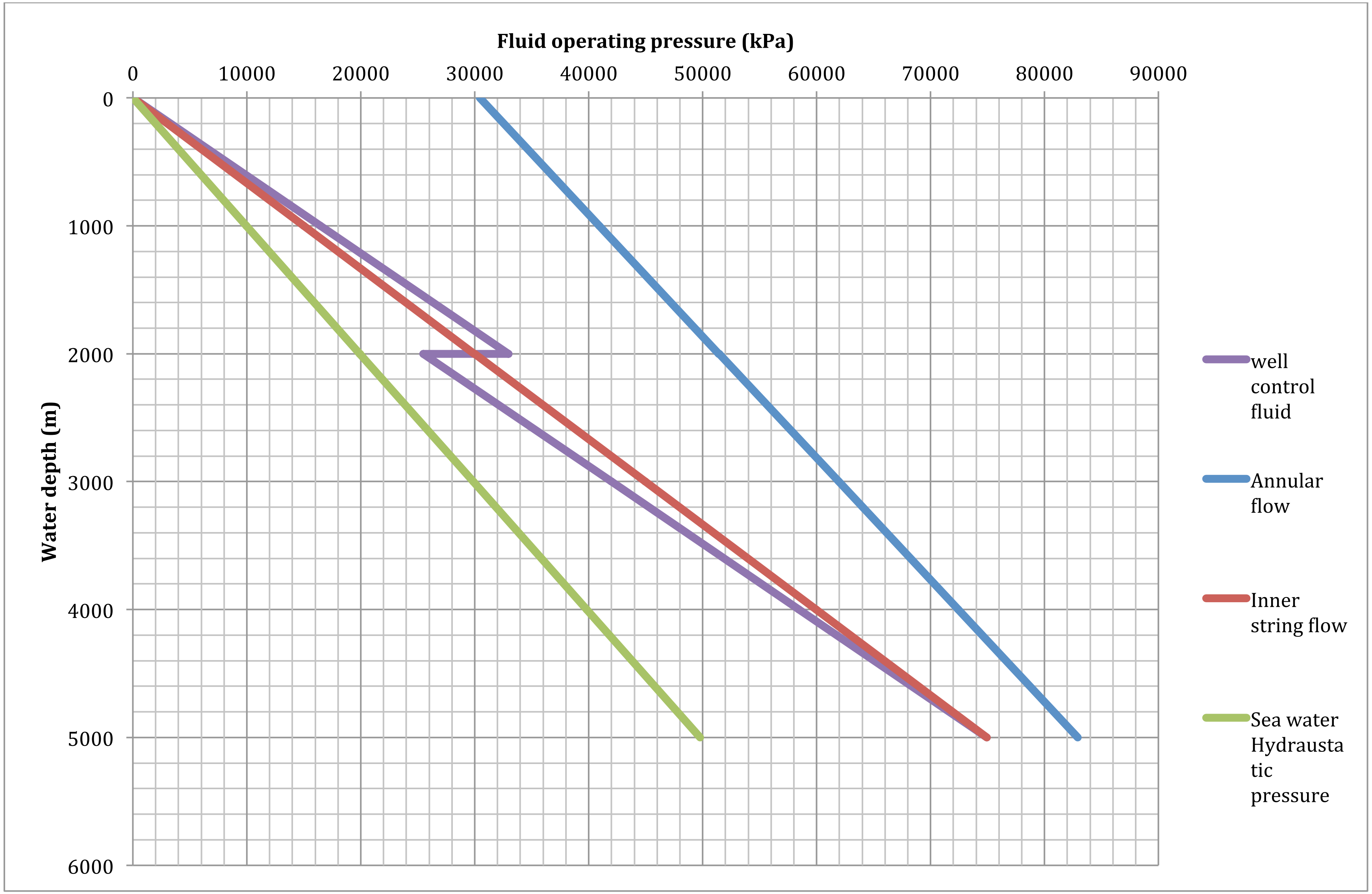


Figure 22 Fluid pressures for the operation at 5000 m depth below the sea level

5.5.2 Sizing, temperature and material requirement

Sizing of the RCD must be able to facilitate the drill bit and/or the casing. Therefore, the minimum inside diameter through the RCD body, including the bottom connection (Bore through body) must be at least 18 ¾" or larger.

Deep subsea condition shall keep minimum operating temperature above 0 °C. Maximum operating temperature could assume maximum as the maximum reservoir/ formation temperature. In the case study, figure 16 showed that the maximum salt section temperature shall not exceed 160 °C.

Material included elastomeric and metallic part must be applicable to the temperature defined above, selected NAF drilling mud and high salinity condition.

5.5.3 Connection and disconnection

In order to seal the pressure while allow the drill string to rotate, RCD is essentially subjected to wear and tear, and it might need to be pulled up to maintain periodically. Because the well is needed to be controlled during the operation, retrieval as a whole package included BOPs is not the option; thus a connect/disconnect latch is required. However, the detail of the connection is included in this study.

5.6 The stack installation and retrieve

There are at least 2 proven alternatives beside the riser, used to deploy and retrieve large and heavy subsea structures, the drill pipe and the cable wire of a crane/winch.

1) Install and retrieve with drill pipe

This is a most common method for the X-mas tree on-rig installation. An X-mas tree is installed and retrieved by the Tree Running Tool (TRT), which is equipment provided by several companies, specially designed to run, retrieve, mechanically release and pressure test an X-mas tree.

Using the same methodology, the drill pipe shall be able to install the BOP stack (included RCD) for the Reelwell-Riserless operation with some adaptation either in the running tool or the stack to be compatible to one another such as the latch connection on top of the stack and weight capacity.

The proven performance is one of the advantages to the concept. The drill pipe and derrick are a compulsory component of the drilling activities, such that it is not need additional weight or to be modified.

The main disadvantage is time consuming. It shall take approximately 8 hours or more to lower the stack to 2000m-depth seabed as it is connected stand-by-stand. This must be a separate run from the drilling tool as it is a need to pull up, install the tool and run down again before start to drill. This could take rig time for a day. This also concern heavy bulky weight attached to the drill pipe in the deep-water environment that might cause drill pipe over-bended or vibration. This must be thoroughly considered in the detail design phase.

2) Deploy and retrieve with cable wire

Deploying the X-mas tree by the cable is a new concept mostly proposed by Inspection, Maintenance and Repair (IMR) contractor such as DeepOcean to retrieve the tree by a small non-rig vessel. The cable wire provides a faster option; cable could be lowered continuously without any connection in between and take less than 3 hour for a trip. Implication of the concept shall allow fast BOP installation and possibly off-rig.

As same as installing the BOP by the drill pipe, this shall need a running tool, which have to be developed to be fit with the stack and purposes. An extra need of the tool for the cable wire installation is the hydraulic power supply from the surface is not available; thus the tool must be energized by electricity, mechanic or external source from ROV.

Another big concern for the alternative is the length and size of the cable. 2000 meter of the cable wire capable of the BOP weight is uncommon, massive and costly. The heavy lifting is also an issue. Installing by Cable wire may concern specific lifting equipment rather than the rig, need for extra caution and narrower operation weather windows.

Table 3 Advantage and disadvantage of the alternatives to install and retrieve the BOP

	Advantages	Disadvantages
By drill pipe	• No need of major top side modification • No need of special lifting equipment • High tensile capacity	• Moderate speed, higher rig time cost • Subject to bending and vibration in drill pipe
By cable wire	• Faster option, less rig time cost • Off-rig option available	• Hydraulic supply to the BOP is not inherent available. • Need of large, long and costly cable wire

Discussion

Table 3 has summarized advantages and disadvantages for both the installation by drill pipe and cable wire. Because tools for both of them do not exist, then the main criterion remained is the cost/benefit comparison. The drill pipe's requires less capital expenditure, but it is slower. The cable wire is faster; thus it is lower operation expenditure due to rig time reduction in the operation. However, this shall need further investigation with more information feed such as rig time cost, rig specification and it equipment, which is not available at the time. A further study is required to determine these options if the information is available.

5.7 Emergency disconnect/reconnect

In conventional drilling with riser, there are several situations that could arise during well control operations that may require disconnecting the LMRP and moving off the well such as high annulus pressures approach the rated working pressure of the BOP's, equipment failure, vessel movement due to adverse weather conditions (anchor chain or DP failure) or impending vessel collision or fire. The procedure included hanging off the pipe on the pipe ram BOP, shearing and sealing with Shear/Blind ram BOP, displacing Marine Riser with sea-water, disconnecting LMRP by hydraulic-controlled device and moving off the location. (Transocean, 2008)

In the Riserless operation, similar situation that required the emergency disconnect could happen. As Riser and LMRP are not be used in the operation, the operation to displace marine riser and disconnect LMRP is not required. The only concern is to contain the active drilling fluid in the drill pipe to do not spill and contaminate the environment.

However, toxicity testing shows that modern NAFs have low aquatic toxicity as might be expected from materials with low water solubility and low aromatic content. NAF cuttings settle very rapidly out of the water column, further reducing possible environmental exposures of organisms (Melton. et al., 2000). Vik, et al., (1996) examined the aquatic and benthic toxicity of a range of synthetic base fluid and found that they would not be considered toxic according to Norwegian government standards. Volume of the spill is much smaller (approximately 43 m3) compare to the conventional (356 m3). Finally, the sheared drill pipe technically does not provide profile for attaching; thus the simply pull the pipe up to surface after shearing is the best option available for now. However the control umbilical should be disconnected properly to allow the rig to move.

To reconnect, the conventional process of fishing is still applicable to the Riserless operation. Then the operation can resume immediately finish the fishing.

5.8 The proposed stack arrangement

This section shall conclude the discussion about the BOP stack by proposing conceptual arrangement and other associated requirement in Rellwell-Riserless operation in Salt section.

Because the risk of the blowout in the pre-salt operation is very low, and there is not prescriptive regulation implemented in the area. The selection of the stack's arrangement is mostly corresponded to the operation requirement. To reflect low risk of the well control situation and prevent excessive BOPs, which cause difficulty to handle and maintenance, the stack is proposed non-redundant. Figure 23 show the proposed stack's arrangement, which its equipment’s bore size shall not be less than 18 ¾” and could be described as following (bottom to top):

Main component

1) One subsea well head connector with 5000 psi rated working pressure to connect the stack to the well head
2) One variable bore ram that operating length cover from 6 5/8” – 7.8” drill pipe with 5000 psi rated working pressure: to seal around the drill pipe and capable to hang off the drill pipe either for temporary or preparation of emergency disconnected
3) One Blind-shear ram BOP with 5000 psi rated working pressure: To sever the dual drill pipe and other smaller object such as logging wire line and seal the well after severing

4) One Annular BOP with 5000 psi rated working pressure: as a first attempt to seal around the drill pipe and a requirement for stripping operation to regain control of the well

5) One RCD connector with rated working pressure according to the RCD static pressure: to be able to connect/disconnect the RCD on top of the BOPS

6) One RCD with “maximum movement pressure” not less than 1500 psi

<u>Associated component</u>

7) Two associated high-pressure line connected seabed and subsea as known as “choke and kill line” with rated pressure not less than 5000 psi.

