NTNU – Trondheim
Norwegian University of
Science and Technology

Reliability assessment of subsea BOP shear ram preventers

Jarand F Klingsheim

Subsea Technology
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Supervisor: Anne Barros, IPK
Co-supervisor: Marvin Rausand, IPK
Asbjørn Andersen, ExproSoft AS

Norwegian University of Science and Technology
Department of Production and Quality Engineering

Preface

This project is part of the course TPK4950 - Reliability, Availability, Maintainability, and Safety, Master's Thesis. It was carried out during the spring semester of 2015. The course is a mandatory part of the Subsea Technology master's degree program at the Norwegian University of Science and Technology (NTNU).

The task description of this project was made together with Professor Marvin Rausand at NTNU and Asbjørn Andersen at Exprosoft. The contact with Andersen at Exprosoft came through the author's summer internship at Exprosoft.

The reader of this thesis is assumed to have general knowledge of reliability and petroleum exploration and exploitation at the level of a subsea technology student.

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Jarand Foldøy Klingsheim

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Finally I would like to thank my fellow students for fruitful discussions and a great study environment.

J.F.K

Executive Summary

The objective of this report is to assess the reliability of blind shear rams (BSRs). The BSR's failure to seal off and secure the well in the Macondo incident proved the necessity of reevaluating the abilities of current BSR designs.

In this report the subsea blowout preventer system description is based on the system used in the Macondo incident. Function, subsystems and classification are introduced.

A detailed description of BSRs based on Cameron's design is provided. The function is described through four probable scenarios of operation.

Standards and regulations for BSRs on the Norwegian Continental Shelf and in the US Gulf of Mexico are described and discussed. Several weaknesses were identified in the current requirements and regulations: the wording found in some instances does not encourage prudent approaches to BSR design; testing of BSRs are performed at ideal and non-realistic conditions; Code of Federal Regulation requires that deadman and autoshear systems are installed in blowout preventers, but does not have to be armed.

Changes in US regulations are likely due to a proposed rule by Bureau of Safety and Environment Enforcement. Relevant for BSRs are the following proposed changes:

- Third party verification of blowout preventer equipment through all life phases.
- Require shear rams that can center the drill pipe when shearing.
- Incorporate API 53 into the regulations.
- Incorporate other standards such as API 6A, API 16A, API 16C, API 16D and API 17D.
- Improved and consistent testing frequencies.
- Failure and near-miss reporting.

The changes proposed has the potential to eliminate some of the weaknesses of current BSRs. There are however deficiencies also in the proposed changes: there will still be too many standards to consult with overlapping and inconsistent information; and the regulations should be more rigid regarding which tubulars the BSR shall be able to shear.

Weaknesses in current BSR concepts are identified in a Failure Mode, Effect and Criticality Analysis. Results from studies of BSR capabilities are discussed and compared with the result from the analysis.

The analysis is performed on 5 different BSR functions. Two failure causes are identified to be of high criticality; drill pipe in compression; and offset/buckling drill pipe. Both causes were identified in a scenario where autoshear activates the BSRs.

Studies performed by MCS Kenny and WEST Engineering identify increased ductility and strength of drill pipes and buckling drill pipes as potential sources of BSR failure.

Two major accidents involving BSR failures are described. The Ixtoc 1 incident in 1979 released 3.1 million barrels of oil, and the Macondo incident in 2010 cost 11 lives, total loss of a drilling platform and released 4.9 million barrels of oil. In both accidents the BSR failed to shear the drill pipe and the then seal the wellbore. In 1979 a tool joint was situated across the shear path preventing the BSR from shearing. In 2010 the pipe buckled in such a way that the pipe was placed outside the shearing area of the BSR.

Studies conducted on BSR performance suffers from limited available data. The data used is partly coming from analyzing daily drilling reports, and partly from extensive searches in news media. It is recommended that a joint industry database is established for better recording of subsea blowout preventer and BSR performance.

En-Tegrity, a new BSR concept, is introduced. It has three principal differences from conventional blinds shear rams: it utilizes wellbore pressure to aid shearing; the rams are pulled instead of being pushed; and it has metal to metal sealing.

All process steps from DNV RP-A203, a industry recognized guideline for qualification of new technology, are described and performed for the En-Tegrity concept. The steps are formulated in such a way that most new BSR concepts may follow them.

The focus of the process is on setting up prudent tests. It is recommended to carry out a combination of simulation and testing to ensure cost efficiency without compromising the reliability of BSRs.

To ensure that the tests cover all possible challenging scenarios, factors influencing shearing capabilities has been divided into four categories. Combinations of categories cover all considered scenarios. Ideally all combination should be tested multiple times for each relevant tubular. This is considered unrealistic due to high costs.

The author has reduced the number of combinations by evaluating which can be omitted. It is also recommended to first perform simulations to further assess if others may be omitted.

Sammendrag

Målet med denne rapporten er å vurdere påliteligheten til isolerende kuttventiler, kjent som blind shear ram (BSR). Etter at BSRen sviktet under Macondo ulykken i 2010 er det stilt spørsmål ved påliteligheten til dagens BSR design.

I denne rapporten er subsea utblåsningsventilsystemer(BOP) beskrevet basert på systemet som var i bruk ved Macondo ulykken. Funksjoner, delsystemer og klassifisering av subsea utblåsningsventiler er beskrevet.

En detaljert beskrivelse av BSR basert på Cameron sitt design er gitt. Funksjonen til BSR beskrives gjennom fire sannsynlige driftsscenarier.

Standarder og regelverk for BSR på norsk sokkel og i den amerikanske delen av Mexicogolfen er beskrevet og diskutert. Flere svakheter er identifisert. Ordlyden oppfordrer ved noen tilfeller ikke til en forsvarlig tilnærminger til BSR-design. Testing er utført under ideelle og ikke realistisk forhold. Code of Federal Regulations krever at deadman og autoshear systemer er installert i utblåsningsventilsystemet, men krever ikke at de er konfigurert for automatisk aktivering.

Innskjerpinger i det amerikanske regelverket er ventet på grunn av foreslåtte endringer fra Bureau of Safety and Environment Enforcement som nylig kom ut. Følgende endringer er relevant for BSR:

- Tredje parts verifikasjon av utblåsningsventilutstyr.
- Krav til at BSRer kan sentrere borerøret ved skjæring.
- Innarbeide API 53 i forskriften.
- Innarbeide andre standarder som API 6A, API 16A, API 16C, API 16D og API 17D.
- Mer konsekvente frekvenser for testing.
- Svikt og nestenulykke rapportering.

Endringene som foreslås har potensial til å eliminere noen av svakhetene ved dagens BSR. Det er imidlertid mangler også i den foreslåtte regelen. Det vil det fortsatt være for mange standarder å rådføre seg med, og overlappende deler gir inkonsekvent informasjon. Regelverket bør i tillegg være mer rigid når det gjelder hvilken type rør BSR skal kunne skjære.

Svakheter i dagens BSR konsepter er identifisert i en feilmode, effekt og kritikalitetsanalyse. Resultater fra BSR-studier er diskutert og sammenlignet med resultatet fra analysen.

Analysen er utført på 5 forskjellige BSR-funksjoner. To feilårsaker er identifisert til å være av høy kritikalitet: borerør i kompresjon og ikke sentrert/bøyd borerør. Begge årsaker ble identifisert i et scenario der autoshear aktiverer BSRen.

Studier utført av MCS Kenny og WEST Engineering identifiserer økt duktilitet og styrke av borerør, samt bøyning av borerør som potensielle kilder til svikt for BSR.

To ulykker der BSR sviktet er beskrevet. Ved Ixtoc 1 ulykken i 1979 ble 3,1 millioner fat olje sluppet ut, og ved Macondo ulykken i 2010 som kostet 11 liv, total tap av en boreplattform ble 4.9 millioner fat olje sluppet ut. I begge ulykkene feilet BSR da den skulle skjære borerøret og deretter forsegle borehullet. I 1979 var en rørkopling i skjærebanen og hindret BSR fra å skjære. I 2010 var røret spent/bøyd på en slik måte at røret ble plassert utenfor skjærområdet for BSR.

Studier utført på BSR ytelse har opplevd begrenset tilgang på data. Den dataen som brukes er fra omfattende søk i nyheter og daglige borerapporter. Det anbefales at en felles industri database etableres for bedre innsamling av data på subsea utblåsningsventilers og BSR ytelse.

En-Tegrity, et nytt BSR konsept, er introdusert. Hovedforskjeller fra konvensjonelle BSR er at den utnytter trykket i brønnen å assistere i skjæringen og den har metall mot metall tetning.

Alle prosesstrinnene fra DNV RP-A203, en ledende retningslinje for kvalifisering av ny teknologi, er beskrevet og utnyttet for å analysere En-Tegrity konseptet. Trinnene er formulert på en slik måte at de fleste nye BSR konsepter kan følge dem.

Fokuset i prosessen er å sette opp fornuftige tester. Det anbefales å bruke en kombinasjon av simulering og testing for å sikre kostnadseffektivitet uten tap av pålitelighet. For å sikre at testene dekker alle scenarier er faktorer som påvirker BSR sin evne til å skjære delt inn i fire kategorier: posisjon, brønn trykk, laster og utvendig trykk. Ved å kombinere en faktor fra hver kategori blir det 36 forskjelluge situation. Sammen dekker de alle vurderte scenarier. Ideelt burde alle kombinasjonene testes flere ganger for hver rørtype, men det er urealistisk med tanke på kostnadene. Av den grunn er et forslag hvor 36 kombinasjoner er redusert til 16 kombinasjoner. Det er gjort ved å fjerne de kombinasjonene som er ansett som urealistiske eller for like.

Contents

Chapter 1

Introduction

In April 2010 a well kick on the Macondo prospect in the US Gulf of Mexico escalated into a catastrophic blowout. 11 lives were lost, total loss of a drilling platform and the marine environment was heavily polluted by the release of 4,9 million barrels of oil. The accident is the largest accidental offshore oil spill in oil and gas industries history.

Several investigation reports have been released in the aftermath of the accident. A common factor among them is the failure of the subsea blowout preventer(BOP), and the blind shear ram(BSR) in particular. Forensic reports revealed that the BSR failed to shear the drill pipe and seal the well upon activation.

Parallels may be drawn to the previously largest oil spill, Ixtoc 1 in 1979, also in the Gulf of Mexico. Also this time the BSR failed due to a tool joint being across the shear path.

New BSR concepts making their way into the market, claiming to provide solutions to said problems. It is however vital that they do not only handle previously experienced situations, but all possible and probable situations. This must be tested and documented if we are to be certain that such accidents will not happen again.

A procedure that inspires innovative designs for prudent equipment is desirable.

This thesis will investigate the current BSR designs for weaknesses. Then a study of how new BSR design shall be qualified will be performed.

The most notable studies assessing BSR abilities are three studies by MCS Kenny. They have analyzed the effects of drill pipe grade, and challenging well control situations through analysis and simulation.

Today there are standards and regulations dictating requirements for design, performance and testing of BSRs. API 53 was upgraded from a recommended practice to a standard post Macondo, and is now the leading industry standard for BSRs in the US Gulf of Mexico.

DNV released their updated guideline for qualifying new equipment, DNV RP-A203, in 2011. It is an industry leading guideline, and is general for offshore equipment. There is no specific guideline for BOP nor BSRs.

The studies on shear ram capabilities have since early 2000 pointed out that there are issues related to the shear rams ability to perform, and in particular the BSRs. The Macondo incident showed that when all else fails, the BSR fail as well. In order to ensure that the final barrier in drilling, performs on demand, BSR weaknesses must be understood and prudent qualification must be a priority.

1.1 Objectives

The main objectives of this master thesis are:

1. Carry out and document a literature survey to reveal the role of subsea shear ram preventer in drilling accidents
2. Specify the functional and reliability requirements to a typical subsea shear ram preventer
3. Identify and discuss the weaknesses of current subsea shear ram preventer concepts
4. Outline a procedure for qualification of a new subsea shear ram preventer concept
5. Perform a reliability assessment of a new subsea shear ram preventer concept

1.2 Limitations

This study is limited to BSRs in:

- subsea BOPs
- deepwater wells (>600 m)

- drilling operations
- operations on Norwegian continental shelf and US Gulf of Mexico

The shear rams being studied will be limited to Cameron shear rams, as they are most common and were used in the Macondo incident.

To delimit the scope the main focus will be on functional performance. Shear rams will be treated as a system, comprised of sub-systems such as locking device, pistons and rams. The components of the sub-systems will not be discussed.

The lack of available information on new BSR concepts limits the analysis of the En-Tegrity concept to a conceptual analysis.

1.3 Approach

The approach used in this thesis is a combination of a literature study and an analysis. Objectives 1 and 2 will be accomplished solely by literature studies. Objective 3 will be accomplished primarily by analysis, but compared with literature found on the topic. Objective 4 will be done through literature found and modified to fit the requirements of this thesis. The final objective, 5, will be accomplished though analysis.

1.4 Structure of the Report

The rest of the report is organized as follows.

Chapter 2 gives an introduction to subsea BOP systems.

Chapter 3 describes shear rams. Design, function and the most relevant requirements are described.

In chapter 4 any weaknesses in current BSR designs are identified and the role of BSRs in accidents are investigated. Weaknesses are identified through analysis and through a literature study on BSR studies. Two major accidents are described and relevant failure data sources are found.

In chapter 5 a new BSR concept is presented before being used as a case study for DNV RP-A203.

In chapter 7 the thesis is summarized and concluded, discussed and recommendations for further work are made.

Chapter 2

Subsea Blowout Preventer

> [Subsea BOP is] equipment installed on the wellhead or wellhead assemblies to contain wellbore fluids either in the annular space between the casing and the tubulars, or in an open hole during drilling, completion, and testing operations.
>
> API 53 (2012)

This chapter provides a general description of the subsea BOP with its functions and standards. This is meant to benefit readers with little or no knowledge of subsea BOPs to understand the system around BSRs.

2.1 Function

BOPs are generally used to seal a wellbore in the event of a blowout.

☞ [A blowout is] an uncontrolled flow of well fluids and/or formation fluids from the wellbore to surface or into lower pressured subsurface zones (underground blowout).

API 53 (2012)

During drilling different rock types, referred to as layers or formations, are penetrated. As deeper formations are penetrated the pressure generally increases. The pressure is controlled by using drilling mud in the wellbore. The mud is inserted from the top through the drill string forming a hydrostatic column that under normal conditions provide pressure greater than the formation pressure. There is however a chance when new layers are penetrated that there is trapped gas or fluids with abnormally high pressure. If this is greater than the pressure from the mud column a kick occurs.

☞ [A kick is an] influx of formation liquids or gas into the wellbore.

API 53 (2012)

The kick has to be controlled by the drilling crew through the use of the subsea BOP to avoid suffering a blowout. Other reasons for experiencing kicks such as the pressure in the well being greater than fracture pressure or swabbing, will not be discussed in this thesis.

The BOP has functions in addition to preventing kicks from escalating, API 53 lists the following as common functions for subsea BOPs:

- "Close and seal on the drill pipe, tubing, and casing or liner and allow shallow circulation
- Close and seal on open hole and allow volumetric well control operations
- Hang-off the drill pipe on ram BOP and control the wellbore
- Shear the drill pipe or tubing and seal the wellbore
- Disconnect the riser from the BOP stack"

The first two are generally related to handling kicks. The latter three are used when the first two do not handle the kick properly, or dynamic positioning fails leading to a drift-off.

