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Geir-Ove Strand

Well Safety

Risk Control in the Drilling Phase of Offshore Wells

Doctoral thesis

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ISBN 978-82-326-2480-5 (printed ver.)
ISBN 978-82-326-2481-2 (electronic ver.)
ISSN 1503-8181

Doctoral theses at NTNU, 2017:204

NTNU
Norwegian University of Science and Technology
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Printed by NTNU Grafisk senter

Synopsis

"A clever man is the one who finds ways out of an unpleasant situation into which a wise man would never have got himself"

Dan V. Segre, in 'Memoirs of a fortunate jew'

The essential function of an oil and gas well is to transport hydrocarbons from the reservoir to the surface in a cost effective and safe manner. The importance of well safety has been recognised and accepted for a long time, and improvements concerning well design, construction, operation and abandonment procedures have been made also in the last decade. In spite of these improvements, failures and accidents still occur and will probably continue to occur also in the future. The industrial and technological developments taking place coupled to recent well accident investigations imply that there is still a need for a more systematic approach towards well safety and over the entire lifecycle of a well.

Careful planning that includes risk assessments related to critical events such as well barrier failures and blowouts is vital for the ability of offshore personnel to maintain well control throughout the lifecycle phases. The offshore personnel must, for instance, be prepared to timely detect and respond to well barrier failures that could occur. The risk assessments may be qualitative as well as probabilistic to serve different needs. Probabilistic risk assessments (PRA) are recognised as important tools for risk management of low probability and high consequence activities. The objective of a PRA is to evaluate major accident frequencies associated with an activity, and a well drilling operation PRA can become useful tool for risk management in the drilling phase of an oil and gas well.

The application of probabilistic methods in well risk assessments is not new, but it still remains fragmented in regards to the well drilling and intervention phase. For example, the widely recognised industry standards and guidelines are primarily relevant for qualitative risk assessments, or focused on well integrity in the well production (operational) phase. The recent criticism in accident investigations for lack of risk indicators, and the general lack of recognised industry tools, standards and guidelines for well integrity in drilling and intervention operations implies that the risk is not sufficiently described and quantified for such operations. For example, the lack of well operation PRA could impair the ability for the operators' change management systems to maintain well risk indicators during the operations, and thereby provide the level of well safety that is expected by society.

The overall objective of this thesis is to develop a systematic approach for risk assessment of offshore wells in the drilling phase. The approach, denoted drilling PRA (DPRA), could be used as an aid to risk informed decision-making in relation to offshore well drilling (and intervention) operations. The focus of a DPRA is on procedures and methods for quantification of probabilities or frequencies associated

with well releases and blowouts. As such, the DPRA is focused on the two main safety functions of a well system:

- Containment of well hydrocarbon fluids, and thereby prevention of uncontrolled flow of well fluids within- or from the well. This function is commonly referred to as 'well integrity' in the oil and gas industry and represents a continuous type safety function typically provided by the passive well barrier elements (WBE).
- Shut-in well in the case of a safety critical situation. This well shut-in function is an 'on demand' type safety function typically provided by active WBEs and based on random activation.

The DPRA approach is based on existing and new PRA methods and knowledge gained during the PhD work. To arrive at such procedures and methods, it was necessary to:

- Describe the regulations, industry standards, and best practices that provides recognised requirements to enable the analysis of well safety functions in the drilling phase.
- Describe well operations and the status related to well barrier control functions (continuous and on demand) during well drilling operations.
- Describe the status related to quantitative analysis and control of the main well safety functions. Identify accepted methods within industry that are applied in the domain of quantitative well operation risk assessments.
- Identify relevant sources for experienced based data available for well risk assessments calculations and verification. Discuss the quality of the data, and suggest improvements in application of experience based data.
- Develop a systematic approach for risk assessment of offshore wells in the drilling phase. In this context a systematic approach means to quantitatively assess well blowout or release risk if a technical, human or organisational barrier related to the well system fails during the well drilling phase.

Figure A shows the DPRA risk modelling principle that make use of traditional fault tree and event tree analysis methods widely adopted for risk assessments in oil and gas industry. The modelling principle is shown with a main blowout risk scenario that can be analysed with DPRA, namely blowout risk associated with drilling mud barrier failure as an initiating event. As such, the DPRA is an approach that may typically be applied by the well engineer responsible for drilling operation risk assessments. The use of PRA methods to assess well blowout risk is not new. Some of the procedures and methods described as DPRA are, however, new based on the following research questions identified in this project:

- How do different BOP designs and maintenance strategies impact the safety function performance of the BOP?

