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ABSTRACT

During well drilling operation, there is a possibility of a kick (influx). When a kick is not controlled properly it will become a blow out. This is an uncontrolled and sudden flow of formation fluid that releases from a reservoir through a well bore into surface as a result of pressure difference in formation and well. The kick could flow to surface and create explosions causing fatality, environment damage and loss of asset resulting in high cost. There are procedures and methods to deal with the occurrence of kicks and blowouts in order to control a well flow. Moreover, well barriers should be established and designed based on the characteristics of the reservoir and rock formation. The last line of protection in well barriers is known as Blowout Preventer (BOP). It is one of the most important barriers to prevent unintentional hydrocarbon release when all well barriers in a well have failed. There are many factors that influence the performance of a BOP. The purpose of this thesis is to determine the criticality of components in BOP related to the redundancies they have during well shut in, stripping, snubbing and BOP testing operation. By knowing the criticality of BOP components, we can assure which components that should be focused on for maintenance and testing. It will also indicate which components that gives redundancy to the BOP during well shut in, stripping, snubbing and BOP testing operation, if one or more components are failed. A literature study is the main work of this thesis. Studying the principal, functions, operations and factors related to drilling activity with respect to the use of BOP. In addition, relevant regulations and standards are also describes to specify the required specification of BOP. The analysis of criticality is done by using risk tools such as reliability block diagram, FMECA, criticality matrix, redundancy and effect table. All of these risk tools complement each other to give the final conclusion of critical component in a BOP. The result of the analysis shows five critical components in a BOP with the prioritization start from shuttle valve (blind shear ram function), blind shear ram (ram piston), flange (BOP stack), gasket (BOP stack) and annular preventer (rubber housing) respectively. In the event of kick and well shut in is initiated, the above critical component is very critical to the safety of personnel. Stripping and snubbing operation also require the critical components to be function properly, but with less critical when well shut in has been done earlier. During BOP testing operation, the critical components might not be critical if it fail as there are many safety measure and procedure for safety.

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TERMINOLOGY

Annulus	The space between two concentric objects, such as between the wellbore and casing or between casing and tubing, where fluid can flow (Schlumberger, 2012)
Blow out	A flow of formation fluids into the wellbore that cannot be controlled at surface (Schlumberger, 2012)
Bell Nipple	A pipe located on the top of a casing string that provides guidance for drilling tools into the hole .It is also called mud riser or flow stack (Schlumberger, 2012) (Goins, W., C., Sheffield, R., 1983)
Blow Out Preventer	A structure with a large set of valves and rams placed on the top of the well that can be closed when the drilling crew have uncontrolled flow of formation fluids (Subsea1, 2010)
Burst Pressure	The differential internal pressure where a joint of casing will fail. It is a key consideration for well control and contingency operation as well as an indicator in the well design process (Schlumberger, 2012)
Casing	Steel pipe used to protect the wall of the well after drilling to prevent it from collapsing and prevent the fluid in the rocks to enter the well bore. (Stoneley, R., 1995)
Caving	Rocks fragments that come from the well bore but not necessarily come from the drill bit cuttings nor drilling fluid flow (Schlumberger, 2012). It could the fragments from the broken weak or impermeable rock formations.
Completion	Assembly of down hole tubulars and equipments required to enable safe and efficient production from an oil and gas well (Odland, J., 2010)
Connection Gas	A short entry of gas into drilling fluid in the drilling operation during pipe connection as a result of mud pumping stoppage which allows gas to enter the wellbore. It is also occur as a result of swabbing effects from the drill string movement during connection (Schlumberger, 2012)
Cut set	A set of events/components in a system whose occurrence (at the same time) ensures the system to fail (Rausand, M., Høyland A., 2004)
Differential Sticking	A situation where the drill string is stick into the well bore/bore hole embedded by mud cake or filter cake and cannot be rotated (Schlumberger, 2012)
Draw Works	A large horizontal hoist carrying cable on the drilling rig used to raise and lower the drill string (Stoneley, R., 1995)
Drill Bit	The tool used to crush or cut rock. It works by scraping or crushing or both, usually as part of a rotational motion (Schlumberger, 2012)
Drill Break	A change in the rate of drilling penetration as a result of drilling into a different rock formation such as from shale into limestone (Malhotra, S., M., 2005)
Drill Collars	Tube that is used between drill pipe and bit in the drill string to provide additional weight on the bit and give more pendulum effect to the drill string (Malhotra, S., M., 2005)

Drill Stem Test	A test to determine the productive capacity, pressure and permeability of a hydrocarbon reservoir (Schlumberger, 2012)
Drill String	The steel pipe where the drill bit is attached on the bottom and which is rotated in the well during drilling. It consists of section(s) with a length of 30 ft (Stoneley, R., 1995)
Drilling Fluid/Mud	A fluid that is used in drilling operation that contains solid suspensions, mixtures and emulsions of liquid, gases and solids (Schlumberger, 2012)
Emergency Disconnect Package	A package which enables quick disconnection between marine riser and blow out preventer (BOP) in case of emergency (Subsea1, 2010)
Equivalent Mud Weight	specific weight of drilling mud that is exerted to hold the pressure of the formation fluid in the equivalent value (SPE E&P, 2011)
Flowing Well	A well that has enough natural pressure from reservoirs to flow oil without the aid of pump (Schlumberger, 2012)
Gas-Cut Mud	A drilling fluid that is contaminated by gas causing reduction in its density (Schlumberger, 2012)
Hydrostatic Pressure	The pressure exerted by a fluid at rest. It increases along with the density and depth of the fluid and is expressed in pounds per square inch (psi) (Malhotra, S., M., 2005)
Kelly	The top section of the drill string, square or hexagonal in cross section. It is used to transmit rotary motion from the rotary table or kelly bushing to the drillstring, while allowing the drill string to be lowered or raised during rotation (Schlumberger, 2012)
Kelly Bushing	An adapter to connect the rotary table to the kelly (Schlumberger, 2012)
Kick	An incoming flow of formation fluid into the wellbore that can be controlled at surface (Hawker, D., 2001)
Kill	Stop the flow of fluid inside the wellbore by circulating higher mud weight to balance the pressure in the well when influx (kick) occur (Schlumberger, 2012)
Landing String	A tool to facilitates well control during completion and workover operations (Subsea1, 2010)
Log (Logging)	The examination of one or more physical characteristics in or around a well against the depth or time or both (Schlumberger, 2012)
Lower Marine Riser Package	A package that makes a quick disconnection between marine riser and blow out preventer (BOP) in case of emergency (Subsea1, 2010)
Lower Riser Package	A package which enables well control in case of emergency (Subsea1, 2010)
Marine Riser	A pipe connection between drilling platform and Blowout Preventer (BOP) on the seafloor (Subsea1, 2010)
Minimum cut set	A cut set that cannot be reduced without losing its status as a cut set (Rausand, M., Høyland A., 2004)
Minimum path set	A path set that cannot be reduced without losing its status as a path set (Rausand, M., Høyland A., 2004)

Nipple	Part of a pipe which have threaded section at both ends with male threads (Schlumberger, 2012)
Open Hole	Parts of a well that are not protected with casing (Schlumberger, 2012)
Path set	A set of events/components in a system whose occurrence (at the same time) ensures the system to function (Rausand, M., Høyland A., 2004)
Pay/Pay Zone	A reservoir or portion of a reservoir which contains economically producible hydrocarbons (Schlumberger, 2012)
Perforation	The path or channel in the final casing or liner that gives communication into the reservoir formation where hydrocarbon is produced (Schlumberger, 2012)
Rate of Penetration	A rate of how fast the bit drills into formations, usually expressed in feet or meters per hour or minutes per foot (meter) (Malhotra, S., M., 2005)
Rotary Table	The rotating part of the drill floor that supplies power to rotate the drill string in a clockwise direction (Schlumberger, 2012)
Shut In	Sealing a well to protect against kick by closing BOP and chokes (Malhotra, S., M., 2005)
Slips	A device used to grip and suspend the drill string on the rotary table (Schlumberger, 2012)
Snubbing	The process of placing drill pipe into the well bore by pushing it down when the BOPs are closed and pressure is contained in the well. The pushing force is necessary because the pressure inside the wellbore exerting the pipe upward. It is important because well kill operations should always be conducted when there is drill pipe inside the well bore. (Schlumberger, 2012)
Spacing out	measurement of average length of drill pipe in the well to prevent the BOP close on tool joints or drill collar (Well Control School, 2004)
Stand	The number of joints of pipe that can be pulled and stood back at one time by the rig, e.g., double or triples (GEKEngineering, 2010)
Stripping	The process of placing drill pipe into the well bore by its own weight when the BOPs are closed and pressure is contained in the well. It is important because well kill operations should always be conducted when there is drill pipe inside the well bore. (Schlumberger, 2012)
Swabbing	The situation where drilling fluid tends to follow the drill string as it is pulled from the hole causing a reduction in well/annulus (Malhotra, S., M., 2005)
Thief Zone	A formation encountered during drilling into which circulating fluids can be lost (Schlumberger, 2012). Usually as a result of large open pores in the formation where sealing mud filter cake cannot be formed (Westergaard, R., H., 1987).
Transition Zone	A zone where the type of flow is changing as a result of gas breakout, gas expansion, shear or turbulence (SPE E&P, 2011)
Trip Margin	An amount of additional mud weight that is used to balance the reduced mud pressure in the well bore as a result of swabbing effect when performing tripping out of the hole (Malhotra, S., M., 2005)

Trip Tank	A small mud tank with a capacity of 10-15 barrels (1590–2385 liters) usually with 1 barrel or 0.5 barrel (159 or 79.5 liters) divisions, used to make sure the required amount of mud when it is displaced by drill pipe (Malhotra, S., M., 2005)
Tripping	Pulling out or replacing the drill string from the hole to change the inefficient and dulled drill bit (Schlumberger, 2012)
Tool Joint	The enlarged and threaded ends of joints of drill pipe used as a pipe connection (Schlumberger, 2012)
Tool Pusher	Supervisor for the drilling contractor to accommodate administration including materials, spare parts and crew's quality assurance for efficient operations (Schlumberger, 2012)
Top Drive	A pipe rotation mechanism in the travelling block section used to turns the drill string. It is suspended from the hook, so the rotary mechanism is free to travel up and down the derrick (Schlumberger, 2012)
Tubing Hanger Running Tool	Tools for installation/retrieval of tubing hanger (Subsea1, 2010)
Underground Blowout	An uncontrollable flow of fluids from one formation into another weaker formation through wellbore. One formation could make a kick while at the same time another formation is losing circulation (Hawker, D., 2001)
Weight on Bit	The additional weight on a drill bit by adding drill collars to improve rate of penetration (Malhotra, S., M., 2005)
Wellhead	The equipment used to seal and control the flow of fluids from the well that is attached on the top of the well and act as an interface between the X-mas tree/tubing hanger and the well. (Odland, J., 2010), (Subsea1, 2010)
Workover Riser	A pipe connection between the drilling platform and the landing string deployed inside the marine riser to give the availability of circulate fluid, test production, well control and deployment of wireline tools (Subsea1, 2010)
Wireline	Activities related to logging which employs an electrical cable to lower tools into the wellbore and to transmit data (Schlumberger, 2012)
X-mas Tree	A structure consists of control valves, pressure gauges and chokes located at the top of a well where the primary function is to control the flow into or out of the well (Odland, J., 2010)

ABBREVIATIONS

f	feet
g	gravity (specific gravity)
m	Meter
psi	Pounds per Square Inch
AAV	Annulus Access Valve
AMF	Automatic Mode Function
AP	Annular Preventer
BOP	Blow Out Preventer
BSEE	Bureau of Safety and Environmental Enforcement
DST	Drill Stem Test
EDP	Emergency Disconnect Package
EMW	Equivalent Mud Weight
ETA	Event Tree Analysis
FCP	Final Circulating Pressure
FMEA	Failure Modes, Effect Analysis
FMECA	Failure Modes, Effect and Criticality Analysis
FTA	Fault Tree Analysis
GOM	Gulf of Mexico
HCR	Hydraulically Controlled
KT	Kick Tolerance
LMRP	Lower Marine Riser Package
LOT	Leak Off Test
LOP	Leak Off Pressure
LPR	Lower Pipe Ram
LRP	Lower Riser Package (LRP)
MAASP	Maximum Allowable Annular Surface Pressure
MPR	Middle Pipe Ram
MTTF	Mean Time To Failure
MTTR	Mean Time To Repair
MW	Mud Weight
NCS	Norwegian Continental Shelf
OCS	Outer Continental Shelf
PLMV	Production Lower Master Valve
PMV	Production Master Valve
PUMV	Production Upper Master Valve
PPG	Pounds Per Gallon
PWV	Production Wing Valve
P&ID	Piping and Instrumentation Diagram
QRA	Quantitative Risk Analysis
ROP	Rate of Penetration
ROV	Remotely Operated Vehicles

RPN	Risk Priority Number
SCR	Slow Circulating Rate
SEM	Subsea Electronic Module
SG	Specific Gravity (gm/cc)
SICP	Shut In Casing Pressure
SIDPP	Shut In Drill pipe Pressure
THRT	Tubing Hanger Running Tool
TVD	True Vertical Depth
UPR	Upper Pipe Ram
WOB	Weight on Bit

1. INTRODUCTION

1.1 Background

Safety during drilling operations is the most important aspect to be considered. Procedures, design, specifications and requirements of all aspects of drilling activities are established to make sure that the operation is safe. All companies and organizations which participate in drilling operations should perform and implement their activities to valid and approved standards and regulations. Standards and regulations vary for different geographic areas, due to many factors such as government policies, level of safety, environmental and geographical condition, etc. It should also be updated continuously to meet the specific needs and requirements which are relevant to present situation.

There are many problems that might occur during well drilling operations, particularly for subsea well drilling where remoteness and access become challenges during operations. One of the main issues that could result in a catastrophe is the occurrence of kick (influx). Kick is described as the unwanted influx of formation fluid into a wellbore during drilling operation as a result of pressure difference in the wellbore. This influx is unwanted because it can flow into surface and create blowout which can harm people's lives, the environment and cause property damage. The pressure inside wellbore, which is exerted by drilling fluid through drill bit, should be higher than the pressure from the formation fluid in order to make a controllable well drilling. This is known as overbalanced pressure condition. Safety precaution should be established for procedures and equipments to handle kicks and blowouts. The blowout preventer (BOP) is one of several barriers in the well to prevent kicks and blowouts and it is the most important and critical equipment as it becomes the last line of protection against blowout. The BOP is a structure with a large set of valves and rams placed on the top of the well that can be closed when the drilling crew have uncontrolled flow of formation fluid in the wellbore. If the BOP is not working properly during a kick, it will keep the well open and which can lead to a kick flow to surface and it can become a blowout.

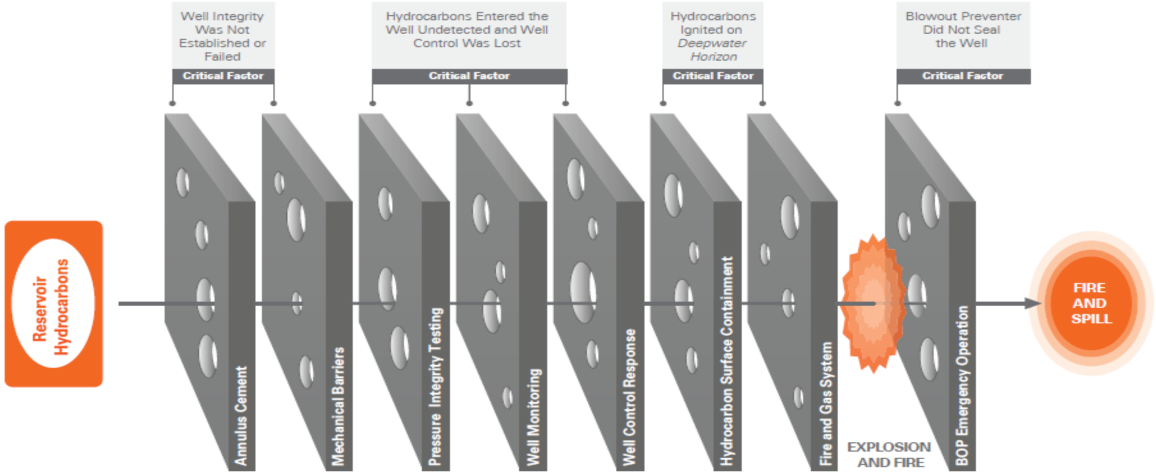


Figure 1.1 Barrier failures in the Deepwater Macondo Accident (BP Investigation Team, 2010)

Figure 1.1 shows an example of how barrier failures escalated into a disaster at the Macondo Deepwater Horizon accident on 20 April 2010. In this case the last and very critical barrier, the blowout preventer, failed causing uncontrolled explosion and fire resulting in eleven losses of lives, massive oil spill, environmental damage, loss of asset and reputation as well as the impact on cost. According to the BP Investigation Team (2010) the causes of the barrier failures were not only from technical problems, but also from other factors such as human error, management and organizational issues. Some of them are related to the discrepancies of the standard and requirement for the drilling operation, particularly for BOP maintenance, procedure and operations. Therefore it is very important to identify and describe the critical components in a BOP to ensure the functionality of BOP by having the right components that should be put more focus for maintenance and testing.

1.2 Purpose

The purpose of this thesis is to determine the criticality of components in BOP related to the redundancies they have for well shut in, stripping, snubbing and BOP testing operation.

1.3 Content

This thesis describes general activities of drilling and the problems that might occur such as kicks and blowouts. The blowout preventer (BOP) as the main barriers against kicks and blowouts is the main focus in the report. Work principles, components and the use of BOP for different operations are described. The analysis of critical component in a BOP during drilling operation is discussed. To support the analysis of the criticality, some risk assessment tools are used such as reliability block diagram, failure mode effect and criticality analysis (FMECA), criticality matrix, redundancy and effect table. Standards and regulation regarding to the requirements of BOP are identified to make sure the alignment of the analysis against them.

To provide a thorough knowledge, this thesis consists of some chapters which are structured in sequence. Chapter one, gives a background, purposes, content, methodology and limitation of the thesis. Second chapter presents the general operations of drilling and how kicks can be evaluated. Kicks and blowouts as part of the problems in drilling operation are described together with its causes and indications. In order to cope with kicks problems, basic well control principles are described in chapter three. The equipments needed to control and eliminate kicks such as BOP stack and BOP control system are described in chapter four. These equipments are somehow should have redundancy in order to ensure the availability and reliability of the functions. The minimum redundancy requirements are described in chapter five including other general requirements for the design of BOP. It refers to a company policy (Sedco Forex and Schlumberger) and local regulations BSEE for OCS (e.g., GOM). The use of BOP in drilling operations is described in chapter five. It includes some procedures for conducting well shut in, stripping, snubbing and testing of BOP. In order to conduct criticality analysis of blowout preventer, the suggested risk tools is presented and discussed in chapter seven. It includes reliability block diagram, FMECA, criticality ranking, criticality matrix, redundancy and effect table as the main discussion. The analysis of criticality by using the suggested risk tools is presented in chapter eight. Chapter nine present and discuss the result of criticality analysis of component in BOP as well as a discussion with regards to the use of BOP in drilling operations. Some conclusion, recommendation and suggestion for further works are presented in chapter ten. The rest of the report consists of references and appendices presented in chapter eleven and twelve.

1.4 Methodology

The methodology use in this thesis is an integrated process of guidance from supervisors, discussion with practitioners, literature study through textbooks and publications to describe drilling activity in general and to focus on the BOP by defining its function, principal, components, characteristics and operations. Relevant factors that influence the criticality of components in a BOP are described and analyzed through the literature study, aid of supervisor and practitioners. In order to analyze the criticality component of BOP, some suggested risk tools are presented and discussed. It includes reliability block diagram (RBD), failure modes, effects and criticality analysis (FMECA), criticality ranking, criticality matrix, redundancy and effect table. All of these methods are complement to each other to support the decision of the critical component in a BOP.

1.5 Limitation

This study is intended to analyze the criticality of component (barriers) in a subsea BOP. It is only focus to the components of BOP in the general stack arrangement and general control system. The analysis is conducted related to the drilling operations where the BOP is used as it gives the most contribution for the occurrence of kicks. The discussion and analysis are to some degree refers to general operations of drilling due to many variations in applications for drilling technologies, methods, government and company regulation. Moreover, the analysis is limited to qualitative approach as there is a scarce of quantified data and the limited amount of time for the works of the report.

2. BASIC WELL DRILLING CONCEPT

2.1 Drilling and Completion

Drilling an oilfield is an elaborate tasks which consists of drillers, complex machineries, tools and equipments that are use to drill a well up to five to six miles below the ground to reach hydrocarbon reservoirs as efficiently and as safely as possible. All necessary equipments are mostly driven from a drilling rig which is use to lower a set of steel string carrying drill bit to make a hole and to pull it out again (Stoneley, R., 1995). Drill rigs have their own specifications and equipments needed to perform the drilling, but generally it can be as shown in the figure 2.1 below.

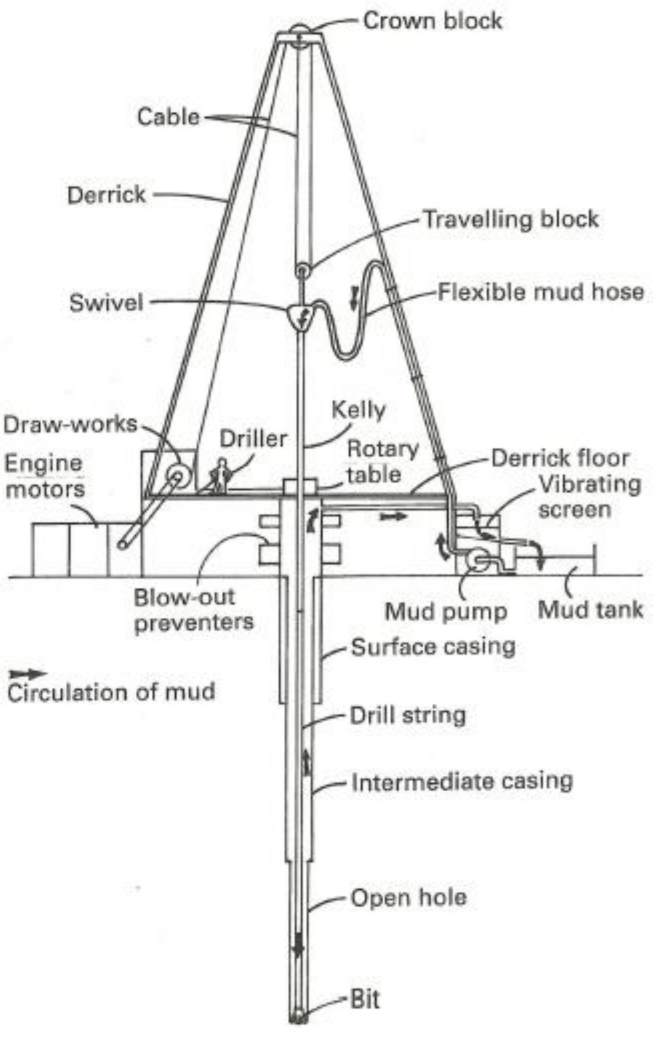


Figure 2.1 The important parts of the drilling rig (Stoneley, R., 1995)

The drill bit is connected to the bottom of the drill string where the drill collars can be attached on it to add more weight which is necessary to give more efficient force to break rock formation. Lowering and raising these sets of drill pipes are done by means of draw-works which is connected to the travelling block. It also used to endure most of the weight of the drill string(s), drill bit and drill collar(s). The drillers should monitor the required weight of the bit to control the amount of the added weight applied.

Drill string and drill bit are both rotated by rotary table where kelly bushing are attached and connected to the drill string via kelly. The rotary table itself is driven by rig motor.

Alternatively a top drive could be used instead of rotary table. A top drive is a device that turns the drill string(s) from above where it is suspended from the hook (travelling block), so it gives free vertical movement while rotating. Kelly and kelly bushing allow connection between drill strings as the well is drilled deeper while maintaining its flexibility to rotate, raise and lower the drill string and the drill bit.

Debris and cuttings of rock during drilling are carried out from the well bore into the surface by drilling fluid (mud) to be collected, examined and logged. The rock sample gives information about the formation of rock in the different depths of a well and also to give indication for the potential hydrocarbon location. Moreover, drilling fluid lubricates and cools the drill bit, balances the pressurized formation fluid that flow in the well bore and cleans out the hole. Figure 2.1 shows the flows and circulations of drilling fluid which is pumped from the mud tank into the kelly through flexible mud hose, down the hole of the drill string until it reaches and out from drill bit, goes up again to the surface carrying debris through annulus and vibrating screen to separate debris and cuttings from the mud before it end up in the mud tank again. The volume in the mud tank and the composition of mud after circulation could be a good indicator for the integrity of the well.

Protecting the wall of the hole after drilling is important to prevent it from collapsing, loss of circulation and withstand the hole from the kick. Casing is established in some depth of the well and the diameters (sizes) are varies according to the depth and formation characteristics. Generally, the deeper the depth, the less the diameters and sizes are. There are several concentric casing that would be required in the well such as conductor casing, surface casing, intermediate casing and production casing. In some depths of the well, usually where the production casing and production tubing are in place, packer would be placed in their annulus to make sure it seals completely.

Another kind of protection is blow out preventer (BOP). It is used to close and seal the well if the drilling crew loss control of formation, also known as kick and blowout. It is attached on the top of the well and consists of some types of rams that can be used for different purposes when closing a well in the emergency situation. BOP is very critical to the safety of the crew, the rig, and the wellbore itself (Subsea1, 2010).

Cementing job is important after casing has been placed in order to prevent the loss of drilling fluid and to seal the annulus between casing and well bore by filling it with proper cement so there is no spaces in the annulus. Primary cementing is placed right after the casing has been run into the hole and if deficiency occurs, then secondary cementing might be done. Casing and cementing operations are parts of the well completion during drilling operation. Drilling and completion operations usually are in line as they are acted as complement to each other to make a good well integrity.

Offshore drilling operations have quite similarities with the onshore drilling as mentioned above. There are some differences in the equipments used particularly during completion as it is drilled from the seabed. Marine riser, work over riser, lower marine riser package (LMRP), lower riser package (LRP), emergency disconnect package (EDP), landing string and tubing hanger running tool (THRT) might be used. There are many different systems and approaches that can be used, but the most common systems are landing string systems for running in marine riser, simplified landing string systems for running in marine riser, open water systems with workover risers and riserless open water system (Subsea1, 2010).

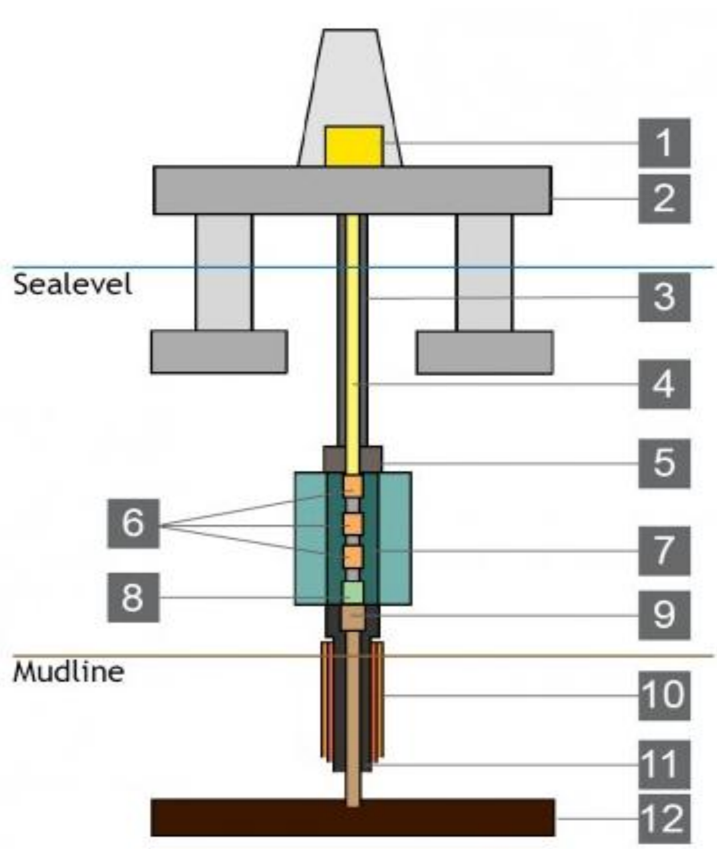


Figure 2.2 Completion by using landing string systems for running in marine riser (Subsea1, 2010)

Figure 2.2 shows the example of completion by using landing string systems for running in marine riser. The number of components can be listed as follows (Subsea1, 2010) :

1. Surface Flow Tree
2. Rig
3. Marine riser
4. Workover riser
5. LMRP
6. Landing string
7. BOP
8. THRT
9. Tubing hanger & X-mass tree
10. Wellhead
11. Completion/tubing
12. Well

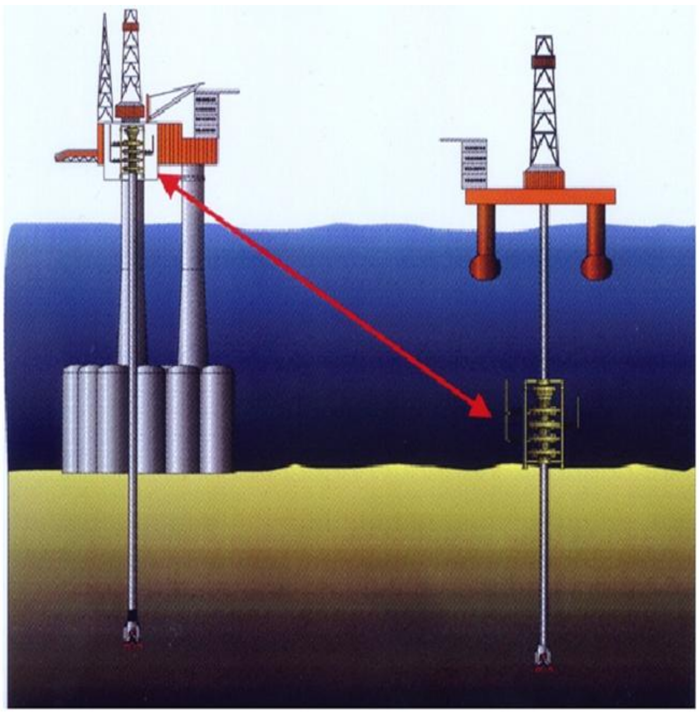


Figure 2.3 Surface and Subsea Tree (Odland, J., 2010)

The offshore drilling can be done from fixed structures (e.g. jacket platform, gravity based platform, etc) or floating structures (e.g. semisubmersible platform). To secure the position of drilling on the seabed, subsea drilling template might be used. Blow out preventer and X-mass tree could be installed on the platform (surface/dry tree) for fixed platform or on the sea bed (subsea/wet tree) for floating platform where the well head is attached on the seabed.

The tree is installed by replacing (removing) BOP during completion operation when drilling is finished and the well is ready for production. To start production, perforation is conducted by making a hole in the casing and formation. The hole in the formation will make a differential pressure which allows the hydrocarbon to flow from high pressure reservoir into the lower pressure of well and up to the surface. The flow of the fluid is control by the tree. The design, installation, operation and maintenance for surface trees are simpler than for wet tree.

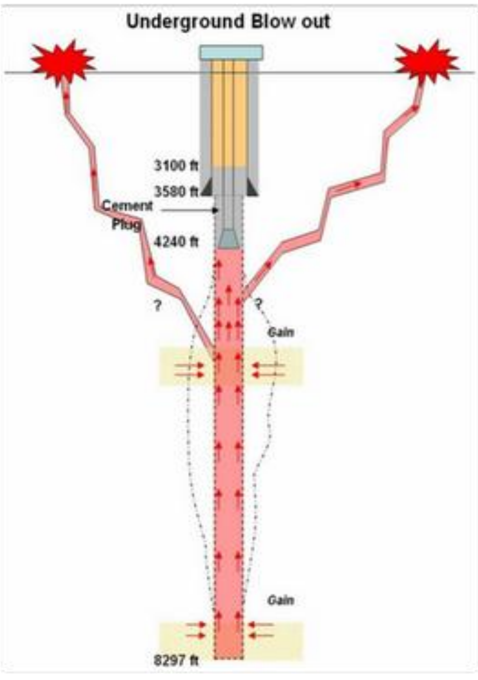
The design of well construction is different from one area to other area, it depends on the location (depth) of the reservoir, layers of rocks that should be drilled, drilling fluid, pressure, temperature, integrity, fracture strength, hole stability of the formation, the available equipment, the economic operation and most importantly the safety of personnel. Here is an example of typical well construction in the North Sea (Odland, J., 2010), (Serene Energy, 2010):

1. Drill 30" – 36" hole to approximately 120 m below seabed by using sea water as a drilling fluid. To place the conductor, it can also be done by using piling technique.
2. Set conductor of 30" diameter.
3. Drill 26" surface hole to approximately 500 m by using mud as a drilling fluid.
4. Run and set 20" surface casing.
5. Cement surface casing and wellhead housing is installed on the top of the casing to provide the weight support of the casings that will be installed after. The BOP is also installed on the top of the casing to anticipate the possibility of high pressure formation fluid that might contain in the next drilling phase.
6. Drill 17½ " intermediate hole to approximately 1800 m.
7. Run and set intermediate casing (13 3/8").
8. Cement intermediate casing.
9. Drill 12 1/4" hole to top of reservoir. In this dept there would be a possibility of hydrocarbon presence in the formation and the sample of drill cutting are collected and examined. The formation in the well is also examined by using wireline technique to know the porosity of the rocks, shale and sands. Drill stem test can also be performed here after knowing the possibility of potential hydrocarbon and the formation fluid that flows in the well.
10. Run and set production casing (9 5/8")
11. Cement casing.
12. Drill 8 ½" hole.
13. Run, set production tubing (7") and placed packer in the annulus between production casing and production tubing
14. Remove BOP and replace with Xmass tree
15. Perforate and production

2.2 Kicks and Blowouts

During drilling operations many problems that can occur such as casing collapse, casing burst, kick, blow out, leaking tube, gas filled casing, etc. Kick and blow out could result in the most catastrophe event in the term of costs, assets, environmental damage and personnel safety when its occurrences and escalations are not handled properly. A kick should be detected early before it reached surface and become a blow out. The crew who work with drilling activities should understand the behaviors and characteristics related to the kick as well as the principles, the causes, the warning signs and the indicators. Drilling and tripping activities are contributing the most for the kick event to occur. In addition, it is also very important to comprehend the theories and procedures for well control operations.

The causes of kicks and blowouts are principally a result of pressure difference in the annulus between the wellbore and the formation. The pressures that are exerted from the drilling fluid should balance the pressure from the formation fluid. It should be larger than the pressure of fluid from the formation. However, the drilling fluid pressure could not be larger than the fracture pressure in the formation which can cause a formation fracture. When fracture occurs, there will be a diversion flow of drilling fluid (mud) into the fracture area resulting in a loss of mud circulation which reduces hydrostatic pressure in the annulus allowing formation fluid to flow up through the annulus and possibly to the surface. Moreover, the fractured formation allows high pressure fluid to flow inside it and if the formation is weak the flows could break the weaker formation above and reach the surface on any random location known as cratered blowout. The blowout will make well control operations become harder.



Kick is occur when the pressure of drilling fluid (mud) in the wellbore has less pressure than the pressure flows in the formation fluid, whether as a result of the loss of mud circulation or increase pressure in the deeper formation, making an unwanted influx of formation fluid into the wellbore. A blowout (surface blowout) occur when an uncontrolled kick in the wellbore reaches the surface, endanger the safety of rig, personnel and environment. Underground blowout occurs when the uncontrolled flow of formations is flowing into another weaker formation.

Figure 2.4 Underground blowouts from a well reach surface (Chu, D., L., 2010)

Blowout could occur when there are some failures in the equipment, operations caused by human error and the force of nature such as annular losses, poor cement, casing failure, swabbing, low density of mud weight, tubing plug failure, well test string failure, gas cut mud, unexpected high well pressure, trapped gas behind casing, shallow gas, etc (Hauge, S. et al., 2011).

Drilling from a floating platform gives another challenge when bad weather occurs or when there is a problem with station keeping. The platform might have to disconnect LMRP from BOP and the well is shut in. If there is a kick and the well is not stable a blowout might occur. Ship or platform collision could also become an indirect cause of a blowout. Gas blowout around the pipe could sink a floater in a relatively shallow water as a result of decrease buoyancy (Goins, W.,C., Sheffield R., 1983).

The well need to be shut in when there is a kick and surface shut in pressure is required to add more pressure balance in the bottom hole of the well which gives additional pressure that are already exerted by drilling fluid (mud hydrostatic). Both pressures (surface and drilling fluid pressures) should not exceed the maximum fracture pressure in the formation and there would be a maximum allowable annular surface pressure (MAASP).

$$P_{frac} > P_{hyd\ at\ shoe} + P_{shut\ in\ (MAASP)}$$

Therefore, $$MAASP = P_{frac} – P_{hyd\ at\ shoe}$$

In addition to the maximum annular surface pressure, we also need to know the maximum pressure that can be exerted by drilling mud without fracturing the formation called kick tolerance (KT).

$$KT = [TVD_{shoe} \text{ x } (P_{frac} – MW)] / TVD_{hole}$$

$$KT = \frac{TVD_{shoe} \times (P_{frac} - MW)}{TVD_{hole}} - \frac{[influx\ \ height \times (MW - gas\ density\ )]}{TVD_{hole}}$$

2.2.1 Causes of Kick

Kick occurs when there is underbalanced pressure in the well. The under balance could occur principally when there is a deviation in the drilling fluid volumes and pressures that are acted in the well. According to Rig Train (2001), the main causes of kick are failing to fill the hole properly when tripping, swabbing in a kick while tripping out, insufficient mud weight, abnormal formation pressure, lost of circulation, shallow gas sands and excessive drilling rate in gas bearing sands.

a. Deviation in the drilling fluid as a result of:

    i. Tripping

    Tripping will create additional volume of drilling fluid that need to be filled in the well replacing the volume of the pulled pipe/string. If the volume of the drilling fluid is reduced or not maintained properly, there will be a reduction in the hydrostatic pressure in the drilling fluid giving the possibility of formation fluid to enter the wellbore. In this case keeping the hole full when drill string are pulled from the hole is very important

ii. Fracture formation

Fracture could happen naturally in the formation or when it is not strong enough to hold the pressure coming from the drilling fluid. It will lead to a deviated drilling fluid flow from annulus into formation resulting in a loss of mud circulation in the well and reduces well pressure. The loss of circulation could also happen when the drilling fluid flow into thief zone. According to Nas (2011), the fracturing of formation could be the result of excessive in drilling fluid density, surface back pressure and annular circulating pressure. In addition, pressure surges related to pipe movement and breaking circulation could also become the source of fracture formation.

iii. Insufficient mud weight

Principally when the drilling fluid hydrostatic is less than the hydrostatic exerted by the formation, there will be influx in the wellbore. Insufficient mud weight can be the result of unexpected penetration fluid from abnormally high pressure zone. Dilution of mud weight with water, for example in mud tank, could also become the causes of insufficient mud weight. In addition, mud weight are reduced intentionally for the underbalanced drilling operation (Rig Train, 2001)

b. Deviation in the hole pressures as a result of:

i. Swabbing and surging

Swabbing is the situation where drilling fluid tends to follow the drill string as it is pulled from the hole causing a reduction in well/annulus (Malhotra, S., M., 2005). According to Hawker (2001), swabbing effect could be overcome by having a slower speed when pulling the pipe and maintain low mud viscosity

ii. Excessive rate of penetration (ROP) during drilling in the gaseous formations could create the release of gas into the hole and it will give some void in the drilling fluid resulting in loss of annular pressure. The characteristics of gas can be described with the relationship between pressure, volume and temperature. Pressure and volume varies inversely with temperature (PV/T) with the constant value. The pressure will be higher in the deeper depth and vice versa. From here we can see that when we have a constant value of PV/T, half pressure (half depth) will result in double volume and vice versa. In application, gas will have double volume as the depth is reduced into half. Therefore, the volume of gas in the surface is much bigger compare to the volume of gas when it is still in the bottom of the hole.

iii. Underpressured formations could occur when there is a fracture resulting in diversion of drilling fluid that creates loss of circulation

iv. Overpressured formations occur when the pressure in the formation exceeds the annular pressure.

v. Shallow gas

In most cases of gas influx, gas is much lighter than the normal drilling mud hydrostatic causing fast flow of gas up to the surface. The behavior of gas that can expand as the pressure is reduced resulting in quick migration of gas from the wellbore into the surface. This situation is very critical to the operator as they must act quickly and properly to know the sign of influx and the treatment of gas influx. Furthermore, it is also very dangerous to the integrity of the hole, particularly when the drilling progress is still in the shallow depth. In the shallow hole, the short surface casing is placed in a relatively weak formation giving the possibility of fracture and broaching. It is necessary to divert the flow of gas influx instead of shut in the well to reduce the risk of formation fracture. In case of gas influx during drilling from floating platform, the occurrence of fracture on seabed which gives expanding air bubbles could cause instability to the platform and even could sinking the platform. The risk for shallow water drilling is higher than drilling in the deeper water.