Dynamic positioning is used to keep a floating vessel in position over the well. This may fail if the weather is too rough or due to mechanical or technical failures. This is referred to as a drift-off(total loss of function, drifting by currents) or drive-off(some function of system leads to rig being propelled away) situations. If this happens the riser has to be disconnected from the BOP and wellhead to avoid damage and potential loss of well integrity.

2.2 Description

This description is mainly based on Andersen (2015b) and MCS Kenny (2013), and use the terminology used by them.

The subsea BOP is usually set on top of and connected to the wellhead. It is divided into the lower marine riser package (LMRP) and the BOP stack. "A critical reason for this arrangement is to allow remote disconnecting of the drilling rig from the BOP stack on the sea floor" (WEST Engineering Services, 2003). This is done by closing valves and rams in a certain sequence, before disconnecting the LMRP from the BOP stack. This leaves the BOP stack on the wellhead, containing the well, while the LMRP hangs from the marine riser. A relevant scenario is a drift/drive off from on a dynamically positioned drilling vessel.

From an economical perspective the subsea BOP is divided to enable full closure of the well by the BOP stack, while the LMRP can be retrieved for maintenance. Functions on the LMRP are used more often during operations, thus in need of more frequent maintenance (Baugh, 2013).

In Figure 2.1 the BOP configuration used on the Deepwater Horizon drilling rig, used on the Macondo well, is presented. It is representative for subsea BOPs used in deepwater operations. It fulfills the requirement from both NORSOK D-001 (2012) and Code of Federal Regulations, CFR (2015) of having 2 shear rams for dynamic positioned vessels. Placing a BSR over a casing shear ram (CSR) is the most common placement when CSRs are used (WEST Engineering Services, 2004).

2.2.1 Lower Marine Riser Package

The LMRP is the upper part of a subsea BOP. The main components are:

Flex joint Reduces the bending moments on the BOP stack and wellhead.

Annular preventer A rubber sealing element to seal around the wellbore or open hole. The rubber elements can seal around tubulars of all diameters.

Control pods Controls the hydraulic flow of the entire subsea BOP while the LMRP and BOP stack are connected.

LMRP connector Connects/disconnects the BOP stack and LMRP.

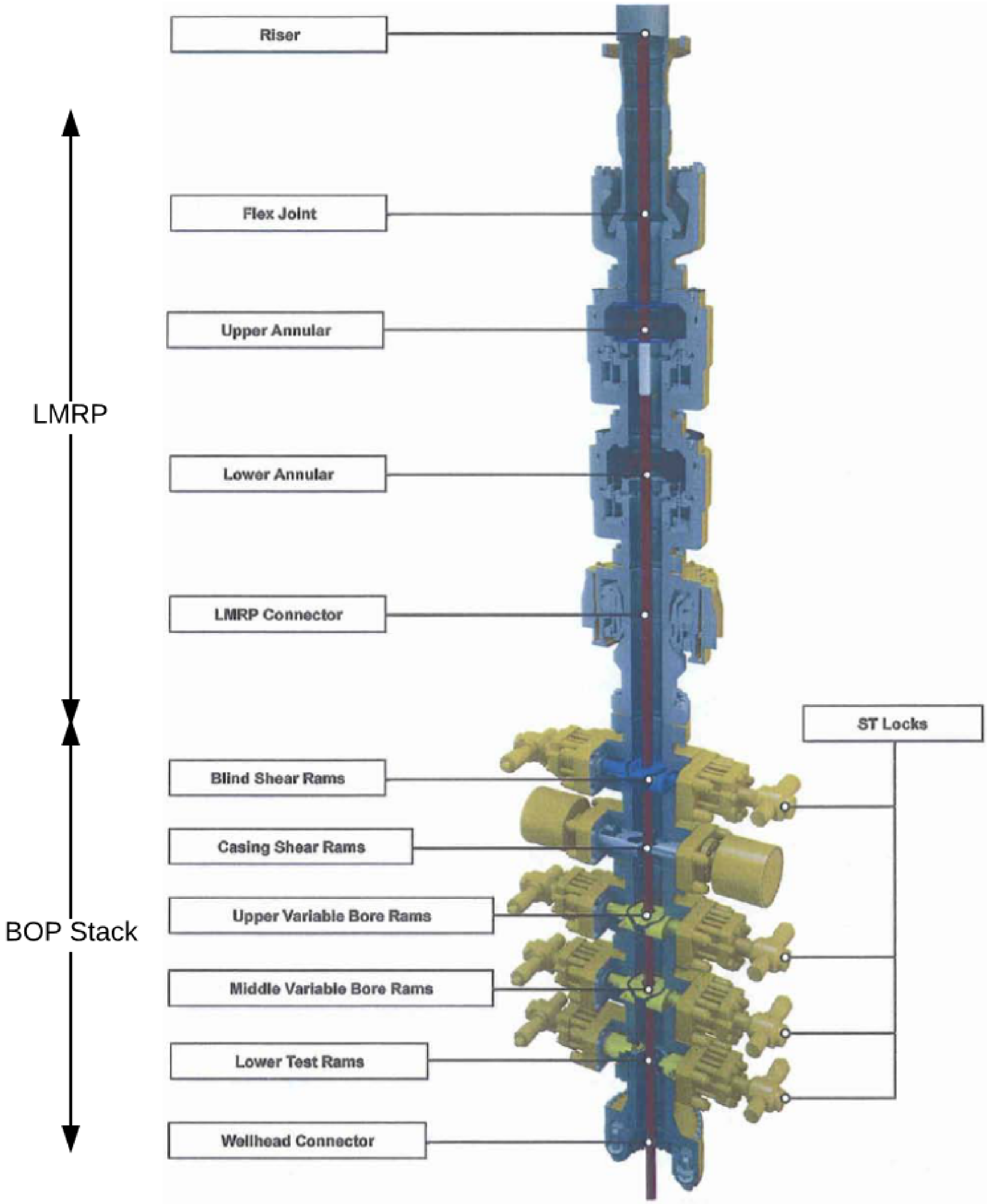

Figure 2.1: Subsea BOP (Transocean, 2011)

2.2.2 BOP Stack

The BOP stack is the lower part of the subsea BOP. The main components are:

Shear rams Designed to be able to shear tubulars going through the subsea BOP. Two common types of shear rams are currently in use, CSRs and BSRs. BSRs are used to seal the well in addition to shearing tubulars. Shear rams are further discussed in Chapter 3.

Pipe rams Designed to close and seal around tubulars. Pipe rams are also used to lock tubulars in place during shearing operations. There are pipe rams in different sizes depending on the diameter of the tubular being run. There are also variable pipe rams that can handle multiple tubular diameters.

Test rams Inverted pipe ram used for pressure testing the rest of the BOP. Being inverted allows it to contain pressure from above.

Wellhead connector Connects and seals between the BOP stack and wellhead.

Choke and kill lines Circulates fluids to the well and pumps fluids into well when the rams are closed (Not visible in Figure 2.1).

2.2.3 Classification

The classification of BOPs are based on the number of rams and annular preventers installed. The sum of annular preventers(A) and ram preventers(R) is known as the class of the BOP. The test rams are not included in the requirements due to them being inverted, and unable to contain pressure from below.

The Class 6-A2-R4 BOP stack in Figure 2.1 has two annular preventers(A2) and 4 ram preventers(R4), totaling to a class 6 BOP.

Currently the class requirements of NORSOK D-001 (2012) and API 53 (2012) are the same:

- Minimum class 5(only specified by API 53)
- Minimum one annular preventer
- Minimum two shear rams(at least one shall be capable of sealing)

- Minimum two pipe rams(fixed or variable, excluding the test rams)

Although the first requirement is only specified by API 53, the sum of the NORSOK D-001 requirements is class 5 as well.

In Holand and Awan (2012) all the wells studied were 18 ¾" bore size and rated to 15 000 psi (1000 bar).

2.3 Standards, Regulations and Guidelines

Petroleum Safety Authority(PSA) is the regulatory authority in Norway for following up safety, emergency preparedness and working environment on the Norwegian Continental Shelf. PSA provides all regulations online, with accompanying guidelines. The guidelines are not legally binding, but they are meant to be applied together with the regulations for the best possible interpretation. PSA does not provide all technical details. It focus on performance. It refers to standards, such as NORSOK D-001 and NORSOK D-010 to provide specific technical requirements.

Code of Federal Regulations, CFR (2015) provides specific technical requirements to be followed in the USA. CFR also refers to standards for details, API 53 is a central standard for BOP and is referred to by CFR.

The most relevant standards and regulations in Norway and USA are presented in Table 2.1. The API standards apply for the USA while NORSOK applies for Norway.

Table 2.1: Standard and guidelines most relevant for subsea BOPs operating in Norway or USA

Standard	Version	Title
API 16A	3. edition, Jun 2004	Specification for Drill Through Equipment
API 16C	1. edition, Jan 1993	Specification for Choke and Kill Systems
API 16D	2. edition, Jul 2004	Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment
API 53	4. edition, Nov 2012	Blowout prevention equipment system for drilling wells
NORSOK D-001	3. edition, Des 2012	Drilling Facilities
NORSOK D-010	4. edition, Jun 2013	Well Integrity in Drilling and Well Operations
NORSOK U-001	3. edition, Oct 2002	Subsea Production Systems
NOG 070	2. edition, Oct 2004	Application of IEC 61508 and IEC 61511 in the Norwegian Petroleum Industry

Chapter 3

Shear Ram Preventer

> [Blind shear ram is a] closing and sealing component in a ram blowout preventer that first shears certain tubulars in the wellbore and then seals off the bore or acts as a blind ram if there is no tubular in the wellbore.
>
> API 53 (2012)

> Mechanical shear rams are typically the last line of defense for emergency situations, e.g., kicks or potential blowouts.
>
> Zediker et al. (2014)

In this chapter BSRs are described. Cameron designed BSRs are used in descriptions as they are the most common worldwide today(Rigzone, 2009).

3.1 Function

Shear rams is the general term for rams able to shear (cut) tubulars in the wellbore.

The rams are activated when fluid comes through the shuttle valve providing pressure on the piston as seen in Figure 3.1. As the rams slide forwards locks are applied at the back to secure the rams in closed position. In Figure 3.1 Cameron wedge locks are used.

BSRs are designed to close and the seal the wellbore, and cutting tubulars if present. BSRs are also called shearing blind rams.

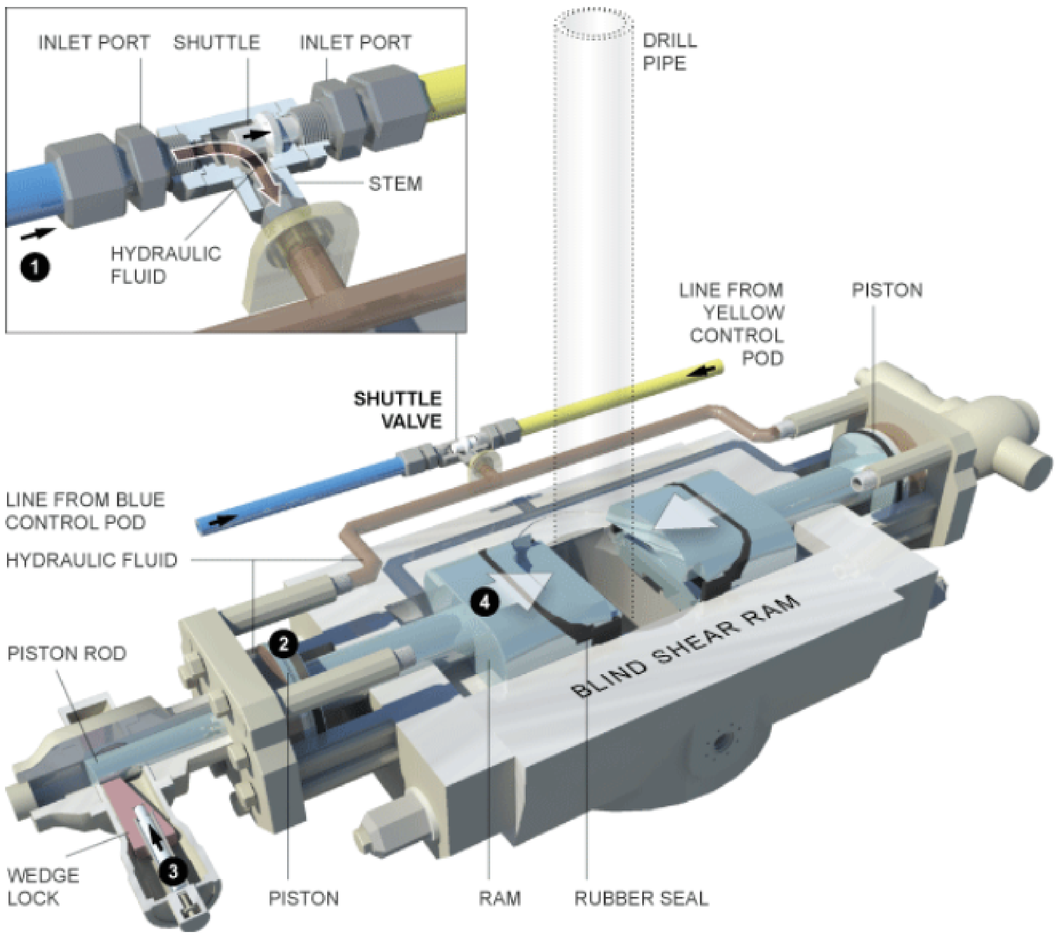

Figure 3.1: BSR assembly (Grondahl, M., et al., 2010)

Figure 3.2 shows a Cameron BSRs folding part of the drill pipe to allow the rams to meet and seal. This eliminates the need to displace the pipe in vertical direction. The part of the pipe above the shearing point is called upper fish, and the part below is called bottom fish.

☞ "Fish is an object that is left in the wellbore during drilling or workover operations and that must be recovered before work can proceed." (Baker, 2001)

CSRs can shear larger tubulars, such as casings, liners and tool joints, but lacks the ability to seal the wellbore. CSRs are sometimes called super shear rams.

The performance of shear rams depend on the conditions and situation in which it is activated. Blowing well, drift-off and function testing are handled differently, and the shear ram is activated in different ways, with different sequences related to the other functions on the BOP.

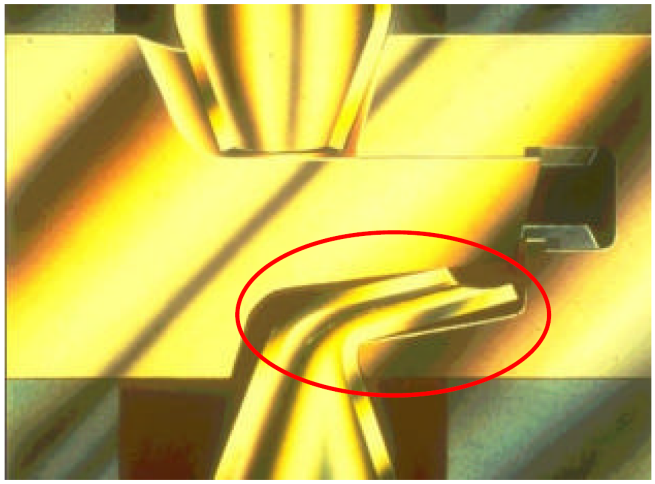

Figure 3.2: BSR fold over fish function (WEST Engineering Services, 2004)

The following situations and activations are relevant:

1. Function and pressure test - close on empty wellbore
2. Controlled operation - close on empty wellbore
3. Controlled emergency operation - Shear the drill pipe and then seal the wellbore
4. Emergency situation - Emergency disconnect system(EDS)
5. Emergency situation - Autoshear
6. Emergency situation - Deadman
7. Emergency situation - Automatic Mode Function(AMF)
8. Emergency situation - ROV and acoustic activation

The different situations has for simplicity and clarity for the reader been divided into five representative scenarios. These first four scenarios are the same as was used by American Bureau of Shipping and ABSG Consulting (2013) in their failure mode, effect and criticality analysis (FMECA) of BOPs. The fifth scenario is not within the scope of thesis, and will only be described briefly.