- How can the influences of human task performance be better incorporated in the well drilling operation PRA to help the drilling crew better manoeuvre within the operation safe envelope?
- How does technology influence human task performance in offshore well operations?

Based on the research questions defined, the main contributions from this thesis are illustrated in Figure A as Paper 1 through Paper 4.

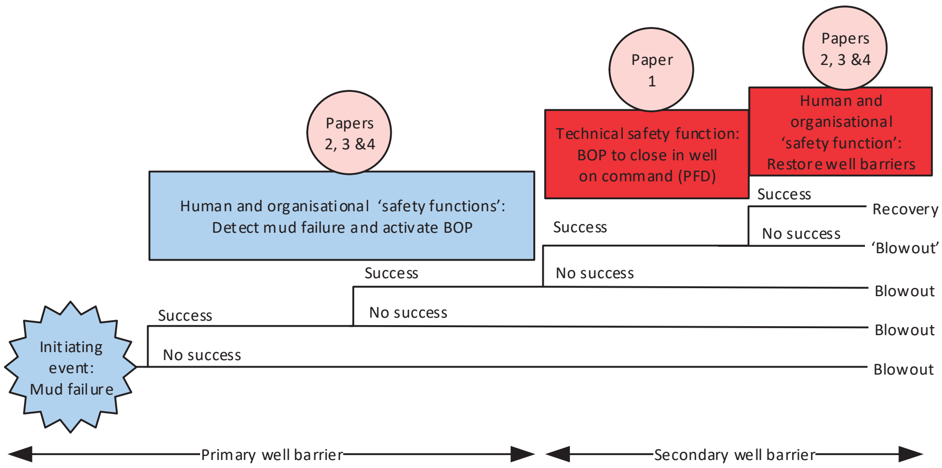

Figure A. DPRA risk modelling principle with paper contributions made in this PhD project

The papers describe new or improved methods and procedures developed as extensions to traditional PRA methods in this thesis and includes;

- In Paper 1, a compact method for dynamic BOP safety and reliability analysis is proposed. The method can be used in physical degradation modelling of BOP systems to evaluate effects of maintenance strategies on safety function availability targets.
- Paper 2 aims to clarify the role and corroborate the importance of the human-machine interface (HMI) in well operation accident prevention and control. The HMI may be considered the most important technology-based risk influencing factor in well drilling. As result of a thorough study, the paper proposes modifications to the operator error causal model adopted in Paper 3.
- In Paper 3, a human reliability analysis (HRA) method is proposed to quantify human and organisational factors impacting on the availability of safety functions in drilling operations.
- Paper 4 proposes some clarifications to taxonomy and key human error concepts used in DPRA for the purpose of consistent treatment of human and organisational factors in the application of the HRA method described in Paper 3.

Acknowledgements

I the course of many years at both school and work, I have been fortunate enough to have been acquainted with and received mentoring from many experts from around the world. It would be unwise of me to try to recall and mention them all here. However, many thanks goes to my Mother, the hard working staff and students here at the RAMS group at NTNU, and to the ladies and gentlemen in the administration for making the workday so much easier for us in every sense. Special credits are also due for the efforts and wise guidance provided by my supervisors at NTNU; Professor Mary Ann Lundteigen and Professor Jørn Vatn. Special credit also to co-author Associate Professor Cecilia Haskins (NTNU), and my peers in the industry Eli Tenold (Statoil), Kåre Kopren (Acona), Per Holand (ExproSoft) and Alex Green (Chevron). Lastly, a special thank for the invaluable contributions made to this thesis from collaborations with SINTEF research project "Learning from successful operations". The SINTEF project is funded by the Norwegian Research Councils (grant no. 228144/E30) as part of the PETROMAKS 2 program.

Preface

This project thesis is submitted in partial fulfilment of the requirements for the degree of Philosophiae Doctor (PhD) at the Norwegian University of Science and Technology (NTNU), Faculty of Engineering Science and Technology. The courses taken part of the PhD project are lectured at the Norwegian University of Science and Technology (NTNU). I wish to thank NTNU for their financial support that has given me this rare opportunity in later life to refresh and extend my knowledge base for addressing oil and gas well leakage risk issues that over the years has become my professional field of expertise.

Our motto here at NTNU is "Knowledge for a better world". The type knowledge that produces a better world is not fully clear to me, but it implies knowledge that has some measurable beneficial effect on the society. My current crude interpretation is that knowledge for most of us will be a type of 'false positive', 'nice to know' and 'useful to know'. This also in the realm of protecting humans, safeguarding the environment and financial interests. With this in mind I have chosen to interpret my mission in a way that this thesis should have some practical utility value for the primary oil and gas industry stakeholders, but only the future will really tell.