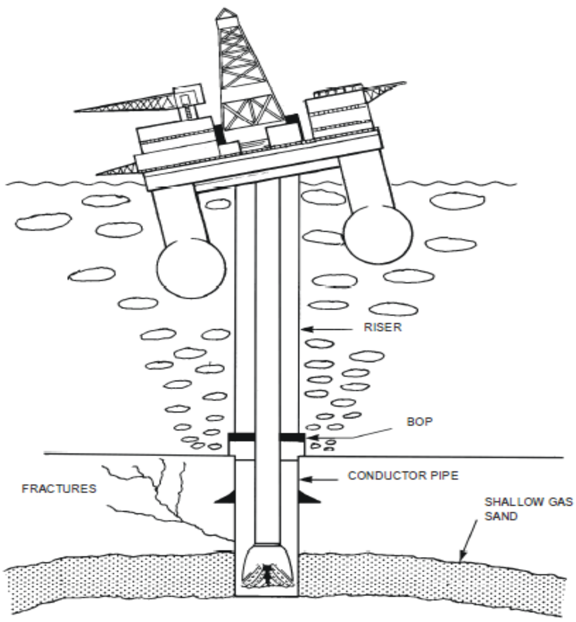


Figure 2.5 Loss of stability in shallow gas kick (Rig Train, 2001)

2.2.2 Kick Warning Signs

According to Hawker (2001), there are a number of signs that are potential to become a kick and can be categorized in three areas such as shown in table 2.1 below.

Table 2.1 Indicators of the occurrence possibility of kicks (Hawker, D., 2001)

Area	Indicators
Lost Circulations Zones	- Large surge pressures (sign of formation fracture and loss of circulation) - Increase in ROP and irregular torque (sign of fracture formation) - Reduction in the volume of the returned mud (indicate loss of fluid into formation)
Transitional Zones	- Increase in ROP - Increase in gas levels - The occurrence of connection gas - Hole instability indications such as irregular torque, drag, etc - Increase in mud temperature - Increase in cutting volumes - Reduce shale density
Sealed Overpressured Bodies	- Immediate change in ROP (indicate pressure differential and high porosity in the formation)

The indication of kicks are varies according to the permeability of the formation and the pressure exist in the hole. Goins and Sheffield (1983), mentioned some indications of kick in different pressure and permeable formation.

Table 2.2 Indicators of the occurrence possibility of kicks (Goins, W.,C., Sheffield, R., 1983)

Area	Indicators
Very permeable formation underbalanced by mud pressure	- Increasing flow rate and pit volume - Reduction of drill pipe pressure and increasing pump rate

Very permeable formation slightly underbalanced by mud pressure	- Initially small rate of flow and slow pit level gain
	- Expansion of gas at surface causing :
	    - Reduction in bottom hole pressure
	    - Rapid increase of flow in the bottom
	    - The occurrence of drilling break

Low permeability formations underbalanced by mud pressure	- Slow rate of pit gain level and gas cut mud
Formation with slightly overbalanced by mud Pressure	- Increase in pit volume - Occurrence of small amount of gas after mud circulation

2.2.3 Indication of Kicks

1. Indications of kicks while drilling (Hawker, D., 2001):
    a. Increase or decrease of pump pressure (pumping rate) gradually or exponentially
    b. Increase of mud flow from annulus. The measurement of mud flow can be done with flow meter
    c. Increase in mud pit volumes
    d. Contaminated mud marked with the reduced in mud density, change in chloride content, change in mud pressure and temperature.
    e. The appearance of connection gas due to pipe connection or caving signed with the reduction in pressure and mud hydrostatic
    f. Variations in weight on bit (WOB)
2. Indications of kicks while tripping (Hawker, D., 2001).
    a. Insufficient volume of drilling fluid in the hole due to swabbing effect or loss of circulation. It can be balanced by adding some pressures according to the trip margin.
    b. The change in a trip tank volume due to swabbing effect
    c. Increase of mud volume in a trip tank
    d. Mud flowing at surface
    e. Increase of mud levels added by caving indicate the possibility of influx
    f. Pinched bit shows imbalance pressure in the hole. When the drill pipe or drill bit is stuck or broken, circulation of mud might not flow properly causing a possibility of harder well control (Westergaard, R., H., 1987)
3. Indications of kick while pulling out of the hole is quite similar to the indications while tripping as it has the same operations. In addition, a small flow of mud in the flow line and the reduction of fluid level during pulling could contribute the indication of kick.

3. BASIC WELL CONTROL PRINCIPLES

When a kick occur, the well need to be closed (shut in) to control the kick. However, not every situation with kick should be handled through well shut in. There are factors such as pressure, casing depth and formation strength that need to be considered before choosing to shut in a well. First consideration is that there would be an increase of pressure in annular which will give a possibility of formation fracture when a shut in is initiated. The fracture could cause other problems such as loss of circulation. Moreover, if the casing is set shallow, it could create fracture until it reaches surface. This phenomenon is also known as "broaching" which is very dangerous to the safety of personnel and can result in loss of well and rig. Therefore, according to Goins and Sheffield (1983), a well should only be shut in when there is an influx of formation fluid and no possibility of broaching to occur. Casing depth and formation strength should be measured to determine the well shut in possibility. The reasons to shut in the well are to protect the crew and rig, stop the influx of formation fluid into the wellbore, allows shut in pressure to be determined and provide opportunity to organize the kill procedure (Well Control School, 2004, p.5-2)

There are some considerations when performing drilling on a floating platform regarding to the kick killing procedure (Goins, W.,C., Sheffield R., 1983) :

- The fracture gradient in deep water are less which require additional casing strings to protect the formation from fracture
- There is a possibility that the floater sink if a gas blowout occur around the string and in relatively shallow water
- There will be an increase of bottom hole pressure as the effect of long choke lines from the subsea wellhead to the choke at surface.
- Special procedure should be established to cope with the vessel's motion in order to perform kick killing

When a kick occur, there are two basic principles that can be used in order to balance the pressure in the well. First, is to give additional pressure into the well to counter the pressure from the kick and secondly by adding mud weight so it gives higher hydrostatic that can balance the formation pressure.

For a drill bit and the circulation of fluid that take place in the bottom of the hole, principally there are two pressures that are contained in the well during drilling to balance the pressure in the well. One is the pressure in the drill pipe and one is in the casing (annulus). U-Tube model is present to illustrate the pressure in the bottom of the hole and further to measure the required pressure and mud weight that might be needed to balance the pressure in the well. On the left side of the tube is drill pipe and on the right side is the annulus (Grace, R., D., 2003).

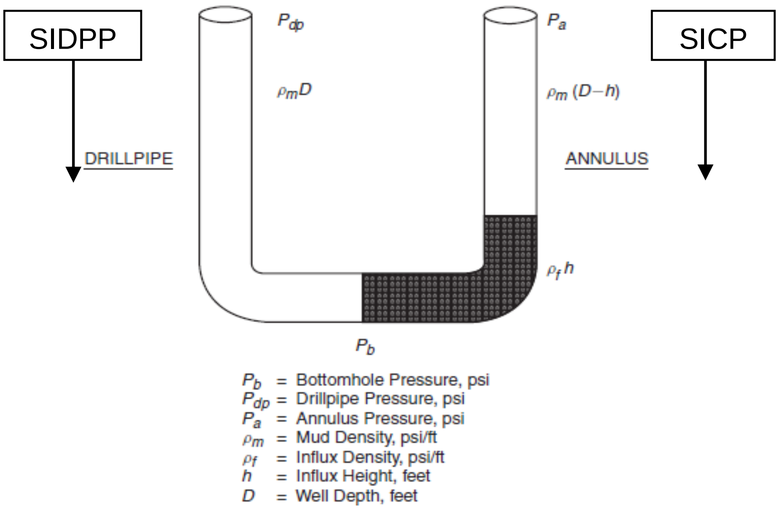


Figure 3.1 U-Tube model of the bottom hole pressure (Grace, R., D., 2003)

During shut in process these pressures are called shut in drill pipe pressure (SIDP) and shut in casing pressure (SICP). The principle is to balance the pressure both in drill pipe and annulus so there is no influx takes place in both holes. The minimum requirement to balance the pressure is when bottom hole pressure is equal to mud hydrostatic. In case of kick occur, bottom hole pressure is equal to the formation kick pressure which shows the highest pressure in the well for balance situation. SIDP is required when hydrostatic mud in the drill pipe is less than the pressure exerted by the formation/kick. In the same way SICP is also required when the hydrostatic mud and hydrostatic of influx is less than the pressure exerted by the formation/kick. Therefore, in order to balance the pressure in the bottom hole we can conclude that:

$$P_{\text{hyd mud drill pipe}} + SIDP \geq P_{\text{formation / kick}}$$

$$P_{\text{hyd mud casing/annulus}} + P_{\text{hyd mud influx}} + SICP \geq P_{\text{formation / kick}}$$

The above method is only useful when the influx is happening in the bottom of the hole. In case that it happens in other places or any other type of influx with related operation (e.g. kick in the middle of the well with further migration), then other method would be useful. The U-tube principal is quite useful in determining the early estimation of influx. The influx volume is normally assumed to be equal to the increase in a pit volume. The indication of migration of gas influx during shut in is when SICP never reach the estimate balance condition while it is still increasing (Hawker, D., 2001).

The required mud weight to counter the pressure of the influx is called kill mud and it is circulated into the well with an initial slow circulating rate (SCR) to minimize the excess of pressure in the well. As the heavier mud is replacing the lighter mud, pressure exerted by the pump into drill string can be reduced. When the kill mud has replaced all the lighter mud, the pressure should be kept constant and final circulating pressure (FCP) can be reached. These procedures are often called constant bottom-hole pressure method. In order to make it practicable the drill pipe should be in the bottom-hole to give the required mud density to kill the well. If there is no pipe in the hole, the pipe must be placed inside by using either stripping or snubbing method.

In order to control the well when influx occurred, there would be some procedures before commencing one of the above methods. Figure 3.2 shows an example of flow chart for a kick control procedure during drilling, tripping and pulled out of hole (no pipe in BOP).

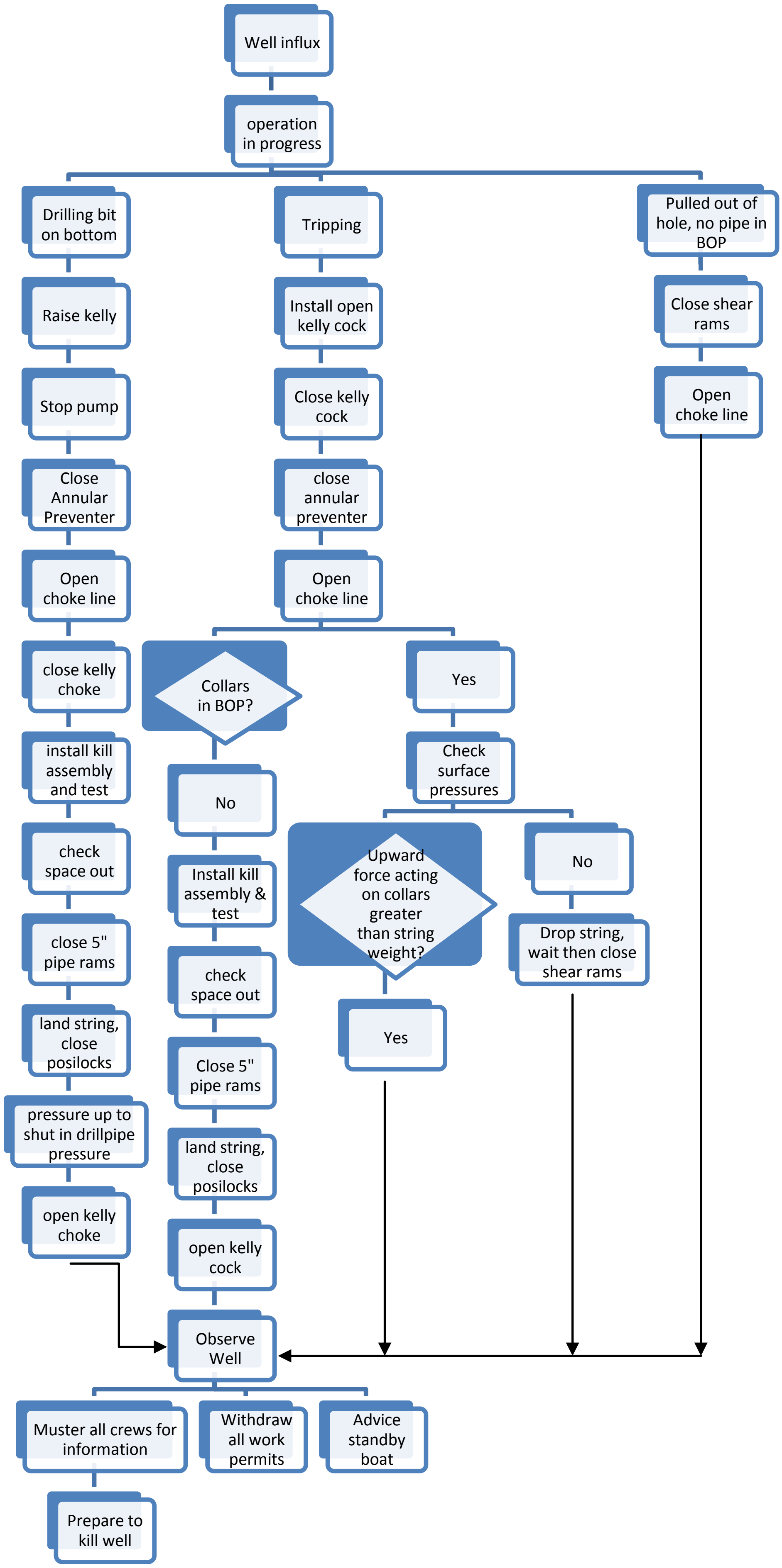


Figure 3.2 Flow chart of kick control procedure (Schlumberger, 2012)

4. KICK CONTROL EQUIPMENTS

Controlling the flow of a kick is very important to maintain balance pressures in a well so that drilling operation can be safely performed. In case of uncontrolled flow which turns into blowout, there should be barriers to stop and mitigate the consequences. Kick control equipments are required to control and regulate fluid flow in a well and to seal wellbore from the uncontrolled flow of fluid.

4.1 Blowout Preventer (BOP) Stack

Blowout preventer (BOP) is a structure with a large set of valves and rams placed on the top of the wellhead that can be closed when drilling crew have uncontrolled flow of formation fluids (Subsea1, 2010). It is also used to hold erratic pressures of a flow that comes from a well during drilling. Other purpose is to centre and hang off the drill string in the wellbore (Hauge, S. et al., 2011). During well killing, BOP also allows the drill pipe to be laid into down hole while maintaining the sealing of the well. The processes are also known as stripping and snubbing. Generally, subsea BOP is incorporated with LMRP to enables quick disconnection between marine riser and BOP in emergency situation. Figure 4.1 shows the main components in BOP and LMRP.

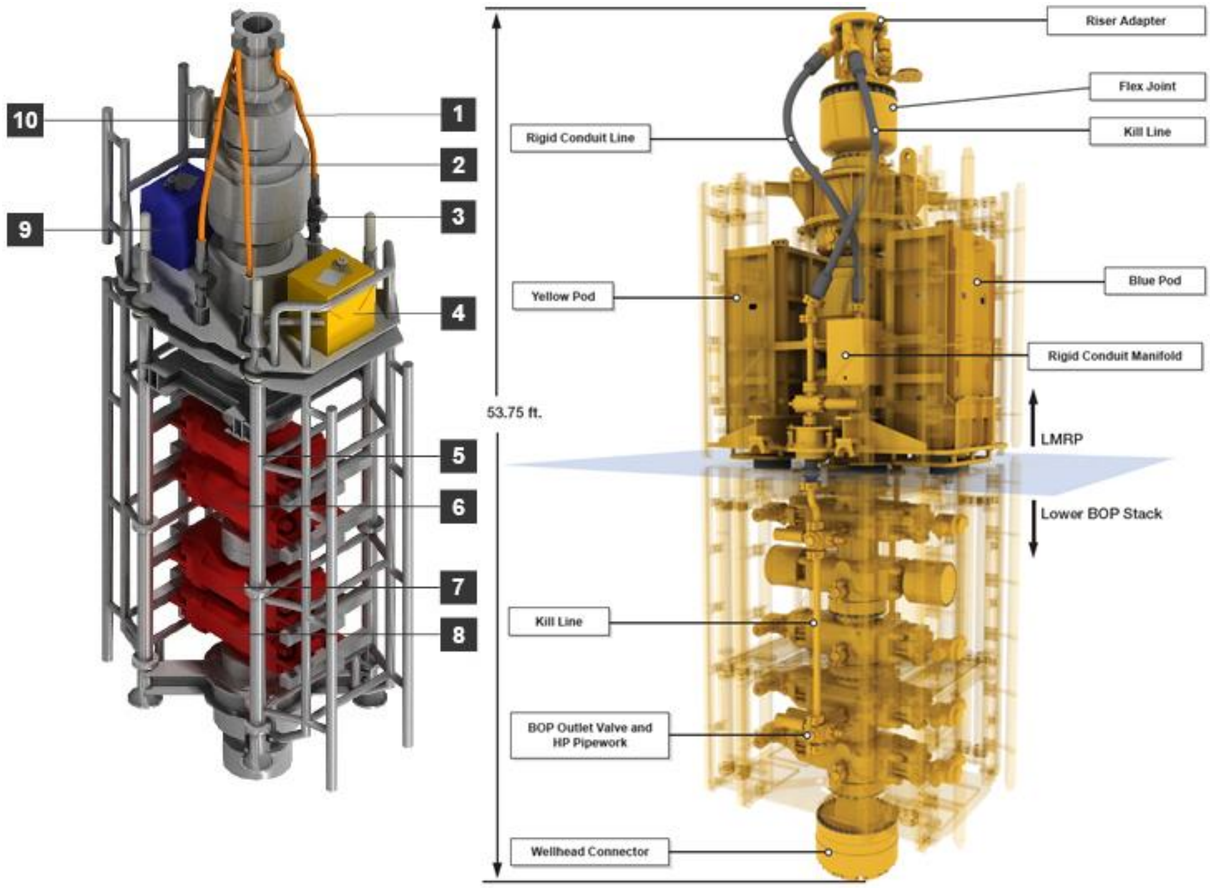


Figure 4.1 Typical main components in subsea BOP and LMRP (Subsea1, 2010) (Transocean, 2011)

From figure 4.1 (left) the components from number one to ten sequentially are kill line, choke line, annular BOP, accumulator, shear blind ram, upper pipe ram, middle pipe ram, lower pipe ram, accumulator and hydraulic line. There are also other components as can be seen in figure 4.1 (right) such as riser adapter, flex joint, rigid conduit line, wellhead connector, yellow and blue pod.

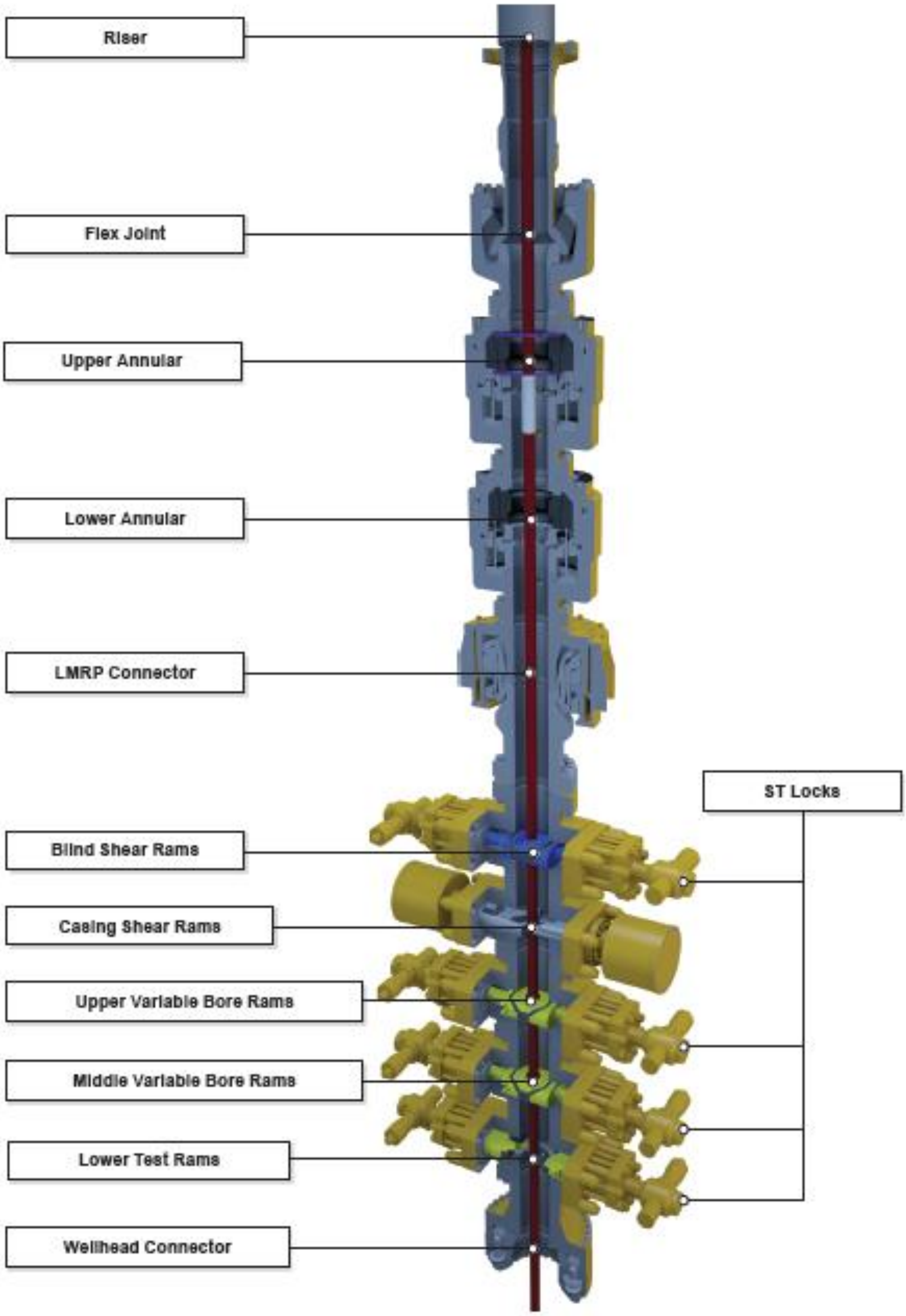


Figure 4.2 Example of cutaway view of blowout preventer stack components (Transocean, 2011)

BOP has different styles, sizes and pressure ratings. Its varieties are depending on the intended function, hazard expectation and the design of the well. Some type of BOPs can be designed to close, seal and cut through drill pipe. On a regular basis BOPs are inspected, tested and refurbished with respect to risk assessment, local practice, well type and legal requirements in order to ensure the reliability and functionality of a BOP (Subsea1, 2010).

BOP mainly consists of preventer, valves, spools and rams that are positioned on the top of the wellhead. The arrangement of these items as can be seen in the above pictures are often called stack. The purposes of the stack are (Hawker, 2001):

- Control the flow of formation fluid by sealing of the well
- Prevent fluid from flowing into surface
- Allow the release of fluids from the well under controlled conditions
- Balance the pressure from formation and prevent further influx by allowing drilling fluid to be pumped into the well under controlled condition
- Allow the drill string to be moved in and out from the well

The configuration of the stack is depending on the expected operations, redundancy, flexibility and the trade off between the advantages and disadvantages of each configuration. The basic typical configurations of the BOP stack from the top to the bottom are bell nipple, flow line, fill line, annular preventer, blind rams, pipe rams, drilling spools, kill line and choke flow line (Goins, W.,C., Sheffield, R., 1983).

When kick occurs, the well will be shut in and annular preventer and/or rams will be closed to stop the influx going further into the surface. The closing and opening of the preventer and rams are mainly driven by hydraulic fluid that is controlled manually from the surface (control room) through BOP control system or by the use of ROV (Remotely Operated Vehicles). Automatic mode function (AMF) or dead man function is an important part of BOP to close blind shear rams automatically in case of loss of communication (hydraulic control and power) from the surface. The required mud weight to balance the pressure from a kick will be circulated into the well through kill line and the flow of fluid in the well will be circulated through choke flow line into mud pit. Figure 4.3 shows the blowout preventer stack with preventer closed, pipe rams closed and blind rams closed.

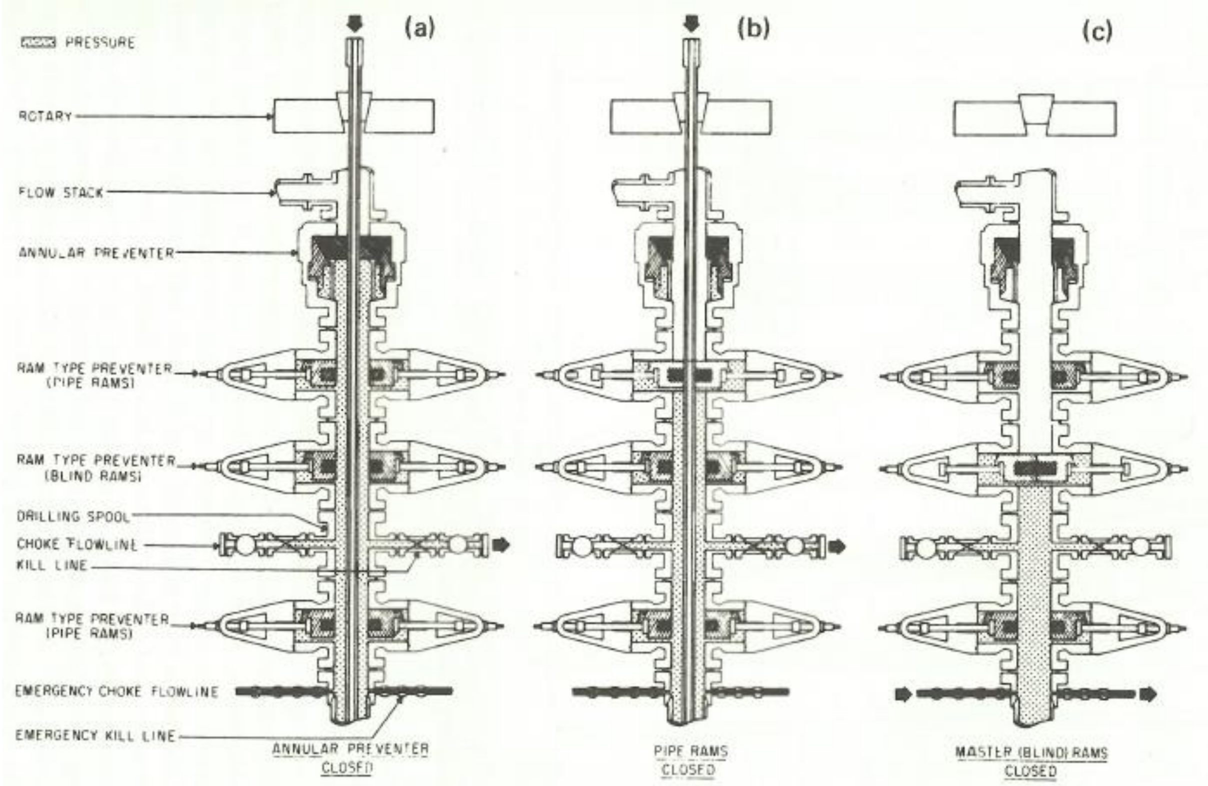


Figure 4.3 Blowout preventer stack with preventer and rams close (Goins, W.,C., Sheffield, R., 1983)

The position of annular preventer is always on the top of the BOP stack. On the other hand, the stack configuration of ram type (e.g. blind ram above pipe rams, blind ram below pipe rams, etc) can be varies and there will be some advantages and disadvantages of these configurations as follows (Hawker, 2001):

- Lower blind rams

  When the well is shut in and blind rams in the lower part is closed, it allows other rams on the upper part of the rams to be repaired or changed, but it has a consequences where the rest of the string below the blind rams could not be hung off. The lower blind rams is act as a master valve (Hawker, 2001).

- Upper blind rams

  When the blind rams in upper part is closed, the rest of the pipe below the blind rams can be hung off by pipe rams below. Moreover, it can be replaced by pipe rams for stripping (ram to ram stripping) to minimize wearing (Hawker, 2001). Consequentially, it prevents other rams for repair or changed.

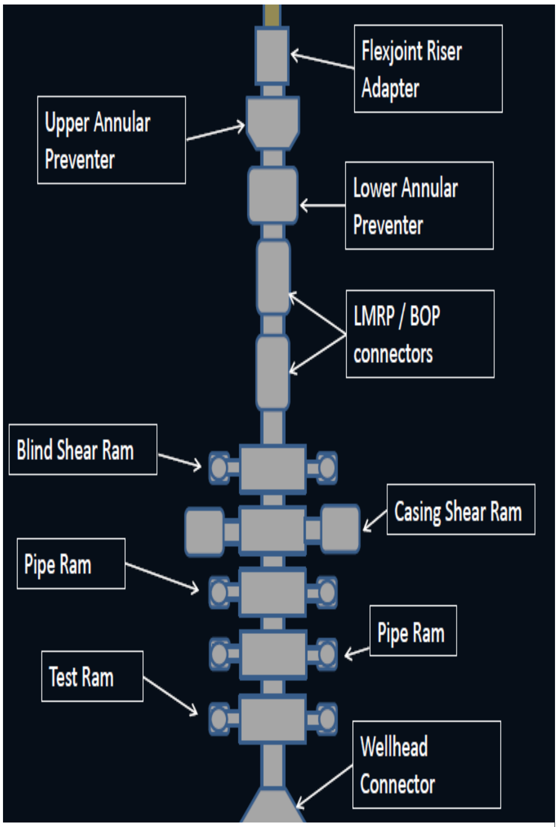


Figure 4.4 Typical subsea BOP stack (Rees, A., Daniel, M., 2011)

The configurations of blowout preventer should maximize the advantages and minimize the disadvantages. One can configure blind ram on top or in the middle for one size drill pipe. It allows the pipe to be hung off in the pipe rams and the circulation can be made through drill string with proper, ram to ram stripping and partial utilization of the blind ram as a master valve to give access for equipment repair (Goins, W.,C., Sheffield, R., 1983). Figure 4.4 shows the common subsea BOP arrangement. Stripping and snubbing during well shut in or well control will make some wear in the sealing element inside rams or preventer. It requires replacement and in this case the ease of repair and access should be taken into consideration when deciding the configuration of the stack.

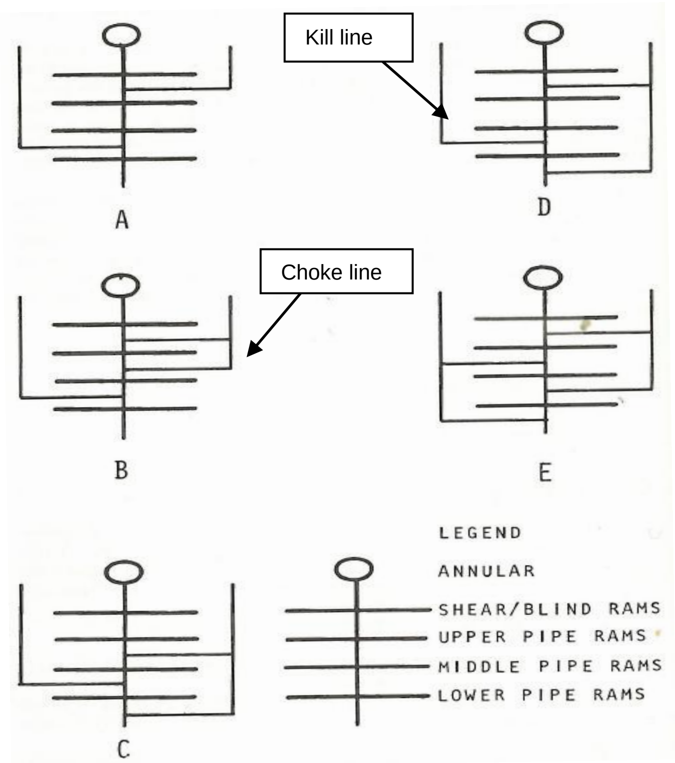


Figure 4.5 Typical kill and choke lines configuration (Goins, W.,C., Sheffield, R., 1983)

Circulation of killing mud and the flow from the formation in the well should be considered in the well control operation. The configuration and position of kill line and choke line also have to be in line with the ram configuration to give access for killing mud, allows equalizing pressure before opening other rams (in case of the other functioning ram) and giving measurement for pressure monitoring. Figure 4.5 shows the example of kill and choke lines configuration for four ram stack.

Components of blowout preventer can be described as follows:

4.1.1 Annular Preventer

The annular preventer is a preventer used to seal and close around the pipe in any sizes (diameter) and shapes such as drill pipes, kelly, tool joints, drill collars, casing or wire line. The prime sealing element is reinforced packer consisting of rubber seal with steel reinforcement segments. Annular preventer allows slow rotation and vertical movement of the pipe while maintaining the sealing which is useful for snubbing and stripping process. It becomes the first barrier to close in a BOP stack when controlling and it is capable to seal on any drill pipe component in the well bore (Hawker, 2001) (Vujasinovic, A., 1986).

The advantages of having annular preventer as an additional barrier compare to ram preventer are (Goins, W.,C., Sheffield, R., 1983) :

- Closure can be made on drill collars or casing
- Closure can be made on tool joints or on the kelly
- Closure can be made on any segment of a tapered drill string
- Closure can be made on swab, logging and perforating lines and tools
- Drill pipe can be reciprocated
- Faster well closure is possible because the pipe does not need to be positioned
- The string can be stripped in or out of the hole
- A back up for both blind rams and pipe rams is provided

There are some types of annular preventer that are mostly produced and used in the oil and gas industry such as Shaffer spherical BOP, Annular Cameron DL, Annular Hydril GK and Annular Hydril GL. Each of these annular preventer have their own features.

- Shaffer spherical BOP

Shaffer annular is a common type of annular preventer that can seal on almost any shapes or sizes such as drill pipes, tool joints, drill collars, casing or wire line. It is also provide positive pressure control for stripping drill pipe into and out of the hole. The closing of the annular is operated by hydraulic pressure. It has some features such as (Rig Train, 2001):

- Simple hydraulic system where it only needs two hydraulic connections
- Prolongs preventer life by reducing metal to metal contact by having wear rings on movable parts
- Suitable for H_2S service
- Element can be changed without getting mud and grit into the hydraulic system

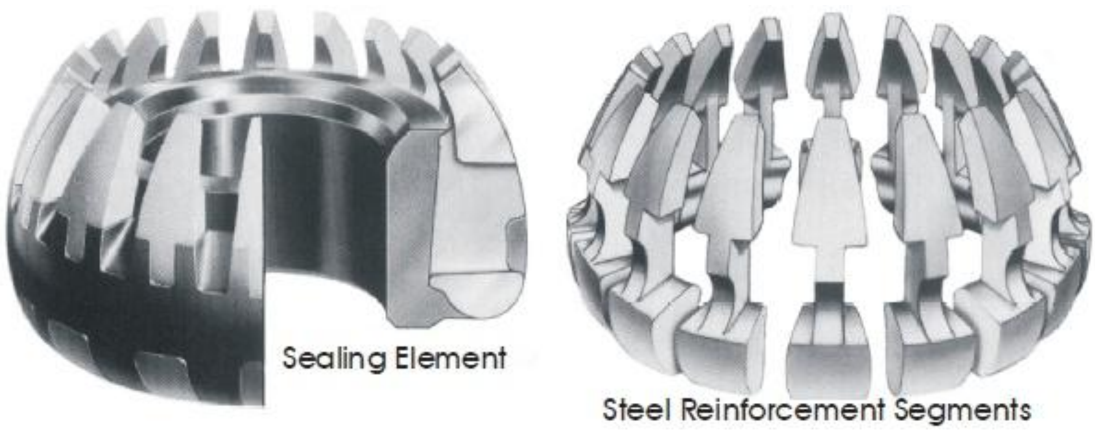


Figure 4.6 Sealing element and steel reinforcement segments in an annular preventer (Vujasinovic, A., 1986)

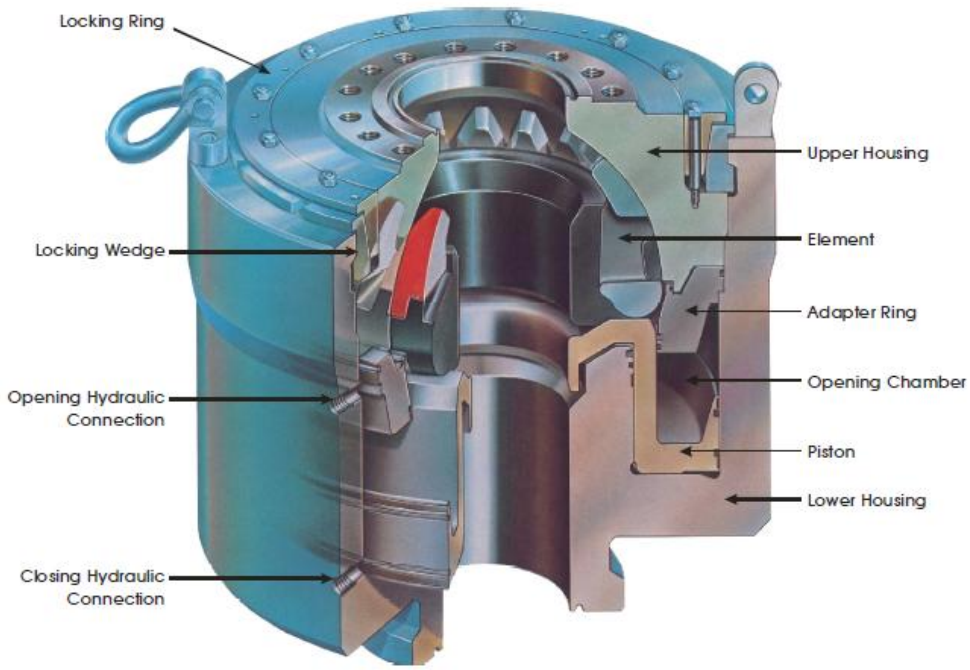


Figure 4.7 Shaffer spherical BOP (Rig Train, 2001)

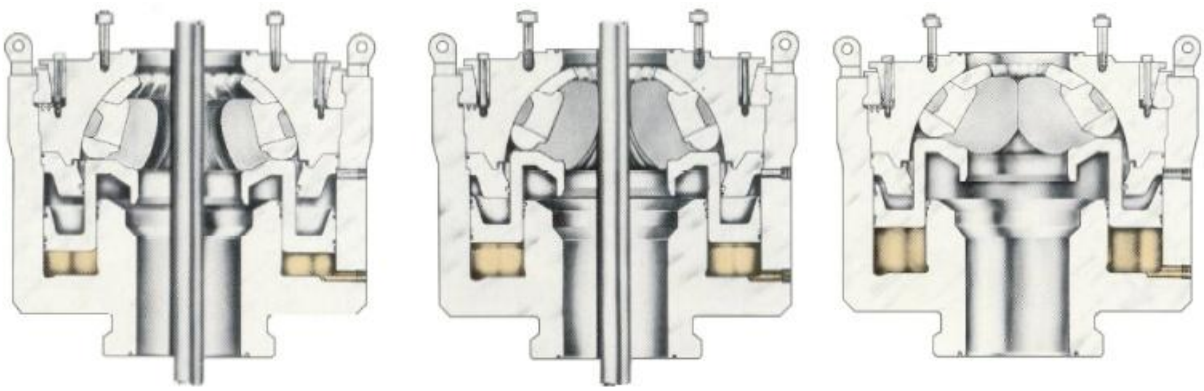


Figure 4.8 The closing of Shaffer spherical BOP (Rig Train, 2001)

Figure 4.8 shows the closing step of Shaffer spherical BOP. Hydraulic fluid is pumped into the closing chamber and it pushes the sealing element up and closes as it goes further up (left). The steel reinforcement element support the rubber element in the sealing element as the well pressure pushes it upward (middle). When there is no pipe in the annular, the sealing element will continue close until it fully closed (Rig Train, 2001).

- Annular Cameron DL

This type of annular has a different type of sealing element compare to the previous one, but the main functions are still the same to seal on almost any size of shape object that will be used in the well bore. It is also has a capacity to strip pipe, close and seal on open hole. Additional feature allowing the preventer to be split for installation while pipe is in the hole (Rig Train, 2001).