3.1.1 Close on Empty Wellbore

This scenario covers situations 1 and 2.

Close on an empty wellbore is the least challenging scenario, and the BSR will in this case function as blind ram and not as a shear ram. Function testing and pressure testing is done on empty hole. WEST Engineering Services (2004) found this to be the most frequently used scenario.

Some thinkable challenges for this scenario may be flowing well, but the most thinkable is an internal failure from BSR itself or interfacing components.

3.1.2 Operator Controlled Operation

This scenario covers situation 3.

This scenario is when there is flow through the tubular in wellbore. Then the annular preventers and pipe rams can not contain the well. Before the operators shear the drill pipe in the wellbore, they will most likely try stabbing the kelly valve.

In this scenario a pipe joint may be hung on a pipe ram to secure that there is no pipe joint across the BSR(WEST Engineering Services, 2004). Then the BSR may shear the drill pipe before the well can be circulated.

If there is casing in the wellbore, the CSR must first shear the casing. Then the operator has to lift the pipe before closing the BSR on the empty wellbore left behind.

3.1.3 Emergency Situation - EDS

This function covers situation 4.

The emergency disconnect system (EDS) is a manually activated automatic sequence where the drill pipe is sheared, wellbore sealed and LMRP is released from the BOP stack (Andersen, 2015b).

According to Andersen the sequence starts by the operator positioning the drill pipe to avoid having a joint at the BSR before activating the sequence. Then the automatic sequence activate the BSR before disconnecting the LMRP.

A challenge here may be that the sequence has to be preprogrammed, which in turn does not allow for flexibility if there should be unforeseen tubular in the wellbore. Even if the sequence is programmed for the tubular in the wellbore at the time, there are still questions related to timing of the functions. With a heavy tubular in the wellbore, the time delay of the BSR has to be enough for a CSR to cut and for the tubular to be moved out of the wellbore.

3.1.4 Emergency Situation - Autoshear

This function covers situations 5, 6 and 7.

These sequences are automatically activated if they are armed. Autoshear is, if armed, activated if the LMRP parts from the BOP stack. The LMRP may part due to the auto disconnect function, that is activated if the flex joint is at a predefined angle(WEST Engineering Services, 2003).

Deadman and AMF are system installed in the subsea BOP that, when armed, activates upon total loss of both hydraulic and electrical communication from the rig. When activated they initiate BOP stack functions, typically the BSRs to completely seal the wellbore (WEST Engineering Services, 2003). They are grouped with autoshear due them being automatically activated with a predetermined sequence.

According to WEST Engineering Services many operator and contractor personnel refrain from arming the autoshear, deadman and AMF as they fear for premature activation.

A challenge here may, as for EDS, be that the preprogrammed sequence that is activated is not adapted for the current tubular in the wellbore.

WEST Engineering Services (2004) also pointed out that in automatically shear sequences the operator does not have the opportunity to ensure no pipe or tool joint is in the shear path, posing additional risk.

3.1.5 ROV and Acoustic Activation

This is situation 8, and is as previously mentioned outside of the scope of this thesis.

ROV and acoustic activation are backup methods of activating the BSR. They will not be discussed or analyzed further as they stand out in when it comes to timing and use. The other four scenarios are usually used in an earlier stage of a well control situation.

3.2 Description

A Ram type BOP is described by Transocean (2011) as a valve consisting of two pairs of opposing steel blocks and pistons that through hydraulically applied pressure are moved toward the center of the BOP wellbore to form a barrier preventing flow. These rams may or may not be fitted with elastomer seals, blades and locks for closed position depending on type and use.

Shear rams usually consist of the following items:

Ram blocks are steal blocks move towards one another across the wellbore.

Blades are placed on the ram blocks and are used to enhance the shearing ability. Today most blades are v-shaped.

Sealing components are placed around and between the ram block in such a way that it seals the wellbore completely. The drawback of the sealing component is that it limits the width and strength of the BSRs. The CSR do not have seals which allows the blades may cover the entire the wellbore. The difference is evident by studying the BSR in Figure 3.3 and the CSR in Figure 3.4.

Locking mechanism is place on the back of the piston rods and when activated moves in to prevent the rams from moving apart.

Pistons apply force on the ram blocks moving them towards the center of the wellbore.

In addition there are other components vital for the operation of the shear rams:

Accumulators are used to store the pressure used to move the rams.

Hydraulic lines supply the pistons with pressure from the accumulators.

Shuttle valve is the valve that enables hydraulic pressure to be applied from either the blue or yellow pod.

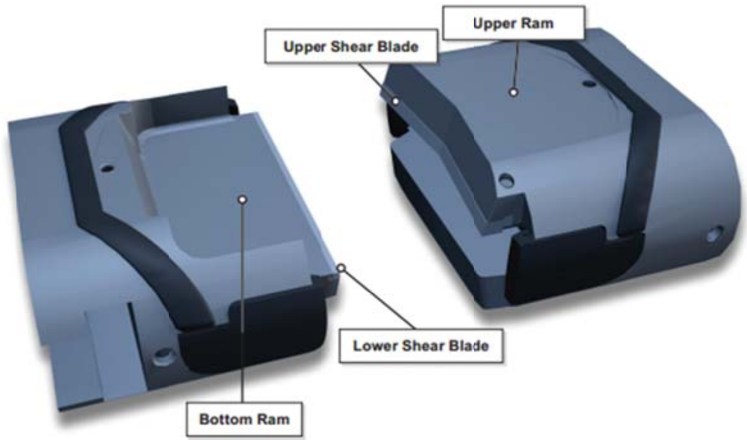

Figure 3.3: Typical BSR (Transocean, 2011)

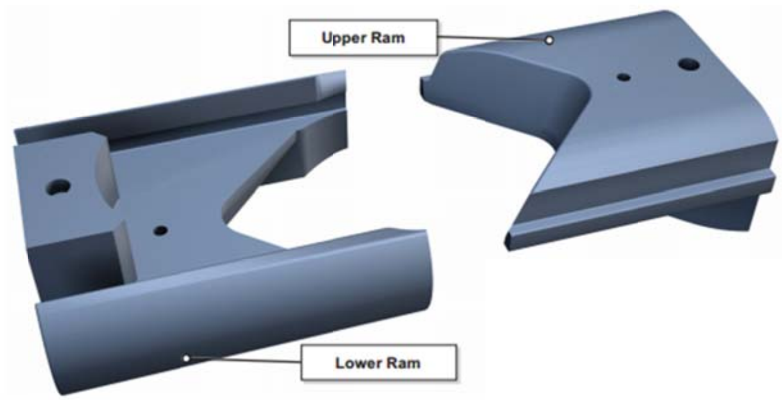

Figure 3.4: Typical CSR (Transocean, 2011)

3.3 Requirements

The most relevant standards and regulations are listed in Table 2.1. The following sections goes into greater detail of the most relevant parts for shear rams. Relevant requirements are divided into section to make them more apprehensible. The first section is a general description of how the requirements are organized. Every section describes the Norwegian requirements in detail before a brief comparison of the requirements in the US Gulf of Mexico.

3.3.1 General

PSA refers to the NORSOK standards and NOG guidelines for the specific requirements regarding shear rams, and their performance. Beside the references to standards and guidelines PSA specifies that "the shear ram should have the capacity to cut the work string, with the exception of collars and bottomhole string components".

The technical requirements for subsea BOPs are found in NORSOK D-001 (2012) and NORSOK D-010 (2013). They are both referenced by PSA giving them regulatory status in Norway.

NORSOK D-010 state that shear rams shall only be activated in emergency when no other option exist but to cut and seal.

The regulations in use in USA are in general similar to the Norwegian regulations. A main difference is that Code of Federal Regulations, CFR contains specific requirements to design, qualification testing, performance and testing.Among these requirements it is specified that there shall be installed BSRs and locking devices.

Some requirements specific Code of Federal Regulations, CFR are also found in API 53 and API 16A, going into more details regarding each part.

API 53 Section 7.1.3.1.1 specifies that rams and annulars shall be capable of handling well control situations. Specifically for floating operations it is stated that the system shall provide a means to close and seal on open hole and allow volumetric well control operations and to shear the drill pipe or tubing and seal the wellbore.

3.3.2 Design

NORSOK D-001 Section 6.35 state that there shall be at least one BSR, and for dynamically positioned vessels there shall be an additional shear ram capable of shearing casings and drill pipe joints. This indicates that as most deep water drilling operations are dynamically positioned a combination of BSR and CSR shall be used.

The section also states that BSR shall be installed with a mechanical locking device securing the rams in closed position.

NORSOK D-001 Section 6.35 states that "considerations for full BOP bore shear capability or pipe/tubular/wire centralization blades/rams shall be given".

NORSOK D-001 Section 6.42 and 6.44 requires there to be alternate activation systems for ram functions including shear rams. These functions include acoustic activation, a ROV stab activation and EDS.

The same requirements apply for the USA. Code of Federal Regulations, CFR also specify that autoshear and deadman systems shall be provided on dynamically positioned rigs. There is however no demand to that they must be used.

3.3.3 Qualification Testing

API 16A describes test that shall be performed prior to use, separated from regular interval testing.

The Norwegian requirements state that "it shall be documented" before many of their requirements. When this is the case it has to be proven by testing or analysis that the solution chosen is capable to fulfill the requirement.

The American requirements found in API 16A is more specific in which tests, and how they are conducted. For BSRs there are tests for sealing, fatigue, shearing and locking mechanism. In this thesis only the shearing test will be discussed further.

The shearing test is described in Section 5.7.2.4 and Appendix C.2.3. of API 16A. It describes a test conducted in atmosphere pressure and without tension in the pipe. The pressure is then increased to between 1,4 MPa and 2,1 MPa.

Documentation of the test shall include BSR and BOP configurations, actual pressure needed to shear, leakage and pipe dimension(size, mass and grade).

Shear pipe requirements are also present in API 16A in table 18.

3.3.4 Performance

NORSOK D-001 Section 6.35.3 states that it shall be verified that the BOP system can shear and seal the following relevant tubulars with adequate weight and grade:

- drill pipe
- production tubing
- landing string and/or shear subs
- wire line
- coiled tubing

The same section also specify that shearing shall be achievable within 90% of available hydraulic system pressure.

NORSOK D-010 Section 15.4 states that for dynamically positioned vessels it shall be possible to shear and seal with casing in wellbore, through a combination of CSR and BSR.

API 53 state in Section 7.3.10.4 that all ram BOP shall close in less than 45 seconds.

3.3.5 Testing

NORSOK D-010 Appendix A contains the pressure test and frequencies for well control equipment. Shear rams shall be function tested weekly, but may be postponed if there is tubular across the BOP. Every 6 months it shall be pressure tested at working pressure.

In addition it is required to function test before drilling out surface casing and to perform maximum section design pressure test before drilling out of deeper casings and liners. It shall also be tested to well design pressure before lowered on to the wellhead.

It is also required that the shear ram is visually inspected before installation and after removal.

Both NORSOK D-010 and API 53 specify the low and high pressure for testing the BSR.

In the USA API 53 state that CSRs and BSRs shall be function tested at least once every 21 days.

Code of Federal Regulations, CFR state that the pressure test for the inside of the BOP shall be performed before 14 days have elapsed since the previous pressure test. This is somewhat unclear as during a pressure test you automatically perform a function test, which is only closing and opening of shear ram. Indicating that if the test interval of 14 days is not exceeded, function test is unnecessary. Furthermore Code of Federal Regulations, CFR state that all blind rams must be tested every 30 days, which also is unnecessary due to the 14 day periodic test.

Both Code of Federal Regulations, CFR and API 53 state that shear rams should be visually inspected after any shearing operation.

3.3.6 BSEE Proposed Rule

In the wake of the Macondo incident investigation reports were conducted to identify failure causes and to make recommendations to decrease the likelihood of new accidents. These have been evaluated and the result is a proposed rule, Bureau of Safety and Environmental Enforcement, BSEE (2015). Among the improvements are additions and changes to regulations and requirements the in US Gulf of Mexico. The most relevant for BSR requirements are (Bureau of Safety and Environmental Enforcement, BSEE, 2015):

- Third party verification of BOP equipment through all life phases.
- Require shear rams that can center the drill pipe when shearing.
- Incorporate API 53 into the regulations.
- Incorporate other standards such as API 6A, API 16A, API 16C, API 16D, API 17D, and API Spec Q1.
- Improved and consistent testing frequencies.
- Failure and near-miss reporting.

3.3.7 Discussion

The requirements for operating on the Norwegian continental shelf and US Gulf of Mexico are similar. This can also be seen by the same BSRs being used in both regions. There are some issues worth looking into from both regions.

It is stated in NORSOK D-001 Section 6.53 that "considerations for full BOP bore shear capability or pipe/tubular/wire centralization blades/rams shall be given".

This is in the authors opinion not a prudent approach. It should be a requirement that there is full bore coverage. This is evident post Macondo (BSR failed due to not having full bore coverage, see Chapter 4.2.2).

A contradicting requirement comes from Code of Federal Regulations, CFR. It is specified that there shall be provided both autoshear and deadman systems for dynamically positioned rigs, but there is no requirement of using these systems. For the systems to be activated in an emergency they must be armed by the operators. As mentioned in Chapter 3.1.4 they usually are not due to fear of premature activation (WEST Engineering Services, 2003).

The procedure for testing shear ram ability previously (Chapter 3.3.3) is a test performed in "ideal conditions". It is not realistic to have such conditions in a well, especially not in a well control operation.

This testing procedure is also criticized by WEST Engineering Services (2004) for their shortage in addressing the evolution of drill pipes. The drill pipes they require sheared are by now outdated and not representative to the thick walled and ductile pipes used today.

The proposed requirements from Bureau of Safety and Environmental Enforcement, BSEE are in the authors opinion a step in the right direction. There is one point that appear counterproductive, incorporating API 53 and several other standards. Including all these standards creates coverage for most aspects of BSRs and BOPs, but they also create contradicting and a surplus of requirements. Interpretations of the requirements may be different depending on which source is weighted the most. In addition some of these standards may be outdated, such as API 16A from 2004.

The proposed rule does not propose to impose stricter requirements to what tubulars the BSRs are able to shear. It would be prudent to include specific requirements to how drill pipes and shearing ability should be classified.

Chapter 4

Failures and Current Weaknesses

This chapter weaknesses of BSRs will be identified through a Failure Mode, Effect and Criticality Analysis (FMECA). Literature on challenges of BSRs is discussed. Major accidents were BSR failure was a contributing factor are described.