Analysis of well safety is a multidisciplinary discipline that requires competence, herein accumulated knowledge and experience, from domains such as; Well integrity, drilling and well, geology and reservoir, petro- and geophysics, rock mechanics, fluid mechanics, production technology, drilling muds, well cementing, well testing, and human factors. It is beyond any single person's capacity to have expertise in all of these subjects, but some good coverage and discussions should be provided in this thesis with good help of my supervisors and industry peers to disclose the most crucial well risk influencing factors during drilling operations. This will help aid in further refinements of the well risk assessments methods and frameworks, but hopefully also that it may be found useful to other high risk activities with potential for catastrophic consequences. This thesis is consciously not intended to be just a re-shuffle of an old deck of cards but also a re-shuffle that is meant to include some refurbished and perhaps even the embodiment of one or two new cards to help successful completion of the deck.

It is assumed that readers of this thesis have graduate-level courses in probabilistic safety and reliability theories and methods, for example (Rausand and Høyland, 2004, Rausand, 2014). Further, some knowledge or experience with offshore well technology and operations or other type activities that have a major accident potential is deemed to be beneficial.

Trondheim, Norway, Primo 2017

Geir-Ove Strand

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1 Introduction

"Difficult to see. Always in motion is the future"

Master Yoda (Star Wars motion picture series)

This chapter presents the background and motivation for the PhD project, along with the objectives and the limitations. The scientific approach adopted for this thesis is also discussed and the structure of this thesis is outlined.

1.1 Background

The Macondo well accident in 2010 was a stark reminder that the oil and gas operators occasionally may face extreme consequences associated with oil and gas well blowouts[1] (11 fatalities, 40+ Billion USD[2]). This reminder has in its aftermath further cemented a societal position about well safety in drilling operations alongside industries such as aerospace and nuclear, which also have low probability and high consequence activities. This is a type of activity where quantification of incident frequencies and management of uncertainties associated with low major accident probabilities are considered vital by society in maintaining an acceptable risk level (GAO, 1996, NUREG-1855, 2009).

An oil and gas well has several lifecycle phases, starting with drilling, followed by completion, production, and finally plugging and abandonment. During the well production phase, workovers and lighter intervention operations may be required to maintain or improve the safety or flow efficiency of the well system. Throughout these lifecycle phases there is a risk of losing control of the high pressure energy stored in a reservoir. The oil and gas industry has in the course of its history adopted some simple rules to ensure an acceptable risk of well control loss. One such 'cardinal rule' widely adopted is to always maintain two qualified and tested well barriers[3] towards a reservoir (API RP 90, 2006, NORSOK D-010, 2013, ISO 16530, 2014). Unfortunately, the task of maintaining the two well barriers can be challenging, and experience from many well accidents reveal that two qualified well barriers were inadvertently not properly maintained by the crew during the operation.

An internet search produced ten public notable offshore well blowouts worldwide in the last decade of which three incidents also caused fatalities. At the same time, further internet search revealed that more than 3,000 offshore wells are drilled worldwide every year without major incidents. The well

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[1] A **well blowout** is a is an unwanted event where formation fluid flows out of the well or between formation layers after all the predefined technical well barriers or the activation of the same have failed. A related term **well release** is similarly used for temporary well control incident where oil or gas flowed from the well from some point were flow was not intended and the flow was stopped by use of the barrier system that was available on the well at the time the incident started (SINTEF Offshore blowout database).

[2] http://www.reuters.com/article/2012/03/03/us-bp-costs-idUSTRE8220R320120303

[3] Envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation or to the external environment (NORSOK D-010)

safety record is supported by decades of well blowout data collected by the industry (Holand, 1997, IOGP #434-2, 2010). The data confirms that severe blowouts are most prone to occurrence during drilling and intervention operations when compared to the other well lifecycle phases. Possible explanations for the observations are that; (i) Well barrier failures occur relatively often (Holand and Awan, 2012, PSA, 2013b), and (ii) the hectic and dynamic nature of such operations could make the task of maintaining the two qualified well barriers a challenge. Most well operations include routine tasks, which includes the introduction of new or maintenance of existing well barriers. However, operations may also include novel and complex sequences of introduction, removal and replacement of individual well barrier elements[4] (WBE), which represents the well barrier building blocks. In addition, Mother Earth is not made of homogeneous material. This makes each well construction operation unique and operations are repeatedly faced with new sets of unknowns. The complexity of well activities is further emphasised in several of the recent accident investigation reports, all of which are critical of the inability of the operator's management of change (MoC) systems to maintain risk indicators during the operation. For example, recent literature on subject includes; Snorre 2004 (PSA, 2004), Montara 2009 (PTTEP, 2009, SEADRILL, 2009), Macondo 2010 (The Deepwater Horizon Study Group, 2011), Gullfaks 2010 (STATOIL, 2010), and Lootz et al. (2013).