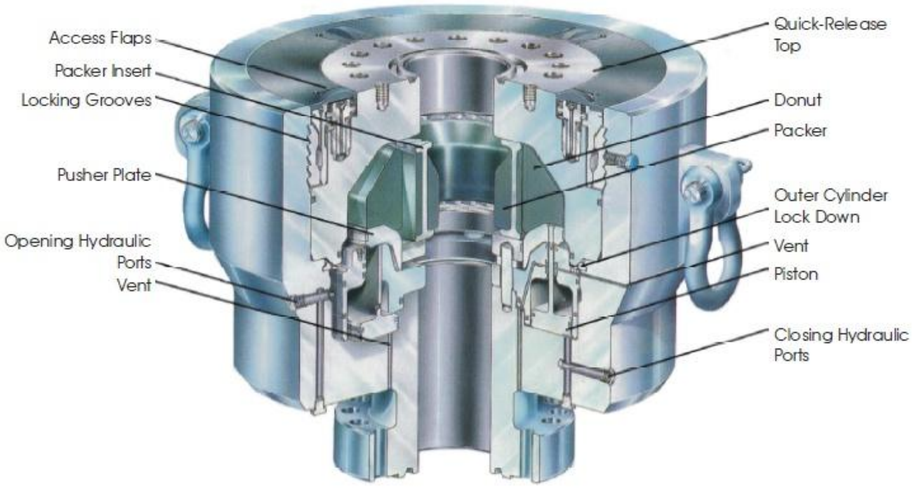


Figure 4.9 DL Annular Blowout Preventer (Rig Train, 2001)

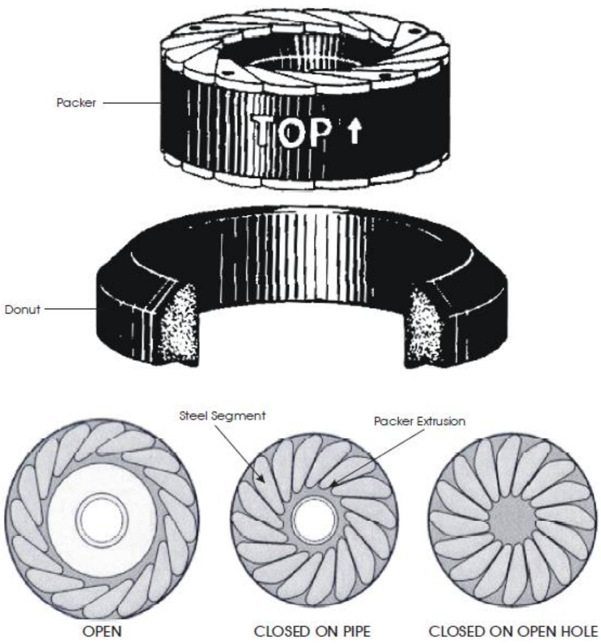


Figure 4.10 Packing element components and operations (Rig Train, 2001)

The closing operation is start when a pressure forcing the operating piston and pusher plate to close upward (see figure 4.10). Packer inserts will rotate inward as the packer closes and forming support to the top and bottom of the packer.

- Annular Hydril GK

This annular is suitable for onshore installation as well as offshore platform and subsea installation. The closing is driven by hydraulic pressures which push the closing chamber to raise the piston and packing unit for sealing (Rig Train, 2001).

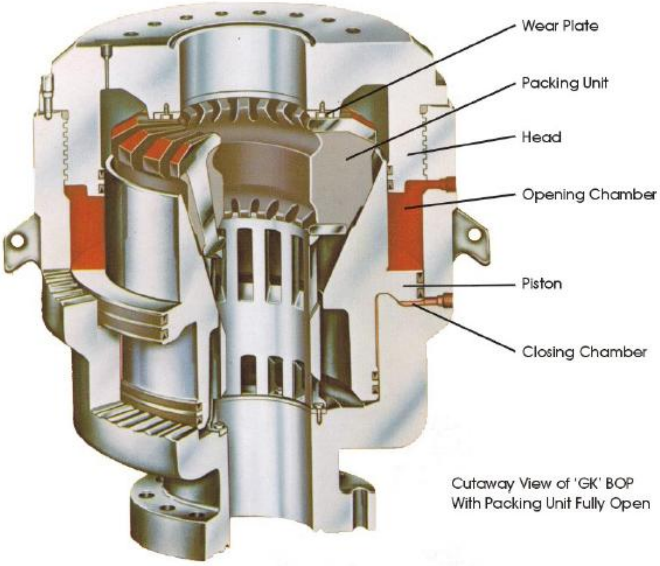


Figure 4.11 Annular Hydril GK type (Rig Train, 2001)

- Annular Hydril GL

The annular has additional secondary chamber which provides greater flexibility of control hook up, reduce closing pressure, minimize the closing and opening volumes (Rig Train, 2001).

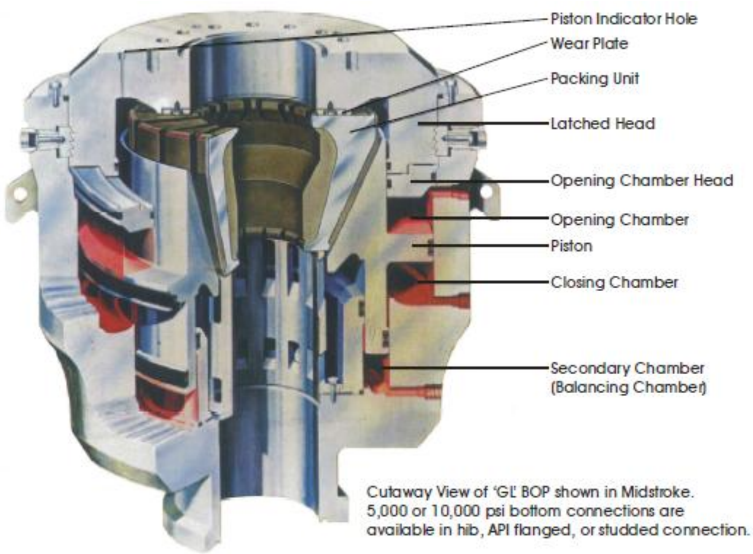


Figure 4.12 Annular Hydril GL type (Rig Train, 2001)

4.1.2 Ram Preventer

Ram is a tool that can be used to seal and close the well in the event of influx from formation into wellbore. It consists of packer and seal divided in two parts which are opposing each other and hydraulic pressure pushes the parts in the middle for sealing purposes (Schlumberger, 2012). The sealing depends on which type of rams, some are intended to close completely by cutting the drill pipe known as blind/shear rams, other are for seal which correspond to the diameter of the pipe known as pipe/casing rams. For some purposes the pipe rams can be used for more than one pipe size and/or more than one pipe known as variable rams.

Rams are controlled by pistons from both sides which are operated by fluid pressure. Closing ratio and opening ratio are used to know the ratio of well bore pressure to pressure required for closure and opening (Goins, W.,C., Sheffield, R., 1983).

i. **Pipe/casing rams**

   Ram type that can close around a pipe. It is specifically use for one size pipe only.

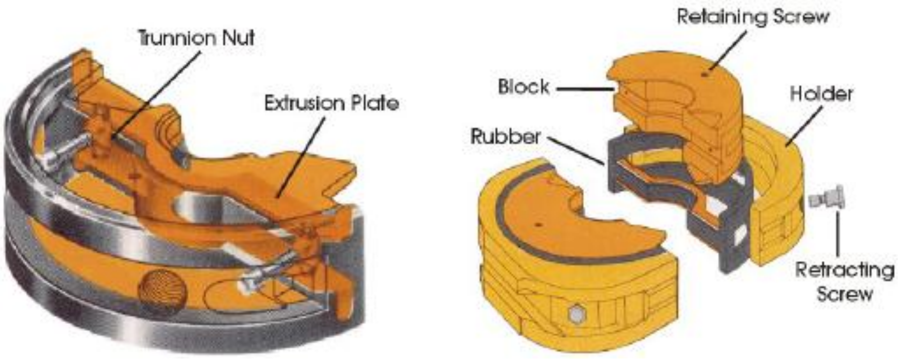


Figure 4.13 Typical pipe/casing rams (Rig Train, 2001)

ii. **Blind/shear rams**

   Blind rams is used to seal a wellbore by cutting through the drill pipe as the rams close off and seal the well (Transocean, 2011)

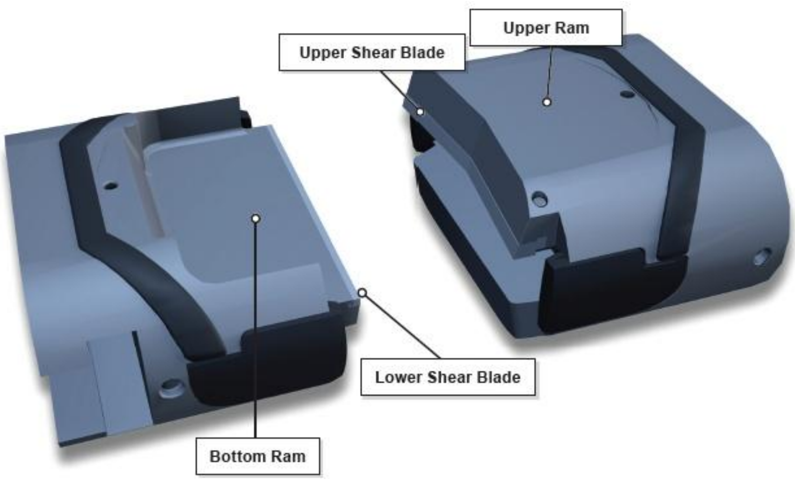


Figure 4.14 Typical blind/shear ram (Transocean, 2011)

iii. Variable rams

a. Variable bore rams (VBR) capable of closing around a range of tubing and drill pipe outside diameters (Transocean, 2011)

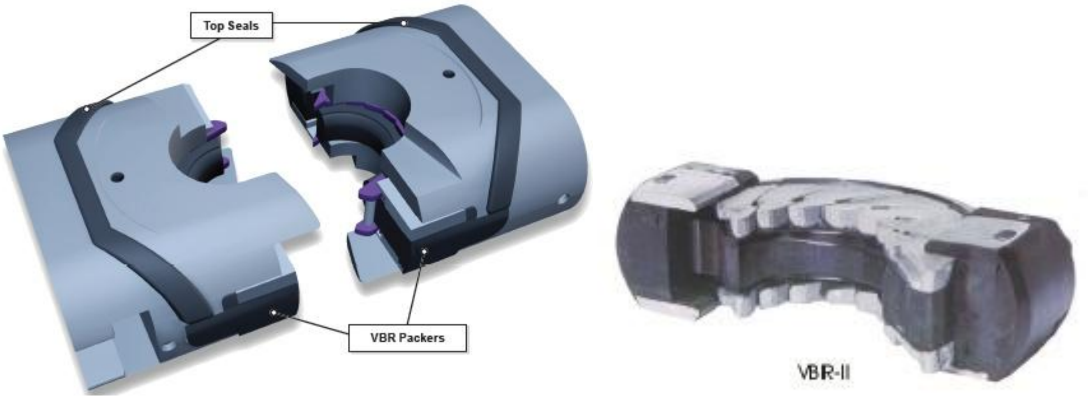


Figure 4.15 Typical variable bore rams (Rig Train, 2001) (Transocean, 2011)

b. Flex packer can close around a range of tubing and drill pipe outside diameter by the use of flexible packer

Figure 4.16 Typical flex packer (Rig Train, 2001)

c. Dual bore flex packer is designed to seal on three different pipe sizes in two different packer bores (Rig Train, 2001).

Figure 4.17 Typical dual bore flex packer (Rig Train, 2001)

iv. Test rams

It is a variable bore rams (VBRs) which is inverted to seal the pressure from above. It is useful to reduce the time required to prepare for BOP pressure testing and resume drilling operations. (Transocean, 2011).

4.1.2.1 Rams Closing Principle

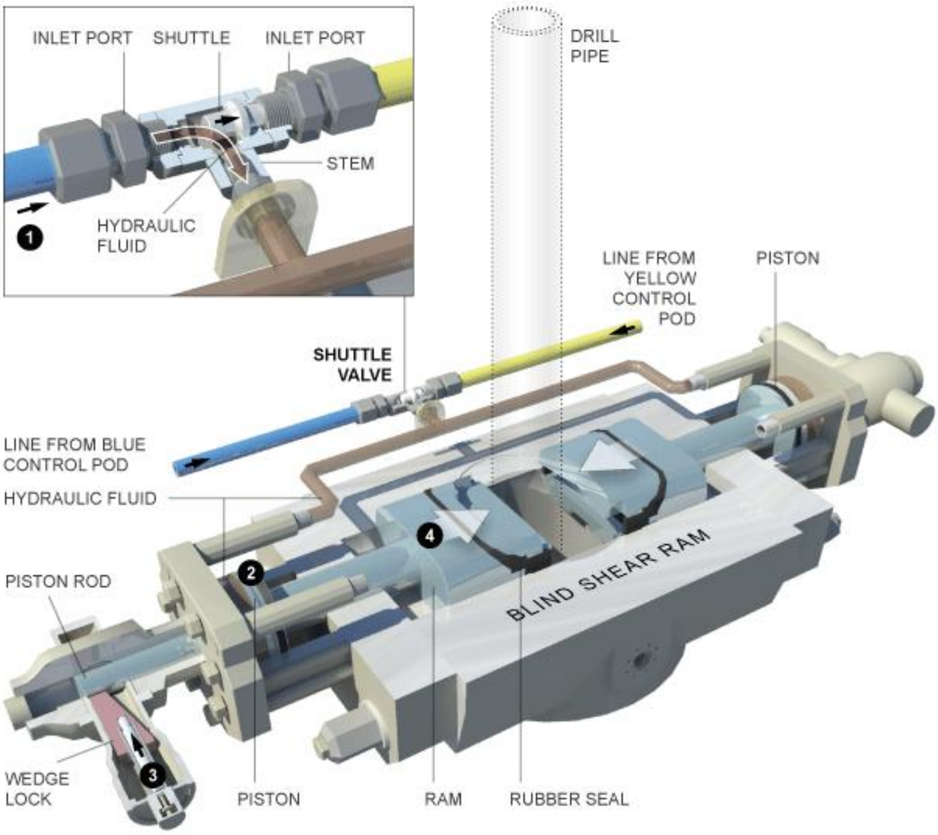


Figure 4.18 Blind shear rams closing (Gröndahl, M., et al., 2010) (Rig Train, 2001)

The closing of rams is controlled by BOP control system which is driven mainly by hydraulic power. The hydraulic used to close rams are carried out from accumulator into subsea control pod. It passes through regulator, SPM valve and shuttle valve. The sequences and functions of this system are described in more detail in BOP control system chapter.

The closing of blind shear rams start when hydraulic fluid from control pod pass through shuttle valve and push both pistons inward. The hydraulic fluid from the other side of the pistons is circulated into another shuttle valve and later into surface. While piston is moving inward, wedge lock is move behind the piston rod to prevent the piston move backward. The well is shut completely when both rams are closed and seal the well.

The opening of the rams has the same principle like the closing one. The hydraulic flow is now pass through the other side of the piston and push it outward. At the same time, the wedge lock is move to its original position to allow the opening of the rams.

The operating sequence for closing and opening of other type of rams (e.g., variable bore rams and fixed pipe rams) are also having the same principle like the mentioned one.

4.1.3 Choke Lines and Kill Lines

Choke line is a line that connecting BOP stack to surface through choke manifold. It is used to circulate the fluid in the wellbore during well control operations. When there is overpressure in the wellbore, choke lines circulate the flow into surface and reduce the pressure in the well (Schlumberger, 2011). The flow should pass through choke line, choke manifold, mud tanks and reserve pit. On floating rig, four or more chokes should be available on the manifold. Two are usually remotely controlled and the other two are manually controlled. Master valve should be available next to the wellhead of each flow line and should not be used during normal operation to prevent unnecessary wearing. It is used to close the line when flow line is repaired (Goins, W.,C., Sheffield, R., 1983).

Kill line is a high pressure pipe that connecting outlet on the BOP stacks and rig pumps (Schlumberger, 2011). It is used to pump killing mud into the wellbore when pumping through drill string is not possible. When drill pipe is pulled out and the well is pressured, then the kill lines can be used to pump mud into the well. It can be located below blind ram. The working pressure of kill line should be equal to or greater than BOPs (Goins, W.,C., Sheffield, R., 1983).

The configuration of rams will determine the position of kill and choke lines. Placing it below one or more rams allows bleed of fluid and pressure under control. The pressure can be monitored by passing choke line into choke manifold. Choke manifold is the arrangement of lines and valves which are connected to the BOP stack to give different flow routes and capable to stop the flow completely (Hawker, 2001). Subsea BOP that is connected to a floating platform, have choke and kill lines which are attached to opposite side of the marine riser. Flexibility of these lines is important to handle movement and heave motion of the floating platform (Hawker, 2001). Furthermore, the volumetric and frictional effects of these long choke and kill lines should be taken into consideration for a proper well control operation (Schlumberger, 2012). The position of the choke and kill line outlets should be arranged so that circulation for well control can be carried out with the drill string suspended in the BOP and the shear ram closed. Each of the choke and kill outlets in the BOP stack should be fitted with two gates arranged in series and installed close to the BOP. One choke outlet should be located below upper annular in order to handle trapped gas (Norsok D-001, 1998). There are some requirements regarding to the choke and kill line as follows:

- The manifold should have a pressure capability equal to the rated operation pressure of the BOP stack (equal to the weakest component) (Hawker, 2001).
- The choke line connecting the manifold to the stack should be as straight as possible and firmly anchored (Hawker, 2001).
- Alternative flow and flare routes should be available downstream of the choke line in order to isolate equipment that may need repair (Hawker, 2001)

4.2 Blowout Preventer (BOP) Control System

BOP control system is a critical component in a BOP stack because this is the heart of a system that drives preventers and rams to close and open with or without using primary rig power. There are some essential elements of a BOP control system such as accumulator system, operating fluid, high pressure piping to carry and direct hydraulic fluid, remote unit for controlling valve with hydraulic unit (Goins, W.,C., Sheffield, R., 1983).

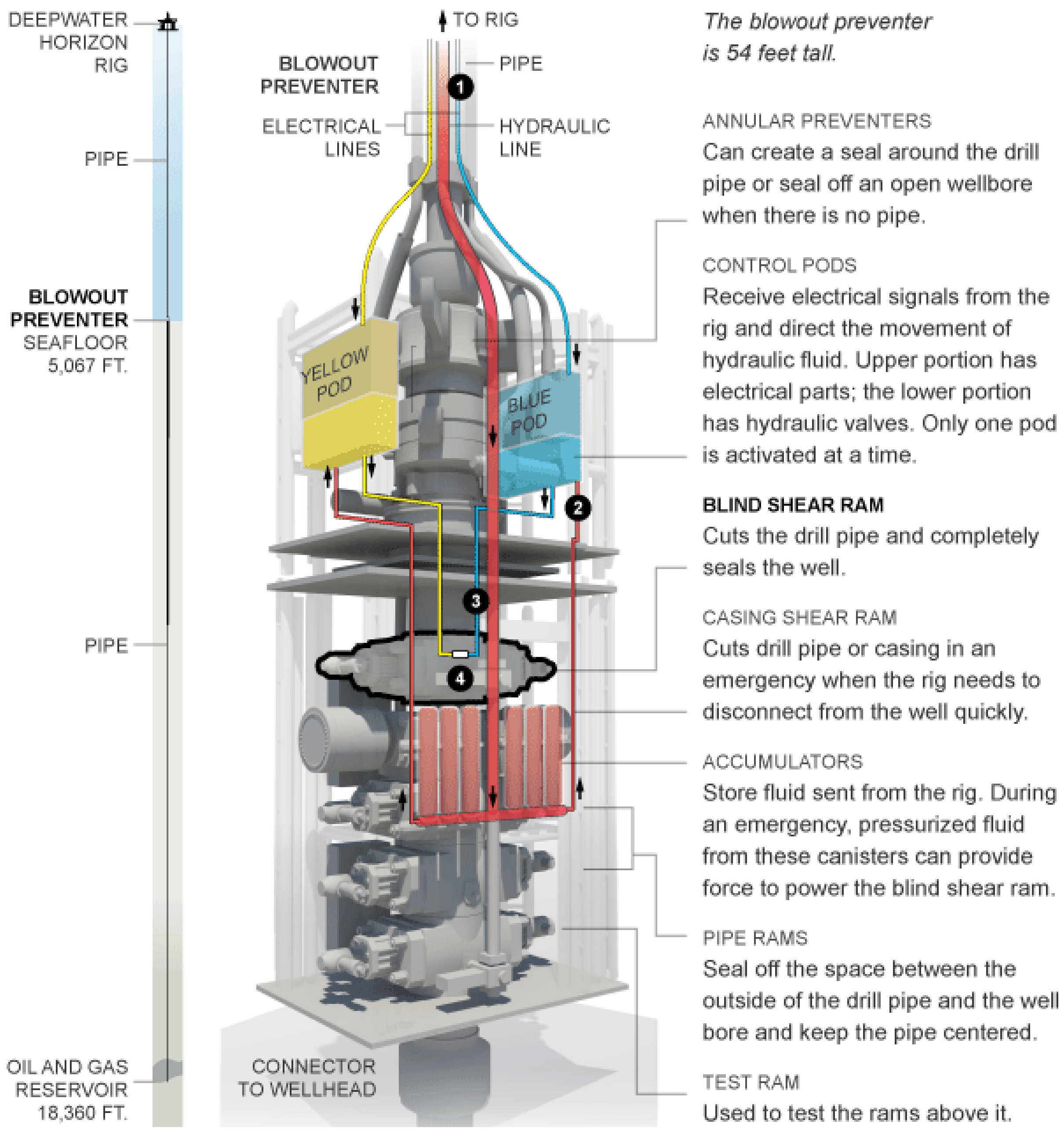


Figure 4.19 BOP control system in Macondo Deepwater Horizon (Gröndahl, M., et al., 2010)

Accumulator is a device used in a hydraulic system to store energy or, in some applications, dampen pressure fluctuation (Schlumberger, 2012). It contains pre-charge nitrogen that is stored in a series of bottles that can supply hydraulic fluid under pressure which will be required to close preventers (Hawker, 2001). It can be used to provide hydraulic power to close blind shear rams and other rams when there is no communication of power or loss of pressure in an emergency situation. In a subsea BOP, the location of accumulator is under blue and yellow pod (see figure 4.19 with red tubes). There are two types of accumulator, float type and bladder type. Both types are having the same system consisting of (Goins, W.,C., Sheffield, R., 1983):

- Accumulator bottles which contains hydraulic operating fluid under compressed nitrogen. The pre-charge nitrogen usually within the range of 750 psi – 1000 psi and when power fluid is pumped into the bottles the pressure inside is increasing and resulting in operating pressure with 1200 psi - 3000 psi (Hawker, 2001)
- High pressure pumps to recharge the accumulator with power fluid. Electric or pneumatic pumps are usually used to deliver hydraulic fluid under pressure (Hawker, 2001)
- A control manifold to regulate the pressure and direct flows into the correct ram and preventer. Pneumatic operation is typically used for the mechanism of opening and closing of preventer, choke, kill lines and to monitor and regulate pressure (Hawker, 2001)
- a reserve tank for storing operating fluid at atmospheric pressure

Activation of control from the surface on floating/offshore platform to a subsea control pod can be delivered by the use of hydraulic system, electrohydraulic system and multiplexed (MUX) system with separate hydraulic line. Control pod is a set of valves and regulator that are grouped together in one place. Nowadays, multiplexed system and electrohydraulic system are the most common use for subsea BOP control system as it gives simplicity for the cost and the size of the lines (hose bundle) as well as reducing the operational problems when running and retrieving large hose bundles.

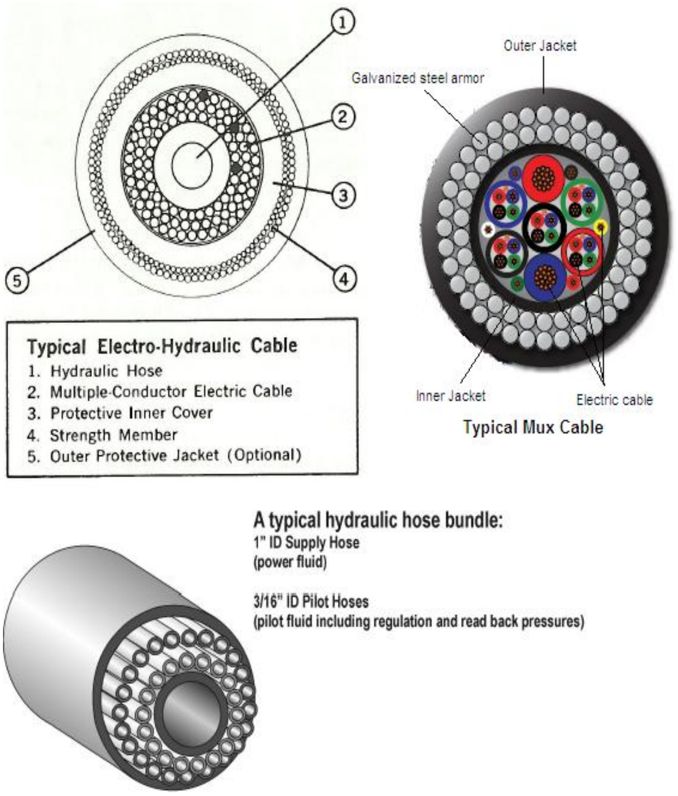


Figure 4.20 Typical electro hydraulic cable (top left), MUX cable (top right) and hydraulic hose (bottom) (Goins, W.,C., Sheffield, R., 1983) (Umbilicals, 2009) (Rig Train, 2001)

The time taken for the hydraulic system to activate BOPs is longer than the other two systems with electric signal. Therefore, hydraulic system is not recommended for deep water drilling as it will require more hydraulic fluid, more pressures to be pumped, high pressure drop and longer activation time to close BOPs.

Instead of supplying hydraulic fluid, hydraulic system also control the activation of the BOPs through hydraulic control. From figure 4.20 (bottom), we can see that the power fluid is carried out by supply hose and the control line are transmitted by a pilot hose. On the other hand, electrohydraulic system uses multiple conductor electric cable for activation control and supply hydraulic fluid through hydraulic hose (figure 4.20, left). Multiplex system will only consists of electric cable for variety of controlling purposes and hydraulic fluid is carried out by a separate line which is connected to subsea control pod.

There should be a minimum of two independent pods to give redundancy and only one pod is activated at a time. Inside a pod, there are pilot valve for the hydraulic system and solenoid valve together with pilot valve for the electrohydraulic and MUX system. Pilot valve will receive hydraulic fluid to regulate and control the flow of power fluid. Before power fluid is regulated by shuttle valve in electrohydraulic and MUX system, the system will give electric signal to operate solenoid valve which will directs hydraulic fluid into pilot valve. Power fluid stored in the accumulator flows pass through the pilot valve to give a regulated power fluid needed to close and open the rams and preventers. The closing and opening of the BOP are regulated by means of shuttle valve. In addition, the hydraulic fluid is not only used to transmit fluid into pod for control on command, but also into accumulator both on surface and subsea control system for storage.

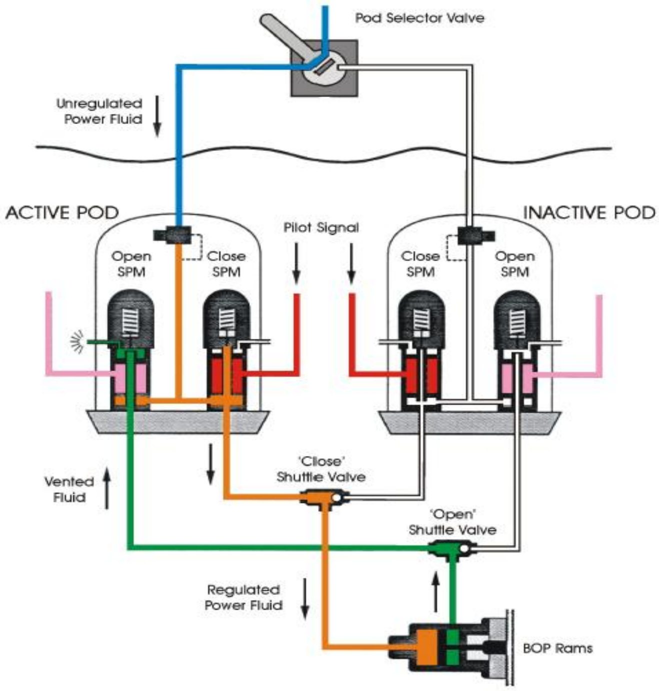


Figure 4.21 Example of redundancy between pods and stack (Rig Train, 2001)

Figure 4.21 shows the redundancy of pods to operate the closing and opening of a ram preventer with one pod activation a time. While one pod is activated to close or open the ram, the flow of hydraulic fluid of the other pod will be closed by means of shuttle valve. The flow of the fluid is controlled by pilot valve. Shuttle valve is used to divert the flow from the active pod and isolate the inactive pod.

In the emergency situation (blowout), there could be two alternatives to close the rams, manual and automatic. Manual approaches is when operator on the rig activates the emergency button which will provide signal to control pod to directs fluids from accumulators into a shuttle valve and drive blind shear ram to cut and seal the well (Gröndahl, M., et al., 2010). In the automatic mode (AMF), the pod will detect if there is no communication of power and hydraulic from the surface and will activate accumulator automatically to direct the pressurized hydraulic fluid into shuttle valve to close blind shear ram and seal the well. In addition, acoustic system could also be used as a back-up system for emergency plan when there is no hydraulic and electric communication from the surface. It uses acoustic signal to activate the system in a pod to close blind shear ram. Manual intervention can be conducted by the use of ROV (Remotely Operated Vehicle) which activate the system through ROV intervention panel attached in the BOP stack.

4.2.1 Hydraulic subsea BOP Control System Overview for BOP Function

Hydraulic BOP control system uses hydraulic power to operate the closing and opening of annular and ram preventer where the initial command is come from electric control panel in the control room. The systems mainly consists of master electric panel, electric mini panel, electric power pack with battery back-up, electric power cable, hydraulic power unit (consists of surface accumulator and central hydraulic control manifold), hydraulic jumper hose bundle, hose reel, subsea hose bundle, subsea control pod, subsea BOP and subsea accumulator. Figure 4.22 shows the general arrangement of hydraulic subsea BOP control system.

The signal initiation of hydraulic control system is using electric signal. This signal can be transmitted from master electric panel or electric mini panel. Independent supply of electric power can be brought by electric power pack with battery back-up. The electric signal will trigger solenoid valve to open pilot control valve and pod select valve inside central hydraulic control manifold to control and direct the hydraulic fluid from surface accumulator into one of the subsea control pod. This direction of hydraulic flow is important since hydraulic control system should have two subsea control pods for redundancy purpose. Blue control pod and yellow control pod are the common name for these two subsea control pods. The hydraulic flow from hydraulic power unit is forwarded into hydraulic jumper hose bundle, hose reel, subsea hydraulic hose bundle (umbilical), subsea accumulator and finally subsea control pod.

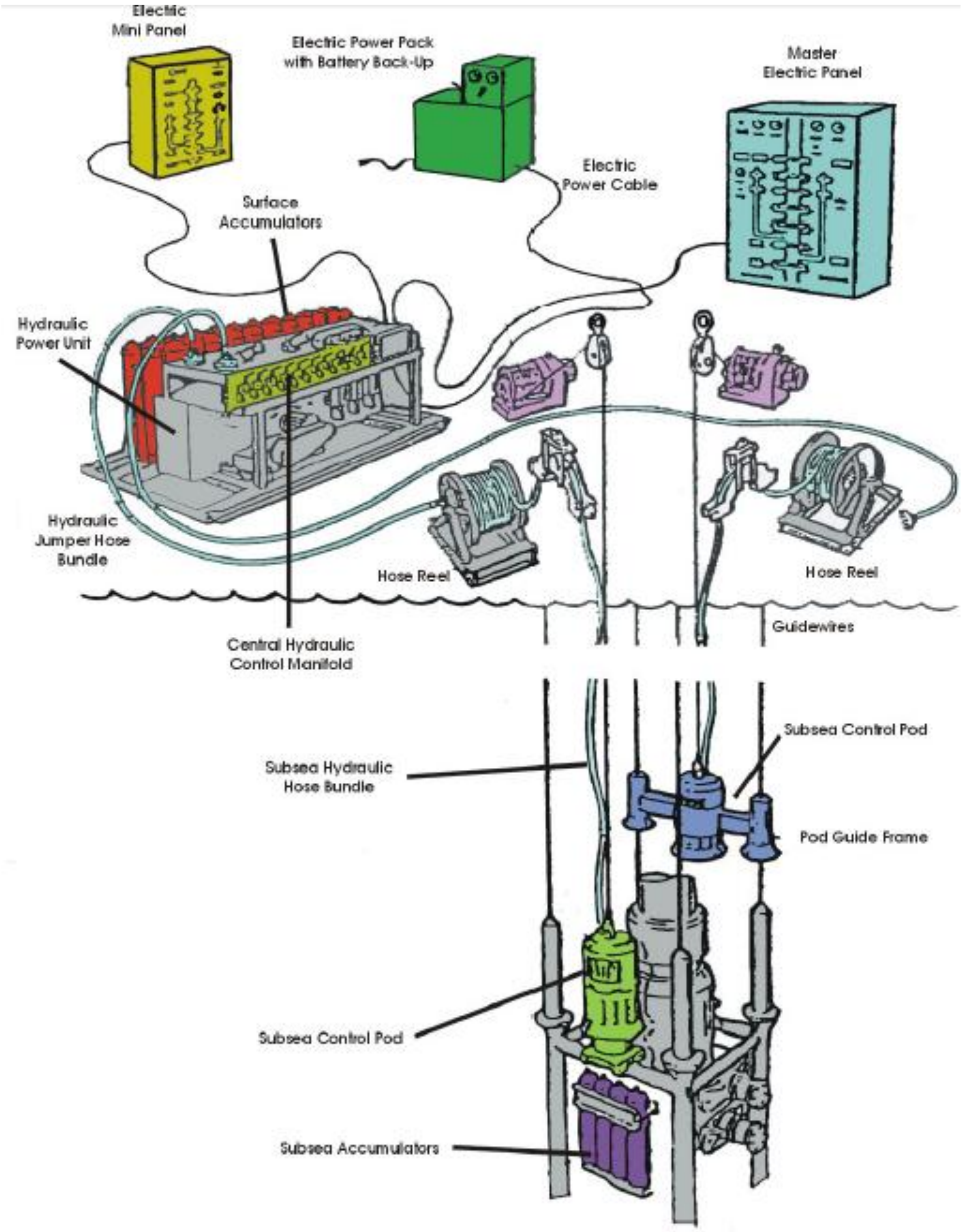


Figure 4.22 General arrangment of hydraulic subsea BOP control system (Rig Train, 2001)

The hydraulic pressure from surface and subsea accumulator usually has 3000 psi. This pressure will be regulated by mean of subsea regulated valve into the required pressure to operate rams and annular preventers. The regulated pressure usually contains 1500 psi.

Information of a more detail sequence of control system operation is needed in order to know which components are required to make the system functioning. The main functions can be divided into three operations which are close function, block function and open function. These three operations require the same components and have some differences in operating the closing and opening of the solenoid valve, pilot control valve and sub plate mounted (SPM) valve. Figure 4.23-4.25 shows the full schematic for operating sequence of block, open and close function in subsea BOP control system.