8) Three connection points for choke line and kill line, a couple of them shall be below the lowermost BOP or at the well head connector and the other in between the Blind-Shear ram and the variable bore ram

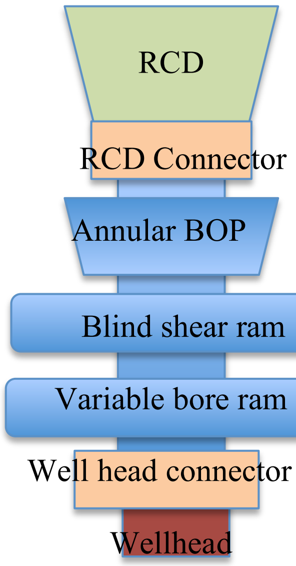


Figure 23 Preliminary configuration of proposed BOP stack

6 BOP control system

Because the stack (BOPs) is based on conventional well control equipment such as annular BOPs and Ram type BOPs, most of the control system basic requirements for the conventional system are still applicable for the Reelwell-Riserless. These requirements are defined in several standards and best practices such as NORSOK standard common requirement U-CR-005, NORSOK Standard D-001, API Spec 16D and API RP53. Reviewing of these requirements shall be further study in the detail design phase. Therefore, the following chapter shall discuss the limitation of the conventional control system, possibility and technology availability with an aim to improve the control system.

6.1 The Technology

The multiplexed electro-hydraulic (MUX E/H) subsea control system is the most common technology for the Deep-water control system. However, new operating regimes always challenge on the BOP control system and push improvements in the control system. There are several initiatives; some are the improvement of the MUX E/H system such as Depth-compensation, some are different systems such as all-electric control system. Therefore, this section aims to review and discuss the advantage and disadvantage of the conventional system and it alternative, then evaluate and select a proper control system for the Reelwell-Riserless operation.

6.1.1 Multiplex Electro-Hydraulic system (MUX E/H system)

Despite MUX E/H's several advantage as discussed previously, the nature of the industry to improve safety, reliability, performance and cost optimization has shown several limitations and weakness of the system. The following section shall roughly discuss notably known MUX E/H limitations.

a) Hydraulic Common mode failure

Despite of its most widely used in the subsea operation, the conventional MUX E/H system is still susceptible to several common mode failures especially on the hydraulic part. The notable common failure for the system are hydraulic fluid cleanliness, the accumulator bank and pressure reducing valve(s), the single hydraulic high pressure hydraulic header, the shuttle valves and the piping to each function. (Donaldson, J., 2013)

b) Limitation of the conventional accumulator

One of most important challenge posed by the deep-water regime to the MUX E/H system is the efficiency of the conventional pressure accumulator under high hydrostatic pressure. The accumulators must provide sufficient fluid capacity to actuate the BOP according to the regulation required, while the hydrostatic pressure of the environment dramatically reduces the volume of usable hydraulic. The standard method to calculate this useable volume is defined in several standards such as API 16D and API RP53.

Figure 24 show the effect of water depth on useable discharge volume percentage, under isothermal and adjusted gas constant. For a practical example, the Deepwater Horizon, which operated at 1600 m depth, need as much as eight 80-gallon accumulators to achieve their 15k psi emergency shear requirement (a blind shear ram and a casing shear ram)(Transocean, 2011). This is almost a triple size of the one operated on the surface. (Donaldson, J., 2013) This burdens a significant portion of load on a BOP stack.

Despite of its criticality as the only power source to actuate the emergency response function of BOP, the subsea accumulators are designed to store the energy just sufficient to actuate the function only once without the supply for surface. If any accumulator fail or leaked, the emergency response function might never be able to complete it task. If the first attempt fails, its second shall take a lot of time and effort to recover the control of the well.

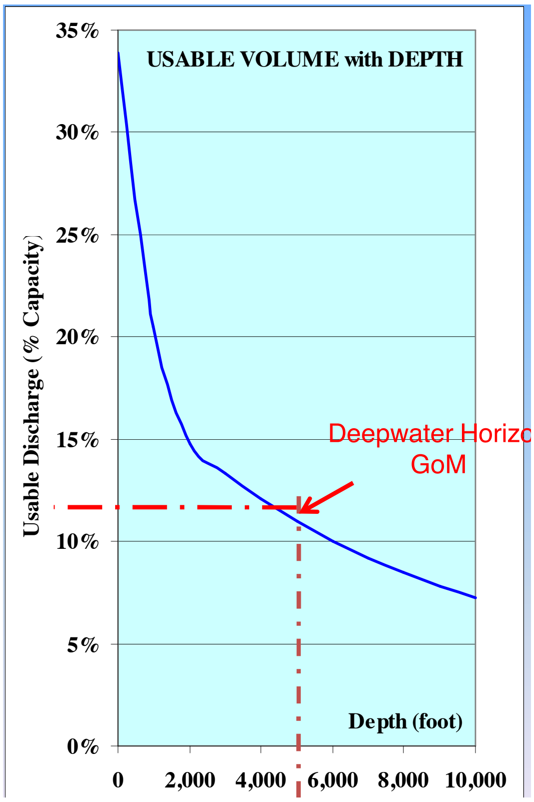


Figure 24 Effect of water depth on the efficiency of the hydraulic accumulator (Donaldson, J., 2013)

c) Reliability of the subsea control pod

Although a control pods are 100% redundant by the other and could be retrieved independently, if there is any major problem with a subsea control pod, the reliability requirement shall stop the operation, and standby until 100% redundancy requirement could be achieved. This becomes even more critical in the deep-water operation as deeper water lead to more time consumed in the process of retrieval and deploying. The history has shown that more subsea control problems were associated with the hydraulic component more than the electrical.

d) MUX E/H umbilical

Without support from a rigid marine riser, the MUX E/H cable is exposed to hydrodynamic loads from the environment. Movement of the umbilical responded to these loads make it valuable to fatigue damage, which is critical for the umbilical lifetime and control reliability, especially the high pressure hydraulic tubes inside. Leaking of power source in the deep-water control system could lead to an uncontrollable incident.

Moreover, a long distance high-pressure hydraulic transportation line cause significant higher risk, higher installation and maintenance cost but lower efficiency than the electricity's one.

6.1.2 The alternative

There are several new technologies try to overcome these limitations of the conventional MUX E/H system included the followings.

a) Depth compensated accumulator

The Depth Compensated accumulator is comprised of a double piston accumulator, with the two pistons connected by a connecting rod as shown in figure 25. The configuration creates four distinct chambers in the accumulator. The first chamber has a vacuum or very low pressure in it; the second chamber is exposed to seawater pressure. The seawater pressure acting on the piston, with the vacuum on the opposite side, creates a large force on the piston connecting rod. The third chamber has system hydraulic fluid, and it counters the seawater pressure by holding the same pressure. Adding nitrogen in the fourth chamber shall further adds to the third chamber's hydraulic pressure. Therefore the compression ratio for the nitrogen pressure in operation at any water depths is theoretical same as it is at the surface, irrespective of water depth. This compensation for ambient seawater hydrostatic is continuous, requiring no further charge from the surface through the main power fluid supply.

Volumetric efficiency of the technology, as a function of nitrogen chamber volume, is generally lower than conventional accumulators in very shallow waters. As water depth increases its efficiency remains constant. The efficiency of the conventional accumulator, however, succumbs to the problems of non-ideal gas behavior; adiabatic expansion and ambient temperature drop as the nitrogen charge pressures are increased to overcome seawater hydrostatic pressure. Another favor for depth compensated accumulator is it does not require continual discharging while pulling the stack to the surface, which increase safety and ease of use. (Springett, F., D. Franklin, 2007)

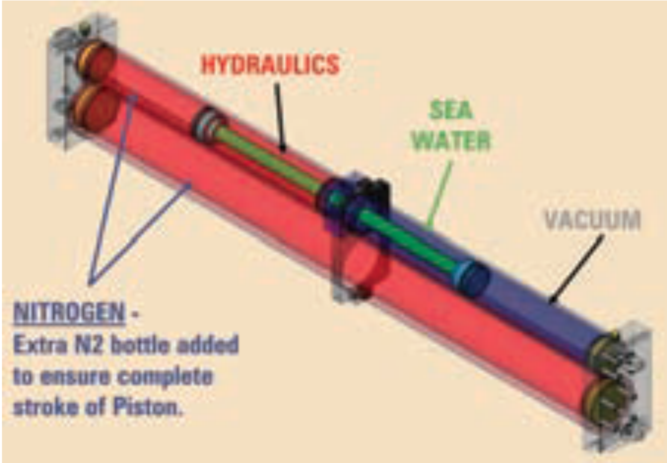


Figure 25 Depth compensated accumulator (Springett, F., D. Franklin, 2007)

b) Subsea battery energy storage

Despite of the system efficiency improvement by the depth compensated accumulator, the MUX E/H system is still susceptible to common mode failures in the hydraulic part. In an attempt to overcome those failure mode, this alternative proposes to use of Direct Current (DC) electric motors close-coupled to variable displacement hydraulic pumps for each actuator, with energy being stored in a local rechargeable battery system.

First advantage of the system is its improvement in reliability. As history shown, most of the failures in MUX E/H system occur in the hydraulic part. This system shall not need any electrically operated hydraulic valves, high-pressure header and piping, which make the control system lighter, less complexity and easier to maintain.

Another advantage is its much size as compared in figure 26 and better power per weight ratio. For example, a system dedicated to shearing 7-5/8" casing and blind sealing the wellbore at 3000 m depth, weighs approximately 10.5 tons with the conventional accumulator system while it is approximately 500 kg for the system with battery, pump, motor and oil reservoir. This contrast will be increasing in parallel to the water depth. Moreover, because of it much lighter weight, the additional redundant to the system such as an additional control pod or storing energy to actuate the BOP twice become more reasonable. (Bamford, A. S., M. Teixeira, et al., 2008).

Moreover, the implementation of hydraulic motors and pumps to other component in the stack shall eliminate the need of high-pressure hydraulic supply system such as Hydraulic power unit and Hydraulic supply in the MUX umbilical. Especially without a solid support riser in the Riserless operation, high-pressure lines in the MUX umbilical are susceptible to fatigue, which significant reduce the umbilical lifetime.

However, to implement the technology into the Reelwell-Riserless case, several further studies are required. First example is to improve its capability to sever large casing and thick drill pipe as defined in the case. The other is to improve its closing response time that still exceeds the requirement (API16D, 2008) of 45 s to meet the requirement.

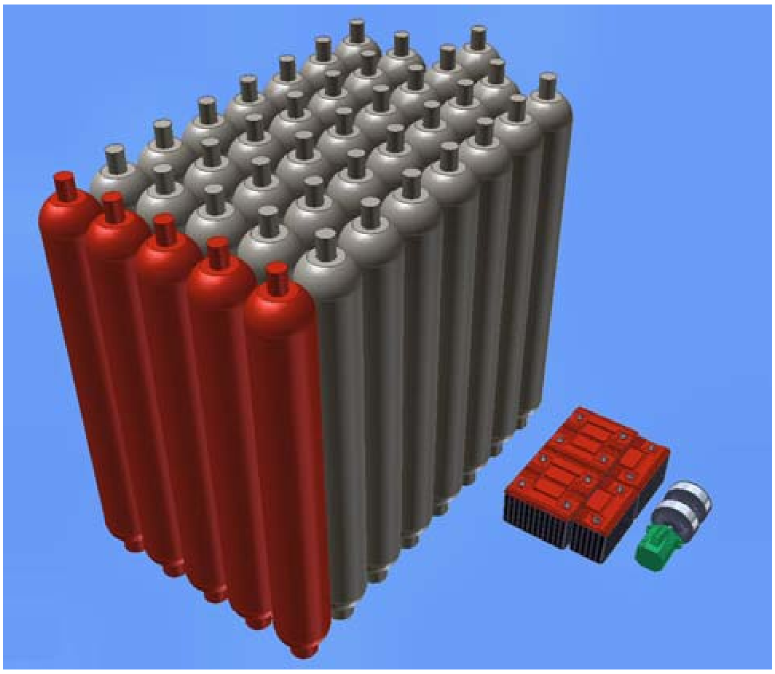


Figure 26 Size comparison between accumulator and battery energy storage (Bamford, A. S., M. Teixeira, et al., 2008).

c) All electric subsea control system

The concept is originated for the production control system, based on the experience that electronic components in general have much higher and better predictable reliability figures than complex mechanical components consisting of a large quantity of moving parts exposed to potentially dirty fluids. It is, therefore, anticipated that electric systems have much better reliability figures than EH-Mux systems. Furthermore, adding the full redundancy design, the inherent system availability is increased.