Careful planning that includes risk assessments related to critical events such as well barrier failures and blowouts is vital for the crews' ability to maintain well control throughout various stages of well drilling and workover operations. The crew must, for instance, be prepared to timely detect and respond to well barrier failures that could occur in a timely manner. The risk assessments may be qualitative as well as probabilistic to serve different needs. For example, probabilistic risk assessments (PRA) are recognised as important tools for risk management of low probability and high consequence activities. The objective of a PRA is to evaluate major accident frequencies associated with an activity during normal and abnormal modes of operation. As such, a well drilling operation PRA can become a useful tool for risk management in the drilling (and intervention) phase of an oil and gas well. We may describe the PRA as a well (drilling) system risk assessment that considers potential loss of two main safety functions of an oil and gas well; (i) The continuous containment of well hydrocarbon fluids. This safety function is typically referred to as 'well integrity' by industry standard definitions (NORSOK D-010, 2013, ISO 16530, 2014). (ii) The shut in of any well flow upon a demand, for instance, in case of a safety critical situation such as a process leak on-board a drilling rig.

The use of probabilistic methods in well risk assessments is not new, see for example Corneliussen (2006). This also includes several recent methods proposed in literature to help assessment of well blowout risk in the well drilling phase (Cai et al., 2013b, Abimbola et al., 2014, Abimbola et al., 2016, Abimbola and Khan, 2016). However, industry standards and guidelines relevant in this domain

[4] A physical element which in itself does not prevent flow but in combination with other WBE's forms a well barrier (NORSOK D-010)

are still primarily found to be more relevant for qualitative assessments, or are focused on well integrity in the well production (operational) phase (ISO 16530, 2014, NORSOK D-010, 2013, API RP 90, 2006). Recent criticism of the lack of risk indicators, and the general industry lack of widely recognised tools, standards and guidelines that concerns PRA in drilling and intervention operations indicate that the well blowout risk are not sufficiently described and quantified for such operations. For example, the lack of well operation PRA could impair the ability for the operators' change management systems to maintain well risk indicators during the operations, and thereby provide the levels of well safety expected by society (Lootz et al., 2013).

Motivation

The short lifespan and the dynamic 'stress and strength' type nature of hazards, well barriers and other safeguards associated with well drilling operations makes PRA modelling a challenge. New drilling technology are also continuously introduced. One example is the technology developed to enable efficient development of shallow, low pressure and low temperature, unconventional resources such as shale oil and gas. Another example is the technology developed for harsh deep water environments that contain deep and prolific, high pressure and high temperature, pre-salt reservoirs. For example, successful applications of new drilling technologies recently includes the introduction of wired drill-pipe and various type 'closed loop' drilling systems for both fixed dry tree and deep water subsea drilling operations.

The production phase of the well is in stark contrast to well drilling operations. As long as the well is producing it can be assumed that operational procedures and well barriers are fixed, or only subject to minor changes related to dynamic reservoir conditions. This situation makes classical bow-tie methods based on fault tree- and event tree analysis suitable, and such are also widely described as adopted for PRAs made for risk management during the well production phase (Holand, 1996, Corneliussen, 2006, Haga and Strand, 2006, Torbergsen et al., 2012). The descriptions and guidelines on how to control risk in drilling operations in a PRA perspective are found to be fragmented based on discussions over recent years with colleagues from drilling and well in industry.

A study of the oil and gas industry literature concerning potential methods adopted for quantitative risk assessments of well drilling operations was performed early in the PhD project. The study found relevant documentation to be scarce with quantified well blowout risk adopted on a high level, for instance, based on adjustments to existing drilling blowout frequencies from the SINTEF Offshore Blowout Database[5] (Vandenbussche et al., 2012), or only established systematically more detailed for a main WBE used in the activity (Holand, 1999, Holand and Skalle, 2001, Holand and Awan, 2012, Cai et al., 2013c). The careful planning that includes risk assessments of critical events such as well barrier failures and blowouts in well drilling operations was only found to be consistent

[5] http://www.sintef.no/home/projects/sintef-technology-and-society/2001/sintef-offshore-blowout-database/

across the industry as qualitative type analysis. The analysis performed according to the requirements provided by regulatory authorities with help of generic standards, and based on the operator's and service provider's internal governing document system (Ådnøy et al., 2009, p. 8).