4.1 Weaknesses of Current Blind Shear Ram Preventer Concepts

4.1.1 FMECA

Methodology

Rausand and Høyland (2004) describes FMECA as a structured method of failure analysis. The method is performed by using a FMECA worksheet. There are numerous variations of the worksheet, making this a flexible analysis. The worksheet used for this analysis is based on Andersen (2015a), and is found in Appendix B.

The analysis is limited to the BSR as subsystem to the subsea BOP. This promotes a detailed analysis, evident by comparing this analysis with analyses performed in American Bureau of Shipping and ABSG Consulting (2013) and WS Atkins Inc (2001) on entire BOPs. This analysis differs from the previously mentioned analyses by analyzing in greater detail possible situations that may be challenging for the shearing situation.

The rating of criticality in an FMECA may be completed in numerous ways. In this FMECA every failure cause will be criticality rated, instead of every failure mode, which is more common. It will also be done without quantifying consequence and frequency rating. Instead there will be a comment when considered necessary.

The criticality rankings used are the following:

Low/Green Highly unlikely or acceptable consequences.

Medium/Yellow There is uncertainty related to the handling of the situation, but it is not unlikely that it will be handled.

High/Red Unacceptable consequences and frequency. Also if there if there is greater uncertainty than at medium criticality.

Economical consequences are considered. Pulling BOP and loss of well are the most common examples. However by comparison they may often be considered negligible due to the severity of failure on demand of a BSR.

System Description

The system analyzed is a Cameron BSR (described in Chapter 3) placed in a standard subsea BOP (described in Chapter 2). In this analysis interfacing components such as accumulators, control pods and hydraulic supply lines are not included to delimit the analysis. Analysis of the full BOP system have been analyzed through FMECAs before by experts, such as American Bureau of Shipping and ABSG Consulting (2013) and WS Atkins Inc (2001). In those analyses the interfacing components are included.

The following functions will be analyzed (described in Chapter 3):

1. Close and then seal on open hole
2. Operator controlled operation - Shear the drill pipe and then seal the wellbore
3. Emergency operation - Autoshear - Shear the drill pipe and then seal the wellbore
4. Emergency operation - Emergency disconnect system(EDS) - Shear the drill pipe and then seal the wellbore
5. Open wellbore after closing shear rams

Results

The entire FMECA worksheet is placed in Appendix B. In this section the results will be presented with focus on medium and high criticality failures. They will be grouped by failure mode, failure cause and criticality rating.

The failure causes analyzed separately here may also occur simultaneously. In the Macondo incident there was compression and flowing well effecting one another and the tragic outcome. As the consequence of these failure causes are in themselves so severe it has been considered unnecessary to analyze them combined in this case.

Several of the results are characterized by the lack of testing and documentation of BSR performance.

1. Close and then seal on open hole All failure causes are rated low criticality. This is due to the failure probability being low and to frequent function and pressure testing. Without any tubular in the wellbore the rams functions as blind rams and are expected to close. If they should not, annular preventers will normally be able to seal the wellbore satisfactory.

2. Operator controlled operation - Shear the drill pipe and then seal the wellbore Four failure causes are rated medium while the remaining is rated low criticality. Three of the causes rated medium are from the "failure to shear tubular":

1. Offset/buckling drillpipe
2. High grade drill string
3. Differential pressure in drill pipe

Number 1 is rated medium due to uncertainty to whether the operator will evaluate and respond to the situation correctly. When he does it is assumed the situation will be resolved.

Number 2 is rated medium due to uncertainty and lack of evidence proving that the BSR is capable of shearing.

Number 3 is also rated medium due to uncertainty. In itself it may not be a problem, however it may affect the stress and tension of a drill pipe in compression or tension.

The final failure cause rated medium is in the "failure to seal the wellbore" failure mode. This failure cause is also rated medium in Autoshear and EDS functions. The failure cause is "Rams unable to meet sufficiently". This may happen if the fish is inadequately folded over, inhibiting the rams to meet and overlap. The primary concern is high grade pipe not folding over enough.

3. Emergency Operation - Autoshear - Shear the drill pipe and then seal the wellbore Most uncertainties here are due to the operation being automatically activated. There are two failure causes rated high criticality, both from the "failure to shear tubular" failure mode. They are:

1. Offset/buckling drillpipe
2. Drillpipe in compression

They are rated high due to the operator not being able to influence the situation. Number 1 is the situation from Macondo, proven not to be managed by Cameron BSRs. Number 2 is due to the force from the pipe vertically will increase the force required to shear, and might in worst case damage the packers as well.

The medium rated situations from "failure to shear tubular" failure mode are:

1. Non-shearable across BSR
2. High grade drill string
3. Differential pressure in drill pipe

Non-shearable is rated medium as the BSR is not able to shear in this situation, but is not likely to occur. Holand and Awan (2012) found no kicks or blowouts when casing is run, and operators take precautions prior to running non-shearables through the BOP.

High grade drill string and differential pressure are rated medium on the same grounds as for operator controlled operation.

4. Emergency Operation - Emergency disconnect system(EDS) - Shear the drill pipe and then seal the wellbore The medium rated situations are the same as for Autoshear, in addition the two rated high of autoshear are also rated medium. Beyond this all is rated low. The same reasoning is behind the criticality as for Autoshear. The two situations rated medium instead of high are rated this way because the driller may make preparations prior to activating the EDS.

5. Open wellbore after closing shear rams Rated low. Function testing diminish probability of technical failures. If the rams should fail the consequence is likely to be downtime to repair and pulling bop stack.

4.1.2 Shear Ram Studies

There has been two noteworthy studies of shear ram abilities carried out by West Engineering Services and MCS Kenny on the behalf of the Bureau of Safety and Environmental Enforcement (BSEE). WEST Engineering Services (2004) focus on the increased toughness and ductility of drill pipes, while MCS Kenny (2013) focus on potential situations the BSR may encounter.

WEST Engineering Services (2004) assessed to what degree the improved drill pipe properties effect the shearing power needed. Wells are dilled at increasing water depth and drill pipe properties improve to enable this development. Material strength, ductility and wall thickness are increasing. These factors increase shearing resistance, and improved shearing ability from BSR is needed.

WEST Engineering Services performed shear test on two pipes with same dimension, and grade. One was however of a newer generation and, although the grade was the same, it had improved ductility.

When comparing the results the new and more ductile drill pipe was sheared a almost 2000 psi higher pressure. This is significant considering that the old pipe was sheared at 1900 psi. In the test requirements, discussed in the chapter, API 16A requires shearing of 3 standard grade drill pipes. Ductility differences are not discussed.

WEST Engineering Services also looked into another potential problem. In a specific case they found the length of the pipe joint to be longer then the available spacing between the upper pipe ram and BSR. The problem with this is when the operator hangs off the pipe joint on the pipe ram before shearing. If the pipe joint is longer than the gap between pipe ram and the BSR, the joint will be across the shear path potentially inhibiting shearing.

In MCS Kenny (2013) data simulation is used to test standard Cameron BSRs ability to shear drill pipes in challenging situations. The model used was verified to be conservative through physical testing.

The shear ram challenges MCS Kenny considered was:

- Centralizing pipe during shearing
- Shearing of compressed/buckled pipe
- Shearing during flowing well conditions
- Non shearables across the BOP

These situations are similar to the ones described in Chapter 4.1.1.

Non shearables across the BOP is however not simulated The study did not consider other tubulars in the wellbore. The relevant results are described in the following paragraphs.

Centralizing pipe during shearing Several offset positions were simulated. In Figure 4.1 the only one with a significant negative effect is shown. The pipe is first punctured by the edge of the blade, reducing required force. The puncturing eases the shearing, but the pipe does not move away from the offset position, where it ends up blocking full closure of the rams.

This scenario is similar to what occurred when closing the BSR in the Macondo incident, described in Chapter 4.2.2.

Shearing of compressed pipe This challenge resulted in the force having to be increased to shear the drill pipe compared to when the pipe was in tension, but not by a significant amount. They did not assess how the compression may affect the sealing surface.

Shearing of buckled pipe This simulation resulted in an 40% increase in required force to shear. A significant amount, that must be accounted for. The buckling was modeled in such a way that the pipe was place toward the upper ram. This is unlike how the Macondo pipe buckled. There the pipe buckled to the sidewall, more like was modeled in the centralizing of pipe during shearing scenario.

4.2 Historical Performance of Shear Rams

Through the history of offshore drilling there are two major oil spills related to failure of BSRs. The Macondo incident in 2010, and the Ixtoc 1 incident in 1979. In these incidents the BSR failed to shear the drill string and seal the wellbore. The BSR is not solely to blame in neither of the cases, but a successful shear and seal may have prevented these large releases of hydrocarbons.

Beside the two there is no public record of other failures of such significance. When WEST Engineering Services in 2004 looked into previous field failures they only found Ixtoc 1. WEST Engineering Services commented in this context "Undoubtedly, there are more failures that were either not reported well or had minimal exposure."

4.2.1 Ixtoc 1 Blowout

The blowout Ixtoc 1 suffered in 1979 was the largest accidental offshore oil spill before the Macondo incident (WEST Engineering Services, 2004). Valladares and Acuna (1980) estimates the blowout to have released 3.1 million barrels of oil.

According to EU Offshore Authorities Group (2015) the accidents happened as the rig crew was pulling the string after loss of mud circulation. With the lack of a hydrostatic column of mud, hydrocarbons and well fluid started flowing to the surface.

When the BSR was activated, a drill collar was across the shear path, preventing the BSR from shearing the drill pipe. Oil and gas was ignited topside engulfing the rig in flames, before it collapsed and sank onto the wellhead. The well was killed nine months later through two relief wells.

In the aftermath of this accident the steps were taken to develop the shear rams further, and the CSR may be considered a result (WEST Engineering Services, 2004) .

4.2.2 Macondo Blowout

In April 2010 the Macondo prospect was being drilled by the Deepwater Horizon rig. While completing drilling operations the crew experienced a kick that evolved to be the largest accidental oil spill in petroleum industry, costing 11 lives and spilling 4.9 million barrels of oil (Graham and Reilly, 2011).

The technical course of events leading to the blowout started with a poor cement job at the casing shoe. This was to due to untried cement design and the operation in itself being demanding. Further the temporary abandonment procedure called for underbalancing the well (lower pressure in wellbore than in formations) before additional barriers were in place to support the cement (Graham and Reilly, 2011).

The leak test for the cement was then misinterpreted, leading to a late detection of the kick. A series of actions were taken to regain control of the well, but no avail (Graham and Reilly, 2011).

At some point it was attempted to shear the drill string and seal the wellbore. However when this was attempted the pipe had buckled and offset across the shear path. In Figure 4.1 the position of the drill pipe is seen to be outside of the shearing area for the BSR. Det Norske Veritas, DNV (2011) found that this led to the BSR being unable to completely shear and then close. The area where the pipe prevented the BSR from closing experienced an increased flow rate. Increased local flow rate resulted in erosion, allowing more well fluids to pass the BSR. Det Norske Veritas, DNV (2011) found this through studying the remnants of the BSR and drill pipe found in the retrieved subsea BOP.

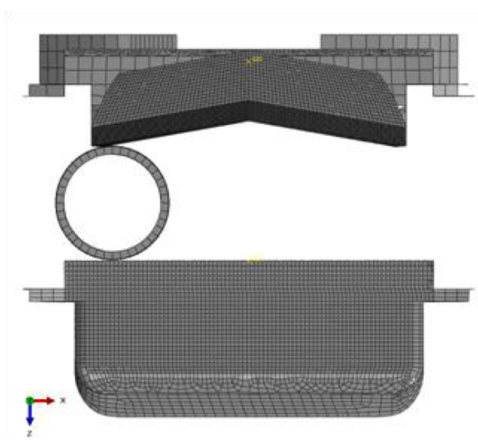

Figure 4.1: Offset drill pipe position and blade surface (Det Norske Veritas, DNV, 2011)

Graham and Reilly convey that the causes of the incident are complex as failures where to be technical, organizational and cultural. Among these causes the performance of the BSR is considered significant.

4.2.3 Data Samples

Three studies that address failures of BOP functions have been found. The latest of these studies, Holand and Awan (2012), incorporates the results from the previous two.

- Holand (1997), referred to as phase I, contain data from 1992 to 1996
- Holand (1999), referred to as phase II, contain data from 1997 to 1998
- Holand and Awan (2012) referred to as phase III, contain data from 2007 to 2009

The studies rely primarily on open data from the US Gulf of Mexico. Where the results incorporated in phase 3, Holand and Awan (2012), is of wells drilled in deep waters. Deep waters considerd water depths greater than 2000 ft (600 meters).

The studies found 6 recorded failures of shear rams. One in phase III, two in phase II and three in phase I. The failures are the following (Holand and Awan, 2012):

- One failure where the BSR failed to shear the pipe during a disconnect situation (phase I)
- 4 BSR leakages in closed position (phase I (2), phase II (1) and phase III (1))
- One BSR failed to close (phase II)

Other BSR related findings by Holand and Awan are:

- Internal leakage is the dominant failure mode for all ram preventers.
- In the two disconnect situations identified in phase III the BSRs succeeded in shearing and sealing.
- Kick frequency is highest during exploration drilling.
- None of the identified kicks occurred when casing or liner was across the BOP.

Due to the above mentioned results Holand and Awan assess the need for cutting of casing to be limited.

Internal leakage is found when pressure testing, resulting in the BOP being pulled and downtime. It is therefore rare that internal leakage results in loss of integrity.

Holand and Awan express that the need for redundancy of BSRs increase when drilling in deeper waters. This is due to drilling margin issues, and loss of position risk for dynamically positioned rigs.

In another study, WEST Engineering Services (2002), they approached 14 rigs for testing their shear capabilities. Out of the 14, 7 chose to participate. The end result, when taking operational condition into account, was that only 3 out of six passed the shearing test. Two of the rigs modified their equipment to enable to shear tougher tubulars.

4.3 Discussion

The Macondo incident and Ixtoc 1 has shown that BSR failures are not improbable. The FMECA and the discussed studies are influenced by uncertainty. MCS Kenny and the Macondo incident shows how the BSRs cannot shear and seal in certain situations.

Previously performed FMECAs, American Bureau of Shipping and ABSG Consulting (2013) and WS Atkins Inc (2001), have in the authors opinion failed to analyze all plausible situations a BSR may encounter. They have, in general, only analyzed failures that cause loss of function due to wear, mechanical failures and leakage. These failures are equally serious as failure to shear but have rare occurrence and is detected through frequent testing. Neither of these two analyses mentioned situations that are similar to the Macondo incident.

In the authors opinion it is interesting to draw parallels to Ixtoc 1 to improve BSR functionality. New concepts are more in demand after such an accident, and the challenging part is assessing if they conform to our reliability standards.

A step on the way may be to standardize and collect data on BSR and BOP performance. The data Holand and Awan present are found by manual and time consuming methods, such as looking through drilling newspapers, and daily drilling reports. The same issues met WEST Engineering Services (2004) when they attempted to find performance data.

In Bureau of Safety and Environmental Enforcement, BSEE (2015) it is proposed that a joint industry database of BOP performance should be established. To this database operators report all failures and "near misses". This may later aid in developing new technology. In the authors opinion this should also be implemented by PSA, preferably in collaboration with BSEE.

Chapter 5

Qualification Procedure Outline

Weaknesses of current BSR design are identified in the previous chapter. Several of these may be results of uncertainty and lack of prudent qualification. In this chapter a new shear ram concept is described and then used as a case while outlining a qualification procedure.

Public available information on En-Tegrity is limited. Thus limiting the analysis to a qualitative and conceptual analysis.