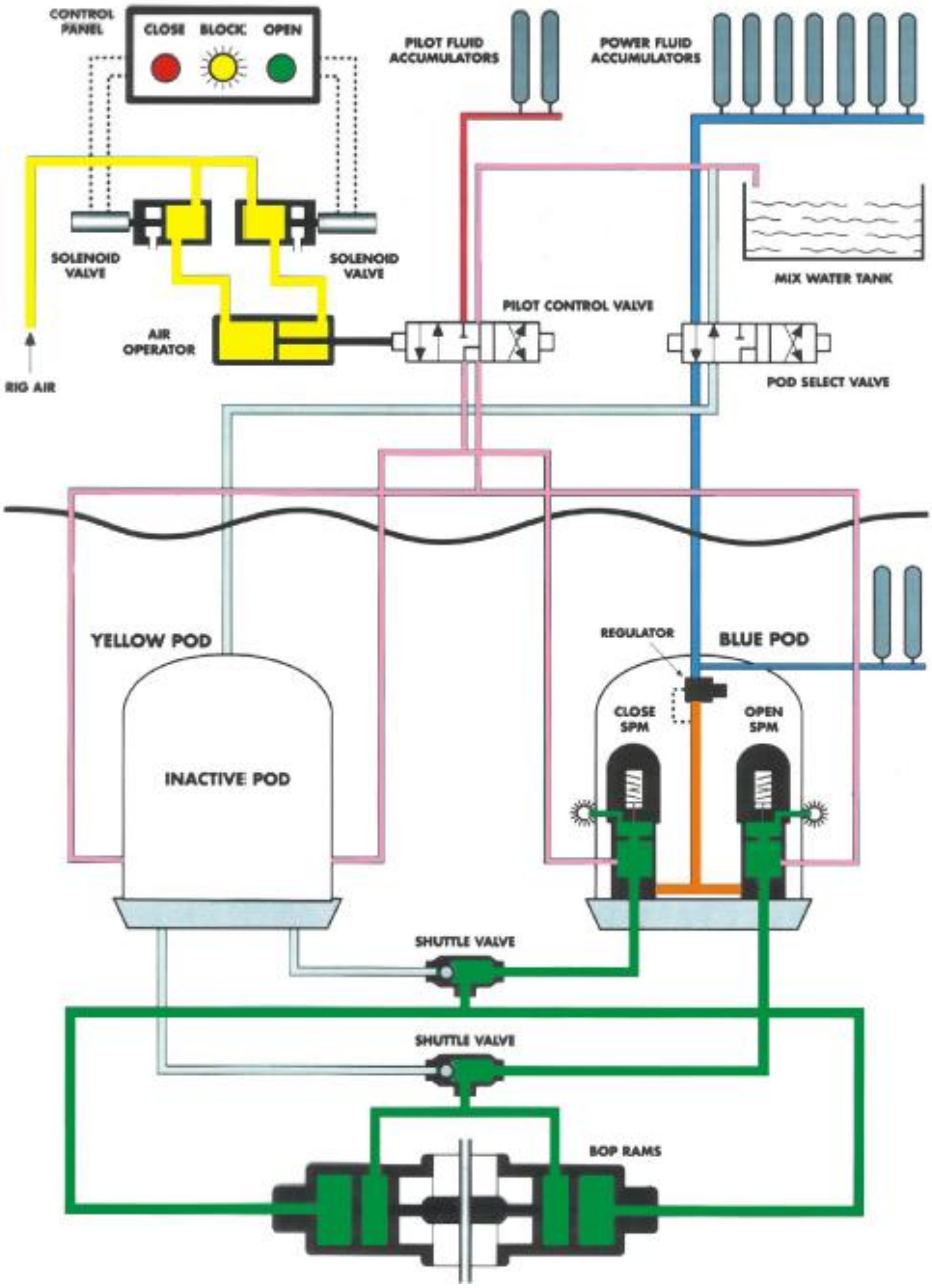


Figure 4.23 Schematic of block function for subsea BOP control system (Rig Train, 2001)

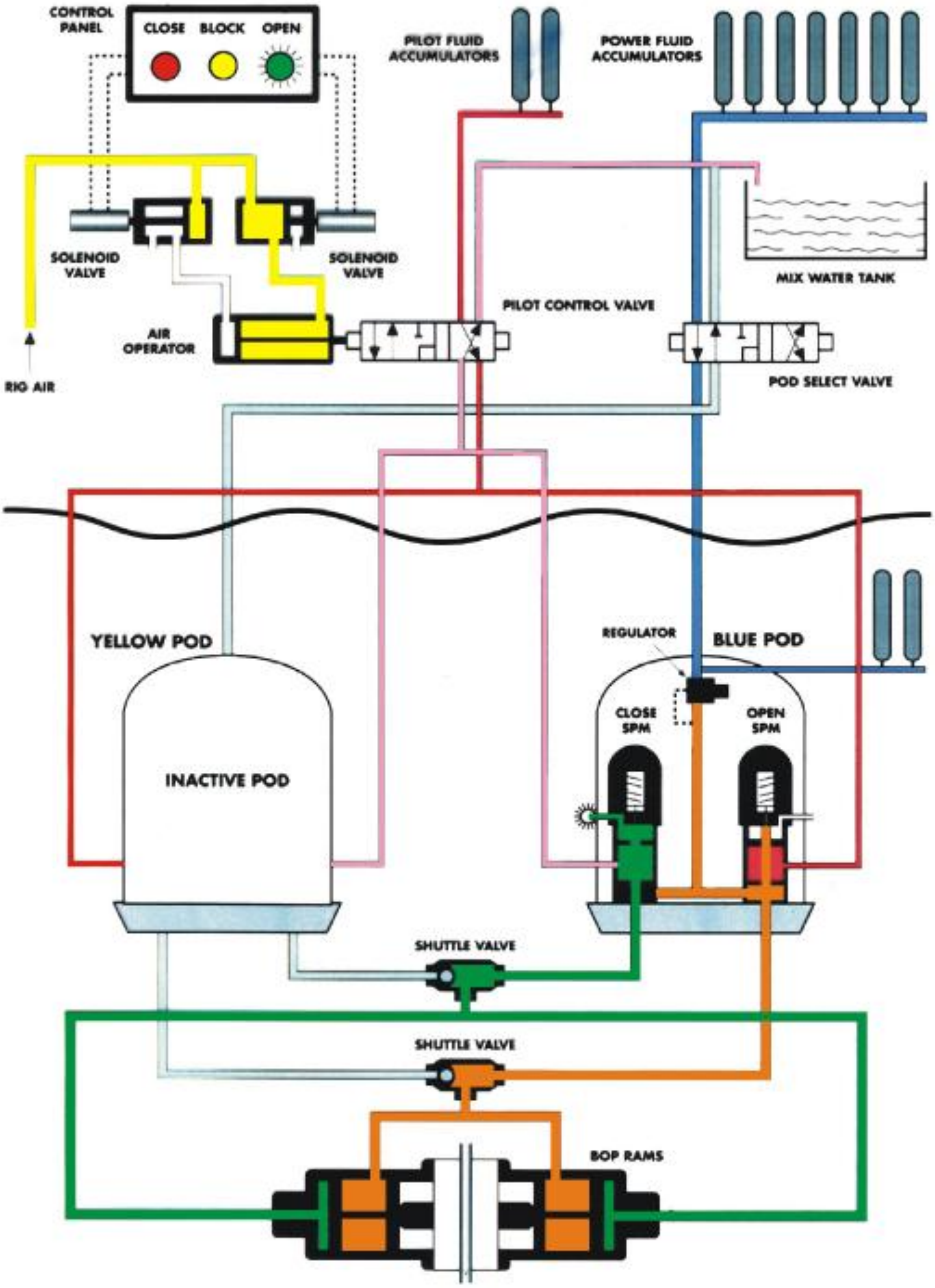


Figure 4.24 Schematic of open function for subsea BOP control system (Rig Train, 2001)

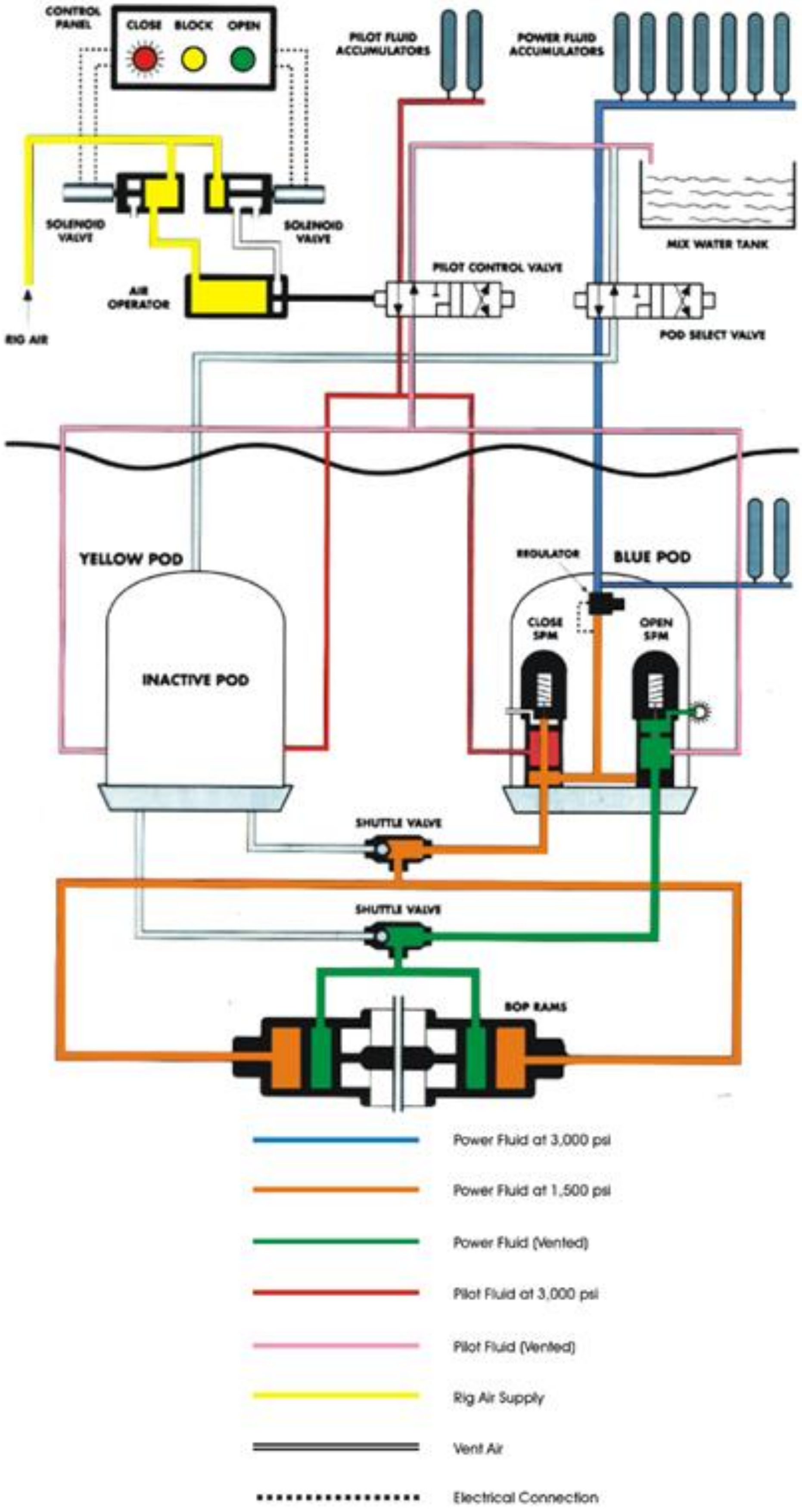


Figure 4.25 Schematic of close function for subsea BOP control system (Rig Train, 2001)

The close function (figure 4.25) start when the operator press the close panel in the control panel (master electric panel or electric mini panel). The electric signal is sent to the associated solenoid valve to open which allows high pressure air to pass and actuate pilot control valve to be in close position. The actuation of pilot control valve gives access to high pressure (3000 psi) hydraulic pilot fluid stored in the surface accumulator to flow through hydraulic jumper hose bundle, hose reel and subsea hydraulic hose bundle into closed sub plate mounted (SPM) valve inside subsea control pod. There are two SPM valves inside subsea control pod. One function is to regulate the valve so it allows the flows of power fluid into the ram and perform the closing/opening function. The other one is to regulate the valve so that power fluid on the opposite side of the ram can be vented up to the surface.

At the same time, the position of pod selector valve is set to allows and directs the flow of power fluid (3000 psi) from surface power fluid accumulator into subsea regulator valve inside one of subsea control pod. Power fluid (3000 psi) from subsea power fluid accumulator are also directed into this regulator as a backup. The regulator valve reduce the pressure in the power fluid into 1500 psi in order to operate the BOP function. The regulated power fluid is pass through shuttle valve into the rams and push it for closing function. The power fluid in the opposite side of the rams is vented through the open SPM valve and pass through pilot control valve into mix water tank for fluid treatment. Shuttle valve has a function to close the flows of power fluid into another control pod (inactive control pod) and allows them to pass through the designated BOP functions.

Block function is initiated to vent a flow in a pilot control valve in order to detect leakage in the control system and preventer. The operation sequence is similar with the closing operation (see figure 4.23). The differences are both solenoid valves are open half way allowing the pilot control valve to be centered and give access for pilot fluid to be vented into both SPM valves inside the subsea control pod. The vented pilot fluid makes the SPM valve to seal against any power fluid to enter into shuttle valve. It makes the power fluid inside BOP rams become available to be vented back through SPM valves.

The open function operation is similar to close function operation. The differences are the position of closing and opening of solenoid valve, pilot control valve and SPM valve. All of the position in the mentioned components are opposite to the closing function. The schematic of open function can be seen in figure 4.24. The pilot control valve will direct the the pilot fluid into the opposite SPM valve to allows flow of power fluid into open rams.

In order to simplify the understanding of operation sequences, type of components and the redundancy they have on subsea BOP control system, the reliability block diagram can be developed based on the function flow from the schematic operation mentioned above.

4.2.2 Control Fluid Circuit and Subsea Accumulator Recharge

BOP control systems is not only function for the closing and opening of BOP rams and preventer but also to control the subsea regulators, provide readback pressure, latch/unlatch the subsea control pods and charge the subsea accumulator (Rig Train, 2001).

Control fluid circuit and subsea accumulator recharge system can be described in the same schematic flows as shown in figure 4.26 below. The control circuit is mainly driven by isolator valve and selector valve which are commanded from hydraulic control manifold and subsea control pod.

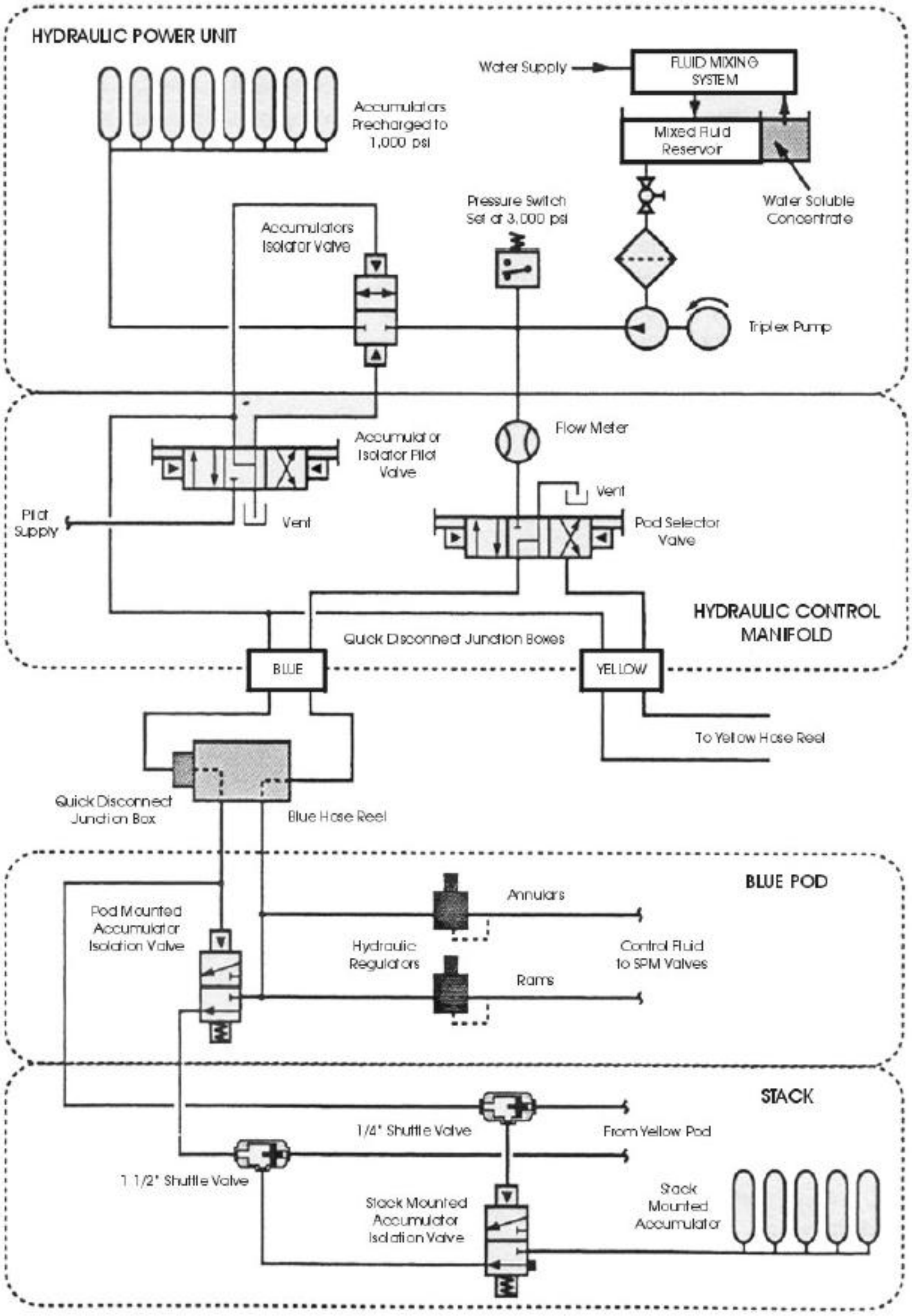


Figure 4.26 Schematic flows of control fluid circuit and accumulator recharge system (Rig Train, 2001)

The recharge operation of subsea accumulator starts from the fluid mixing system and mixed fluid reservoir for preparing the required hydraulic power fluid for storage. The power fluid is flowed into surface accumulator by using pump and to subsea accumulator later. In order to reach subsea accumulator, the fluid flows in two ways. One flow through accumulator isolation valve (AIV) and pass through accumulator isolator pilot valve (AIPV) and the other flow pass through pressure switch, flow meter and pod selector valve. The pressure switch set the required pressure for storing (3000 psi). Flow meter is needed to measure and read the flow of the fluid. Pod selector valve (PSV) is used to direct the flow into one of a subsea control pod.

After pass through AIPV and PSV, the fluid is go into one of the subsea control pod by passing through hydraulic jumper hose bundle, quick disconnect junction box, hose reel and subsea hydraulic hose bundle (umbilical). From there it can be routed into annular or preventer for closing/opening purpose by passing through subsea regulated valve, SPM valve and shuttle valve. In addition, the fluid can directed into shuttle valve directly or pass through pod mounted accumulator isolation valve (PMAIV) and shuttle valve for accumulator recharging purposes.

4.2.3 Pilot Fluid Circuit

The control of pilot valves in the subsea pods are performed by using control valve located in the hydraulic control manifold. BOP stack function can have a system of open or close function (2 position function) and open and close function (3 position function). This control can be operated manually from the control manifold or remotely by means of solenoid valve. The pilot fluid function for 2 position functions have two solenoid valves, while 3 position functions have three solenoid valves. These valves are commanded by electronic connection via electric panel and are driven by air in order to move the pilot valve. The schematic operation of this function is generally the same as mentioned in the system overview of BOP function (chapter 4.2.1). In addition, pressure switch is connected to each line of the control valve and will transmit signal to the appropriate control panel lamp. Figure 4.27 shows the schematic flows of pilot fluid circuit for 3 position functions.

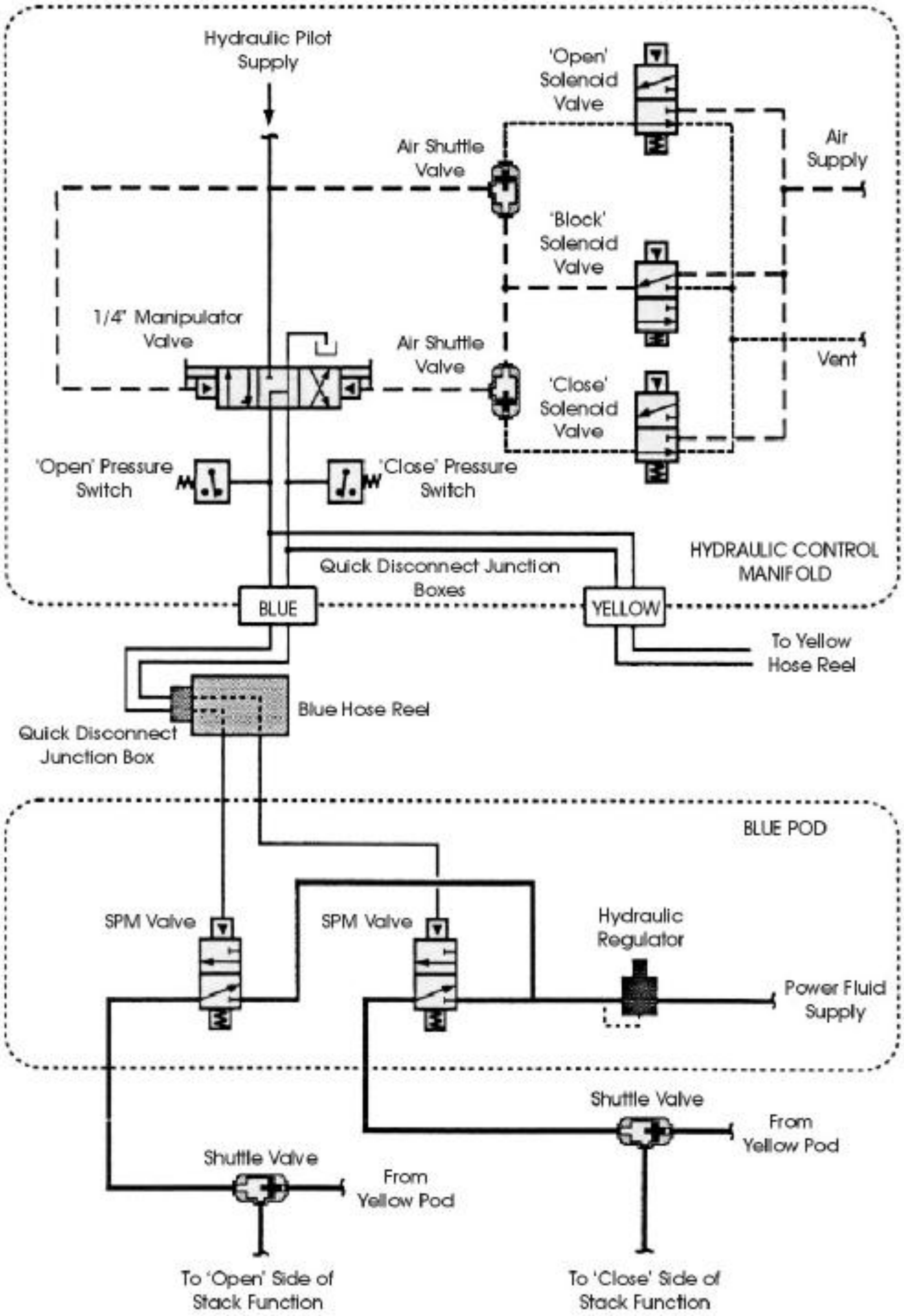


Figure 4.27 Schematic flows of pilot fluid circuit (Rig Train, 2001)

5. REQUIREMENTS FOR BOP

5.1 Redundancy Requirements for BOP

The critical components and system in a BOP should be made redundant in order to give functional availability in case of system or component failure during kicks occurrence. The required redundancies can be determined by the local standard regulations and company policy based on their best knowledge and expertise to reflect the minimum requirements of redundancies. According to Sedco Forex (p 192-193, 1999) together with Schlumberger expertise, the subsea BOP should consists of five BOP rams and two annular preventers in order to have minimum redundancies requirements.

1. 5 BOP rams:
    - 3 pipe rams
    - 1 casing shear rams
    - 1 blind shear rams
2. 2 annular preventers:
    - 1 upper annular BOP
    - 1 lower annular BOP

Figure 5.1 shows the example of preferred stack arrangement for subsea BOP

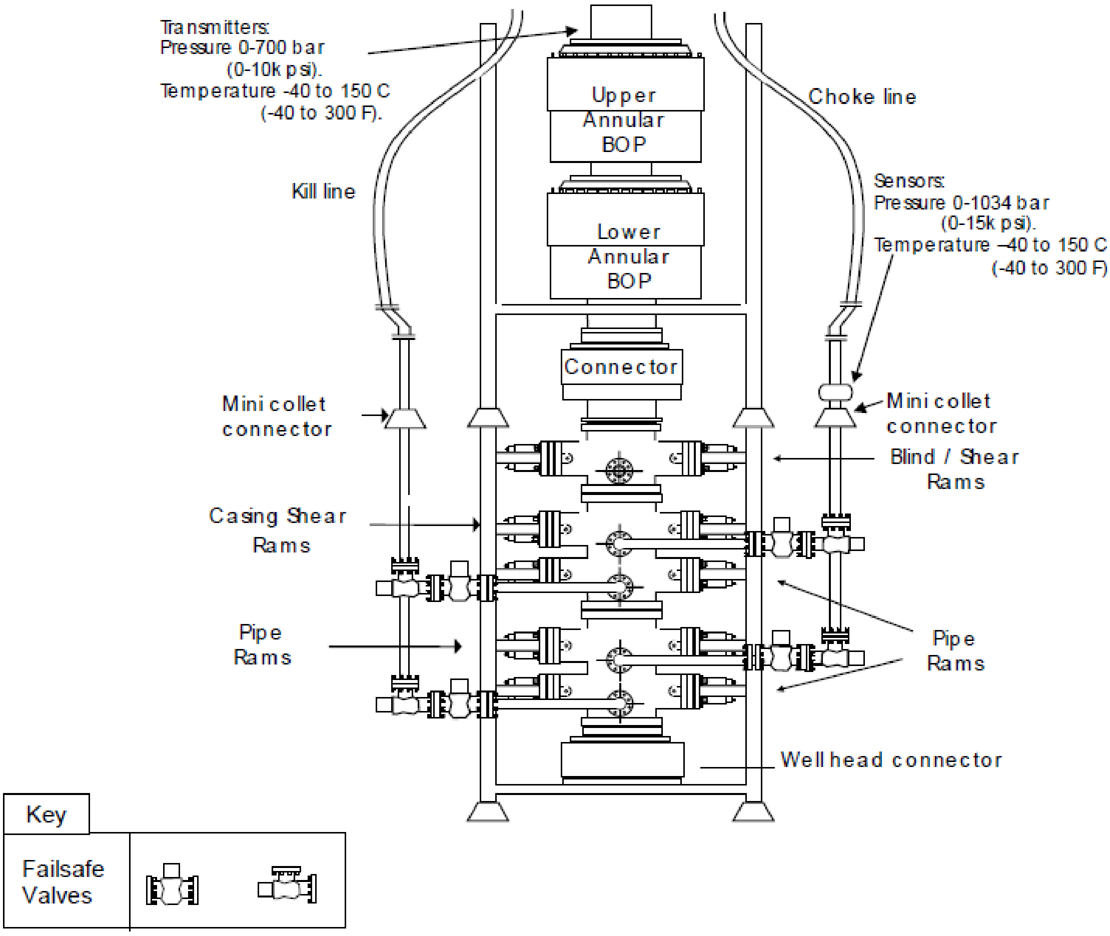


Figure 5.1 Subsea BOP stack arrangement (Sedco Forex, 1999)

When a tapered drill string is used, the BOP stack should be equipped with one of the following pipe ram configurations (Sedco Forex, 1999, p.193):

a. 2 sets of pipe rams for the larger size string and 1 set for the smaller size string of drill pipe
b. 2 sets of pipe rams for the larger size string and one set of variable bore pipe rams to fit both sizes of drill pipe
c. 2 sets of variable bore pipe rams to fir both sizes of drill pipe
d. 1 set of pipe rams for the larger size string and 1 set of variable bore pipe rams to fit both sizes of drill pipe
e. 1 set of pipe rams for the larger size string and one set of pipe rams for the smaller size string and 1 set of variable bore pipe rams to fit both sizes of drill pipe

Another regulation such as from Bureau of Safety and Environmental Enforcement (BSEE), which formerly known as Mineral Management Service as an American body for energy regulations maker in the outer continental shelf (OCS), announced their minimum requirements for a subsea BOP stack as follows (BSEE, 2012):

- 1 annular preventer
- 2 pipe rams
- 1 blind shear ram

According to Norsok D-001, the BOP should have a minimum component consists of the following:

- 1 annular preventer
- 1 shear ram preventer
- 2 pipe ram preventers
- 1 choke line outlet
- 1 kill line outlet
- 1 wellhead coupling or connector
- 2 manual gate valves
- 2 remote operated gate valve

5.2 General Requirements for BOP

Overall, the general requirements for a BOP stack and systems must be met and are describe as follows:

- There must be sufficient casing to provide a firm anchor for the stack (Hawker, 2001)
- It must be able to close off and seal the well completely, with or without string in the hole (Hawker, 2001)
- It must have a simple and rapid procedure (Hawker, 2001)
- It must have controllable lines through which to bleed off pressure (Hawker, 2001)
- It must provide the ability to circulate fluids through both the string and annulus (Hawker, 2001)
- There must be the ability to hang or shear pipe, shut in a subsea stack, detach the riser and abandon the location (Hawker, 2001)
- Subsea stacks cannot be affected by the lateral movement of the riser caused by currents movement and tidal variations. This achieved through a ball joint connection (Hawker, 2001)
- BOP must have ROV (Remotely Operated Vehicle) intervention capability equipment. At a minimum the ROV must be capable of closing one set of pipe rams, closing one set of blind shear rams, and unlatching the LMRP) (BOEM, 2011)
- BOP must have auto shear and deadman systems (BOEM, 2011)
- BOP system must have an automatic backup to the primary accumulator-charging system. The power source must be independent of the power source for the primary accumulator-charging system. The independent power source must be able to close and hold the closure of all BOP components (BSEE, 2012)
- There must be at least two BOP control stations. One placed on the drilling floor and the other should be placed in the readily accessible location away from the drilling floor (BSEE, 2012)
- BOP must have separate side outlet for kill and choke lines. If the stacks does not have side outlets, drilling spool must be installed with side outlets (BSEE, 2012)
- Remote controlled of subsea choke and kill line valves. Choke lines must be installed above the bottom ram and kill lines can be installed at the bottom ram (BSEE, 2012)

Annular preventer closing time

- API RP 53 state that surface annular preventers closing times should not exceed 30 seconds for smaller than 18 ¾” and 45 seconds for 18 ¾” and larger
- Subsea annular preventers should not exceed 60 seconds

Ram Preventer closing time

- API RP 53 requirements state that surface rams must close within 30 seconds
- Subsea rams must close within 45 seconds

6. THE USE OF BOP IN DRILLING OPERATION

Principally, the use of BOP is to hold the flow and pressure of reservoir fluid in case of influx entering the wellbore up to the surface when other barriers inside the well have failed. It is acting as a last line of protection against kicks and blowouts. In general, the use of BOP during drilling operations can be divided into four operations, well shut in, stripping, snubbing and testing BOP. Well shut in is required in the most of the well control methods (e.g., wait and weight method, driller's method, concurrent method, etc.) in order to close and seal the wellbore. Stripping and snubbing can be useful for giving a possibility of access for circulation of influx and drilling fluid (kill mud). It is important that testing of BOP is performed to ensure the functionality of system and components in a BOP.

6.1 Shut In

Shut in is a process to seal a well in order to protect it against kicks, by closing BOP and chokes. There are some situations during drilling operation where the well must be shut in such as (Well Control School, 2004):

1. Shut in when the pipe is on the bottom
2. Shut in while tripping pipe
3. Shut in when on trip with top drive
4. Shut in while spacing out
5. Shut in on collars
6. Shut in while out of hole
7. Shut in while running casing
8. Shut in while running pipe

From all of the shut in situations mentioned above, principally they are conducted in either of three ways which are hard shut in, modified shut in and soft shut in. The differences between them are the sequences of closing and opening of choke line and BOP as shown in table 5.1. It is important to know that shut in process is the first approach to close the well in order to protect the crew, stop the flow, gain time and read pressures

Table 6.1 Shut in procedures (Well Control School, 2004)

Step	Hard shut in	Modified shut in	Soft shut in
1	Open choke line valve on BOP stack	Close designated BOP	Open choke line valve on BOP stack
2	Close designated BOP	Open choke line valve on BOP stack	Close designated BOP
3	Notify company crew	Notify company crew	Close choke, follow the pressure in the casing to ensure it does not exceed the limit or pressure trapped
4	Read and record SIDPP and SICP each minute	Read and record SIDPP and SICP each minute	Notify company crew
5			Read and record SIDPP and SICP each minute

6.2 Stripping and Snubbing

Stripping and snubbing are the process to put in/out drill pipe in the wellbore in order to distribute and circulate killing mud into the bottom hole. It is conducted when either preventer or rams in the BOP is closed to prevent influx travel up to the surface. Stripping use its own weight to enter the wellbore as the pressure inside is less than the pressure exerted by the weight of the pipe. Snubbing is performed when the pressure exerted by the pipe is not enough to enter the wellbore by its own weight. It has to be snub in by exerting additional pressure using back pressure to force drill pipe enter the wellbore. There are two types of stripping/snubbing operation:

1.Stripping in/out the hole with annular preventer
2.Stripping in/out the hole with pipe rams

6.2.1 Stripping in the hole with the annular preventer

When stripping in, fluid will have to be released from the hole equal to total cross section area of pipe. Some steps to perform stripping in the hole with the annular preventer (Well Control School, 2004):

1. Construct landing nipple and backpressure valve and install open safety valve on top of pipe
2. Lower pipe into the hole slowly and pass tool joints through preventer carefully (the preventer are closed according to the diameter of the lowered pipe). At the same time check annular regulator valve on accumulator to ensure it is working and regulated pressure to preventer is remaining constant. To keep the bottom hole pressure constant during the stripping operation, the drilling fluid is circulated through kill line and choke line

3. Land the pipe, fill the pipe, install safety valve on the next pipe which will be stripped into the hole. Remove safety valve from the previous pipe. The new pipe is connected to the next pipe and repeat step two until the pipe has reached the bottom

6.2.2 Stripping out of the hole with the annular

When stripping out, fluid will have to be pumped into annulus to keep the hole full. The safety valve should be open during stripping out to prevent the pipe pulled up (float) by the pressure inside the well in case of float leak situation. Some steps to perform stripping out of the hole with the annular preventer (Well Control School, 2004):

1. The annular preventer should be closed according to the diameter of the pipe. Stripping out can be started by circulating the drilling fluid through kill and choke line with initial pressure greater than shut in pressure (100 psi difference). Install safety valve and begin to pulling the pipe slowly
2. While stripping out, check the annular preventer from leaking and the hole must be ensured to be circulated by drilling fluid in order to keep the constant bottom hole pressure. Pass the tool joints in the pipe carefully through the preventer. Check annular regulator
3. Land the pipe on slips. Check drilling fluid displacement and annular pressure. Break off stand and install safety valve. Repeat the process from step one for the next stripping out pipe until all the string has been pulled out

6.2.3 Stripping in the hole with pipe rams

Stripping in the hole can be performed with ram to ram stripping technique where it uses combination of closing and opening (depends on the diameter of pipe) of rams to allow drill string stripped into the hole. The upper rams should be used to take maximum wear when stripping the pipe/string. If rams on bottom are used as a master valve or safety valve, ram to ram stripping should be conducted with four stacks of ram or an annular preventer with a set of rams stack. Stripping rams must have some distance so that tool joint in the pipe will not interrupt both rams when they are close. During the stripping process, the safety valve must always be installed and keep open to prevent float leak situation. Some steps to perform stripping in the hole with two upper pipe rams and one blind ram at the bottom of the stack (Well Control School, 2004):

1. Shut in the well with blind ram. Lower the pipe until the bottom edge of the pipe is just above the blind ram. Use open safety valve on each stand and keep annulus pressure constant by circulating drilling fluid through kill and choke line
2. Close the upper stripping ram and pressure up the fluid between closed blind ram and upper ram until it reached the same pressure in the well by using pump
3. Open blind ram and lower the next tool joints into the stack until it is just above the upper stripping ram
4. Close the lower stripping ram. Bleed off pressure between the two rams. Open upper rams
5. Lower the pipe until the tool joint is just below the upper stripping ram
6. Close upper rams and choke, circulate and pressure up the drilling fluid between rams until it reach the equal pressure in the well by using pump through kill and choke line
7. Open lower pipe until tool joint is just above upper stripping ram and repeat the sequences starting from step four until the pipe has reached the bottom

6.2.4 Stripping out of the hole with pipe rams

Most requirements for stripping out of the hole with pipe rams are the same as for stripping in operation. The upper rams should be used to take maximum wear when stripping out the pipe/string. The float must be ensured that it can be hold properly and safety valve should always be opened. Some steps to perform stripping out of the hole with two upper pipe rams and one blind ram at the bottom of the stack (Well Control School, 2004):

1. Close upper pipe ram (according to the diameter of the pipe). Begin circulating drilling fluid through kill and choke line until it reach the equal pressure in the well. Slowly raise the pipe until next lower tool joint is just below upper stripping ram. Automatic drilling fluid injection should fill the hole as the pipe is pulled out of the hole
2. When lower tool joint is below upper stripping ram, stop the pipe, close the lower stripping ram. Shut down the drilling fluid circulation pump and bleed off the pressure between stripping rams
3. Open upper ram, pull tool joint above the upper ram
4. Close upper stripping ram, circulate the drilling fluid again and pressure up until it has the same pressure in the well by using pump through choke and kill lines
5. Open the lower stripping ram and repeat the sequence from step one until the pipe has been pulled out of the hole

6.3 Testing of BOP

BOP testing is very important to be performed to ensure the functionality of system and components in a BOP. It should resist the maximum pressure they are intended according to their design specifications. The test includes function test, reaction time test, low and high pressure tests. Each of these tests should be recorded. Low pressure test should be performed first by giving pressures between 200 to 300 psi (13.79 bar to 20.69 bar). The high pressure test should be a little lesser than the maximum expected surface pressure, minimum burst pressure of the well's tubing or the rating of the stack. The fluid for conducting the test must not cause pollution and harm the personnel in case of leak occurs (Well Control School, 2004). Testing of BOP can be divided into BOP simulation and BOP testing.

6.3.1 BOP Simulation

BOP should be tested by having simulation of drilling operation to reflect the functionality of BOP in real situation. The simulation usually concerns on the reaction time during operation such as crew's reaction time, time of drill, time for closing and opening of rams and preventer, etc. All of the times taken during simulation are recorded. The simulation conditions are divided into four categories as follows:

- On bottom drilling
- While tripping drill pipe
- When drill collars are in the blowout preventer
- Out of the hole

Here are some examples of procedure for conducting BOP simulation during drilling operation based on Goins and Sheffield (1983). In this example, the drilling rotation mechanism is driven by rotary table instead of top drive. The simulation can be different depends on the required specification.

6.3.1.1 Condition 1: On bottom drilling

1. Stop rotary, hoist kelly joint above rotary table and shut down the pumps while picking up. Check for flow
2. Record the time taken and pit level for the above operations into drill report and pit level chart
3. Open choke flow line while one choke is open
4. Close annular preventer or pipe rams (steps 3 and 4 are done simultaneously)
5. Close variable choke or choke line valve at choke
6. Check all lines and BOP from leakage and record the total time taken

6.3.1.2 Condition 2: Tripping drill pipe

1. Position upper tool joint just above rotary table and set slips
2. Install a full opening valve or inside blowout preventer to close the drill pipe
3. Open choke flow line while one choke is open
4. Close drill pipe rams (annular preventer acceptable)
5. Close variable choke or choke line valve at choke
6. Record the time taken and pit level for the above operations into drill report and pit level chart
7. Check all lines and BOP from leakage

6.3.1.3 Condition 3: Out of the hole

1. Open choke flow line, keeping one choke line open
2. Close blind rams
3. Close variable choke or choke line at choke
4. Record the time taken and pit level for the above operations into drill report and pit level chart
5. Check all lines and BOP from leakage

6.3.1.4 Condition 4: Drill collars in preventers

1. Position upper drill collar box at rotary table and set slips
2. Open choke flowline with one choke open
3. Install a full opening valve and close in the drill collar string
4. Close annular preventers
5. Close variable choke or manifold valve at choke
6. Check that all actions have been correctly accomplished. If only one stand of drill collars remains to be hoisted, the stand should be pulled and the well treated as in condition 3
7. Record the time taken and pit level for the above operations into drill report and pit level chart

6.3.2 BOP Testing

The components inside BOP do not always work as intended, sometimes they fail because of defects from factory, bad design, wear, ageing, etc. Component testing gives status of its availability and performances. The deviation from its intended function can be adjusted by doing maintenance including repair and replacement. According to Goins and Sheffield (1983), there are many likely causes of failure in the BOP components such as improper equipment design and construction, leakage of seal gaskets and rings caused by vibration or added loading, wearing in casing, abrasion of lines and fittings by mud flow, accumulation and deposition of cement, freezing valves, loss of lubricants, partially closed valves caused by erosion, deterioration of rubber seal, etc. Some considerations when performing BOP component test are:

- All choke manifolds, choke and kill lines should be flushed out
- Always use clean water for testing the inner system. The use of drilling mud is not recommended as it will create sealant
- Pipe rams should be closed only where there is pipe in the hole. The closing on open hole and wrong size of pipe diameter can create ram-packer damage
- Casing head valves should always be open when a casing head plug tester is used. The opening allows detection of leakage and prevent overpressure burden inside
- For specific equipment test procedures, always consult manufacturer’s guide as well as local regulations
- Always perform low pressure test before commencing high pressure test
- The minimum time, required component and pressure required are depends on the policy, regulations and standard

The testing of components in BOP can be vary depends on their configuration, type and the number of components being tested. It can be divided into:

- ➢ Closing unit pump capability test
- ➢ Accumulator closing test
- ➢ BOP inspection and test

6.3.2.1 Closing unit pump capability test

Pressure testing on BOP should be conducted after the closing unit test has been performed. The closing mechanism should be driven by the accumulator instead of main power unit to ensure the redundancies in power supply in case of emergency situation during the test. Each well should be tested with BOP closing unit test. The test generally should include the following steps (Well Control School, 2004):

1. Position a joint of drill pipe/tubing in the BOP stack
2. Isolate the accumulator from closing unit manifold by closing the necessary valves
3. If the pumps are powered by air, isolate rig air system from the pumps. A separate closing unit air storage tank or nitrogen bottles should be used to power the pumps during the test. For two redundancies power supply, both system should be tested separately
4. Simultaneously turn the control valve for the closing of annular preventer and turn the control for the opening of hydraulically controlled valve (HCR)
5. By using the power from the pump, the time taken for annular preventer closing and hydraulically controlled valve opening are recorded. Moreover, the remaining pressure is also recorded. According API RP 53 (1997), the recommendation time for this test should less than two minutes
6. Close the hydraulically controlled (HCR) valve and open the annular preventer. Open the accumulator system to the closing unit, charge the accumulator system to its proper operating pressure and record the time required to do this

6.3.2.2 Accumulator closing test

Accumulator closing test should be performed on each well before BOP testing is performed. Some typical procedures are as follows (Well Control School, 2004):

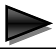
1. Position a joint of drill pipe/tubing in the BOP stack
2. Close power supply to accumulator pumps
3. Record the initial accumulator pressure. Adjust the annular regulator to 1500 psi or designated pressure
4. Depending on standard, policy or regulations, perform the functions that are required such as close the annular, pipe ram and the hydraulic choke line valve
5. Record the time required for accumulators to close. Record the final accumulator pressure. It should not be lower than 200 psi above the pre-charge pressure
6. After preventers have been opened, recharge accumulator system to designed operating pressure and record time for complete power up

6.3.2.3 BOP inspection and test

Some verification of BOP components is necessary before conducting the test. It includes verification of wellhead type, wellhead bowl protector, preventer type, drilling spool, spacer spool, valve types, pump type, rams type, drill pipe/tubing connection type, and all their working pressure rates. It is also important to verify the placement of rams. Other things that should be considered for the test are (Well Control School, 2004):

1. Open casing valve during test, unless pressuring the casing or hole is intended
2. Test pressure should not exceed the manufacturer's rated working pressure for body or seals of assembly being tested
3. Test pressure should not exceed the values for collapse and internal yield pressures tabulated for the appropriate drill pipe/tubing used. Do not exceed tensile strength of pipe

The main concern for this testing is the capability of BOP components, particularly accumulator, preventer, rams, chokes line, kill line and valves, to works under the maximum designated pressure and minimum closing time of BOP. Figure 5.1 and 5.2 shows the example of performing the BOP testing on some components in the BOP. The explanations of symbols in the figures are as follows:

	Test pressure
	Test pressure inlet
	Equipment being tested

In the figures, the arrow point may be subjected to components being test

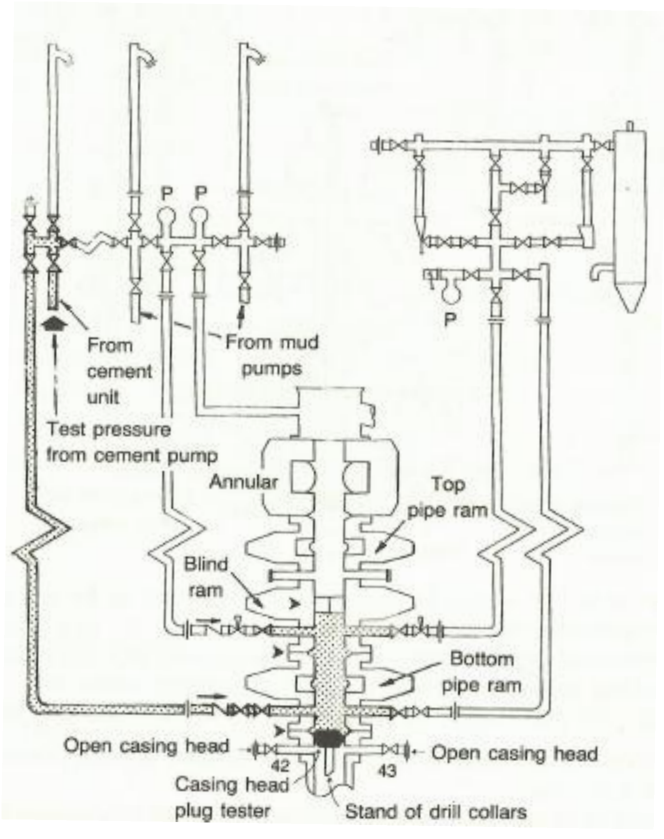
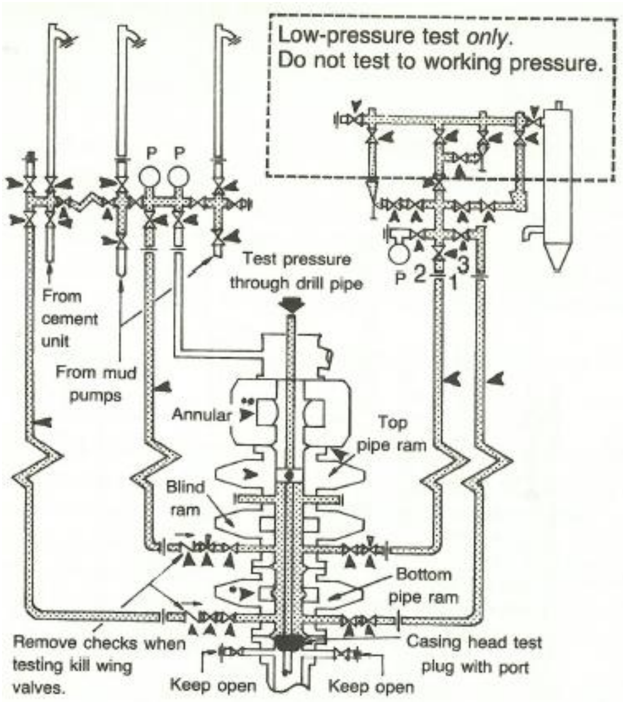


Figure 6.0.1 Testing blind ram (Goins, W.,C., Sheffield, R., 1983)

Procedures in performing blind ram testing (Goins, W., C., Sheffield, R., 1983):

1. All equipments should be tested at 200-300 psi and then to the rated working pressure of the weakest member
2. Install one stand of drill collars below an appropriate casing-head plug tester. Land the plug tester and back off the running joint. Open bore type plug testers can be provided with a plug in order to test blind rams with the drill string removed. Fill the BOP with water and close the blind shear rams
3. Open casing head valves to prevent casing rupture or formation breakdown if the plug tester leaks

4. Apply test pressure as illustrated in the figure. This test also applied to other component than blind ram as indicated by the arrows in the figure



Procedures in performing BOP components testing (Goins, W., C., Sheffield, R., 1983):

* Bottom pipe ram tested by using same procedure as for top pipe ram

** Annular preventer tested using same procedure as for pipe rams

1. All equipments in the test should be tested to rated working pressure of the weakest member

Figure 6.0.2 Testing pipe rams, annular and all choke and kill manifolds, flowlines and BOP wing valves (Goins, W.,C., Sheffield, R., 1983)

2. From previous test, open the blind rams and install appropriate test string and screw into the plug tester. Fill BOP with water and close top pipe ram
3. Apply test pressure down the drill pipe and through a perforated sub or through the pug tester if it has an integral port
4. The bottom ram can be tested in a similar manner. The test string must fit ram size
5. The annular preventer can also be tested similarly, but do not test to more than 70% of rated working pressure unless required, or 50% of rated working pressure where regulations do not specify

7. SUGGESTED RISK ANALYSIS TOOLS FOR BOP CRITICALITY ASSESSMENT

Risk analysis is the process of identification, definition, analysis and measurement of problems, hazard, causes, consequences and alternatives in a system to give a risk picture that will be used for a decision making process through some accepted parameters. According to Norsok Z-013 (2001), risk analysis is the process of using information to identify hazards and estimate risk. It covers the analysis of cause and consequence of risk to personnel, environment and asset.