From interactions with colleagues and my own work experiences from well risk assessment professional work an interest was spurred by the author to perform more dedicated and extensive work on the possible industry needs for more knowledge, or on bridging the existing knowledge gaps identified between the adopted industry practices and the existing academic theories. This is to help improve the risk informed decision-making[6] part of risk control in offshore well drilling (and intervention) activities. The work effort, with financial aid from NTNU, turned into a PhD project after some years at the brink of the oil industry downturn in 2015. The PhD project was initially to focus on exploring the concept of 'dynamic safety barriers', which later in the study became refocused on; (i) Existing knowledge and methods relevant to the quantification of risks associated with well drilling operations, and (ii) how this knowledgebase may be applied or developed further, for improved decision making in the planning/preparation phase, and for change management, for such operations.

This thesis represents research that concerns the risk management of offshore well operations with the main objective of help establishing a systematic approach for blowout risk analysis of well systems in the planning and follow-up of well drilling operations. The research is applied science oriented with focus on the qualified well barriers that are commonly used in well drilling operations, but as such it also needs to identify and incorporate important human and organisational risk factors. The intended use of the contributions from this research is to reduce the well system risk during well drilling operations.

1.2 Objectives

The main objective of this thesis is to develop a systematic approach for risk assessment of offshore wells in the drilling phase. The approach, denoted drilling PRA (DPRA) in this thesis, could be used as an aid to risk informed decision-making in relation to offshore well drilling (and intervention) operations. The focus of DPRA is on procedures and methods for the quantification of probabilities or frequencies associated with well releases and blowouts. The DPRA is focused on the two main safety functions of a well system:

- Containment of well hydrocarbon fluids, and thereby prevention of uncontrolled flow of well fluids within- or from the well. This function is commonly referred to as 'well integrity' in the

[6] A decision-making approach in which risk analysis is used as one among several inputs to make a decision that involves trade-offs between multiple objectives (Johansen, 2014). A concept that is contrast to risk based decision making, which is type of decision making that almost solely is based on the results of risk assessment (Rausand, 2011).

oil and gas industry and represents a continuous type safety function typically provided by the passive well barrier elements (WBE).
- Shut-in well in the case of a safety critical situation. This well shut-in function is an 'on demand' type safety function typically provided by active WBEs and based on random activation.

To arrive at such new procedures and methods, the main objective is split into the following sub-objectives:

- Describe the regulations, industry standards, and best practices that provides recognised requirements to enable the analysis of well safety functions in the drilling phase.
- Describe well operations and the status related to well barrier control functions (continuous and on demand) during well drilling operations.
- Describe the status related to quantitative analysis and control of the main well safety functions. Identify accepted methods within industry that are applied in the domain of quantitative well operation risk assessments.
- Identify relevant sources for experience based data available for well risk assessments calculations and verification. Discuss the quality of the data, and suggest improvements in application of experience based data.
- Develop a systematic approach for risk assessment of offshore wells in the drilling phase. In this context a systematic approach means to quantitatively assess well blowout or release risk if a technical, human or organisational barrier related to the well system fails during the well drilling phase.

1.3 Delimitation

The PhD work is focused on procedures and methods for risk assessment in the domain of well safety. **Safety** is defined as "freedom from unacceptable risk" in ISO/IEC Guide 51 (1999). The ISO/IEC standard describes safety as a technical state (condition) or a situation (mode) in relation to human activity where the risk is found acceptable to society. An interpretation of safety also used in this thesis is related to the human efforts made, for instance, quantitative or qualitative risk assessments, aimed at prevention or reduction of harm from random unwanted events. The term security may be found used in a similar context towards efforts and studies where deliberate hostile actions by humans are the source of unwanted events. The subject of security is not addressed in this thesis.

ISO/IEC Guide 51 (1999), NORSOK D-010 (2013) and ISO 12100 (2010) defines **risk** as "a combination of the probability of occurrence of harm and the severity of that harm". The term harm relates to physical injury or damage to health, property, and livestock. The term hazard refers to a potential source of harm, and a well drilling operation represents a potential source of harm with potential to cause hazardous events (blowouts and releases), and operation risk must therefore be found acceptable to society. As such, this thesis focuses on prevention of significant loss in application of risk assessment as means to help protect human health, the environment and financial interests. The possible value generated from a more efficient risk management process produced by the proposed method(s) is not considered in this thesis.