5.1 En-Tegrity

The description of the En-Tegrity concept is made by using information from Edwards (2013) and Mazerov (2012). This concept was chosen over other concepts, such as GEs new 5k shear ram, due to its innovative design. References are made to numbering in Figures 5.1 and 5.2 by placing the associated number in a parenthesis in the text.

The concept is based on reversing central parts of how a conventional BSR functions. The first being that the rams are pulled through the wellbore instead of being pushed into it. This is accomplished by the ram designed with two distinct parts. The aperture part, and the sealing part. The aperture parts of both rams are aligned with the wellbore making a through bore for running equipment. At this point the pistons are fully retracted as seen in Figure 5.1.

When sufficient force is applied to the pistons they are extended pulling the rams. The blades located in the aperture will move towards and past the center of the bore. As they move past each other the sealing surface enter the wellbore sealing off the well.

En-Tegrity claimed advantages over conventional BSRs are:

- Full bore coverage
- Metal to metal sealing
- Wellbore pressure aid in closing, instead of counteracting closure
- No elastomer increase strength of rams
- Separated shearing and sealing surface
- "Fail-safe" functionality
- Claims to shear all relevant tubulars

Uncertainties related to En-Tegrity are:

- No fold over function of drill pipe, pipe must be displaced vertically
- If drill pipe is in compression it may "dig" on the sealing surface
- Unproven

In Figure 5.2 the rams has been activated and the pistons fully extended. The upper gate(18) has been "pulled" by the left hand side pistons to the extent where the sealing part occupies the wellbore. The bottom gate has been "pulled" by the right hand side pistons, achieving the same.

The gates are activated when the internal force (FIN) is larger than the external force (FEX). This is done either by introducing hydraulic pressure through inlet ports (not shown in figures), or if the wellbore pressure is a predetermined amount higher than the external pressure (marine environment). The way this works is through the leak paths (97, 99) from the wellbore into the chamber (16).

5.2 DNV-RP-A203

DNV RP-A203 (2011) is a procedure developed by Det Norske Veritas for qualifying new technology. DNV RP-A203 focus on the technology qualification process. A technology qualification

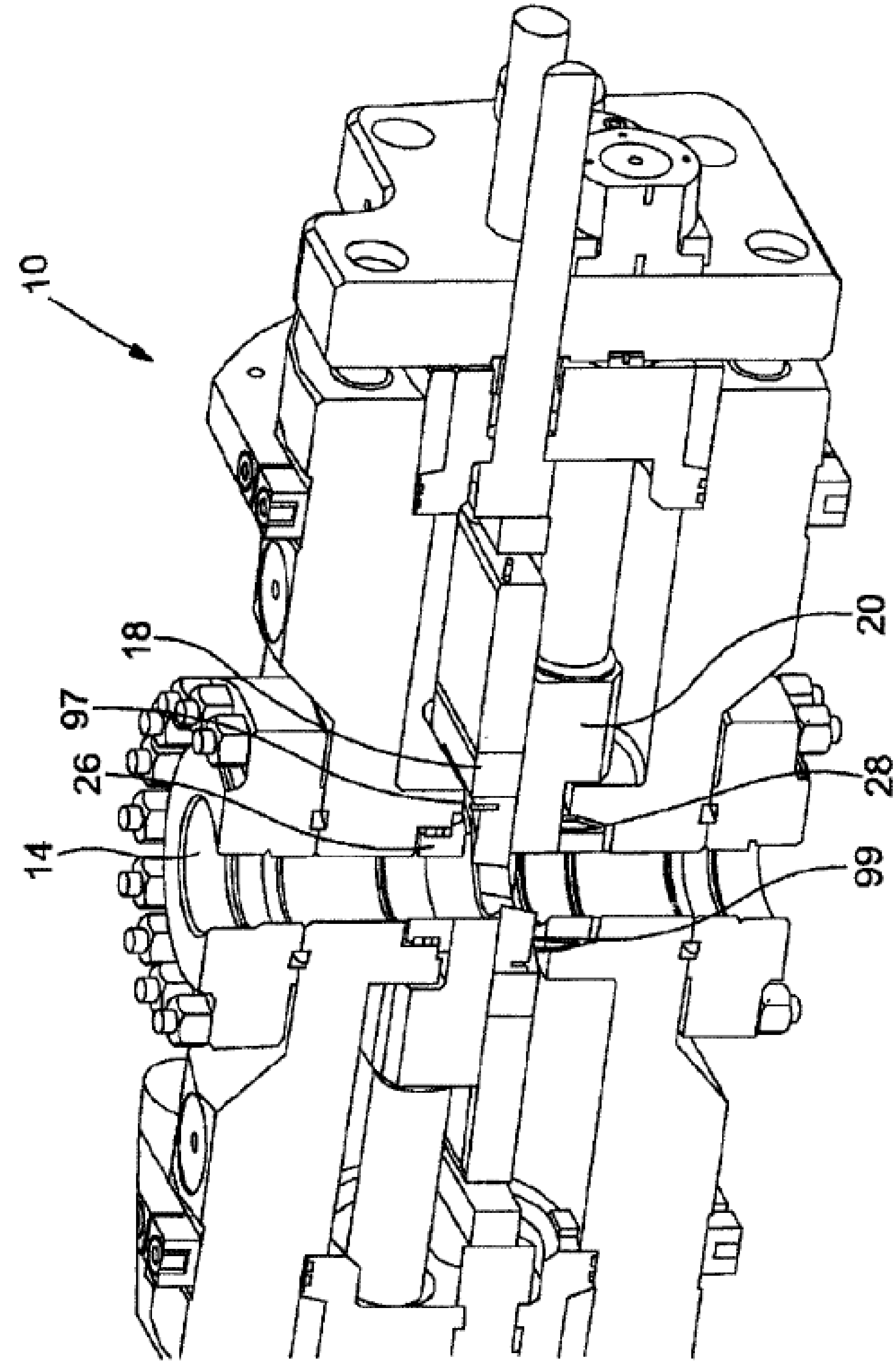

Figure 5.1: En-Tegrity concept open wellbore (Edwards, 2013)

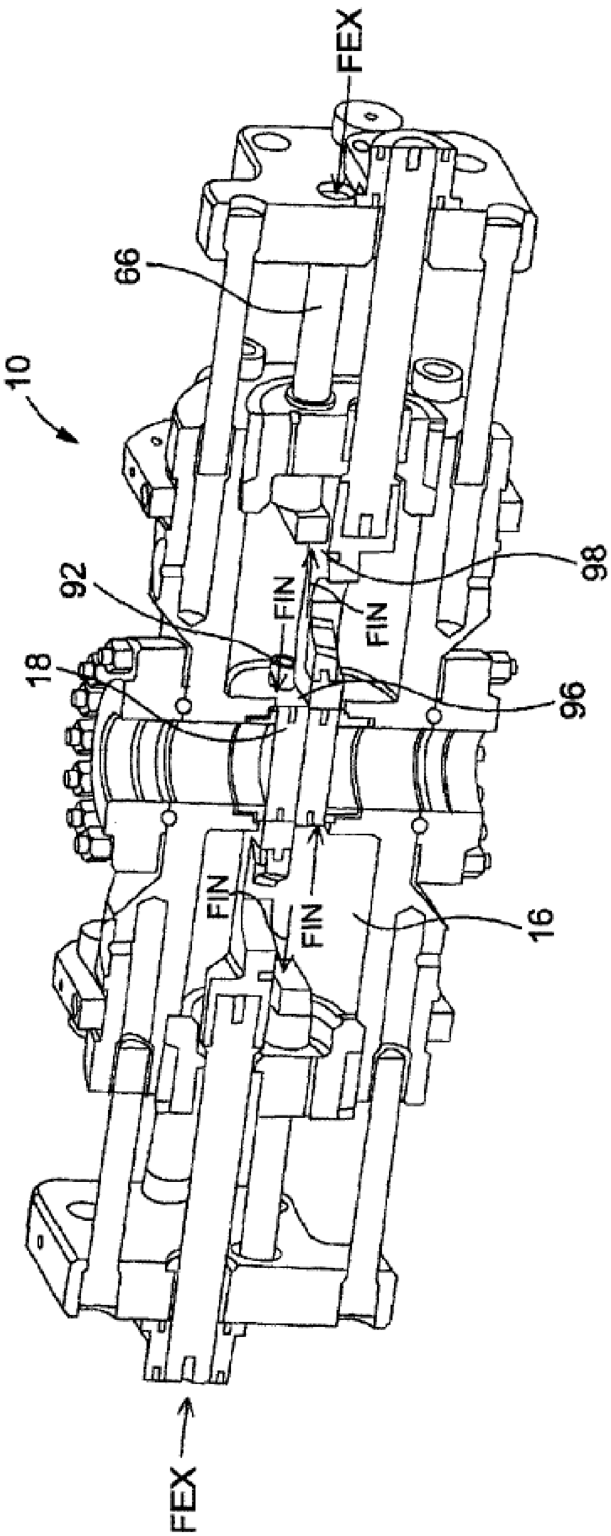

Figure 5.2: En-Tegrity concept closed wellbore (Edwards, 2013)

program is described by DNV RP-A203 to provide a framework for the process. The content of the document is similar to most project programs. Strategies, budget restraints, milestones, resources, qualification team information should be included. For the full list of content in the program and more detailed description DNV RP-A203 may be consulted.

The qualification process is divided into 6 steps. Figure 5.3 adapted from Nyland (2012) summarize the inputs and outputs of each step in the qualification procedure. Beyond this summary of the process, small explanations will be provided in each step in the qualification procedure outline.

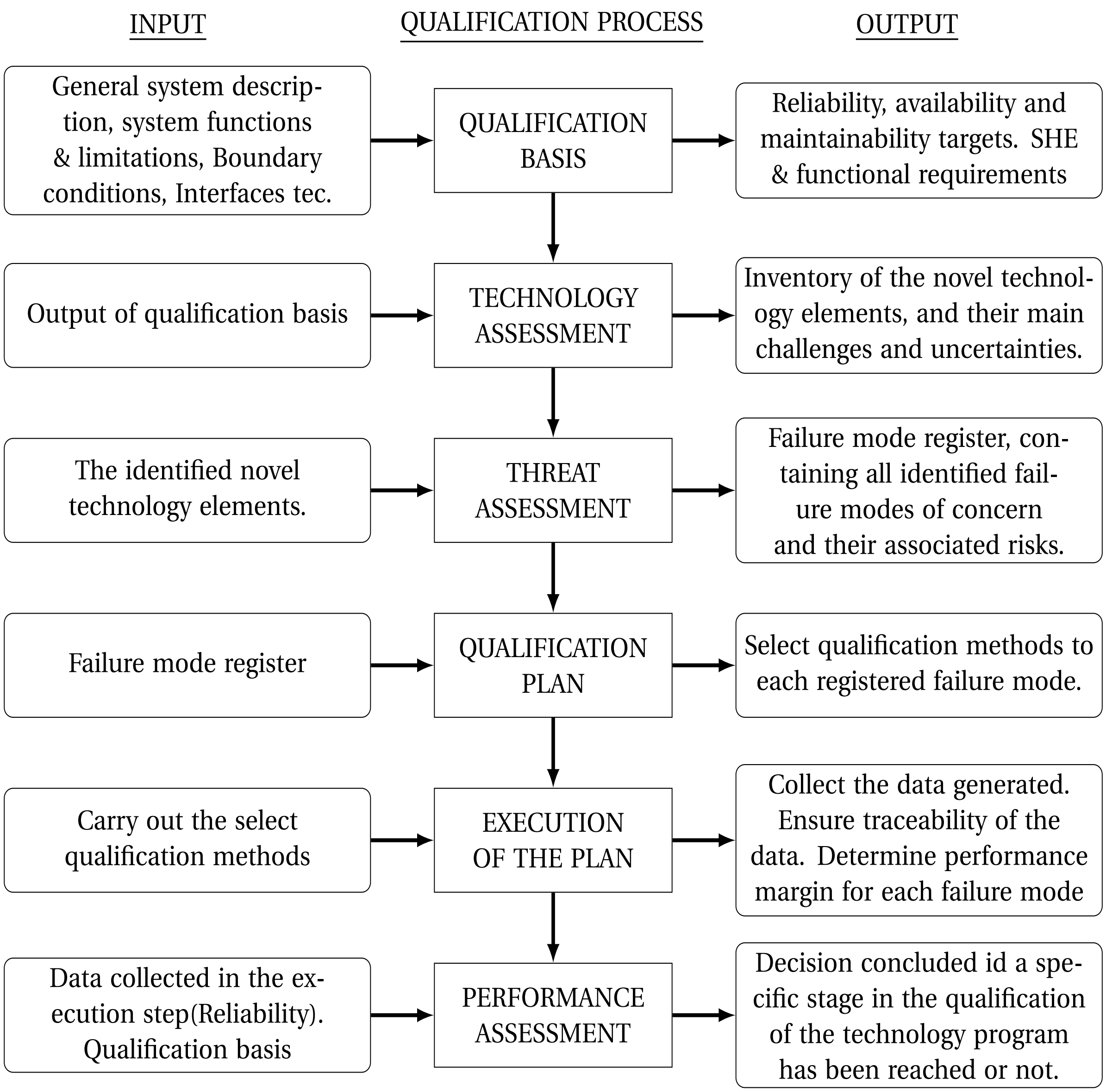

Figure 5.3: DNV RP-A203 overview (Nyland, 2012)

5.3 Blind Shear Ram Qualification Procedure Outline

The BSR being analyzed is as previously mentioned En-tegrity manufactured by Enovate. In DNV RP-A203 a part of the qualification basis is describing the system. In this case it is described separately; making the qualification basis general for BSRs.

This procedure is limited to contain well integrity issues related to qualification and will not address the other life cycle phases of a BSR. The analysis will only cover operational phase, however some factors not related to operational phase may be discussed.

5.3.1 Qualification Basis

This step defines the system, its boundary and qualification criteria. These criteria will be used throughout the process, and what the qualification evidence will have to fulfill.

This step is divided into 2 sub-steps:

Technology specification The relevant content includes description of system, functions, classification, regulatory requirements, standards and industry practice, boundary conditions, interfacing equipment and existing evidence.

Requirement specification This part contains quantitative measure to reliability, availability, safety requirements and functional requirements.

Both of these steps is combined for this case. The requirement specification may not be relevant to a great extent as there is not enough data and quantified history to set satisfying requirements. For example; the BSRs availability measure is that it must be available at all times due to the severe consequences when it fails on demand.

The technical description demanded by the guideline is provided in Chapter 5.1. In addition Edwards (2013) may be consulted.

The functions to be performed by the BSR are the following:

- Close on open hole and then seal wellbore
  - Controlled operations
  - EDS activated shearing

  - Autoshear activated

- Close and shear drill pipe in wellbore and then seal wellbore
  - Controlled operations
  - EDS activated shearing
  - Autoshear activated

- Open after closure and/or shearing

In addition it is advantageous if the BSR if capable of shearing casing, tool joints, wireline and snubbing string. New regulations may require that BSR can shear some or all of these. Especially shearing of tool joint must be a priority ensure longevity on the market.

Relevant regulatory requirements and industry standards are found in Chapter 3 and will not be repeated here.

An important factor is that the BSR system is to be part of a system, the BOP stack. New BSR must integrate into already existing dimensions. This includes standard bore size of BOPs and that the BSR does not add a significant amount of weight or height to BOP stack. Height and weight both effect handling of BOP stack on rig, storin, loads and bending of wellhead and increased maintenance time, costs and complexity (Andersen, 2015b).

