SINTEF A22763 Unrestricted

# Report

## Barriers to prevent and limit acute releases to sea

Environmental barrier indicators

**Author(s)**
Stein Hauge
Solfrid Håbrekke
Tony Kråkenes
Mary Ann Lundteigen
Mariann Merz

**SINTEF Technology and Society**
**Safety Research**
August 2012

SINTEF Teknologi og samfunn
SINTEF Technology and Society

Address:
Postboks 4760 Sluppen
NO-7465 Trondheim
NORWAY

Telephone:+47 73593000
Telefax:+47 73592896

ts@sintef.no
www.sintef.no
Enterprise /VAT No:
NO 948007029 MVA

KEYWORDS:

# Report

## Barriers to prevent and limit acute releases to sea

Environmental barrier indicators

**VERSION**
1.0

**DATE**
2012-08-15

**AUTHOR(S)**
Stein Hauge, Solfrid Håbrekke, Tony Kråkenes, Mary Ann Lundteigen, Mariann Merz

**CLIENT(S)**
Multiclient

**CLIENT'S REF.**
Håkon S Mathsien

**PROJECT NO.**
60S051

**NUMBER OF PAGES/APPENDICES:**
89 incl. appendices

**ABSTRACT**
This report summarizes the work performed in PDS-BIP activity 2: "Environmental barrier indicators".

The purpose of the present report is to propose a set of suitable indicators for a specified drilling scenario and to describe a methodology for developing such indicators.

**PREPARED BY**
Stein Hauge et al.

SIGNATURE
Stein Hauge

**CHECKED BY**
Tor Onshus

SIGNATURE

**APPROVED BY**
Lars Bodsberg, Research Director

SIGNATURE

| REPORT NO. | ISBN | CLASSIFICATION | CLASSIFICATION THIS PAGE |
|---|---|---|---|
| SINTEF A22763 | 978-82-14-05396-8 | Unrestricted | Unrestricted |

# Document history

| VERSION | DATE | VERSION DESCRIPTION |
|---|---|---|
| Version No. 1.0 | 2012-05-04 | Draft version for PDS member comments |
| Version No. 1.1 | 2012-08-15 | Final version for distribution |

# Table of contents

# Summary and conclusions

This report has been developed as part of the on-going joint-industry project "Development of barriers and indicators to prevent and limit pollutants to sea", funded by the Norwegian Research Council and the members of the PDS forum[1]. The work has mainly been carried out by SINTEF and may therefore not express the view of all the PDS participants.

Investigation reports following the Deepwater Horizon accident and other well control incidents/accidents have pointed at lack of control with the integrity of key safety barriers as one of the important underlying failure causes. This finding resulted in the following recommendation in BP's own investigation report after Deepwater Horizon (BP, 2010):

> *Establish leading and lagging indicators for well integrity, well control and rig safety critical equipment (p. 184 in report).*

As a result of findings from accident and incident reports there is generally an increasing focus in the petroleum industry on barriers and barrier management. E.g. the PSA Norway has pointed out barriers as one of their main priority areas (PSA, 2011). This increased focus should also be beneficial with respect to introducing separate barrier indicators, which can be seen as one of several tools to systematically follow-up the barriers.

The purpose of the present report is to propose a set of suitable indicators in relation to some of the safety barriers that have a key role in the prevention of environmental releases. A drilling scenario has been considered and focus has been on barriers that are implemented to prevent releases during drilling rather than on measures that mitigate the consequences once a release has occurred. The report also describes a methodology for developing such indicators.

For the purpose of developing indicators, a relatively pragmatic approach has been chosen. As described in Chapters 2, 3 and 4, an *event tree* combined with barrier element diagrams are used. The event tree has been applied in order to model a typical kick/blowout scenario and illustrate the relationship between the relevant barrier elements. The event tree also serves as a means of identifying the relative importance of the barrier functions. *Barrier element diagrams* have been applied to illustrate factors that, on an overall level, influence the status and performance of the barriers. Then, *expert judgements* have been applied to identify more detailed factors that influence the reliability of barriers/functions and how these factors could be measured / monitored.

The suggested indicators for selected barrier functions are listed in the table below. For a somewhat more detailed discussion of the barriers and the barrier selection criteria, reference is made to Chapter 5.

[1] PDS is a Norwegian acronym for "reliability of safety instrumented systems". For more information about PDS see: www.sintef.no/pds

**Table 0-1: List of suggested indicators**

| No. | Indicators for "early kick detection" function (barrier function 1) | Unit |
|---|---|---|
| 1.1 | Time since last test / calibration of kick detection sensors (e.g. level sensors in pit tank and flow rate sensors) | Months |
| 1.2 | Average number of active mud pits/tanks since drilling start-up | Number |
| 1.3 | Fraction of spurious alarms (to the total number of alarms) | % |
| 1.4 | Number of formal verification meetings between mud logger and driller (to number of drilling days) | Ratio |
| **No.** | **Indicators for "BOP annular preventer seals" function (barrier function 2)** | |
| 2.1 | Fraction of failed functional tests (both closure tests and pressure tests) to the total number of tests | % |
| 2.2 | Fraction of repeated failures revealed during testing and maintenance (to the total number of revealed failures) | % |
| 2.3 | Number of stripping operations during lifetime of BOP | Number |
| **No.** | **Indicators for "heavy mud to kill well" function (barrier function 3)** | |
| 3.1 | Time since last functional test of essential choke and kill line assemblies | Months |
| 3.2 | Average amount of spare mud available throughout the operation | $m^3$ |
| 3.3 | Average number or fraction of mud and cement pumps out of service throughout the operation | Number or % |
| **No.** | **Indicators for "shear ram cuts and seals" function (barrier function 5)** | |
| 5.1 | Fraction of failed functional tests of shear ram (both closure tests and pressure tests) to the total number of tests | % |
| 5.2 | Fraction of repeated failures revealed during testing and maintenance (to the total number of repeated failures) | % |
| 5.3 | Service life of shear ram – time since last cutting verification | Months |
| **No.** | **General indicators** | |
| G.1 | Number of deviations from original "detailed drilling program" handled onshore (e.g. during last three months) | Number |
| G.2 | Number of deviations from original "detailed drilling program" handled offshore (e.g. during last three months) | Number |

# 1 Introduction

## 1.1 Background

Kongsberg Maritime has on behalf of the PDS Forum members been awarded funding from the Norwegian Research Council to complete a project called ”*Utvikling av barrierer og indikatorer for å hindre og begrense miljøutslipp til sjø*” (translates into “Development of barriers and indicators to prevent and limit pollutants to sea”). A brief summary of the work to be completed as part of this project is shown in Table 1-1 and in Figure 1-1.

The focus of this report is on activity 2; “Environmental barrier indicators”. The other activities in the PDS-BIP project will be addressed in separate SINTEF reports or memos. In particular, activity 1 is documented in the report **“***Barriers to prevent and limit acute releases to sea – Environmental acceptance criteria and requirements to safety systems*” (SINTEF, 2011b).[2]

**Table 1-1: Overview of activities in the PDS-BIP project**

| Project Title:<br>Development of barriers and indicators to prevent and limit pollutants to sea | | | |
|---|---|---|---|
| **Main Activity** | | **Sub-Activity** | |
| 1 | Environmental acceptance criteria and technical and operational requirements to safety systems | 1.1 | Mapping and development of environmental acceptance criteria |
| | | 1.2 | Technical and operational requirements to systems |
| **2** | **Environmental barrier indicators** | **2.1** | **Development of indicators for environmental barriers and follow-up of the indicators** |
| 3 | Developing analytical tools and guidelines for estimating the reliability of barrier functions to avoid environmental releases | 3.1 | Input to OLF-070 update |
| | | 3.2 | PDS method handbook 2013 |
| | | 3.3 | PDS data handbook 2013 |
| | | 3.4 | PDS example collection |
| | | 3.5 | PDS tool |
| 4 | Publication of results and project information | | Reports, memos, papers, articles, web, participation in standardisation work, etc. |

[2] This report can be downloaded from the PDS webpages: http://www.sintef.no/pds

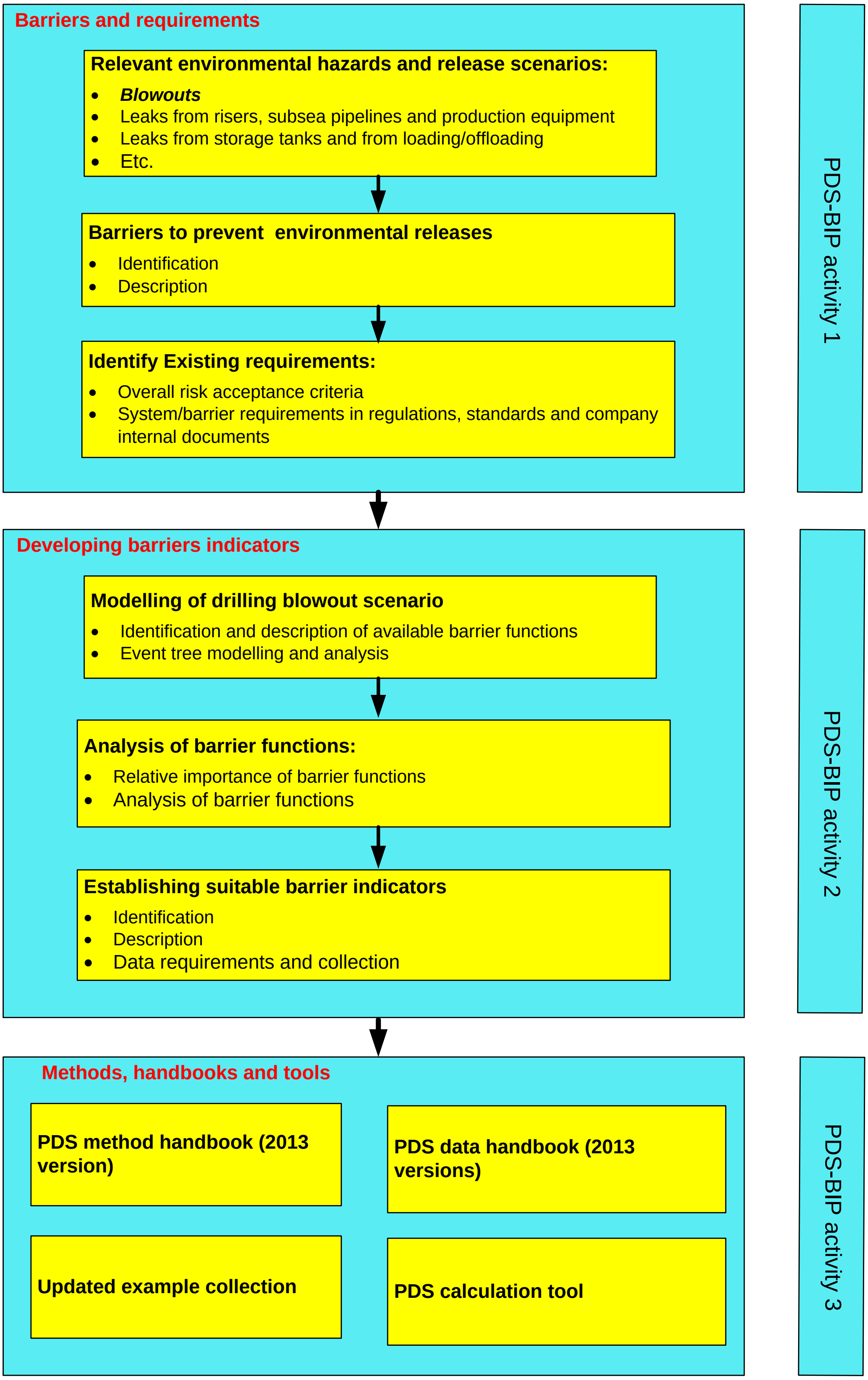


**Figure 1-1: Overall PDS-BIP approach**

## 1.2 Scope of present activity

This report documents the work performed as part of the project activity "*development of environmental indicators*". The purpose of this activity has been to propose a set of suitable indicators in relation to those safety barriers that have a key role in the prevention of environmental releases. The indicators address functional as well as reliability performance. The focus in this activity has been on barriers that prevent releases rather than on barriers that mitigate the consequences once a release has occurred.

The main steps in the development of these indicators:

1. Identify possible critical events that may lead to environmental releases
2. Prioritize critical events and identify initiating event.
3. Establish a simplified event tree to identify possible event sequences and the associated barrier functions
4. Describe the barriers in some more detail with respect to main function, constituting elements, requirements, factors influencing the performance of the barriers and obtain an estimate of the reliability.
5. Use the estimated reliability of the barrier function and the simplified event tree to identify the relative importance of the barriers with respect to blowout risk.
6. Based on the above steps propose indicators suitable to measure the status of the most important barriers and barrier elements. The indicators should fulfil a set of defined criteria (e.g. measureable, correlated to safety, etc.)
7. Identify the type of data needed to measure (quantitatively or qualitatively) the indicators, and in particular, to indicate to what extent such data is available today. Indicate an approach for data collection, technology/systems to be used, collection intervals, quality assurance, etc.

The methodology for establishing barrier indicators, i.e. step 1 – 6 above, is more thoroughly described in Chapter 2.

## 1.3 Limitations

Acute environmental releases may be due to a number of accident scenarios like e.g. blowouts (from drilling and well intervention activities), pipe leaks, ship collisions, releases from storage tanks and releases during loading/offloading. Within the scope of this project it was not feasible to develop environmental indicators for the critical safety barriers for all possible release scenarios. In order to generate a useful contribution in the effort of developing environmental indicators, it was decided to focus on one specific operational scenario that we judged to have high priority. In this document, we restrict ourselves to blowouts that occur during (bottom-hole) drilling activities, both due to the large potential consequences from a blowout and since this operation involves a number of the most critical safety barriers available during drilling.

The present document focuses on barriers that are, at least partly, implemented by instrumented/programmable electronic technology, and as such relevant for the PDS-BIP project. Physical well barriers like casing and cement are not included in this indicator study.

## 1.4 Abbreviations

Below is a list of abbreviations used in this report:

| | | |
|---|---|---|
| ALARP | - | As Low As Reasonably Practicable |
| BIP | - | *Brukerstyrt innovasjonsprosjekt*. Translates into “User directed innovation project” which represents a type of research activity that is funded by The Research Council of Norway |
| BOP | - | Blowout Preventer |
| BSR | - | Blind Shear Ram |
| CSU | - | Critical Safety Unavailability |
| DHSV | - | Downhole Safety Valve |
| EIL | - | Environmental Integrity Level |
| IL | - | Integrity Level |
| LOPA | - | Layer Of Protection Analysis |
| MIRA | - | *Metode for miljørettet risikoanalyse*. Translates into ”Method for environmental risk analysis” |
| MoC | - | Management of Change |
| NCS | - | Norwegian Continental Shelf |
| NORSOK | - | *Norsk sokkels konkurranseposisjon*. Translates into ”The competitive position of the Norwegian continental shelf” |
| OLF | - | *Oljeindustriens landsforening*. Translates into ”The Norwegian Oil Industry Association” |
| PDS | - | *Pålitelighet av datamaskinbaserte sikkerhetssystemer*. Translates into “Reliability of safety instrumented systems”. Refers to a reliability prediction method for safety instrumented systems developed by SINTEF in co-operation with the Norwegian petroleum industry |
| PFD | - | Probability of Failure on Demand |
| PSA | - | Petroleum Safety Authority |
| SIF | - | Safety Instrumented Function |
| SIL | - | Safety Integrity Level |
| SIS | - | Safety Instrumented System |

A list of relevant definitions is included in Appendix A.

# 2 Methodological Approach

The purpose of this chapter is to explain the method for selecting barrier indicators. A stepwise approach has been applied as described in the following sections:

- *Step 1*: Identify possible critical events that may lead to environmental releases.
- *Step 2*: Select critical scenario and identify initiating event
- *Step 3*: Establish a simplified event tree to identify likely event sequences and the associated barrier functions.
- *Step 4*: Perform an analysis of the relevant barrier functions to identify weaknesses and an estimated reliability
- *Step 5*: Assess the relative performance of the barrier functions by performing event tree analysis
- *Step 6*: Propose barrier indicators based on findings from above steps.

## 2.1 Step 1: Identify possible critical events that may lead to environmental releases

In the report from PDS-BIP activity 1, **"***Barriers to prevent and limit acute releases to sea – Environmental acceptance criteria and requirements to safety systems*" (SINTEF, 2011b.), the following critical events for loss of containment were identified:

A. Blowouts and well releases during exploration and production drilling
B. Blowouts and well releases during wireline and coiled tubing operations
C. Riser and pipeline leaks
D. Process leaks, both from topside and subsea production equipment
E. Releases from storage tanks
F. Releases when loading/offloading oil
G. Releases initiated from other accidents (e.g. fire, explosion, structure loss, collision, etc.)

In order to cover all the critical events listed above, a large number of operations would need to be studied in detail in order to analyse the primary safety barriers for each scenario and to identify suitable indicators for these. In order to limit the scope of the project but at the same time deliver a useful input, it was decided to analyse one critical scenario in detail (described under Step 2), and to thoroughly document the method that was used so that it could easily be adapted to other critical scenarios.

## 2.2 Step 2: Select critical scenario and identify initiating event

In this report, we have focused on addressing the barriers that prevent blowouts during subsea drilling when the drill bit is positioned at the bottom of the hole. This particular scenario was selected for the following reasons:

- It was judged by the study participants to represent the critical scenario with the highest potential for a large environmental spill that could be prevented by careful monitoring and management of *instrumented* barrier functions
- It represents the "normal" drilling scenario on the Norwegian shelf today
- Drilling scenarios are believed to carry large environmental risk due to their dynamic nature
- Analysis of drilling activities is still a relatively immature area and has also been made more relevant due to the Deepwater Horizon accident and other recent well control incidents on the NCS.

After selecting the particular analysis scenario, the initiating event must be identified. The “starting point” for a possible blowout will be a well kick, i.e. an influx of formation liquids or gas into the well.

## 2.3 Step 3: Establish a simplified event tree to identify sequences and barrier functions

In order to prevent a kick from developing into a critical event (here a blowout), a number of safety barriers are in place. The functions of these barriers are both to detect a kick when it occurs and further to act upon the kick to prevent any further escalation of the hydrocarbon influx to the environment.

Identification and description of barrier functions related to a possible blowout during bottom-hole drilling were partly done as a part of PDS-BIP activity 1 (SINTEF, 2011b) and has been used as input in the present activity. In order to ensure that all the likely event sequences have been addressed, an event tree has been established. Different event sequences may develop based on the successful (or unsuccessful) operation of the barrier functions. Here, an event sequence is defined as a chain of events, including system failures, that starts with an initiating event and ends with a certain outcome in relation to the critical event. Hence, several event sequences may be associated with one initiating event.

The starting point of an event tree is not unique, and what to use as the initiating event is often closely related to the study objective. In some assessments it may be relevant to start with the critical event itself (like blowout) and use the event tree to analyse the subsequent outcomes with respect to potential consequences and damages to the environment. Barriers of interest are then contingency measures used to limit the impact of the critical event (such as well capping, oil collection / dispersion and drilling of a relief well).

In this project, however, we focus on the prevention of releases. As discussed under Step 2, a well kick has been identified as the initiating event and blowout becomes a possible outcome. The event tree is used to indicate which of the barriers are available depending on the sequence of events.

The event tree can be constructed based on expert inputs, lessons learnt from previous accidents, experience from previous analyses of similar scenarios and methods like hazards and operability studies (HAZOP). In this report we have based the event tree primarily on discussions with drilling experts, small workshops and seminars and studies of relevant reports.

Based on this process, the following barrier functions have been identified and are further studied in this report:

- Kick detection
- Closure of BOP annulus preventer(s)
- Circulation of heavier mud to kill well
- Closure of Drill string safety valve
- BOP shear ram cuts and seals hole
- Diverter system directs flow away from installation

Note that the barrier functions are identified in an iterative process by asking “what events, technical systems, or human interaction may impact the development of the accident scenarios?” The barrier functions are described in more detail in Appendix B and Appendix C.

Additional details on the development of a simplified event tree for the selected scenario are provided in Chapter 3.

## 2.4 Step 4: Perform an analysis of relevant barrier functions

An event tree analysis is often performed in combination with a more detailed analysis of the performance of the barrier functions that make up the "branches" of the event tree. The detailed analysis may be based on fault trees, reliability block diagrams and/or influence diagrams, in combination with historic data and scenario-specific conditions. It is important to note that the performance of a barrier function at a specific branch point is *conditional*, i.e. influenced by the earlier events. The performance associated with a particular barrier function may differ from one event sequence to another, even if the functions are composed of the same technical components and operated by the same personnel. For example, successful control of a kick by pumping heavy mud into the well depends on when the kick is detected.

The event tree starts with a kick, and identifies the subsequent barriers that are available, depending on the performance of previous barriers. For each barrier, the barrier function is briefly described in terms of required action (role), main components (i.e. barrier elements), and requirements to testing of the barrier elements (whenever applicable). Also, simple barrier models have been constructed, showing the main barrier elements needed to perform the barrier function. It is important to identify to what extent the performance of barrier functions is independent from the initiating event. If a failure of a barrier function is *the direct cause* of the initiating event, the barrier function may be unable to perform in response to the same initiating event (e.g. a failure of the hydrostatic mud column may influence the ability to kill the well with heavier mud).

The conditional failure probabilities associated with each barrier function are roughly estimated. Historical databases and reports are investigated to identify information about their *experienced* reliability performance. Since historic data are seldom broken down to a sufficiently detailed component level, it is not possible to suggest that the reliability estimates are more than "rough estimates", averaged over a number of possible demand conditions. Normally, reports and historical data do not provide information that can be used to adjust the barrier performance to the specific scenario in question. Expert opinions are therefore used to adjust the rough estimate of experienced performance, based on foreseen influences from the scenario specific conditions.

Additional details on the barrier function analysis for the subsea bottom-hole drilling kick event are provided in Appendix C.

## 2.5 Step 5: Assess the relative performance of the barrier functions by performing event tree analysis

After establishing the event tree and the conditional failure probabilities of the barrier functions (i.e. the branches in the event tree), it is clear that a number of outcomes result (in this case study numbered from A to O). The severity of the outcomes varies from full blowout to successful control of the kick. It is recognized that the environmental risk associated with a given outcome may include the following two elements:

- Potential amount of released hydrocarbons to the environment
- Residual risk, i.e. risk associated with full recovery from the outcome of the particular critical event. Prior to the re-establishment of all the well barriers, steps are taken which may give rise to a new loss of containment situation

To rank the severity of the outcomes, it is suggested that both factors are accounted for by using two "weight factors" $C_{Env}$ and $C_{RR}$ for release volume and residual risk respectively.

The relative importance of the barrier functions is not a function of the severity alone, but can be further understood by performing sensitivity analysis, for instance:

- How the blowout frequency changes when changing the PFD of the barrier functions
- How the risk changes when changing the PFD of the barrier functions
- Etc.

It should be noted that barrier function analysis (step 4) and event tree analysis (step 5) is part of an iterative process.

Additional details on the event tree analysis for the selected drilling scenario are provided in Chapter 4.

## 2.6 Step 6: Identify barrier indicators

A safety indicator can be defined as an observable and measurable variable quantity that can be used to monitor the risk. In this project indicators provide a means of monitoring the status and performance of the most important barrier functions applied during drilling. Some important criteria for a good indicator will be measurability, that it should be linked to the *integrity* of a barrier function and that it may change over time (so that changes in barrier performance can be revealed).

Integrity is a concept that is sometimes used to characterize a sound, unimpaired, or perfect condition of a system. In relation to barrier functions, where the main purpose is to ensure safe operation, the term safety integrity has been widely adopted (ref: IEC standards). According to IEC 61511, safety integrity is defined as "*average probability of a safety instrumented system satisfactorily performing the required safety instrumented functions under all the stated conditions within a stated period of time*". For repairable systems, which include all the barrier functions of interest during drilling operations, availability (or lack of availability) is used to measure safety integrity. Within this context, barrier indicators are needed to support the early detection of barrier impairment, i.e. a potential reduction in the availability of a barrier function.

When identifying barrier indicators, it is distinguished between leading and lagging indicators and also between general indicators, scenario based indicators, and indicators based on specific reliability parameters. These concepts are further discussed in Chapter **Error! Reference source not found.**.

Additional details on the identification and follow-up of barrier indicators for the subsea bottom-hole drilling kick event are provided in Chapter I.A.1.a)(1)D and 5 respectively.

# 3 Establish event tree to identify possible event sequences and associated barriers

In this chapter an event tree is constructed to indicate how the performance of the relevant safety-critical system may influence the development of a blowout after a kick has occurred. The primary purpose of the coarse event tree analysis is to gain additional insight into the possible event sequences associated with a subsea bottom-hole drilling kick scenario, to clearly identify the barriers in place to prevent or minimize the release of hydrocarbons to the environment.

In order to help construct the event tree for a given accident scenario, it has proved useful to engage a small team of experts from relevant disciplines to ensure that all eventualities are considered. While some simplifications of the event sequences will typically be necessary, it is critical to capture the outcomes that have a significant likelihood of occurring. In this particular study, experts that were consulted included personnel from the safety discipline, a BOP system expert and subsea engineers with extensive drilling experience.

## 3.1 Event tree for subsea kick event (bottom-hole drilling scenario)

A hazardous kick event starts upon influx of hydrocarbons from the formation into the well. This occurs when the formation pressure exceeds the wellbore pressure, leading to an unplanned flow of formation fluid into the wellbore. The underlying causes may be a sudden and unexpected change in the formation pressure, insufficient pore pressure predictions and/or insufficient mud weight, or a technical failure of the mud circulation system.

A kick may, in the worst case, cause hydrocarbons to flow through the drill string or the annular all the way up to the installation, and ultimately be released to the environment. A kick can have several possible outcomes, based on the successful or unsuccessful response by the BOP and other key systems. Additional safety-critical systems that may save the installation, like fire and gas system, ventilation system, firewater system, etc. have not been included since the scope of this analysis is limited to environmental risk and focus is on barriers implemented to prevent a release.

As discussed in Appendix B.5, the main function of the diverter system is to protect on-board personnel by directing the flow of hydrocarbons to the sea. In this study the diverter function is included primarily to ensure that personnel are able to perform required actions to limit the environmental impact. If the drill pipe is full of gas and circulation of heavy mud is required in order to stabilize the well, it is assumed that the gas must be vented over board for the platform personnel to be able to perform mud circulation.

Also, for the purposes of this analysis, the mud circulation function assumes that heavy mud is pumped into the well and that gas and light mud is allowed to exit through the choke lines. While it may be possible to kill the kick without opening the choke valve to allow circulation, this is a procedure (bull heading) that on its own carries significant risk. Note that mud circulation can be a lengthy process that can cause significant wear on the preventers and valves and in the worst case itself be the cause of component failures.

**Figure 3-1** illustrates the event tree and the possible outcomes from a kick event depending on whether the barrier function works successfully (Y=Yes) or not (N=No).