The work is limited to offshore ‘well-systems’ with their two safety functions described in Section 1.2. Further, this thesis only focuses on the drilling phase of the well lifecycle. The drilling phase involves short-term and dynamic situations where a loss of WBE safety function (‘leak’) may occur quickly and result in unacceptable changes in blowout risk level. The drilling phase may represent the first phase in well lifecycle (‘development/exploration drilling’) or start after the well is handed over from production operations (‘re-drilling/side-tracking’). Similar intrusive well intervention operations performed to maintain efficiency of an existing well are not focused on, but treated as relevant in review of ‘lessons learned’ from historic well accidents for purposes of DPRA development.

An oil and gas well may be a source of several types of hazards as defined by ISO 12100 (2010). The only unwanted event focused in DPRA is the uncontrolled release of inflammable and explosive fluids (hydrocarbons) to the surrounding environment as historically by far the most significant risk factor.

A sequence of unwanted events leading to a blowout may start with a WBE removal, failure or an external hazardous event affecting the well barrier system. The frequencies of external hazardous events that may result in well blowouts are not covered. The loss of individual WBE safety functions are focused on in this thesis. The loss of more than one WBE is an indication of a significant increase in well operation risk, and should be treated accordingly.

This thesis focuses on the practical application of methods that may be used to quantify blowout risk in well drilling operations. If existing methods identified in literature are found suited to be adopted or adapted for purpose of DPRA, such methods are used as natural elements in DPRA. Focus in such cases is on making improvements from perspective domain of well safety as advised by Rasmussen (1997), for instance to models established or to input data used, rather than proposing new methods.

The well shut-in function comprises three basic parts; (i) Signal detection (well monitoring by sensors or human actions), (ii) decision to activate the shut-in function (logic controller or human action) and (ii) actuation of active WBEs. This thesis focuses on the human, organisational and technical factors that may impair main well shut-in functions, but the methods and results may also serve as input into the design and follow-up of continuous safety functions.

Well operation risk acceptance criteria (RAC)[7] are described as prescriptive from recognised regulations and industry standards. To establish explicit RACs are not within the scope of this thesis.

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[7] Criteria based on regulations, standards, experience and/or theoretical knowledge used as a basis for decisions about acceptable risk. Acceptance criteria may be expressed verbally or numerically (NS 5814). Risk which is accepted in a given context based on the current values of society (ISO 17776).

To establish RAC is considered the responsibility of the operator or service provider in charge of a specific well activity.

1.4 Scope of work

The principle approach to analysis of well safety is to address 'well-system' blowout risk in line with regional regulations and provisions for the establishment of well barriers in petroleum activities. This thesis considers regulations established for two offshore regions, which are considered the most influential world-wide from a well safety perspective; (i) the US Gulf of Mexico outer continental shelf (USGoM OCS) regulated by the Bureau of Safety and Environmental Enforcement (BSEE) (BSEE CFR 30-II-B, 2014 (October)), and (ii) the Norwegian Continental Shelf (NCS) regulated by the Petroleum Safety Authority Norway (PSA) (PSA, 2014a).

Many of the principles used in BSEE regulations are also found in PSA regulations since US based major oil and service companies have been dominating world-wide since the early days of the 'oil age'. An important difference in regulations is the dominating use of rules ('what you must do') in the BSEE regulations, while the PSA regulations are more functionally oriented ('what you must achieve'). The PSA in practice require operators and service companies to develop their own in-house rules and procedures ('governing documents'). Governing documents typically make use of both rules and risk assessments to demonstrate acceptable risk. For example according to the PSA (2013a), the principles for barrier management recommends the use of risk assessment before an evaluation of the number and location of barriers required to maintain an acceptable risk level for the activities. Rules may be found easier to comply with and enforce, while functional requirements give operators and service companies more freedom to develop a range of technologies/solutions to achieve the same function, which reduces efforts needed for revision (upkeep) of regulations.

Both BSEE and PSA regulations make extensive use of national and international standards as references for how to comply with regulations such as API, ISO and IEC standards. In NCS, a range of NORSOK standards have been developed that are accepted by the PSA. Both BSEE and PSA may grant departures from their regulations ('deviation from best practice/rule'). Departures are typically granted on basis of discourse when credible arguments are made for no significant increase in well blowout or release risk as result of the departure (Haga and Strand, 2006).

Figure 1 illustrates a typical generic risk management[8] process adopted to a technical system entity by oil companies, rig contractors and other service providers. The process is based on an accepted standard with associated work tasks described directly in the flowchart. The first part in Figure 1 includes developing risk assessments that are associated with two main tasks:

[8] Systematic application of management policies, procedures and practices to the tasks of analysing, evaluating and controlling risk (IEC 60300-3-9). This corresponds to the abridged definition given of a risk management process in ISO/Guide 73:2009.

(i) Risk analysis concerned with identification and analysis of probability and severity of harmful/ hazardous situations.