Previously attained evidence of functions or performance is also presented at this point in the process. There is, to the authors knowledge, no public available evidence that proves or disproves parts of the En-Tegrity concept. However according to Mazerov (2012) there has been performed some tests that have been validated by major operators.

An example of functional requirements for a modern BSR the BSR are presented in Table 5.1. Table 5.1 present minimum requirements for drilling in deep waters.

The BSR shall also perform its functions with all types of well fluids. This includes oil and gas containing sand, H2S and other eroding or chemical substances found in rock formations.

5.3.2 Technology Assessment

This step determines to what degree the system and sub-systems involves new technology, and identifies challenges and uncertainties.

Table 5.1: Functional requirements for BSR

Parameters	Functional requirements	
Bore size	18 ¾	inches"
Design life	30	years
Design water depth	10000	feet
Max wellbore pressure	1000	bar
	15 000	psi
Max wellbore temperature	150	°C
External temperature	0-30	°C

In DNV RP-A203 this step is divided into parts:

1. Technology composition analysis

Decomposition the technology into function/sub-function and/or component/sub-component.

2. Technology categorization

Categorize technological components into four groups of novelty. DNV RP-A203 use Table 5.2 to set a novelty category.

Table 5.2: Technology categorization (DNV RP-A203, 2011)

Application area	**Degree of novelty of technology**		
	Proven	Limited Field history	New or Unproven
Known	1	2	3
Limited Knowledge	2	3	4
New	3	4	4

Where categorization is described by DNV RP-A203 as:

1. No new technical uncertainties
2. New technical uncertainties
3. New technical challenges
4. Demanding new technical challenges

Another common used categorization is Technology Readiness Levels(TRLs) developed by NASA Mankins (1995). This method may also be used

3. Identification of main challenges and uncertainties

Analyses are performed to identify challenges, hazards and uncertainties related to the new technology.

For this BSR concept the three parts are combined into a technology assessment analysis form. A functional approach has been chosen and the functions are:

1. Close shear rams
2. Shear drill pipe
3. Seal wellbore
4. Be part of wellbore
5. Shear other tubulars(Not a requirement from standards, but it is claimed that En-Tegrity can shear all tubulars)

The technology assessment is presented in Figure 5.4

Summarizing the Figure 5.4: all function scored 2 or higher in the categorization. This as expected due to limited knowledge of operating in deep waters, and the novelty of the concept. This signifies that they must be assessed further.

5.3.3 Threat Assessment

In this step classical threat assessment methods are used to identify failure modes and causes, and associated risk. Methods such as FMECA, failure tree analysis, hazard and operability study may be used. An FMECA will be performed in this case.

To evaluate the criticality probability and consequence classes are used (Tables C.1 and C.2 in Appendix C). The tables are based on DNV RP-A203 (2011) and American Bureau of Shipping and ABSG Consulting (2013) to best meet the requirements of a BSR. Most companies have their own perception and standards regarding consequences, thus usually makes their own tables. By using the categories in Tables C.1 and C.2 a risk matrix (Figure C.1 in Appendix C) is made with high, medium and low risk. Failure modes categorized medium or high has to be covered in the qualification plan, while green may be qualitatively analyzed (DNV RP-A203, 2011).

	Functional requirement	Challenges/Uncertainties	Categorization	Comments
1	Close shear rams	Mechanical failures	2	The new concept is based on proven mechanical solutions: limited knowledge of application area, proven technology.
		Hydraulic failure - Insufficient accumulator pressure	2	The new concept is based on proven mechanical solutions: limited knowledge of application area, proven technology.
		- High wellbore pressure - Low wellbore pressure - High external pressure - Low external pressure - High flow rate in well	4	New and unproven technolgy related to closing the rams with use of wellbore pressure, limited knowledge of application area
2	Shear drill pipe	Ability to shear: - high grade drill string - offset/buckling pipe - drill pipe in compression - movnig work string - with flowing well	4	New and unproven technolgy related to closing the rams with use of wellbore pressure, limited knowledge of application area
		Displacement of drillpipe (due to lack of fold over function)	4	Thick rams deviating from standard BSRs: new technolgy and limited knowledge o application area
3	Seal wellbore	Damage to rams due to "scraping during shearing"	2	Although different, experiance from conventional BSRs indicate not a problem. Limited knowledge of application area.
4	Act as part of wellbore	Leakage through BSR unit or interfacing surfaces	2	The new concept is based on proven mechanical solutions: limited knowledge of application area, proven technology.
		Spurious activation by "fail-safe" functionality due to high wellbore pressure	3	Not completely new tchnolgy: limited field history and limited knowledge of application area
		Opening with high wellbore pressure	3	Not completely new tchnolgy: limited field history and limited knowledge of application area
5	Shear other tubulars (not required, but claimed to be able to do so)	- Drill collar - Casing - Tool joint - Upper/lower completion - Snubbing string - Wireline	4	New and unproven technolgy related to closing the rams with use of wellbore pressure, limited knowledge of application area

Figure 5.4: Technical assessment

The functions in this FMECA will not be the same as in the FMECA in Chapter 4.1. The results from the previous FMECA revealed through dividing into three separate shearing situations that the same failure modes and causes were generally ranked medium or high. It also revealed that all the autoshear situation was ranked equal or higher than the other two shearing situations. To summarize, in this FMECA the shear and then seal situation will only be analyzed through the assumed worst case, autoshear.

Results

The result of this FMECA is highly dependent on the probability of each failure cause. This is due to the BSRs role as last line of defense, implying most failures may potentially lead to the highest consequence severity rating.

The failures rated high are all in relation to shearing and are the following:

- Failure to close rams(Failure mode) with the following failure causes:
  - Mechanical failure
  - Hydraulic failure
  - Flowing well
- Failure to shear tubular with the following failure causes:
  - Drill pipe in compression
  - other tubular than drill pipe across BSR

Results with comments are presented in Table 5.3, the full FMECA in Appendix C.

5.3.4 Qualification Plan

The threat assessment performed in the previous step is used to decide what qualification activities needs to be performed. Simulations, calculations and tests may be performed to ensure that all critical failure modes are addressed. The plan must ensure and document that the requirements of the qualification basis are met.

Table 5.3: Results of FMECA

Failrue mode	**Failure causes**	**Rating**	**Comment**
Failure to close on open hole	Mechanical failure Hydraulic failure	Medium	Consequence medium, and failure rate fairly low results in medium risk. Since there is no tubular to shear, annular preventer are capable of sealing.
Failure to close (when shearing)	Mechanical failure Hydraulic failure Flowing well	High	The same as for open hole in probability, but with tubular in wellbore the consequence is at the highest.
Failure to shear	Damaged blades Offset/buckling pipe Flowing well Moving drill string Differential pressure in drill pipe	Medium	The consequence is at highest here as well, but it assumed the concept can handle these cases with confidence. Must still be tested or simulated for validation.
Failure to shear	Drill pipe in compression High grade drill string Other tubular than drill pipe across BSR	High	The consequence is again at highest, the probability is medium and testing must be performed to analyze the performance of the BSR in these cases.
Closes too slowly	Slowed due to shearing activity	Medium	Uncertainty to how the speed of closure reacts to high grade drill pipes is the main concern.
Failure to seal wellbore	Rams unable to meet sufficiently Damage to sealing area due to scraping of surface	Medium	Uncertainty to whether the sheared pipe may jam or damage the sealing area when a potential pipe in compression travels over.

The threat assessment resulted in that all failure modes must be assessed further. The ideal way of producing evidence of function and reliability is through numerous test to failure. This may not feasible for BSRs as they are expensive to manufacture. Another issue is that there is currently, to the authors knowledge, no test facilities capable of testing BSRs in simulated well conditions. Through calculations and engineering judgment it is possible to account for most of the situations in a prudent manner without these test facilities.

The procedure presented in API 16A (2004), and discussed in Chapter 3, is limited and not enough to provide confidence in a concept. The author suggest more extensive testing in combination with simulations.

Shear Influencing Factors

To systematize the testing and simulating, the failure modes and causes have been broken down into external factors influencing the shear capability, presented in Table 5.4. One factor is purposely left out: which tubular is being sheared. It is left out as all tubulars may not be relevant for all new designs. The most important tubulars are the drill pipes and tool joints.

Ideally multiple tests should be performed for each of the 36 possible combinations for each tubular. Considering that it may be natural to test drill pipe with different grades, tool joints, casings, wirelines and coiled tubings this may not be feasible. An approach is necessary to decide which combinations may be omitted. A combination may be omitted if it can be documented that it is covered by another.

Table 5.4: Shear capability influencing factors

Position	**Wellbore pressures**	**Loads**	**External pressure**
Centralized	Atmosphere pressure	Tension	Expected minimum
Offset toward ram	Design pressure (15 000 psi)	Compression	Expected maximum
Offset toward side wall		Buckling	

To reduce number of tests two actions are suggested: the first, mentioned previously, is to reduce combination by omitting those that are covered by others; and the second is to perform computer simulations.

In each BSR case it should be assessed which combinations can be reduced. In Table 5.5 16 combinations are suggested to represent the original 36.

Table 5.5: Proposal of representative combinations of shear capability influencing factors

Position	**wellbore pressures**	**Loads**	**External pressure**
Centralized	Atmosphere pressure Design pressure (15 000 psi)	Tension Compression	Expected minimum Expected maximum
Offset toward ram	Atmosphere pressure Design pressure (15 000 psi)	Buckling	Expected maximum Expected maximum
Offset toward side wall	Atmosphere pressure Design pressure (15 000 psi)	Buckling	Expected minimum Expected maximum

The reasoning is based on testing the worst case scenarios, and realistic scenarios. For centralized pipe, which is the most probable position, buckling is considered unrealistic as buckling causes the pipe to be offset.

For both the offset positions the only load included is buckling, reducing test numbers considerably. Compression loads are omitted due to buckling test being achieved by applying pressure on the pipe, compressing it.

Tension loads are omitted as the pipe is likely to center itself if it is in tension.

Another reasoning is that it is assumed that there is not enough difference in the situations to necessitate tension and compression testing beyond the centralized position tests.

Simulating and Testing

Performing simulations may further reduce the number of tests by producing evidence that eliminate uncertainty of certain aspects, and through proving combinations likeness.

If all situations have been simulated multiple times, testing may be focused on particular combinations where the uncertainty is the greatest. For example; a combination of a tool joint, offset towards a ram, at design pressure, buckling with maximum expected external pressure, may be considered worse than a a centralized drill pipe in tension at atmosphere pressure and minimum external pressure.

Methods of Emulating the Influencing Factors

Performing tests at increased pressure may be done by installing blind flanges above and below the BSR, or installing the BSR in a BOP stack and using annular preventers or such to seal off when increasing pressure.

For non-centralized position and/or an applied load it may be difficult to raise the pressure inside the bore to design pressure. A solution to this is to calculate the effect increased pressure in the wellbore has on necessary pressure for closing rams. These calculations can be verified by closing the rams without tubular across BSR, and monitor increase in applied pressure.

Another pressure issue is of environmental pressure. At great water depth the accumulators lose a considerable amount of their capacity, this must be calculated subtracted from available accumulator pressure as well.

Buckling drill pipe may be tested by applying force vertically on to the drill pipe until it buckles and then shear.

How Failure Modes and Causes are Accounted for Through Influencing Factors

In the threat assessment flowing well is a scenario. The flowing in itself does not effect the well shearing significantly (MCS Kenny, 2013). An effect of flowing well is that the pipe may buckle. This is caused by gas traveling up the annulus, expanding as it rises. When it expands pressure at the bottom of the hole increase pushing liquids up the drill string increasing the internal pressure. As the gas pass the shear path it may have a lower pressure then the internal pressure in the drill pipe. The pressure difference may cause the drill pipe to buckle. This is the worst case scenario for the flowing well situation.

5.3.5 Execution of the Plan

In this step the activities planned in the previous step is performed and documented. Normal steps are performing tests, documenting failure modes and their frequencies and ensuring traceability of the data.

When performing the activities it is important that all activities and their results are documented. The results will be used as evidence of the abilities of the BSR. In addition new failure modes may be discovered. Modifications may be made dealing with these, and properly documented testing may be an important part of achieving this.

Between all shearing tests the BSR should be inspected and pressure tested. All failure modes should be recorded. After each shearing the rams should be restored to "good as new" condition. There is no requirement or situation where shearing is performed twice. The standards also specify that the shear ram shall be retrieved and inspected after shearing.

5.3.6 Performance Assessment

This step compares the output of the activities performed in the previous steps with the qualification basis. For the product to be taken into use, there should be no deviance from the qualification basis.

5.4 Discussion

Found the qualification testing to be the place to improve the process. This may be done by comprehensive simulating and testing of all probable situations. In particular for shearing situations of offset tough drill pipes under high pressure with loads applied.

Technology have evolved to a point where computer simulations are able to model real situation with multiple factors. The industry should take advantage of this to better understand the effects of the well conditions in potential accident scenarios.

The DNV RP-A203 (2011) qualification procedure is comprehensive and may be completed step by step to ensure reliable equipment. It is however not specified for BSRs, and the team performing the analysis may neglect certain challenges.

In the authors opinion it is evident that challenges have been neglected in the past. The Macondo incident illustrates how offset drill pipes and buckling affect shearing, and Ixctoc 1 illustrated that the BSRs cannot shear tool joints. These scenarios should in the authors opinion have been addressed prior to the accidents through prudent analyses.

DNV RP-A203 is a leading guideline for qualification of new technology in oil and gas industry, it is however not intuitive enough for non-experts to carry out. A skilled, and preferably experienced, facilitator should guide the team through the process. The guideline contains vast amount of information to be considered and included in the process. There are templates in the appendix, but they work only on the equipment exemplified there.

Chapter 6

Summary and Recommendations for Further Work

6.1 Summary and Conclusions

The objective of this report is to assess the reliability of blind shear rams (BSRs). The Macondo incident proved the necessity of reevaluating the abilities of current BSR designs.

Chapter 2 introduces subsea blowout preventers (BOPs). Common functions and components are described based on the BOP used in the Macondo incident. Classification and relevant regulations are also introduced

Chapter 3 provides a detailed description of current BSR. Designs description are based on Cameron's BSRs, as they were used in the Macondo incident and have a leading market share. BSR functions are described in general and through four detailed descriptions of relevant scenarios of operation.

Objective 2 is answered in Chapter 3 when relevant requirements for BSRs on the Norwegian Continental shelf and US Gulf of Mexico are described and discussed. Current regulations in both regions are similar regarding BSRs. The main difference is how the Petroleum Safety Authority Norway (PSA) have performance based requirements while the Code of Federal Regulation (CFR) in the US are specific on technical requirements. PSA reference standards where specific technical requirements are described.

Several weaknesses were identified in the current requirements and regulations: the wording found in some instances does not encourage prudent approaches to BSR design; testing of BSRs are performed at ideal and non-realistic conditions; CFR requires that deadman and autoshear systems are installed in BOPs, but does not have to be armed. When these systems are not armed they will not activate.

A proposed rule by Bureau of Safety and Environment Enforcement (BSEE) is likely to change the US regulations. Relevant for BSRs are the following proposed changes:

- Third party verification of BOP equipment through all life phases.
- Require shear rams that can center the drill pipe when shearing.
- Incorporate API 53 into the regulations.
- Incorporate other standards such as API 6A, API 16A, API 16C, API 16D, API 17D, and API Spec Q1.
- Improved and consistent testing frequencies.
- Failure and near-miss reporting.