Typically there are two approaches for risk analysis, qualitative and quantitative risk analysis. Qualitative risk analysis uses the knowledge of risk from experts through brainstorming and group discussion to present the simplify risk picture in a descriptive categories or coarse scale, i.e. high, medium, low, etc, while quantitative risk analysis (QRA) use the knowledge of risk from model-based risk such as event tree analysis, fault tree analysis and other tools to represent the risk picture in more detail (Aven, T., 2008, p. 4). The limitation of information and data in the beginning of a project make brainstorming and group discussions among experts become a good way to conduct risk picture. Quantitative risk analysis needs quantified data in order to assess risk in more detail, usually by combining the judgment from the expert. The risk picture resulted from risk analysis should be evaluated with regard to risk acceptance criteria and when applicable compared to alternative. Risk reducing measures is presented and cost benefit analysis can be used as part of decision making. Figure 8.1 shows the schematic to determine the appropriate risk analysis approaches.

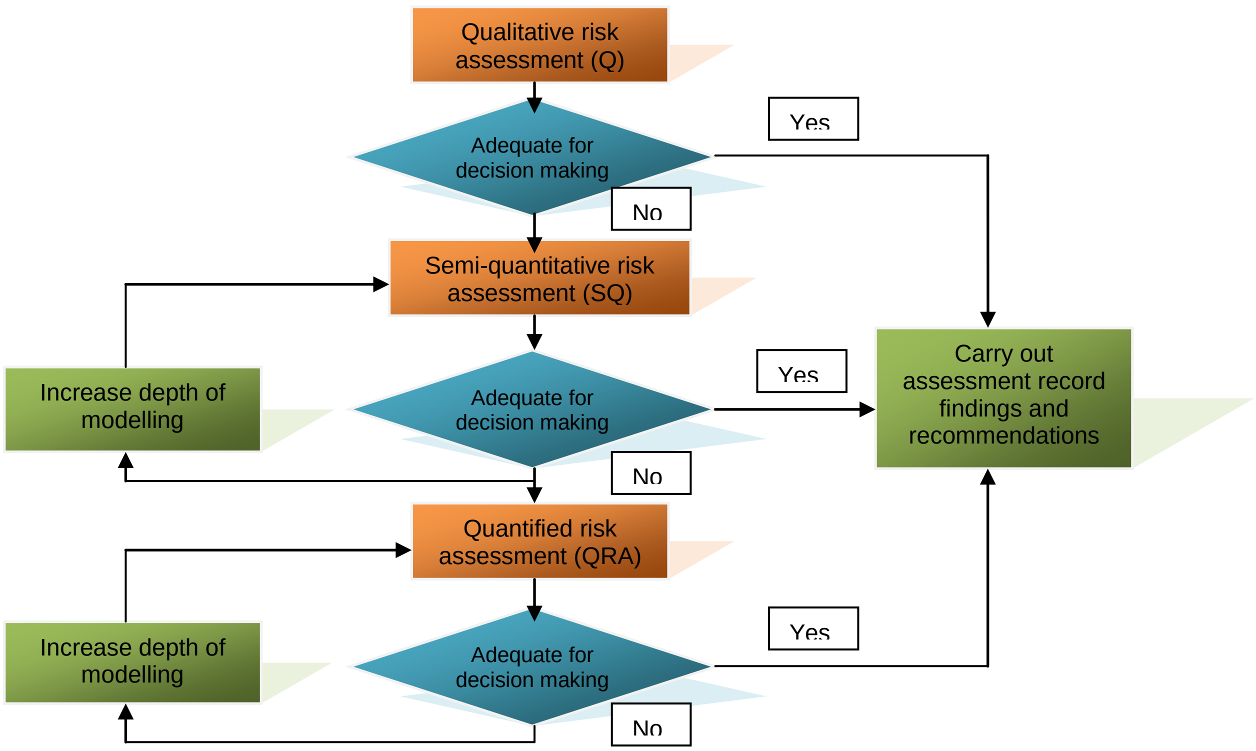


Figure 7.1 Step to determine appropriate risk assessment (HSE, 2006)

There are tools to support the risk analysis process. The use of tools depends on the intention of the analysis and result. In some risk analysis, criticality and reliability can be the main focus of the analysis, particularly for the design of components or machineries in the production and safety systems where functionality is the most prominent aspect to gives the highest value of production and safety assurance. The needs for robust and redundant system are determined through this process. Moreover, criticality and reliability analysis are also used in maintenance area where the assessment of the component's reliabilities are very important to determine maintenance plan which is needed to optimize component's uptime, reduce component's downtime and prevent unplanned maintenance.

Engineering system, such as BOP, usually consists of a number of subsystems and components that interacts with each other to perform some specific function. Critical components in the system need to be identified and ranked to determine the robustness and redundancies of the system if one or more components in the system fail. Mainly, the criteria are chosen from the severity of consequences, occurrence (frequency or probability) of failure, detection of failure, functionality requirement of the items and redundancy in the system. Knowing these criteria can help us to determine the proper risk analysis tools to determine the criticality of components in a system such as reliability block diagram (RBD), failure modes, effects and criticality analysis (FMECA), risk (criticality) matrix, redundancy and effect table.

7.1 Reliability Block Diagram (RBD)

Reliability block diagram is used for BOP criticality assessment because it presents functional flow diagram of how the logical relation of components in the BOP system runs a BOP function. It ensures that all components that make up a BOP function are presented which can be useful for failure identification. Identification of component's failure in the BOP system is important to find out which components are the most critical to the availability of the BOP function. It can be achieved by identifying minimal cut set. The components in the minimal cut set are then considered as the critical components.

In the reliability block diagram, a system can be assumed to consist of n components and have a state of functioning or failure. We can assign the binary state of component i with x_i and binary state for a system with Φ_i, (Aven, T., 1992, p.87-88).

$$x_i = \begin{cases} 1 \ if\ component\ i\ is\ in\ the\ functioning\ state \\ 0 \ if\ component\ i\ is\ in\ the\ failure\ state \end{cases}$$

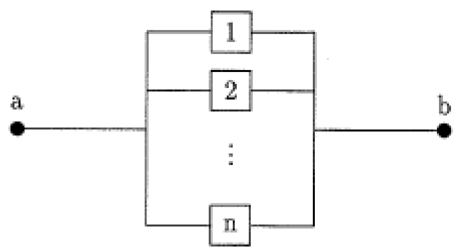
$$\phi_i = \begin{cases} 1 \ if\ the\ system\ is\ in\ the\ functioning\ state \\ 0 \ if\ the\ system\ is\ in\ the\ failure\ state \end{cases}$$

The state of a system is determined by the state of components in the system, therefore structure function Φ(x) is:

$$\phi = \phi(x) \quad \text{, where } x = (x_1, x_2, \ldots, x_n)$$

Basically, the components in a system have two logic structures, series and parallel structure. There may be series, parallel or combination of both structures. These structures determine the failure characteristics of a system. In the series structure, the system fails if one of the components in a system fails. On the other hand, parallel structure will have a system failure if all of the components in the system fail. Table 8.1 shows the difference between series and parallel structure and formula to determine the state (function or failure) of a system.

Table 7.1 figure and formula of series and parallel structure in RBD

Series Structure	Parallel Structure
	
$\phi(x) = x_1 \cdot x_2 \cdot \ldots \cdot x_n = \prod_{i=1}^{n} x_i$	$\phi(x) = 1 - (1-x_1)(1-x_2)\cdots(1-x_n)$ $\phi(x) = 1 - \prod_{i=1}^{n}(1-x_i) = \coprod_{i=1}^{n} x_i$

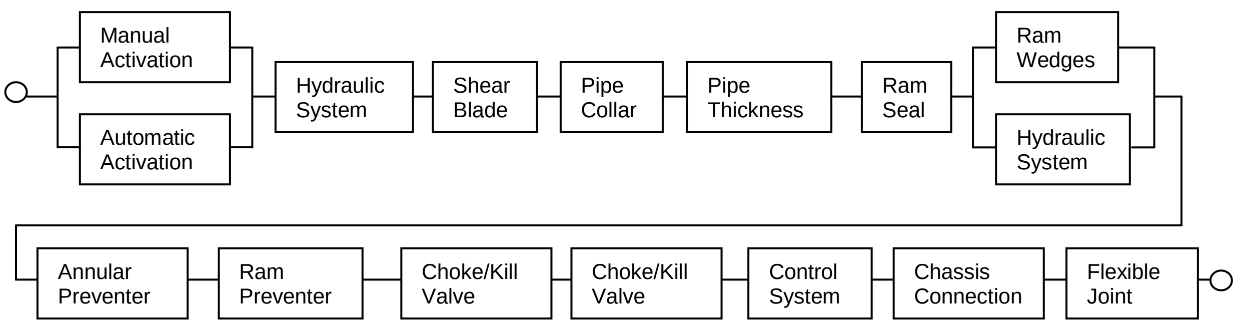


Figure 7.2 Example of reliability block diagram of BOP activation (Tumer, I., et al., 2010)

7.2 Failure Modes, Effects and Criticality Analysis (FMECA)

The critical component analyzed in the reliability block diagram is not enough to present the criticality on BOP system. There could be more than one critical component in a system and it is quite hard to determine which component that gives significant consequences to the BOP system by only knowing the failure state of the components. Other factors related to the occurrence of component's failure such as failure causes, failure effects and level of consequences need to be identified to get a broader scope of the component's criticality. One of the tools which analyze these factors is failure modes, effects and criticality analysis (FMECA).

Failure modes, effects and criticality analysis identify all possible failures modes and its effects that may occur as well as the criticality of each component to know the reliability and performance of a system. The diagram from RBD is useful to identify components and the effects of failure modes against other component in the system. This analysis also identifies the compensation activity or risk reducing measures to prevent the occurrence of component's failure and to mitigate the effects of failure in a system.

The main goals of conducting FMECA for BOP system are:

1) Identify failure modes for the subsystem/function of the BOP systems and the resulting effects of these failure modes on each subsystem or component at a local level and for the total system/component as a whole
2) Identify how the failure modes can be detected, and describe the possible existing, provisions and safeguards that prevent the system from failing. If none is available, alert mode should be defined if hazards are present when the system fails. It shows attention to increase safety and reduce the probability or consequence which reduces the risk as well
3) Assess the criticality of the failure modes by estimating the probability and severity, and then plot it in the criticality matrix

The approach of conducting FMECA can be done in qualitative and quantitative way. Quantitative method is used when failure rates, failure modes, failure mode ratios and failure effect probabilities are known which are required to quantify the criticality number of components. Qualitative method is used when there is no available data for failure rates and failure modes. The criticality in qualitative method is determined by making some subjective measurements for ranking the severity and occurrence of the failures (Department of the Army, 2006). In this report, the analysis is conducting in a qualitative approach as there is inadequate time and effort to do the quantitative as well as scarcity in the BOP system data. Discussion, brain storming and using experience from experts is considered a good way to present the criticality of the BOP components.

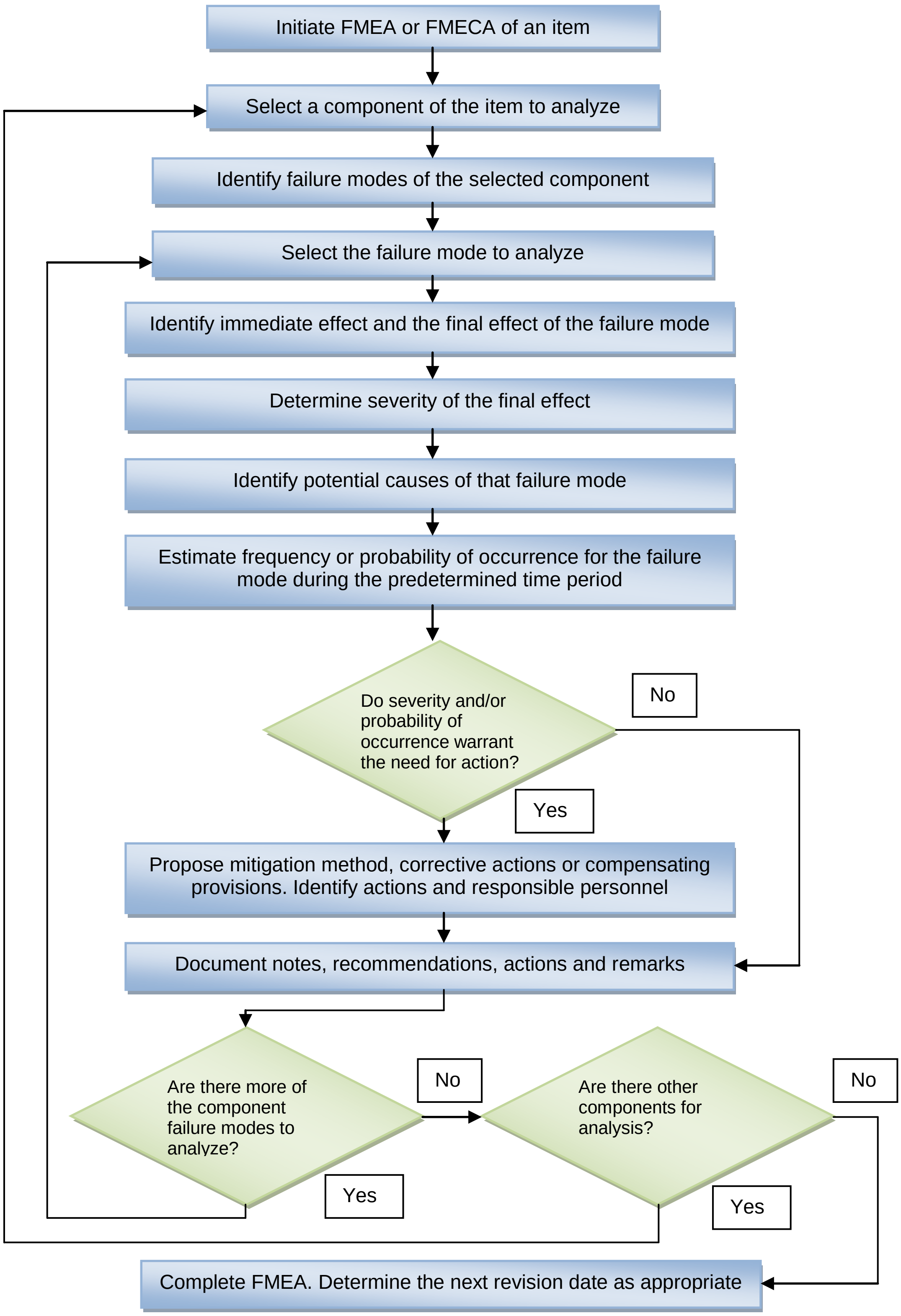


Figure 7.3 Flowchart of FMECA (IEC 60812, 2006)

7.2.1 Failure Modes, Effects and Criticality Analysis (FMECA) Methodology

The construction of FMECA is systematically created in a sheet containing some parameters. These parameters can vary from one sheet to other sheets, but basically it contains parameters which describe identification (item number), function (operation state), failure modes, failure mechanism, effect on other units in the system, effect on system, corrective measure, failure frequency, failure effect ranking and remarks (Aven, T., 2008, p.64). The sheet for qualitative and quantitative method may have some distinction in the parameters. Moreover, a good work flows are also required to conduct a thorough analysis of FMECA. Failure modes and effect analysis (FMEA) is usually conducted first before assigning criticality analysis (FMECA).

a. Defining the system clarifies the purpose of the system and gives an initial schematic and operational detail of the system. Rules and assumptions should be made when conducting the analysis to give more understanding of the system. Typically, there are two systems which are mostly defined in the analysis, functional and hardware (component) systems.

    - Functional systems definition usually uses in the early phase of design and commonly conducted in the top down approach. It will be used to analyze the effects of a system or subsystems on a specific condition. To do this the analyst should define and identify each system functions, potential failure modes and failure causes for each functional output.

    - Hardware systems definition commonly outlines the components in the system and their possible failure mode. It uses bottom up approach to analyze the component's failure mode.

b. Reliability block diagram is constructed to give a representation of interrelationship and interdependencies of functional component in the intended operation of a system. The interdependencies are illustrated with the functional flow sequence with series and parallel structure. It also helps the analyst to follow the failure mode and its effect of component and function.

c. Failure and fault sometimes been interpreted in the same meaning. According to Norsok Z-008 (2001), failure can be described as the termination of the ability of an item to perform a required function, while fault can be described as the inability of an item to perform a required function. Further, failure mode is the observed of failure in a function, subsystem, or components. It can be identified by studying the output of the various functions. Failure mode concern depends on the specific component, system, environment and past history (Department of the Army, 2006). According to Blanche and Shrivastava (1994), the failure mode can be classified into two categories such as:

1. Intermittent failures is failures that caused by some problems in the functionality of components and only happen in a short period of time

2. Extended failure is failures that caused by some problems in the functionality of components continuously until some parts are repaired. This type of failure can be classified again into :
   - Complete failures is failures that cause complete lack of a required function
   - Partial failures is failures that lead to a lack of some function but do not cause a complete lack of a required function
   - Sudden failures is failures that could not be predicted by testing or examination
   - Gradual failures is failures that can be predicted by testing or examination
   - Catastrophic failures is failures which are sudden and complete
   - Degraded failures is failures which are partial and gradual

The application of failures is not only limited to the above categorizations. It sometimes depends on the application they are applied on such as primary failure, secondary failure and command failure are introduced. Primary failure is a failure that is cause by the natural ageing of the component(s). Secondary failure is a failure that is cause by load or stress that is beyond the limited design of a component. Command failure is a failure cause by an improper control signal or noise (Rausand, M., Høyland A., 2004, p.85-86).

Thorough failure mode analysis can be done by examining each component failure mode and/or output function for the following condition (Department of the Army, 2006):

- Failure to operate at the proper time
- Intermittent operation
- Failure to stop operating at the proper time
- Loss of output
- Degraded output or reduced operational capability

d. Another important parameter in FMECA is failure cause or mechanism. According to IEC 50(191), failure cause is the circumstances during design, manufacture or the use that have led to a failure. Failure cause can be defined in different aspects such as design failure, weakness failure, manufacturing failure, ageing failure, misuse failure and mishandling failure (Rausand, M., Høyland A., 2004, p.87).

e. Failure effect analysis is performed to all relevant components prior to the failure mode on the system. To simplify the work, the relevant component can be taken from the reliability block diagram which defines the functional relationship between components in the system. Normally, there are three types of failure effects in the FMECA:

- Local effect is the specific effect as an immediate result from the failure mode of component. Local effects are determined without taking into account existing provisions and safeguards
- Global effect is the effects that influence other failure mode in the operation and functionality of other components in a system.
- End effect shows the state of the system whether function or failure. It is determined after taking all the existing provisions and safeguards into account. It consists of different categories as follows:

  1. System failure which shows that the failed component can make disturbance to the operation and function of the system
  2. Degraded operation which shows that the failed component can influence the operation of the system but it still can be performed as intended
  3. No immediate effect of failed component in the system

f. Prior to the failure of component(s), there should be indicator(s) to detect failure so that operator can perform the required action in order to prevent system failure or other sequence that can influence the performance of other component and system as a whole. Supervisory control and data acquisition (SCADA) is one example of detection system with visual or audible warning devices and automatic sensing device. If there is no detection device in the working component, the failure effects should be examine whether it is affecting the objective of the system or safety. The Indicator can be a normal indicator, abnormal indicator or incorrect indication. Normal indicator shows a normal operation condition, abnormal indicator shows that the system or component has failed or malfunction, incorrect indicator shows an opposite indication status of component or system from its actual condition/status (e.g., fault indicator while the component/system is still functioning normally).

   The failure detection system or method gives the availability to operator to perform compensating provisions to prevent and mitigate the effect of a failure in a system. It can be achieved by adding active or passive compensating provisions such as (Department of the Army, 2006):

   - Redundancies in a system to ensure the operability and allow more safe operation
   - Safety devices such as alarm or monitoring systems which gives the indication of limited parameter in the operation. Monitoring system can be done with regular testing or regular condition monitoring
   - Automatic self compensating devices that can set the required operation parameter automatically to ensure the performance of the intended component (e.g., automatic adjustment of variable speed in a pump)
   - Manual operator action such as manual turn on/off of a component’s function

g. The assignment of severity (consequences) and probability of occurrence ranking is to give first overview of the criticality of component in a system. It is derived from generic data and will be discussed with experts in the workshop.

- Probability (P) is derived from qualitative assessment of the likelihood for the failure mode to occur, rated from 1 (least likely/frequent) to 5 (most likely/frequent)
- Consequence (C) is derived from qualitative assessment of the consequence or severity of the failure mode, rated from 1 (least severe) to 5 (the most severe)
- Risk (R) is the risk rank of failure mode rated as low (L), medium (M) and high (H)

The available provisions and safeguards are taken into consideration when assigned probability and consequence value.

h. Remarks field consists of additional information and recommendation as well as the responsible party who are in charge for resolving the problem.

7.3 Criticality Ranking and Criticality Matrix

The criticality ranking can be described by showing the failure mode with consequences and the probability of occurrence. The consequence and probability can be ranked based on the subjective probability based on the knowledge from experts and engineering judgment.

Table 7.2 Failure probability rank

Failure probability rank	Description
P=1	Could occur, but never heard of in the world (<1/10,000 years)
P=2	Has occurred in the world, but very unlikely (1/10,000 – 1/1000 years)
P=3	Incident has occurred in some operations (1/1000 – 1/100 years)
P=4	Incident has occurred several times in some operators (1/100 – 1/10 years)
P=5	Incident has occurred several times in most operators (1/10 – 1 years)

Table 7.3 Effect severity rank

Effect severity rank	Description
C=1	First aid/medical treatment case
C=2	Serious injury
C=3	1-10 fatalities
C=4	10-30 fatalities
C=5	30+ fatalities

Criticality matrix (risk matrix) is established to show the criticality level and risk acceptance criteria of failure modes in the BOP components. Normally, there are three levels of risk in the matrix, low, medium and high (Gudmestad, O.T., 2001). The matrix has probability and consequence values as their axes where the criticality (risk) value taken from FMECA can be plotted in the matrix to see the level of criticality of the BOP's component. The failure modes within the area of high or intolerable critical (risk) level must be reduced to the medium region by using risk reducing measures/actions and/or barriers.

High (H) level or Intolerable risk level is considered as the most critical failure mode for components and indicated by the red area in the risk matrix.

The medium (M) region is also known as ALARP (As Low As is Reasonably Practicable). This is where the criticality of component should be treated and assessed for possibility of another risk reducing measure or whether a more detail studies should be performed (Norsok Z-013, 2001). Intermediate region is indicated by the yellow area in the matrix.

The low (L) region is considered as a low critical area and indicated by green area in the matrix.

		Probability				
		P=1	P=2	P=3	P=4	P=5
		Could occur, but never heard of in the world	Has occurred in the world, but very unlikely	Incident has occurred in some operations	Incident has occurred several times in some operations	Incident has occurred several times in most operators
	Description	< 1/10,000 years	1/10,000 – 1/1000 years	1/1000 – 1/100 years	1/100 – 1/10 years	1/10 – 1 years
C=5	30+ fatalities					
C=4	10-30 fatalities					
C=3	1-10 fatalities					
C=2	Serious injury					
C=1	First aid/medical treatment case					

Figure 7.4 Criticality matrix

When consequence and criticality of one or more components are same, the alternative of the criticality can be reassessed by considering the safety and the objective of the component's function. If the most concern in the system is safety or functionality of component, then area on the top side of the diagonal in the criticality matrix should be put more emphasize for criticality because high severity is considered more important than high occurrence.

7.4 Redundancy and Effect Table

Redundancy can be described as a duplicate system or component to serve as a back up when the other system with the same function has failed. Redundancy should be added in the system or components that are critical to the safety and functionality. If redundancy is considered to be unavailable, then robust system or component needs to be employed. If it is also unavailable, then reaction plan or operation should be created to replace the function of the failed component. Redundancy and effect table lists all the numbers and types of redundancies for the specific component that is assumed to be in the total failure in the BOP system as well as showing the effects of the redundancy given the failure of the component. It might have the similarity with FMECA, but it is specifically present the redundancy when total failure of component is considered. The critical component can then be identified from the component failure effects and the redundancy they have.

7.5 Discussion of the Suggested Risk Analysis Tools for BOP Criticality Assessment

The suggested risk tools for BOP criticality assessment are reliability block diagram (RBD), failure modes, effects and criticality analysis (FMECA), criticality matrix, redundancy and effect table. All these tools are complement to each other to give a better perspective of criticality in the BOP system.

Reliability block diagram (RBD) is important to shows the functional flow of the components and their logic relations in the BOP system. The construction of RBD in this report is based on the hydraulic BOP control system schematic, function flow and P&ID. Knowing the relations between components, give the ease of reliability identification in the system. We can assume which component failure that can make a failure of the system through minimum cut set. The components in the minimum cut set can be considered as the critical components. In this case, one component is more critical than more than one component in the minimum cut set. Due to the complexity of BOP control system, the minimum cut set is only considered for one component that can make a system to fail.

In this RBD analysis, the components are only considered to have binary states (function or failure). Reliability analysis based on the quantified data of failure rate is not conducted as there is a lack of source and it requires a lot of time and man work to conduct quantitative analysis.

Binary state analysis in the RBD is the first overview of criticality in BOP regarding to its simplicity. However, RBD has lack of information of how the component fails and what compensating measures can be taken into account to prevent the failure of the component. Thus, one of the tools to assess that, FMECA, is needed to cope with the issues.

FMECA is used to describe failure modes, failure causes and safeguards of the components as well as giving the description of its effects for other component and the system as a whole. It is also describe the level of failure modes occurrence and the consequences that might occur. FMECA is considered to be an easy way to assess criticality in a system.

The method used in FMECA is qualitative analysis by using expert judgment and discussion among other interest parties. The lack of BOP's component failure data and less time consuming make qualitative method is the best approach for the criticality analysis. The failure modes in the analysis are based on the best knowledge of experts and are presented only for the most important for the BOP function. The level of occurrences and consequences of failure modes are plotted into the criticality matrix by considering the safeguards to see the critical level of the component.

Regarding to the ease of using qualitative FMECA analysis, there are some considerations to take into account. FMECA does not include the relations between components in the system and assume that other components are function perfectly. It might give a wrong conclusion given the system fails as a result of components failure sequences in the system. Furthermore, the assignment of consequence value is based on individual component which might give inaccurate value of criticality of the system as a whole.

Despite of the issues, qualitative FMECA is a simple tool that can systematically analyze the critical component in a system to provide a preliminary reliable overview of critical components in a BOP system given that the data is rare. Table 8.4 shows the pros and cons of FMECA.

Table 7.4 Pros and Cons of FMECA

Pros	**Cons**
FMECA is a systematic analysis and reliable method to evaluate the performance and criticality of component and system as a whole (Rausand, M., 2005)	FMECA is not suitable for multiple failures as it assumes only one failure occur at a time and other components are working perfectly (Rausand, M., 2005)
Simple concept and application allow that can be easily learned (Rausand, M., 2005)	The process of constructing FMECA may be tedious, time consuming and expensive (Rausand, M., 2005)
Complex system can be evaluated easily (Rausand, M., 2005)	FMECA is not suitable for analyzing system with some redundancies (Aven, T., 2008, p.69)
FMECA can be used as a good basis for more comprehensive quantitative analysis (Aven, T., 2008, p.69)	FMECA put more emphasizes on technical failures and sometimes ignore the human failure contribution (Aven, T., 2008, p.69)

The FMECA sheet for BOP system produced in this report are refers to the FMECA workshop done by some interest company who own and operate the BOP control system such as Statoil, NOV, Fabricom as well as from consultancy company, Scandpower.

The FMECA workshop is done by having discussion and brainstorming between experts from different expertise related to the operation of BOP. It involves field operator engineer, drilling engineer, technician (maintenance and inspection of BOP), BOP risk consultant and BOP project manager. The step in conducting the FMECA is the same as the flow shown in figure 7.3. The item identification, failure modes, failure causes, failure effects, detection, compensating provisions (safeguards), consequences, probability, risk value and additional information are discussed thoroughly among experts. The information of these parameters is taken from the specific P&ID (piping and instrument diagram) of the related item/component and the experience from experts through discussion among them.

The FMECA is performed by dividing the relevant BOP systems into subsystems or main components and looking at the functions, these subsystems and main components needed to perform in order for the BOP systems to work as intended. Then it is assessed in the FMECA meeting how these functions could fail (the failure modes) and the effects of these failures, as well as the criticality rated as a combination of the probability and consequence of the failure modes which are based on the knowledge from the meeting.

The FMECA facilitator makes a preliminary breakdown of the BOP systems and a proposal for potential generic failure modes. The proposed division of the BOP systems and the generic failure modes is presented at the start of the FMECA meeting. The final divisions of the BOP system into main components and subsystems, and the potential failure modes for these are then modified and agreed by brainstorming with the FMECA participants during the meeting. Moreover, for each of the subsystems, the scoring of probability and consequence of the failure modes are also discussed and agreed between participants. These values are then plotted into the criticality matrix.

The effect severity rank (scale) is related to personnel injuries or fatalities due to a failure. The consequence has been divided into five categories according to the severity. The effect consequence scale is available during the FMECA workshop and is determined based on the subjective prediction from experts through discussion in the meeting.

The criticality matrix and the rank of failure mode occurrence probability are derived and proposed by risk consultant company, Scandpower, based on their expertise and related discipline. The cause probability or frequency related to failures was determined using engineering judgment. The assessment of probability of each FMECA items is based on experiences with the different parties in the company and from the joint experience of the participators, and engineering judgments.

Some failure modes in this report are not discussed in the workshop and thus the assessment of some occurrence probabilities and consequences in this report are based on the Sintef report by Holand, P., (2007) and case study report of Deepwater Horizon risk assessment by Tumer, I., et al., (2010). Sintef report gives failure data occurrence probabilities (failure rates) for some BOP component's failure modes. Failure mode rate (λ) is taken by dividing 1 with MTTF (Mean Time To Failure).

$$\lambda = \frac{1}{MTTF}$$

In this analysis the effects of consequences are only focus on the personnel injury or fatalities due to a component failure. It is considered as the most critical element for safety. Potential loss of money due to delays/material damage, environment damage and loss of reputation might not be discussed directly.

There are some failure modes that might not really influence the functionality of a component. In this case, the analysis of criticality should also be based on the assumption if one component is totally not functioning and analyze its effect to other component in the system. The number of redundancy based on the back up component/system and alternative operations are documented in the redundancy and effect table. The information of effect and redundancy can be taken from FMECA. Through this table, we can see which component that has high effect (consequence) with less/no redundancy to be the critical component.

The purpose of using redundancy and effect table together with FMECA is to give different views of criticality based on their failure modes. The results of both methods are compared and final critical component in the BOP system can be presented.

8. ANALYSIS OF CRITICALITY COMPONENT IN BOP

The analysis of BOP components in this report is based on some parameters and assumptions as follows:

- The components analyzed are hydraulic BOP control system, BOP stack, choke valve, kill valve, connector (LMRP and wellhead) and general component inside rams and preventer
- The analysis is based on the simple schematic and/or simple P&ID of the BOP control system
- Some analysis in FMECA is taken from the BOP control system workshop done by some interest companies
- The analysis use subsea BOP stack arrangement typically similar as shown in figure 5.1 consisting of:
    - 1 Annular preventer:
    - 4 rams:
        - 1 blind shear ram
        - 1 variable bore ram
        - 1 middle pipe ram
        - 1 lower pipe ram
    - 2 pairs of choke and kill lines with standard valves configuration

8.1 Reliability Block Diagram

8.1.1 Reliability Block Diagram for Close Function of Subsea BOP control System

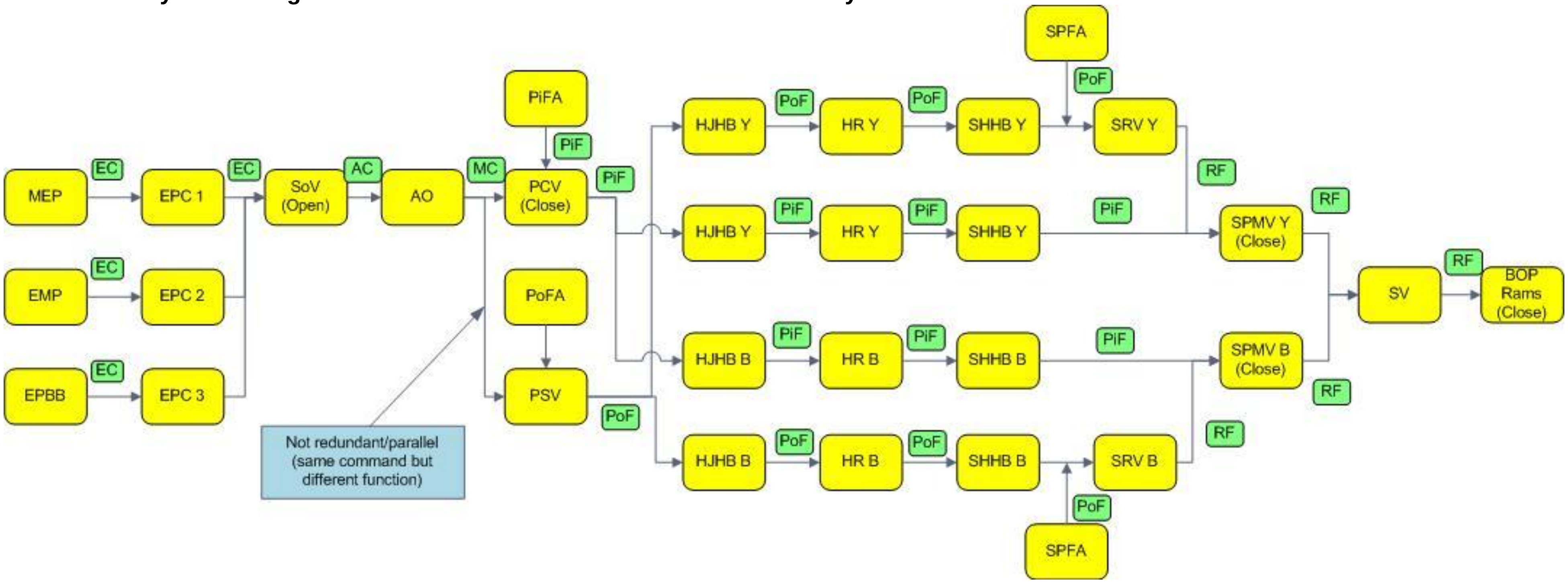


Figure 8.1 Reliability block diagram for BOP rams close function

Legends of BOP rams close function block diagram

MEP	: Master Electric Panel	PSV	: Pod Selector Valve	AC	: Air Control
EMP	: Electric Mini Panel	HR Y/B	: Hose Reel Yellow/Blue	MC	: Mechanical Control
EPC	: Electric Power Cable	SHHB Y/B	: Subsea Hydraulic Hose Bundle Yellow/Blue	PiF	: Pilot Fluid
EPBB	: Electric Power Pack with Battery Back-up	SPFA	: Subsea Power Fluid Accumulator	PoF	: Power Fluid
SoV	: Solenoid Valve	SRV Y/B	: Subsea Regulated Valve Yellow/Blue	RF	: Regulated Fluid
AO	: Air Operator	SPMV Y/B	: Sub Plate Mounted Valve Yellow/Blue	VF	: Vent Fluid
PiFA	: Pilot Fluid Accumulator	SV	: Solenoid Valve		
PCV	: Pilot Control Valve	MWT	: Mix Water Tank		
PoFA	: Power Fluid Accumulator	EC	: Electric Control		

The reliability block diagram above based on the schematic flow figure 4.22 and 4.25. The opening and blocking function of the subsea BOP control system have the same reliability block diagram as the closing one. There are only some differences in the operations of some components as shown in table 8.1 below.