(ii) Risk evaluation concerned with decisions making on the basis of the risk assessment in light of criteria established for acceptable/tolerable risk[9].

The last risk management task is risk control, which is concerned with the generation and maintenance of RAC, and of the quality assurance of the risk assessments that are already in effect as part of activities. It is noted that results from well risk assessments may also be used in case-based discourse as part of this task, which is not part of the scope of this thesis.

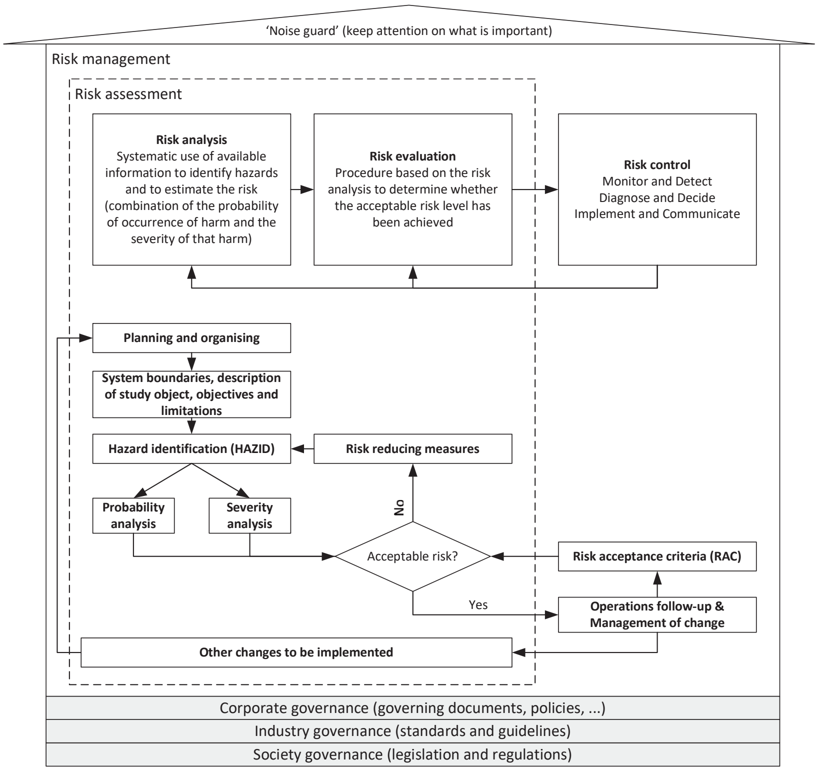

Figure 1. A typical technical system entity risk management process based on IEC 60300-3-9 (1995)

Figure 1 includes a 'noise guard' indicated as the roof of a building that envelopes and 'protects' the risk management process. The need to consider some level of protection of the risk management process is recommended by several popular risk management theorists, based on the fact that we all live in fast

[9] Tolerable risk is a term used to indicate that risk reducing measures have been implemented in activity to achieve an acceptable risk level.

pace and complex political environments (Rasmussen, 1997). Moreover, the noise guard is included so that the signal to noise ratio is consciously considered (Perrow, 1981), and so that changes made, for instance, to well risk management practices remain focused on the major well accident potential and on the (historic) resident pathogens that are important for such (Reason, 1988).

The identification of stakeholders, their requirements and preferences is considered important as basis for project communications, evaluation and decision (trade-off) analysis. The main stakeholders identified in this PhD project are indicated with respective governance and enforcement provided as the foundation for the building in Figure 1. Stakeholders can be described as individuals, organisations or entities, which may be identified as direct or indirect recipients of the implications, or the ripple effects, of a solution. The key stakeholders identified are; (i) Operating companies, rig contractors and other main service providers that seek to maximise the profits from their business on behalf of owners. (ii) The PSA, BSEE and similar authorities responsible for prudent conduct of oil and gas extraction activities. Prudence is achieved through regulations and supervisions that specify level of acceptable risk with regards to protection of human health and for safeguarding the environment.

The risk management process in Figure 1 may also require that the well system risk is covered in risk assessments for offshore installations, such as described in the Norwegian offshore sector (NORSOK Z-013, 2001). Corneliussen (2006) in this respect considers three levels shown in Figure 2 that are explicitly associated with well blowout risk in the context of risk management of an offshore installation; (i) WBE level, (ii) well system level, and (iii) offshore installation (rig) level. In Figure 2 the installation risk management is described by a typical hierarchy where requirements on installation level determine boundary conditions for activities at lower subsystem levels. On each level the typical design basis is illustrated with boxes in greyscale. The design basis includes requirements for safety and reliability[10] analysis illustrated with white boxes. The dotted lines in Figure 2 indicate that risk assessments on WBE and well systems level may serve as input to technical safety analysis on installation level. These feedback loops are not treated specifically in this PhD thesis.