The changes proposed has the potential to eliminate some of the weaknesses of current BSRs. There are however deficiencies in the proposed rule: there will still be too many standards to consult with overlapping and inconsistent information; and the regulations could be more rigid regarding which tubulars the BSR should be able to shear.

Objective 3 is answered in Chapter 4.1. Weaknesses in current BSR concepts are identified by a Failure Mode, Effect and Criticality Analysis (FMECA). Results from studies of BSR capabilities are discussed and compared with the result from the analysis.

The FMECA was performed by analyzing 5 different BSR functions. Uncertainties were identified in all shearing situations. Especially autoshear activated shearing has potential for failure. The autoshear is automatically activated, excluding the operator to perform shearing enhancing actions. In the other situations an operator may lift or position the tubular in such a way that shearing more likely to succeed.

Two failure causes were identified to be of high criticality. These two were for drill pipe in compression and for an offset/buckling drill pipe.

Studies performed by MCS Kenny and WEST Engineering identify increased ductility and strength of drill pipes and buckling drill pipes as potential sources of failure to shear and then seal the wellbore for BSRs. Confirming the results of the FMECA.

Objective 1 is answered in Chapter 4.2 where two major accidents involving BSR failures are described and a literature study of BSR failure data is performed.

The Ixtoc 1 incident in 1979 released 3.1 million barrels of oil, and was the largest accidental offshore oil spill before the Macondo incident. When the BSR was activated a tool joint was situated across the shear path. The BSR did not have the ability to shear tool joints, thus not able to shear.

The Macondo incident in 2010 cost 11 lives, total loss of a drilling platform and released 4.9 million barrels of oil. The forensic reports concluded that the BSR was attempted closed, but that the drill pipe was buckled across the shear path. The drill pipe was not centered by the BSR, resulting in the pipe staying at the edge of the shear path. The BSR then cut parts of it, but was not able to close and seal. Other factors also influenced the course of events, but the BSR was among the contributing factors leading to the complete loss of well control.

Studies conducted on the performance of subsea BOPs are limited, and the ones that are available suffers from issues obtaining data. (Holand and Awan, 2012) studied deep water wells drilled in three separate periods, spanning a total of 10 years, in the US Gulf of Mexico. Data collection is not standardized, by the industry, and Holand and Awan findings came partly from analyzing daily drilling reports, and partly from extensive searching in news media. It is suggested that a joint industry database should be established for better recording of subsea BOP and BSR performance.

Among the findings 6 relevant failures were detected. One of these was related to a well control situation, while the others were discovered in function and pressure testing. Holand and Awan also found that none of the kicks occurred with casing across BOP, and internal leakage detected during testing is the main failure cause in all ram type.

Objectives 4 and 5 are answered in Chapter 5. En-Tegrity, a new BSR concept, and DNV RP-A203 are introduced then used to outline a qualification procedure for BSRs.

The En-Tegrity concepts is described primarily through the patent application. Information is therefor limited to a conceptual level. The concept has three principal differences from conventional BSRs: it utilizes wellbore pressure to aid shearing; the rams are pulled instead of being pushed; it has metal to metal sealing.

The outlined procedure is limited to well reliability related aspects. All process steps from DNV RP-A203 are described and performed for the En-Tegrity concept. The steps are formulated in such a way that most new BSR concepts may follow them. The step weighted most is qualification plan.

It is recommended to carry out a combination of simulation and testing to ensure cost efficiency without comprising the reliability of BSRs.

Four categories have been made for factors influencing shearing capability: position, wellbore pressure, loads and external pressure. By making all possible combinations of one factor from each category, all considered well situation are covered. In total there are 36 combinations. The intent is to create transparency of the failure causes. Ideally all combination should be tested multiple times for each relevant tubular. This is considered unrealistic due to high costs.

The author has based on assumptions reduced the combinations to 16 by considering which combinations are unrealistic or similar enough to another to be omitted. It is also recommended to first perform simulations to further assess if others may be omitted as well.

6.2 Discussion

This thesis focus solely on the BSR system. Normally this system is analyzed as part of the subsea BOP system. This may be considered both a weakness and a strength. It allows the analysis be more in depth, but it may also lead to complex failures involving other parts of the subsea BOP system to be overlooked.

In the thesis functional failures is the priority, leaving out detailed analysis on mechanical issues such as leak paths and mechanical wear. Macondo and Ixtoc 1 incidents and the studies looking into BSR weaknesses also focus on functional failures, legitimatizing this approach.

The literature used in this thesis is primarily created by various experts from within the oil and gas industry. In some cases the experts may have own interests influencing their work, for example in patents. This has been taken into consideration by the author of this thesis.

Authors of the various studies are in general considered to be objective in their considerations due to them being part of third part organizations.

6.3 Recommendations for Further Work

Response to Major Accidents

Following major accidents, such as the Macondo and the Ixtoc 1 incidents, there is normally a response to improve safety and avoid recurrence. An in depth study of the response to accidents in the oil and gas industry may uncover potential for improvement. This is not limited to BSRs related accidents, others like Exxon Valdez in 1989 and Bravo blowout in 1977 may also be interesting to investigate.

The findings may also be compared to how other industries respond to their major accident.

Modeling Blind Shear Ram Simulations

It is the author's opinion that a study of how best to perform computer simulations for BSRs may be of interest to the industry. Different approaches can be considered and compared before an assessment of the possibility to standardize the process is conducted.

Comparison of Qualification Of New Technology Procedures

It is known to the author that North Atlantic Treaty Organization (NATO), National Aeronautics and Space Administration (NASA) and United States Department of Defense (DoD) all have their own procedures to qualify new technology. All of these institutions have strict reliability requirements to ensure the safety of their personnel. It may be interesting to compare the leading guidelines of the oil and gas industry to that of NATO, NASA and DoD.

Appendix A

Acronyms

API American petroleum institute

BOP Blowout Preventer

BSR Blind shear ram

BSEE Bureau of Safety and Environmental Enforcement

CFR Code of Federal Regulations

CSR Casing shear ram

EDS Emergency disconnect system

FMECA Failure Mode, Effect and Criticality Analysis

LMRP Lower marine riser package

NOG Norsk olje og gass

PSA Petroleum Safety Authority Norway

SIL Safety integrity level

Appendix B

Cameron BSR FMECA Spreadsheet

This FMECA is performed to uncover weaknesses in current BSR design. Results are in Chapter 4.1.

	Component Functions	Operational threats and hazards			Barriers	Consequences	Crit.	Suggested actions and remarks
			Potential failure mode	Potential failure causes				
1	Close and seal on open hole This include autoshear and EDS situations where the wellbore is empty	1.1	Failure to close on open hole through blind-shear rams	Mechanical failures: - Dameged seal - Corrosion - Debris in system - Damaged internal components	Detection: - Visual inspection (before BOP is installed on wellhead) - Function testing(API: every 21 days, NORSOK D-010: every week)	Worst case consequence: - Loss of containment =>Blowout • Loss of lifes • Release of hydrocarbons to environment • Loss of equiqment/rig/production time/well • Damaged reputation Most probable consequence: - Stabbing of kelly valve or closing of annular preventer contains well • Loss of production time - Found during testing => Maintenance • Loss of production - If drive off or drift off situation • Release of hydrocarbons to marine environment		Likely to be detected before a demand occurs
				Hydraulic failure - Insufficient accumulator pressure	Detection: - Function testing(API: every 21 days, NORSOK D-010: every week) Existing consequence reducing actions: - Standards dictate that shear rams shall close within 90% of available system pressure at expected maximim wellhead pressure			Likely to be detected before a demand occurs
				Flowing well - Late kick detection	Detection: - Early kick detection			Does not affect the ability to close significantly
		1.2	Closes too slowly - API 53 require closing within: 45 seconds	Insufficient accumulator pressure - Leaking hydraulics - Friction in actuator - Clogging	Detection: - Visual inspection (before BOP is installed on wellhead) - Function testing(API: every 21 days, NORSOK D-010: every week)	Worst case consequence: - If closes to slowly during flowing well there is more time to erode compoents. This may lead to damaged packers and sealing problems Most probable consequence: - Found during testing => Maintenance • Loss of production		Likely to be detected before a demand occurs
				Friction on pistons - Debris	Detection: - Visual inspection (before BOP is installed on wellhead) - Function testing(API: every 21 days, NORSOK D-010: every week)			Likely to be detected before a demand occurs
				Excessive pressure in wellbore - high pressure in the wellbore may restrain moving of shear rams	Detection: - well monitoring			Does not affect the ability to close significantly
		1.3	Unintentional opening/closing	Spurious activation by hydraulics/electronics	Existing consequence reducing actions: - Function testing	Worst case consequence: - Opening prematurely of a well that is not killed • blowout		Considered outside the scope as this failure is by the control system

Figure B.1: FMECA sheet 1 for Cameron design BSR

				Human activation	Existing consequence reducing actions: - Procedures - Fear of pressing button in vain	• has to close again on flowing well - Closing before tubular is run • tubular hits rams leading to inspection that may require pulling BOP - downtime Most probable consequence: - Close on open hole • has to open again with minimal loss of time. • investigation to why rams are activated		Studies performed by MCS Kenny for BSEE indicate culture where operators fear to press button in vain due to costs if tubing is sheared.
				Lock Failure - Corrosion - Human error	Detection how: - Visual inspection (before BOP is installed on wellhead) - Fucntion testing(API: every 21 days, NORSOK D-010: every week)			Likely to be detected before a demand occurs
		1.4	Fail to seal	Damaged ram block - Damage from maintenance	Detection how: - Visual inspection (before BOP is installed on wellhead) - Pressure testing(API: every 14 days, NORSOK D-010: before drilling new section)	Worst case consequence: - Fail to seal during well control operation leading to high flow rate increasing erosion and escalating event. Most probable consequence: - discoverd during pressure testing • downtime		Annular preventer can in most cases seal.
				Damaged packers - Due to high/low temperature - High pressure - Wear over time - Erosion - Wrong material for specific well (H2S) - Deformation of seal	Detection how: - Visual inspection (before BOP is installed on wellhead) - Pressure testing(API: every 14 days, NORSOK D-010: before drilling new section)			Annular preventer can in most cases seal.
2	Operator controlled operation - Shear the drill pipe and then seal the wellbore This operation is performed by the operator to regain control of the well. A typical sequence may be to: 1) lift pipe 2) close pipe rams 3) lower pipe joint onto pipe rams 4) activate BSR With casing being run: 1) shear casing with CSR	2.1	Failure to close	see 1.1	see 1.1	see 1.1		see 1.1
		2.2	Failure to shear tubular	Damaged blades	Detection how: - Visual inspection (before BOP is installed on wellhead) - Fucntion testing(API: every 21 days, NORSOK D-010: every week)	Worst case consequence: - Loss of containment =>Major blowout • Multiple lifes lost • Major release of hydrocarbons to environment • Loss of equiqment/rig/production time/well • Severely damaged reputation Most probable consequence: - Loss of containment =>Blowout • Personell injured • Minor release of hydrocarbons to environment • Loss of equiqment/production time/well		Likely to be detected. It may be argued that the brute force in the shearing is enough to shear in most cases.
				Offset/buckling drillpipe May occur due to: - drill pipe in compression	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR can shear over entire wellbore - pipe rams and annular preventer may aid in "straightening" the pipe			In controlled operation competent operators may be able to handle this situation.

Figure B.2: FMECA sheet 2 for Cameron design BSR

	2) Lift pipe to above BSR 3) Close BSR			Drillpipe in compression May occur due to: - Flowing and pressurized well	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability	• Some damage to reputation		In controlled operations competent operators may be able to handle this situation.
				Nonshearable in wellbore • Drill collar • Casing • Tool joint • Other items: Upper completion, lower completion, intervention tool	Detection: - Failure to shear leading to flow through drillpipe not stopping - Operator knows what is run in hole Existing consequence reducing actions: - CSR have increased shearing capability			In controlled operations the operator should be able to position the drill string or use CSR before shearing with BSR
				High grade drill string - Developement of drill strings is resulting high ductility and strength drill pipes in use.	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability			Marking on drillstrings are not always specific beyond standard marking. This may lead to high ductility and strength drill pipes being used. This must be tested to confirm blind shear rams ability to shear.
				Moving drill string	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability			Not very likely in controlled sistuation
				Flowing well - Late kick detection	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability			Effects of this has not been tested, or simulated extensively to the knowledge of the author. However, MCS Kenny tested it did one simple simulation indicating no issues. Erosion will most likely not be significant due to closing of shear rams in less than 45 seconds (required).

Figure B.3: FMECA sheet 3 for Cameron design BSR

				Differential pressure in drill pipe(significatnt pressure inside drill pipe compared to annulus.	Detection: - Failure to shear leading to flow through drillpipe not being stopped Existing consequence reducing actions: - CSR have increased shearing capability			May lead to buckling. Uncertainty is the reason for medium rating.
		2.3	Closes too slowly	Slowed due to shearing activity - Same as causes from failure mode 5.2		Most probable consequence: - Will still close within a time that allows the BSR to perform its function		
				see 1.2	see 1.2	see 1.2		see 1.2
		2.4	Failure to seal the wellbore	Rams unable to meet sufficently - Inadequate fold over bottom fish - too great diameter of tubular, or to thick walled tubular. - high grade tubular	Detection: - Flow not stopping Existing consequence reducing actions: - Fold over design	Worst case consequence: - Cannot seal properly. Flow through rams in high velocity erodes and snowballs into full flow and blowout. Most probable consequence: - Same		Most likely caused by same failure causes as failure to shear.
				Damage to sealing components during shearing	Detection how: - Failure to stop flow Existing consequence reducing actions: - Design protects sealing elements			Design pr
3	Emergency Operation - Autoshear - Shear the drill pipe and then seal the wellbore This category is distinguishable by being depended on automatic activation (No human intervention or judgement involved) The sequence of rams is preprogrammed. Autoshear category includes deadman, AMF	3.1	Failure to close	see 1.1	see 1.1	see 1.1		see 1.1
		3.2	Failure to shear tubular	Damaged blades	Detection how: - Visual inspection (before BOP is installed on wellhead) - Fucntion testing(API: every 21 days, NORSOK D-010: every week)	Worst case consequence: - Loss of containment =>Major blowout • Multiple lifes lost • Major release of hydrocarbons to environment • Loss of equiqment/rig/production time/well • Severely damaged reputation Most probable consequence: - Loss of containment =>Blowout • Personell injured • Minor release of hydrocarbons to environment • Loss of equiqment/production time/well		Likely to be detected. It may be argued that the brute force in the shearing is enough to shear in most cases.
				Offset/buckling drillpipe May occur due to: - drill pipe in compression	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR can shear over entire wellbore - pipe rams and annular preventer may aid in "straightening" the pipe			Macondo demonstrated inability to handle this situation.