**Figure 3-1: Event tree for drilling operation**

A summary of the *assumptions and limitations* underlying the event tree is given below:

- It is assumed that normal bottom hole drilling operation is in progress at the onset of the kick event. If a different type of operation is on-going, additional recovery steps or a different sequence of steps may be required
- Early kick detection is assumed to influence the reliability of the BOP annular preventer. In case of flowing well and gas in riser a higher failure probability of the BOP is assumed than if the kick is detected early and the BOP annular preventer is closed before any hydrocarbons enter the riser.
- In order to enable circulation with heavier mud it is assumed that the BOP annular preventer must be closed successfully
- If the BOP annular preventer fails to close it is assumed that the operator shall activate the BOP shear ram.
- Upon late kick detection and hydrocarbons in the riser, it is assumed that the diverter system shall be activated and the hydrocarbons vented over board before platform personnel is able to perform mud circulation
- If circulation of heavy mud in unsuccessful, but the annular preventer is closed, the drill string safety valve if first attempted closed. Upon failure of the drill string safety valve, the BOP shear ram is assumed activated.
- The event tree illustrates a simplified event sequence. In particular, some end states represent a situation where the kick event is temporarily under control but not necessarily where all the risk introduced by the kick event has been removed. I.e. there may be additional recovery steps required in order to return the normal well operations.

## 3.2 Main barrier functions for subsea kick event

As illustrated in the event tree in **Figure 3-1**, the main barrier functions in a subsea kick situation includes the following:

1. Hydrocarbon inflow is detected before it reaches BOP (early kick detection)
2A. BOP seals annulus with all hydrocarbons below BOP (i.e. given successful kick detection)
2B. BOP seals annulus with flowing hydrocarbons in riser (i.e. early kick detection has failed)
3. Mud with appropriate weight is pumped into well and the choke lines vent gas and light mud from well
4. Drill string safety valve closes drill string
5A. Shear ram cuts and seals well – no flow through BOP
5B. Shear ram cuts and seals well – flow through BOP
6. The diverter valve opens to vent gas and mud away from installation

While barrier functions 2A and 2B and also barrier functions 5A and 5B represents the same function (i.e., the same equipment), they are given a unique number in order to recognize that the reliability of the function is assumed to depend on the preceding events, i.e. the initial conditions for the barrier function is not the same between the A and B scenarios.

It should be noted that several of the barrier functions are performed by the same safety-critical systems, and thus will have shared components. One example is the BOP control systems (blue and yellow POD), which are common to barrier functions 2 and 5. A BOP seal failure that is caused by a loss of hydraulic pressure or a control pod failure will also prevent the normal activation of the shear ram. However, BOP systems that are built according to NORSOK requirements can operate the shear ram by an acoustic back-up system. It is however important to note that the barrier functions included in the event tree are not to be considered as fully independent.

Each barrier function is considered in additional detail in Appendix C.

## 3.3 Possible outcomes for subsea kick event

As illustrated in the event tree in **Figure 3-1**, the possible outcomes resulting from the kick event are:

A. Well in balance with proper mud weight (open hole stable).
B. Kick is killed, but gas is trapped below BOP and in drill pipe. The initial gas in the riser will be lost to the environment.
C. All well fluids are contained, but gas is trapped below shear ram.
D. **Blowout** through drill pipe.
E. All well fluids are contained, but gas is trapped below shear ram.
F. Full **blowout**.
G. Well in balance with proper mud weight. The initial gas in the riser is lost to the environment.
H. Kick is killed, but gas is trapped below BOP. The initial gas in the riser is lost to the environment.
I. Kick is killed, but gas is trapped below shear ram. The initial gas in the riser is lost to the environment.
J. **Blowout** through drill pipe.
K. Kick is killed, but gas is trapped below BOP and in drill pipe. The initial gas in the riser will be lost to the environment.

L. Kick is killed, but gas is trapped below shear ram. The initial gas in the riser is lost to the environment.
M. **Blowout** through drill pipe.
N. Kick is killed, but gas is trapped below shear ram. The initial gas in the riser is lost to the environment.
O. Full **blowout**.

Outcome A represents the normal and desired outcome of a kick situation. The other outcomes result in more or less undesired situations; ranging from a full blowout of well fluids to the environment (outcomes F and O) to less critical outcomes where some gas is trapped in the drill pipe, however leaving the well in a state where some action may be required before operations can be safely resumed. Rather than introducing much added complexity to the event tree by including functions necessary to circulate out trapped gas below BOP and to fully stabilize the well, the residual consequences associated with these outcomes have been modelled by an additional consequence parameter as discussed in Chapter 4.

In order to obtain a quantitative comparison of the likelihood of the different outcomes, it is necessary to have a rough estimate for the expected performance of the different barrier functions. This has been addressed in Appendix C and the results from these quantifications are applied in the event tree analysis in Chapter 4.

# 4 Risk Modelling for Subsea Drilling – Event Tree Analysis

Based on the event tree developed in Chapter 3 and the rough probability assessment of each barrier function from Appendix C, it is possible to make a comparison of the relative importance of the barrier functions. The quantitative results should only be treated as indicative, since e.g. impact of system dependencies is not well captured in the analysis. However, the results can be used as a basis to identify possible indicators as discussed in Chapter I.A.1.a)(1)D.

## 4.1 Risk estimation based on the event tree

The primary objective of the method outlined in this section is to obtain a rough estimate of the contribution from each barrier function to the overall risk associated with the drilling operation. A more detailed and accurate approach has been rejected for two main reasons:

1) A general lack of reliability data for a majority of the barrier elements.
2) The detailed implementation of the barrier functions are proprietary information and will also vary significantly from one well to the next.

Coming up with a "complete" generic industry representation of all details related to a potential kick and blowout scenario is therefore not considered possible within the scope of this project. However, an effort has been made to identify areas that may be studied in more detail in future projects/efforts, and these will be summarized in the conclusions to this document. As part of this work, components and systems for which reliability data is missing have been identified and summarised. This will also be important input to future updates of the PDS data handbook (SINTEF, 2010b).

### 4.1.1 Risk model

The quantitative event tree analysis requires conditional probabilities for each of the safety-critical systems' ability to function when demanded. The conditional probabilities may be found by calculating the average probability of failure on demand (PFD) for each of the barrier functions, bearing in mind the operating conditions that apply at the time of the demand. For example, the annular preventer may be more likely to close if a kick is detected early (before reaching the BOP) than if the kick is detected late (i.e. after the hydrocarbons have passed through the BOP or reached the rig). In this report, the PFD for each barrier function has been estimated based on available data from studies discussed in Appendix C.1, based on the PDS method (SINTEF, 2010) and data from the PDS data handbook (SINTEF, 2010b) or based on conservative judgement by experts in the field. Seminars with drilling/well personnel have been conducted and have been an important source for the expert judgements. The estimated PFD values used in the calculations are summarized in Table 4-1. Additional justification for the selection of these values can be found in Appendix C.

**Table 4-1: Assumed barrier function failure probabilities**

| # | Barrier Function | PFD | Ref |
|---|---|---|---|
| 1 | Gas inflow is detected before it reaches BOP | 0.05 | Appendix C.2.5 |
| 2A | BOP seals and HC is trapped in well below BOP | 0.013 | Appendix C.3.5 |
| 2B | BOP seals, but HC in riser above BOP | 0.05 | Appendix C.3.5 |
| 3 | Mud with appropriate weight into well and choke line vents | 0.2 | Appendix C.4.5 |

| # | Barrier Function | PFD | Ref |
|---|---|---|---|
| | gas and light mud from well | | |
| 4 | Drill string safety valve closes drill pipe | 0.012 | Appendix C.5.5 |
| 5A | Shear ram cuts and seals well before HC has reached BOP | 0.06 | Appendix C.6.5 |
| 5B | Shear ram cuts and seals well, flow in riser | 0.11 | Appendix C.6.5 |
| 6 | Diverter system diverts hydrocarbons/mud away from the platform | 0.10 | Appendix C.7.5 |

Risk is a function of both probability and consequence. Since the objective of this analysis is to quantify the importance of each well barrier function in terms of their contribution to environmental risk, an environmental consequence factor ($C_{Env}$) has been applied to sufficiently "penalize" the outcomes that result in immediate spills to the environment. To better reflect the risks involved, the most critical outcomes therefore result in a relatively larger "environmental penalty" in terms of scoring of the consequence parameter $C_{Env}$ as shown in Table 4-2.

**Table 4-2: Definition of consequence classes and related immediate consequence parameter ($C_{Env}$)**

| Consequence class | Potential released volume of oil to sea | Immediate consequence parameter $C_{Env}$ |
|---|---|---|
| No harm | 0 | 0 |
| Minor harm | < 10 $m^3$ | 1 |
| Moderate harm | 10–100 $m^3$ | 10 |
| Significant harm | 100–1000 $m^3$ | 100 |
| Major harm | > 1000 $m^3$ | 1000 |

The following assumptions are here made:

- A blowout through the drill string is assumed to have a potential to cause releases ranging from 100–1000$m^3$ and is given a "consequence weight" of 100
- A full blowout is assumed to have a significantly higher release potential (>1000$m^3$) and is given a "consequence weight" of 1000

As indicated in the event tree, the severity of a blowout may differ, depending on which of the safety-critical systems that have failed to perform as intended. For some of the events where the kick is stopped ("killed"), additional operations are required in order to return the well to a normal state and to restore the required well barriers. These potentially risk-prone operations have not been explicitly modelled in the event tree, but in order to reflect the risk associated with non-standard well recovery operations, a residual consequence parameter $C_R$ has been defined (Table 4-3).

**Table 4-3: Definition of residual consequence parameter ($C_R$)**

| Outcome | | Complexity of actions required to return well to "normal" | Residual consequence parameter $C_R$ |
|---|---|---|---|
| A, G | Well in balance with proper mud weight | No actions required | 0 |
| B, H, K | HC trapped below BOP annular preventer | Low complexity actions | 1 |
| C, D, E, I, | HC trapped below BOP | High complexity actions | 10 |

| | | | |
|---|---|---|---|
| J, L, M, N | shear ram | | |
| F, O | Full blowout | Complete damage potential already materialised | 0 |

The resulting "penalty" associated with immediate environmental consequence and residual consequences for an outcome *i* is calculated as follows:

$$W_i = (C_{Env})_i + (C_R)_i$$

The probability of each outcome can be calculated given the probabilities associated with the branches in the event tree. The outcomes of each branch point are determined by a) the probability of failure to perform on demand (PFD) or b) the probability of successful performance (1-PFD) for the specific function in question. The probability of the final outcome is determined by multiplying the corresponding probabilities for the branches leading up to it. By factoring in the consequences (immediate and residual) for each outcome, the associated risks can be compared and the criticality of each branch assessed. For instance for outcome *A*, the barrier functions 1, 2A and 3 are in action, so the associated risk $R_A$ becomes:

$$W_A = (C_{Env})_A + (C_R)_A$$
$$R_A = W_A \cdot (1 - PFD_1) \cdot (1 - PFD_{2A}) \cdot (1 - PFD_3)$$

Similarly, the associated risk for outcome *B* is:

$$W_B = (C_{Env})_B + (C_R)_B$$
$$R_B = W_B \cdot (1 - PFD_1) \cdot (1 - PFD_{2A}) \cdot PFD_3 \cdot (1 - PFD_4)$$

The total risk associated with the kick is the sum over all the outcomes A–O, i.e.:

$$Risk = \sum_{i=A}^{O} R_i$$

Note that the *absolute value* of the risk will be a more or less "fictive" figure since it will be a function of the "environmental weights" allocated to each outcome. Also note that the risk model above does not take into account the fact that the barrier/safety functions are not completely independent. Hence, these factors must be catered for in the qualitative evaluation and discussion of the results.

### 4.1.2 Risk associated with outcomes

The risk for each possible outcome for the subsea kick event is summarized in Table 4-4.

**Table 4-4: Risk related to possible outcomes for the subsea kick event**

| | | | | Safety Function | | | | | Probability | | Weighting (W) | | Risk | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **F1** | **F2A** | **F2B** | **F3** | **F4** | **F5A** | **F5B** | **F6** | **Prob\|kick** | **%** | **Cenv** | **Cr** | **Renv** | **%** |
| PFD= | 0,05 | 0,013 | 0,05 | 0,2 | 0,012 | 0,06 | 0,11 | 0,1 | | | | | | |
| **A** | Y | Y | | Y | | | | | **7,50E-01** | 75 % | 0 | 0 | 0,00E+00 | 0 % |
| **B** | Y | Y | | N | Y | | | | **1,85E-01** | 19 % | 1 | 1 | 3,71E-01 | 17 % |
| **C** | Y | Y | | N | N | Y | | | **2,12E-03** | 0 % | 0 | 10 | 2,12E-02 | 1 % |
| **D** | Y | Y | | N | N | N | | | **1,35E-04** | 0 % | 100 | 10 | 1,49E-02 | 1 % |
| **E** | Y | N | | | | | Y | | **1,10E-02** | 1 % | 0 | 10 | 1,10E-01 | 5 % |
| **F** | Y | N | | | | | N | | **1,36E-03** | 0 % | 1000 | | 1,36E+00 | 61 % |
| **G** | N | | Y | Y | | | | Y | **3,42E-02** | 3 % | 1 | 0 | 3,42E-02 | 2 % |
| **H** | N | | Y | N | Y | | | Y | **8,45E-03** | 1 % | 1 | 1 | 1,69E-02 | 1 % |
| **I** | N | | Y | N | N | Y | | Y | **9,64E-05** | 0 % | 1 | 10 | 1,06E-03 | 0 % |
| **J** | N | | Y | N | N | N | | Y | **6,16E-06** | 0 % | 100 | 10 | 6,77E-04 | 0 % |
| **K** | N | | Y | | Y | | | N | **4,69E-03** | 0 % | 1 | 1 | 9,39E-03 | 0 % |
| **L** | N | | Y | | N | Y | | N | **5,36E-05** | 0 % | 1 | 10 | 5,89E-04 | 0 % |
| **M** | N | | Y | | N | N | | N | **3,42E-06** | 0 % | 100 | 10 | 3,76E-04 | 0 % |
| **N** | N | | N | | | | Y | | **2,23E-03** | 0 % | 1 | 10 | 2,45E-02 | 1 % |
| **O** | N | | N | | | | N | | **2,75E-04** | 0 % | 1000 | | 2,75E-01 | 12 % |
| | | | | | | | | | **1,00E+00** | **100 %** | | | **2,24E+00** | **100 %** |

The two *most probable* outcomes are: A (75 %) and B (19 %). Note that outcome B only has minor environmental consequences, but due to its high probability, the associated risk is significant (17 %). The other outcomes carrying *most of the risk* are outcome F (61 %) and O (12 %). Grouping the outcomes in three categories according to severity (i.e. full, partial or no blowout, Table 4-5) gives a more aggregated risk picture, showing that the outcomes with full blowout (F and O) accounts for 73 % of the risk. This is mostly due to the very high environmental consequences associated with a blowout; the probability of a full blowout is on the other hand very low.

**Table 4-5: Aggregated risk results related to possible outcomes for the subsea kick event**

| Outcomes | Category | Prob\|kick | | Cenv | Cr | Renv | % |
|---|---|---|---|---|---|---|---|
| F, O | **Full BO** | 1,63E-03 | | 10000 | - | 1,63E+00 | 73 % |
| D, J, M | **Some BO** | 1,45E-04 | | 100 | 10 | 1,59E-02 | 1 % |
| Others | **No BO** | 9,98E-01 | | 0/10 | 0/1/10 | 5,88E-01 | 26 % |
| Sum | | 1,00E+00 | | | | 2,24E+00 | 100 % |

As a validity check the frequency of outcomes can be compared to values based on other studies. Based on the calculations above, the total probability of an outcome that involves a blowout *given a kick* (outcomes D, F, J, M and O) is 0.178 %. In “Deepwater Kicks and BOP Performance” (Holand, 2001), the average probability of failing to close in a kick was estimated to be 0.125 %, which is a comparable result.

### 4.1.3 Risk associated with barrier functions

In order to evaluate which barrier functions that have the greatest influence on the environmental risk it is necessary to "look beyond" the basic figures and consider dependencies and connections between the barriers.

By mere inspection of Table 4-5 and Table 4-4 we see that the majority of the risk (73 %) is associated with a full blowout (outcomes F and O), and that the failed barriers involved in a full blowout are barriers F2 and F5. This clearly indicates the high importance of the BOP barrier.

It is also possible to consider Table 4-4 from another point of view. Outcome A is the most desirable and risk-free outcome. In order to "reach" this outcome, it is necessary that the kick is detected early, that the BOP annular preventer closes and that control of the well with heavier mud is successful. Hence from this point of view, barriers F1, F2A and F3 are the most important ones.

The influence of individual barrier functions on the total risk can be quantified by performing a sensitivity analysis where the PFD of each barrier function is changed one at the time, *while the other PFDs are kept constant*. In Table 4-6 results are shown when the PFD is individually improved by a factor 2 (i.e. halved). The column "Risk reduction" quantifies the change in risk with respect to the risk for the base case.

**Table 4-6: Risk reduction obtained by reducing the PFD for the various barrier functions with 50% (while keeping the others constant)**

| Barrier function modified | Original PFD | Modified PFD | Risk reduction |
|---|---|---|---|
| **F1** | 0.05 | 0.025 | -6 % |
| **F2A** | 0.013 | 0.0065 | -33 % |
| **F2B** | 0.05 | 0.025 | -7 % |
| **F3** | 0.2 | 0.1 | -9 % |
| **F4** | 0.012 | 0.006 | -1 % |
| **F5A** | 0.06 | 0.03 | 0 % |
| **F5B** | 0.11 | 0.055 | -36 % |
| **F6** | 0.1 | 0.05 | 0 % |

As an example of interpretation of Table 4-6, we consider the row of barrier function F1. The original PFD for F1 is 0.05. If this PFD is reduced with 50 %, the modified PFD is 0.025. Keeping all other PFDs constant at their original values, the risk model then estimates a risk reduction of 6 % compared to the base case. The absolute risk values are not of much interest, what matters is the relative values.

The risk reduction numbers given in Table 4-6 can be interpreted directly as the distribution of influence from the barrier functions on the risk. A normalization of the distribution of risk influence is shown in Figure 4-1.

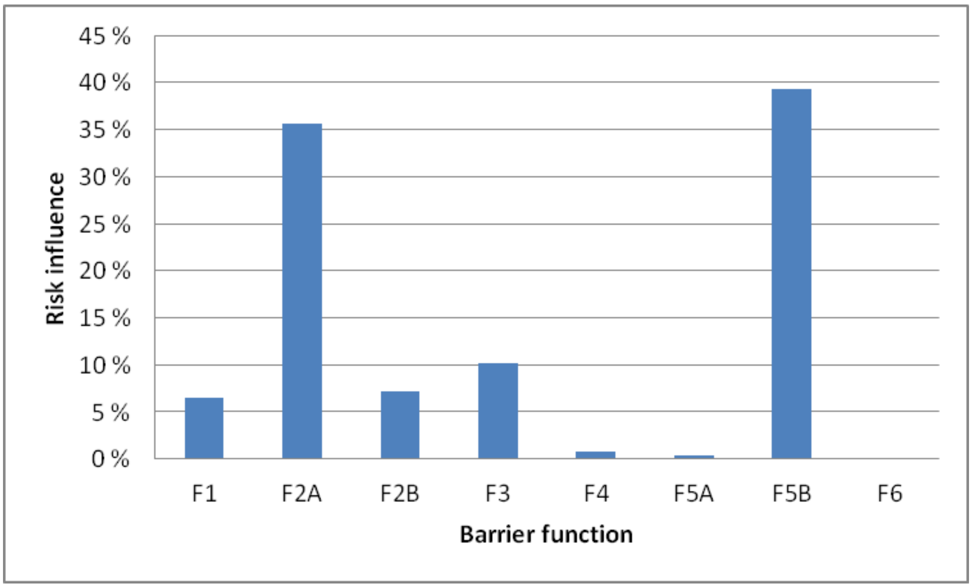


**Figure 4-1: Distribution of risk influence from the barrier functions on the total risk**

The results confirm that the most influential barriers on the risk is F2A (BOP seals and gas is trapped in well below BOP) and F5B (shear ram cuts and seals well, flow in riser).

The graph also indicates that "circulation of heavier mud" and "early kick detection" are barriers of significant importance in this scenario.

## 4.2 Sensitivity Evaluation

### 4.2.1 A linear risk model

The risk model described above is linear. This means that the risk as a function of one of its parameters *p* always can be described as

$$Risk(p) = a + bp$$

where *a* and *b* are constants specific for the parameter *p*. Furthermore, linearity implies that if a parameter is changed by a quantity $\Delta p$, the risk change will be proportional to $\Delta p$, with *b* as the proportionality factor. As an example, we return to Table 4-6 and barrier function F1: The reduction (improvement) of the PFD by 50 % entails a reduction of risk by 6 %. This implies that an *increase* (worsening) of the PFD by 50 % will give an increase in risk by the same 6 %. A doubling of the PFD will give a risk increase of 12 %, while a tripling will give 18 % etc. Furthermore, eliminating the PFD by reducing it by 100 % will give a risk reduction of 12 %.

This linear property provides a justification for using the 50 % PFD reduction approach (Table 4-6) as a basis for determining the barrier function influence distribution calculated in section 4.1.3, since all other PFD modifications would have produced the same distribution.

### 4.2.2 Sensitivity to $C_{Env}$ and $C_R$

In the base case, $C_{Env}$ increases roughly linearly with the amount of released oil (cf. Table 4-2). It can be argued that this relation should be concave, i.e. that a doubling of the release should be considered to be somewhat less than “twice as bad” in terms of consequences. Reducing $C_{Env}$ from 1000 to 500 for the worst outcomes (full blowout), yields a risk distribution of the outcomes A–O that is quite similar to the base case (Figure 4-2). The full blowout outcomes still dominate despite a significant reduction in relative risk contribution, while notably outcome B increases its relative risk contribution.

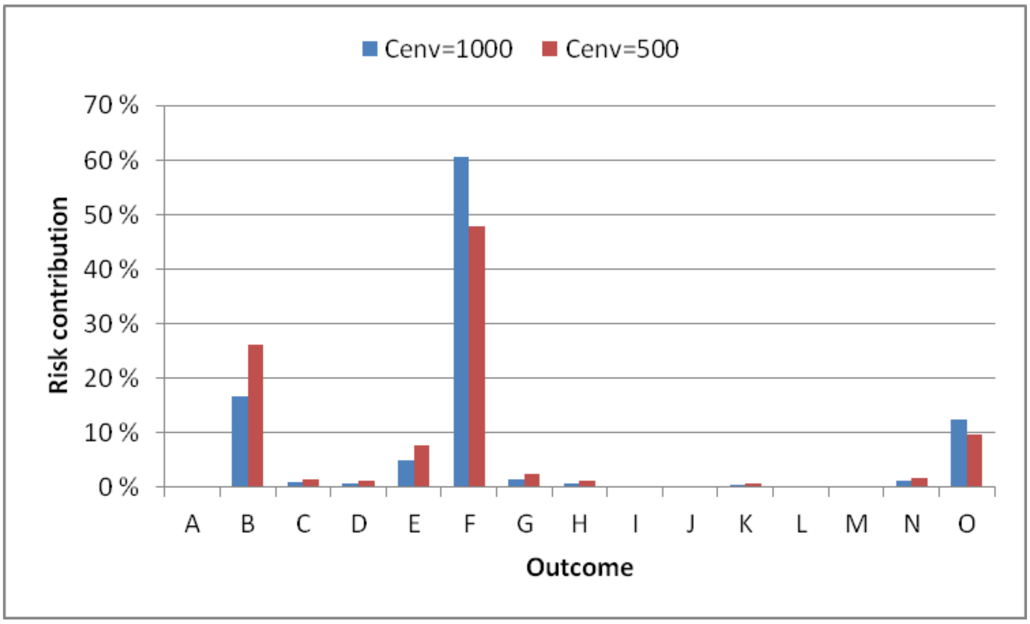


**Figure 4-2: Relative risk contribution from outcomes for $C_{Env}$ =1000 (base case) and $C_{Env}$ = 500**

The distribution of barrier function importance is also somewhat influenced by this reduction in $C_{Env}$. Figure 4-3 shows the distribution of risk influence from the barrier functions for $C_{Env}$ = 1000 (base case) and $C_{Env}$ = 500. For $C_{Env}$ = 500, we see that barriers F2A and F5B are still the most influential, but now barrier F3 (mud with appropriate weight into well) increases its relative importance significantly.

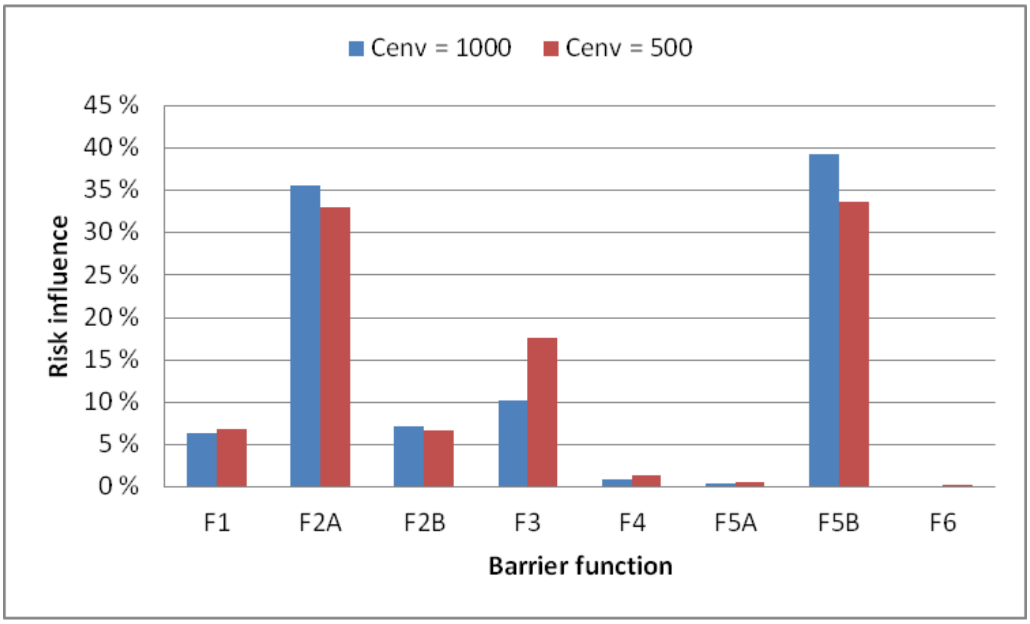


**Figure 4-3: Distribution of risk influence from the barrier functions for $C_{Env}$ =1000 (base case) and $C_{Env}$ = 500**

When it comes to the parameter $C_R$ for residual risk, the results are mainly insensitive to variations in this parameter. The reason for this is that the residual risk is most often negligible compared to the direct environmental risk captured in $C_{Env}$.

## 4.3 Qualitative discussion of results

Some main results from the event tree analysis are summarised below:

1. The consequence of a full blowout is considered high as compared to the other outcomes. Despite low probabilities, we therefore see that the full blowout scenarios (F and O) are major contributors to the environmental risk with an estimated 74 % of the estimated risk.

2. F2A (BOP annular preventer closes upon early kick detection) and F5B (BOP shear ram seals with hydrocarbons in riser) are the most influential barrier functions with respect to environmental risk in the considered kick scenario.