The implementation in the production system is successful to reduce system unavailability up to 50% relatively to MUX E/H system, reduce both operation, capital expenditure for the control system and justify in the cost-benefit evaluation. This perceived improvement is currently being verified on various projects worldwide, and the initial results are promising. The other aspects of using Electric technology are achieving environmental ZERO discharge systems, enabling for real-time feedback, ultra long offsets (removes the problem of flocculation of static fluids), and ultra deep water (no need for subsea accumulation) (Bouquier, L., J. P. Signoret, et al., 2007)

The system concept is shown in figure 27. It consists of the topside master control station (MCS) and electric power unit (EPU), installed on surface, supply power and communications via the control's umbilical to the umbilical termination (UTA) on the subsea template. The umbilical contains several coaxial cables that supply the required power and signal to the power regulation and communication subsea modules (PRCM). Each PRCM provides regulated power and signal to the individual subsea control modules on the trees. This configuration provides complete redundancy of power and signal from the surface to the control functions. In effect, the control system provides for dual independent control channels through the coaxial cables in the umbilical and control modules into the individual actuators.

The umbilical could also include hydraulic hoses, tubes as required by function. (Abicht, D. and J. V. D. Akker, 2011)

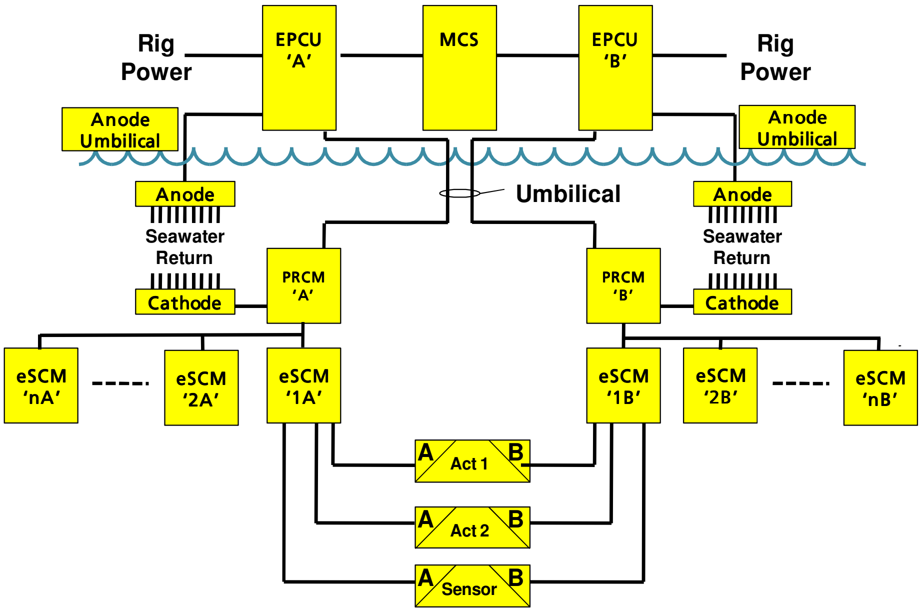


Figure 27 A concept of all electric subsea control system concept (Abicht, D. and J. V. D. Akker, 2011)

To implement the concept in subsea BOP, Pipe ram BOP's actuator can adapt qualified solution used in the production system such as an electrically actuated gate valve developed by Cameron. The case is different for Shear ram BOP and Annular BOP.

Shear ram BOP requires a powerful and reliable actuator. Several concepts had been developed, but not yet qualified, included explosive method and Shape memory alloy. Annular BOP depended on the elastomer and the delicate mechanism driven by hydraulic pressure to achieve its high flexibility to seal around any shape and size in the wellbore. To design electrical driven Annular BOP and make it qualified are also challenging.

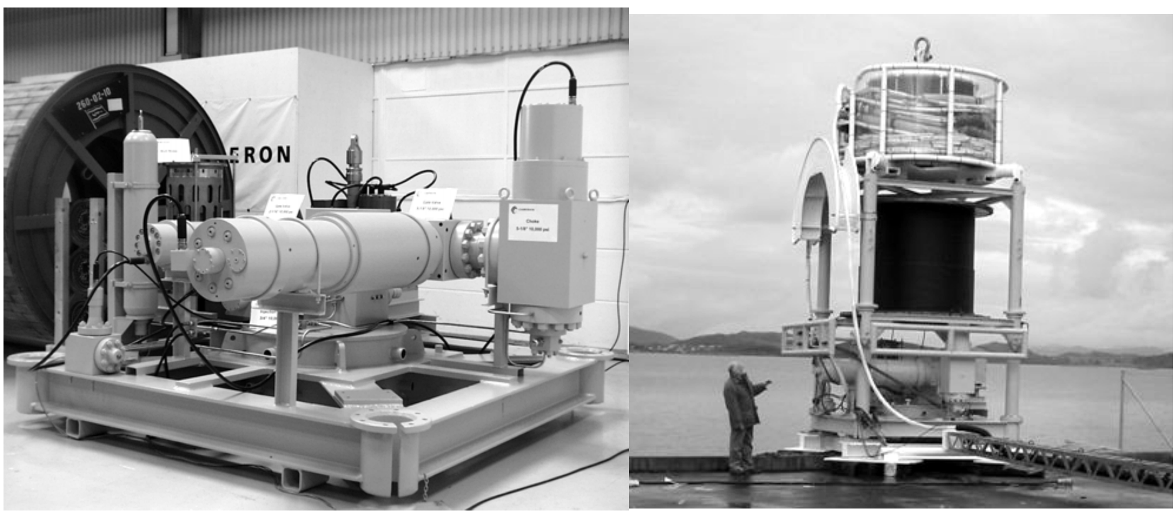


Figure 28 Prototype All-Electric Subsea Xmas Tree. (Picture courtesy of Cooper Cameron Corporation.)

Summary

The advantages and disadvantages to implement the alternative in the Reelwell - Riserless operation have been summarized in table 4, considered in several aspects included safety, reliability, environmental friendly, technology availability and others.

Table 4 Advantages and disadvantages of the conventional MUX E/H and the alternatives

System	Advantage	Disadvantage
Conventional MUX E/H	- Proven Technology - Several alternative supplier and manufacturer in the market - Easier to find and manage spare part - Well known operating and maintenance procedure	- Large size and heavy weight - Capacity to actuate emergency function only once - Unpredictable reliability in Hydraulic part - Costly and fatigue-valuable high-pressure hydraulic supply line
Depth compensated accumulator	- Smaller subsea accumulator (In order of 1/4 from conventional one) - Opportunity to provide more redundant in energy storage - Efficiency is irrelevant to operating depth - Actuator remain proven, well known and widely available	- Unpredictable reliability in Hydraulic part - Costly and fatigue-valuable high-pressure hydraulic supply line
Subsea battery storage	- Much smaller energy storage (in order of 1/20 compared with conventional one) - Zero discharge with Close hydraulics loop - Less complexity but more predictable reliability in control part - Opportunity for more redundant energy storage and control pod - Actuator remain proven, well known and widely available - Various degree of implementation	- Response time depend on motor and pump capacity under developed - Reliability concern for subsea rotating device e.g. motor and pump - Partial implementation of the concept, still need high-pressure hydraulic hose
All electric control	- Much smaller energy storage (With subsea battery) - Zero discharge - Less complexity but more predictable reliability in control part - Opportunity for more redundant energy storage and control pod - Opportunity to develop fast response actuator, such as explosive or memorized shape alloy - Eliminate need of high pressure hydraulic hose - Free up rig deck area because no need of hydraulic power package	- Unproven technology and manufacturer for the actuator of ram BOP - Need a new design for Annular BOP

6.2 Evaluation of the Technology for the Riserless operation

To evaluate the alternatives in previous section systematically, a decision model had been developed as shown in Figure 25. The concerns for the evaluation could be listed as followed:

General concerns

- Safety
- Reliability
- Environmental
- Operation and maintenance
- Cost
- Weight

Specific project concerns

- Water depth
- Working pressure
- Riserless
- No LMRP
- Time frame
- Local regulation

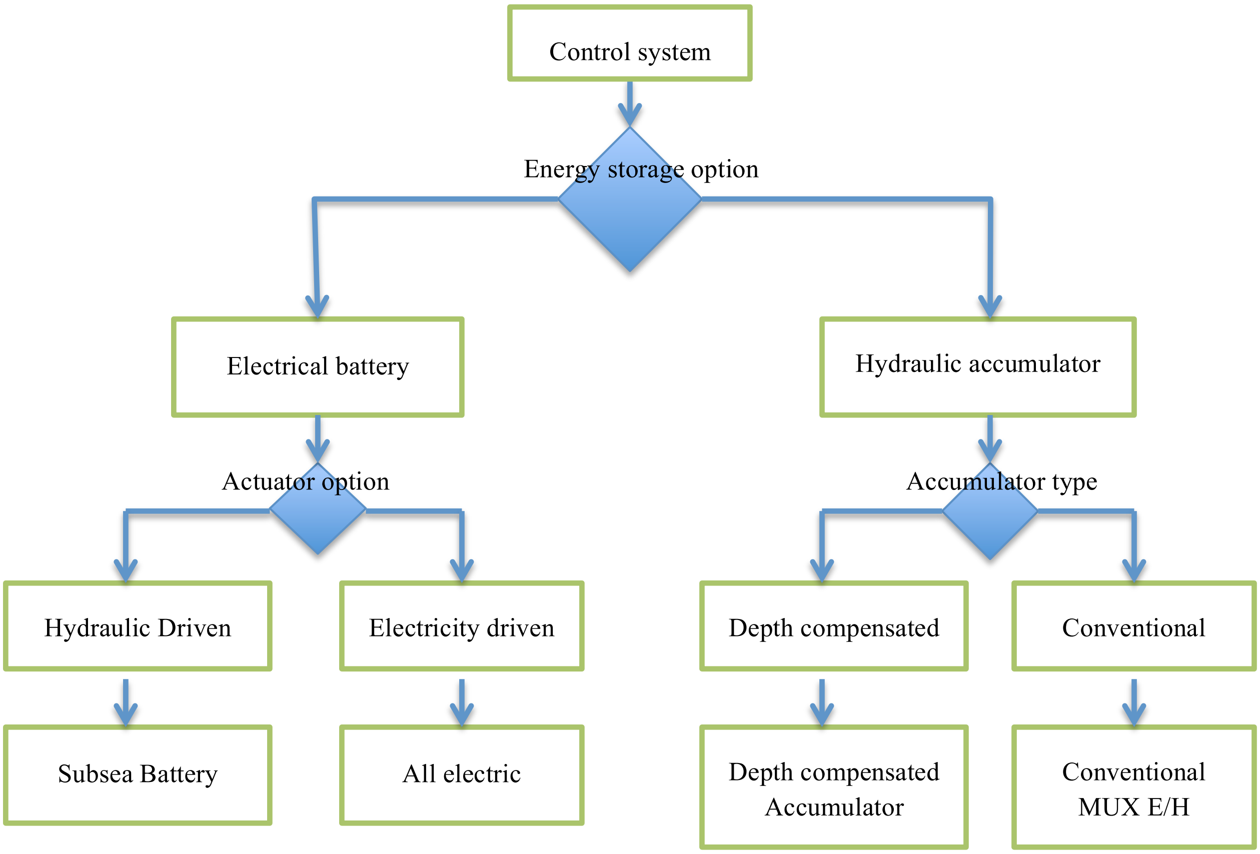


Figure 29 Decision model developed to evaluate the alternatives of the control system

a) Energy storage

The Hydraulic energy storage, the accumulator is the proven technology widely use in the industry with a reliable track record. The operation and maintenance procedure are well known. Plenty of manufacturers and suppliers provide the system and its spare parts on the shelf. However, the hydraulic itself is the problematic in the control system, resulted in unpredictable reliability, large size and heavy weight especially when the operation go deeper. Moreover, it hydraulic open discharge is becoming under environmental concern in several area.