Figure B.4: FMECA sheet 4 for Cameron design BSR

				Drillpipe in compression May occur due to: - Drill pipe fall back upon top drive fail - Parting of drill pipe in riser - Flowing and pressurized well	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability	• Some damage to reputation		CSR may be used, the pipe will however not be moved post shearing. The BSR must do the shearing and sealing.
				Non-shearable across BSR • Drill collar • Casing • Tool joint • Other items: Upper completion, lower completion, intervention tool	Detection: - Failure to shear leading to flow through drillpipe not stopping - Operator knows what is run in hole Existing consequence reducing actions: - CSR have increased shearing capability			Drill collar is the most likely problem. Operators takes precautions before running non-shearables through the BOP.
				High grade drill string - Developement of drill string is higher grade drillstring to enhance drilling, especially at greater depths	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability			Marking on drillstrings are not always specific beyond standard marking. This may lead to high ductility and strength drill pipes being used. This must be tested to confirm blind shear rams ability to shear.
				Moving drill string	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability			This should not be a particular problem, there ahs however not been acquired any evidence.
				Flowing well - Late kick detection	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability			Effects of this has not been tested, or simulated extensively to the knowledge of the author. However, MCS Kenny tested it did one simple simulation indicating no issues. Erosion will most likely not be significant due to closing of shear rams in less than 45 seconds (required).

Figure B.5: FMECA sheet 5 for Cameron design BSR

				Differential pressure in drill pipe(significatnt pressure inside drill pipe compared to annulus.	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability			May lead to buckling. Uncertainty is the reason for medium rating.
		3.3	Closes too slowly	Slowed due to shearing activity - Same as causes from failure mode 6.2		Most probable consequence: - Will still close within a time that allows the BSR to perform its function		
				see 1.2	see 1.2	see 1.2		see 1.2
		3.4	Failure to seal the wellbore	Rams unable to meet sufficently - Inadequate fold over bottom fish - too great diameter of tubular, or to thick walled tubular. - high grade tubular	Detection: - Flow not stopping Existing consequence reducing actions: - Fold over design	Worst case consequence: - Cannot seal properly. Flow through rams in high velocity erodes and snowballs into full flow and blowout. Most probable consequence: - Same		
				Damage to sealing components shearing	Detection how(when): - Visual inspection (before BOP is installed on wellhead) - Pressure testing(API: every 14 days, NORSOK D-010: before drilling new section)			
4	Emergency Operation - Emergency disconnect system(EDS) - Shear the drill pipe and then seal the wellbore EDS is activated by operator. The operator may perform certain actions before activation such as positioning tool joints. EDS activates an preprogrammed sequence.	4.1	Failure to close	see 1.1	see 1.1	see 1.1		see 1.1
		4.2	Failure to shear tubular	Damaged blades	Detection how: - Visual inspection (before BOP is installed on wellhead) - Fucntion testing(API: every 21 days, NORSOK D-010: every week)	Worst case consequence: - Loss of containment =>Major blowout • Multiple lifes lost • Major release of hydrocarbons to environment • Loss of equiqment/rig/production time/well • Severely damaged reputation Most probable consequence: - Loss of containment =>Blowout • Personell injured • Minor release of hydrocarbons to environment • Loss of equiqment/production time/well		Likely to be detected. It may be argued that the brute force in the shearing is enough to shear in most cases.
				Offset/buckling drillpipe May occur due to: - drill pipe in compression	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR can shear over entire wellbore - pipe rams and annular preventer may aid in "straightening" the pipe			Operator may be able to perform actions prior to activating EDS to prevent the situation. Needs further testing and/or simulating to conclude.

Figure B.6: FMECA sheet 6 for Cameron design BSR

				Drillpipe in compression May occur due to: - Drill pipe fall back upon top drive fail - Parting of drill pipe in riser - Flowing and pressurized well	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability	• Some damage to reputation		Operator may be able to perform actions prior to activating EDS to prevent the situation. Needs further testing and/or simulating to conclude.
				Nonshearable in wellbore • Drill collar • Casing • Tool joint • Other items: Upper completion, lower completion, intervention tool	Detection: - Failure to shear leading to flow through drillpipe not stopping - Operator knows what is run in hole Existing consequence reducing actions: - CSR have increased shearing capability			Operator may be able to perform actions prior to activating EDS to prevent the situation. Needs further testing and/or simulating to conclude. Operators also check with dynamic positioning operator prior to running these tubulars to prevent this situation
				High grade drill string - Developement of drill string is higher grade drillstring to enhance drilling, especially at greater depths	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability			Marking on drillstrings are not always specific beyond standard marking. This may lead to high ductility and strength drill pipes being used. This must be tested to confirm blind shear rams ability to shear.
				Moving drill string	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability			This should not be a particular problem, there is however not been acquired any evidence.
				Flowing well - Late kick detection	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability			Effects of this has not been tested, or simulated extensively to the knowledge of the author. However, MCS Kenny tested it did one simple simulation indicating no issues. Erosion will most likely not be significant due to closing of shear rams in less than 45 seconds (required).

Figure B.7: FMECA sheet 7 for Cameron design BSR

				Differential pressure in drill pipe(significatnt pressure inside drill pipe compared to annulus.	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability			May lead to buckling. Uncertainty is the reason for medium rating.
		4.3	Closes too slowly	Slowed due to shearing activity - Same as causes from failure mode 7.2		Most probable consequence: - Will still close within a time that allows the BSR to perform its function		
				see 1.2	see 1.2	see 1.2		see 1.2
		4.4	Failure to seal the wellbore	Rams unable to meet sufficently - Inadequate fold over bottom fish - too great diameter of tubular, or to thick walled tubular. - high grade tubular	Detection: - Flow not stopping Existing consequence reducing actions: - Fold over design	Worst case consequence: - Cannot seal properly. Flow through rams in high velocity erodes and snowballs into full flow and blowout. Most probable consequence: - Same		
				Damage to sealing components shearing	Detection how: - Visual inspection (before BOP is installed on wellhead) - Pressure testing(API: every 14 days, NORSOK D-010: before drilling new section)			
5	Open wellbore after closing shear rams	5.1	Failure to open on demand	Generalized lock failure - Mechanical damage to internal components - Corrosion	Detection: - function testing and pressure testing locks are locked Existing consequence reducing actions: - function and pressure test	Worst case consequence: - killing the well if it can not be killed/is not killed • Very costly Most probable consequence: - downtime due to pulling and reparing ram		
				Locked by sheared tubular	Existing consequence reducing actions: - Fold over fish			Not probable. If this occurs most likely the well is not contained and not being able to open the rams is of great concern

Figure B.8: FMECA sheet 8 for Cameron design BSR

Appendix C

En-Tegrity FMECA Spreadsheet

The FMECA performed here is part of the qualification process in Chapter 5. The tables are used to set consequence and frequency ratings in the FMECA.

Table C.1: Failure probability classes for BSR

No.	Description	Frequency/Rig year
1	Less than every 100 years	<1 events every 100 rig years
2	Less than every 10 years	<1 events every 10 rig years
3	Less than once a year	<1 events/rig year
4	Less then once a quarter	<4 events/rig year
5	Once a week or more often	>50+ events/rig year

Table C.2: Failure consequence classes for BSR

nr.	People	Environment	Downtime	Reputation
1	No or superficial injuries	No impact	No downtime	Slight impact
2	Minor injuries	No impact	Downtime less than 24 hours	Limited impact
3	Major injury, lost time	Leakage	Pulling BOP stack	Considerable impact
4	single fatality	More than 100 bbl	Stop drilling, loss of well	National impact and public concern
5	single to multiple fatalities	More than 1000 bbl and severe environmental damage	Stop drilling, loss of rig	Extensive negative attention in international media

		Failure probability				
		1	2	3	4	5
Failure consequence	1	L	L	L	M	M
	2	L	L	M	M	H
	3	L	M	M	H	H
	4	M	M	H	H	H
	5	M	H	H	H	H

Figure C.1: Risk matrix for BSR; L=Low, M=Medium, H=High

	Component Functions		Operational threats and hazards		Barriers	Consequences	Prob. rating	Cons. rating	Risk	Suggested actions and remarks
			Potential failure mode	Potential failure causes						
1	Close and seal on open hole and then seal on open hole This include autoshear and EDS situations where the wellbore is empty	1.1	Failure to close on open hole through blind-shear rams	Mechanical failures: - Corrosion - Debris in system - Damaged internal components	Detection: - Visual inspection (before BOP is installed on wellhead) - Function testing(API: every 21 days, NORSOK D-010: every week)	Worst case consequence: - Loss of containment =>Blowout • Loss of lifes • Release of hydrocarbons to environment • Loss of equiqment/rig/production time/well • Damaged reputation Most probable consequence: - Stabbing of kelly valve or closing of annular preventer contains well • Loss of production time - Found during testing => Maintenance • Loss of production - If drive off or drift off situation • Release of hydrocarbons to marine environment	2	3	M	Likely to be detected before a demand occurs
				Hydraulic failure - Insufficient accumulator pressure	Detection: - Function testing(API: every 21 days, NORSOK D-010: every week) Existing consequence reducing actions: - Standards dictate that shear rams shall close at 90% of maximum available pressure		2	3	M	Likely to be detected before a demand occurs
				Flowing well - Late kick detection	Detection: - Early kick detection		1	3	L	Does not affect the ability to close significantly
		1.2	Closes too slowly - API 53 require closing within: 45 seconds	Insufficient accumulator pressure - Leaking hydraulics - Friction in actuator - Clogging	Detection: - Fucntion testing(API: every 21 days, NORSOK D-010: every week) Existing consequence reducing actions: - Standards dictate that shear rams shall close at 90% of available pressure	Worst case consequence: - If closes to slowly during flowing well there is more time to erode compoents. This may lead to damaged packers and sealing problems Most probable consequence: - Found during testing => Maintenance • Loss of production	2	1	L	Likely to be detected before a demand occurs
				Friction on pistons - Debris	Detection: - Visual inspection (before BOP is installed on wellhead) - Function testing(API: every 21 days, NORSOK D-010: every week)		2	1	L	Likely to be detected before a demand occurs
				Excessive pressure in wellbore - high pressure in the wellbore may inhibit the moving of shear rams	Detection: - well monitoring		2	1	L	Likely to be detected before a demand occurs

Figure C.2: FMECA sheet 1 for En-Tegrity design BSR

		1.3	Unintentional opening/closing	Spurious activation by hydraulics/electronics	Existing consequence reducing actions: - Function testing	Worst case consequence: - Opening prematurely of well that is not killed • blowout • has to close again on flowing well - Closing before tubular is run • tubular hits rams leading to inspection that may require pulling BOP - downtime Most probable consequence: - Close on open hole • has to open again with minimal loss of time. • investigation to why rams are activated	1	3	L	Considered outside the scope as this failure is by the control system
				Human activation	Existing consequence reducing actions: - Procedures - Fear of pressing button in vain		1	2	L	Studies performed by MCS Kenny for BSEE indicate culture where operators fear to press button in vain due to costs if tubing is sheared.
				Lock Failure - Corrosion - Human error	Detection how: - Visual inspection (before BOP is installed on wellhead) - Fucntion testing(API: every 21 days, NORSOK D-010: every week)		1	2	L	Likely to be detected before a demand occurs
3	Emergency Operation - Autoshear - Shear the drill pipe and then seal the wellbore	3.1	Failure to close	Mechanical failures: - Corrosion - Debris in system - Damaged internal components	Detection: - Visual inspection (before BOP is installed on wellhead) - Function testing(API: every 21 days, NORSOK D-010: every week)	Worst case consequence: - Loss of containment =>Major blowout • Multiple lifes lost • Major release of hydrocarbons to environment • Loss of equiqment/rig/production time/well • Severely damaged reputation Most probable consequence: - Loss of containment =>Blowout • Personell injured • Minor release of hydrocarbons to environment • Loss of equiqment/production time/well • Some damage to reputation	2	5	H	Likely to be detected before a demand occurs
				Hydraulic failure - Insufficient accumulator pressure	Detection: - Function testing(API: every 21 days, NORSOK D-010: every week) Existing consequence reducing actions: - Standards dictate that shear rams shall close at 90% of available pressure		2	5	H	Likely to be detected before a demand occurs
		3.2	Failure to shear tubular	Damaged blades	Detection how: - Visual inspection (before BOP is installed on wellhead) - Fucntion testing(API: every 21 days, NORSOK D-010: every week)	Worst case consequence: - Loss of containment =>Major blowout • Multiple lifes lost • Major release of hydrocarbons to environment • Loss of equiqment/rig/production time/well • Severely damaged reputation Most probable consequence: - Loss of containment =>Blowout • Personell injured	1	5	M	Most likely detected. It may also be argued that the brute force in the shearing is enough to shear in most cases
				Offset/buckling drillpipe May occur due to: - drill pipe in compression	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - Full bore coverage		1	5	M	Macondo demonstrated inability to handle this situation.

Figure C.3: FMECA sheet 2 for En-Tegrity design BSR

				Drillpipe in compression May occur due to: - Drill pipe fall back upon top drive fail - Parting of drill pipe in riser - Flowing and pressurized well	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability	• Minor release of hydrocarbons to environment • Loss of equiqment/production time/well • Some damage to reputation	2	5	H	CSR may be used, the pipe will however not be moved post shearing. The BSR must do the shearing and sealing.
				Other tubular than drill pipe across BSR • Drill collar • Casing • Tool joint • Other items: Upper completion, lower completion, intervention tool	Detection: - Failure to shear leading to flow through drillpipe not stopping - Operator knows what is run in hole Existing consequence reducing actions: - CSR have increased shearing capability		3	5	H	Drill collar is the most likely problem. Operators takes precautions before running non-shearables through the BOP.
				High grade drill string - Developement of drill string is higher grade drillstring to enhance drilling, especially at greater depths	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability		3	5	H	Marking on drillstrings are not always specific beyond standard marking. This may lead to high ductility and strength drill pipes being used. This must be tested to confirm blind shear rams ability to shear.
				Moving drill string	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability		1	5	M	This should not be a particular problem, there ahs however not been acquired any evidence.
				Flowing well - Late kick detection	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability		1	5	M	

Figure C.4: FMECA sheet 3 for En-Tegrity design BSR

				Differential pressure in drill pipe	Detection: - Failure to shear leading to flow through drillpipe not stopping Existing consequence reducing actions: - CSR have increased shearing capability		1	5	M	Effects of this has not been tested, or simulated extensively to the knowledge of the author.
		3.3	Closes too slowly	Slowed due to shearing activity - Same as causes from failure mode 6.2		Most probable consequence: - Most likely the it will still close within a time that allows the BSR to perform its function	3	3	M	
				see 1.2	see 1.2	see 1.2			L	see 1.2
		3.4	Failure to seal the wellbore	Rams unable to meet sufficently - Crushed drill pipe may block for complete closure - high grade tubular	Detection: - Flow not stopping Existing consequence reducing actions: - Fold over design	Worst case consequence: - Cannot seal properly. Flow through rams in high velocity erodes and snowballs into full flow and blowout. Most probable consequence: - Same	3	5	H	
				Damage to sealing area due to scarping of surface during shearing	Detection how(when): - Visual inspection (before BOP is installed on wellhead) - Pressure testing(API: every 14 days, NORSOK D-010: before drilling new section)		1	5	M	
5	Open wellbore after closing shear rams	5.1	Failure to open on demand	Generalized lock failure - Mechanical damage to internal components - Corrosion	Detection: - Function testing and pressure testing locks are locked Existing consequence reducing actions: - Function and pressure test	Worst case consequence: - Killing the well if it can not be killed/is not killed • Very costly Most probable consequence: - Downtime due to pulling and reparing ram	1	2	L	

Figure C.5: FMECA sheet 4 for En-Tegrity design BSR

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