3. Other important barrier functions are found to be "circulation of heavier mud" (F3) and "early kick detection" (F1).

4. When performing sensitivity calculations and decreasing the relative consequence of a full blowout, the relative importance of the heavy mud barrier function increases.

As seen from the items above, the BOP is – not very surprisingly – pointed out as the most important barrier. Both closing the BOP annular preventer and/or ultimately activating the BOP shear ram are critical barrier functions in order to stop a kick from developing into a full blowout.

When interpreting the above results, it is important to keep in mind that our scenario starts at the *onset of a kick*: Hence, it is implicitly assumed that the primary barrier, i.e. the mud column, has already failed or been insufficient in some sense (ref. discussion in section 3.1). Therefore, although circulation with heavier mud (after having closed the annular preventer) is one of the barrier functions included in the event tree analysis, the actual importance of the mud column is not properly reflected in the event tree analysis, since functionality of this barrier function is a prerequisite for avoiding a kick in the first place.

The event tree analysis discussed above, is one possible approach to study the relative importance of each barrier function. In a large study performed by SINTEF as part of the RNNP[3] project, causal factors relating to well control incidents on the Norwegian Continental Shelf were considered. Based on a review of available investigation and event reports, it was found that 67% of the direct causes of well control incidents could be explained by technical factors. In particular it was found that:

- 22 % of the directs causes were subject to weaknesses in the mud column, i.e. typically: "too low/insufficient mud weight";
- Closely related to the above, 19 % of the direct causes were subject to unforeseen geological conditions in the reservoir, i.e. typically: "higher pore pressure than predicted" or "unforeseen gas in the formation";
- 13 % of the direct causes could be attributed to imperfect or technical failure of the kick detection function, e.g. "missing alarms / sensors", "bad location of sensor" or "inadequate synchronisation between systems";
- 6 % of the direct causes were subject to deficiencies in the well design related to cementing, casing, plugs, etc.

As we see, failure or deficiencies of the BOP is not among the major contributing causes since we are here considering well control incidents which have generally not developed into a full blowout (and the BOP annular preventer has generally been activated successfully).

Based on the results from the event tree analysis, and also drawing on the results from the RNNP study, it can be concluded that:

**Particular focus should be put on developing indicators for the BOP, the mud column / mud circulation system and also the kick detection system. These are all important barriers in order to prevent a kick from developing into a potential blowout.**

[3] RNNP is a PSA project that aims to measure and improve health, safety and environmental conditions in the Norwegian petroleum activities offshore and at the petroleum facilities on land. See http://www.ptil.no/trends-in-risk-level/category155.html for more information.

# 5 Selection of Barrier Indicators in PDS

In this chapter a discussion of the suggested barrier indicators in PDS are given. A somewhat more comprehensive discussion related to indicators is given in Appendix D.

## 5.1 What is an indicator?

An indicator may be defined as an observable and measurable variable quantity that can be used to monitor the risk, here the risk from acute hydrocarbon releases to sea during drilling. In order to prevent such releases, multiple safety barriers as discussed in previous chapters, are implemented. The status and performance of the safety barriers are influenced by a number of factors, which may be referred to as influencing factors. Finding indicators for these influencing factors therefore provide us with a tool for measuring the status of the barriers and consequently the environmental risk.

Figure 5-1 shows an example of the possible relation between a barrier element, an influencing factor and a corresponding indicator. Here, the barrier element chosen is the blind shear ram (BSR) in the BOP. An important factor influencing the reliability of the shear ram is the maintenance quality. A possible indicator for monitoring the maintenance quality is the degree of repeating failures revealed during maintenance and testing.

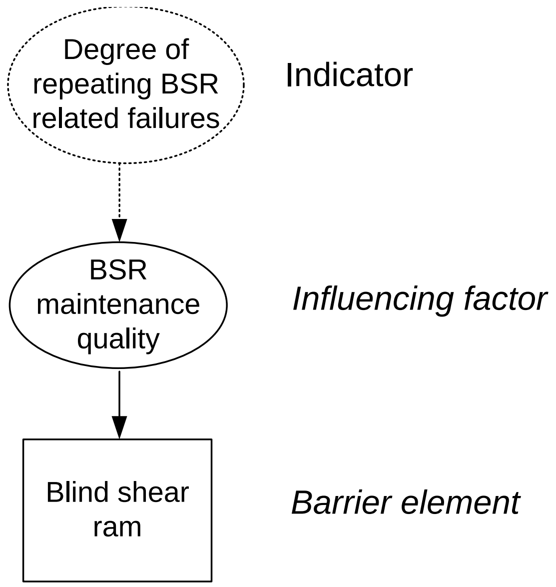


**Figure 5-1: Example of barrier element, influencing factor and indicator**

An indicator comprises two key components (OECD 2008):

- An operational definition, which should clearly state *what is being measured* in terms that are meaningful to the intended users.
- A *metric*, which defines the unit of measurement or *how the indicator is being measured*, and should be precise enough to highlight trends in safety/risk/state over time and/or highlight deviations from safety/state expectations that require action. This measure could be either quantitative or qualitative. However, trends are more easily identified for quantitative indicator metrics.

Extending the example from Figure 5-1, the relation between barrier element, influencing factors, indicator definition and indicator metric is given in Figure 5-2.

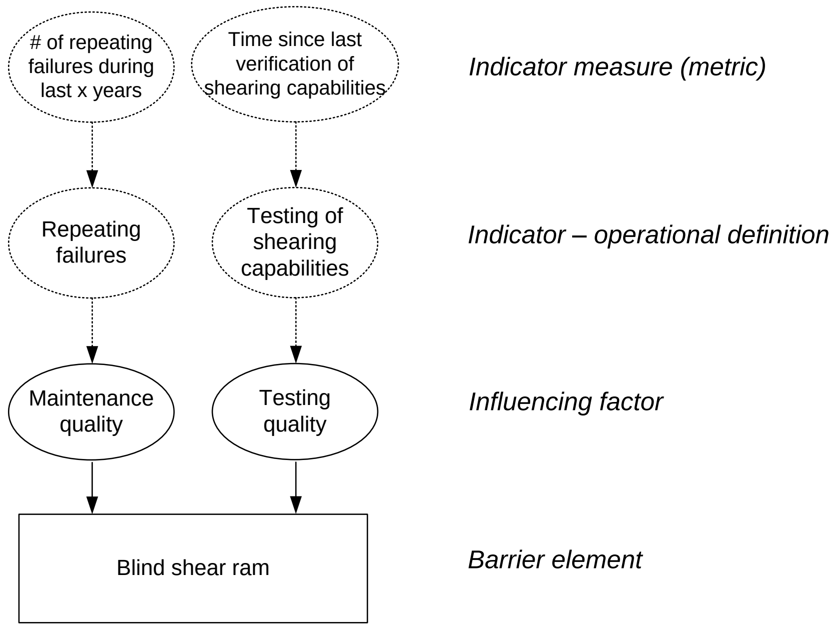


**Figure 5-2: Indicator definition and metric with example**

## 5.2 Purpose of developing barrier indicators

The purpose of applying indicators is to monitor safety (or reliability) and to identify changes or possible trends in the risk level or status of performance. Based on status and possible changes, it may be decided to search for and implement risk reducing measures, i.e. indicators shall make a difference (Hopkins, 2008). Hale (2008) mentions three areas of applications:

1. *Monitoring* the level of safety in a system. Is the level acceptable or is there a need for implementation of measures?
2. *Decision making*. Where and how to take action if risk reducing measures are necessary. Should further analysis be performed?
3. *Motivating* those in position to take the necessary action.

It should be noted that the objective of indicators is not only to reduce the risk, but also to motivate increased reporting, and to motivate discussions about good and bad practises.

***What is the purpose and ambition of developing barrier indicators in PDS?***

*The barrier indicators proposed in PDS shall provide a means of monitoring the status and performance of vital safety barriers during drilling. The status of the indicator may require measures to be implemented in order to reduce the risk of a blowout.*

## 5.3 Indicator selection criteria

A general discussion of possible criteria for selecting a "good" indicator is given in Appendix D. Some important criteria when developing environmental barrier indicators are:

***Important criteria for the PDS environmental barrier indicators:***

- *There must be a strong relationship between the indicator and the status of the barrier element (e.g. related to its integrity/reliability, its testing/maintenance quality, other follow-up in operation aspects, etc.)*
- *The indicator must be dynamic rather than static, i.e. it must change according to some predefined operational conditions. For this reason, issues related to the actual design of the system, such as degree of redundancy, is not a relevant indicator.*
- *The indicators must be defined objectively so that possible manipulation of the scoring is avoided ("bias-proof").*
- *It must be possible to "operationalize" the indicators. E.g. information/measurement of the indicator status should ideally be easily obtainable from existing information systems on the installation.*
- *The indicators (or at least some of them) should ideally be linked to one or several parameters in the PDS model in order to make it possible to assess the effect of changes.*

In general, only indicators that are "influence able" and that may change during operation are proposed. By that we mean that more or less fixed issues/conditions should be avoided as indicators. For example most design conditions are fixed and will often not change throughout the operation. Hence, aspects such as redundancy, HMI, capacity, response times, etc. are not necessarily good indicators. Furthermore, framework conditions related to e.g. resources and competency/experience are also often fixed, at least for a given operation, and indicators such as e.g. "number of years of experience of driller" and "availability of good procedures" are therefore avoided (although these are factors that may certainly affect the integrity of the barriers).

Furthermore, it has been attempted to select indicators that are easily "verifiable". For example, the fraction of time that the driller and mud logger are actually looking at the well monitoring screens (and perform analysis of trends) *could* have been a good indication of the quality of the kick detection function. This indicator is, however, very difficult to measure or verify.

## 5.4 Identification of indicators for each of the relevant barrier functions

In this section, indicators are proposed for some of the considered barrier functions. As concluded in Chapter 4, special attention is given to the kick detection function, the BOP and the mud column.

### 5.4.1 Barrier 1: Early kick detection

As discussed in Appendix 0 and C.2, the purpose of this barrier/safety function is to detect the inflow of fluid (or “kick”) to the well early and preferably before the fluid has reached beyond the BOP, such that the subsequent BOP closure will prevent release of gas/fluid to the environment.

The well monitoring / kick detection function comprises a number of sensors, control logic, operator displays and monitoring screens (HMI). Furthermore, the function relies heavily on human interpretation of data from the instrumented monitoring systems, as there is generally no automatic action involved.

Proposed indicators for the barrier function "early kick detection" are shown in the table below. P/N tells if an increased value is positive (+) or negative (-) with respect to the integrity of the barrier function.

**Table 5-1: Suggested indicators for "early kick detection"**

| No. | Indicator | Unit | P/N |
|---|---|---|---|
| 1.1 | Time since last test / calibration of kick detection sensors (e.g. level sensors in pit tank and flow rate sensors) | Months | - |
| 1.2 | Average number of active mud pits/tanks since drilling start-up | Number | - |
| 1.3 | Fraction of spurious alarms (to the total number of alarms) | % | - |
| 1.4 | Number of formal verification meetings between mud logger and driller (to number of drilling days) | Ratio | + |

Some arguments for selecting the indicators are summarised below:

***Indicator 1.1 Time since last test / calibration of kick detection sensors***
The reliability of the detection equipment will directly depend upon the time since last functional test of the equipment. Since there are no regulatory requirements concerning the testing frequency of such equipment - the time since last test is proposed as an indicator.

***Indicator 1.2 Average number of active mud pits/tanks since drilling start-up***
The uncertainty related to measuring the volume in / volume out of the well will depend on several factors such as the accuracy, sensitivity and reliability of the drilling instrumentation. From a more operational point of view, the number of mud pits that are active at the time will also influence the reliability of the kick detection function. Generally, the more mud pits in use, the larger the uncertainty related to the mud-volume in/out of the well will be. If several mud-pits are in use at the same time this also adds to the complexity experienced by the driller / mud logger when interpreting the data from the various sensors.

***Indicator 1.3 The rate of spurious alarms (to the total number of alarms)***
The drillers work load is a challenge as he has many tasks, e.g. alarm handling, following up measurements, answering the telephone, etc. In particular, the amount of alarms is huge during start-up, installation or testing. Both alarm handling and driller decision support are important factors that will be and need to be improved. As the spurious trip rate increases, the confidence in the kick detection sensor system will decrease and a high alarm rate will also add to the general complexity for the driller. Therefore, the rate of spurious alarms to the total number of alarms from the kick detection system is suggested as a possible indicator.

***Indicator 1.4 Number of formal meetings between mud logger and driller***
There are two persons independently following the measurement of flow, pressure, etc., i.e. the driller and the mud logger. They are independent in the way that they work from different rooms and assess the data based on different systems. The driller can see the mud logger's screen in addition to his own screen.

Since the mud logger and the driller basically read the same physical parameters from the well, but from two different well monitoring systems, it is reasonable to assume that the quality of the cooperation and interaction between the two will influence the kick detection function. The quality of this cooperation is obviously difficult to measure objectively, especially in terms of informal contact between mud logger and driller. Also, on some fixed installations, the mud loggers are located onshore in the operational centre. However, here the number of formal meetings between the driller and the mud logger has been suggested as a possible indicator of the cooperation between the two.

***Other possible indicators (not included)***

- *The total drilling depth;* The reliability of the kick detection function will depend upon the total drilling depth (water depth + well depth) since the total volume of drilling mud will increase the uncertainty of the volume measurement functionality. On the other hand, a very deep well will increase the time it takes for the hydrocarbons to reach the BOP, thereby increasing the available response time. Hence this indicator may be somewhat dubious.

- *The number of kick detection sensors by-passed or malfunctioning;* The reliability of the kick detection function will also depend upon the number of active sensors available at any time. However, since the number of active sensors will depend on the original configuration of the system and since the complexity of the system may increase with number of measuring points, this indicator may be dubious.

### 5.4.2 Barrier 2: BOP annular preventer seals

As discussed in Appendix B.4 and C.3, the purpose of this barrier function is to seal the annulus upon activation from the rig, in order to prevent flow of hydrocarbons out of the wellbore. In practise, this barrier is typically made up of one or two annular preventers, two or more ram preventers and the systems required to activate the valves. The annular preventer(s) and the rams are manually activated from rig, typically by pilot hydraulic activation.

It should be noted that the industry has a major focus on the drilling BOP, and as such the BOP is probably the one piece of equipment where operational follow-up in terms of testing and maintenance is at its most extensive. On the one hand this implies that additional indicators for the BOP may not be necessary. On the other hand, it also means that there will be lots of information available from e.g. the maintenance systems to measure the status of the BOP.

Here, an attempt has been made to come up with indicators that to our knowledge are not broadly used in the industry as per today. The suggested indicators for the barrier function "BOP annular preventer seals" are shown in the table below.

**Table 5-2: Suggested indicators for "BOP annular preventer seals"**

| No. | Indicator | Unit | P/N |
|---|---|---|---|
| 2.1 | Fraction of failed functional tests (both closure tests and pressure tests) to the total number of tests | % | - |
| 2.2 | Fraction of repeated failures revealed during testing and maintenance (to the total number of revealed failures) | % | - |
| 2.3 | Number of stripping operations during lifetime of BOP | Number | - |

Some arguments for selecting the indicators are summarised below:

***Indicator 2.1 Fraction of failed functional tests***

An indication of the reliability of the BOP annular preventer function is given by the fraction of failed functional tests (on first attempt) to the total number of tests. Some installations are already using this indicator, and the required data are collected as part of the RNNP statistics.

***Indicator 2.2 Fraction of repeated failures***

An indication of the quality of the BOP maintenance and follow-up, and therefore the reliability of the BOP annular preventer function, will be given by the fraction of identified failures that repeat themselves throughout the operational lifetime. The quality of root cause analysis and the ability to identify and remove failure causes will be revealed through this indicator. In order to implement the indicator, it will be necessary to perform operational reviews of maintenance data / notifications in order to get an overview of repeated failures. This will require some additional resources, but will be very useful as part of general barrier follow-up and in order to identify potential areas of improvement.

***Indicator 2.3 Number of stripping operations during lifetime of BOP***

The reliability of the annular preventer is a function of its service life (see discussion in section C.3.6). Degradation due to aging is, however, not straightforward to measure. Here the stripping history of the BOP is suggested as a possible indicator, since stripping operations historically has been found to negatively influence the BOP annular reliability.

***Other possible indicators (not included)***

- *Amount of hydraulic oil during test;* The amount of hydraulic oil used to close the different BOP elements is a measure of the technical condition of the BOP and may reveal hydraulic leaks etc. For this area there is however standard performance requirements that must be adhered to, hence this is not considered a particularly good indicator.

- *Closing time during test;* Comparable to above, this indicator can also be used as a measure of the technical condition of the BOP. Also here there will be prescriptive requirements to adhere to, reducing the value of this indicator.

### 5.4.3 Barrier 3: Heavier mud is used to kill well

As discussed in Appendix B.2 and C.4, the normal way to control a kick is to close the annular preventer and then adjust the weight of the drilling mud that is pumped down the drill string. This operation includes both pumping heavy mud into the well and allowing gas and light mud to exit through the choke lines.

Indicators for the barrier function are shown in the table below.

**Table 5-3: Suggested indicators for "heavy mud to kill well"**

| No. | Indicator | Unit | P/N |
|---|---|---|---|
| 3.1 | Time since last functional test of essential choke and kill line assemblies | Months | - |
| 3.2 | Average amount of spare mud available throughout the operation | $m^3$ | + |
| 3.3 | Average number or fraction of mud and cement pumps out of service throughout the operation | Number or % | - |

Some arguments for selecting the indicators are summarised below:

***Indicator 3.1 Time since last functional test of essential choke and kill line assemblies***
As discussed in Appendix C.4 there are little regulatory requirements to testing of mud system equipment. It is however specified (ref. API RP 53) that essential choke and kill line assemblies shall be maintained and checked regularly. No specific requirements concerning frequency of testing are however given. Hence this is suggested as a possible indicator.

***Indicator 3.2 Average amount of spare mud available throughout the operation***
A critical factor during emergencies may be the amount of available spare mud in case of killing operations. This is therefore suggested as an indicator.

***Indicator 3.3 Average number of mud and cement pumps out of service throughout the operation***
As discussed in Appendix C.4, the availability of spare mud and cement pumps are normally good on the drilling rigs. It is however also stated that historical events show that the cement pumps are frequently used for mud circulation due to malfunction of the mud pumps. Hence, a possible indicator of the availability of mud pumps at any time may be the average number of pumps out of service throughout the operation. Alternatively the ratio between the number of pumps out of operation to the total number of pumps can be used.

### 5.4.4 Barrier 4: Drill string safety valve seals drill pipe

As concluded in Chapter 4, the drill string safety valve does not appear among the most important barrier functions. Therefore, no indicators for this function have been proposed.

### 5.4.5 Barrier 5: Blind shear ram cuts drill string and seals well

Indicators for the barrier function are shown in the table below. P/N tells if a high value is positive (+) or negative (-) with respect to environmental safety.

**Table 5-4: Suggested indicators for "blind shear ram cuts and seals"**

| No. | Indicator | Unit | P/N |
|---|---|---|---|
| 5.1 | Fraction of failed functional tests of shear ram (both closure tests and pressure tests) to the total number of tests | % | - |
| 5.2 | Fraction of repeated failures revealed during testing and maintenance (to the total number of repeated failures) | % | - |
| 5.3 | Service life of shear ram – time since last cutting verification | Months | - |

Some arguments for selecting the indicators are summarised below:

***Indicator 5.1 Fraction of failed functional tests of shear ram***
An indication of the reliability of the BOP shear ram function is given by the fraction of failed functional tests (on first attempt) to the total number of tests. Some installations are already using this indicator, and the required data is collected as part of the RNNP statistics.

***Indicator 5.2 Fraction of repeated failures***

As discussed in section 5.4.2 the fraction of identified failures that repeat themselves throughout the operational lifetime may be a good indication of the quality of the BOP maintenance and follow-up, and therefore the reliability of the BOP shear ram function.

***Indicator 5.3 Service life of shear ram - years since last cutting verification***

The reliability of the shear ram will be a function of its service life and in particular the operational time since last verification of the shear rams "cut and seal" ability (these two measures are often concurrent since such cutting verifications are not standard).

***Other possible indicators (not included)***

Reference is made to the discussion in section 5.4.2.

### 5.4.6 Barrier 6: Diverter system

The analysis in Chapter 4 shows that the diverter system is not among the most important barrier functions. Therefore, no indicators for this function have been proposed.

## 5.5 General drilling indicators

In addition to the specific barrier indicators discussed above, it is possible to define some more general indicators that apply merely to the drilling operation itself rather than the specific barriers.

Two general indicators relevant for the drilling case are suggested in the table below. The motivation for these indicators is the fact that "insufficient" change management historically has been an important contributing failure cause in many incidents/accidents. Therefore, two indicators related to deviations from the original drilling program have been proposed.

**Table 5-5: Suggested general drilling indicators**

| No. | Indicator | Unit | P/N |
|---|---|---|---|
| G.1 | Number of deviations from original "detailed drilling program" handled onshore (e.g. during last three months) | Number | - |
| G.2 | Number of deviations from original "detailed drilling program" handled offshore (e.g. during last three months) | Number | - |

***Indicator G.1 Number of deviations from original "detailed drilling program" handled onshore***

Standard procedures for handling deviations imply that "larger deviations" must be dealt with onshore, whereas minor changes are handled offshore. Implementation of this indicator will require some kind of definition of *what is a deviation from the original drilling program*.

It may be argued that the quality of the MoC system will be more important than the number of changes. It is however a fact that a large number of changes in itself may represent a challenge. This will in particular apply to changes that are handled offshore.

***Indicator G.2 Number of deviations from original "detailed drilling program" handled offshore***

Reference is made to the discussion under G.1.

# 6 Follow-up and implementation of the suggested indicators

Based on results from workshops and interviews with drilling personnel (SINTEF RNNP study, 2012) it is our impression that registration of deviations, failure history, test and maintenance data etc. to a somewhat limited degree are systematized and analysed on drilling rigs. This may have cultural, historical as well as organisational causes. At the same time we see that the general focus on barriers has increased in the industry, partly initiated by the fact that PSA has set out barrier management as one of their main priority areas (PSA, 2011). This increased focus should therefore be beneficial with respect to introducing separate barrier indicators, which can be one of several means of following up the barriers.

Important issues to consider when implementing the selected indicators are:

1. How shall data for these indicators be collected and who are responsible for collecting the data?
2. How often and how should the indicators be updated – continuously, daily, weekly, monthly, quarterly or more seldom?
3. Who are responsible for following up the indicators and make decisions (e.g. to implement risk reducing measures) based on the indicator trends?

These questions are addressed in the following sections .

## 6.1 Data collection and follow-up responsibility

Having defined the indicators, the next question that arises is: Who will be responsible for implementation of the indicators, data collection, preparing results and follow-up of the indicators, respectively? Is it the operators, the HSE responsible on the rig or is it onshore personnel?

When defining environmental barrier indicators in PDS this may be seen in relation to the requirements in the PSA Management regulation, §5: *"Personnel shall be aware of which barriers are not functioning or have been impaired. The responsible party shall implement the necessary measures to remedy or compensate for missing or impaired barriers" (PSA Management regulation, §5).*

Hence, it is already established that *the responsible party* shall follow-up the barriers and implement measures when the barrier is impaired. In this context the barrier indicators can be seen as *a tool* for following-up the barrier status and as such the persons responsible for follow-up of the barriers should also be responsible for following up the indicators.

In order to measure an indicator it is important with periodical (or continuous) registration of data about the status/value of the indicator. A sufficient number of registrations over a sufficient time period will be necessary to identify trends to support decision making. By "sufficient" we mean that changes from one measurement period to another should (ideally) not be too sensible to random variations.

Today, quite a lot of data and information on drilling related barriers is already collected. Using already available information is beneficial with respect to time, cost and resources. However, using solely data presently available may restrain the quality of the indicators.

Concerning the question on how the environmental barriers indicators can be measured, this obviously depends on which indicator is considered. Typical systems relevant as sources of information will be the maintenance management system (e.g. SAP), systems for recording different well parameters, systems for incident recording (e.g. SYNERGI), information management systems, automatic shutdown reports and manual logs (e.g. logs for inhibits and overrides).

For each selected indicator a data sheet should be established. Typical contents of this data sheet are definition of indicator, metric, responsible persons, acceptance criteria, etc.

## 6.2 Defining an aggregated risk indicator

In order to have useful indicators, in particular leading indicators, they need to be defined and displayed in such a way that they catch the attention of the target audience and that the criticality of the indicator is easily understood. In this study we have decided to focus on a kick situation that occurs during bottom-hole drilling. In general, drilling operations tend to be very dynamic in nature, and may require rapid decision making to avoid a hazardous event from developing further. Consequently, it may seem appropriate to identify the drilling crew as the target audience for the indicators.

Based on lessons learned from the Deepwater Horizon accident (see also Appendix E), the accident was helped along by a number of risk-increasing factors that could have been identified days and weeks earlier. However, many of the critical decisions were also made in the last few hours. In the previous chapter some barrier specific indicators and a few more general indicators were suggested. While none of these indicators *alone* will generate enough reason for concern to trigger some action, it may be argued that *the aggregated risk* represented by these indicators *could* have proved to be outside some acceptable limit. What may be needed is therefore an aggregated indicator for the purpose of "getting attention" from key personnel to perform a more detailed review of the risk picture.

By generating an *aggregated* risk indicator that is a function of all the suggested indicators (and probably some more), the drilling crew will be provided with a single tool to track the overall risk level of the on-going operations without having to be familiar with all the details. By using a simple display method (for instance a green, yellow or red light), the control room operators could use this as an aid for how to proceed the operation. It would be recommended to have a "go-ahead" / "low risk level" (green light), a "proceed cautiously" / "higher risks than normal are present" level (yellow light) and a "some action is required" level (red light).

The major challenge associated with the proposed strategy is obviously to define a set of barriers that aggregated give a representative picture of the risk. It is foreseen that optimization of the set of indicators must take place based on a longer real-time test/development phase on-board one or several installation. While many indicators will be the same from one facility to the next, some facility-specific indicators will also probably be required to cater for local conditions.

Many of the indicators are relatively straight forward and easy to implement. For example "fraction of failed functional tests" which is already a quantitative measure and where the information should be available from the maintenance system on-board. For other indicators, such as "number of deviations from original detailed drilling program" (handled onshore and offshore respectively), the required information will probably not be directly available, but could become so with reasonable efforts.

## 6.3 Collection of data for the proposed indicators

The table below summarizes required data and some guidelines for data collection for the proposed barrier indicators. As discussed in section 6.1 above, the responsibility of collection and processing indicator data must be clearly defined.