The subsea battery with the electrical control system in general is more predictable than the hydraulic one. Because it is much smaller, lighter, and higher efficiency, this is a chance for an additional redundant for higher reliability. This also makes the subsea installation and maintenance much easier and lower cost especially for the operation without a rigid subsea lifting tool such as a riser. The only drawback for this option is how to convert electricity to mechanical power and actuate the BOPs.

Though not qualify yet, there are several studies as discussed previously, demonstrate the capacity of the technology to deal with the problem, only fine-tuned is needed. The operation of the case study is still in the conceptual phase. Thus, the timeframe still allows this fine tune to be qualified. Therefore, the subsea battery storage system is considered the most appropriate option.

b) Actuator

As the battery energy storage is chosen, there are 2 alternatives to actuate the BOPs, to convert electricity to hydraulic power by motor and pump or drive BOP directly by the electricity. Both of them similarly perform as regardless to water depth, zero discharge to environment, almost similar size and weight. Although the direct driven actuator tends to weigh less, it is not significant to the overall weight of the stack and control system. For the reliability, the motor and pump system is expected less reliability because moving parts. However, this could be recover by the additional redundancy of the motors and pumps.

The mud and pump option allows the use of existing BOP component, which is proven, better known operating and maintenance procedure and better availability of product and spare part. The study has already demonstrated its capacity to shear the pipe as designed. The latter need a new concept of the reliable actuator, which is still in the conceptual phase and possess several unknown factor.

<u>Conclusion</u>

The discussion suggests implementation of the battery energy storage system with motor and pump. It can improve the system reliability and reduce the system’s weight significantly. Technology’s availability, spare part, and operating and maintenance procedure are also favorable. However major drawbacks of the system are it still needs to improve responding time to meet the standard’s requirement and develop a new subsea control module with to handle all electrical signal and high electrical current used to drive the motors.

6.3 Requirement of the energy storage system

By reviewing, adapting and calculating the regulation and standard practice of the control system, this section shall preliminary establish the requirement for the subsea energy storage.

6.3.1 Hydraulic work required to operate the BOPs

The energy required to operate BOP functions are depend on several factor as follow:

- Rated working pressure
- Hydrostatic pressure
- BOP characteristic such as closing ration and actuator type
- Shearing force required (in case of shear ram)

For the system with hydraulic accumulator storage, the BOP suppliers normally recommended the energy required to operate the BOP in form of hydraulic operating pressure, useable volume required to close/open for a specific BOP as shown the example in Table 5 and see more in Appendix C. This information applies to most of the BOPs, except Shear ram and Blind Shear ram BOP, which a specific calculation is required.

Table 5: Engineering data of Hydril Pressure Control GL Annular Blowout Preventer (Courtesy of General Electric)

Bore (inches)			18.75	Dual 18.75	21.25
Working Pressure (psi)			5,000	5,000	5,000
Hydraulic Operating Pressure (psi)			1,500	1,500	1,500
Gal. to Close (U.S. gal.)			44	44	58
Gal. to Open (U.S. gal.)			44	44	58
Stud to Flange Height (inches)	Flanged bottom	5 m	65.25	112.00	77.50
		10 m	-	-	84.25
Stud to Flange Weight (lbs)	Flanged bottom	5 m	35,000	63,100	45,000
		10 m	-	-	-
Clearance Diameter (inches)			76.00	76.00	78.25

From the information provided by the supplier, the energy required to operate the BOP that was proposed in previous section can be estimated. The following estimation is performed roughly and depended on the information publicly available.

a) Variable bore ram

As shown in Appendix C, A Cameron 18 ¾" U-type single cavity BOP required 21.3 and 23.1 U.S. gallon to open and close with closing ratio 3.4:1 and 7.4:1 accordingly.

Closing ratio is the ratio between the wellbore pressure and the operating-piston pressure needed to close the rams on a given BOP design. If considering at rated pressure 5000 psi, the operating pressure to open and close the ram is 1470 and 675 psi accordingly. 1500 psi is the hydraulic operating pressure recommended by most of the BOP supplier except for the ram with Shear function, which the specific calculation is required.

b) Shear ram and Blind shear ram

Due to more variable in pipe strength properties and dimension, the recommended hydraulic pressure required to shear the drill pipe is generally given in form of the formulas, which are different among the supplier. The volume required to close depended on the operator type, bore size and working pressure is generally given as a table for a specific condition.

Thus, the blind shear ram, as discussed previously, is not capable to shear the drill pipe and it function is to seal the well and shear small object such as wireline logging tool, the calculation in Appendix B, which show the calculation of the recommended hydraulic pressure required to shear the dual drill string according to Cameron recommended formulas (Cameron Drilling systems, 2007), is mainly based on the shear ram as its higher capacity.

Since the formula is developed for the steel properties and steel is normally stiffer, the calculation is under assumption that the steel section is the most critical. For the aluminum inner pipe, it sectional area is added to the steel section, as it was an additional inner part of the steel pipe.

The result from the calculation in appendix B show that the recommended hydraulic pressure required to shear (P_{shear}) is 1026.80 psi. This is less than general recommended pressure. Thus the general function recommended hydraulic pressure of 1500 psi should be used to operate the blind shear ram and casing shear ram.

Because information of capable 18 ¾” - 5M/10M TL BOP is not available, volume of the operating fluid required to close and open are taken from 18 ¾” - 5M/10M U BOP (table 10) as an approximation as 21.3 and 23.1 U.S. gallon to open and close respectively for each of Shear ram or Blind Shear ram.

c) Annular BOP

There is also generally provided by the supplier for the set of size and working pressure. From table 5, one Hydril 18 ¾” annular BOP with 5000 psi working pressure needs 44 U.S. gallons of 1500 psi fluid to open or close.

Recommended hydraulic operating pressure is 1500 psi for all BOP with the operating volume as concluded in following table 6.

Table 6 Hydraulic operating volume required to operate the BOP

BOP	US gallon to open	US gallon to close
Variable bore ram	21.3	23.1
Blind shear ram	21.3*	23.1*
Annular	44	44

* Approximation from an equivalent size and rating, because of unavailable of information

6.3.2 Energy storage requirement

API RP 53, Norsok-D001 and Bureau of Safety and Environmental Enforcement (BSEE) require the accumulator's capacity, without recharging, must provide:

- Total capacity sufficient to supply 1.5 times of energy necessary to close and hold closed all BOP equipment units with a proper safety margin (minimum pressure of 200 psi above the pre-charge pressure) without assistance from a charging system.
- A subsea energy storage unit or a suitable alternate to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power connection to the surface (Acoustic, Autoshear and/or Deadman system)

As the hydraulic pressure from the pump is assumed constant and the hydraulic is incompressible, the useful work required could be calculated from above information by principle of work as:

$$W_{useful} = p\,\Delta V$$

Where	W_{useful}	=	Useful work required to complete the operation
	p	=	constant pressure of the working fluid
		=	Recommended hydraulic operating pressure
	ΔV	=	Recommended useable fluid volume to close/open

To prevent excessive loss in long distance low voltage transmitting, all energy storage (Battery) shall be placed subsea. As the requirement to store energy 1.5 times of the necessary amount to close and hold closed every BOP function with 200 psi margin, Subsea energy storage system need to deliver useful hydraulic work as:

$$W_{useful} = 1.5 \times (1500 + 200) \times (23.1 + 23.1 + 44) \quad \text{(psi x US gallon)}$$

$$= 1.5 \times (1700 \times 6894.745) \times (90.2 \times 3.785/1000) \quad \text{(J)}$$

$$= 1.5 \times 4.0 = 6.00 \text{ MJ}$$

6.3.3 Electric and hydraulic conversion

As the motors and pumps are located subsea next to the actuator and electrical signal can travel fast, assumption that the loss in the hydraulic system and system response time is negligible are made. In worse case scenario, if every functions is needed in concurrent, delivering the useful works within the time limitation of 45 S need hydraulic power output (P_{output}) excluded redundancy as:

$$P_{output} = 4/45 \quad \text{MJ/S}$$

$$= 88.89 \quad \text{kW}$$

This is a total requirement, the system can configure as a single or multiple train but the multiple ones is recommended for an easier redundancy management. The power delivery of the system is affected by several factors such as pump and motor efficiency, pressure loss due to friction and effect of ambient temperature. Thus minimum motor input and the required energy storage become:

P_{input} = $P_{output}/(Pe \times Me)$

$W_{Storage}$ = $W_{useful}/(Pe \times Me \times Be)$

Where Pe is efficiency of the pumps, assume typical value as 65%. Me is efficiency of the motor, assume the typical value as 90% for motor larger than 15kW. (Richards, A. and P. Smith, 2003). Be is battery efficiency, which is affected from the subsea ambient temperature assumed reduction by 20% and High current rate discharge assumed reduction by 80%. (Bamford, A. S., M. Teixeira, et al. 2008), thus Be is 0.16 approximately in total.

Therefore the battery bank must be able to store energy up to 64.1 MJ and able to provide 152 kW power discharge. For example, if assume 72V DC motor is used, the nominal discharge current of the batteries must be more than 2110 A in total and could be higher when the motors is starting. This is a very higher current situation that must be handle carefully. The actuators operating sequence, the motors starting sequence or higher voltage system are the examples of the solutions.

6.3.4 Weight of the system

In the demonstrating model from Bamford, A. S. and M. Teixeira (2008), the system required 3.7 MJ total energy capacity weighs approximately 500 kg including pumps, motor, battery bank and hydraulic reservoir. The approximately weight of 1 tons with similar circumstance is estimated by extrapolating the system energy required.

6.4 Other concerns

The following shall list and roughly discuss the other concern, which is related to the control system but was not included in the scope of the study.

a) Redundancy

The use of an additional SCM will reduce number of functions required to be operated by the emergency release system, and will offer significant improvement in reliability and availability when compared to conventional dual SCM architectures. This shall be justified by analysis of the cost and performance criteria of potential configurations.

b) Choke line, Kill line and Control umbilical

Without Riser, these lines are still mandatory to the operation. Therefore there are several related concerns are needed to be considered. First of all, how these lines shall be supported against the deep-water environmental and other accidental load. Ocean’s current can cause over bending in the lines and wave load might cause fatigue failure especially the high-pressure ones.

Moreover, these lines shall be whether installed as an integrated bundle or as a set of separated line. Integrated bundle get advantages, as it is easier to handle, be installed, supported and protected. On the other hand, the high-pressure fluid line cause more valuable to fatigue.