Table 8.1 Operation modes of components for different BOP functions

Component	**Position of Operation**		
	Close Function	**Open Function**	**Block Function**
Solenoid Valve (SoV)	Open	Close	½ open
Pilot Control Valve (PCV)	Close	Open	½ open
Sub Plate Mounted Valve (SPMV)	Close	Open	½ open
BOP rams/annular preventer	Close	Open	½ open

Critical components based on the minimum cut set (one component):

- Solenoid valve (SoV)
- Air operator (AO)
- Pilot control valve (PCV)
- Pod selector valve (PSV)
- Rams or annular preventer
- Shuttle valve
- Surface fluid accumulator (pilot and power fluid is in one accumulator)
- Subsea fluid accumulator

8.1.2 Reliability Block Diagram for Control Fluid Circuit and Subsea Accumulator Recharge System

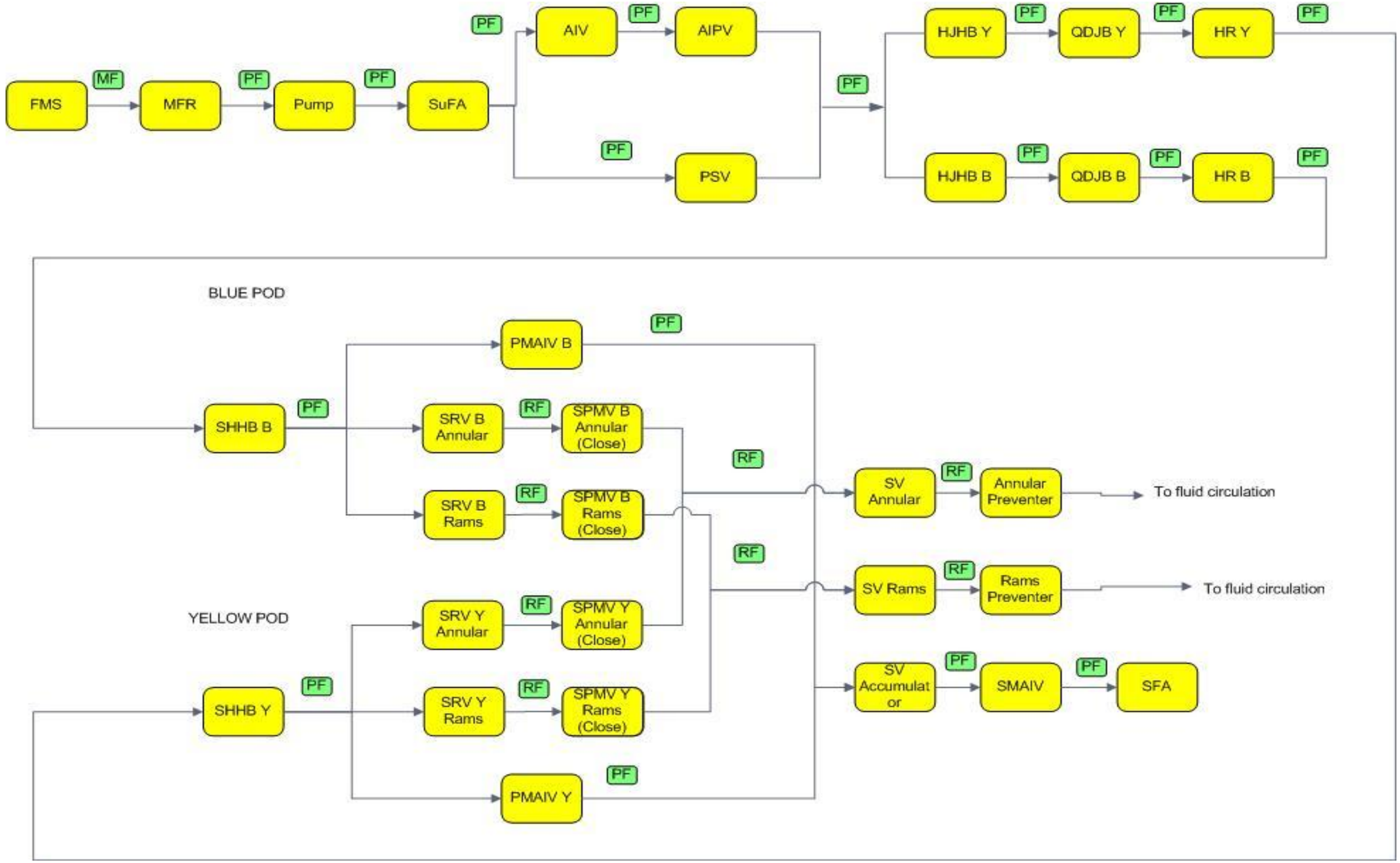


Figure 8.2 Reliability block diagram for control fluid circuit and subsea accumulator recharge system

Legends of BOP control fluid circuit and accumulator recharge system block diagram

FMS	: Fluid Mixing System
MFR	: Mixed Fluid Reservoir
SuFA	: Surface Fluid Accumulator
AIV	: Accumulator Isolation Valve
AIPV	: Accumulator Isolation Pilot Valve
PSV	: Pod Selector Valve
HJHB Y/B	: Hydraulic Jumper Hose Bundle Yellow/Blue
QDJB Y/B	: Quick Disconnect Junction Box Yellow/Blue
HR Y/B	: Hose Reel Yellow/Blue
SHHB Y/B	: Subsea Hydraulic Hose Bundle Yellow/Blue
PMAIV Y/B	: Pod Mounted Accumulator Isolation Valve Yellow/Blue
SRV Y/B	: Subsea Regulated Valve Yellow/Blue
SPMV Y/B	: Sub Plate Mounted Valve Yellow/Blue
SV	: Shuttle Valve
SMAIV	: Stack Mounted Accumulator Isolation Valve
SFA	: Subsea Fluid Accumulator
MF	: Mixed Fluid
PF	: Power Fluid
RF	: Regulated Fluid

The diagram based on figure 4.26. It has critical components based on minimum cut set (one component) as follows:

- Fluid mixing system (FMS)
- Mixed fluid reservoir (MFR)
- Pump
- Surface fluid accumulator
- Shuttle valve (SV) annular
- Annular preventer
- Shuttle valve (SV) rams
- Rams preventer
- Shuttle valve (SV) accumulator
- Stack mounted accumulator isolation valve (SMAIV)
- Subsea fluid accumulator

8.1.3 Reliability Block Diagram for Annular Preventer

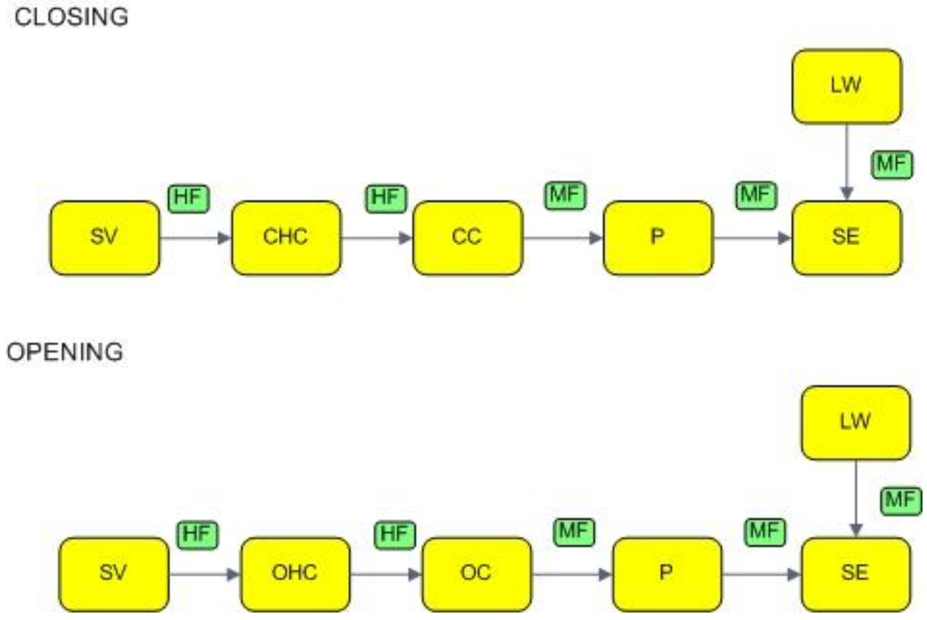


Figure 8.3 Reliability block diagram for annular preventer close and open function

Legends of annular preventer function flow block diagram

SV	: Shuttle Valve
CHC	: Closing Hydraulic Connection
OHC	: Opening Hydraulic Connection
CC	: Closing Chamber
OC	: Opening Chamber
P	: Piston
SE	: Sealing Element
LW	: Locking Wegde

The diagram based on figure 4.7. All of the components in the diagram, except locking wedge, are critical.

8.1.4 Reliability Block Diagram for Ram Preventer

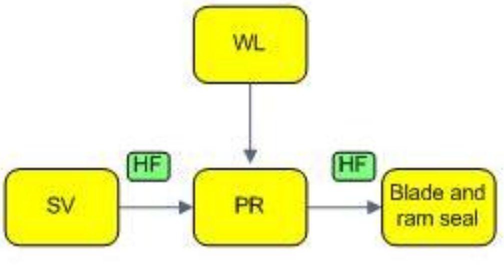


Figure 8.4 Reliability block diagram for ram preventer

Legends of ram preventer function flow block diagram

SV	: Shuttle Valve
PR	: Piston Rod and blade
WL	: Wedge Lock

The diagram based on figure 4.18. All of the components in the diagram plus shear ram housing, except wedge lock, are critical.

8.2 Failure Modes, Effects and Criticality Analysis (FMECA)

8.2.1 System Breakdown

The BOP system is broken down into components based on the information from reliability block diagram and additional component taken from the FMECA workshop that are significant for the BOP functionality. Failure mode of each component are identified and given a unique identifying number. More than one component may have the same failure modes, but it can has different effects depends on the type of component. Main component and its corresponding failure mode can be seen in table 8.2 below.

Table 8.2 Lists of components and the corresponding failure modes

ID No.	Item/Functional Identification	Failure mode(s)	Description
Node 1: Hydraulic BOP control system			
1.1	Accumulator bottles	F-1.1.1	Burst bladder
		F-1.1.2	Leakage through nitrogen "fill"- system (valve)
		F-1.1.3	Lack of stored accumulation pressure, reduced capacity,
		F-1.1.4	Lack of stored accumulation pressure, reduced capacity,
1.2	Hydraulic line from HPU to BOP	F-1.2.1	Leakage, bursting, plugged line
1.3	Solenoids to valves	F-1.3.1	Fail to move
1.4	Pilot valve (air)	F-1.4.1	Not operating
1.5	Subsea regulated valve	F-1.5.1	Regulator stuck in position
		F-1.5.2	Fail to open/close
1.6	Shuttle valve (rams and annular preventer)	F-1.6.1	Not able to change position
1.7	Fluid reservoir	F-1.7.1	Rupture of reservoir
		F-1.7.2	Contamination of hydraulic fluid
		F-1.7.3	Too low volumetric capacity of reservoir (1200 gal. reservoir)
1.8	Pressure regulator (hydraulic manifold)	F-1.8.1	Regulator stuck in position
		F-1.8.2	Fail to open
		F-1.8.3	Fail to close
		F-1.8.4	Seal failure / washout failure
1.9	Flow meter, instrumentation on HPU, pressure transmitter	F-1.9.1	Failure of pressure transmitter, loss of signal
		F-1.9.2	Failure of pressure transmitter, wrong signal
		F-1.9.3	Failure of flow transmitter, loss of signal
		F-1.9.4	Failure of flow transmitter, wrong signal
1.10	Pump in hydraulic manifold	F-1.10.1	Pump does not start, pump not running when intended to run
		F-1.10.2	Pump does not start, pump not running when intended to run
		F-1.10.3	Pump does not stop
		F-1.10.4	Pump running but not building up pressure, or giving enough flow
		F-1.10.5	Vibration
		F-1.10.6	Pump runs when not intended to run
1.11	Air pressure switch for pumps	F-1.11.1	Switch is not switching when intended to
		F-1.11.2	Switch is not closing when intended to
1.12	Strainer upstream pumps	F-1.12.1	Clogging of strainer
1.13	Filter downstream pumps	F-1.13.1	Clogging of filter
		F-1.13.2	No filtering effect
		F-1.13.3	Bursting filter/filter collapse
1.14	Hose upstream strainers	F-1.14.1	Ingress of air into hydraulic system gives potential small vacuum/ under pressure on the pump suction side when pump is stroking
1.15	Level transmitter in reservoir	F-1.15.1	Fails to read correct level (i.e. reading low level when level are not low)
		F-1.15.2	Fails to read correct level (i.e. not reading an actual low level)
1.16	Pressure safety valve (PSV)s	F-1.16.1	Open when not suppose to open (manifold)
1.17	Pilot control valve/panel valve	F-1.17.1	Fails to move
		F-1.17.2	Wash out
1.18	Flange and gasket	F-1.18.1	Leakage

1.19	Master electric panel and electric mini panel	F-1.19.1	Fail to give electric signal for some intended valves and BOP function
1.20	Electric power pack with battery back up	F-1.20.1	Fail to give electric power for BOP panel command initiation
1.21	Electric power cable	F-1.21.1	Not able to distribute electric signal
1.22	Air operator	F-1.22.1	Fail to regulate
1.23	Pod selector valve	F-1.23.1	Fail to move (change position)
1.24	Sub plate mounted (SPM) valves	F-1.24.1	Fail to close
		F-1.24.2	Fail to open
		F-1.24.3	Fail between positions (not completely closed nor opened)
1.25	Fluid mixing system	F-1.25.1	Fail to make the required hydraulic fluid
1.26	Accumulator isolator valve (inside HPU)	F-1.26.1	Fail to open/close
1.27	Accumulator isolator pilot valve (inside control manifold)	F-1.27.1	Fail to open/close
1.28	Pod mounted accumulator isolation valve	F-1.28.1	Fail to open/close
1.29	Stack mounted accumulator isolation valve	F-1.29.1	Fail to open/close
1.30	Batteries inside subsea pod	F-1.30.1	No voltage
Node 2: BOP stack			
2.1	Fixed pipe ram	F-2.1.1	Not able to close
		F-2.1.2	Not able to open
		F-2.1.3	Not able to seal around tubular
		F-2.1.4	Degradation of packers over time
		F-2.1.5	External leakage (bonnet/door seal or other external leakage path)
		F-2.1.6	Internal leakage (leakage through a close ram)
2.2	Variable bore ram	F-2.2.1	Not able to seal around tubular
		F-2.2.2	Not able to close
		F-2.2.3	Unable to hold the hang-off weight
		F-2.2.4	Degradation of packers over time or high temperature
		F-2.2.5	Not able to open
2.3	Blind shear ram	F-2.3.1	Unable to cut string, thus unable to seal of wellbore
		F-2.3.2	Not able to close Not able to perform complete shut off and seal the annulus
		F-2.3.3	Degradation of packers over time
		F-2.3.4	Not able to open
2.4	Annular BOP	F-2.4.1	Not able to seal around tubular
		F-2.4.2	Not able to open to full or within 30 minutes (API)
		F-2.4.3	Degradation of elements over time
2.5	Automatic subsea ram locks	F-2.5.1	Unable to lock
		F-2.5.2	Unable to open
Node 3: Choke valve, kill valve and connector			
3.1	Choke and kill valve	F-3.1.1	External leakage (leakage to environment in main valve or valve connectors)
		F-3.1.2	Internal leakage (leakage through a closed valve)
		F-3.1.3	Failed to open
		F-3.1.4	Failed to close
3.2	Hydraulic connector	F-3.2.1	External leakage
		F-3.2.2	Failed to unlock
Node 4: Component inside rams and preventer			
4.1	Blind/shear ram seal (sealing element)	F-4.1.1	Deformed, worn, stiff, eroded
4.2	Piston on both sides	F-4.2.1	Galling, seizure, misalignment, pitting
4.3	Wedge on both sides	F-4.3.1	Galling, seizure, misalignment, impact failure
4.4.	Blade on both sides	F-4.4.1	Impact failure, brittle failure, pitting, dulling
4.5	Shear ram housing	F-4.5.1	Deformation, cracking, erosion
4.6	Annular preventer rubber housing	F-4.6.1	Deformation, worn, stiff, eroded parts
4.7	Annular sealing element (rubber seal and steel reinforcement segments)	F-4.7.1	Deformed, worn, stiff, eroded
4.8	Annular piston	F-4.8.1	Galling, seizure, misalignment, pitting
4.9	Annular locking wedge	F-4.9.1	Galling, seizure, misalignment, impact failure

8.2.2 FMECA Sheet

The analysis of FMECA sheet can be seen in appendices 12.1.

8.2.3 Criticality Ranking and Criticality Matrix

		Probability				
		P=1	P=2	P=3	P=4	P=5
		Could occur, but never heard of in the world	Has occurred in the world, but very unlikely	Incident has occurred in some operations	Incident has occurred several times in some operations	Incident has occurred several times in most operators
	Description	< 1/10,000 years	1/10,000 – 1/1000 years	1/1000 – 1/100 years	1/100 – 1/10 years	1/10 – 1 years
C=5	30+ fatalities	F-1.6.1				
C=4	10-30 fatalities					
C=3	1-10 fatalities	F-1.8.3, F-4.4.1, F-4.5.1	F-4.2.1	F-2.3.1, F-4.6.1		
C=2	Serious injury	F-4.1.1, F-4.7.1	F-3.2.2, F-4.8.1	F-1.2.1, F-1.18.1		
C=1	First aid/medical treatment case	F-1.1.1, F-1.4.1, F-1.5.2, F-1.8.2, F-2.1.5, F-3.1.3, F-3.1.4	F-1.1.2, F-1.1.3, F-1.1.4, F-1.7.3, F-1.9.1, F-1.9.2, F-1.9.3, F-1.9.4, F-1.10.2, F-1.10.3, F-1.10.4, F-1.10.5, F-1.11.1, F-1.11.2, F-1.12.1, F-1.13.1, F-1.13.2, F-1.13.3, F-1.14.1, F-1.19.1, F-1.20.1, F-1.21.1, F-1.22.1, F-1.23.1, F-1.25.1, F-1.30.1, F-2.1.2, F-2.1.3, F-2.1.6, F-2.2.3, F-2.2.5, F-2.3.2, F-2.3.4, F-2.4.2, F-2.5.1, F-2.5.2, F-3.1.1, F-3.1.2, F-3.2.1, F-4.3.1, F-4.9.1	F-1.3.1, F-1.5.1, F-1.7.2, F-1.8.1, F-1.8.4, F-1.10.1, F-1.10.6, F-1.15.1, F-1.15.2, F-1.16.1, F-1.17.1, F-1.17.2, F-1.24.1, F-1.24.2, F-1.24.3, F-1.26.1, F-1.27.1, F-1.28.1, F-1.29.1, F-2.1.1, F-2.1.4, F-2.2.1, F-2.2.2, F-2.2.4, F-2.3.3, F-2.4.1, F-2.4.3	F-1.7.1	

Figure 8.5 Criticality matrix for BOP control system failure modes

We can see that the critical failure modes are in the medium region of the matrix. The most critical failure modes can be sorted from the highest consequences and probabilities of occurrence as follows:

Table 8.3 Prioritization of BOP component criticality from criticality matrix

Priority	Component	Failure mode	Description
1	Shuttle valve (rams and annular preventer	F-1.6.1	Not able to change position
2	Blind shear ram	F-2.3.1	Unable to cut string, thus unable to seal of wellbore
	Annular preventer rubber housing	F-4.6.1	Deformation, worn, stiff, eroded parts
3	Piston on both sides	F-4.2.1	Galling, seizure, misalignment, pitting
4	Hydraulic line from HPU to BOP	F-1.2.1	Leakage, bursting, plugged line
	Flange and gasket	F-1.18.1	leakage
5	Fluid reservoir	F-1.7.1	Rupture of reservoir

8.3 Redundancy and Effect Table

Table 8.4 Redundancy and effect table of subsea BOP

No	System/Function	Redundant(Yes /No)	How many redundancy(ies)			Possibility to Effect other component's functions after redundancy	Redundant equipment
			Local	Global	Total		
Hydraulic BOP control system							
1.1	Accumulator bottles	Y	3	0	3	Not significant (redundancy)	- Some number of accumulator (25% over capacity + 3 extra bottles)
1.2	Hydraulic line from HPU to BOP	Y	1	0	1	Not significant (redundancy)	- Line for yellow and blue pod
1.3	Solenoids to valves	Y	0	1	1	Not significant (redundancy)	- manual override and manual initiation of pilot control valve
1.4	pilot valve (air)	Y	0	2	2	Not significant (redundancy)	- Closing sub plate mounted on the shear ram via the panel - Manual override by closing sub plate mounted on the shear ram
1.5	subsea regulated valve (rams and preventer)	Y	2	1	3	Not significant (redundancy)	- subsea regulated valve on other pod - Can be operated manually - each rams and annular has separate regulator
1.6 a	shuttle valve (pipe rams, VBR and annular preventer)	Y	0	1	1		- each rams and annular has separate shuttle valve for operations trough other rams or preventer.
1.6 b	Shuttle valve (blind shear rams)	N	0	0	0	- The corresponding blind shear ram cannot be operated. Thus effecting the operation of well shut in	
1.7	fluid reservoir	N/A	0	0	0	According to FMEA sheet, there is no failure mode that gives a failure for a component (e.g., contamination, rupture, low volume)	N/A
1.8	pressure regulator (hydraulic manifold)	Y	2	1	3	Not significant (redundancy)	- Can be operated manually - Bypass the regulator via high pressure bypass directly to the ram valves - Global: separate regulator on rams and annular preventer

1.9	flow meter, intrumentation, pressure transmitter	N	0	0	0	Not significant (still possible to perform BOP functions)	(this is just the instrumentation, reading devices, etc. which are not directly influence the functionality of the BOP function, but could be a problem for well control operations)
1.10	pump in hydraulic manifold	Y	2	1	3	Not significant (redundancy)	- redundant pump - emergency pump (in case all powers are lost) - accumulator banks
1.11	air pressure switch for pumps	Y	1	1	2	Not significant (redundancy)	- electric driven pumps as primary pumping system - accumulator banks
1.12	strainer upstream pumps	Y	0	2	2	Not significant (redundancy)	- Redundancy of pump - accumulator banks
1.13	filter downstream pumps	Y	2	2	4	Not significant (redundancy)	- Redundant filters - Bypass of filter - Redundant pump - Accumulator banks
1.14	hose upstream strainers	Y	1	1	2	Not significant (redundancy)	- Redundant strainer - Redundant pump
1.15	level transmitter in reservoir	N	0	0	0	Not significant (still possible to perform BOP functions)	(it is a level reading of fluid in reservoir which does not directly influence the functionality of the BOP function, but could be a problem for well control operations)
1.16	pressure safety valve (PSV)s	N	0	0	0	- The accumulator will not have enough hydraulic fluid pressure for BOP functions (failure to close allows fluid to leakage)	
1.17	pilot control valve/panel valve	Y	0	1	1	Not significant (redundancy)	- Manual operation/override of valves
1.18	flange and gasket	N	0	0	0	- for the worst case, it can drain all hydraulic fluid in the accumulator (there will be alarm for a leakage) and could effect the BOP functions	
1.19	master electric panel and electric mini panel	Y	1	0	1	Not significant (redundancy)	- Redundant electric panel (mini panel)

1.20	electric power pack with battery back up	Y	1	0	1	Not significant (redundancy)	- Redundant main power from main generator
1.21	electric power cable	Y	0	1	1	Not significant (redundancy)	- Manual override of valve or other command
1.22	air operator	Y	0	1	1	Not significant (redundancy)	- Manual intervention of solenoid and pilot control valve
1.23	pod selector valve	Y	0	1	1	Not significant (redundancy)	- Manual intervention of pod selector valve
1.24	sub plate mounted (SPM) valves (rams and preventer)	Y	1	2	3	Not significant (redundancy)	- Redundant SPM from other pod - Manual override (possible to manually operate BOP functions) - Redundancy from other rams or annular preventer
1.25	fluid mixing system	N	0	0	0	According to FMEA sheet, there is no failure mode that gives a failure for a component (e.g., fail to make the required hydraulic fluid)	
1.26	accumulator isolator valve (inside HPU)	Y	0	1	1	Not significant (redundancy)	- redundancy by having flow through other valve
1.27	accumulator isolator pilot valve (inside control manifold)	Y	0	1	1	Not significant (redundancy)	- Redundancy by having pod selector vavle to regulate the hydrauic flow into subsea accumulator
1.28	pod mounted accumulator isolation valve	Y	0	1	1	Not significant (redundancy)	- Redundancy by having the flow through other valve
1.29	stack mounted accumulator isolation valve	Y	0	1	1	Not significant (redundancy)	- Redundancy by having the flow through other valve
1.30	batteries inside both pods	Y	1	1	2	Not significant (redundancy)	- Redundancy by having batteries from other pod - Redundancy of initiating blind shear ram function by using accoustic system
BOP stack							
2.1	fixed pipe rams	Y	1	2	3	Not significant (redundancy)	- Redundancy by having variable bore rams - Redundancy by having blind shear ram - Redundancy by having annular preventer
2.2	variable bore rams	Y	1	2	3	Not significant (redundancy)	- Redundancy by having pipe rams - Redundancy by having blind shear ram - Redundancy by having annular preventer

2.3	blind shear ram	Y	0	1	1	Not significant (redundancy)	- Redundancy by having annular preventer (possible to close annular on empty hole up to 10,000 psi in combination with the choke system)
2.4	annular BOP	Y	0	1	1	Not significant (redundancy)	- Redundancy by having shear ram and/or pipe ram
2.5	automatic subsea ram locks	Y	0	1	1	Not significant (redundancy)	- Redundancy by having hydraulic pressure in the closing chamber
Choke valve, kill valve and connector							
3.1	choke and kill valve	Y	1	0	1	Not significant (redundancy)	- Redundancy by flowing the flow through other choke and kill valve
3.2	hydraulic connector	Y	1	1	2	Not significant (redundancy)	- Redundancy of secondary connection unlatch - Redundancy of unlatch from LMRP or wellhead
Component inside rams and preventer							
4.1	blind/shear ram seal (sealing element)	Y	0	1	1	Not significant (redundancy)	- redundancy by having other rams and/or annular preventer to close
4.2	piston on both sides (shear ram)	Y	0	1	1	Not significant (redundancy)	- redundancy by having other rams and/or annular preventer to close
4.3	wedge on both sides (shear ram)	Y	0	1	1	Not significant (redundancy)	- Redundancy by having hydraulic fluid to secure the linier mechanical energy on piston
4.4	blade on both sides (shear ram)	Y	0	1	1	Not significant (redundancy)	- Redundancy by having other rams and annular preventer to seal the well
4.5	shear ram housing (shear ram)	Y	0	1	1	Not significant (redundancy)	- Redundancy by having sealing device such as blind ram and pipe ram
4.6	annular preventer rubber housing	Y	0	1	1	Not significant (redundancy)	- Redundancy by having sealing device such as blind ram and pipe ram
4.7	annular sealilng element	Y	0	1	1	Not significant (redundancy)	- Redundancy by having other rams close
4.8	annular piston	Y	0	1	1	Not significant (redundancy)	- Redundancy by having other rams close
4.9	annular locking wedge	Y	0	1	1	Not significant (redundancy)	- Redundancy by having hydraulic fluid to secure the linier mechanical energy on piston

The component inside variable bore rams and pipe rams have more or less the same type of component inside blind shear ram. The difference is only in the rams parts.

Based on table 8.5, the critical components can be seen with the green mark having neither redundancy/back-up with the same component (local), nor other different types of components or actions/operations (global). Some components listed in the table are having no redundancy, but it is not significant to the failure of the BOP function.

Table 8.5 Summary of critical component from redundancy and effect table

ID no.	Failure of the critical components	Redundancy	Effects
1.6	Shuttle valve (blind shear ram)	No	The corresponding blind shear ram cannot be operated. Thus effecting the operation of well shut in
1.16	Pressure safety valve (PSV)s	No	The accumulator will not have enough hydraulic fluid pressure for BOP functions (failure to close allows fluid to leakage)
1.18	Flange and gasket	No	For the worst case, it can drain all hydraulic fluid in the accumulator (there will be alarm for a leakage) and could effects the BOP functions

9. DISCUSSION

9.1 Result of Criticality Analysis

Different risk tools give different result for the critical components in the BOP as can be seen in the summarized Table 9.1. The highest numbers of critical components are found in the reliability block diagram follows by FMECA and redundancy table respectively.

In table 9.1, some assumptions are made for some components related to their similar functionality. Surface and subsea fluid accumulator are both considered as bottle accumulator. All shuttle valves for different functions (e.g., rams, annular preventer and accumulator) are assumed to be the same. Closing hydraulic connection, opening hydraulic connection, closing chamber and opening chamber of annular preventer are some components inside annular preventer rubber housing.

Table 9.1 List of critical components based on the used risk tools

ID No.	List of critical components based on each risk tools		
	Reliability Block Diagram	**FMECA & Criticality Matrix**	**Redundancy and effect table**
1.1	Accumulator bottles		
1.2		Hydraulic line from HPU to BOP (4)	
1.3	Solenoid valve		
1.6	Shuttle valve	Shuttle valve (1)	Shuttle valve
1.7	Fluid reservoir	Fluid reservoir (5)	
1.10	Pump		
1.16			Pressure safety valve (PSV)s
1.17	Pilot control valve		
1.18		Flange and gasket (4)	Flange and gasket
1.22	Air operator		
1.23	Pod selector valve		
1.25	Fluid mixing system		
1.29	Stack mounted accumulator isolation valve		
2.1	Fixed pipe ram		
2.2	Variable bore ram		
2.3	Blind shear ram	Blind shear ram (2)	
2.4	Annular preventer		
4.1	Blind/shear ram seal		
4.2	Ram piston on both sides	Ram piston on both sides (3)	
4.4	Ram Blade on both sides		
4.5	Shear ram housing		
4.6	Annular preventer rubber housing	Annular preventer rubber housing (2)	
4.7	Annular sealing element		
4.8	Annular piston		

The critical components of BOP found in reliability block diagram are only based on every single minimum cut set. It is analyzed without considering the effect of compensating provisions (safeguard) and no information is used to analyze how the failure mechanism of the component failure. In order to assess which components are critical with respect to the functionality of BOP system and fatality as parameters, FMECA and redundancy table can be used. Both FMECA and redundancy table are complement to each other to determine the final critical component of BOP.

FMECA and redundancy table might present the similar method. The basic assessment between these two methods is from the failure modes being analyzed. FMECA method analyzes failure modes where every relevant and significant possibility for the deterioration of the component function is assessed and then ranked according to their critical levels (e.g., low, medium, high). While redundancy table only consider the failure mode when component is in the total failure state.

FMECA presents shuttle valve for ram and annular function as the most critical component in the BOP, followed by blind shear ram, annular preventer (rubber housing), ram piston, hydraulic line from HPU to BOP, flange, gasket and fluid reservoir respectively. This criticality rank is based on the level of fatality and the occurrence probability which are in the medium area (no failure mode in high are) of the criticality matrix. In this assessment, every critical component on the topside/surface can be neglected since problems occurring on the surface are consider more accessible for detection, testing, inspection, maintenance and repair. Moreover, dual redundancies component can also be considered as not critical since they have a back-up system to compromise with one failure for the same function of component since FMECA consider one component failure at a time and others are function perfectly. Based on this premises, fluid reservoir and hydraulic line from HPU to BOP can be excluded as critical component.

In the FMECA, annular preventer (rubber housing) and blind shear ram become the second most critical component. In this case, we can prioritize annular preventer (rubber housing) into the last priority for criticality since it has redundancy component such as blind shear ram, variable bore ram and pipe ram to replace the function of annular preventer. Although annular preventer rubber housing has redundancies, it can still be considered as critical component. It is because annular preventer has an important role in the BOP function as a first device to be activated during well shut in to seal the well which is very important to prevent the influx reach surface. Moreover, it is also more practicable to conduct stripping or snubbing operation through annular preventer than through ram to ram stripping method.

Redundancy and effect table presents four critical components which are shuttle valve, pressure safety valve (PSV), flange and gasket. There is no criticality rank in this table since all the components are analyzed based on the redundancy and back-up operation they might have to compensate the failure of the component.

Pressure safety valve is a component which does not have direct impact with regard to BOP function. In the analysis, the pressure safety valve is used to release pressure of hydraulic fluid only when overpressure occurs in the accumulator. Furthermore, criticality matrix shows low consequences of fatality and tolerable occurrence probability. Thus, pressure safety valve can be excluded as a critical component.

Overall, shuttle valve for ram and annular function is the most critical component in BOP. It is used to shuttles hydraulic fluid from the control pod to annular preventer and rams preventer. There is no other way and no other redundancy for the hydraulic fluid to enter annular or ram without shuttle valve. Moreover, the annular and preventer are function only by means of hydraulic fluid. No manual intervention can be initiated to operate annular and ram. The failure of shuttle valve means no annular or ram function.

Each preventer and ram have their own shuttle valve. In this case the most important shuttle valve is for the blind shear ram function. Other shuttle valves such as for pipe rams and variable bore rams functions have advantage to substitute their function to shuttle the hydraulic which drive the rams to seal the well. Shuttle valve in annular preventer could also substitute the function of every rams including blind shear ram for shut in operation. However, annular preventer is not design to seal the well in case of emergency, only blind shear ram has the capability to completely shut off the well. The maximum pressure that annular preventer can hold usually less than the maximum pressure that blind shear ram can hold. Moreover, in case of drifting floating platform due to bad weather, the drill string need to be cut off and LMRP disconnection is initiated. If the string cannot be cut, it can endanger the personnel on platform. Therefore, the shuttle valve for blind shear ram function and the blind shear ram itself are the most critical component in the BOP.

Leakage is the main problem for flange and gasket. In the subsea accumulator connector or other pipe connection, the leakage problem usually never make sudden catastrophe. Usually the problem is only a small leakage and seepage of fluid. The drainage of hydraulic fluid in the accumulator or drilling fluid in the pipe connection can be detected with alarm to prevent bigger leakage. However, in case of large leaks and operator does not have time to react, then it could be a catastrophe. Thus, flange and gasket become the next critical component in the BOP.

9.2 BOP Criticality Component With Regards to the Use of BOP for Well Shut-in, Stripping, Snubbing and BOP Testing

In the drilling operation, BOP has several roles such as well shut in, stripping, snubbing and BOP testing. In author opinion, the most important operation is well shut in. Shut in the well is needed when kicks occur to prevent influx into the surface by sealing the well either with annular or ram preventer. Shut in process is the first approach to close the well to protect the crew, stop the flow and pressure reading. The operations of well shut in is just simply close the ram/preventer and operate the choke and kill valve for pressure reading. Special attention should be taken for shut in when the drill string/pipe/casing/collar/tool joint are in the ram position. Drill string or pipe can be cut by means of blind ram, but drill casing, tool joint and drill collar are too thick for blind ram. The position of drill collar and tool joint should be maintained in the ram, so only the pipe section that should be in the position of the ram.

In this case, the critical component of BOP mentioned before such as shuttle valve for blind shear ram function, blind shear ram and annular preventer are very critical to the successful closing of the well. If these components fail during shut in, it can create very catastrophe fatality and damage to the platform as well as environment.

Well shut in usually follows by stripping or snubbing operations (depends on the hole pressure) in order to gives killing fluid access into the bottom hole of the well. The killing fluid in the bottom hole is necessary to perform the well control based on constant bottom-hole method. Since the stripping or snubbing is perform after well shut in, then it is necessary for the critical component, shuttle valve (blind shear ram) and blind shear ram/annular preventer, to maintain its functionality. If the critical component fails after well shut in, the ram or annular preventer can still have the locking wedge as a safety device to prevent the rams or sealing element move backward. In this case, it only cause delay in the operation of stripping or snubbing. Otherwise, kill line can be used to direct killing fluid into the well without having to put drill string into the bottom hole of the well.

BOP testing is part of the precautionary action to know the condition and performance of the BOP system. During this test, the performance of the critical component can be tested and ascertained. In this operation, the critical component might not be critical as it has many safety measure and procedure to handle with the expected raising problems.

10. CONCLUSIONS

Safety of drilling operation, particularly during the event of kicks, can be improved by having more component redundancy or back-up operation in the subsea blowout preventer (BOP). It is important for well shut in, stripping, snubbing and BOP testing operation. The redundancy is particularly required for the critical components in the BOP as it has been analyzed in this report. The critical components of BOP can be summarized and prioritized as follows:

1. Shuttle valve for blind shear ram (e.g., for closing function)
2. Blind shear ram, additional critical components inside shear ram:
    - Ram piston
3. Flange and gasket (in the BOP stack)
4. Annular preventer (rubber housing)

In the event of kick and well shut in is initiated, the above critical component is very critical to the safety of personnel. Stripping and snubbing operation also require the critical components to be function properly. It might not be a big problem if the critical components are fail when the shut in has been initiated since it is only causing the delay of the operation. Alternatively, well control can be done by regulating kill fluid directly into the hole through kill line. During BOP testing operation, the critical components might not be critical if it fail as there are many safety measure and procedure for safety.

10.1 Recommendation

If possible the design of rams and annular preventer are equipped with two shuttle valves for each preventer. It might not common for the BOP design nowadays. There is a need for additional shuttle valve for each annular and ram preventer as this is the most critical equipment for operation of closing BOP (well shut in). Shuttle valve should also be more robust against fire and explosion to ensure its functionality in case of blowouts.

The design of BOP should consider two blind shear rams in the stack to give more availability for well shut in operation. Annular preventer should have the same maximum rate pressure such as in the blind shear ram so it can act like blind shear ram when blind shear ram is unavailable due to failure.

10.2 Suggestion for further works

The works conducted in this report is the analysis of criticality based on qualitative approach. The scarce of data and the amount of time required to finish the report making qualitative analysis become a good approach for the analysis. Literature study and experts judgment with experience are the dominant sources for the analysis. There could be a hidden or mislead information during the analysis, study, discussion and brainstorming session. Hence, thorough quantitative analysis of criticality and reliability of BOP component in more detail is necessary for further works to give a better insight of criticality in the BOP component. Moreover, the consequences for loss of asset and environment damage should also be analyzed in more detail in the further work.

The work done in this report is mainly for hydraulic BOP system. Further analysis on electrohydraulic, multiplex system, ram intervention and acoustic intervention can also be conducted.