**Table 6-1: Required data and data collection for the proposed barrier indicators**

| No. | Indicators for "early kick detection" | Required data and data collection |
|---|---|---|
| 1.1 | Time since last test / calibration of kick detection sensors (e.g. level sensors in pit tank and flow rate sensors) | Information related to elapsed time (e.g. number of months) since critical kick detection sensors were tested and calibrated should be available from the rig's maintenance system. |
| 1.2 | Average number of active mud pits/tanks since drilling start-up | This information should be available from the drilling instrumentation package / well monitoring system. |
| 1.3 | Fraction of spurious alarms (to the total number of alarms) | Spurious alarm rate will not be directly available and will require an analysis of alarm data from the well monitoring system. It may also be difficult to distinguish true and false alarms. Hence some judgements are probably required. |
| 1.4 | Number of formal verification meetings between mud logger and driller (to number of drilling days) | The number of such formal meetings should be available from various administrative systems. |
| **No.** | **Indicators for "BOP annular preventer seals"** | **Required data and data collection** |
| 2.1 | Fraction of failed functional tests (both closure tests and pressure tests) to the total number of tests | Information related to test results for the annular and ram preventers should be available from the rig's maintenance system (and is also part of the RNNP data that are reported to PSA Norway). |
| 2.2 | Fraction of repeated failures revealed during testing and maintenance (to the total number of revealed failures) | The fraction of repeated failures will not be directly available and will require an analysis and review of test/maintenance data. Such an analysis will however be beneficial with respect to revealing important failure causes and getting an overview of the failure history (as part of operational follow-up). |
| 2.3 | Number of stripping operations during lifetime of BOP | This information should be easily available from rig management and administrative systems. |
| **No.** | **Indicators for "heavy mud to kill well"** | **Required data and data collection** |
| 3.1 | Time since last functional test of essential choke and kill line assemblies | Information related to time (e.g. number of months) since last test of critical choke and kill line assemblies should be available from the rig's maintenance system. |
| 3.2 | Average amount of spare mud available throughout the operation | This information should be available from the well monitoring system. A good metric for this indicator needs to be specified (either total spare mud available or fraction of spare to required amount). |
| 3.3 | Average number or fraction of mud and cement pumps out of service throughout the operation | Information related to the average number of pumps out of operation for a given operation should be available from maintenance systems and the drilling instrumentation package / well monitoring system. |
| **No.** | **Indicators for "shear ram cuts and seals"** | **Required data and data collection** |
| 5.1 | Fraction of failed functional tests of shear ram (both closure tests and pressure tests) to the total number of tests | Information related to test results for the shear ram(s) should be available from the rig's maintenance system. |

| | | |
|---|---|---|
| 5.2 | Fraction of repeated failures revealed during testing and maintenance (to the total number of repeated failures) | The fraction of repeated failures will not be directly available and will require an analysis and review of test/maintenance data. |
| 5.3 | Service life of shear ram – time since last cutting verification | This information should be easily available from rig management and administrative systems. |
| **No.** | **General indicators** | **Required data and data collection** |
| G.1 | Number of deviations from original "detailed drilling program" handled onshore (e.g. during last three months) | Retrieving this information will require a review of relevant rig management and administrative systems. |
| G.2 | Number of deviations from original "detailed drilling program" handled offshore (e.g. during last three months) | Retrieving this information will require a review of relevant rig management and administrative systems. |

## 7 References

**Ale, 2008**; Ben Ale, *More thinking about process safety indicators*, Safety Science, 2008

**API RP 53**; American Petroleum Institute, *Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells*, API Recommended Practice 53, Third Edition, March 1997

**BP, 2010,** *Deepwater Horizon, Accident Investigation Report*. <www.bp.com>, London, UK.

**Chief Counsel, 2011**; *National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling: Macondo the Gulf Oil Disaster*. <www.oilspillcommission.gov/chief-counsels-report>, United States.

**Christensen et al., 2003**; Christensen, F., Andersen, O.,Duijm,N., and Harremoës, P. (2003). *Risk terminology platform for common understanding and better communication*. Journal of Hazardous Materials, 103:181–203.

**Delvosalle et al., 2006**; Christian Delvosalle, Cécile Fievez, Aurore Pipart, Bruno Debray; ARAMIS project: *A comprehensive methodology for the identification of reference accident scenarios in process industries* Journal of Hazardous Materials, Volume 130, Issue 3, 31 March 2006, Pages 200-219

**DHSG, 2011**; *Final Report on the Investigation of the Macondo Well Blowout*, Deepwater Horizon Study Group, March 2011

**DNV, 2011**; *Final Report for United States Department of the Interior. Forensic Examination of Deepwater Horizon Blowout Preventer*, Report No. EP030842 <www.boemre.gov/pdfs/maps/AddendumFinal.pdf>, Dublin, United States

**DOE, 2005**; U.S. Department of Energy, *Implementation guide Aviation Program Performance Indicators (Metrics) for use with DOE O 440.2B, Aviation Management and Safety*, 2005

**Hale, 2008**; Andrew Hale, *Why safety performance indicators?*, Safety Science, 2008

**Holand, 1999**; Per Holand, *Reliability of Subsea BOP Systems for Deepwater Application, Phase II DW*, SINTEF report STF38 A99426, July 11th 1999.

**Holand, 2001**; Per Holand, *Deepwater Kicks and BOP Performance*, SINTEF report STF38 A01419, July 24th 2001.

**Hopkins, 2008**; Andrew Hopkins, *Thinking about process safety indicators*, Safety Science, 2008

**HSE, 2006**; Health and Safety Executive, *Developing process safety indicators – A step-by-step guide for chemical and major hazard industries*, HSE, 2006

**IAEA, 2000**; International Atomic Energy Agency, *Operational safety performance indicators for nuclear power plants*, May 2000

**NORSOK D-001**; NORSOK STANDARD, *Drilling facilities*, D-001, Rev. 2, July 1998

**NORSOK D-010**; NORSOK STANDARD, *Well integrity in drilling and well operations*, D-010, Rev. 3, August 2004

**OECD, 2008**; Organisation for Economic Cooperation and Development, *Guidance on developing safety performance indicators – related to Chemical Accident Prevention, Preparedness and* Response, Environment, OECD Health and Safety Publications, Series on Chemical Accidents No. 18, Paris 2008

**OLF, 2004**; *Application of IEC 61508 and IEC 61511 in the Norwegian Petroleum Industry*, OLF Guideline 070, rev. 02

**President Commission, 2011,** National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling: Deepwater. *The Gulf Oil Disaster and the Future of Offshore Drilling.* Report to the President. <www.oilspillcommission.gov/final-report>, United States.

**RNNP, 2012**; Petroleumstilsynet, *Risikonivå i petroleumsvirksomheten, Hovedrapport – Utviklingstrekk 2011 norsk sokkel*, 2012

**SINTEF, 2011**; *Deepwater Horizon-ulykken: Årsaker, lærepunkter og forbedringstiltak for norsk sokkel*, SINTEF report A19148, June 2011

**SINTEF, 2011b**; *Barriers to prevent and limit acute releases to sea – Environmental acceptance criteria and requirements to safety systems*, SINTEF rapport A20727, October 2011

**SINTEF, 2010**; *Reliability Prediction Methods for Safety Instrumented Systems – PDS method handbook 2010 Edition*, SINTEF 2010.

**SINTEF, 2010b**; *Reliability Data for Safety Instrumented Systems – PDS data handbook 2010 Edition*, SINTEF 2010.

**SINTEF, 2001**; Knut Øien and Snorre Sklet, *Metodikk for utarbeidelse av organisatoriske indikatorer*, SINTEF Rapport, 2001

**Sklet, 2006;** Snorre Sklet, *Safety barriers: Definition, classification, and performance*, Journal of Loss Prevention in the process industries 19 (2006) 494-506

**Vinnem et al. 2005**; Jan Erik Vinnem, Terje Aven, Troleif Husebø, Jorunn Seljelid, Odd J. Tveit, *Major hazard risk indicators for monitoring of trends in the Norwegian offshore petroleum sector*, Reliability Engineering & System Safety 91, 778-791, 2006

**Webb, 2008**; Peter Webb, *Process safety performance indicators: A contribution to the debate*, Safety Science, 2008

**Øien, Utne, Herrera, 2010**; *Building Safety Indicators: Part 1 – Theoretical foundation*, Safety Science 49, 148-161, 2011

**Øien, 2000**; K. Øien, *Risk indicators as a tool for risk control*, Reliability Engineering & System Safety 74, 129-145, 2001

# A Definitions

In this Appendix definition of selected terms used in this report is given.

## A.1 Methodical definitions

**Barrier**
A barrier can be regarded as a function which prevents a specific sequence of events from taking place, or which directs the sequence of events in an intended direction to limit harm (PSA, 2011)

**Barrier function**
The assigned responsibility or action of the barrier, e.g. prevent leakage, limit amount of release or prevent ignition (PSA, 2011).

**Barrier element**
The personnel, equipment or systems that implement the barrier function (PSA, 2011). Typically a barrier constitutes several barrier elements.

**Barrier reliability/availability**
The barrier reliability/availability is the ability to perform a function with an actual functionality and response time while needed, or on demand (Sklet, 2006).

**Critical event**
Critical events are events that may cause harm to humans, the environment, or material assets. Critical events may be loss of containment (LOC) or loss of physical integrity (LPI) (Delvosalle et al., 2006). Release of fluids or gases is usually associated with LOC, whereas changes in chemical and/or physical state of solid substances, for example structures, are associated with LPI.

**Hazard**
Hazards may be defined as the inherent property/properties of a risk source potentially causing consequences/effects (Christensen et al., 2003).

**Hazardous event**
Incident which occurs when a hazard is realized (NORSOK Z-013)

**Indicator**
An indicator is an observable characteristic of an operational system that can be presumed to have a strong connection to the system performance.

**Initiating event**
Initiating events are events that enable the realization of a hazard into a hazardous event

**Safety Integrity**
Probability of an E/E/PE safety related system [SIS] satisfactorily performing the specified safety functions under all the stated conditions within a stated period of time (IEC 61508-4)

**Safety Integrity Level (SIL)**
Discrete level (one out of possible four), corresponding to a range of safety integrity values, where safety integrity level 4 has the highest level of safety integrity and safety integrity level 1 has the lowest.

## A.2 Equipment definitions

**Annular preventer**
A device that can seal around any object in the wellbore or upon itself. Compression of a reinforced elastomer packing element by hydraulic pressure effects the seal. (API RP 53)

**Blind / shear rams**
Blind rams with a built-in cutting edge that will shear tubulars that may be in the hole, allowing the blind rams to seal the hole. (API RP 53)

**Blowout preventer (BOP)**
A device attached to the casing head that allows the well to be sealed to confine the well fluids in the wellbore. The device is an assembly of well control equipment including preventers, spools, valves, and nipples connected to the top of the casing head. (API RP 53)

**Control pod**
An assembly of subsea valves and regulators, that when activated from the surface will direct hydraulic fluid through special apertures to operate the BOP equipment. (API RP 53)

**Diverter system**
The assemblage of an annular sealing device, flow control means, vent system components, and control system that facilitates closure of the upward flow path of well fluids and opening of the vent to atmosphere. (API RP 53)

**Kill line**
A high pressure line between the mud pumps and some point below a BOP. This line allows fluids to be pumped into the well or annulus with the BOP closed. (API RP 53)

**Pipe rams**
Rams whose ends are contoured to seal around pipe to close the annular space. Unless special rams accommodating several pipe sizes are used, separate rams are necessary for each size (outside diameter) pipe in use. (API RP 53)

**Drill string safety valve**
A (ball) valve used to stop the flow through the drill string (also referred to as iBOP, upper kelly valve, stab-in safety valve, etc.)

Some of the main BOP components are illustrated in the figure below.

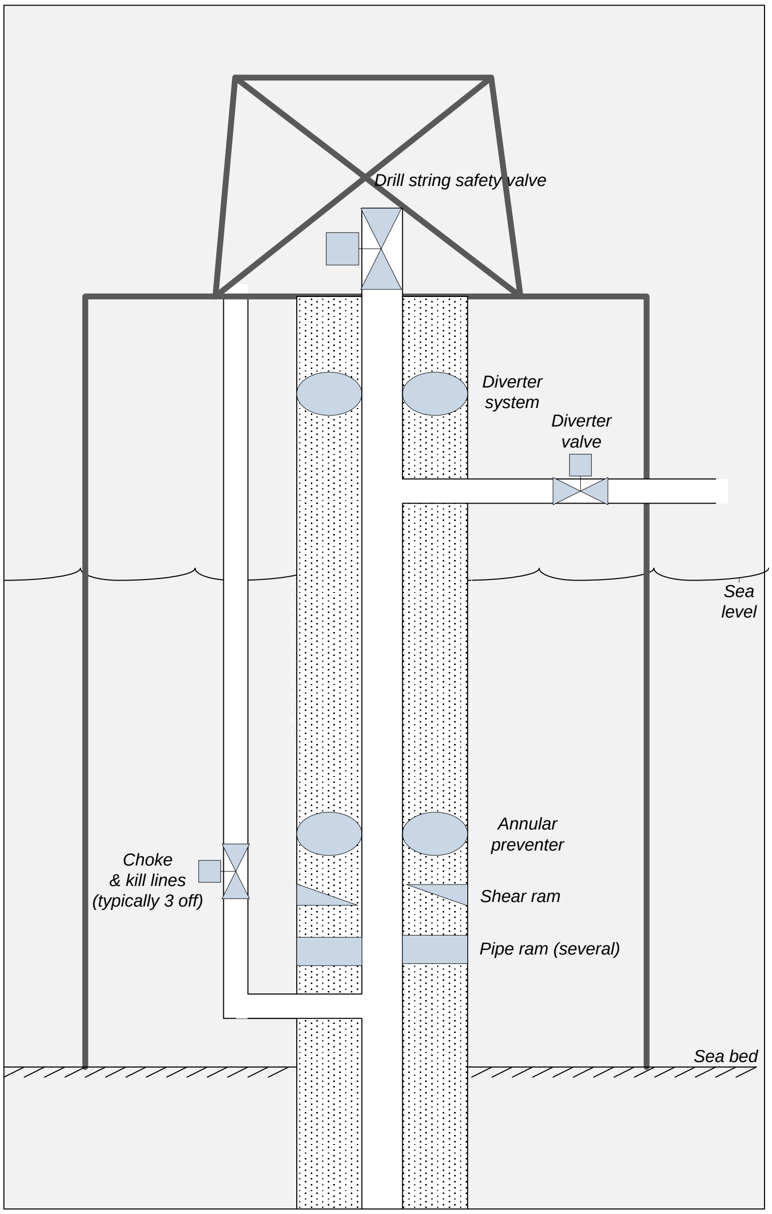


**Figure A-1: BOP schematic**

Figure A-1 shows the schematic of a traditional BOP with one shear ram. Note that equipment redundancies may vary from one BOP to another.

## A.3 Operational definitions

**Blowout**
An uncontrolled flow of well fluids and/or formation fluids from the wellbore or into lower pressured subsurface zones (underground blowout). (API RP 53)

**Function test**

The operation of a piece of equipment or system to verify its intended operation. Closing and opening (cycling) equipment to verify operability. Does usually not include pressure testing. (API RP 53)

**Kick**
Influx of formation liquids or gas that results in an increase in pit volume. Without corrective measure, this condition can result in a blowout. (API RP 53)

**Pressure test**
Periodic application of pressure to a piece of equipment or a system to verify the pressure containment capability for the equipment or system. (API RP 53)

**Stripping**
The act of putting drillpipe into the wellbore when the blowout preventers (BOPs) are closed and pressure is contained in the well. This is necessary when a kick is taken, since well kill operations should always be conducted with the drillstring on bottom, and not somewhere up the wellbore. If only the annular BOP has been closed, the drill pipe may be slowly and carefully lowered into the wellbore, and the BOP itself will open slightly to permit the larger diameter tool joints to pass through. If the well has been closed with the use of ram BOPs, the tool joints will not pass by the closed ram element. Hence, while keeping the well closed with either another ram or the annular BOP, the ram must be opened manually, then the pipe lowered until the tool joint is just below the ram, and then the ram closed again. This procedure is repeated whenever a tool joint must pass by a ram BOP. Rig crews are usually required to practice ram-to-ram and ram-to-annular stripping operations as part of their well control certifications. In stripping operations, the combination of the pressure in the well and the weight of the drill string is such that the pipe falls in the hole under its own weight, whereas in snubbing operations the pipe must be pushed into the hole (based on Schlumberger Oilfield glossary: http://www.glossary.oilfield.slb.com/search.cfm).

## B Blowout Protection Equipment for Subsea Drilling

This Appendix gives a brief introduction to the key safety barriers in relation to subsea drilling operations.

### B.1 Main barriers during subsea drilling

The Norwegian Petroleum Safety Authority (PSA) requires that two well barriers shall be in place for operations on the Norwegian continental shelf whenever a hazardous pressure differential exists. NORSOK Standard D-010 (section 4.2.3.2) specifies:

*"There shall be two well barriers available during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled outflow from the borehole/well to the external environment."*

During subsea drilling activities, the primary barrier is the fluid (mud) column that balances the reservoir pressure and the secondary barrier is the blowout preventer (BOP) combined with structural barrier elements such as the wellhead and casing.

In the following, the available instrumented barriers are briefly described, including the fluid/mud column, well monitoring / kick detection equipment, the BOP and the diverter system.

### B.2 The fluid (mud) column

#### B.2.1 Description

The fluid column or drilling mud is a primary barrier during drilling. The purpose of the fluid column is to exert a hydrostatic pressure in the well bore that will prevent well influx/inflow (kick) of formation fluid (NORSOK D-010). As long as the column of drilling mud inside the well exerts pressure on the formation that exceeds the pore pressure, hydrocarbons should not flow out of the formation and into the well. If mud pressure exceeds pore pressure, the well is said to be *overbalanced*. Vice versa, if the pore pressure exceeds mud pressure, the well is *underbalanced*, meaning that the mud pressure is no longer sufficient on its own to prevent hydrocarbon flow.

The ability to maintain the mud column barrier is highly dependent on the availability of the mud circulation system. The mud circulation may be considered as (more or less) a continuously running system. A failure while running, for example a pump failure or lack of access to adequate mud quality may be the underlying cause of a kick. In this case, mud circulation may not be available for stopping the further development of the kick. The situation is different if the kick is due to a sudden change in reservoir conditions: Then the mud circulation becomes a barrier that may help to stop the kick from developing into a blowout. This lack of independence between initiating event and the safety barrier is important to recognize in the assessment of barrier performance.

Upon failure of the mud column barrier (underbalanced well) and possible flow of formation fluids into the well (i.e. a kick), action must be taken to control the situation. There will be several options for dealing with a kick depending on its size and severity. In a routine kick response scenario, the driller activates an annular preventer or a pipe ram to seal off the annular space in the well around the drill pipe. The driller can then pump heavier mud ("kill mud") into the well to counteract the pore pressure of the rock formation. Because the BOP has sealed off the annular space around the drill pipe, the driller opens the choke line (one of the three separate pipes running from the rig to the BOP) to allow circulating mud to return to the rig. Once the weight of the heavier drilling mud overbalances the hydrocarbon pressure and any hydrocarbons that flowed into the well have been circulated out, the driller can reopen the BOP and resume operations (see e.g. Chief Counsel, 2011).

If a kick progresses beyond the point where shutting in the annular preventer (or pipe ram) and pumping in heavier mud is sufficient, the last resort will be to activate the BOPs blind shear ram in order to cut the drill string and seal the well.

### B.2.2 Key requirements

| Standard | Requirement |
|---|---|
| NORSOK D-001 (Rev.2) | • The total capacity of the mud, bulk and storage system shall be sufficient to replace 100 % of any hole volume including the riser if applicable<br>• All tanks shall be equipped with a minimum of one level sensor.<br>• The level monitoring system should be of a load cell type and have a heave and list compensating system when applicable<br>• The high pressure mud pumping system shall be capable of delivering all drilling and completion fluids in normal use at the specific pressures and volumes. The system shall be designed for continuous service, and have regularity as high as possible.<br>• The HP mud pumps and supercharge pumps shall be operated from the drillers cabin |
| | The position of the BOP choke and kill line outlets should be arranged so that circulation for well control can be carried out with the drill string suspended in the BOP and the shear ram closed. |
| | Each of the Choke and Kill outlets on the BOP stack shall be fitted with two gate valves arranged in series and installed close to the BOP. The valves shall be protected against damage from external loads. One choke outlet should be located below upper annular in order to handle trapped gas. |
| | All of the gate valves shall be hydraulically operated and of remote control type. The valves shall be of the "fail-safe" closing type, and shall be capable of closing under dynamic flow conditions. |

The OLF-070 guideline (OLF, 2004) uses the following justification for not specifying a SIL requirement for the mud circulation function:

*The mud circulation system is one of the two main barriers for drilling and completing a well. The mud column and its control is an operations function, even though loss of control can lead to an emergency situation. It is comparable thus to the process control function of a process plant; only in instances of loss of process control (LAHH, LALL, PAHH, TALL, etc.) are minimum SIL requirements set for the safety function. Similar is the case for the mud column, e.g. in case of loss of well control, requirements for the safety function "closing the BOP", are set.*
*The reliability of the mud circulation system as a barrier is very dependent on geological factors of the well, mud mixing and the knowledge of the people involved. The impact of the instrumented systems is marginal.*

This reasoning is somewhat questionable and should be challenged during a future update of the OLF-070.

## B.3 Well monitoring / kick detection

### B.3.1 Description

Kick detection is not defined as a separate safety barrier in NORSOK D-010, but is covered as a *Monitoring* feature of the fluid column. Defining detection systems as safety barriers is also questionable, as a safety barrier should be able to not only detect, but also act upon (i.e., stop) the escalation into a critical event. Detection systems do not have this capability. However, detection systems may have a significant impact on the severity of an undesired event, as early detection may increase the ability of other barriers to respond successfully to a demand, such as a kick. In other words, a good and reliable kick detection system has the ability to direct the sequence of an event in an intended direction to limit harm (ref. PSA barrier definition in Appendix A). This is an argument for drawing attention to the importance of the kick detection function.

Kick detection is characterized as a conglomerate of sensor readings and events that must be compared and interpreted by highly qualified personnel. A *single* reading may not give a clear indication of whether a kick is under development, and readings from different sensors need to be compared with other events, such as unexplained changes in drill pipe or other pressures, and changes in the weight, temperatures, or electrical resistivity of the drilling mud (Chief Counsel, 2011). Examples of key sensors are:

- Sensors that measures the amount of fluid going into and coming out of the well. The former includes sensors for level indication in mud pits and the latter is a flow sensor mounted in the return line. If flow out of the well exceeds flow in or the volume of mud in, the mud pits increases anomalously, potentially due to hydrocarbons flowing into the well.
- Sensors that measures the gas content in the returning drilling mud

Automatic alarm (or action) on kick detection is typically not provided/used, and sometimes hand calculations are necessary to interpret the sensor data during non-standard procedures (this was the case during the Deepwater Horizon accident).

During well operations, rig personnel must always monitor the well for such kicks and respond to them quickly. Their options for responding to a kick diminish rapidly as the kick progresses.

### B.3.2 Key requirements

| Standard | Requirement |
|---|---|
| NORSOK D-010 (Rev. 3) | • Fluid level in the well and active pits shall be monitored continuously.<br>• Fluid return rate from the well shall be monitored continuously.<br>• Flow checks should be performed upon indications of increased return rate, increased volume in surface pits, increased gas content, flow on connections or at specified regular intervals. The flow check should last for 10 min. HTHP: All flow checks should last 30 min.<br>• Measurement of fluid density (in/out) during circulation shall be performed regularly.<br>• Measurement of critical fluid properties shall be performed every 12 circulating hours and compared with specified properties.<br>• Parameters required for killing of the well |
| | • The A annulus shall be continuously monitored for pressure anomalies. Other accessible annuli shall, if applicable be monitored at regular intervals.<br>• If wear conditions exceed the assumptions from the casing-/liner design, indirect or direct wear assessment should be applied (e.g. collection of metal |

| | |
|---|---|
| | shavings by use of ditch magnets and wear logs). |
| | • Kick drills (i.e., training in responding to well kicks) are required from once per week to once per tour for drilling personnel. |

OLF guideline 070 (OLF, 2004) summarizes the kick detection technologies used in the industry as follows:

*Historical (up till today)*

- *Tripping - Level measure of trip tank gain / loss with alarm*

*Drilling - Difference between flow in and flow return and gain / loss*

- *New Technology*

*Early kick detection. Sensors that detect pressure waves, monitor rig movement, stand pipe pressure gain loss combined with mathematical models (multi-parameter comparison)*

- Well stability analyser – losses, wash out, restrictions, etc.

*Active pit systems are also available. These systems automatically monitor the flow in and out of several pits, as it was one single pit. Other methods have been proposed for enhanced decision-support, e.g., kick detection that combines sensor readings and event recordings with probabilistic /Bayesian models and theory.*

The OLF guideline 070 does not suggest a SIL requirement for kick detection based on the following reasoning:

- *Kick detection is only one of the information elements required in the decision process for activating the BOP.*
- *Kick detection is required for process control of the mud column. It does not automatically initiate an action.*

Also this argumentation should be challenged during a future update of the OLF-070.

## B.4 The BOP system

### B.4.1 Description

The BOP is designed to stop the flow of fluids from the well by closing and sealing the well bore under all conditions, i.e. with or without tools/equipment through the BOP (NORSOK D-010). Additionally, the BOP should also allow both movement of the drill pipe in the hole and fluid circulation thought the well annulus without releasing pressure. To satisfy all the design requirements, several types of valves/preventers are required.

*Annular preventers* are made up of a synthetic rubber ring that contracts in the fluid passage and conforms to the shape of the pipe in the hole, effectively stopping the flow of annulus fluids from the well. The well pressure helps to keep the annular valves closed.

Several types of ram preventers are in use. *Pipe ram preventers* are designed to close around a certain pipe-diameter and have semi-circular openings to match. If more than one diameter pipe is used, additional pipe rams are required. *Blind rams* are designed to close over an open hole, and *blind shear rams* are designed to cut the drill pipe and stop the flow of fluid from the well. Ram preventers do not depend on well pressure to remain sealed.

Note that the annular and pipe ram preventers are design to close the annulus when the drill pipe is in the hole, and that a *drill string safety valve* is required in order to prevent flow from inside the drill string.

If a kick is detected, normal procedure with respect to operation of the BOP is:

1. Closing an annular preventer
2. Positioning "tool joints" as properly as possible in BOP
3. Closing pipe ram(s)
4. If required activate blind shear ram

The BOPs used on the Norwegian continental shelf are from 0 to 30 years old. During the last decades especially the subsea BOPs have become heavier and heavier due to increased amount of equipment and redundancy. However, the load from the heavy BOPs on the existing wellheads has now reached a critical point. Weight therefore restricts the addition of extra equipment, nice-to-have systems, and increased redundancy.