7 Conclusion and further study

The reviews and discussions on the BOP stack and its controls system accomplished in this thesis can be concluded as following. The further study for improvement as another outcome of the study is also listed as a separated part.

7.1 Conclusion

a) The BOPs

The defined Reelwell-Riserless drilling operation is limited only in the salt section, which the main subsurface risk is from well closure and pipe struck due to salt creeping. Therefore, it is recommended to utilize the dual mud gradient. The well control fluid is recommended to be Non-aqueous fluid (NAF) with density at 1.68 kg/l (14 ppg), which is designed especially to prevent salt creeping.

The BOPs rated working pressure is considered from 2 maximum pressure scenarios. Although the kick of formation fluid is considerably low, it is not negligible. The brine kick from encountering brine pocket in the salt section is the most critical case, and it might cause the BOPs to anticipate wellhead effective pressure up to 4206 psi. On the other hand, the active fluid operating pressure, which is a combination of the pressure loss and mud hydrostatic pressure, cause the BOPs to anticipate with effective pressure up to 4581 psi in the annular of the dual drill pipe. Therefore, the BOPs are recommended to design as 5000 psi rated working pressure, the next standard working pressure. However, the discussion is based on several assumptions, such as the active fluid flow rate, density and the dual drill pipe diameter, which should be reviewed progressively.

Rotating control device (RCD), although is not well control equipment, is roughly discussed in order to complete the stack's basic requirement. According to the analysis, the RCD must be able to allow stripping in or tripping out at the different pressure across the SCD (maximum movement pressure) more than 1465 psi. Then other operating pressure criteria shall be established according to recommendation from the supplier based on the maximum movement pressure. Noteworthy, decreasing well control fluid density below 1.53 kg/l shall make the requirement higher.

Because the local (Brazilian) regulation does not prescript the procedure and requirement, the BOPs stack requirement for the operation is mainly based on consideration of the risk and operational requirement. Thus, the BOPs stack is recommended to be 18 ¾" bore size, with the following components from bottom to top:

1) One subsea well head connector with 5000 psi rated working pressure to connect the stack to the well head
2) One variable bore ram that operating length cover from 6 5/8" – 7.8" drill pipe with 5000 psi rated working pressure: to seal around the drill pipe and capable to hang off the drill pipe either for temporary or preparation of emergency disconnected

3) One Blind-shear ram BOP with 5000 psi rated working pressure: to sever the dual drill pipe and other smaller object such as logging wire line and seal the well after severing
4) One Annular BOP with 5000 psi rated working pressure: to seal around the drill pipe and require by stripping operation
5) One RCD connector with rated working pressure according to the RCD static pressure: to connect/disconnect the RCD on top of the BOPs
6) One RCD with “maximum movement pressure” 1500 psi or higher
7) 5000 psi rated pressure kill line, choke line, associated valves and 3 connecting points in total, a couple in below the lowermost ram and the other between the variable bore ram and the blind shear ram

There are 2 alternatives to install and retrieve the BOP stack. Both of them needs to develop tools to connect and provide a mechanism and power to latch on the wellhead. Installing and retrieving by drill pipe do not require additional weight and modification. In contrast with the cable wire, the installation can be faster but require 2 km of large cable wire on the rig. This needs further cost/benefit analysis for consideration.

For emergency disconnect, after shearing, the disconnection procedure shall be simple as pull up the drill pipe to the surface only. Although it causes some drilling fluid spill, the amount is small. With the improvement of low toxicity fluid, this should be acceptable.

b) The BOP control system

Most of the control system basic requirements for the conventional system are still applicable for the Reelwell-Riserless. An additional requirement is to include function to control the RCD in the BOP control system to minimize complexity of the system. Then the study focuses on improvement of the conventional control system.

The discussion suggests implementation of the battery energy storage system with motor and pump, which will improve the system reliability and reduce the system’s weight significantly. The technology’s availability, spare part, and operating and maintenance procedure is also favorable. However major drawbacks of the system are it still needs to improve responding time to meet the standard’s requirement and need to develop a new subsea control module with to handle all electrical signal and high electrical current used to drive the motors.

According to the stack proposed above, the control system has to be able to deliver at least 6.00MJ to be complied with the standard. There are several factors that decrease the energy storage efficiency such as high current discharge, temperature, pump and motor efficiency. In conclusion, the battery bank has to store energy at least 64.1 MJ and able to deliver current more than 2110 A for a 72 V system. However, the system is estimated less than 1000 kg, much less than the conventional system with accumulator, and reliability improvement is expected.

7.2 Further study

This section presents suggestions for further study. They are categorized into 2 sections, further works for detail design and further works for improvement of the concept. The first suggests detail design work based on the current conclusion for the project's proceeding. The latter emphasizes to improve or review the concept to enhance the project's efficiency, safety and benefit.

a) Further work for detail design

Currently there is no variable bore ram applicable to the huge size of the dual drill pipe. Using of the fixed bore pipe ram is also not an option due to variable of diameter along the pipe. Thus, corporation with the manufacturer to develop an applicable variable bore ram for the project is mandatory. Ensuring the ram hang off load must be included in the work.

The Aluminum presents several characteristics from the steel such as non-linear elasticity, non-true-yield, hardness, and ductility. Thus, the drill pipe characteristic in the shear-blind ram is unknown. Then, further investigations in effects of these differences, shear-blind ram capability for the dual drill pipe are required. A full-scale compatibility test for the blind-shear ram to shear the actual dual drill pipe and seal the well is also recommended.

Selection of methods to install the stack needs a detail cost/benefit analysis compare between 2 methods, by drill pipe or cable wire. However both of them shall needs development of the special tools to connect the drill pipe to the stack and also provide a mechanism and power for latching and pressure testing.

The subsea battery energy storage system is needed to improve its cutting capacity, to be able to shear thicker pipe, and decrease its responding time to meet the standard requirement as it must be able to complete assigned function within 45 S. Quick discharge and high current handling system are other concerns that need to develop further.

The lines connected surface and seabed, such as choke line, kill line and the umbilical, are mandatory components to the operation. They must be designed to withstand stresses due to the deep-water environmental loads, such as fatigue and bending while maintain reliable and simple to operate with the optimal cost.

b) Further work for the concept improvement

Installing the well control package by the cable with the help of ROV is a possible solution to improve the project's efficiency. However, this concerns heavy lifting, additional weight on the rig deck and needs to develop the tool for the installation. Finally, the cost/benefit should be carried out to ensure its benefit.

According to the current solution, after the disconnection by shearing, some active drilling fluid might spill to environment unavoidably. Although the fluid is a small volume and low toxic, the stakeholder shall prefer spill none. The development of the emergency disconnection equipment or procedure to minimize this discharge is recommended.

The use of an additional SCM will reduce the number of functions required to be operated by the emergency release system, and will offer significant improvement in reliability and availability when compared to conventional dual SCM architectures. This shall be justified by analysis of the cost and performance criteria of potential configurations.

This section presents suggestions for further study. They are categorized into 2 sections, further works for detail design and further works for improvement of the concept. The first suggests detail design work based on the current conclusion for the project's proceeding. The latter emphasizes in improvement or reviewing of the concept to improve the project efficiency, safety and benefit.

8 Reference

Abicht, D. and J. V. D. Akker (2011). The 2nd Generation DC All-Electric Subsea Production Control System. OTC 21300, Offshore Technology Conference. Houston, Texas, USA.

API RP 53 (1997). API recommended practise 53, Recommended practices for Blowout prevention equipment systems for Drilling wells, Third edition. American Petroleum institute (API), Exploration and production department, Washington, USA.

API spec 16D (2004). Specification for Control systems for Drilling well control equipment and Control systems for Diverter equipment, Second edition. American Petroleum institute (API), Exploration and production department, Washington, USA.

API spec 16RCD (2005). Specification for Drill Through Equipment—Rotating Control Devices, First edition. American Petroleum institute (API), Exploration and production department, Washington, USA.

Bamford, A. S., M. Teixeira, et al. (2008). Building and Testing a Battery-Operated Subsea Shut-Off System. SPE112660, IADC/SPE Drilling Conference. Orlando, Florida, USA, 2008, IADC/SPE Drilling Conference.

Bouquier, L., J. P. Signoret, et al. (2007). First Application of the All-Electric Subsea Production System-Implementation of a New Technology. OTC 18819, Offshore Technology Conference. Houston, Texas.

BP (2010). Deepwater Horizon accident investigation report, Appendix H Description of the BOP Stack and Control System. BP. Available at http://www.bp.com/liveassets/bp_internet/globalbp/globalbp_uk_english/incident_response/STAGING/local_assets/downloads_pdfs/Deepwater_Horizon_Accident_Investigation_Report_Appendices_ABFGH.pdf

Bureau of Safety and Environmental Enforcement (BSEE) (2011). Code of Federation regulations, Title 30: Mineral Resources, PART 250 - Oil and Gas and Sulphur operation in the outer continental shelf, subpart D – Oil and Gas drilling operation, Blowout preventer requirement § 250.440-250.451. Access Mar 8th,2013. http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=&SID=3d6be6989085749cc68b014d8215becf&n=30y2.0.1.2.2&r=PART&ty=HTML - 30:2.0.1.2.2.4.68.36

Cameron Drilling systems (2007). EB702D - Shearing capacities of Cameron Shearing Rams, rev.8. Engineering bulletin. Cameron Drilling systems.

Canto, L. D. S. (2010). ANP Resolution 43: Operational Safety Management System - SGSO. SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production. Rio de Janeiro, Brazil, Society of Petroleum Engineers.

Cantu, J. A., J. May, et al. (2004). Using Rotating Control Devices Safely in Today's Managed Pressure and Underbalanced Drilling Operations. SPE/IADC Underbalanced

Technology Conference and Exhibition. Houston, Texas, SPE/IADC Underbalanced Technology Conference and Exhibition.

Cooper Cameron (2004). TC1001-04. Cooper Cameron, Cameron Division.

Donaldson, J. (2013). Project Sea sprite, the subsea/deepwater AUV-HPU. Access Apr 2nd, 2013. http://www.aogexpo.com.au/ckfinder/userfiles/files/Subsea Drilling Presentations/1530 - John Donaldson - Presentation.pdf

Dusseault, M. B., V. Maury, et al. (2004). Drilling Through Salt: Constitutive Behavior And Drilling Strategies, American Rock Mechanics Association.

French, S. (2012). Drilling Fluids – New developments and Salt formation. Angola Pre-Salt Workshop, Schlumberger. Access Apr 4th, 2013. (http://www.slb.com/resources/events/2012/angola_dw_presalt_workshop/~/media/Files/events/angola_presalt_presentations/angola_presalt_workshop_12.ashx)

Halliburton (2012). Pre-Salt. Accessed Dec 19th, 2012. http://www.halliburton.com/ps/default.aspx?navid=2115&pageid=3231

Heriot-Watt IPE (2006). Drilling Engineer. Lecture note for MSc. Petroleum Engineering, 2006/07.

John Henry Foster Co. (2012). Hydraulic Accumulators. Access Feb 2nd, 2013. http://www.jhf.com/home/products/hydraulic/accumulators.

McCurdy, P. J. A. (2009). Developments in Accumulator Technology: A Review of Fluid Power Options in Subsea BOP Control Systems. SPE/IADC 118415. SPE/IADC Drilling Conference and Exhibition. Amsterdam, The Netherlands, SPE/IADC Drilling Conference and Exhibition.