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12. APPENDICES

12.1 FMECA sheet

Table 12.1 FMECA of hydraulic BOP system

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
					Local	Global								
1.1	**Accumulator Bottles** **Function:** Store energy (hydraulic fluid)	Used for all operational modes, shall be available at all times	F-1.1.1 Burst bladder	Wear due to ageing Human error when refilling the bottles Potential for damage to bladder from Valve in the bottom of the bottle, when the bladder expands downwards during depressurization of the bottles.	Gas in the system (increased motive force behind the fluid during hydraulic return to reservoir). Reduced accuracy of the flow meter Affected bladder will not function	Some reduced capacity Worst case: possibility of particles from burst bladder to pressure regulating valve in the hydraulic system BOP functions will still be upheld due to overcapacity	Maintenance and inspection procedures. When draining the system; if the pressure decreases below the charging pressure, it is an indication of a burst bladder in the bottle rack.	Redundancy with regards to number of bottles (25% overcapacity + 3 extra bottles) Routine for control of charge pressure in place Competence of operators when refilling the accumulator bottles. The bottles are rated for 5000 psi Function testing of BOP functions every week	1	3	L		Evaluate to add strainer upstream pressure regulating valve in the shear boost system Check the calculations for precharge pressure on the accumulator bottles Evaluate having one burst disk for the entire accumulator bank. Take into consideration that this may reduce the number of leak points compared to having one bursting disk for each bottle. Update P&ID to reflect the chosen solution	
			F-1.1.2 Leakage through nitrogen "fill"-system (valve)	Poor quality of valve mechanical damage	Affected accumulator has reduced capacity/does not function	No consequence due to safeguards BOP functions will still be upheld due to overcapacity	Audible if a big leakage. When draining the system; if the pressure decreases below the charging pressure, it is an indication of a burst bladder in the bottle rack.	Maintenance procedures (leak check each time the valve is operated) Redundancy with regards to number of bottles (25% overcapacity + 3 extra bottles) Function testing of BOP functions every week	1	2	L			

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
					Local	Global								
			F-1.1.3 Lack of stored accumulation pressure, reduced capacity,	Rupture of bladder, leaks	Affected accumulator(s) will have reduced capacity	Dampening effects	Nitrogen blown back to reservoir, causing foaming	Maintenance procedures. Redundancy gives loss of one bottle will not effect other. Bladders are changed out every five years The gauges on the accumulator banks are included in the maintenance program. API RP 53, section 12.5.3g gives requirements with regards to the pressure gauges. Accumulator pressure gauges are currently checked for calibration yearly **Optional:** There are currently provisions in the design for using nitrogen as a pressure source for operating the BOP. *This is not taken into consideration in the risk ranking*	1	2	L		When bringing a rack of accumulator bottles back into operation, there will be 3000 psi on one side of the isolation valve (towards the rest of the hydraulic system), and no pressure on the other side of the valve. A sudden opening of the isolation valve could cause damage to the valve itself. It should be considered to include a balancing line/tubing with a needle valve between each rack of accumulators in order to minimize the potential for damage to the isolation valve due to sudden pressure	Engineering
			F-1.1.4 Lack of stored accumulation pressure, reduced capacity,	Leak on gas side of bladder, failure in nitrogen fill valve assembly	Affected accumulator(s) will have reduced capacity	Dampening effects	Measurement of bladder	Maintenance procedures. Redundancy gives loss of one bottle will not effect other Testing.	1	2	L		Ensure that maintenance and inspection procedures include snooping of the nitrogen fill valves. It is also a possibility to use soapy water to detect leaks (via bubbling) every time the valve are operated	Maintenance

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
					Local	Global								
1.2	**Hydraulic line from HPU to BOP (Jumper hose line, subsea hose bundle, choke and kill line)** **Function:** Route of hydraulic fluid from HPU to BOP	Used for all operational modes, shall be available at all times	F-1.2.1 Leakage, bursting, plugged line	Mechanical failure. Corrosion. Fatigue External forces Insufficient or incorrect support, vibration. Climbing on the pipes. Mechanical failure in fittings, gaskets, etc	Spillage (water, glycol, hydraulic fluid) to environment. Potential for personnel injury	Worst case: Drain all hydraulic fluid in the bottle racks (normally the alarms will ensure that this does not happen, except for very large leaks where the operator does not have time to react) Potential loss of individual BOP functions Potential loss of the complete surface volume of hydraulic fluid through burst hose	Visual Low level and low pressure alarms Excessive running of the pumps	Support in accordance with regulations and standards. Use environmentally friendly hydraulic fluid. Fittings are stainless steel, reducing corrosion issues Hoses are fire resistant and placed in a restricted area Hoses are equipped with whip-checks Short pipe stretches. Operators (competence) normally have time to react and isolate a leak Function testing of BOP functions every week. Maintenance and inspection procedures Redundant BOP functions and hydraulic line for both each pod	2	3	M		Ensure that layout and design ensures access to the valves etc. that need maintenance. Ensure that grating or similar is in place / available to prevent climbing on pipes Verify the design specification concerning piping to the accumulator banks. Take into consideration that a break or leak from a common hydraulic pipe could increase the potential for draining all hydraulic fluid from the accumulator banks, compared to separate piping. Ensure that all valves in the main hydraulic lines are equipped with a car seal system, and ensure that procedures and routines incorporate this. Ensure that inspection (and documentation) of hoses and pipes are included in the maintenance and inspection programs. Review the required change-out intervals for the hoses, including maintenance procedures. Ensure that hoses and connected pipes are properly tagged, in order to prevent misunderstandings when reattaching hoses after maintenance	

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
					Local	Global								
													Ensure that the hose are manufactured in accordance with relevant standards, and that there are no weak links in the fire protection of the hose Ensure that a scenario with rupture of a hose and a rapid loss of hydraulic fluid surface volume is included in the operator training, in order to ensure that correct actions are being taken to isolate the leak source in an emergency situation. *After implementation of these recommendations, the probability of the failure mode may be reduced from 3 to 2, and the risk thus becomes L (Low)*	
1.3	**Solenoids to valves** **Function:** Controlling the opening and closing of valves and rams **Type:** Solenoid valves to valves and rams (13 off)	Used for all operational modes, shall be available at all times	F-1.3.1 Fail to move	Burnt/broken coil Wire break Dust Contamination Stuck (too high friction) Electrical failure Loss of air Mechanical failure Obstruction	Affected solenoid cannot be operated from the panels, and thus corresponding pilot control valve cannot be activated from panel	No consequence due to safeguards (still possible to operate the BOP functions manually from the BOP control unit room)	Loop monitoring of solenoid through the PLC, raising an alarm Flow meter and pressure transmitter monitoring Visual, when function is activated Indicator light for valve position on the remote panels	Manual override and manual initiation of pilot control valve Maintenance and inspection procedures Function testing of BOP functions every week. Function testing of the sheer boost system every new well	1	3	L		The solenoid is attached on the central hydraulic control manifold Consider to include a test of the high/low override function	Mainten ance

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
					Local	Global								
1.4	**Pilot Valve (air)** **Functions:** Close shuttle valve to the hydraulic manifold	Shall be available at all times for well control operations	F-1.4.1 Not operating	No credible failure causes found	None	No consequence due to safeguards	Visual	Redundancy, i.e., it is possible to close the sub plate mounted (SPM) valve on the shear ram via the panels Manual override (it is possible to manually close the sub plate mounted (SPM) valve on the shear ram) Maintenance and inspection procedures Function testing of the hydraulic system for every new well	1	1	L		Since no credible failure causes were identified, the probability and consequence of the failure mode was considered low	
1.5	**Subsea Regulated Valve** **Functions:** Regulating pressure of hydraulic fluid to the annulus and rams system	Used for all operational modes, shall be available at all times	F-1.5.1 Regulator stuck in position	Loss of air pressure, error in air solenoid, corrosion, solenoid valve failure, electric failure	Cannot operate the regulator from the panels	No consequence due to safeguards	Visual Pressure gauges	Can be operated manually (to be verified) Upper and lower pipe ram are on a separate line, and have a separate pressure regulator, and may therefore still be operated Maintenance and inspection procedures Used often, thus corrosion is not a problem Built in pressure relief valve in annulus system, relieving back into reservoir, will prevent pressures above 1500 psi in downstream annulus system	1	3	L		Confirm if the regulator can be operated manually (hand wheel, etc). update P&ID accordingly	

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
					Local	Global								
			F-1.5.2 Fail to open/close	Broken spring	Fail to open: No consequence (all equipment is rated for 3000 psi) Fail to close: No pressure to downstream equipment	Fail to open gives no consequence due to safeguards Fail to close gives loss of all equipment functions downstream except the sheer boost and the annular (other main hydraulic lines)	Visual. Pressure transmitters	Upper and lower pipe ram are on a separate line, and have a separate pressure regulator, and may therefore still be operated Function testing of BOP functions every week	1	1	L		Check whether the pressure regulator fails open or closed (confirm failure modes) – if it fails close it can be evaluated whether the bypass should be included. Vendor should provide information about failure rates. Thus probability may be changed	
1.6	**Shuttle Valve (rams and annular preventer)** **Function:** Shuttles hydraulic fluid from the control pod to the shear ram and preventer	Shall be available at all times for well control operations	F-1.6.1 Not able to change position	Wear on slide, causing jam, corrosion (shuttle valve is exposed)	Shuttle valve cannot move	Loss of redundancy with regards to shear ram functions Worst case: Delayed or no shearing	Visual when shuttle valve should move. Indicator light on shear ram functions	Function testing of the control pod for every new well	5	1	M		The shuttle valve is deemed to be critical for safety, and thus needs to be better documented Vendor should document how the valve functions in a situation with equal pressure on both sides (e.g., in a situation with 3000 psi pressure on the normal system, and the sheer boost system needs to be initiated). The probability for having the same pressure on both sides is low, as the pressure in the manifold system is normally down to 1500 psi Evaluation of test frequency and documentation of reliability of valve can decrease the overall risk level. It should be evaluated if the sheer boost system should be included in weekly function test. Take into consideration the increased wear on the pipe and valve system if 3000 psi is routed through every week	

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					Local	Global								
1.7	**Fluid Reservoir** **Function:** Open tank (with lid) storage for hydraulic fluid. Closed hydraulic circuit (all returns to tank)	Used for all operational modes, shall be available at all times	F-1.7.1 Rupture of reservoir	Too small or clogged vent on hydraulic reservoir	Leakage of hydraulic fluid	No consequence due to safeguards (still possible to operate the BOP functions)	Alarm from the level transmitter (leakage) Visual	Vent is designed to take full blow down from bottle rack Accumulator banks store enough hydraulic power to ensure operation of BOP	1	4	M		Check calculations (dimension of the vent), to ensure that the vent line has sufficient capacity to prevent over pressurization of the reservoir in case of a full blow down from bottle rack. Also take into consideration the potential for larger motive force in case of a nitrogen leak Probability was rated as 4, but when calculations have been confirmed and if they show that the vent is big enough then the probability may be reduced, and thus the risk	
			F-1.7.2 Contamination of hydraulic fluid	Failure in lining giving rise to contaminants in hydraulic fluid entry of dirt and other contaminants to reservoir through breathers	Hydraulic fluid quality is inadequte	Clogging of suction strainers upstream hydraulic pumps. Fine particles may pass through and increase wear on pump	Sampling of hydraulic fluid. Sampling is done on a regular basis (monthly or every three months) as part of the maintenance procedures	Strainers on suction side of hydraulic pumps will remove large particles. Place filters downstream the pumps, after the accumulators The filters will be monitored during regular maintenance in order to detect if there are any particles in the hydraulic fluid	1	3	L		The Y strainers on the suction side of the electrical pumps may have too large mesh size to protect the pumps adequately. Too fine filters may cause cavitation. The mesh size of the filters should be considered taking this into consideration To prevent layering of water, glycol and chemicals, circulation in the reservoir should be considered. A filter could be installed in such a circulation system in order to facilitate cleaning and improve quality of the hydraulic fluid. It is recommended to circulate three times the reservoir volume each eight hours	Maintenance Engineering

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			F-1.7.3 Too low volumetric capacity of reservoir (1200 gal. reservoir)	Reservoir volume too small, too low level in reservoir, too high volume in reservoir	Tank will be emptied, or reservoir may overflow if there are more stored energy (hydraulic fluid) in the system and accumulators that the capacity of the reservoir	Potential for spills of hydraulic fluid to the environment	Level switch detects low level, gives alarm and trips pumps. Sight glass is the detection method for too high level in reservoir	Environmental friendly hydraulic fluid. Low level alarm. Maintenance / inspection routines	1	2	L		The calculations should be reviewed and the need for a day tank should be considered	
1.8	**Pressure Regulator (hydraulic manifold)** **Functions:** Regulating the pressure of the hydraulic fluid to the manifold	Used for all operational modes, shall be available at all times	F-1.8.1 Regulator stuck in position	Loss of air pressure, error in air solenoid, corrosion, failure in solenoid valves, electrical failure	Cannot operate the regulator from the panels	No consequence due to safeguards	Visual (manifold pressure does not change when you are trying to regulate)	Can be operated manually. Regulator system could be bypassed Maintenance and inspection procedures Used often, thus corrosion is not a problem	1	3	L		Confirm if the regulator can be operated manually	
			F-1.8.2 Fail to open	Broken spring	Fail to open: No consequence (all equipment is rated for 3000 psi)	Fail to open: no consequence due to safeguard	Visual Pressure transmitters	Annular preventer is on a separate line, thus may still be operated Function testing of BOP functions every week	1	1	L		Check whether the pressure regulator fails open or closed (confirm failure modes) – if it fails close it can be evaluated whether the bypass should be included. Vendor should provide information about failure rates. Thus probability may be changed	
			F-1.8.3 Fail to close		Fail to close: no pressure to downstream equipment	Fail to close: Lose all equipment functions downstream			3	1	L			

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			F-1.8.4 Seal failure / washout failure	Contaminated hydraulic fluid	Leak of hydraulic fluids due to seal washout	No global effects due to safeguards allowing for BOP functions to be upheld	Visual Noise Pumps will be starting frequently	Spare regulator available on the rig. Leak rate will be smaller that pump capacity, allowing for the BOP function to be upheld even in case of a leak. This means that leaks does not need to be repaired in critical situations. It is also possible to bypass the regulator via the high pressure bypass, and route 3000 psi hydraulic fluid directly to the ram valves Maintenance program Filter	1	3	L			
1.9	**Flow meter, instrumentation on HPU, pressure transmitter** **Functions:** Provide information about the status (pressure and flow) of the hydraulic system	Used for all operational modes, shall be available at all times	F-1.9.1 Failure of pressure transmitter, loss of signal	Mechanical failure, mechanical damage, electrical failure	Loss of pressure reading from affected transmitter	No global effect, still possible to perform BOP function	Visual, check of manifold pressure low pressure alarm inspection	Maintenance and inspection procedures Yearly calibration check Daily check of functionality	1	2	L			
			F-1.9.2 Failure of pressure transmitter, wrong signal	Electric failure, clogging of transmitter	False pressure reading	No global effect, still possible to perform BOP functions	Visual, check of manifold pressure low pressure alarm inspection	Maintenance and inspection procedures Yearly calibration check Daily check of functionality	1	2	L		When running casing, ensure that cross checks of pressures are made in order to ensure that a false low pressure reading would not lead to damage of the casing. Check that this is stated in the operational procedures Evaluate to amend the daily check list to include cross referencing of pressure measurements from the different gauges	Operation Operations & maintenance

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			F-1.9.3 Failure of flow transmitter, loss of signal	Mechanical failure, mechanical damage, electrical failure	Loss of flow reading	No global effect, still possible to perform BOP functions	Visual, inspection on BOP pressure changes, pumps are running	Maintenance and inspection procedures Functional cross checks every 4 weeks	1	2	L		Include in the maintenance procedure that the flow meter is cross checked and calculated against the time for closing in depletion tests, and the pressure before and after, and the pump running time	mainten ance
			F-1.9.4 Failure of flow transmitter, wrong signal	Mechanical failure	False flow reading	No global effect still possible to perform BOP functions	Visual, inspection on BOP pressure changes, pumps are running	Maintenance and inspection procedures Functional cross checks every 4 weeks	1	2	L			
1.10	**Pump in hydraulic manifold** **Functions:** Providing flow and pressure in the hydraulic system	Used for all operational modes, shall be available at all times	F-1.10.1 Pump does not start, pump not running when intended to run	Broken transmission belt, electrical errors, mechanical errors, pressure switch controlling pump not working, damage to chain drive	Affected pump does not run	No consequence due to safeguards (still possible to operate the BOP functions)	PLC registers if a pump does not run Alarms Visual Visual readout on pressure switch	100% redundancy with regards to pump capacity in hydraulic manifold. If all power are lost, one of the pumps will run on emergency power Accumulator banks Maintenance and inspection procedures. A check of the chain drive is part of the planned maintenance procedures	1	3	L		The duty and standby pump will be switched by the PLC, to prevent increased wear in one of the pumps compared to the other The bleed valve from the pulse dampener on the pressure side of the pumps is currently a ball valve. Consider to replace the ball valve with a needle valve to facilitate regulation of air purging from the system	Enginee ring
			F-1.10.2 Pump does not start, pump not running when intended to run	Poor quality linings in electrical motor	Affected pump will not run	No global effect. System will still operate as intended due to redundancy	Visual Visual readout on pressure switch	A check of this is a part of the planned maintenance Redundant pump system, accumulators	1	2	L			
			F-1.10.3 Pump does not stop	Electrical failure, MCC failure, signal failure	Increased wear of pump	No consequence due to safeguards (PSV)	Redundant PTs programmed to start/stop the pumps High pressure alarm Excessive running alarm	PSVs prevent over pressurization on the system Redundant pressure transmitters Maintenance and inspection procedures	1	2	L		Check max design pressure of the pumps, and confirm if the pumps may over pressurize the system. Confirm with vendor what max design pressure is and evaluate against set and design pressure in system	

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			F-1.10.4 Pump running but not building up pressure, or giving enough flow	Broken piston shaft, wear and tear in pump, blocked strainer, low level in reservoir, leaking piston packers, other leaks, damage to downstream check valve	Affected pump cannot build up pressure No or reduced flow trough affected pump	No consequence due to safeguards. System will still operate as intended due to redundancy	Excessive running alarm (observe stable low pressure over a long time)	Accumulator banks Maintenance and inspection procedures Redundant pump system in hydraulic manifold	1	2	L		There are one primary and one secondary pump. This is not switched around during normal operation. This was deemed good as the pumps are mainly needed when the BOP is used, and in that case, both pumps will be used. I.e., there will not be increased wear and tear on the primary pump compared to the secondary	
			F-1.10.5 Vibration	Positive displacement pumps. Misalignment of drive chain	Failure of pump	No global effect due to adequate pulsation dampener	Noise, visual	Inspection. Pulsation dampener as safeguard against pulses from PD pumps	1	2	L			
			F-1.10.6 Pump runs when not intended to run	Electrical failure, failure in pressure switch controlling the pump	High pressure in the system, over pressurization	No global effect due to pressure relief valves and redundant system	Pump running light on drillers and auxiliary panel. Visual	Pressure relief valves Redundant pump system Maintenance procedures, competence of drillers	1	3	L			
1.11	**Air pressure switch for pumps** **Functions:** Supply air to air driven pumps	Used for all operational modes, shall be available at all times	F-1.11.1 Switch is not switching when intended to	Mechanical failure in the switch itself	No air supply to pump, pump will not start	No global effect. Pressure will be maintained in order to allow for operation of BOP	Pressure indication in the hydraulic system. Low pressure alarms	Electrical driven pumps as primary pumping system. Accumulators. Maintenance procedures cover the functionality of the whole pump system, including the switch	1	2	L			
			F-1.11.2 Switch is not closing when intended to	Mechanical failure in the switch itself, dirt/particles	High pressure in the system, over pressurization	No global effect due to pressure relief valves and redundant system	Visual (it will be noticed when the pressure relief valves lifts). Pressure gauges	Pressure relief valves. Maintenance procedures, competence of drillers	1	2	L			

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M,H)	Dwg.	Additional Information and recommendation	Resp. party
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1.12	**Strainer upstream pumps** **Functions:** Removing particles to prevent damage to pump	Used for all operational modes, shall be available at all times	F-1.12.1 Clogging of strainer	Contamination of hydraulic fluid	Cavitation of pump (loss of redundancy) Reduced capacity through strainer, lower NPSH for pump	No consequence due to safeguards (still possible to operate the BOP functions)	Excessive running alarm (will alert operator before the pump breaks) Physical inspection	Acid resistant strainers 100& redundancy with regards to pump capacity in hydraulic manifold Redundant strainer and pump system Accumulator banks Maintenance and inspection procedures	1	2	L		Verify that inspection of filters and strainers is included in the maintenance manual and procedures Verify that isolation valves is available for maintenance purpose	
1.13	**Filter downstream pumps** **Functions:** Filtering hydraulic fluid and removing impurities / contamination	Used for all operational modes, shall be available at all times	F-1.13.1 Clogging of filter	Contamination of hydraulic fluid	Clogged filter, erratic operation of the pumps, increased wear	No consequence due to safeguards	Clogging indicator (gree/yellow/ red)	Bypass of filters is possible Redundant pump system and filters Maintenance and inspection procedures Accumulator banks	1	2	L		The set points of dP alarms should be evaluated in order to prevent unnecessary alarms. Consider to measure the condition of the filters via dP measurement over the filter in order to minimize the need for change of filters on a regular basis	
			F-1.13.2 No filtering effect	Burst filter Wrong installation of filter (human error)	A burst filter may cause a leak, and in worst case empty the accumulators and hydraulic reservoir. Particles not being filtered out of the system. Potential for clogging of downstream system	No consequence due to safeguards	Pump running, low level alarm on reservoir (first low, then low-low and stop). Visual. Wrong installation of the filters will be detected visually when starting the system	Maintenance and inspection procedures Competence of operators Accumulator banks	1	2	L			

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			F-1.13.3 Bursting filter/filter collapse	High differential pressure over the filter caused by clogging of the filter	Damaged filter	No global effect due to redundancy	Clogging indicator internally in each filter	Redundant filters. Filters are exchanged when needed through normal maintenance. Safety factor built into filter element with regards to structural integrity/strength	1	2	L		Consider to measure the condition of the filters via dP measurement over the filter in order to minimize the need for change of filters on a regular basis	
1.14	**Hose Upstream Strainers**	Used for all operational modes, shall be available at all times	F-1.14.1 Ingress of air into hydraulic system gives potential small vacuum/ under pressure on the pump suction side when pump is stroking	Deterioration of clamps for connection of hose or the hose itself	Pump damage, reduced operational capacity	No global effect. System will still operate as intended due to redundancy	Visual, noise	Maintenance procedures, inspection Redundant strainer and pump system	1	2	L			
1.15	**Level transmitter in reservoir** **Functions:** give low level alarm and trip pumps at low level in reservoir	Used for all operational modes, shall be available at all times	F-1.15.1 Fails to read correct level (i.e. reading low level when level are not low)	Damaged wire, electric failure	Unnecessary trip of electrical pumps	No global effect	Audio and visual alarm on drillers and auxiliary panels. Low pressure alarm in accumulators	Air pumps will start when electric pumps are shut down. Accumulators will maintain pressure in system. Maintenance procedures (testing of switch)	1	3	L		Ensure that testing incorporates a physical verification of the level switch function	mainten ance
			F-1.15.2 Fails to read correct level (i.e. not reading an actual low level)	Level switch hung up	Dry running of electrical pumps, damage to pumps	No global effect	Low pressure alarm in accumulators Running pumps indication on panels (light)	Accumulators will maintain pressure in system Alarm, pumps will not be damaged immediately, so there is time to react. Competence of the drillers.	1	3	L		Ensure that testing incorporates a physical verification of the level switch function	

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1.16	**Pressure safety valve (PSV)s** **Functions:** Pressure reduction to prevent over pressurization of the equipment	Used for all operational modes, shall be available at all times	F-1.16.1 Open when not suppose to open (manifold)	Corrosion Human error (installation error) Wrong set point	Affected PSV will lift when not intended to	Will empty the accumulators. All BOP functions will be unavailable	Inspection, visual Pressure transmitter will indicate falling pressure Excessive running alarm	Excessive running alarm Yearly control of PSVs Maintenance and inspection procedures Competence of operators PSVs is made of corrosion resistant material	1	3	L		If the PSV opens when not intended to, the accumulator banks may be emptied back into the hydraulic reservoir	
1.17	**Pilot Control Valve/Panel Valve** **Functions:** Controlling the opening and closing of valves and rams **Type:** Panel valve	Used for all operational modes, shall be available at all times	F-1.17.1 Fails to move	Loss of air from solenoid valve, mechanical failure, stuck (too high friction), obstruction, corrosion	Affected 4 way valve does not work, corresponding BOP function (depending on which 4 way valve that fails) will be lost	No global effects due to safeguards	Visual monitoring of flow meter and pressure transmitter. Indicator light for valve position on the remote panels	Manual operation / override of valves. Maintenance and inspection procedures	1	3	L		Consider to include greasing of the 4 way valves in the maintenance program	
			F-1.17.2 Wash out	Contaminated hydraulic fluid	Leak of hydraulic fluid due to seal washout	No global effects due to safeguards allowing for BOP functions to be upheld	Visual, noise. Pumps will be starting frequently. Leak will be back to reservoir	Maintenance and inspection procedures Filters	1	3	L			
1.18	**Flange and Gasket** **Function:** Connection and seal between pipe and valves	Used for all operational modes, shall be available at all times	F-1.18.1 Leakage	Poor quality of gaskets. Wrong torque applied when fastening bolts (too little torque or skewed). Insufficient or wrong support, vibration Human error (wrong installation) Misalignment	Spillage (water and glycol)	Worst case: drain all hydraulic fluid in the bottle racks (normally the alarms will ensure that this does not happen, except for very large leaks where the operator does not have time to react)	Visual Low level and low pressure alarms Excessive running of the pumps	Certificate for each flange after installation Pipe support respects the current standards and requirements Short pipe stretches Standard, proven gaskets will be used Piping, flanges and gaskets will comply with TR2000 Maintenance and inspection procedures	2	3	M		Evaluate to include a torque check in maintenance programs (e.g., on a 5 years basis)	

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
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1.19	**Master Electric Panel and Electric Mini Panel** **Function:** Initiate electric command for BOP function, valves, flow of hydraulic.	Used for all operational modes, shall be available at all times	F-1.19.1 Fail to give electric signal for some intended valves and BOP function	Failed electric power cable, human error when switching panel	No initiation of valve or BOP function	No global effect due to safeguard	Visual, Feedback from the hydraulic system Flow meter, pressure gauges (to see if the electric signal has been sent)	Testing, Redundancy by having master electric and mini panel for initiation of command	1	2	L			
1.20	**Electric Power Pack with Battery Back Up** **Function:** Independent supply of electric power into manifold	Used for all operational modes, shall be available at all times	F-1.20.1 Fail to give electric power for BOP panel command initiation	Obsolete battery, failed electric power cable	Not significant effect	No global effect due to safeguard	Indicator light	Redundancy by having generator as a main power Testing and maintenance	1	2	L			
1.21	**Electric Power Cable** **Function:** Provide flow of electric command from control panel into manifold	Used for all operational modes, shall be available at all times	F-1.21.1 Not able to distribute electric signal	Worn cables, short circuit, no signal sent from electric panel, cables are cut	Unable to initiate solenoid valve and other function of valves	Worst case scenario: No command can be initiated from the control panel	Visual Feedback from the hydraulic system Flow meter, pressure gauges (to see if the electric signal has been sent)	Regular visual check to see if cables are worn, scratch, etc. Manual override of valve or other command	1	2	L			

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
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1.22	**Air Operator** **Function:** Allow the opening and closing of pilot control valve by using air as a media	Used for all operational modes, shall be available at all times	F-1.22.1 Fail to regulate	Air leakage, worn parts of air operator, corrosion, not enough air pressure, failure of solenoid valve	Pilot control valve cannot be operated	No pilot hydraulic fluid can be regulated into subsea pod for BOP function	Visual, noise	Manual intervention	1	2	L			
1.23	**Pod Selector Valve** **Function:** Select one of the subsea pods to be flowed by hydraulic power fluid for BOP function. There are two subsea pods for redundancy and only one pod should only be flowed at a time	Shall be available at all times for well control operations	F-1.23.1 Fail to move (change position)	Loss of air from solenoid valve, mechanical failure, stuck (too high friction), obstruction, corrosion	Routing failure of hydraulic fluid into the intended subsea pod	In case of failure in one of the subsea pods, the hydraulic fluid cannot be routed into another subsea pod. It gives no BOP function causing high probability of blowout	Indicator light for valve position Visual monitoring of flow meter and pressure transmitter	Regularly scheduled testing, maintenance and inspection Manual intervention	1	2	L		Manual intervention with ROV requires longer response time. It could be the last effort for BOP intervention when other electric and hydraulic system for BOP function has failed.	
1.24	**Sub Plate Mounted (SPM) Valves** **Function:** Direct the power hydraulic fluid either to close ram or open ram by closing and opening its valve	Shall be available at all times for well control operations	F-1.24.1 Fail to close	Hydraulic leakage, worn/degrade parts in the valve causing leakage, corrosion, stuck, mechanical failure, loss of instrumented air, broken solenoid, loss of signal Not enough pilot hydraulic fluid pressure	Affected sub plate mounted (SPM) valve will not close	No consequence due to safeguards (still possible to operate the SPM from other pods)	Indicator light for valve position Visual monitoring of flow meter and pressure transmitter Alarms	Regularly scheduled testing, maintenance and inspection Redundancy by operating other SPM valve trough other pods Manual override (possible to manually operate BOP functions) Function testing of BOP functions every week	1	3	L			

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
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			F-1.24.2 Fail to open	Hydraulic leakage, worn/degrade parts in the valve causing leakage, corrosion, stuck, mechanical failure, loss of instrumented air, broken solenoid, loss of signal Over pressure in the pilot hydraulic fluid	Not able to circulate the hydraulic fluid properly causing not proper ram/annular function (not significant effect, just cause delay)	No consequence due to safeguards (still possible to operate the SPM from other pods)	Indicator light for valve position Visual monitoring of flow meter and pressure transmitter Alarms	Regularly scheduled testing, maintenance and inspection Redundancy by operating other SPM valve trough other pods Manual override (possible to manually operate BOP functions) Function testing of BOP functions every week	1	3	L			
			F-1.24.3 Fail between positions (not completely closed nor opened)	Contaminated hydraulic fluid, mechanical fail in actuator, wear	Affected sub plate mounted (SPM) valve will not close or open completely	No consequence due to safeguards (still possible to operate the BOP functions manually from the BOP control unit room)	Visual (flow meter) Pressure transmitter Indication lights on panels Alarms	Manual override (possible to manually operate BOP functions) Maintenance and inspection procedures In some cases there is redundancy from other rams/preventer for closing Function testing of BOP functions every week	1	3	L			
1.25	**Fluid Mixing System** **Function:** Mixing the fluids to become hydraulic fluid needed for BOP operation	Used for all operational mode, shall be available at all times	F-1.25.1 Fail to make the required hydraulic fluid	Inadequate mixture, human error, leakage	Might need more powerful pump to transfer into accumulator Might deteriorate accumulator	Improper opening/closing of SPM valve Improper opening/closing of rams or preventer	Pump stroke reading	Quality control of hydraulic fluid from fluid mixing system	1	2	L			

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
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1.26	**Accumulator Isolator Valve (inside HPU)** **Function:** Isolate hydraulic fluid from accumulator	Used for all operational mode, shall be available at all times	F-1.26.1 Failed to open/close	Corrosion, mechanical failure	Fail to open: Unable to flow the hydraulic flow from the valve Fail to close: The flow can still be stop with isolator pilot valve or hose reel	No consequence due to redundancy	Flow meter and pressure transmitter monitoring	Regular testing and maintenance Redundancy by having the flow through other valve	1	3	L			
1.27	**Accumulator Isolator Pilot Valve (inside control manifold)** **Function:** Regulate and control the flow of fluid through isolator valve into subsea pod	Used for all operational mode, shall be available at all times	F-1.27.1 Failed to open/close	Stuck, mechanical failure, corrosion, no pilot supply	Fail to open/open: No consequence (the flow can be directed from other valve)	No consequences due to safeguard	Flow meter and pressure transmitter monitoring Indicator light for valve position	Regularly testing and maintenance Redundancy by having pod selector valve to regulate the hydraulic flow into subsea accumulator	1	3	L			
1.28	**Pod mounted accumulator isolation valve** **Functions:** Isolate hydraulic fluid in the pod	Used for all operational mode, shall be available at all times	F-1.28.1 Failed to open/close	Corrosion, mechanical failure	Fail to open: Unable to flow the hydraulic flow from the valve Fail to close: The flow can still be stop with other accumulator isolator valve	No consequence due to redundancy	Flow meter and pressure transmitter monitoring	Regular testing and maintenance Redundancy by having the flow through other valve	1	3	L			
1.29	**Stack mounted accumulator isolation valve** **Function:** Isolate hydraulic fluid in the stack accumulator	Used for all operational mode, shall be available at all times	F-1.29.1 Failed to open/close	Corrosion, mechanical failure	Fail to open: Unable to flow the hydraulic flow from the valve Fail to close: The flow can still be stop with other accumulator isolator valve	No consequence due to redundancy	Flow meter and pressure transmitter monitoring	Regular testing and maintenance Redundancy by having the flow through other valve	1	3	L			

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
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1.30	**Batteries inside subsea pod** **Functions:** Give electric power and signal into subsea solenoid valve to activate the emergency BOP functions. Usually the batteries will function automatically by means of PLC when there is no communication (electric and hydraulic) from the surface	Shall be available at all times for well control operations	F-1.30.1 No voltage	Obsolete battery, corrosion, thermal variations	Solenoid valve inside subsea not function	In case of emergency well shut in, the AMF will not activate blind shear ram to function, causing a high probability of blowout into surface. Reduce effect due to redundancy	After emergency situation (no electricity and hydraulic communication), where there is no sign of influx sealed by the BOP	Regularly scheduled testing, maintenance and inspection Redundancy by having batteries from other pod Redundancy of initiating blind shear ram function by having BOP acoustic intervention system	1	2	L			

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
					Local	Global								
2.1	**Fixed Pipe Rams** **Function:** Protecting topside from uncontrolled pressure from the well	Shall be available at all times for well control operations	F-2.1.1 Not able to close	Mechanical failure, hydraulic failure	Affected ram not able to operate	No global effect, due to redundancy and safeguards	Flow meter, pressure gauges Feedback from the hydraulic system Visual indication on BOP Increase in trip tank volume	Regularly scheduled testing, maintenance and inspection Function test every week Redundancy Competence of personnel Pressure testing	1	3	L			
			F-2.1.2 Not able to open	Mechanical failure, hydraulic failure, human error	Affected ram not able to operated	No global effect, due to redundancy and safeguards	Flow meter, pressure gauges Feedback from the hydraulic system Visual indication on BOP	Regularly scheduled testing, maintenance and inspection Function test every week Redundancy Competence of personnel Pressure testing	1	2	L			
			F-2.1.3 Not able to seal around tubular	Wrong ram with regards to tubular diameter/geometr y Worn parts (e.g., seals and packers), closing pressure not maintained, not correct space-out	During well control situations, unable to seal off the well, leading to well fluid leaking through	Unwanted amounts of fluids or gas influx into the wellbore, and also possibility for influx to surface for the amount of time it takes from trying to close the first ram until the next one is closed	Potential for increase in trip tank volume. Unstable shut-in pressures	Testing, regularly scheduled testing, maintenance and inspection. Function test every week More than one fixed ram available. Variable ram available Competence of personnel Pressure testing	1	2	L		Verify that pressure testing according to recommendations from manufacturer and regulations	mainten ance

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s) Local	Failure effect(s) Global	Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
			F-2.1.4 Degradation of packers over time	High temperature	Not able to seal around tubular	Elastomers may have to be exchanged	Visual indication on BOP. Visual inspection of the weep hole on the rod seal. Increase in trip tank volume	Pressure testing every two weeks. Function tests every week When temperature reach 180^{0}F, pumping rate will be reduced in order to allow fluids to cool before reaching the surface Temperature gauges in the systems. Spares of the elastomers are kept on the rig	1	3	L		Evaluate to keep a log of the temperature readouts on all temperature sensors Evaluate if the ram packers and seals should be exchanged after they have been exposed to temperature above their maximum continuous design temperature, regardless of their state as an extra safeguard Evaluate to update operation procedures to take into consideration the HPHT drilling	Maintenance & operations Engineering & operations operations
			F-2.1.5 External leakage (bonnet/door seal or other external leakage path)	Loosen bonnet bolts, Loosen ram housing flange, Worn parts (seal, packers, etc)	Fluid leakage to environment	In the worst case: Influx can deteriorate the seal and bolt causing massive environment spill	Visual, Reduction in hydraulic pressure	Regularly scheduled testing, maintenance and inspection Pressure testing Competence of personnel	1	1	L			
			F-2.1.6 Internal leakage (leakage through a close ram)	Worn part (seal, packers, etc,	Some influx into wellbore	In the worst case: Influx can deteriorate seal and packers causing failure in ram function. It allows influx to reach surface and endanger personnel	Visual indication on BOP Flow meter, pressure gauges Reduction in kill mud pressure	Regularly scheduled testing, maintenance and inspection Pressure testing Competence of personnel Redundancy by having annular preventer	1	2	L			

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
					Local	Global								
2.2	**Variable Bore Rams** **Functions:** Protecting topside from uncontrolled pressure from the well	Shall be available at all times for well control operations	F-2.2.1 Not able to seal around tubular	Worn parts (e.g., seals and packers), closing pressure not maintained	During well control situations, unable to seal off the well, leading to well fluid leaking through	Possibility for influx to surface for the amount of time it takes from trying to close the variable ram until the next one (annular preventer or shear ram) is closed	Potential for increase in trip tank volume. Unstable shut-in pressures	Testing, regularly scheduled testing, maintenance and inspection. Function test every week Competence of personnel Pressure testing Annular preventer available, depending on pressure. Shear ram available	1	3	L			
			F-2.2.2 Not able to close	Mechanical failure, hydraulic failure	Affected ram not able to operate	No global effect due to redundancy and safeguards	Flow meter, pressure gauges, feedback from the hydraulic system. Visual indication on BOP. Increase in trip tank volume	Testing, regularly scheduled testing, maintenance and inspection. Function test every week Competence of personnel Redundancy Pressure testing	1	3	L			
			F-2.2.3 Unable to hold the hang-off weight	Mechanical failure	Not able to hang off, potential for dropped string	No global effect, due to safeguards	Visual, string movement	Possibility for hanging off the fixed rams. Known hang-off weight. Competence to operate within tolerance limits. Maintenance and inspections	1	2	L			

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
					Local	Global								
			F-2.2.4 Degradation of packers over time or high temperature	High temperature	Not able to seal around tubular	Elastomers may have to be exchanged	Visual. Indication on BOP. Visual inspection of the weep hole on the rod seal. Increase in trip tank volume	Pressure testing every two weeks Function tests every week When temperature reaches 180^0F, pumping rate will be reduced in order to allow fluids to cool before reaching the surface Temperature gauges in the system. Spares of the elastomers are kept on the rig.	1	3	L		Review operational procedures to take into consideration dropping of string and tubular which is outside the shearing capacity and subsequent closing of shear rams Check the regulations and legislations to see if it is allowed to run casing or tubular that cannot be sheared A risk assessment should be performed before executing this kind of operations After implementation of these recommendations, the probability of risk of the failure mode may be	
		After well control situations and pressure tests	F-2.2.5 Not able to open	Mechanical failure, hydraulic failure, human error	Affected ram not able to operate	No global effect due to redundancy and safeguards	Flow meter, pressure gauges, feedback from the hydraulic system. Visual indication on BOP	Testing, regularly scheduled testing, maintenance and inspection. Function test every week Competence of personnel Redundancy Pressure testing	1	2	L			

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
					Local	Global								
2.3	**Blind Shear Ram** **Functions:** Cutting drill string, pipe/tubular and protecting topside from uncontrolled pressure from the well	Shall be available at all times for well control operations	F-2.3.1 Unable to cut string, thus unable to seal of wellbore	Hydraulic failure, mechanical failure, human error (including incorrect space out) too high wellbore pressure. Pipe not in the centre position Potential for tubular dimensions outside the shear ram specifications	No shearing	Potential for need to drop string or tubular before closing shear ram	Visual, datasheets, known ram specifications	Maintenance and inspections Pressure testing Hang off in centre Redundancy (annular up to 10000psi, variable ram) Check of datasheets for tubular against known ram specifications	3	3	M		Review operational procedures to take into consideration dropping of string and tubular which is outside the shearing capacity and subsequent closing of shear rams Check the regulations and legislations to see if it is allowed to run casing or tubular that cannot be sheared A risk assessment should be performed before executing this kind of operations After implementation of these recommendations, the probability of risk of the failure mode may be reduced	Operations Operations Operations
			F-2.3.2 Not able to close Not able to perform complete shut off and seal the annulus	Mechanical failure, hydraulic failure	Affected ram not able to operate	No global effect, due to safeguard	Flow meter, pressure gauges, feedback from the hydraulic system. Visual indication on BOP. Increase in trip tank volume	Testing, regularly scheduled testing, maintenance and inspection. Function test every week Competence personnel Pressure testing Possible to close annular on empty hole up to 10000 psi in combination with the choke system	1	2	L			

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
					Local	Global								
			F-2.3.3 Degradation of packers over time	High temperature	Not able to seal off the wellbore	Elastomers may have to be exchanged	Visual indication on BOP. Visual inspection of the weep hole on the rod seal. Increase in trip tank volume	Pressure testing every two weeks Function tests every week When temperature reaches 180^{0}F, pumping rate will be reduced in order to allow fluids to cool before reaching the surface Temperature gauges in the system. Spares of the elastomers are kept on the rig. Possible to close annular on empty hole	1	3	L		Evaluate to keep a log of the temperature readouts on all temperature sensors Evaluate if the ram packers and seals should be exchanged after they have been exposed to temperature above their maximum continuous design temperature, regardless of their state as an extra safeguard Evaluate to update operation procedures to take into consideration the HPHT drilling After implementation of these recommendations, the probability of the failure mode may be reduced	
		After a well control situation or pressure test	F-2.3.4 Not able to open	Mechanical failure, hydraulic failure, human error	Affected ram not able to operate	No global effect, due to redundancy and safeguards	Flow meter, pressure gauges, feedback from the hydraulic system, visual indication on BOP	Testing, regularly scheduled testing, maintenance and inspection. Function test every week. Redundancy. Competence of personnel. Pressure testing	1	2	L			
2.4	**Annular BOP** **Functions:** Protecting topside from uncontrolled pressure from the well	Shall be available at all times for well control operations	F-2.4.1 Not able to seal around tubular	Worn parts, closing pressure not maintained	During well control situations, unable to seal off the well, leading to well fluid leaking	Possibility for influx to surface for the amount of time it takes from trying to close the annular until the other rams with suitable size or shear ram is closed	Potential for increase in trip tank volume. Unstable shut-in pressures	Testing, regularly scheduled testing, maintenance and inspection. Function test every week Competence of personnel Pressure testing Shear ram and potentially other rams available	1	3	L			

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
					Local	Global								
			F-2.4.2 Not able to open to full or within 30 minutes (API)	Mechanical failure, hydraulic failure, human error. Worn elements	Annular not able to operate	No global effect, due to redundancy and safeguards	Flow meter, pressure gauges, feedback from the hydraulic system	Testing, regularly schedule testing, maintenance and inspection. Function test every week Competence of personnel	1	2	L			
			F-2.4.3 Degradation of elements over time	High temperature or mud type (e.g. OBM), extensive use (including stripping)	Not able to seal around tubular	Elements may have to be exchanged	Increase in trip tank volume. Unstable shut in pressures	Pressure testing every two weeks. Function tests every week When temperature reaches 180^0F, pumping rate will be reduced in order to allow fluids to cool before reaching the surface Temperature gauges in the system. Spares of the elements are kept on the rig. Correct choice of element type	1	3	L			
2.5	**Automatic Subsea Ram Locks** **Functions:** Locking the ram in closed position	Shall be available at all times for well control operations	F-2.5.1 Unable to lock	Rusted, bended, mechanical damage, human error	Unable to lock rams in closed position	No global effects due to safeguards	Visual	Testing and maintenance Hydraulic pressure in the closing chamber	1	2	L		Update the operational procedure to ensure that testing is done according to API 53, and including the locks in the test when energizing the rams	
			F-2.5.2 Unable to open	Rusted, bended, mechanical damage	Unable to unlock rams, and thus open them	Unable to proceed with operation, delays	Visual	Testing and maintenance	1	2	L		Update the operational procedure to ensure that testing is done according to API 53, and including the locks in the test when energizing the rams	

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
					Local	Global								
3.1	**Choke ad Kill Valve** **Function:** Regulate the flow of kill fluid and influx	Shall be available at all times for well control operations	F-3.1.1 External leakage (leakage to environment in main valve or valve connectors)	Worn or degraded parts (ring gasket and flange) Over pressure Human error (improper valve connection installation)	Leakage in the connection between the inner valve and the BOP body Leakage in connection between two valves	The worst case: If leakage occurs in the lower inner valve below the LPR, the BOP will leak if attempting to close in a well kick	Visual inspection with SSTV (Subsea test Valve) and ROV Pressure gauges	Regularly scheduled testing, maintenance and inspection Pressure testing Regulate the flow through other redundant choke and kill valve is possible	1	2	L			
			F-3.1.2 Internal leakage (leakage through a closed valve)	Worn or degraded parts of valves (seat, gate, etc) Over pressured Human error (improper valve connection installation)	Leakage through a closed valve	No global effect, due to redundancy and safeguards	Visual inspection Pressure gauges	Redundancy in the choke and kill valve (have more than one lines) Flushed and greased the valves Pressure testing Regularly schedule testing, maintenance and inspection	1	2	L			
			F-3.1.3 Failed to open	Plugged line, Failure valve	Kill fluid and influx flow cannot be regulated through the valve	No global effect, due to redundancy and safeguards	Visual inspection Pressure gauges	BOP test (pressure test) Flushed and greased the valves Redundancy	1	1	L			
			F-3.1.4 Failed to close	Plugged line, Failure valve	Kill fluid and influx flow	No global effect, due to redundancy and safeguards	Visual inspection Pressure gauges	BOP test (pressure test) Flushed and greased the valves Redundancy	1	1	L			

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
					Local	Global								
3.2	**Hydraulic connector** **Function:** Connect BOP with LMRP and wellhead	Used for all operational modes, shall be available at all times	F-3.2.1 External leakage	Leakage in wellhead gasket, Damage seal ring, over pressure	Leakage of drilling fluid into environment during drilling operation	Delays in well control operations	Visual inspection	Redundancy by BOP during well control operation BOP testing Regularly schedule testing, maintenance and inspection	1	2	L			
			F-3.2.2 Failed to unlock	Failure in wellhead connector, failure in LMRP connector, Connector stuck, hydraulic system failure	Damage to wellhead connector during drift off.	Major fatalities damages to subsea riser and very costly rig downtime when drift off, kick (influx) and black out happen at the same time, especially in the floating DP vessel. Possibility of major leakage if not handle properly Leakage of fluid into environment	No hydraulic response Well abandonment operation	BOP testing Redundancy of secondary unlatch to unlatch the stack Redundancy of unlatching the connection during bad weather for floating vessel by unlatch LMRP or wellhead connector Dumped the accumulator fluid through the connector to flush hydrates/debris that can cause clog or plug Redundancy of BOP function when kick occur	2	2	L			

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
					Local	Global								
4.1	**Blind /shear ram seal (sealing element)** **Function:** Seal the ram from influx	Shall be available at all times for well control operations	F-4.1.1 Deformed, worn, stiff, eroded	Chemical corrosion, mechanical elastic/plastic deformation	Kick influx flow not contained	The deterioration of seal during kick influx might escalate the leakage. The small leakage of kick influx could create influx liquid splash out of the ram like water jet that can erode the blade and string being cut	Pressure gauge reading Volume of mud pit (might be general, it is not only showing the failure of ram seal	Schedule testing and maintenance Redundancy by having other rams and/or annular preventer close	2	1	L		The shearing of drill pipe during drilling and when kick occur is necessary when pipe ram and annular preventer could not hold the pressure generated during the influx. In this case the well need to be shut completely by using shear ram	
4.2	**Piston on both sides** **Function:** Convert hydraulic pressure to mechanical energy	Shall be available at all times for well control operations	F-4.2.1 Galling, seizure, misalignment, pitting	Corrosion, thermal variation	Shear ram not operational	In the worst case, Influx might escalate and escape into surface	Pressure gauge reading Volume of mud pit (might be general, it is not only showing the failure of piston)	Schedule testing and maintenance Redundancy by having other rams and/or annular preventer close	3	2	M		Other type of ram (pipe ram) and annular preventer are designed to hold the influx but not intended to shut off the well completely. The well needs blind shear ram to complete shut off.	
4.3	**Wedge on both sides** **Function:** Secure linier mechanical energy on piston	Shall be available at all times for well control operations	F-4.3.1 Galling, seizure, misalignment, impact failure	Thermal variation in combination with excess force	Oil contained temporarily	No global effect, due to redundancy and safeguards	Pressure gauge reading	Scheduled testing and maintenance Redundancy by having hydraulic fluid to secure the linier mechanical energy on piston	1	2	L			
4.4	**Blade on both sides** **Function:** Shear or cut the string and/or casing	Shall be available at all times for well control operations	F-4.4.1 Impact failure, brittle failure, pitting, dulling	Excess force, corrosion, thermal fatigue	Shear ram not effective, fails to cut pipe	In the worst case, influx might enter the riser up to the surface endanger personnel live	Pressure gauge reading Volume of mud pit (might be general, it is not only showing the failure of piston)	Scheduled testing and maintenance Redundancy by having other rams and annular preventer to seal the well	3	1	L		Other type of ram (pipe ram) and annular preventer are designed to hold the influx but not intended to shut off the well completely. The well needs blind shear ram to complete shut off.	