### B.4.2 Key requirements

| Standard | Requirement |
|---|---|
| OLF Guideline 070 | The annular/pipe ram function shall satisfy a SIL 2 requirement (minimum)<br>The blind shear ram function shall satisfy a SIL 2 requirement (Minimum)<br><br>The total safety function include activation from the drillers console or the tool pushers console and the remotely operated valves needed to close the BOP sufficiently to prevent blowout and/or well leak |
| NORSOK D-001 (Rev.2) | The BOP system shall as a minimum consist of:<br>• **One (1) annular preventer**<br>• **One (1) shear ram preventer**<br>• **Two (2) pipe ram preventers**<br>• Minimum one (1) Choke Line outlet<br>• Minimum one (1) Kill Line outlet<br>• One (1) wellhead coupling or connector<br>• Minimum two manual gate valves<br>• Minimum two remote hydraulic operated gate valves<br><br>Above valve arrangement applies to fixed installations where the BOP is readily accessible. |
| | The pipe rams shall be dimensioned to suit the actual tubular string. |
| | Shear and pipe ram preventers shall be fitted with a mechanical locking device in closed position. |
| | The shear ram shall be capable of shearing the pipe body of the highest grade drill pipe in use, as well as closing off the wellbore. |
| | For DP operated vessels dual shear rams should be given due consideration. |
| NORSOK D-010 (Rev. 3) | One of the well barriers should have WBE(s) that can<br>• shear any tool that penetrates the well barrier and seal the wellbore after having sheared the tool. If this is not achievable, well barrier descriptions for operational situations which do not require shearing of tools shall be identified,<br>• seal the well bore with any size tool that penetrates the well barrier. If this is not achievable, well barrier descriptions for operational situations which require shearing of tools shall be identified. |

| | |
|---|---|
| | Activation of the shear rams/shear valves or other shearing devices shall only take place when there is an emergency situation and no other options exist but to cut. |
| API RP 53 | The BOP control system should be capable of closing each ram preventer within 30 seconds. Closing time should not exceed 30 seconds for annular preventers smaller than 18 ¾ inches nominal bore and 45 seconds for annular preventers of 18 ¾ inches nominal bore and larger. Response time for choke and kill valves (either open or close) should not exceed the minimum observed ram close response time |

## B.5 The diverter system

### B.5.1 Description

The diverter system is not defined as a safety barrier in NORSOK D-010. Like the detection system, the diverter system cannot be defined as a ``true'' safety barrier, as the system cannot stop the flow. However, the diverter system may highly impact the severity of the critical event, as the system may route the release into areas where ignition is less likely to occur.

Mud coming out of the well normally flows up the riser, through the mud cleaning system and into the mud pits. In the case of an uncontrolled situation the crew also has the possibility to prevent flow up the riser and potentially onto the drill floor by activating the diverter system. When the rig crew activates the diverter, an annular packer in the diverter closes around the drill pipe (or closes the open hole if no drill pipe is in the hole). When closed, the packer normally forces the flow to one of two overboard lines on either side of the rig. The rig crew can thus select the direction of overboard flow in order to discharge gas on the downwind side of the rig.

On some drilling rigs the diverter system is also connected to the mud gas separator (as was the case on Deepwater Horizon) meaning that the crew also has the possibility to route flow via the diverter system to the mud gas separator. In such case, an important decision when activating the diverter system is whether to send the fluid influx overboard or to send it to the mud gas separator. The choice will depend on the size of the hydrocarbon influx in the riser. The mud gas separator is the right choice for small quantities of mud and hydrocarbons. But sending a large influx to the mud gas separator may cause overfilling of the separator and potential discharge of hydrocarbons onto the rig (as was the case on Deepwater Horizon).

### B.5.2 Key requirements

| Standard | Requirement |
|---|---|
| NORSOK D-001 (Rev.2) | The diverter shall have a suitable diverter piping arrangement leading to opposite sides of the installation. |
| | The diverter system shall as a minimum be remotely operable from drillers position and main BOP control unit, and be able to close around relevant drill string dimensions. |

# C Barrier Function Analysis

In this appendix each barrier function for the subsea bottom-hole drilling scenario is discussed in more detail in terms of technical implementation, key barrier elements and the requirements to testing. In addition to gaining a better understanding of each of the barrier functions for the purposes of developing safety indicators (as addressed in Chapter 5), a primary objective is to come up with a rough estimate of the predicted performance for use in the quantitative event tree analysis in Chapter 4. The idea is that by obtaining an estimate of the reliability of the individual barrier functions, it will be easier to compare their relative importance and to the focus the efforts on monitoring (and even improving) the most critical barrier functions and/or barrier elements.

## C.1 Related studies and data from operations

Access to historical data and previous studies is important to better understand why and how often safety-critical drilling systems fail during operations. Two reports have been identified that concern in-service Blowout Preventer (BOP) failure data, both published by SINTEF based on data collected from 83 wells in the US Golf of Mexico in 1997 and 1998[4].

The first report, called "Reliability of Subsea BOP Systems for Deepwater Application, Phase II DW" (Holand, 1999), presents failure statistics for various BOP systems operating in waters deeper than 400 meters (from here on referred to as deepwater). The table below summarizes the BOP configurations that were included in the study. This is a good indication of the level of redundancy that is common in the industry.

**Table C-1: Various BOP configurations included in BOP study (Holand, 1999)**

**Table 2.3 Stack configuration for the various BOPs included in the study**

| BOP no. | No. of BOP items of each type | | | | | | | Lower outlet below lower piperam | Main control system principle | Approximately depth for drilled wells (m/ft) | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Ann-ulars | Rams | BS rams | Pipe rams | VBR rams | Fixed pipe rams | C/K valves | | | Min | Max |
| 50 | 2 | 4 | 1 | 3 | 0 | 3 | 8 | No | Pilot hydraulic | 590 / 1936 | 700 / 2297 |
| 51 | 1 | 5 | 1 | 4 | 2 | 2 | 8 | Yes | Pilot hydraulic | 450 / 1476 | 450 / 1476 |
| 52 | 1 | 4 | 1 | 3 | 1 | 2 | 8 | Yes | Pilot hydraulic | 450 / 1476 | 530 / 1739 |
| 53 | 2 | 4 | 1 | 3 | 1 | 2 | 10 | Yes | Mux | 1410 / 4626 | 1790 / 5873 |
| 54 | 2 | 4 | 2 | 2 | 1 | 1 | 10 | Yes | Mux | 1960 / 6430 | 2020 / 6627 |
| 55 | 2 | 4 | 1 | 3 | 1 | 2 | 10 | Yes | Pilot, unknown | 990 / 3248 | 990 / 3248 |
| 56 | 2 | 4 | 1 | 3 | 2 | 1 | 8 | Yes | Pilot hydraulic | 540 / 1772 | 650 / 2133 |
| 57 | 2 | 4 | 1 | 3 | 1 | 2 | 8 | Yes | Pilot, unknown | 630 / 2067 | 1090 / 3576 |
| 58 | 2 | 4 | 1 | 3 | 1 | 2 | 6 | Yes | Pilot hydraulic | 520 / 1706 | 520 / 1706 |
| 59 | 2 | 4 | 1 | 3 | 2 | 1 | 8 | Yes | Pilot pre-charge h. | 1310 / 4298 | 1310 / 4298 |
| 60 | 1 | 4 | 1 | 3 | 1 | 2 | 6 | Yes | Pilot hydraulic | 570 / 1870 | 570 / 1870 |
| 61 | 2 | 4 | 1 | 3 | 1 | 2 | 8 | Yes | Pilot hydraulic | 600 / 1969 | 1110 / 3642 |
| 62 | 2 | 4 | 1 | 3 | 1 | 2 | 8 | Yes | Pilot pre-charge h. | 1160 / 3806 | 1160 / 3806 |
| 63 | 2 | 4 | 1 | 3 | 2 | 1 | 8 | Yes | Pilot hydraulic | 410 / 1345 | 630 / 2067 |
| 64 | 2 | 4 | 1 | 3 | 2 | 1 | 8 | Yes | Pilot hydraulic | 440 / 1444 | 630 / 2067 |
| 65 | 2 | 4 | 1 | 3 | 1 | 2 | 6 | Yes | Pilot hydraulic | 780 / 2559 | 1050 / 3445 |
| 66 | 2 | 4 | 1 | 3 | 2 | 1 | 10 | Yes | Pilot pre-charge h. | 1110 / 3642 | 1110 / 3642 |
| 67 | 2 | 4 | 1 | 3 | 1 | 2 | 6 | No | Pilot hydraulic | 440 / 1444 | 520 / 1706 |
| 68 | 2 | 4 | 1 | 3 | 1 | 2 | 6 | Yes | Pilot hydraulic | 1100 / 3609 | 1120 / 3675 |
| 69 | 1 | 4 | 1 | 3 | 1 | 2 | 4 | Yes | Pilot, unknown | 540 / 1772 | 540 / 1772 |
| 70 | 1 | 4 | 1 | 3 | 1 | 2 | 4 | Yes | Pilot, unknown | 600 / 1969 | 600 / 1969 |
| 71 | 2 | 4 | 1 | 3 | 3 | 0 | 8 | Yes | Pilot hydraulic | 1230 / 4035 | 1300 / 4265 |
| 72 | 1 | 4 | 1 | 3 | 3 | 0 | 8 | Yes | Pilot, unknown | 1620 / 5315 | 1620 / 5315 |
| 73 | 2 | 4 | 1 | 3 | 1 | 2 | 6 | Yes | Pilot hydraulic | 720 / 2362 | 720 / 2362 |
| 74 | 2 | 4 | 1 | 3 | 2 | 1 | 8 | Yes | Pilot pre-charge h. | 910 / 2986 | 910 / 2986 |
| 75 | 2 | 4 | 1 | 3 | ? | ? | 10 | Yes | Mux | 890 / 2920 | 890 / 2920 |

[4] These reports are currently being updated and will be issued autumn 2012.

The most common BOP configuration includes 2 annular preventers, 1 blind shear ram, 3 pipe rams and 8 choke and kill valves. This study also summarizes the type of component failure and whether the failure occurred at a safety critical time as shown in the next table.

**Table C-2: Registered BOP failures in BOP study (Holand, 1999)**

**Table 5.1 Observation of BOP failures**

| BOP subsystem | *BOP on the rig* | | | *Running BOP* | | BOP on the wellhead | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | *Test prior to running BOP* | *Not relevant* | *Unknown* | *Test prior to running BOP* | *Not relevant* | Installation test | Test after running casing or liner | Test scheduled by time | Not relevant | |
| | ***Safety non-critical failures*** | | | | | | ***Safety critical failures*** | | | |
| Flexible joint | | | | | | | | | 1 | 1 |
| Annular preventer | 1 | | | | | 1 | 4 | 3 | 3 | 12 |
| Ram preventer | 3 | | | | 1 | 1 | 5 | 1 | | 11 |
| Connector | 2 | 2 | | | | 2 | | | 4 | 10 |
| Choke and kill valve | 9 | | | | | 1 | 1 | 2 | | 13 |
| BOP attached line | 1 | | | 1 | | | | | | 2 |
| Riser attached line | 1 | | | 2 | | | | | 1 | 4 |
| Jumper hose line | | | | 1 | | | 1 | | | 2 |
| Control system | 16 | | 3 | 5 | | 10 | 6 | 7 | 13 | 60 |
| Dummy Item | 2 | | | | | | | | | 2 |
| Total | 35 | 2 | 3 | 9 | 1 | 15 | 17 | 13 | 22 | 117 |
| | 34% | | | 9% | | 57% | | | | |

Fault tree analyses are also summarized in the report. The analyses are based on the most common BOP configuration, except with 6 choke and kill valves. The analyses do not assume an acoustic backup control system which is required for operations on the Norwegian continental shelf. Neither do the analyses capture the contribution from the other safety barriers. The data of interest to this study have been summarized in the table below:

**Table C-3: Estimated failure probabilities from BOP study (Holand, 1999)**

| **Description of fault scenario** | **Average probability of failing to close in a kick (%)** |
|---|---|
| **No failures:** 3 pipe rams and 2 annulars can seal around the drill pipe and the BSR can cut the pipe and seal the well | 0.10511 |
| **Lower pipe ram unavailable**: 2 pipe rams and 2 annulars can seal around the drill pipe and the BSR can cut the pipe and seal the well | 0.12678 |
| **2 annulars, the middle pipe ram and the BSR are unavailable**: 2 pipe rams can seal around the drill pipe | 0.10537 |
| **2 annulars, the lower and upper pipe rams and the shear ram is unavailable**: 1 pipe ram can seal around the drill pipe | 0.21473 |
| **All rams are unavailable:** 2 annulars can seal around the casing in the hole | 0.18093 |
| **One pod is pulled for repair:** All the pipe rams and the annular can seal around the drill pipe/tubular and the BSR can cut the pipe and seal off the well | 0.32812 |

The second report, called "Deepwater kicks and BOP Performance" (Holand, 2001) contains detailed information regarding the nature of kicks and related BOP problems. The fault tree analyses from the first report have been further refined (for instance to take into account geometric sealing capability for the preventers/rams given the size of the drill pipe inside BOP based on historical information) and are used to estimate the effects of BOP failures on the ability to close in a kick during subsea operations. The table summarizing these results has been included below.

**Table C-4: BOP failure probabilities related to kick prevention (Holand, 2001)**

**Table 8.10 Effect of various BOP failures on the ability to close in a kick with subsea BOP**

| Type of failure | Probability of failing to close in a kick | Ratio vs. base case | Risk increase |
|---|---|---|---|
| No known failure in the BOP (base case, from Table 8.3) | 0.1251 % | 1.0000 | 0.00 % |
| One pod is pulled for repair | 0.3513 % | 2.8074 | 180.74 % |
| Inner kill valve (below LPR) leaks in closed position (see Figure 8.1) | 0.1329 % | 1.0619 | 6.19 % |
| Lower inner choke valve (below MPR) leaks leaks in closed position (see Figure 8.1) | 0.1262 % | 1.0086 | 0.86 % |
| Lower annular is leaking in closed position | 0.1251 % | 1.0000 | 0.00 % |
| Blind-shear ram is leaking in closed position | 4.3031 % | 34.3918 | 3339.18 % |
| Upper pipe ram is leaking in closed position | 0.1256 % | 1.0035 | 0.35 % |
| Middle pipe ram is leaking in closed position | 0.1263 % | 1.0097 | 0.97 % |
| Lower pipe ram is leaking in closed position | 0.1438 % | 1.1490 | 14.90 % |
| One pilot valve for lower pipe ram failed, or similar | 0.1252 % | 1.0005 | 0.05 % |
| One pilot valve for blind-shear ram failed, or similar | 0.1376 % | 1.1000 | 10.00 % |
| Manifold regulator one pod fails to supply pressure | 0.1379 % | 1.1021 | 10.21 % |
| Annular regulator one pod fails to supply pressure | 0.1252 % | 1.0006 | 0.06 % |

## C.2 Barrier Function 1 – Gas inflow is detected before it reaches BOP

### C.2.1 Definition

The purpose of this barrier/safety function is to detect the inflow of fluid (or "kick") to the well before the fluid has reached beyond the BOP, such that the subsequent BOP closure will prevent release of gas/fluid to the environment.

Note that there are many aspects outside of the instrumented systems that influence the ability to reliably detect kicks. For example well characteristics, such as the well depth, and the heave dynamics of the drill rig/vessel will strongly influence the ability to reliably detect gas/fluid inflow.

### C.2.2 Diagram illustrating the barrier elements

The diagram below illustrates the different elements of barrier function 1. Volumetric comparison by level (pit gain) and rate comparison by flow are assumed to be standard kick detection methods, whereas other methods for kick detection such as drill pipe pressure and gas content in the mud may vary from one installation to the next. While the reliability of the instrumentation is important, in particular the location of the sensors, the problem identification and handling by the human operator is critical to successful detection. The human-machine interface in relation to kick detection often requires that personnel monitor information on a large number of monitoring screens. Each monitoring screen may trend readings from different types of sensors that are hooked up to different types of systems. Kick-alarms based on certain trends are definitely possible to implement, but there is not a lot of evidence of widespread use of this technology today. Note that this barrier function has no "final elements" as such. The function relies on human interpretation of data from instrumented monitoring systems for successful kick detection, and there is no automatic action involved.

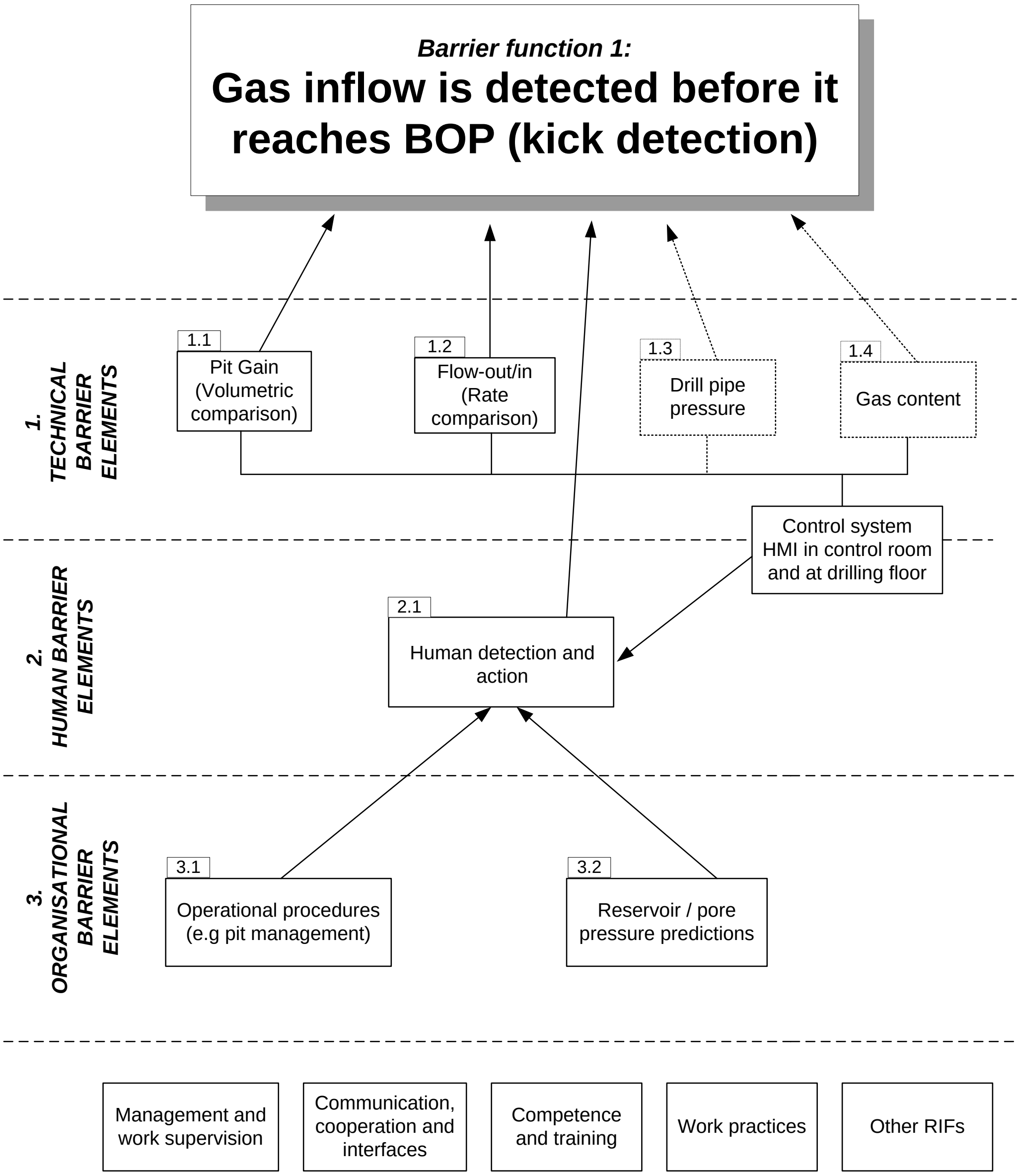


**Figure C-1: Barrier element diagram for kick detection function**

### C.2.3 Equipment overview

The conventional methods for kick detection during normal drilling operations includes ***pit volume indicators*** and/or ***mud flow indicators*** designed to detect an increase in the flow of fluid returning from the well compared to what is being circulated by the pump. The pit volume indicator is traditionally implemented by the use of floats in each pit. The more rapidly responding flow indicators are implemented as a paddle-type sensor in the flowline combined with a pump stroke counter to assess the flow in and out of the well. There are two independent measurement systems.

Other methods used as part of kick detection methods in the industry today include:

- ***Gas content sensors*** to measure gas content in the fluid returned from the well (high value indicates kick)
- ***"Drilling breaks"***, i.e. rapid/unexpected changes during drilling, typical drilling quickly 1-2 metres (indicates looser formation, discovery of oil/gas and a possible kick)
- ***Drill pipe pressure*** (unexplained fluctuations can indicate a kick), used during negative pressure testing. Should also be used when the pumps are stopped. A flow check is then performed.
- ***Flow sensors*** for return flow detecting a kick at a late phase, in which case the annular BOP should immediately be activated.
- ***Acoustic kick detection*** (gas in annulus reduces the speed of sound in the mud, detects the size of a gas bubble under the BOP). The method was more common in the 80-ies.
- ***Flow line cameras*** placed on mud pit (detects small flow variations compared to the flow sensor). The method is seldom used.
- ***ECD*** (equivalent circulating density). Measures the increase in bottom hole pressure.

The detailed implementation of kick detection functionality will vary from one installation to the next. However, it is reasonable to assume that most methods consist of a selection of sensors and some amount of computer processing (for instance to remove noise and limit the number of spurious trips). Whether the kick detection is partly automated by the use of alarms (and other support systems such as Active Pit System that allows the driller to aggregate the volume of several pits into one volume) will also depend on the rig equipment and the actual set-up of the system prior to drilling.

An overview of the equipment involved in kick detection is shown below in Figure C-2. The level of redundancy indicated in the figure should be considered as kooN rather than a 1ooN, since a single sensor or event may not give enough information to identify the kick.

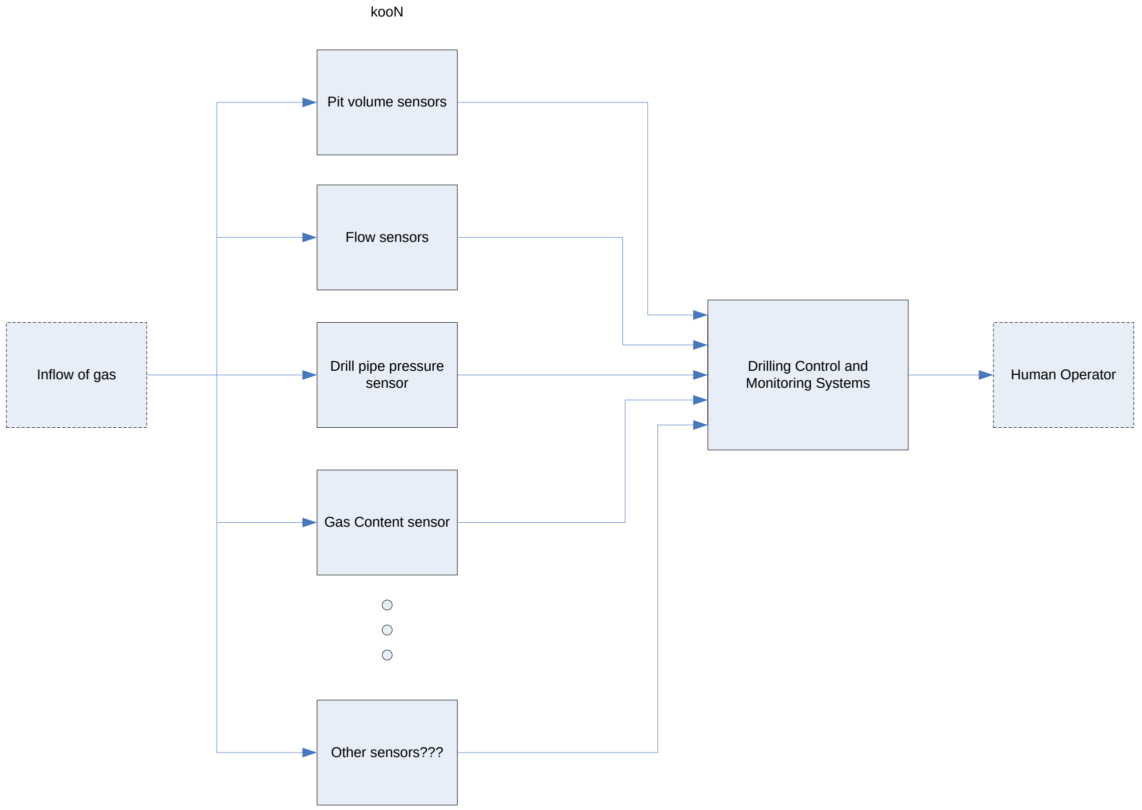

**Figure C-2: Equipment involved in kick detection**

## C.2.4 Testing

Well monitoring / kick detection equipment seems to be tested (calibrated) at least once a year (tanks filled and emptied). However, no specific requirements have been identified in relation to such activities.
Personnel's ability to respond to kicks are subject to periodic drills, but it is unclear whether such drills practise personnel’s ability to identify early kick indications using available information, and to which degree coordination of available resources that have a responsibility for kick detection is part of the drills.

## C.2.5 Rough PFD Assessment

In order to come up with a realistic measure for how frequently the kick detection systems fail to detect a kick before the gas has passed the BOP, operational data was consulted. The data that forms the basis of the “Deepwater Kicks and BOP Performance” report (Holand, 2001) indicate that 5 of the 48 well kicks were not detected before the gas had passed the BOP. Note that this figure was obtained upon request from the author (Per Holand), as this figure is not explicitly stated in the report.

Based on the above, we could assume a PFD of 0.1 for this function for deepwater wells. However, this is considered a conservative figure for drilling operations on the Norwegian Continental Shelf where not all wells are in deep water where kicks are more difficult to detect. In another SINTEF project performed for PSA Norway (RNNP, 2012), some 30 well control incident reports (for the period 2003 – 2010) have been gone through and 4 or 5 of these events seem to have resulted in hydrocarbons above the BOP. These incidents only include so called category 2-5 incidents, i.e. the less critical and most frequent category 1 incidents are excluded. Taking all events for the period, i.e. some 127 incidents in total, a conservative estimate for delayed kick detection on NCS wells seem to be *0.05*.

Important factors influencing the probability for detecting kick are type of kick, type of drilling mud, degree of instrumentation and equipment types and awareness and competency of personnel. In addition, both the kick probability and the probability of detecting the kick vary with the type of operation. The highest kick probability and also the lowest probability of detecting a kick (due to limited monitoring) are assumed to be during connection. It is also more difficult to detect a kick when drilling with oil based mud since gas separated from the mud will not expand until it reaches the riser, and a continuous increase of gas cannot be easily detected. As discussed above, the depth of the well is also an important factor.

## C.2.6 Discussion

Kicks are primarily detected from monitoring flow and pit volumes. Many circumstances may complicate kick detection, for example during start-up and stop of pumps. When the pumps are stopped the flow will stop and the fluid in the pipes starts to return. When the pumps are started again, the volume levels are exceeded and alarms will appear. If a kick occurs in this situation it will be difficult to detect, as the alarms are “expected”.

Early kick detection is critical in order to prevent/minimize spills to the environment. Current technology makes it possible to instrument a large number of sensors that can be used to detect influx of well fluid, but a safe outcome relies on the human operator to correctly interpret and act on the available information in a timely manner. Even if the monitoring of flow and pit volume has improved, it is still difficult to understand

and make decisions based on those reading alone. It is also challenging to get reliable pit volume measurements on floating rigs due to rig movements.

The design of advanced monitoring systems (including high quality sensors suited for the purpose) that generate audible alarms in emergencies, while keeping spurious trips (false alarms) at an absolute minimum, remains a challenge. In particular, a user friendly monitoring system that can provide operator support during non-standard operations with a minimum of “special setup” could lead to improved kick detection.