Melton, H. R., J. P. Smith, C. R. Martin, T. J. Nedwed, H.L. Mairs, D. L. Raught, (2000). Offshore Discharge Of Drilling Fluids And Cuttings -A Scientific Perspective On Public Policy, IBP44900. Rio Oil & Gas Conference. Rio de Janeiro, Brazil.

Mirrajabi, M., Nergaard, A. I., et al. (2009). Application of Reelwell Drilling Method From Floating Drilling to Address Related Challenges. SPE 123953. Asia Pacific Oil and Gas Conference & Exhibition. Jakarta, Indonesia, Society of Petroleum Engineers.

Montgomery, M. E. (1995). Inspection and testing procedures improve BOPs for HPHT drilling. Oil and Gas Journal, edition February 6th, 1995. PennWell Corporation. Access May 5th, 2013. http://www.westengineer.com/Images/Inspection and Testing Procedures Improve BOPs for HPHT Drilling_tcm161-241766.pdf

Morais, C. P. (2011). Application of the 17 Practices of the Management System for Operational Safety on Marine Installations for Drilling and Production of Oil and Natural Gas in Brazil. OTC Brasil. Rio de Janeiro, Brazil.

Nergaard, A. I. (2005). BOP control. University of Stavanger. Lecture note for MSc. Offshore Technology.

Newswires (2009). Brazil: Petrobras discovers oil in BM-S-17 Santos Basin block. Access Dec 19th, 2012. http://www.energy-pedia.com/news/brazil/petrobras-discovers-oil-in-bm-s-17-santos-basin-block

Nguyen, J. and Gabolde, G. (2006). Drilling Data Handbook 8th. IFP Publications.

NORSOK Standard D-010. (2004). Well integrity in drilling and well operations. Available at http://www.standard.no/PageFiles/1315/D-010r3.pdf

OLF 070 (2004). OLF 070 – Norwegian oil and gas application of IEC 61508 AND IEC 61511 in the Norwegian petroleum industry, P.84-85. The Norwegian Oil Industry Association (OLF). Available at http://www.norskoljeoggass.no/Global/Retningslinjer/HMS/TekniskSikkerhet/070 - Application of IEC 61508 and IEC 61511.pdf

Poiate, Edgard J., Costa, A. Maia, and Falcão, Jose L. (2006). Drilling Brazilian Salt-1: Petrobras studies salt creep and well closure. Access Mar 14th, 2013. http://www.ogj.com/oil-drilling-and-production/more-drilling-and-production.html

Reelwell AS (2011). The RDM Technology. Access Dec 19th, 2012. http://www.reelwell.no/The-RDM-Technology

Reelwell AS (2012). Operational phases, Sketches and pressure gradients for discussions. Internal presentation. Unpublished.

Richards, A. and P. Smith (2003). How efficient is your pump? Agfact E5.11, first edition November 2003. Access 16th, 2013. http://www.dpi.nsw.gov.au/__data/assets/pdf_file/0010/165196/efficient-pump.pdf

Schlumberger (2013-1), The Oilfield Glossary: Where the Oil Field Meets the Dictionary. Access Feb 21st , 2013. http://www.glossary.oilfield.slb.com/en.aspx

Shanghai Sunry Petroleum Equipment Co. Ltd. (2009). Rotating Control Device WDXK35/192-17.5/35 Service manual. Access Mar 25th, 2013. http://sunrypetro.com/download/rotating_control_device_service_manual.pdf

Shanks, E., Dykes, A., et al. (2003). Deepwater Bop Control Systems - A Look At Reliability Issues. OTC 15194, Offshore Technology Conference. Houston, Texas.

Springett, F., D. Franklin, (2007). New generation of subsea BOP equipment, controls smaller, stronger, cleaner, smarter. Drilling contractor, March/April 2008. Access Mar 15th,2013. http://www.drillingcontractor.org/dcpi/dc-marapr08/DC_Mar08_WC-NOV.pdf

Theobald, M. and Lindsey-Curran, C. (2005). Benefits Of All-Electric Subsea Production Control Systems. OTC 17106. Offshore Technology Conference. Houston, Texas.

Transocean (2011). Macondo well incident, Transocean Investigation Report. Available at http://www.deepwater.com/fw/main/Public-Report-1076.html

Transocean, (2008). Well control, HQS-OPS-HB-01, Well Control Complications/Emergency, Emergency. Access Mar 28th, 2013.

http://democrats.energycommerce.house.gov/documents/20100512/TRO-Surface.BOP.Operations.From.Floating.Vessels.pdf

Variable Bore Ram, Inc. (2013). Ram. Access May 5th, 2013. http://www.vbri.com/CatSubCat/CatSubCat.asp?p9=CSC1

Vik, E.A., Dempsey, S; Nesgard, B. (1996). Evaluation of Available Test Results from Environmental Studies of Synthetic Based Drilling Muds. OLF Project, Acceptance Criteria for Drilling Fluids. Aquateam Report No. 96-010.

Well Control School (2007). Volumetric method and Stripping operations. Training presentation. International training service, Inc. Oman training center, Muscat.

West Engineering Services (2004). Shear ram capabilities study for U.S. Minerals Management, Service Requisition No. 3-4025-1001. West Hou Inc., Houston, Texas.

Wilsons Ltd. (2013). Datasheets, Aluminium alloy, BS-L/ L168 T6511 - 2014A Bar. Access May 23rd, 2013. http://www.wilsonsmetals.com/datasheets/Aluminium-Alloy_L168-T6511-2014A-Bar_23.asmx

Wipertrip.com (2010). Subsea Blowout prevention (BOP) Equipment. Access Mar 6th, 2013. http://www.wipertrip.com/well-control/equipment/203-subsea-blowout-prevention-bop-equipment.html

Appendix A Fluid operating pressure in the drill string

A.1 Formulas

From Drilling data handbook, with assumption of Bingham fluid, smooth pipe and turbulent flow regime, the pressure loss in a tubular pipe due to friction could be roughly estimated as:

$$p_f = \frac{Ld^{0.8}Q^{1.8}\mu^{0.2}}{901.63D^{4.8}}$$

And pressure loss in the annular conduit could be roughly estimated as:

$$p_f = \frac{Ld^{0.8}Q^{1.8}\mu^{0.2}}{706.96\,(D_o + D_i)^{1.8}(D_o - D_i)^3}$$

Where;	p_f =	Pressure loss in the conduit (kPa)
	μ =	dynamic Viscosity (or Plastic viscosity for Bingham fluid) (cP)
	L =	Length of the flow path (m)
	Q =	Flow Volume (liters/min)
	d =	Fluid density (kg/liter)
	D =	Inner string's internal diameter (in)
	D_o =	Annulus outer diameter (External string's outer diameter) (in)
	D_i =	Annulus inner diameter (Inner string's external diameter) (in)

A.2 Assumption

Following assumption has been established for the calculation according to available information. Progressive review of the assumption is recommended.

μ	=	20 cP	; As recommended from an expert
Q	=	1200 l/min	; Estimated flow rate required by the bit
d	=	1.32 kg/l	; Base case from mud weight assumption
p_{bha}	=	30 bar	; Pressure loss at the BHA, recommended by Reelwell
p_{bit}	=	50 bar	; Pressure loss at the bit and motor, recommended by Reelwell
p_j	=	0.05 bar/joint	; Pressure loss across the tool joint, recommended by Reelwell

A.3 Calculation for BOP operating pressure

Friction loss Section1 (Steel)					
μ	20	cP			
Q	1200	l/min	(Base case)		
d	1.32	kg/l	(Base case)		
D	3.54	in			
Do	5.5	in			
Di	4.09	in			
L	5000.0	m			
L1/L	0.21		(Steel section/overall length)		
L1	1071.43	m	(Total steel section length)		
Friction loss in inner string (return)					
p	2182.3	kPa	=	316.5	psi
Friction loss in outer string (Pump-in)					
p	7325.4	kPa	=	1062.5	psi
Friction loss Section2 (Al)					
μ	20	cP			
Q	1200	l/min			
d	1.32	kg/l			
D	3.54	in			
Do	6.77	in			
Di	4.09	in			
L	5000	m			
L2/L	0.79		(Al section/overall length)		
L2	3928.57	m	(Total steel section length)		
Friction loss in inner string (return)					
p	8001.7	kPa	=	1160.5	psi
Friction loss in outer string (Pump-in)					
p	3127.0	kPa	=	453.5	psi
Friction loss subtotal			=	2993.1	psi

Minor loss		
Tool joint loss	0.7	psi/joint
Number of joint	357.1	joints
Tool joint loss substotal	250	psi
BHA loss	435	psi
Drill bit and mud motor	725	psi
Total loss		
Total loss	4403.1	psi

Pressure at different depth (psi)					
		Annular		Inner string	
Depth	Effective Hydrostatic	Mud P	Total	Mud P	Total
0	0	4403	4403	0	0
1000	442	4050	4492	295	738
2000	885	3697	4581	591	1475
3000	1327	3343	4670	886	2213
4000	1769	2990	4759	1182	2951
5000	2211	2637	4848	1477	3688

A.4 Calculation for RCD operating pressure

a) Operation at 2001 m below sea level

Section1 (Steel)			
μ	20	cP	
Q	1200	l/min	(Base case)
d	1.32	kg/l	(Base case)
D	3.54	in	
Do	5.5	in	
Di	4.09	in	
L	2000.0	m	
L1/L	0.21		(Steel section/overall length)
L1	428.57	m	(Total steel section length)
Friction loss in inner string (return)			
p	872.9	kPa	
Friction loss in outer string (Pump-in)			
p	2930.1	kPa	
Section2 (Al)			
μ	20	cP	
Q	1200	l/min	
d	1.32	kg/l	
D	3.54	in	
Do	6.77	in	
Di	4.09	in	
L	2000.0	m	
L2/L	0.79		(Al section/overall length)
L2	1571.43	m	(Total steel section length)
Friction loss in inner string (return)			
p	3200.7	kPa	
Friction loss in outer string (Pump-in)			

p	1250.8	kPa			
Friction loss subtotal			=	8254.5	kPa

Minor loss		
Tool joint loss	5	kPa/joint
Number of joint	142.9	joints
Tool joint loss substotal	714.3	kPa
BHA loss	3000	kPa
Drill bit and mud motor	5000	kPa
Total loss		
Total loss	16968.8	kPa

Pressure at different depth (kPa)							
		Annular		Inner string			
Depth	Mud Hydrostat	Mud P	Total	Mud P	Total	Water Hy st	1.68 Mud
0	0	16969	16969	0	0	0	0
1000	12949	14521	27470	2037	14986	9957.15	16480.8
2000	25898	12074	37972	4074	29972	19914.3	32961.6
2001	25911	12071	37982	4076	29987	19924.3	30003.5

b) Operation at 5000 m below sea level

Section1 (Steel)			
μ	20	cP	
Q	1200	l/min	(Base case)
d	1.32	kg/l	(Base case)
D	3.54	in	
Do	5.5	in	
Di	4.09	in	
L	5000.0	m	
L1/L	0.21		(Steel section/overall length)
L1	1071.43	m	(Total steel section length)
Friction loss in inner string (return)			
p	2182.3	kPa	
Friction loss in outer string (Pump-in)			
p	7325.4	kPa	
Section2 (Al)			
μ	20	cP	

Q	1200	l/min			
d	1.32	kg/l			
D	3.54	in			
Do	6.77	in			
Di	4.09	in			
L	5000	m			
L2/L	0.79		(Al section/overall length)		
L2	3928.57	m	(Total steel section length)		
Friction loss in inner string (return)					
p	8001.7	kPa			
Friction loss in outer string (Pump-in)					
p	3127.0	kPa			
Friction loss subtotal			=	20636.4	kPa

Minor loss		
Tool joint loss	5	kPa/joint
Number of joint	357.1	joints
Tool joint loss substotal	1785.7	kPa
BHA loss	3000	kPa
Drill bit and mud motor	5000	kPa
Total loss		
Total loss	30422.1	kPa

Pressure at different depth (kPa)							
		Annular		Inner string			
Depth	Mud Hydrostat	Mud P	Total	Mud P	Total	Water Hy st	1.68 Mud
0	0	30422	30422	0	0	0	0
1000	12949	27974	40924	2037	14986	9957.2	16480.8
2000	25898	25527	51425	4074	29972	19914.3	32961.6
2001	25911	25524	51436	4076	29987	19924.3	25504.1
3000	38848	23079	61927	6110	44958	29871.5	41968.4
4000	51797	20632	72428	8147	59944	39828.6	58449.2
5000	64746	18184	82930	10184	74930	49785.8	74930.0

Appendix B Shear ram selection and consideration

This appendix shows an example of the shear ram selection and checking for its shear compatibility. The method and formula use below is quoted from Cameron document "EB702d rev.b8 – Shearing capability of Cameron shear ram" (Cameron drilling systems, 2007), which has been developed to assist Cameron equipment users in defining the shearing requirements for drilling operations. The method comprise of 2 simply steps.