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
					Local	Global								
4.5	**Shear ram housing** **Function:** Guiding piston and the flow of hydraulic fluid	Shall be available at all times for well control operations	F-4.5.1 Deformation, cracking, erosion	Excess pressure, thermal variation, corrosion, fatigue	Hydraulic fluid not contained, leakage of hydraulic fluid	Failure on rams function (unable to close and seal the well)	Visual Hydraulic pressure reading	Scheduled testing and maintenance Redundancy by having sealing device such as blind ram and pipe ram	3	1	L			
4.6	**Annular preventer rubber housing** **Function:** Guiding sealing element (rubber) to seal around the tubular	Shall be available at all times for well control operations	F-4.6.1 Deformation, worn, stiff, eroded parts	Excess pressure, thermal variation, corrosion, fatigue	Hydrocarbon influx not contained, leak	Failure on annular prevention function (unable to close and seal the well)	Visual Hydraulic pressure reading	Scheduled testing and maintenance Redundancy by having sealing device such as blind ram and pipe ram	3	3	M			
4.7	**Annular sealing element (rubber seal and steel reinforcement segments)** **Function:** Seal the well by pushing the sealing element upward through piston	Shall be available at all times for well control operations	F-4.7.1 Deformed, worn, stiff, eroded	Chemical corrosion, mechanical elastic/plastic deformation	Kick influx flow not contained	The deterioration of seal during kick influx might escalate the leakage. The small leakage of kick influx could create influx liquid splash out of the ram like water jet that can erode the sealing element and drill string being clamped	Pressure gauge reading Volume of mud pit (might be general, it is not only showing the failure of ram seal	Schedule testing and maintenance Redundancy by having other rams close	2	1	L		The shearing of drill pipe during drilling and when kick occur is necessary when pipe ram and annular preventer could not hold the pressure generated during the influx. In this case the well need to be shut completely by using shear ram	
4.8	**Annular Piston** **Function:** Convert hydraulic pressure to mechanical energy to pushed the sealing element upward for sealing purpose	Shall be available at all times for well control operations	F-4.8.1 Galling, seizure, misalignment, pitting	Corrosion, thermal variation	Annular preventer not operational	In the worst case, Influx might escalate and escape into surface	Pressure gauge reading Volume of mud pit (might be general, it is not only showing the failure of piston)	Schedule testing and maintenance Redundancy by having other rams close	2	2	L		Other type of ram (pipe ram) and annular preventer are designed to hold the influx but not intended to shut off the well completely. The well needs blind shear ram to complete shut off.	

ID no.	Item/functional identification	Operational mode	Failure mode(s)	Failure Cause(s)	Failure effect(s)		Detection method	Compensating provisions (safeguards)	C (1-5)	P (1-5)	Risk (L,M, H)	Dwg.	Additional Information and recommendation	Resp. party
					Local	Global								
4.9	**Annular locking wedge** **Function:** Secure linier mechanical energy on piston	Shall be available at all times for well control operations	F-4.9.1 Galling, seizure, misalignment, impact failure	Thermal variation in combination with excess force	Oil contained temporarily	No global effect, due to redundancy and safeguards	Pressure gauge reading	Scheduled testing and maintenance Redundancy by having hydraulic fluid to secure the linier mechanical energy on piston	1	2	L			

12.2 Well Barrier elements in drilling operation

Well barriers are layers of one or several dependent well barrier elements which prevents fluids to flow unintentionally from one formation to other formation or to surface. Well barriers element is a dependent object to prevent flow from one side to the other side of itself. According to Norsok D-010 (2004), there are four conditions where well barriers element should be established in the drilling operations as follows:

- Drilling, coring and tripping with shearable drill string
- Running non shearable drill string
- Running non shearable casing
- Through tubing drilling and coring

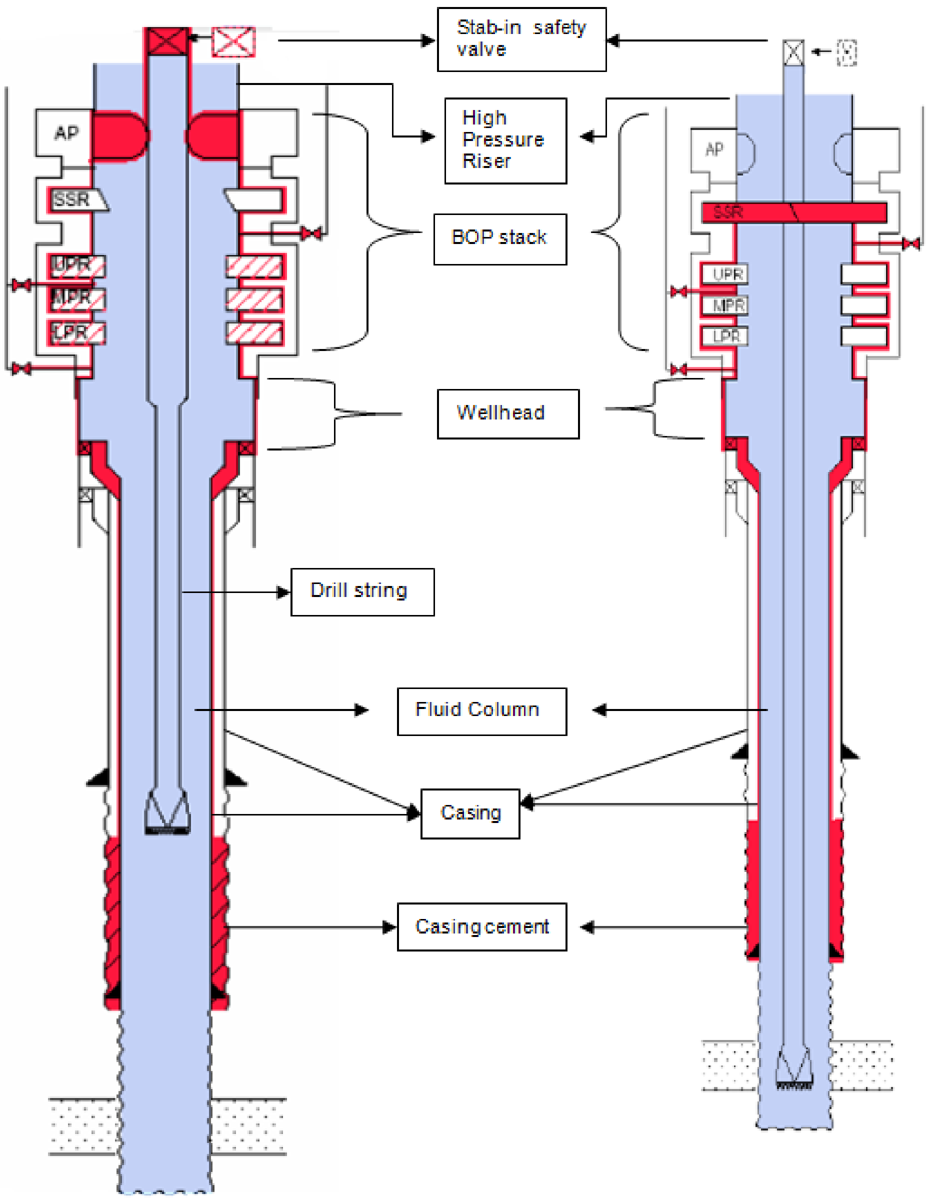


Figure 12.1 Well barrier schematic for running non-shearable drill string (left) and drilling, coring and tripping with shearable drill string (right) (Norsok D-010, 2004)

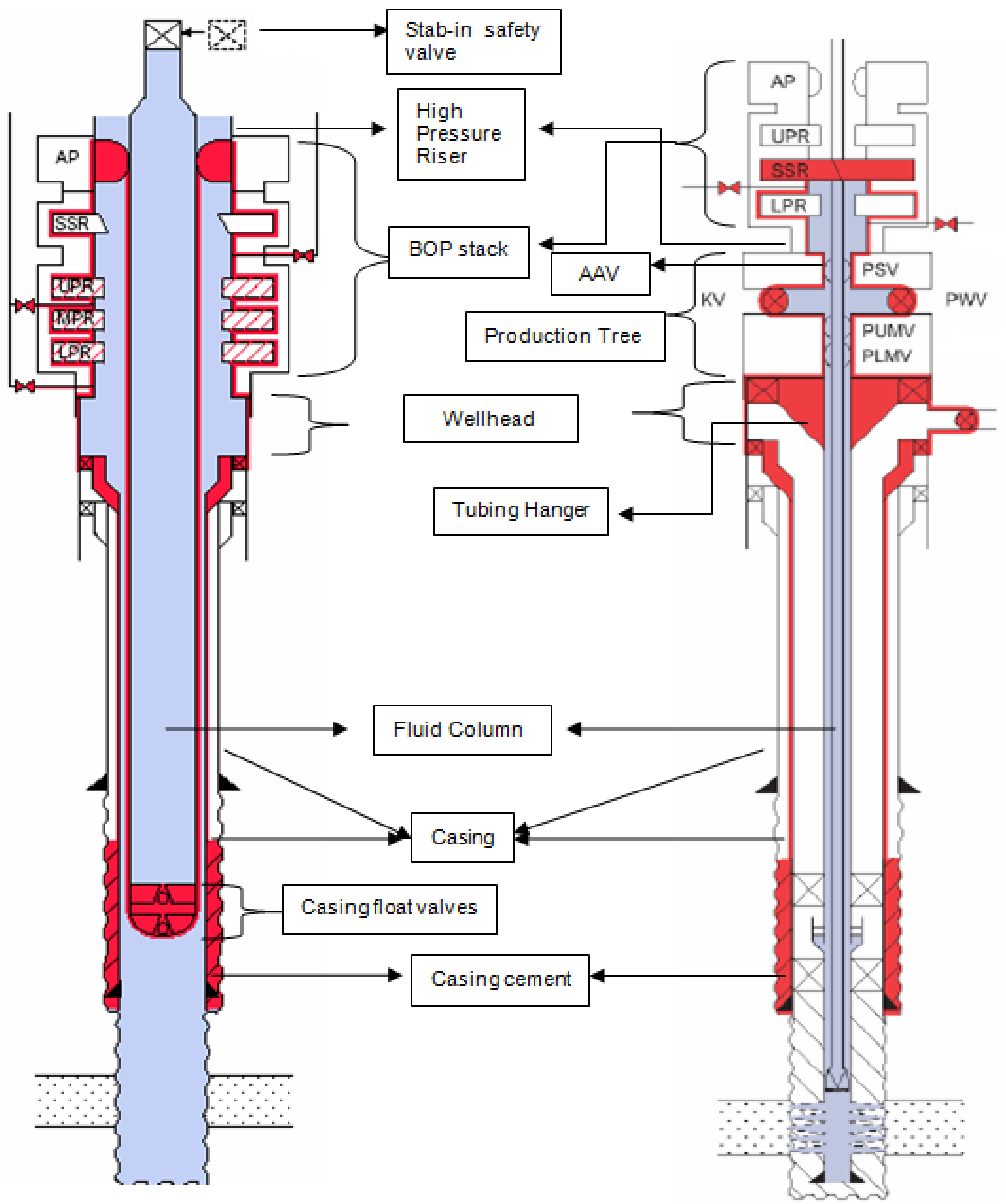


Figure 12.2 Well barrier schematic for running non-shearable casing (left) and drilling through tubing drilling and coring (right) (Norsok D-010, 2004)

According to the figures above, there are some basic well barrier elements during drilling operation such as fluid column, casing cement, casing, wellhead, high pressure riser, drilling BOP, drill string, stab-in safety valve, casing float valve, production tree, annulus access line and tubing hanger (Norsok D-010, 2004). The well barriers elements are generally accepted and required when doing some operations where BOP is used such as when well shut in, stripping, snubbing and BOP testing.

12.2.1 Fluid column

Fluid column is the fluid located in the wellbore which is used to balance the pressure in the wellbore by exerting hydrostatic pressure that will prevent influx (kicks) entering wellbore. It is important that the hydrostatic pressure of fluid column do not exceed the formation fracture pressure (Norsok D-010, 2004). Fluid column can be represented by drilling fluid which can be oil, oil-based fluids (oil in water, water in oil emulsions), gas-based mud and water-based mud. There are eight basic functions of drilling fluids as follows (Well Control School, 2004):

1. Transportation of cuttings to surface
2. Suspension of cuttings when circulation is stopped
3. Control of annular pressure and delivery of hydraulic energy
4. Lubrication and cooling of the drilling assembly
5. Provision of wall support
6. Suspension of drilling assembly and casing
7. Provision of a suitable medium for wireline logging

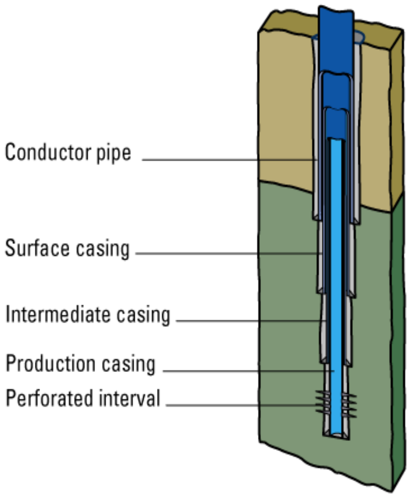
12.2.2 Casing cement

Casing cement is application of liquid slurry of cement and water to be placed inside or outside casing. There are three types of cementing which are primary cement, secondary cement and squeeze cement. Primary cement is the first cementing process into the well. Secondary cement is used to isolate producing formation, seal off water, repair casing leak, etc. Squeeze cementing is forcing cement into the wells to fill channels in the primary cementing (Well Control School, 2004)

The placement of cement should be in the annulus between concentric casing string or the casing/liner and the formation. Cement is used to provide continuous, permanent and impermeable hydraulic seal along hole in the casing annulus or between casing strings in order to prevent flow of formation fluids, resist pressures from above or below, and support casing or liner string structurally (Norsok D-010, 2004).

12.2.3 Casing

Casing is element consist of casing/liner and/or tubing in case tubing is used for through tubing drilling and completion operations. The purpose is to provide a physical barrier to uncontrolled flow of formation fluid or injected fluid between the bore and casing (Norsok D-010, 2004).



- Conductor pipe

Conductor pipe is established to prevent the hole from caving in at the surface and endangering the drilling rig foundation (Odland, J., 2010). It is cemented to prevent drilling fluids circulating outside the casing that can cause surface erosion (Schlumberger, 2012). The unconsolidated layers below seabed/surface will be isolated and it support template, marine riser on floating rigs, mud line suspension/riser system on jack up rigs, surface casing and wellhead (Aadnøy, B., S., 1999).

Figure 12.3 Casings inside wellbore (Schlumberger, 2012)

- Surface casing

  Surface casing provides protection from freshwater formations and prevents shale, sand and gravel to fall into the hole (Odland, J., 2010). Blow out preventer can be anchored to surface casing and support deeper casing strings (Schlumberger, 2012). It is also isolates weak formations to sufficiently form formation integrity where proper control of abnormal pressure from the formations below can be assured. Furthermore, the isolation will prevent the influx of potential shallow gas zone to establish integrity for further drilling (Aadnøy, B., S., 1999).

- Intermediate casing

  Like any other basic casing function, Intermediate casing is cemented to prevent loss of circulation in the well by isolating the formation (Schlumberger, 2012). It also isolates all formations up to the surface casing to allow the safe and efficient drilling for the next holes sections through the pay zone. Moreover, intermediate casing gives sufficient well integrity for drilling the pay zone or any abnormally pressurized zones (Aadnøy, B., S., 1999).

- Production casing

  The last casing which is production casing is used to prevent oil moving to thief zones and avoid sloughing of formations causing a reduction in productivity (Schlumberger, 2012). In addition to isolating the productive zones, it maintains well integrity during production and work over periods as well as allows further drilling into deeper hole if needed (Aadnøy, B., S., 1999).

12.2.4 Wellhead

According to Norsok D-010 (2004), wellhead is an element consists of the wellhead body with annulus access ports and valves, seals and casing/tubing hangers with seal assemblies. It is used to provide mechanical support for the suspending casing and tubing strings and for hook up of risers of BOP or production tree and to prevent flow from the bore and annuli to formation or the environment.

12.2.5 Riser (High Pressure Riser)

Riser is a tubular that connects drilling BOP (subsea BOP) into surface rig. It is act as an extension of the drilling BOP on platforms where the wellheads is positioned at different levels and thus prevent flow from the bore to the environment (Norsok D-010, 2004). It includes connectors and seals connecting the drilling BOP to the wellhead.

12.2.6 Drilling BOP

BOP is a tool that acting as a last line of protection against kicks and blowouts. It consists of rams and preventers that can be closed and seal the well in case of influx occurrence inside the well. The elements that construct drilling BOP are consists of wellhead connector, BOP, kill/choke line and valves. According to Norsok D-010 (2004), the function of these constructions is to allow wellhead connector to prevent flow from the bore to the environment and to provide a mechanical connection between drilling BOP and wellhead.

12.2.7 Drill String

Drill string is an extension of tubular pipe/column connecting drill collar and drill bit from the surface with attached tool joints that transmits fluid and rotational power as part of the drilling tools. The purpose of the drill string as well barrier element is to prevent flow of formation fluid from wellbore into external environment. It should be designed to resists against abrasive environment, fatigue and buckle as it will be used continuously as a rotating tools to drill a well.

12.2.8 Stab in safety valve

Stab in safety valve is a valve that is connected to the work string when the well begins to flow when running or retrieving the string. It gives protection against tubing plug or backpressure valve pressure during snubbing operation (Schlumberger, 2012). This element consists of housing with a bore and a ball valve. Stab in safety valve is used to allow mounting and closure at the top of any free tubular joint sitting in the rotary table.

12.2.9 Casing float valves

Casing float valves is a valve used to prevent flow of fluids from the wellbore up the casing/liner during installation of casing/liner and to allow for circulating the well. The fluid should be pumped down into the casing/liner while at the same time prevent the flow back in the opposite direction. It consists of a tubular body with pin and box threads and internal one-way valve (Norsok D-010, 2004).

12.2.10 Production tree

Tree or x-mas tree is a structure consists of control valves, pressure gauges and chokes located at the top of a well where the primary function is to control the flow into or out of the well (Odland, J., 2010). According to the location of installation, production tree can be divided into two types, subsea and surface production tree. Subsea production tree or wet x-mas tree is located on the top of the subsea wellhead. It has some elements consist of housing bores that are fitted with production and annulus master. It has some functions as follows (Norsok D-010, 2004):

- Provides a flow conduit for hydrocarbons from wellbore into surface by having the ability to adjust the flow by opening or closing the valve and/or PMV (production master valve).
- Provides monitoring and pressure adjustment of the annulus as well as provide vertical tool access through the swab valve(s) (Norsok D-010, 2004).

Surface production tree is located on the surface platform and has the same function as subsea production tree with additional function to gives access point where kill fluid can be pumped into the wellbore.

12.2.11 Annulus access line and valve (AAV)

Annulus access line and valve is a line and valve which allows monitoring of pressure and flow in the annulus below the tubing hanger. It consists of wellhead housing and an isolation valve.

12.2.12 Tubing hanger

Tubing hanger is acting as an interface between the tubing from the well and the x-mas tree. It directs the flow from the well to the x-mas tree and provide interface possibilities for downhole electrical and hydraulic lines from the x-mas tree (Subsea1, 2010). According to Norsok D-010 (2004), tubing hanger consists of body, seals and bore which may have a tubing hanger plug profile. It has some functions to support the weight of the tubing, prevent flow from the bore and to the annulus, provides sealing in annulus space between tubing and wellhead and provides a stab-in connection point for bore communication with the tree.

12.2.13 Diverters

Diverter is a low pressure system to direct well flow away from rig. It is installed to provide safety when there is a flow of shallow gas (Hawker, 2001). It is designed to divert low pressure gas which comes from a pressurized gas zone during drilling in case of incapability of casing shoe to hold shut in pressure. Massive flows of gas and sand can quickly destroy a diverter (Rig Train, 2001). Flex/ball joint between BOP stack and the rig is installed to deal with the relative motion of the floating platform.

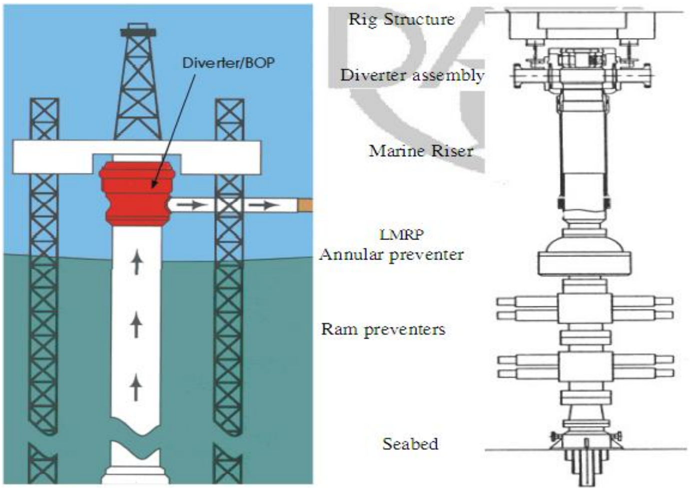


Figure 12.4 Flow of diverted gas (left) and schematic of typical installation for floating drilling platform (right) (Rig Train, 2010) (Hawker, 2001)

Two diverter lines are usually installed to direct gas into starboard side and portside of the platform. In the event of a kick, one or both lines will be opened and the annulus will be closed. Minimum one vent must be open before closing annulus to prevent gas accumulating in the pipe. The gas can be directed away from the rig until the pressure is reduced.

12.2.14 Drilling Spools

Drilling spool is a spool which connecting the kill lines and choke lines to the BOPs. When BOPs are closed, the fluid flows through the choke line and injection of drilling fluid is through the kill line.

- Minimum drilling spool specifications include one or two side outlets no smaller than two inches nominal diameter
- A vertical bore at least equal to the maximum inner diameter of the innermost casing (if the spool is to pass slips, hangers, or test tools, the bore should at least equal the inside diameter of the top casing head).

12.2.15 Relief Lines

The relief line is a large line to relieve well pressure when BOP is closed and when there is back pressure that is resulting from the flow in the smaller choke lines which can endanger the well.

12.2.16 Rotating Preventer (Rotating Head/Stripper)

Rotating preventer is a tool located in the top of the BOP stack which is use to seal the annular space where it has a capability to prevent the well from blowing out and allowing underbalanced drilling. The most used application for rotating preventer is for underbalanced drilling.

Underbalanced drilling is a drilling of a well where the drilling fluid has less hydrostatic pressure than the formation pressure while maintaining the bottom hole pressure by using rotating preventer features to release and control the pressure. This method is the opposite of the conventional drilling where the drilling fluid should have higher pressure than formation pressure to prevent any influx (kick) to become a blowout. The advantages of using underbalanced drilling methods are:

- Loss of circulation/mud is reduce as the pressure in the well is less than the pressure in the formation, preventing it from cracking or fracturing the formation in the borehole which can cause the flow to loss in the crack.
- It allows hydrocarbon production while drilling. During drilling operation, drill bit will pass through some layer of formation and has lower hydrostatic pressure than formation allowing hydrocarbon that could be trapped in some drilled layers to be flown into the surface.

For subsea use, the rotating preventer are mounted on top of the standard BOP stack and act as a rotating flow diverter. It allows rotation and vertical movement of the drill string during drilling while in the same time it seals around and rotates with the pipe or kelly (Hawker, 2001).

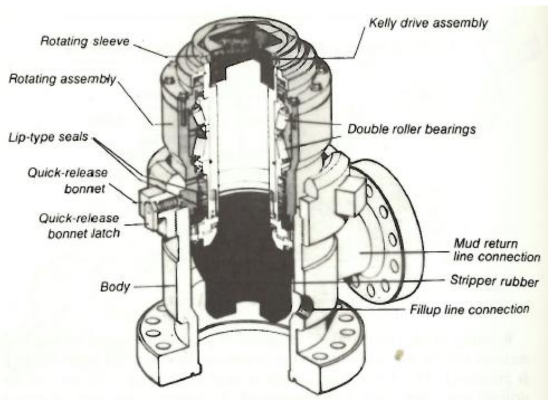


Figure 12.5 haffer rotating head and stripper (Goins, W.,C., Sheffield, R., 1983)

12.2.17 Flex Joints

A flexible joint is a connector between riser and BOP stack which allows some degree of movement to handle the movement of a floating rig. It gives capability to allow riser system to rotate with minimum bending moment. The design of flex joints should consider the maximum accepted rotation, fatigue ranges, tensions of the riser when it is in the hang off mode and the effects of that tension (Bai, Y., Bai, Q., 2005, p. 444). Figure 4.21 shows some type of flex joints. The tendon system inside the flex joint gives possibility to accept some movement.

Figure 12.6 Some type of flex joint (Oil States, 2012)

12.2.18 Wellhead Connector

Wellhead connector is a connector between BOP stack and well head. It consists of parts (figure 4.22) that should be designed for the specific purpose of expected pressures and weight of the stack.

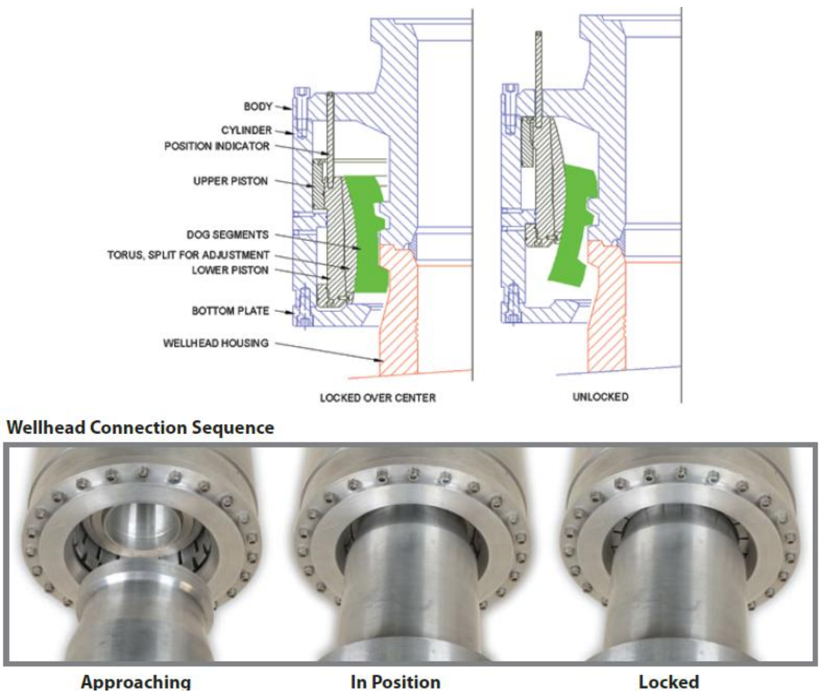


Figure 12.7 Wellhead connector and its connection sequence (Radoil, 2009)

12.3 Pressures Acted in the Well

1. formation related pressures that consists of:
   a. Overburden pressure is the pressure as a result of accumulated deposit in the sediments as a function of rock matrix and pore fluid (Hawker, D., 2001)
   b. Formation pressure is the pressure exerted from the fluid in the pores of rocks (Hawker, D., 2001)
   c. Fracture pressure/gradient is the maximum pressures that the formation can withstand without collapsing (Hawker, D., 2001)

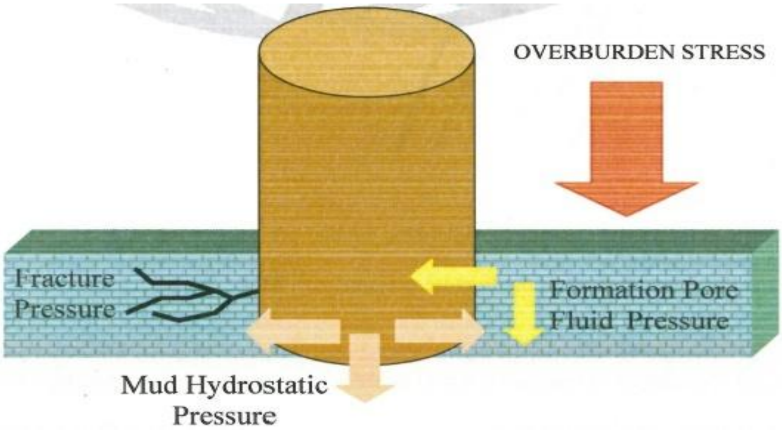


Figure 12.8 Pressures acted in a wellbore (Hawker, D., 2001)

2. Wellbore balancing pressures that consists of :
   a. Mud hydrostatic pressure is the static pressure exerted by the weight of a vertical column of mud at a given depth. This is the pressure of drilling fluid (mud) to balance the fluid pressure from formation at static or when there is no drilling activity. When drilling activity take place there would be a frictional pressures loss causing an increase or decrease in the balancing pressures (Hawker, D., 2001).

$$P_{hyd\ mud} = MW \times TVD \times g$$

Where: $P_{hyd\ mud}$: Mud hydrostatic pressure

Unit : PSI = PPG x ft x 0.052

PSI = SG x ft x 0.433

KPa = kg/m^3 x m x 0.00981

   b. Equivalent circulating density is the increase of frictional pressure in annulus as a result of mud circulation activity which gives an increase in the annular pressure (Hawker, D., 2001).

c. Surge pressure is the increase of frictional pressure in annulus as a result of vertical movement of running drill string in the hole which gives an increase of annular pressure. Excessive surge pressure can damage formation and create fracture allowing drilling fluid to enter the formation and create loss of mud circulation which will decrease the annulus pressure (Hawker, D., 2001).

d. Swab pressure is the loss of frictional pressure as a result of lifting pipe activity out from hole which gives a decrease in the annular pressure. Swab can occur from the slow pull out of drill string that makes drilling fluid to have an effect of being attached to the pipe and dragged up. Other case would be by rapid pull out movement of drill string that makes drilling fluid to replace the emptied volume left by the pipe. Both scenarios would reduce annular pressure (Hawker, D., 2001).

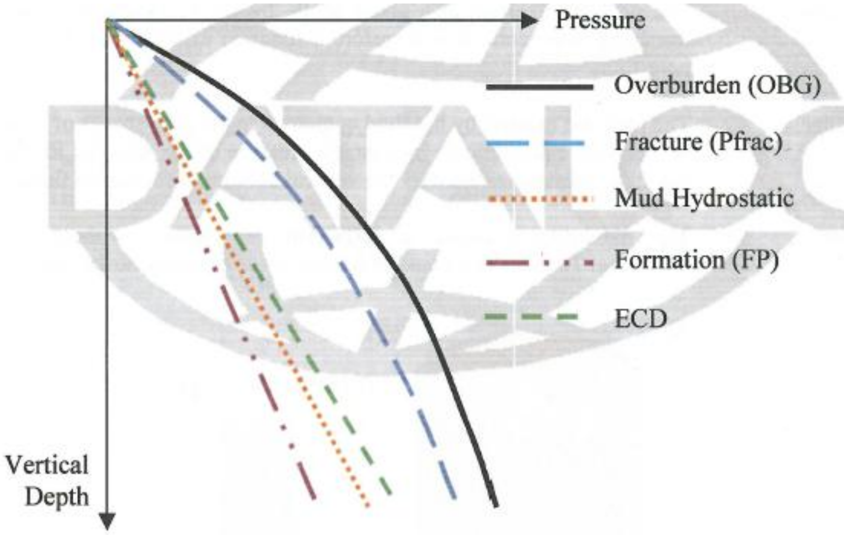


Figure 12.9 Relationship between depth and pressure for different pressures acting in a wellbore (Hawker, D., 2001)

The conclusions can be seen in the figure 2.6. The mud hydrostatic should be larger than the formation pressure to prevent a kick. On the other hand, the increase of annular pressure as an effect of mud circulation and drill string vertical movement should still be below the fracture pressure to prevent formation collapse and damage. The reduced annular pressure caused by swabbing should be handled to keep it above the formation pressure.

In order to know the required fracture pressure, a leak off test (LOT) needs to be performed. The test is carried out after casing or cementing activity related to the next drilling in the deeper depth. There are two principles in conducting this test. Firstly, cement integrity test is performs to know the strength of the cement in order to withstand from the high flowing pressures. Secondly, fracture pressure test is conducted after cement integrity test has proven acceptable. It is conducted in order to know the maximum value of fracture pressure in the formation, where the mud is allows to be pumped for the next drilling operation without causing fracture. It is done by letting the formation fracture under a given pressure from mud in a control manner. The result of this fracture pressure test also known as leak of pressure (LOP). There are some factors that determine the fracture pressure such as rock type, in situ stresses, weakness (fractures, faults), condition on the borehole, relationship between wellbore geometry and formation orientation and mud characteristics (Hawker, D., 2001).

$$P_{fracture} = P_{hyd\ mud\ at\ shoe} + LOP$$

$$P_{fracture\ (EMW)} = MW + LOP/(TVD\ shoe \times g)$$

12.4 Basic Well Control Methods

There are three methods to control a well when influx occurred by using constant bottom-hole pressure method such as:

1. Wait and weight method

   Shut in the well, prepare the required killing mud (mud weight) and when it is ready, it will be used to circulate out the kick (Goins, W.,C., Sheffield, R., 1983, p.27).
2. Driller's method

   The lighter mud in the well is circulated out from the hole and the well is shut in. During this circulation the required mud is calculated and built. The killing mud will be circulated to kill the well once it is ready (Hawker, D., 2001, p.62)
3. Concurrent method

   The circulation of mud is conducting directly and the weights are added up until it reaches the required killing mud weight to kill the well (Hawker, D., 2001, p.64).

In some situations where constant bottom-hole pressure could not be applied, there are other methods that can be used to control a well such as:

1. Volumetric method

   This method is used when the above methods are not possible due to the position (e.g. out of hole, twisted off, etc.) and the pressure (less than required) of the drill string. The plugged bit nozzle also allows volumetric method to be used. The principal is to maintain the pressure in the bottom hole by allowing drilling fluid to escape from annulus. The volume of the escape fluid is measured. When the influx goes up into surface, its volume will expand and SICP should be increased to maintain the pressure (Hawker, D., 2001, p.65)

2. Killing diverted blowout

   This method is used when pipe is still set in the shallow depth and a kick occur. As a result there is not enough back pressure that can be used at the surface. In this case a BOP is used to divert the well fluid out of the rig. It requires maximum rate of pumping to provide mud fluid in the well (Goins, W.,C., Sheffield, R., 1983, p.28).

3. Low choke pressure method

   This method is used when a kick occur and there is a concern that the casing pressure will not sufficient enough to maintain its strength. It is important to prevent broaching. When a kick occurs, the bottom-hole pressure is kept constant by circulating back pressure in a higher rate than normal killing rate. Meanwhile, the choke holds its maximum allowable pressure to circulate these flows when the mud density is increase to balance the well. The back pressure gives higher annular friction pressure and increase mud-gas ratio which in turn increase bottom hole pressure used to prevent gas influx (Goins, W.,C., Sheffield, R., 1983, p.29).

4. Top kill

   The temporary well control when gas influx has reached surface or when the drill pipe is quite far from bottom-hole where constant bottom-hole pressure method could not be applied to control a well. It is conducted by pumping mud and bleeding gas into the well (Goins, W.,C., Sheffield, R., 1983, p.30).

5. Bull heading

   Well control method by pumping the kick back into formation. It uses when there is a concern of surface pressure that can exceed the strength limit of casing such as when string plugs, pipe is out of the hole or when there is a possibility of hazardous fluid (Goins, W.,C., Sheffield, R., 1983, p.30). It is also used when there is an influx of formation fluid into the wellbore during well control operation, contamination of toxic gas such as hydrogen sulfide and in normal operation like for example borehole collapse (Schlumberger, 2012). Bull heading method is quite risky method to kill a well as the operator has no control on the flow of the pumped fluid. It can flow into weak formation and create broaching.