Lack of failure data in relation to kick detection equipment is a problem, in particular if it is decided to set quantitative requirements to the instrumented part of the kick detection function. Systematic data collection and analysis of reported failures should therefore be considered for implementation by the drilling companies (rig owner). Due to the criticality of this system, the associated technical components may need to be classified as safety-critical and a more rigorous system may need to be established to ensure that inspections, calibrations, and testing are performed on a regular basis. It may also be important to address kick detection in new versions of standards, like NORSOK D-001 and NORSOK D-010.

## C.3 Barrier Function 2 – BOP seals and hydrocarbons are trapped below BOP

### C.3.1 Definition

The purpose of this barrier function is to seal the annulus based on activation from the rig, in order to prevent flow of hydrocarbons out of the wellbore. In practise, this barrier is typically made up of one or two annular preventers, two or more ram preventers and the systems required to operate the valves. The annular preventer(s) and the rams are activated from rig, typically by pilot hydraulic activation.

### C.3.2 Diagram illustrating the barrier elements

The diagram below illustrates the different elements of barrier/safety function 2. The barrier elements include (mainly manual) activation, actuation of the annular / ram preventers and the preventers themselves.

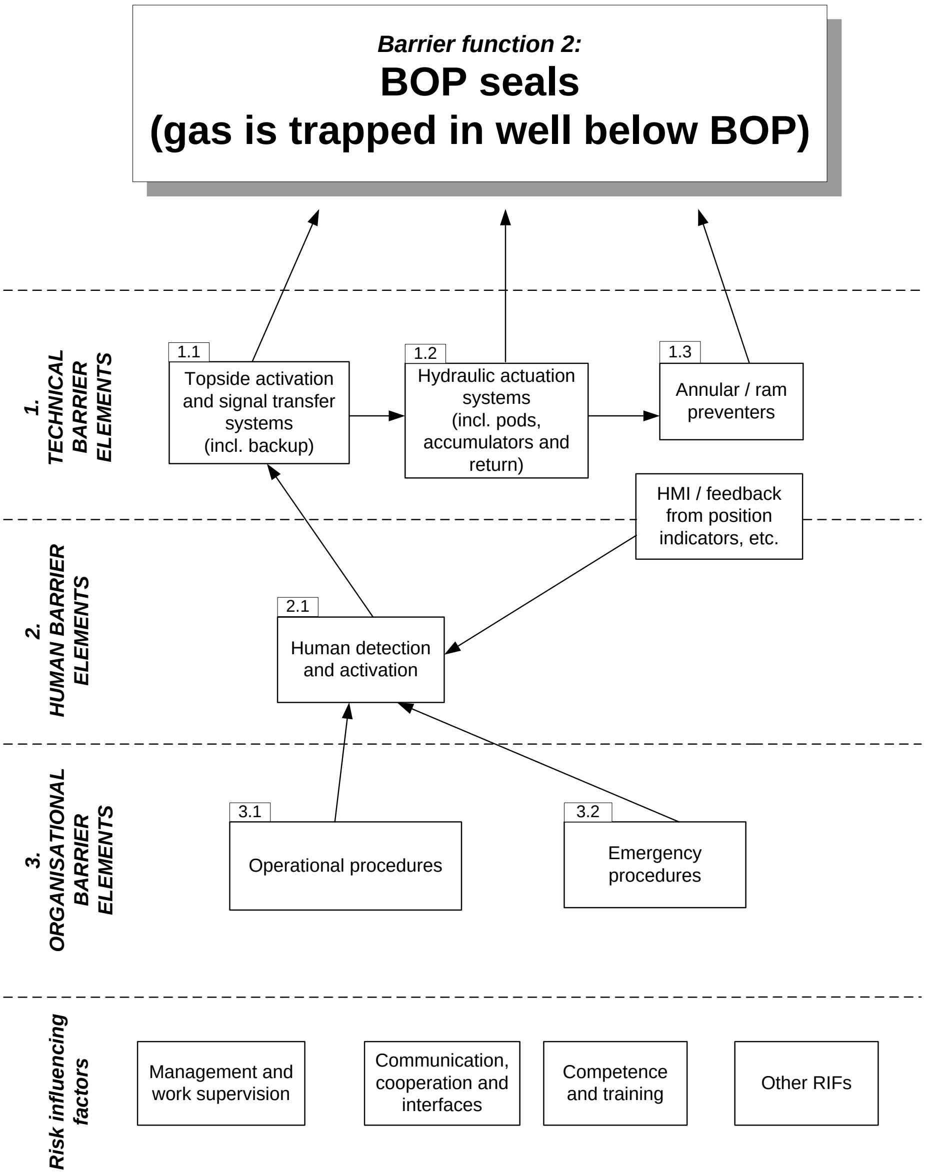


**Figure C-3: Barrier element diagram for BOP seal function**

### C.3.3 Equipment Overview

Annular preventers are made up of a synthetic rubber ring that contracts in the fluid passage and conforms to the shape of the pipe in the hole, effectively stopping the flow of fluids from the well. The well pressure helps to keep the annular valves closed. The annular preventers are closed first in a kick scenario, as they have a simpler design that will typically be able to handle more wear and tear than the ram preventers.

Ram preventers are designed to close around a certain pipe-diameter, and have semi-circular openings to match. If more than one diameter pipe is used, additional ram preventers are required. Ram preventers do not depend on well pressure to remain sealed.

All the preventers rely on the same *activation* mechanisms. For subsea wells, the following methods are feasible:

- Electrical Control Signal from the surface (through a cable)
- Acoustic Control Signal from the surface
- Mechanical control by Remotely operated vehicles
- Deadman switch or automatic shear function in case all control lines are severed.

While the methods above provide some redundancy for certain worst-case scenarios, only the first two options are really candidates for "normal" handling of kick scenarios. Electrical control is the primary means of activation and two control pods are required for BOP redundancy. Acoustic backup is required for operations on the Norwegian Continental Shelf.

Hydraulic *actuation* is required for operation of all the preventers. An example of the equipment required to close one preventer is shown in Figure C-4. Note that the preventers would be selected and operated one at a time, and that only the equipment shown as orange boxes is unique for each preventer. All the preventers may not have the option of acoustic activation.

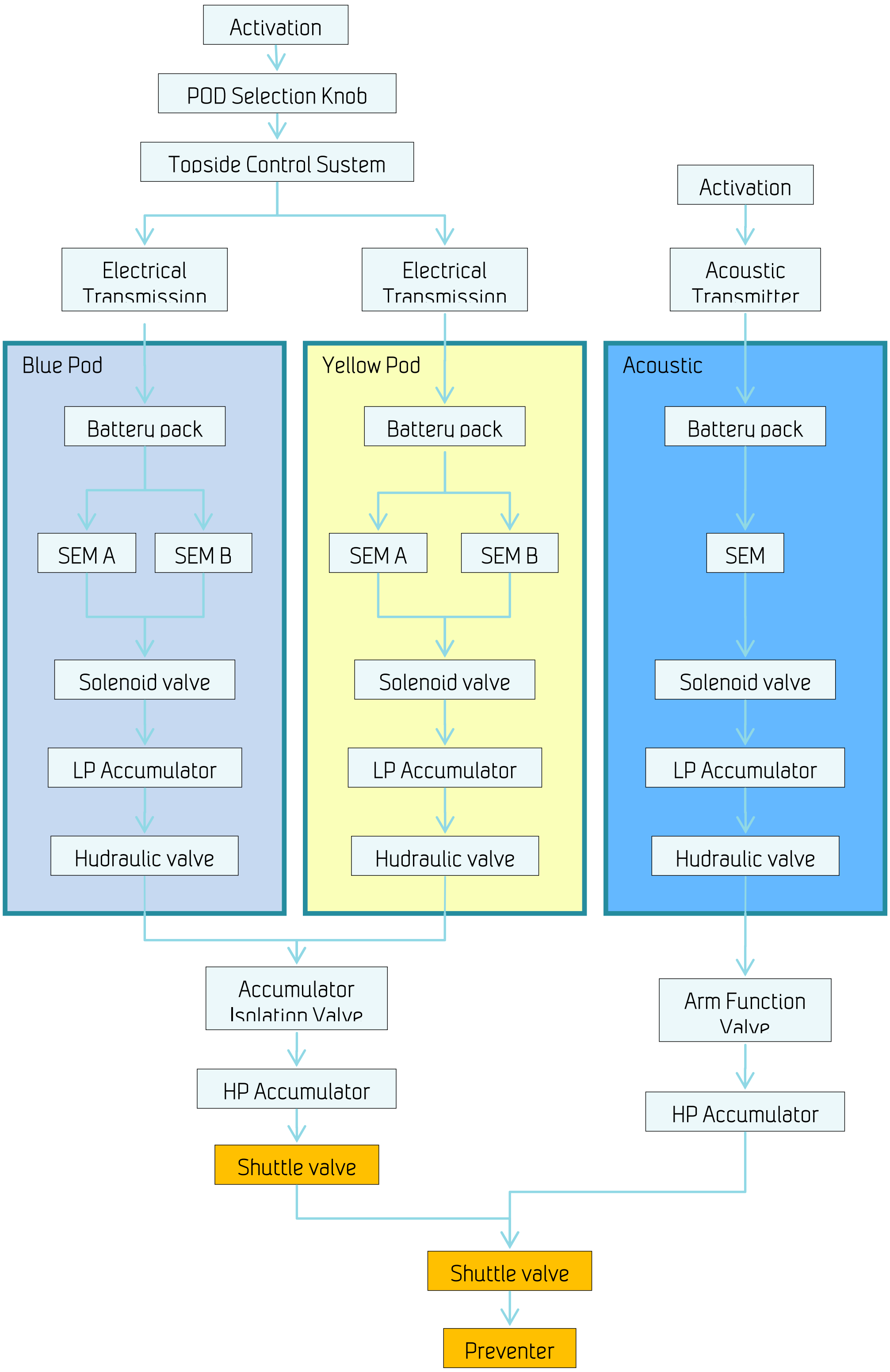


**Figure C-4: Equipment required for closing one preventer**

## C.3.4 Testing and Monitoring

The BOP is normally a passive system during drilling operations. Functional testing is therefore needed on a regular basis to reveal failures. Functional testing should be performed once a week, pressure testing to maximum section design pressure should be performed every 14th day and pressure testing to working pressure (only 0.7*working pressure for annular preventers) should be performed every 6 months according to NORSOK D-010 (Appendix A, Table A.1). A functional test is also performed after the BOP has been installed subsea prior to drilling operation start-up. Furthermore it is required that the BOP with associated valves and other pressure control equipment shall be subjected to a complete overhaul and shall be recertified every five years (NORSOK D-010, Table A.1).

API RP 53 also contains requirements for testing frequency of BOP and well barrier equipment: *All operational components of the BOP equipment systems should be functioned at least once a week to verify the component's intended operations. Function tests may or may not include pressure tests* (section 18.3.1 of the standard). Further (section 18.3.3): *Pressure tests on the well control equipment should be conducted at least: a) Prior to running the BOP subsea and upon installation. b) After the disconnection or repair of any pressure containment seal in the BOP stack, choke line, choke manifold, or wellhead assembly, but limited to the affected component. c) Not to exceed 21 days.*

Equipment degradation should not only be detected / monitored based on numbers of operations / activations. Other important factors influencing the degradation process includes type of operation, maintenance, operational and environmental parameters.

The technical condition of the annular preventer can be monitored by:

- Measuring pressure volume consumed: In case of degraded gasket, more pressure and volume is needed to close the valve. Pressure and volume consume is logged for each function test.
- Measuring closing time: Long closing time indicates degraded valve. Closing time is logged at every function test.

The technical condition of the pipe rams (is also relevant for shear ram) can be monitored by:

- Volume consume: If only half of the expected fluid is consumed during test, the pipe rams have been partly closed.
- Inspection when BOP is pulled. For some types of pipe rams it is difficult to get indication of technical status based on volume consume as the volume consume between a healthy and a degraded valve is small.
- Ensuring that the suitable size available.

## C.3.5 Rough PFD Assessment

The "Reliability of Subsea BOP Systems for Deepwater Application, Phase II DW" (Holand, 1999) report as discussed in section C.2, specifies 4 safety critical failures for the annular preventers over a total of 4009 BOP days (from 83 wells). By taking into account the number of annular preventers in each BOP stack, the in-service days for this component amounts to 7449.

For ram preventers, 6 safety critical failures were reported over the 4009 BOP days (this includes 2 shear ram failures). By taking into account the number of ram preventers in each BOP stack, the in-service days for this component amounts to 16193.

The report also describes 25 safety critical control system failures, including 3 failures that resulted in loss of some or all functions in both pods. These failures will be included in our estimate for preventer failure rate, as they could have resulted in a failure to close any of the preventers.

The critical failure rates per hour for the annular preventers, the ram preventers and the control systems can be calculated as follows:

$$\lambda_{annular} = \frac{4}{(7449 \times 24)} = 2.2 \cdot 10^{-5} \; per\ hour$$
$$\lambda_{ram} = \frac{6}{(16193 \times 24)} = 1.5 \cdot 10^{-5} \; per\ hour$$
$$\lambda_{controlsyst} = \frac{3}{(4009 \times 24)} = 3.1 \cdot 10^{-5} \; per\ hour$$

Due to the many shared components involved in successful operation of each BOP preventer, we will assume only two redundant preventers (one annular and one pipe ram) for the purposes of this rough assessment. It is reasonable to assume two redundant paths given the pod redundancy and the acoustic backup system. The PFD for this barrier/safety function can be estimated by conservatively assuming that 10 % of the failures are due to common causes (the contribution from independent failures can be neglected). The common cause factor has been selected to be relatively high given the significant number of failures observed in both pods based on the data from the operators, combined with other sources of common failures (such as the supply of hydraulic fluids).

In order to estimate the PFD, we also need to know the test frequency and test coverage for each component. The testing requirements vary depending on operating country. Here we assume that the testing is performed in accordance with the Norwegian regulations. NORSOK D-010 specifies that the annular and the pipe rams shall be function tested weekly, pressure tested to maximum section design pressure every 14 days and pressure tested to working pressure every 6 months. A weekly function test is also required for the shear rams, but no periodic pressure test is required. Since the shear rams are treated in a separate section, a 14 day test interval has been assumed for all the preventers here. Due to the preventer redundancy, the effect of modelling all the different test intervals with expected test coverage is expected to have limited impact on the overall PFD. Using the method outlined in the PDS Method Handbook (SINTEF, 2010), the PFD can be roughly estimated as shown below.

$$PFD \approx \frac{3.1 \cdot 10^{-5} \times 168}{2} + 0.1 \times \frac{\sqrt{2.2 \cdot 10^{-5} \times 1.5 \cdot 10^{-5}} \times 336}{2}$$

$$PFD = 0.0026 + 0.1 \times 0.0031 = 0.0029$$

As a reality check, a comparison was made to the fault tree data that was performed as part of the report “Reliability of Subsea BOP Systems for Deepwater Application, Phase II DW” (Holand, 1999). With only two annular valves available to seal the annulus, the probability of failing to close in a kick was estimated to be 0.0018. With only one pipe ram available to seal the annulus, the probability of failure was estimated to be 0.0021.

Note that the PFD estimated above only takes into account the reliability of the equipment required to perform the function. The relatively low probability of an equipment failure is closely related to the frequent testing. However, the ability of the operator to understand the developing situation and to trigger the function if required is not included in the fault data. Here we need to differentiate the situation: Upon early kick detection the operator will have some time to evaluate the situation and close the BOP preventers. In this situation it is assumed that the operator will perform correctly 99 out of 100 times. On the other hand in case of late detection of the kick and well fluid already having escaped above the BOP, the situation will be considerably more stressful and in such a case the operator is assumed to perform correctly in only 95 out of 100 times (also the flow across the BOP may impact the reliability of the annular preventer – see discussion below). Based on this, the estimated probability of failure on demand of this function (2A and 2B respectively) will be as follows:

Function 2A: BOP fails to seal annulus with all HC below BOP: $PFD_{2A} = 0.0029+0.01 = 0.0129 \approx 0.013$

Function 2B: BOP fails to seal annulus with HC flow in riser: $PFD_{2B} = 0.0029 + 0.05 = 0.05029 \approx 0.05$

Note the dependencies and shared components between the present barrier function and barrier function 5 (closure of shear ram) and partly barrier function 6 (activation of diverter). In order to compute a realistic PFD, we may need to integrate all these common elements into one RBD, or alternatively allow for dependencies between the barrier functions in the event tree.

### C.3.6 Discussion

As discussed in the previous section, it is reasonable to assume that the reliability of the annular preventer is a function of how early it is activated. If, as was the case on Deepwater Horizon, the annular preventer is activated when a large flow of mud and hydrocarbons is already flowing through the BOP, the likelihood of successful operation may be less than with no flow through BOP. Also the stress on the operator is considerable higher when well fluids are coming up through the riser. The negative impact on the BOP sealing capability from gas/mud passing through it (and what flow-rates that may constitute a threat), obviously represents an area of uncertainty and requires additional research. For the purpose of this study, and as seen from the discussion in section C.3.5, a considerable higher failure probability of the annulus sealing function has been assumed when hydrocarbons have already escaped above the BOP.

The reliability of the annular preventer is also a function of its service life. Data presented in the “Deepwater Kicks and Performance” study (Holand, 2001), indicates that for 2 recorded annular preventer failures, the failure was likely related to previous kick killing operations. In both cases, the annular preventer had been used for stripping.

As documented in section C.3.5 above, the "Deepwater study" (Holand, 1999) identified control pod failures that prevented successful BOP closure. In particular, 2 failures involved the loss of all functionality in both control pods. The report concluded the following:

*"It seems that the isolation between the pods is not good enough in “modern” BOP control system. A single subsea failure should not drain both the blue and yellow pod and make the BOP inoperable. The failures in the main hydraulic supply are observed when they occur and do not require a BOP test to be observed. From a safety point of view this is beneficial."*

This issue must be carefully monitored and appropriate design changes must be considered if this trend is supported by additional data.

In the RNNS project (Risk level on the Norwegian Continental Shelf) test data for different safety critical elements are reported to PSA Norway. For the function "Well isolation with BOP" this include leakage testing of the blind shear ram, the upper and lower pipe ram and the annular preventer. For the period 2008-2010 the average amount of test failures for these elements is in the order of 0.006. This figure is accumulated for the different elements and is therefore difficult to directly apply in calculations, but at least it indicates an order of magnitude for an ideal test situation with no stress on the operators.

*Discussions from workshops:*
There have been events where BOP equipment has functioned during topside test but failed when lowered subsea, due to different temperatures, influence on electrical equipment and influence from other rigs/vessels (battery, accumulator, DP system). There has also been an event where the shear ram (barrier function 5, ref, section C.6) was closed (during test) under flow. The shear ram gaskets were then “washed out” causing increased leakage probability. The event was due to lack of communication between driller and subsea.

Typical week points in a BOP are single points of failures such as connector leakages (all BOPs), failures of single riser tubing (multiplex BOPs) and loss of electrical signal to subsea solenoid (new BOPs). Also Common Cause Failures (CCFs) are critical, in particular CCFs of the two control pods as discussed above.

## C.4 Barrier Function 3 – Circulation of Heavier Mud

### C.4.1 Definition

The normal way to control a kick is by adjusting the weight of the drilling mud that is pumped down the drill string, i.e. the circulation of heavier mud is the preferred method to regain control of the well in a kick situation. This operation includes both pumping heavy mud into the well and allowing gas and light mud to exit through the choke lines.

For this analysis, all operations that involves the pumping of a matter (mud, cement or other) into the well for the purposes of gaining control of the well in a kick situation, is considered a part of the mud circulation function.

### C.4.2 Diagram illustrating all barrier elements

The diagram below illustrates the different elements of barrier/safety function 3. As for barrier function 1 this function also depends heavily on manual intervention and operation.

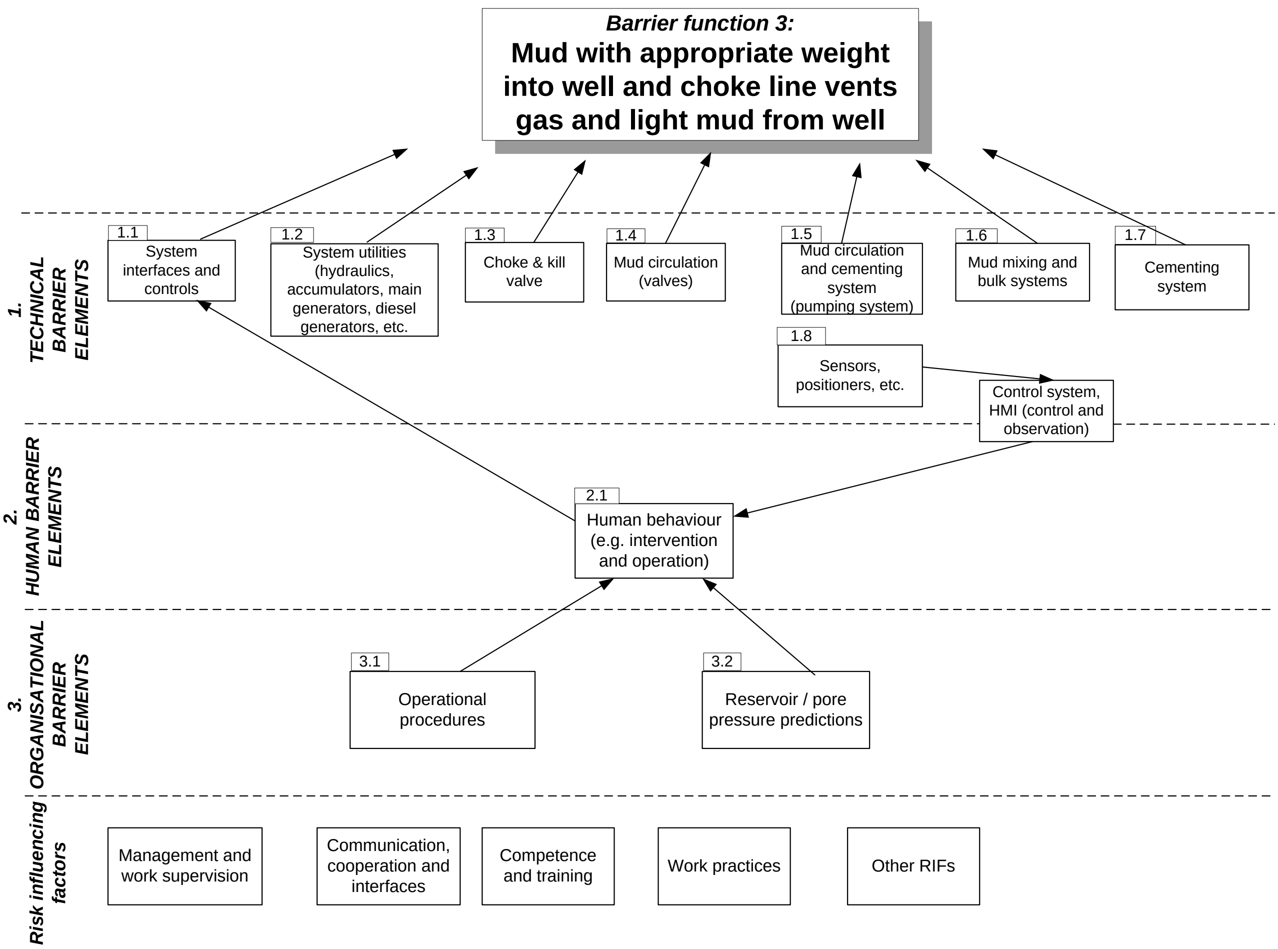


**Figure C-5: Barrier element diagram for heavy mud circulation function**

## C.4.3 Equipment Overview

The main components that together enable the pumping of heavier mud into the well after BOP closure consist of the mud pits/tanks where the mud is stored, the main mud pump (typically a triplex piston/plunger type), mud-mixing equipment that allows mixing of the correct density mud and the choke valves and lines that facilitates the removal of the lighter mud in the well. Mud circulation at an early stage is important to prevent well damage that can cause a possible seabed blowout.

In general, two or three mud pumps (electrically driven) are required. However, normally the drilling rigs have three or four pumps installed. In addition there are cement pumps (diesel driven) functioning as stand-by (emergency) pumps. Historical events show that the cement pumps are frequently used for mud circulation due to malfunction of the mud pumps. It should be noted that the cement pumps typically have less capacity than the mud pumps.

The heavier drilling mud is mixed and is pumped from the mud pits/tanks to the main mud pump using low-pressure pumps. From there the mud is pumped down through the drill string to the bit, through the nozzles of the bit and back up the annular. Since the BOP seals the annular space and normal mud circulation is not possible, the adjustable choke is used to let the lighter mud circulate out of the well. The choke is remotely controlled from the surface to maintain sufficient pressure to keep the formation fluids out of the well but to prevent pressures high enough to damage the well. The kill lines are not used for normal kick control and have not been included in the rough PFD assessment.

## C.4.4 Testing

The mud system is not tested regularly. According to API RP 53 preventive maintenance of the choke and kill line assemblies should be performed regularly, checking particularly for wear and plugged or damaged lines. Frequency of maintenance will depend upon usage.

## C.4.5 Rough PFD Assessment

The key equipment involved in this barrier/safety function is shown below (excludes structural components).

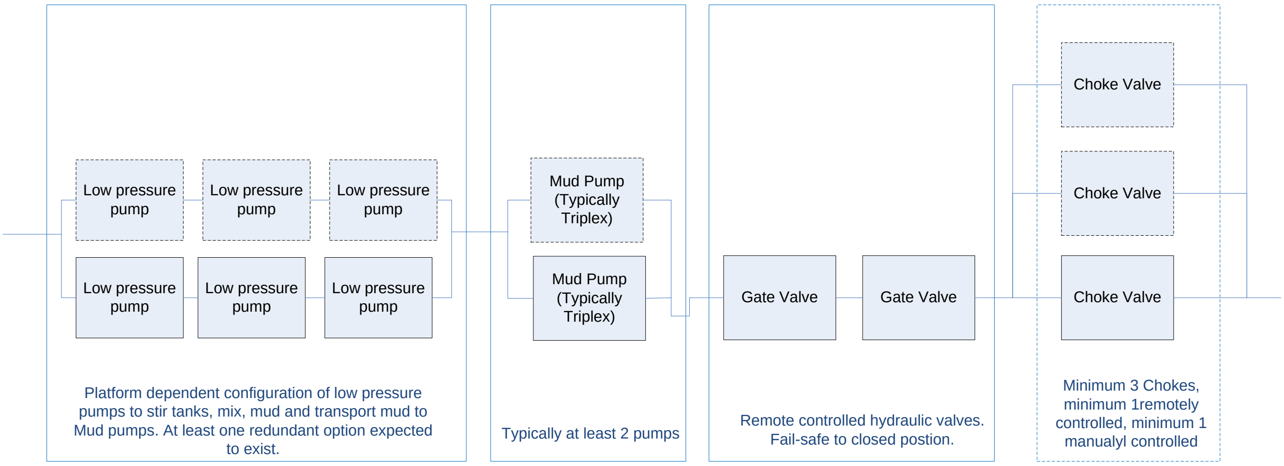


**Figure C-6: Block diagram for heavy mud circulation function**

According to the “Deepwater Kicks and BOP Performance” study (Holand, 2001) the circulation of heavier mud alone was used to successfully regain control of 29 of the 48 kicks that were reported. For 6 kick events circulation was never attempted for various reasons (like re-cementing in case of a poor casing cement job). That leaves a total of 13 cases where measures in addition to the circulation of heavier mud were required in order to regain control of the well. In some of these cases, the additional measure was cementing, which can be argued is a part of the mud circulation function. However, for seven cases either bull-heading, bleed off or diverting was used to regain control. All of these cases involve procedures carrying more risk and/or involve actual emissions to the environment. For the purpose of this study, it is argued that the barrier/safety function involving regaining control of the well by the injection of heavier mud failed in 7 of 42 cases.