- Select the ram that the tubular is geometrically feasible to shear with the BOP shearing configuration under consideration by checking with maximum diameter and thickness provided in table 6
- Calculate the required Operator shear pressure according to the distortion energy equation or the formula provided by the manufacturer

B.1 Shear Ram selection

As assumed to consider the dual drill pipe shear feasibility from a single wall pipe with wall thickness equal to the summation for of the inner and outer. Then the selection shall critical at the aluminium section, as it is larger and thicker.

Aluminium section OD	198 mm	➔	7.8"
Aluminium section wall thickness	13 + 6 mm	➔	0.75"

Check in table 7:

18 ¾" - 5M/10M TL BOP with DVS (double "V" shear) ram is the only ram capable.

Table 7: Maximum thickness and diameter compatible for Cameron shear ram from Cameron EB702D rev.b8 (Cameron drilling systems, 2007)

BOP TYPE	RAM TYPE	MAX. WALL THICKNESS (IN)	MAXIMUM DIAMETER (IN)
7 1/16 3-15M U/UM BOP	SBR	N/A	3.82
	DVS	.59	3.86
	DSI	*	4.50
7 1/16 10M C BOP	DSI	*	4.50
11 5-10M U BOP	SBR	.41	5.02
	DS	*	5.80
11 15M U BOP	SBR	.46	5.02
13 5/8 5-10M U/UM BOP	SBR	.46	6.28
	DS	*	7.53
	ISR	*	7.53
13 5/8 15M U/UM BOP	SBR	.46	6.28
16 5-10M U BOP	SBR	.55	8.52
18 3/4 10M U BOP	SBR	.55	8.84
20 3/4-3M 21 1/4-2M U BOP	SBR	**	10.26
21 1/4 5-10M U BOP	SBR	.59	8.91
18 3/4 10/15M UII BOP	SBR	.42	9.70
	CDVs	.73	11.75
13 5/8 10M T/TL BOP	SBR	.52	6.29
18 3/4 5/10M T/TL BOP	DVS	.77	10.50
18 3/4 15M T/TL BOP	SBR	.56	9.70
	DVS	.55	10.50
	CDVs	.73	11.75
	SUPER SHEAR (TL ONLY)	*	16.75

B.2 Distortion energy theory

As the energy distortion equation:

S_{SY} = $0.577\ S_Y$

Where : S_{SY} = Shear yield strength

S_Y = yield strength (or Tensile strength for conservative)

= σ_Y x A

c) Steel section

A_{inner} = 1847 mm^2

σ_{Yinner} = 435 MPa (Aluminium S2014)*

A_{outer} = 6773 mm^2

σ_{Youter} = 930 MPa (Steel S135)

S_{SY} = 0.577 x [(1847 x 435) + (6773 x 930)]

= 0.577 x (803445 + 6298890)

= 4098 kN

d) Aluminium section

A_{inner} = 1847 mm^2

σ_{Yinner} = 435 MPa (Aluminium S2014)*

A_{outer} = 7556 mm^2

σ_{Youter} = 435 MPa (Aluminium S2014)*

S_{SY} = 0.577 x [(1847 x 435) + (7556 x 435)]

= 0.577 x (803445 + 3286656)

= 2360 kN

* Because Aluminium does not exhibit the true yield, the tensile stress is used for conservative.

Therefore the shear force requirement is obviously critical at the steel section.

Table 8 BOP operator constant from Cameron EB702D rev.b8 (Cameron drilling systems, 2007)

BOP Type	Operator Type	Constant, C1	Constant, C2
7-3M THRU 15M U BOP	SB	37	6
7-3M THRU 15M U BOP	SBT	75	6
7-3M THRU 15M UL/UM BOP	SB	63	6
7-3M THRU 15M UL/UM BOP	SBT	101	6
11-3M THRU 10M U BOP	SB	65	9
11-3M THRU 10M U BOP	SBT	146	9
11-3M THRU 10M U BOP	LB	107	9
11-3M THRU 10M U BOP	LBT	188	9
11-15M U BOP	SB	88	9
11-15M U BOP	SBT	176	9
11-15M U BOP	LB	136	9
11-15M U BOP	LBT	224	9
11-5M/10M UL/UM BOP	SB	114	9
11-15M UM BOP	SB	110	13
11-15M UM BOP	SBT	194	13
13-3M/10M U BOP	SB	88	13
13-3M/10M U BOP	SBT	176	13
13-3M/10M U BOP	LB	136	13
13-3M/10M U BOP	LBT	224	13
13-15M U BOP	SB	133	13
13-15M U BOP	SBT	266	13
13-15M U BOP	LB	203	13
13-15M U BOP	LBT	336	13
13-10M UM BOP	SB	110	13
13-10M UM BOP	SBT	198	13
13-10M TL BOP	SB	157	16
16-5M/10M U BOP	SB	133	20
16-5M/10M U BOP	SBT	219	20
16-5M/10M U BOP	LB	203	20
16-5M/10M U BOP	LBT	290	20
18-10M U BOP	SB	228	31
18-10M U BOP	SBT	458	31
18-10M U BOP	LB	337	31
18-10M U BOP	LBT	564	31
18-10M UII BOP	SB	242	36
18-10M UII BOP	SBT	472	36
18-10M UII BOP	LB	309	36
18-10M UII BOP	LBT	539	36
18-15M UII BOP	SB	271	36
18-15M UII BOP	LB	334	36
18-5M/10M TL BOP (ST LOCK/MANUAL)	SB	203	20
18-5M/10M TL BOP (RAMLOCK)	SB	214	20
18-5M/10M TL BOP (RAMLOCK)	SBT	293	20
18-15M T/TL BOP (ST LOCK/MANUAL)	SB	238	36
18-15M T/TL BOP (ST LOCK/MANUAL)	SBT	475	36
18-15M TL BOP SUPERSHEAR	SS	615	36
18-15M T/TL BOP (RAMLOCK)	SB	254	36
18-15M T/TL BOP (RAMLOCK)	SBT	394	36
18-15M T BOP	LB	297	36
20-3M & 21-2M U BOP	SB	88	13
20-3M & 21-2M U BOP	SBT	175	13
20-3M & 21-2M U BOP	LB	136	13
20-3M & 21-2M U BOP	LBT	223	13
21-5M & 10M U BOP	SB	256	36

B.3 Calculation of shear pressure required according to Cameron formulas

If there is any wellbore pressure effect existing at the time of the shear (e.g created by kick pressures or drilling fluid weight), the calculated shear pressure required shall then be:

$$P_{Shear} = \frac{\left(C_3 \times ppf \times \sigma_y\right) + (P_w \times C_2)}{C_1}$$

Where:

P_{shear} is the calculated required operator shear pressure (psi).

C_1 is the BOP/Operator constant corresponds to the piston closing area (in^2), obtained from Table 2.

C_3 is the Shear ram type/pipe grade constant from Table 7. This is an empirical constant obtained from laboratory testing with various pipe grades and ram types.

σ_{yield} is the minimum yield strength of the tubular material.

ppf is the nominal weight of the tubular (pounds per foot).

P_w is the wellbore pressure at the time of the shear (psi).

C_2 is the BOP/Operator constant corresponds to the operator piston rod opening area (in2), obtained from Table 7.

Table 9 Constant corresponded to shear ram type and material from Cameron EB702D rev.b8 (Cameron drilling systems, 2007)

Ram Type	Pipe Grade	Constant C3
SBR	E75	.33
	L80	.31
	X95	.30
	G105, P110 & Q125	.24
	S135	.23
DS,ISR, DSI, DVS,SS	E75	.28
	L80	.26
	X95	.25
	G105, P110 & Q125	.22
	S135	.19

To consider shearing the dual string drill pipe, using of 18 ¾" - 5M/10M TL BOP (RAM lock), single bonnet (SB) operator, and Double V shear (DVS) satisfy the requirement. So C1 from Table 7 is 214 and C2 is 20. Due to S135 material is used in steel section, C3 from Table 6 are .19 for any kind of ram except BSR (Simple blind shear ram).

The dual drill string parameter is as follow:

Wall thickness 19 mm ➔ 0.75"

Weight (ppf, assumed inner pipe additional area as steel) 69.47 kg/m➔46.68 lb/ft

σ_{yield} 13500 psi

P_w 5000 psi

Then;

$$P_{shear} = \{(0.19x46.68x13500)+(5000x20)\}/214$$

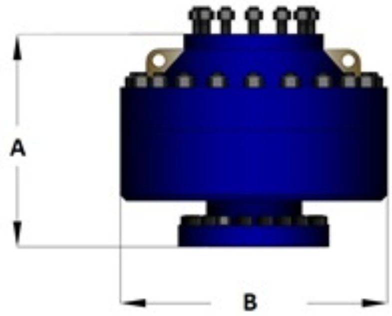
$$= 1026.80 \text{ psi}$$

Therefore P_{shear} is calculated to be 1026.80 psi

Appendix C Other engineering information

C.1 BOP information

Annular BOP (Shaffer)



Shaffer Annular BOP											
Vertical Bore Size (inches)	Working Pressure (psi)	Ring Groove (top)	Ring Groove (bottom)	Head Type	Old Nominal Size	Chamber (Closing)	Volume gal. (Opening)	Hydraulic Port Size - NPT	Height - A (inches)	Body Diameter - B (inches)	Approx. Weight (lbs)
4-1/16"	10M	BX-155	BX-155	BOLTED		2.38	1.95	.25"	25.5"	23"	1850
7-1/16"	5M	RX-46	RX-46	BOLTED	6"	4.57	3.21	1"	30.875"	29"	3175
7-1/16"	10M	BX-156	BX-156	BOLTED	6"	17.2	13.95	1.25"	42.25"	43"	10600
11"	5M	BX-54	BX-54	BOLTED	10"	18.67	14.59	1.25"	41.5"	44.25"	9550
11"	10M	BX-158	BX-158	WEDGE		30.58	24.67	2"	53"	57"	26140
13-5/8"	5M	BX-160	BX-160	BOLTED		23.58	17.41	1.25"	40.69"	50"	9500
16-3/4"	5M	BX-162	BX-162	WEDGE		33.26	25.61	2"	51.94"	60"	22900
21-1/4"	2M	RX-73	RX-73	BOLTED		32.59	16.92	1.5"	46.13"	49"	10850
21-1/4"	5M	BX-165	BX-165	WEDGE		61.37	47.76	2"	66"	71"	44500
30"	1M	BX-95	BX-95	BOLTED		122	55	2"	65.63"	71"	28750

Drawings and information contained herein are for general purposes only and is not intended to replace OEM data. Individual BOP Data may differ from one BOP to another. Please verify all information priors to use.