Based on the above, the PFD for this function is estimated to be 0.2. It should be noted that the reliability of the mud pumps will vary from situation to situation. Failures of mud pumps are mainly due to external factors such as lack of power supply or gas on the rig. The PFD figure of 0.2 is assumed to include various types/causes of pump (and other equipment related) failure.

### C.4.6 Discussion

Examples of challenges related to the successful circulation of heavier mud are access to a sufficient amount of mud, power supply (the emergency generator does not have enough capacity to feed the mud pumps), capacity of back-up pumps (cement pumps) and the continuous need for adjustment during circulation (weight, methods, etc.).

Further, if it is decided to set quantitative requirements to instrumented parts of the mud circulation function, the lack of relevant failure data on instrumentation and logic may also be a future challenge.

## C.5 Barrier Function 4 – Drill string safety valve seals drill pipe

### C.5.1 Purpose

The purpose of this barrier/safety function is to prevent flow from inside the drill string, since the annular and ram preventers can only stop the flow from the annulus as long as the drill pipe is in the hole. Several additional safety valves are available to prevent flow up the drill string.

### C.5.2 Diagram illustrating all barrier elements

The diagram below illustrates the different elements of barrier/safety function 4.

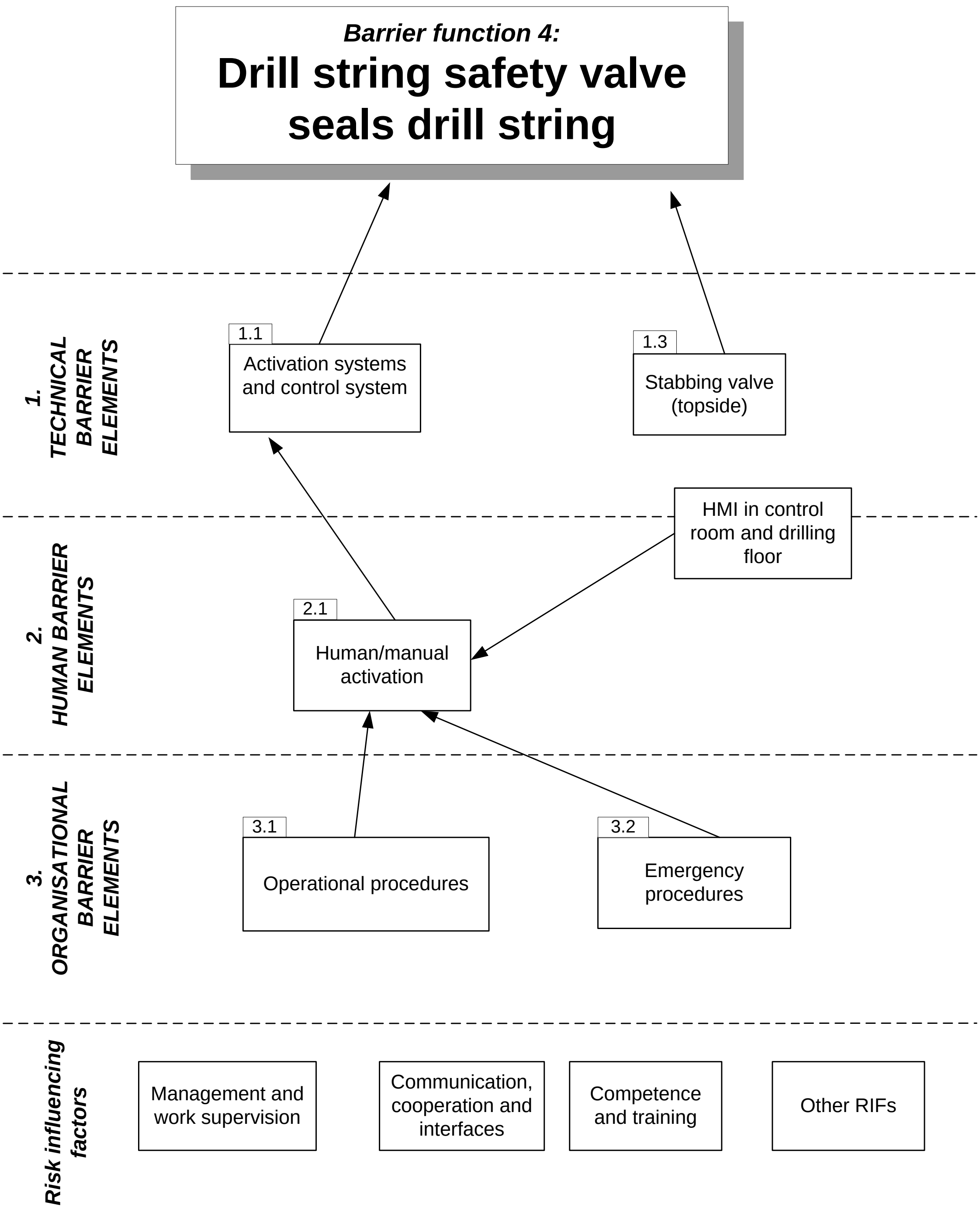


**Figure C-7: Barrier element diagram for drill string safety valve function**

## C.5.3 Equipment Overview

Traditionally, drilling operations have relied upon manual safety valves, typical wrench operated ball valves. The traditional kelly drive systems, includes a safety valve above and below the kelly (upper and lower kelly cock). In addition, another safety valve (often referred to as stabbing valve or internal BOP) would be available to prevent blowouts during tripping operations (usually on-hand and ready to be inserted/installed in a kick situation). Normally, there are two manual kelly-cock valves and two internal BOPs (iBOPS) for recovery to stop internal gas – one manual one-way valve (mounted when needed) called iBOP and one remote-controlled ball valve (always in place) called inside valve.

The top drive systems used for most subsea drilling operations today, allows easy and quick reconnection to the top drive if a kick is detected during tripping. The systems typically includes at least one remotely controlled hydraulic safety valve above the saver/crossover sub and the main shaft (similar to a lower kelly valve) to enable fast shut in of the drill pipe. At least one other valve is expected to be available (similar to an upper kelly valve), and the manual stabbing valve can of course still be installed if needed.

While many options may exist to seal the drill pipe, for the purposes of this study one remotely controlled valve is assumed available to prevent hydrocarbons to escape through the top of the drill string. This valve will be referred to simply as the *drill string safety valve*.

### C.5.4 Testing

According to operational personnel (through workshop discussions), the drill string safety valves are pressure tested prior to each drilling operation. After this it is function tested every week and pressure tested every 14$^{th}$ day. Whether this practice is consistently implemented throughout the industry is however unclear.

### C.5.5 Rough PFD Assessment

For the purposes of this study (blowout protection during bottom-hole drilling) we will assume that one remotely controlled drill string safety valve is available to prevent flow up the drill string. This system is illustrated below:

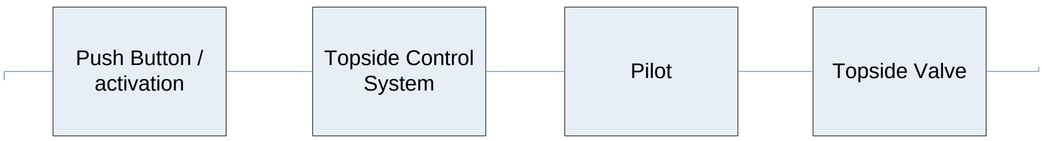


**Figure C-8: Block diagram for drill string safety valve function**

The PFD can be calculated using the methods described in the PDS Method Handbook (SINTEF, 2010). The failure data is based on the failure rates for comparable components in the PDS Data Handbook (SINTEF, 2010b). A 14 day test interval has been assumed in accordance with Annex A in NORSOK D-010. For the purposes of this rough PFD assessment, the following assumptions have been made:

- 75 % of all “testable valve failures” (i.e. DU failures) will be detected during the weekly function test
- An additional 15 % of the failures will be detected during the bi-weekly pressure test to maximum section design pressure
- 100 % of all “testable valve failures” will be detected during the pressure test every 6 months

$$PFD = PFD_{PushButton} + PFD_{ControlSystem} + PFD_{Pilot} + PFD_{TopsideValve}$$

$$PFD = \frac{0.4 \cdot 10^{-6} \times 336}{2} + \frac{4.9 \cdot 10^{-6} \times 336}{2} + \frac{0.8 \cdot 10^{-6} \times 336}{2} + 0.75 \times \frac{2.1 \cdot 10^{-6} \times 168}{2} + 0.15 \times \frac{2.1 \cdot 10^{-6} \times 336}{2} + 0.10 \times \frac{2.1 \cdot 10^{-6} \times 4380}{2}$$

$$PFD = 6.72 \cdot 10^{-5} + 8.23 \cdot 10^{-4} + 1.34 \cdot 10^{-4} + 1.32 \cdot 10^{-4} + 5.29 \cdot 10^{-5} + 4.6 \cdot 10^{-4} = 0.0017$$

Note that the above estimated PFD only takes into account the reliability of the equipment required to perform the function. The relatively low probability of an equipment failure is closely related to the assumed frequent testing. However, the ability of the operator to understand the developing situation and to trigger the function when required is not included in these failure data. For the scenario under consideration the annular preventer is assumed closed but circulation with heavier mud has failed. In this case the operator will have some time to evaluate the situation and is assumed to perform correctly 99 out of 100 times. The estimated reliability of this function then becomes 0.0117.

Based on the above, a PFD of 0.012 has been assumed for this barrier/safety function.

### C.5.6 Discussion

*From workshop discussions:*
A typical problem with the drill string safety valves appears after cementation. During the test performed after each cementation it is often discovered that the valve either leak or is stuck/jammed.

Also, it may be relevant to set a SIL requirement to the function that prevents flow up the drill string. However, obtaining relevant failure data for the drill string safety valve may be a challenge.

## C.6 Barrier Function 5 – Blind shear ram cuts drill string and seals well

### C.6.1 Definition

The purpose of this barrier/safety function is to cut the drill string and to seal the well when all other measures fail. The function consists of one (or sometimes two) ram preventer(s) with shear blades and the systems required for operation of the shear ram.

### C.6.2 Diagram illustrating all barrier elements

The barrier elements are more or less identical to those shown for annular preventers in section C.3. A diagram for the shear ram function is shown below.

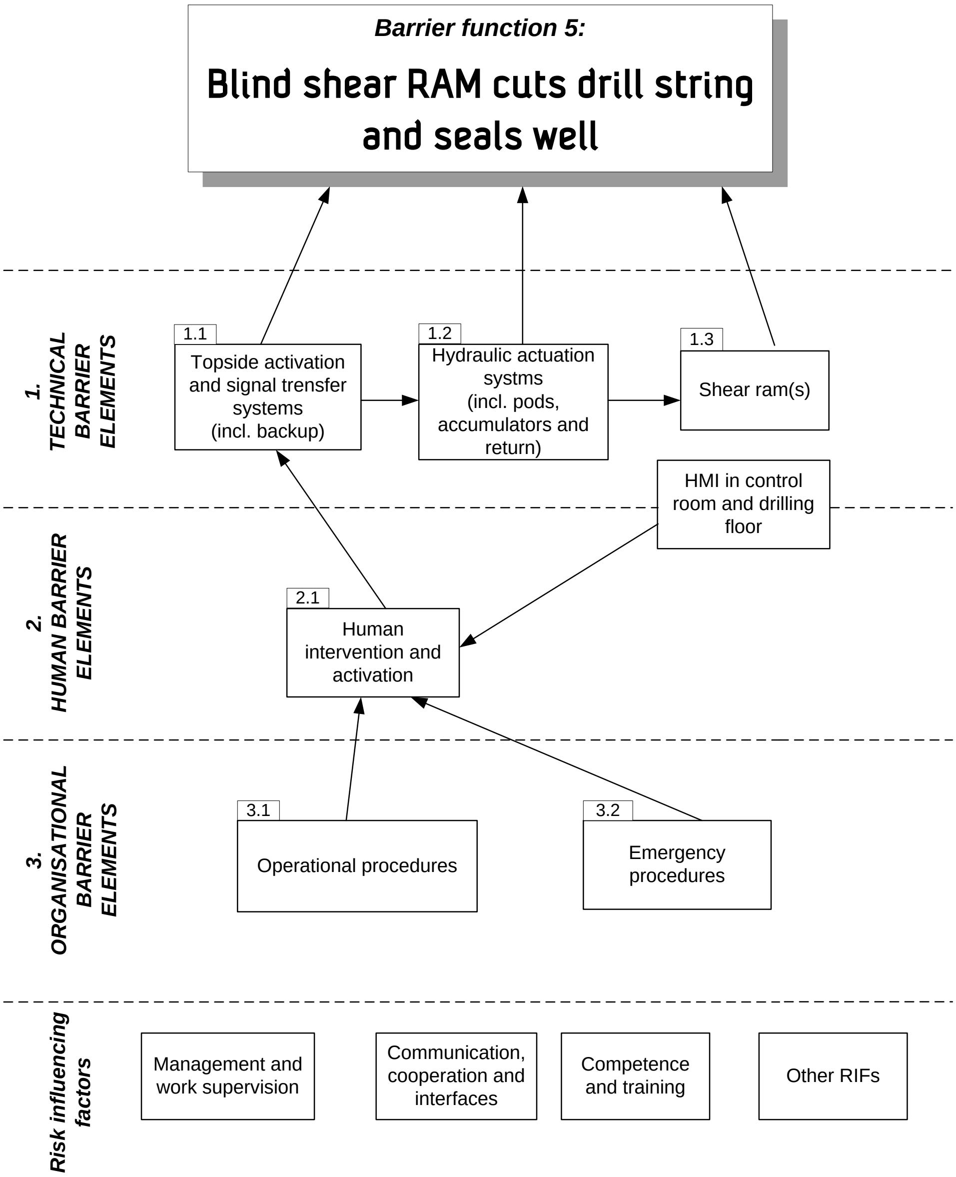


**Figure C-9: Barrier element diagram for blind shear ram function**

### C.6.3 Equipment Overview

The blind shear ram is designed to cut though the drill pipe with hardened steel shears and therefore requires the greatest closing force compared to other preventers. For most BOPs there is one shear ram while for deepwater drilling on the NCS some BOPs are equipped with two shear rams.

In order to activate the blind shear ram there will normally be a number of different possibilities including;

- direct activation of the ram by pressing a button on a control panel on the rig
- activation by the automatic mode function (AMF) or "deadman" system due to emergency conditions
- activation of the emergency disconnect function (EDS) by rig personnel;
- activation by the autoshear function if the rig moves off location without initiating the proper disconnect sequence
- Direct subsea activation of the ram by an ROV (hot stab intervention)

On NCS BOPs there will also be requirements to an acoustic back-up activation system.

Lately, a new type of shear ram, so-called "super shear" or "casing-shear" has been introduced *in addition* to an ordinary blind shear ram. The "super shear" is designed to cut "everything" - it is however only designed for cutting and not (as is the case for the ordinary blind shear ram) sealing purposes (no gaskets), even though it will partly stop inflow.

Note that the shear ram is also applied for cutting empty pipes (no flow), e.g. during disconnect or bad weather.

### C.6.4 Testing

The BOP is normally a passive system during drilling operations. Functional testing is therefore needed on a regular basis to reveal failures. Functional testing for blind shear rams should be performed once a week and pressure testing should be performed each 14 days to maximum section design pressure (MSDP) and every 6 months to working pressure, according to NORSOK D-010 (Appendix A, Table A.1). A functional test is also performed after the BOP has been installed subsea before the drilling operation starts. Furthermore it is required that the BOP with associated valves and other pressure control equipment shall be subjected to a complete overhaul and shall be recertified every five years (NORSOK D-010, Table A.1).

The API (American Petroleum Institute) recommended practice (RP) 53 "Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells" also contains e.g. requirements for testing frequency of BOP and well barrier equipment: *All operational components of the BOP equipment systems should be functioned at least once a week to verify the component's intended operations. Function tests may or may not include pressure tests* (section 18.3.1 of the standard). Further (section 18.3.3): *Pressure tests on the well control equipment should be conducted at least: a) Prior to running the BOP subsea and upon installation. b) After the disconnection or repair of any pressure containment seal in the BOP stack, choke line, choke manifold, or wellhead assembly, but limited to the affected component. c) Not to exceed 21 days.*

The cutting blades of the blind shear ram are inspected every 6$^{th}$ month with respect to degradation. Normally when not activated the blades themselves are not significantly degraded. Gaskets may become damaged during washing of cavity, but this kind of activity is usually performed right before pulling the BOP.

### C.6.5 Rough PFD Assessment

In section C.3.5, the critical failure rate for the ram preventers was estimated to be $1.5 \cdot 10^{-5}$. It was also noted that the shear rams are not subjected to periodic pressure testing while installed on the well. A function test is performed every week, but this test does not verify the ability of the shear ram to close in the presence of realistic pressures. A pressure test is performed once every 6 months. None of the tests verify the ability of the shear ram to actually cut through the materials with the drill pipe in the hole. Following the Deepwater Horizon accident and other studies, concerns have been raised regarding the fact that blind shear rams are not designed to cut through multiple pieces of drill pipe or tool joints connecting two sections of drill pipe (which makes up some 10 % of the total drill string).

For the purposes of the rough PFD assessment, the following assumptions have been made:

- 80 % of all "testable ram faults" will be detected during the weekly function test
- 100 % of all "testable ram faults" will be detected during the pressure test every 6 months
- Concerning the likelihood of the shear ram to hit a tool joint and therefore being unable to cut the drill pipe we need to differentiate the situation: In case of early detection (situation 5A) the operators will have some time to locate the drill pipe in a favourable position to enable cutting. In this situation it is assumed that successful location of the drill pipe in the BOP will take place 95 out of 100 times. On the other hand, in case of late detection of the kick and well fluid already having escaped above the BOP (situation 5B), the situation will be considerably more stressful and the operator is assumed to have no additional time to adjust the position of the drill pipe. In such case it is assumed that a tool joint will interfere with the shear ram in 10 % of the cases. We then get:

Generally:

$$PFD = PFD_{ControlSystem} + PFD_{ShearRam}$$

For situation 5A (Shear ram cuts and seals well - no flow through BOP):

$$PFD_{5A} = \frac{3.1 \cdot 10^{-5} \times 168}{2} + 0.8 \times \left(\frac{1.5 \cdot 10^{-5} \times 168}{2}\right) + 0.2 \times \left(\frac{1.5 \cdot 10^{-5} \times 4380}{2}\right) + 0.05$$

$$PFD_{5A} = 0.0026 + 0.001 + 0.0066 + 0.05 = 0.06$$

And for situation 5B (Shear ram cuts and seals well - flow through BOP):

$$PFD_{5B} = \frac{3.1 \cdot 10^{-5} \times 168}{2} + 0.8 \times \left(\frac{1.5 \cdot 10^{-5} \times 168}{2}\right) + 0.2 \times \left(\frac{1.5 \cdot 10^{-5} \times 4380}{2}\right) + 0.1$$

$$PFD_{5A5B} = 0.0026 + 0.001 + 0.0066 + 0.1 = 0.11$$

Based on the above, a PFD of 0.06 and 0.11 has been assumed for this function for situation 5A and 5B respectively.

A study performed based on data from all wells on the NCS in the period from 1984-1997 (approximately 700 wells in total) showed that the shear ram had been activated about five times and failed in one out of these five (Holand, 2001). Based on this very limited data material a PFD of 0.2 could be assumed.

### C.6.6 Discussion

One major challenge is to develop test and monitoring programmes for the blind shear ram that makes it possible to assess, during operation, whether the unit is able to cut the drill pipe upon a real demand. The shear rams usually function during pressure test, the uncertainty is attached to the cutting.

As previously noted, the Deepwater Horizon accident brought attention to the fact that many existing shear rams are not capable of cutting through tool joints which typically makes up 10 % of the drill-pipe. In a dynamic drilling environment on-board a floating drilling rig/ship, it is very difficult to predict if a tool joint is positioned such that it will prevent the successful cutting of the pipe in a stressful emergency situation. If the shear ram cannot be designed powerful enough to also cut through tool joints, a redundant set of shear rams could be considered. This will however increase the weight and the complexity of the BOP, which in itself is an operational challenge.

The common shuttle valve for the different (redundant) activations is considered to be highly reliable. However, the pilot lines are a typical problem. These are flushed approximately once a year. Also the hydraulic return system can fail such that the shear ram is not able to cut and seal properly. If this case the other pod (if the pod is functioning) will be used. This shows the importance of having two independent pods functioning.

## C.7 Barrier Function 6 – Diverter system vents hydrocarbons overboard

### C.7.1 Definition

The purpose of this barrier function is to vent the mud and hydrocarbons in the riser above the BOP overboard through pipelines to either side of the platform. It is critical to divert the wellbore fluids away from the rig floor, due to the possibility of ignition and since any gas/mud released here may prevent the workers from taking the proper actions to prevent the situation from escalating further.

### C.7.2 Diagram illustrating all barrier elements

A diagram for the diverter function is shown below.

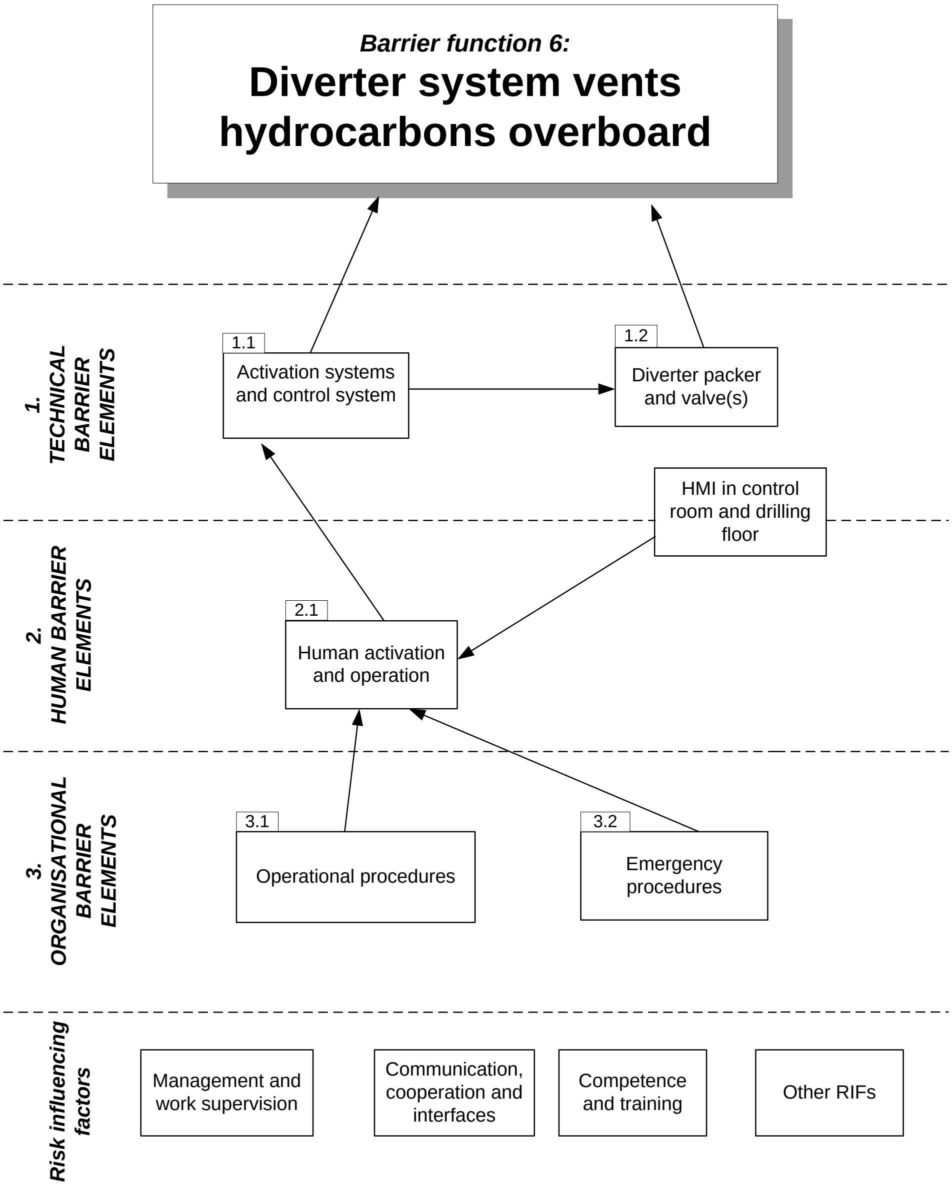


**Figure C-10: Barrier element diagram for diverter function**

## C.7.3 Equipment Overview

A diverter packer (comparable to an annular preventer) is used for the purpose of redirecting the upward flow of fluids into the diverter vent lines which are made of large diameter steel pipes. When activating the diverter system, the diverter packer is closed. Valves (typically remote controlled) are located on the diverter vent lines to close off access during normal drilling operations. A hydraulic closing system is used to operate both the diverter and flowline/overboard valves. Diverter lines are installed to lead the flow to the most favourable (particularly in terms of wind-direction) side of the platform.

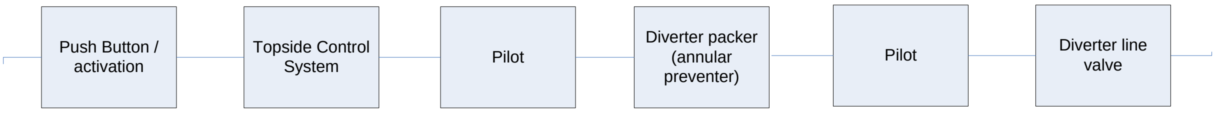


**Figure C-11: Block diagram for diverter function**

## C.7.4 Testing

No specific testing requirements for the diverter system have been found.

According to (API RP 53) the diverter and all valves should be function tested at appropriate times during operations, e.g. to ascertain that line(s) is not plugged. It is not further defined what is meant by “appropriate times”. According to some rig personnel that SINTEF has spoken to, the diverter system is seldom tested. “During 14 years of operation I have experienced one function test of the diverter system” (Operator on drilling rig). Other personnel however state that the diverter system is tested routinely prior to every operation when the system is considered a barrier during that particular situation. Hence, there are obviously varying practices among the drilling rigs and between operations.

## C.7.5 Rough PFD Assessment

A rough PFD estimate for the diverter system has been made. The failure data is based on failure rates for similar components as given in the PDS Data Handbook (SINTEF, 2010). Since there are no formal requirements to periodic testing of the diverter system, a test interval of one year has conservatively been assumed.

$$PFD = PFD_{PushButton} + PFD_{ControlSystem} + 2 \times PFD_{Pilot} + 2 \times PFD_{TopsideValve}$$

$$PFD = \frac{0.4 \cdot 10^{-6} \times 8760}{2} + \frac{4.9 \cdot 10^{-6} \times 8760}{2} + 2 \times \frac{0.8 \cdot 10^{-6} \times 8760}{2} + 2 \times \frac{2.1 \cdot 10^{-6} \times 8760}{2}$$

$$PFD = 1.75 \cdot 10^{-35} + 0.021 + 7.0 \cdot 10^{-3} + 0.018 = 0.05$$

Note that the PFD calculated above only takes into account the reliability of the equipment required to perform the function. The ability of the operator to understand the developing situation and to trigger the function when required is not included in the estimate.

The complexity and design of the diverter system will vary as will the likelihood of a mal-operation by the operators. Here we will assume that the operator will perform correctly 95 out of 100 times in a stressful kick situation when the diverter packer must be closed and the correct diverter line opened (which may be optimistic).

Based on the above, an approximate PFD of 0.1 can be assumed for this barrier function with *annual testing* of diverter system components.

### C.7.6 Discussion

The diverter system is not normally considered a safety function, merely as a "nice-to-have" system, even if it actually functions as a safety barrier in an emergency by directing hydrocarbons away from the rig. E.g. during top hole drilling (riserless drilling) the drilling mud and the diverter system are normally the only barriers.

A key aspect to consider related to the diverter system is its impact on other systems. If, like on Deepwater Horizon, the diverter system fails to direct hydrocarbons away from the rig in an emergency situation, the presence of a large gas cloud on the installation may cause secondary effects, such as loss of main power, loss of mud circulation and loss of other utility systems.

Normal practice for operation of the diverter system will be on a daily basis (every morning) to establish the selection of overboard diverter line based on the prevailing wind direction. This is not a written procedure, and it is questionable if this is indeed performed daily or whether the procedure needs to be more formalised. It should also be discussed whether the procedure should dictate diverter selection more often.

# D Indicators – General Discussion and Methodology for Selection

In this report the ambition has been to identify a set of indicators and implement these in such a way that we are able to discover changes in the status for a barrier element or barrier function and thus changes to the environmental risk.

In this report a relatively pragmatic approach for identification of indicators has been chosen. As described in Chapters 2, 3 and 4, an *event tree* combined with barrier element diagrams have been chosen. The event tree has been applied in order to model a typical kick/blowout scenario and illustrate the relationship between the relevant barrier elements. The event tree also serves as a means of identifying the relative importance of the barrier function. *Barrier element diagrams* have been applied to illustrate factors that, on an overall level, influence the status and performance of the barriers. Then, *expert judgements* have been applied to identify more detailed factors that influence the reliability of barriers/functions and how these factors could be measured / monitored.

## D.1 Some types of indicators

Below is a brief discussion of possible classification schemes for indicators. Note that the categories are overlapping.

### D.1.1 Leading versus lagging indicators / alerts

In recent research on safety indicators the distinction between so called leading and lagging indicators is discussed (e.g. Øien et al., 2010). By a lagging indicator we understand a direct or “after-the-event” type of indicator where the number of accidents, incidents, near misses or failures are registered and counted. Lagging indicators are related to reactive monitoring and show when a desired safety outcome has failed, or when it has not been achieved. Examples of lagging indicators can be the number of unexpected well kicks, number of failures of safety critical instrumentation/alarms, occurrences of common cause failures, etc. Many operators already have maintenance management systems in place to collect data related to component reliability (e.g. SAP), and also systems for incidence reporting (e.g. SYNERGI) which provide good sources for lagging indicators. In addition to ensuring that all the relevant data is collected, a challenge remains to provide good guidelines on how to process, interpret and make decisions based on this data.

Lagging indicators are much related to learning from mistakes but are not necessarily useful as pre-warnings or early warnings. For early warnings, one needs to look further back in the causal chain, at the underlying causes and the condition of the factors that leads to accidents. This has previously been termed indirect or proactive indicators, nowadays often referred to as ‘leading’ indicators (Øien et al., 2010). The leading indicators are a form of active monitoring used as inputs that are essential to achieve the desired safety outcome. Hence, leading indicators may provide feedback on performance before an accident or incident occurs. Examples of leading indicators can be maintenance backlog on safety critical equipment and degradation of a safety function.

It is often difficult to make a clear-cut distinction between leading and lagging indicators. It can be a challenge to come up with good leading indicators, as it is difficult to make decisions regarding the high-level risk situation based on the trend of a singular indicator/measurement. However, if a combination of relevant indicators all indicate a similar trend; the evidence may support a direct impact to the overall risk level. Hence, it may make more sense to discuss the definition of a leading alert, where the alert can be based on the status of a number of different indicators.

### D.1.2 Scenario based barrier indicators

Scenario based barrier indicators are related to the specific scenario under consideration - in our example case a kick during drilling - and the barriers available for preventing the kick to develop into a blowout. For the purpose of modelling the specific scenario, and the barriers available, an event tree has been used in this study. Indicators are identified by considering the relative importance of the barriers (from the event tree analysis and sensitivity evaluations, ref. Chapter 4), and by considering factors that influence the barrier performance (from the barrier element diagrams). Identification of specific barrier indicators may also partly be based on experience from previous accidents and accident sequences (e.g. from lessons learned through investigation reports).

### D.1.3 Reliability parameter based indicators

Reliability based indicators are data that may support the estimation of key reliability parameters, like the number of recorded failures, time needed for restoration, the number of failures that are potential common cause failures, the number of human induced failures during testing, and so on. The advantage of these indicators lies in the fact that the reliability model can be applied to directly reflect the importance of any changes in the parameters. Systematic collection of such data may also support future reliability assessments with more updated data, as well as supporting rig specific follow-up of barrier performance.

A major challenge with these indicators is however that reliability model parameters, and in particular the failure rates and beta factors (and also $P_{TIF}$) require extensive data basis in order to conclude on significant changes. Hence, the usefulness of reliability parameters as leading indicators on an installation level may in practice be limited.

### D.1.4 General indicators

General indicators are identified based on experience from previous projects, often human and organizational factors that may measure impairment of human capabilities to perform the intended activities (as part of the barrier function or indirectly through the interaction with the technical barrier elements). In addition, they can include known features of the reservoir or the installation that contribute to increased risk.

## D.2 Indicator limitations

Using indicators is only one of several methods for following up the status of safety barriers and has some important limitations related to its use. Therefore, decisions cannot be made based on indicators alone, but should also include general knowledge about the barrier status, inspections, quality assurance, etc. It is therefore important to be aware that indicators will not cover or represent *all* risk influencing factors.

*"Even when all indicators are in the acceptable range of values, the probability of an accident is not zero"* (Ale 2008).

Often it will be challenging to define indicators so precisely that they cannot be manipulated. Said in other words, when scoring the indicator it will often be tempting to use subjective judgement. E.g. if the indicator measures some kind of undesirable outcome, like failure of a specific equipment, cases of doubt will arise as to whether a failure has occurred or not. It is therefore important to define the indicator as clearly as possible with a unique associated metric.

Often, several indicators are merged together to give some kind of overall risk indicator (an example is the RNNP "major accident indicator"). This often makes sense as an attempt to measure "the big picture", but at the same time such an overall indicator for a system may neutralise trends of individual indicators (IAEA 2000, SINTEF 1999).

## D.3 Indicator selection criteria

### D.3.1 General criteria

In the literature a great number of general criteria for an "ideal indicator" are given. In real life it will be rather challenging to fulfil all these criteria, and in most cases it is a question of balancing several criteria against each other. The most common criteria for a good and relevant indicator are:

- Meaningful
- Measurable
- Valid, i.e. correlated with risk. *"The indicators do not need to be casually linked to safety outcomes, as long as the correlation is and stays high and the numbers are big enough to show trends"* (Hale 2008)
- Contribute to risk reduction and continuous improvement (Webb 2008)
- Focus on key information (DOE, Hale 2008)
- Cost-effective, with respect to time consume
- Objective / Difficult to manipulate
- Clear and easy to understand for those persons responsible for the indicators
- Reliable, i.e. different users get the same result (minimum of variations) under the same conditions
- Sensitive, i.e. responding to changes
- Can be integrated into operation
- Owned and accepted by users
- Measures can be performed locally based on the indicators
- Information on the indicators is "easily available" and preferably from already existing information systems

### D.3.2 More specific criteria – alternative approach to identifying indicators

As stated in the introduction of this appendix, a relatively pragmatic approach has been applied for identifying the indicators. In this section a somewhat more structured (and theoretical) approach has been described, although not thoroughly implemented in this project.

The barrier functions considered in this study typically comprise technical elements (physical components, including hardware and software) and human elements (actions). The identification of specific barrier indicators may therefore alternatively start with a breakdown of the main contributors to reduced availability, of the technical elements as well as the human elements. The following breakdown could be foreseen:

- Unavailability due to technical failures and/or degradations
- Unavailability due to repair and/or regular testing
- Unavailability due to human errors, misjudgements and mal-operation

Once identified, the indicators may be related to one of the following classes of reliability influencing factors:

- **Change in operating and environmental conditions:** Changes may alter the magnitude of or add new stresses. In addition, the changes may lead to more or less frequent demands for the barrier functions.
  *Relevant barrier indicators* are observations that may detect if operating and environmental conditions become different from initial assumptions or outside the design envelope.
- **Change in the inherent reliability of components**: Design weaknesses may be revealed, or new ones introduced (e.g., due to rebuilding), after the component has been put into operation. *Relevant barrier indicators* are observations that may indicate that the number of failures is increasing with time, to what extent the same type of failure comes over and over again and to what extent procedures for management of change is in place and used in relation to all modifications.
- **Change in operation and maintenance strategy:** Test coverage, test intervals, and the ability to restore any detected failure within a short time impact the reliability of a safety-critical function. Remark: It is not possible to state that a short test interval is better than a long, as long as the adjustments are based on analysis of recorded failure. *Relevant barrier indicators* are observations that may indicate that the test coverage is being reduced, that failures are not corrected within specified time, that there is a lack of practises to failure cause analysis and that there is a lack of assessments about the test intervals in light of recorded failures.
- **Human and organizational factors:** Stress levels, adequacy of human-machine interfaces, adequacy of procedures, and coordination between involved personnel in various drilling operations are all factors that may influence human error probabilities, of the human elements, or indirectly, by introducing new failures into the technical elements. *Relevant barrier indicators* are observations that may indicate that the human-machine interface is inadequate, if systems provide inadequate decision support, if competence and training is inadequate and if the coordination between the personnel involved in the operation is inadequate.

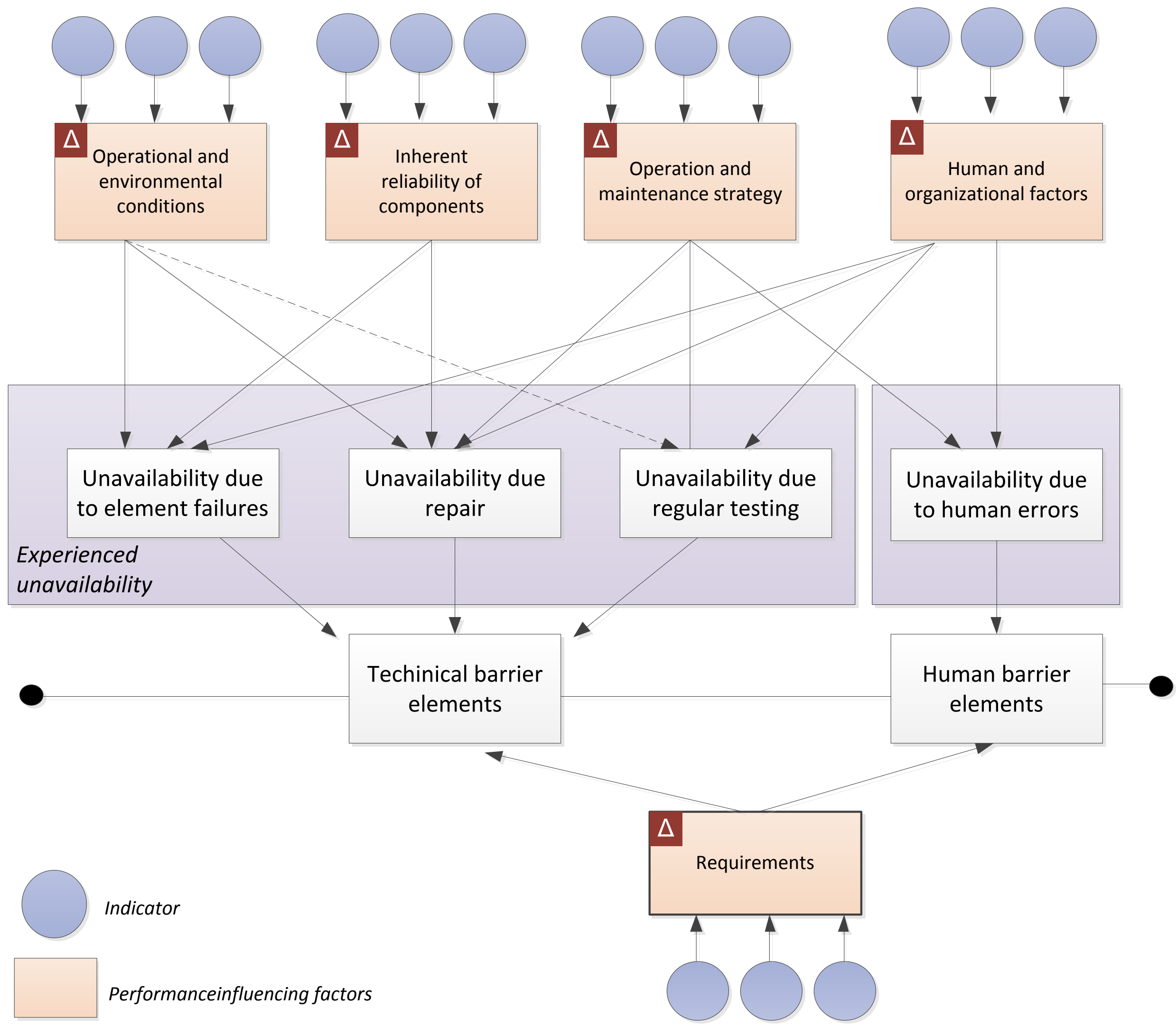


**Figure D-1: Alternative methodology for establishing barrier indicators**

As briefly mentioned in section 5.3 concerning indicator selection criteria, it will be beneficial, if possible, to link some of the indicators towards existing parameters in the PDS model. We then consider the parameters that are used to calculate the CSU and identify risk influencing factors and associated indicators related to these parameters. In practice we then include the parameters needed to calculate the average PFD value and also the $P_{TIF}$ in the sense that the possibility of experiencing a “test independent” failure is also considered.

Typical parameters included in the PDS model are rate of dangerous undetected failures, rate of test independent failures, test interval, degree of redundancy, the rate of common cause failures, repair philosophy (e.g. for dangerous detected failures), etc. These parameters can, in theory serve as indicators in themselves, but more relevant will be to consider important factors that influence these parameters. The approach is illustrated in Figure D-2.

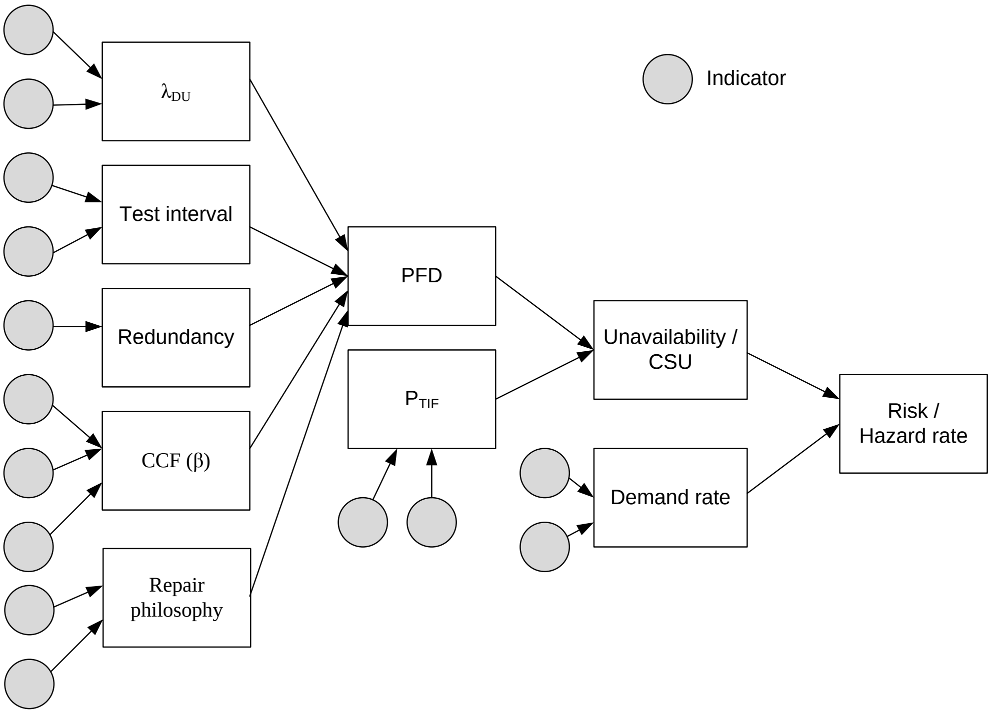


**Figure D-2: Relationship between reliability parameters and possible indicators**

# E Some relevant experiences from the Deepwater Horizon Accident

In this Appendix we briefly discuss the Deepwater Horizon accident and some experiences and lessons learned from the accident considered relevant for the PDS-BIP project. In particular it may be of interest to question whether proper use of specific indicators could have prevented the accident from occurring.

## E.1 The accident

On April 20, 2010, an uncontrolled blowout of oil and gas occurred on the Deepwater Horizon drilling rig, in the Gulf of Mexico off the Louisiana coast. The accident caused the loss of 11 lives and the resulting environmental oil spill has been estimated to almost 5 million barrels, i.e. by far the largest oil spill in US history. Many investigation reports following the Deepwater Horizon accident have pointed at a lack of control with the integrity of key safety barriers as one of the underlying causes of why the kick was allowed to develop into a catastrophe. This finding has resulted in the following recommendation in BP's own investigation report (BP, 2010):

> *Establish D&C (drilling and completion) leading and lagging indicators for well integrity, well control and rig safety critical equipment (p. 184 in report).*

This recommendation (and similar ones) recognizes the relevance of the research that is carried out through the on-going PDS project.

## E.2 Direct causes of the accident

Based on the different investigation reports following from the Deepwater Horizon accident, it is seen that a number of barriers or defences were breached prior to and during the accident. Some important *direct causes* of the DWH accident have been identified as (SINTEF, 2011):

1. The cement outside the production casing and at the bottom of the well (at the "shoe track") did not prevent influx from the reservoir
2. The crew misinterpreted the result of the negative pressure test and considered the well as being properly sealed
3. The crew did not respond to the influx of oil and gas before hydrocarbons had entered the riser
4. The crew routed the hydrocarbons to the mud gas separator instead of diverting it overboard
5. The fire and gas system did not prevent ignition
6. The BOP did not isolate the wellbore and the emergency methods available for operating the BOP also failed

After major accidents like Deepwater Horizon, it is often tempting to question how so many safety barriers could possibly fail simultaneously. Drilling and well operations differ from many other offshore operations due to the dynamic nature of the safety challenges and the large number of different operations that are required during the various phases of the well's lifecycle. It is therefore challenging to maintain overview and control with all the barriers in all the various lifecycle phases. Barrier indicators can be a useful tool to help with this task.

## E.3 Recommendations from Deepwater Horizon reports

In the Deepwater Horizon investigation reports after the accident and in the SINTEF report for PSA concerning the accident (SINTEF, 2011), a number of recommendations have been provided. The table below summarizes some selected recommendations that may be of relevance to the work in this report.

**Table E-5: Relevant recommendations from Deepwater Horizon reports**

| Relevant Barrier (Element) | Description | Reference |
|---|---|---|
| General | Establish D&C (drilling and completion) leading and lagging indicators for well integrity, well control and rig safety critical equipment | BP, 2010, p. 184 |
| General | Require drilling contractors to implement an auditable integrity monitoring system to continuously assess and improve the integrity performance of well control equipment against a set of established leading and lagging indicators | BP, 2010, p. 184 |
| General | Improve the understanding of a comprehensive strategy for barrier control, including the application of the principle of two independent and tested well barriers, and the monitoring of these | SINTEF, 2011, p. |
| General / maintenance | Follow-up on a regular basis the drilling contractors' progression in managing the maintenance backlog | SINTEF, 2011, p. |
| General / performance requirements | Ensure and follow-up that the companies have implemented performance requirements (including reliability requirements) for critical safety functions related to drilling and well operations, and verify that these requirements are followed-up during operation. | SINTEF, 2011, p. |
| BOP | By considering drilling operations on an individual basis, evaluate whether the present blowout preventers (BOP) design with single blind shear ram (BSR), is acceptable | SINTEF, 2011, p. |
| BOP | Establish minimum levels of redundancy and reliability for BP's BOP systems. Require drilling contractors to implement an auditable risk management process to ensure that their BOP systems are operated above these minimum levels. | BP, 2010, p. 186 |
| BOP | The BOP functionality testing indicated not all back-up control systems had built in redundancy.<br>It is recommended the industry reviews and revises as necessary the practices, procedures and/or requirements for evaluating the vulnerability of the back-up control systems of a Blowout Preventer to assure they are not subject to an event or sequence of events that lead to common mode failure. | DNV, 2011, p. 7 |
| BOP | The industry needs to consider their procedures for closing of different valves in the BOP in emergency situations. Further, training and drills on how to operate the BOP in cases of emergency should be conducted. | SINTEF, 2011, p. 80 |
| Diverter system | Consider the need for new requirements and guidelines on design and operation of the diverter system in order to minimise the likelihood of mal-operation | SINTEF, 2011, p. 23 |
| Diverter system | Separate mud/gas separators should be used for the output from the diverter system and for the output from the choke and kill manifold | DHSG, 2011, p. 122 |

## E.4 Relevant experiences for the PDS-BIP project

### E.4.1 General

As discussed above, the Deepwater Horizon accident did not happen as a result of one crucial misstep or a single technical failure, but as a result of a series of events and failures. An important lesson learned from the accident is therefore the importance of maintaining continuous control of all the barriers so that in an emergency and/or upon a demand they are available and functioning. This, however, requires quite a few prerequisites to be in place:

- The right personnel and departments need to be aware of which barriers are actually installed and their associated functions.
- Due to the dynamic nature of drilling operations, the availability and function of the barriers during all operational modes need to be known.
- Operational and emergency procedures on how to operate the barriers in an emergency situation need to be available and familiar to the crew.
- Any interdependencies between the barriers and the barrier elements should be known. Can a degradation of one barrier function (or element) affect other barrier functions (or elements)?
- It should be known which performance requirements apply for the different barrier elements and these performance requirements need to be followed-up during operation.
- Requirements for testing and maintenance of the barrier elements need to be known and followed-up.
- Any weaknesses and limitations in the design of the barriers that may influence their operation need to be known.
- It needs to be known whether the barrier (element) is automatically or manually initiated.
- Any bypasses, inhibits or other degradations of the barriers need to be known and compensating measures need to be in place as required.

All these (selected) points are important in order to be able to claim that the status of the barriers is *known*. In the Deepwater Horizon accident several of these prerequisites were not fulfilled and the outcome, as we know, was tragic.

### E.4.2 Experiences related to specific barrier functions – kick detection

Prior to the blowout on Deepwater Horizon, several rig operations were performed in a manner that made *kick detection* more complicated. The kick detection function on Deepwater Horizon also had some technical shortcomings as pointed out in the Chief Counsel's report (2011), chapter 4.7. Some important findings from the report:

- A number of (concurrent) rig activities potentially confounded the kick detection function;
    - Sea water were pumped directly into the well from the sea chest, thereby bypassing the mud pits, creating a non-closed loop system and thus making it harder to monitor and compare the pit gain volume
    - During the latter part of seawater displacement, returns were sent directly overboard bypassing the pits, again making it harder to monitor pit gain.
    - Cranes were used, resulting in rig sway which complicates kick detection since background noise in the level data increases.
    - Mud pits, sand traps and trip tanks were being emptied during seawater displacement, all complicating kick detection

- Kick detection instrumentation was mediocre and highly dependent on human factors;
    - No camera to monitor returns sent overboard and no sensor to indicate position of valve sending returns overboard.
    - Low accuracy of some instruments, such as sensors for pit volumes.
    - Imprecise sensors and sensors sensitive to movements unrelated to state of the well, e.g. during crane operations. This may result in rig personnel discounting the value of the data they receive

- No automation of simple well monitoring calculations. Non-closed-loop system calculations had to be performed manually but could easily have been automated and displayed for enhanced real-time monitoring.
- The scales of the displays were set up so that fluctuation in data was sometimes hard to see.

- Despite these complications and weaknesses, the rig personnel on Deepwater Horizon should have detected the kick earlier. In the Chief Counsel's report (2011) several possible explanations to why the rig crew failed to recognize signs of a kick are given:
  - Lack of vigilance during the final displacement phase
  - Lack of management attention to the hazards associated with the final riser displacement operation
  - Lack of training to recognize that certain data anomalies indicated a kick
  - BP and Transocean management allowed simultaneous operations that could complicate or confound well monitoring to take place
  - Insufficient communication of information at different levels

### E.4.3 Experiences related to specific barrier functions – BOP

Investigations related to the Deepwater Horizon BOP are not yet completed and final conclusions concerning the BOP are therefore not made. What is known, however, is that the BOP did not isolate the well and as a result the blowout was allowed to continue. After the first explosion on Deepwater Horizon *the emergency methods available for operating the BOP also failed*. The cause of BOP failure is not finally concluded, but a main theory is that the drill pipe was elastically buckled within the wellbore and was partly outside the shearing blade surfaces of the blind shear ram. Also, it appears that the dead man function would not have function due to low battery voltage in one of the control pods and a solenoid valve failure in the other pod.

An important recommendation from the SINTEF Deepwater Horizon study (SINTEF, 2011) is as follows:

> *By considering drilling operations on an individual basis, evaluate whether the present blowout preventers (BOP) design with single blind shear ram (BSR), is acceptable.*

### E.4.4 Experiences related to specific barrier functions – diverter system

When the Deepwater Horizon crew noticed that hydrocarbons had passed the subsea BOP and were rapidly expanding up through the drilling riser towards the rig’s drilling floor, they attempted to close the BOP and then routed the hydrocarbons to the mud gas separator instead of diverting it overboard. However, the mud gas separator had insufficient capacity to handle the large flow from the well, and the gas quickly overwhelmed the separator and escaped through gas vent lines, discharging onto the rig.

An important recommendation from the SINTEF Deepwater Horizon study (SINTEF, 2011) related to the diverter system is as follows:

> *Consider the need for new requirements and guidelines on design and operation of the diverter system in order to minimise the likelihood of mal-operation.*

Technology for a better society

www.sintef.no