(Source: http://www.quailtools.com)

Single cavity BOP (Cameron)

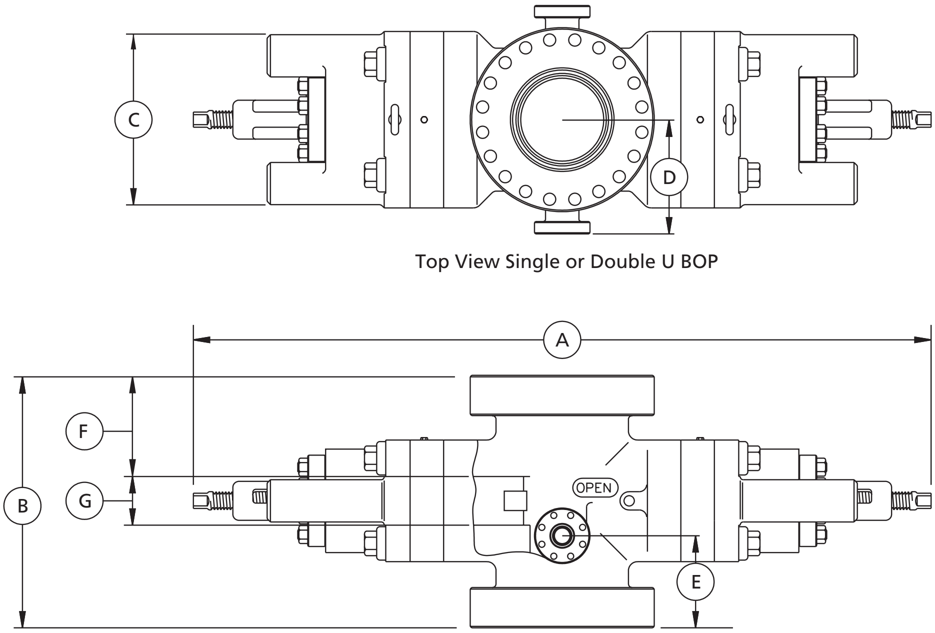
Table 10 Cameron standard single U-BOP operating data and fluid requirement (Cooper Cameron, 2004)

Bore Size and Working Pressure	Gals to Open Pipe Rams (1 Set)	Gals to Close Pipe Rams (1 Set)	Locking Screw Turns (Each End)	Closing Ratio	Opening Ratio
7-1/16" All WP	1.3	1.3	18	6.9:1	2.2:1
11" Except 15,000 psi	3.4	3.5	27	7.3:1	2.5:1
11" 15,000 psi	5.7	5.8	32	9.8:1	2.2:1
13-5/8" Except 15,000 psi	5.5	5.8	32	7.0:1	2.3:1
13-5/8" 15,000 psi Model B	10.4	10.6	45	10.6:1	3.6:1
16-3/4" 3000 psi Model B	9.8	10.6	38	6.8:1	2.3:1
16-3/4" 5000 psi Model B	9.8	10.6	38	6.8:1	2.3:1
16-3/4" 10,000 psi	11.6	12.5	45	6.8:1	2.3:1
18-3/4" 10,000 psi	21.3	23.1	54	7.4:1	3.7:1
20-3/4" 3000 psi	8.1	8.7	46	7.0:1	1.3:1
21-1/4" 2000 psi	9.0	8.7	46	7.0:1	1.3:1
21-1/4" 5000 psi	27.3	30.0	54	7.2:1	4.0:1
21-1/4" 10,000 psi	24.5	26.9	51	7.2:1	4.0:1
26-3/4" 3000 psi	10.1	10.8	58	7.0:1	1.0:1

Table 11 Cameron Large bore shear bonnet operating data and fluid requirement (Cooper Cameron, 2004)

Bore Size and Working Pressure	Gals to Open Pipe Rams (1 Set)	Gals to Close Pipe Rams (1 Set)	Locking Screw Turns (Each End)	Closing Ratio	Opening Ratio
7-1/16" All WP	-	-	-	-	-
11" Except 15,000 psi	6.8	7.0	27	12.0:1	4.8:1
11" 15,000 psi	8.9	9.0	32	15.2:1	3.7:1
13-5/8" Except 15,000 psi	10.5	10.9	32	10.8:1	4.5:1
13-5/8" 15,000 psi Model B	16.0	16.2	45	16.2:1	6.0:1
16-3/4" 3000 psi Model B	18.2	19.0	38	10.4:1	4.4:1
16-3/4" 5000 psi Model B	18.2	19.0	38	10.4:1	4.4:1
16-3/4" 10,000 psi	18.2	19.1	45	10.4:1	4.4:1
18-3/4" 10,000 psi	-	-	-	-	-
20-3/4" 3000 ps	14.3	14.9	46	10.8:1	1.7:1
21-1/4" 2000 psi	14.3	14.9	46	10.8:1	1.7:1
21-1/4" 5000 psi	-	-	-	-	-
21-1/4" 10,000 psi	-	-	-	-	-
26-3/4" 3000 ps	-	-	-	-	-

Table 12 Cameron standard single U-BOP dimension (Cooper Cameron, 2004)



Top View Single or Double U BOP

Side View Single U BOP

SD 034601

Size (in.)	Pressure Rating (psi)	Vertical Bore (in.)	A-1 (in.)	A-2 (in.)	A-3 (in.)	A-4 (in.)	B-1 (in.)	B-2 (in.)	C (in.)	E-1 (in.)	E-2 (in.)	F-1 (in.)	F-2 (in.)	G (in.)	Approx. Weight (lb)
7-1/16*	3000	7-1/16	74.00	109.50	-	-	24.06	-	20.25	8.75	-	7.84	-	5.50	2600
7-1/16*	5000	7-1/16	74.00	109.50	-	-	27.50	25.19	20.25	10.41	9.25	9.63	8.47	5.50	2800
7-1/16	10,000	7-1/16	74.00	109.50	-	-	30.56	27.19	20.63	11.06	9.38	12.03	10.34	5.50	3550
7-1/16	15,000	7-1/16	74.00	109.50	-	-	31.81	-	20.63	11.69	-	12.66	-	5.50	3800
11*	3000	11	96.25	146.88	-	-	29.06	-	25.13	9.81	-	10.53	-	6.75	5300
11*	5000	11	96.25	146.88	110.13	150.19	34.31	29.31	25.13	12.44	9.94	13.16	10.66	6.75	5600
11*	10,000	11	96.25	146.88	110.13	150.19	35.69	32.19	25.75	13.13	11.38	13.84	12.09	6.75	6400
11 Model 79	15,000	11	124.00	175.31	124.50	167.13	44.81	33.88	32.00	16.69	11.22	17.78	12.31	9.25	10,300
13-5/8	3000	13-5/8	112.13	171.50	122.69	166.06	31.31	-	29.25	10.31	-	11.53	-	7.50	7200
13-5/8	5000	13-5/8	112.13	171.50	122.69	166.06	33.81	31.94	29.25	11.56	10.63	12.78	11.84	7.50	7700
13-5/8	10,000	13-5/8	114.13	172.75	124.69	167.31	41.69	32.81	30.25	15.13	10.69	17.09	12.66	7.50	10,300
13-5/8 Model B*	15,000	13-5/8	139.00	214.38	152.25	205.50	53.69	42.00	39.50	21.38	15.50	22.84	17.00	8.00	23,700
16-3/4 Model B	3000	16-3/4	127.25	204.56	147.25	199.38	40.06	31.75	35.75	13.31	9.16	15.41	11.25	9.25	13,700
16-3/4 Model B	5000	16-3/4	129.25	202.13	149.25	202.25	43.06	34.94	35.75	14.81	10.75	16.91	12.84	9.25	13,750
16-3/4*	10,000	16-3/4	139.00	218.38	155.50	212.00	49.69	41.94	39.50	19.38	15.50	20.22	16.34	9.25	23,300
18-3/4	10,000	18-3/4	156.38	242.13	166.50	226.63	56.00	43.23	42.50	20.50	13.88	22.00	15.34	12.00	28,900
20-3/4	3000	20-3/4	143.69	226.81	163.94	223.88	40.56	33.31	39.52	14.31	10.69	16.28	12.66	8.00	13,650
21-1/4	2000	21-1/4	143.69	226.81	163.94	223.88	37.9	33.31	39.52	12.63	10.69	14.59	12.66	8.00	13,250
21-1/4	5000	21-1/4	164.25	247.25	180.94	239.25	50.94	46.13	42.50	17.97	17.19	18.72	14.69	13.50	30,000
21-1/4*	10,000	21-1/4	163.38	250.38	181.13	239.50	66.00	53.00	47.25	24.53	18.03	26.25	19.75	13.50	34,650
26-3/4	3000	26-3/4	169.63	275.38	-	-	48.31	-	46.25	17.44	-	19.91	-	8.00	24,000

* Available with stud X flange connection

Weights shown are for flange X flange top/bottom

Note: *All weights listed are based on utilizing closed die forgings.*

C.2 Aluminum Alloy // BS-L // L168 T6511 - 2014A

Aluminum alloy L168 - 2014A is a very high mechanical strength alloy used for critical applications and is the most widely used aluminum bar alloy in the aerospace industry. It has very good machinability and is thus used for the production of complex machined parts.

Alloy designations

Aluminum alloy BS L168 - 2014A has similarities to the following standard designations and specifications: 2014, AMS4121

Chemical Element	% Present
Silicon (Si)	0.50 - 0.90
Iron (Fe)	0.0 - 0.50
Copper (Cu)	3.90 - 5.00
Manganese (Mn)	0.40 - 1.20
Chromium (Cr)	0.0 - 0.10
Magnesium (Mg)	0.20 - 0.80
Zinc (Zn)	0.0 - 0.25
Nickel (Ni)	0.0 - 0.10
Titanium (Ti)	0.0 - 0.15
Titanium + Zirconium (Ti+Zr)	0.0 - 0.20
Others (Total)	0.0 - 0.15
Aluminum (Al)	Balance

Physical Property	Value
Density	2.80 g/cm³
Melting Point	640 °C
Thermal Expansion	22.8 x10^-6 /K
Modulus of Elasticity	73 GPa
Thermal Conductivity	155 W/m.K
Electrical Resistivity	40 % IACS

Temper types

The most common tempers for L168 - 2014A aluminum are:

- T6 - Solution heat treated and artificially aged
- T6510 - Solution heat treated and stress-relieved by stretching then artificially aged with no straightening after aging - Equivalent to T4 condition
- T6511 - Solution heat treated and stress-relieved by stretching then artificially aged with minor straightening after aging - Equivalent to T4 condition

Mechanical properties

These Mechanical Properties are for bar in the T6511 temper (MPa)

Diameter	Proof Strength (Min)	Tensile Strenth (Min)	Elongation % (Min)
Up to & incl 2.5	370	415	6
Over 2.5 up to and incl. 10	385	435	6
Over 10 up to and incl. 25	415	460	7
Over 25 up to and incl. 75	440	490	7
Over 75 up to and incl. 100	435	480	7
Over 100 up to and incl. 150	420	465	7
Over 150 up to and incl. 200	390	435	7

Source: (Wilsons Ltd, 2013)