[10] The ability of an item to perform a required function, under given environmental and operational conditions and for a stated period of time (BS 4778, ISO8402).

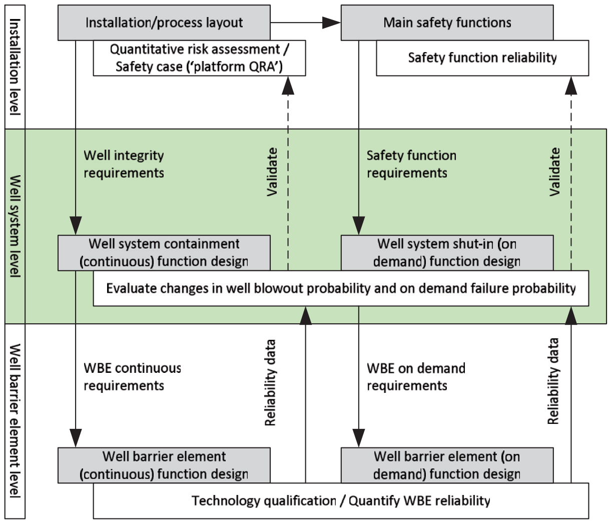

Figure 2. DPRA in offshore installation risk management adapted from (Corneliussen, 2006)

This PhD project is focused on a well risk assessment approach applied at offshore well system level with focus on two main safety functions described in Section 1.2. The approach includes risk assessment of both continuous containment and on-demand safety functions as illustrated in Figure 2. It is implied by regulations, industry standards and industry best practises that if the risk is acceptable on a well system level, then the well system risk is also considered acceptable on an installation level.

ISO 16530 (2014) defines well integrity for the well operational phase as; "Containment and the prevention of the escape of fluids (i.e. liquids or gases) to sub-terrane formations or surface". An earlier definition of well integrity stems from the Norwegian oil and gas industry's NORSOK D-010 (NORSOK D-010, 2013) standard. The definition encompasses well integrity for all well lifecycle phases; "Application of technical, operational and organisational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well". Focal to both standards is the technical means (WBEs) for containment of the energy in oil and gas reservoirs. What the 'operational and organisational solutions' in the NORSOK D-010 definition entails is not explicitly discussed. This thesis adopts the interpretation of the influences that personnel have on well operation risk through decision making about the introduction, activation or re-establishment of well barriers (PSA, 2013a).

The regulations and industry standards described provide numerous explicit examples of the minimum technical well barrier solutions required, and include many detailed WBE design and usage specifications. The noise guard in Figure 1 may also here help emphasise well safety as a knowledge domain, similar to the way its described for use of PRA in the nuclear power industry (ERIN, 2013). The textbook risk assessment methods described, for instance by Vinnem (2007), (Rausand, 2011), may therefore not always be applicable. For example, the automated risk matrix based risk management process described by NORSOK Z-013 (2001) is not widely adopted by the drilling and well community.

In contrast, best industry practices and best available (safest) technology are enforced as explicit principles for risk acceptance by BSEE CFR 30-II-B (2014 (October), part 250.401). Relevant to RACs, the regulations also, for instance, state requirements to; (i) Have persons onsite that are trained to fulfil all responsibilities, (ii) Use and maintain equipment and materials necessary to ensure safety. Similarly, PSA states explicit requirements to well barriers (PSA, 2014b, Section 85, PSA, 2014c, Section 48); (i) Use tested well barriers with sufficient independence; (ii) If a well barrier fails, activities shall not be carried out other than those intended to restore the barrier. (iii) Well barriers shall be designed such that that they do not hinder well activities, and such that their performance can be verified. In general, the drilling and well community risk management practices may be described as largely based on qualitative risk assessments and on typical precautionary 'rule-based' and discourse 'case-based' criteria for acceptable risk (Klinke and Renn, 2002). The practices also imply that probability reducing measures are to be given priority over consequence reducing measures in risk reduction (Haga and Strand, 2006).

1.5 Scientific approach and verification

"A good theory is better than a lot of data without a theory"

Dennis V. Lindley (Lindley, 2014)

Research is a systematic inquiry to describe, explain, predict and control an observed phenomenon. Research involves inductive and deductive methods (Babbie, 1998). Inductive methods analyse the observations made of a phenomenon to identify the underlying principles, structures, or processes. Deductive methods verify theoretical hypothesised principles about a phenomenon through experiments and observations. The purposes of the methods are different: inductive to develop explanations, and the deductive to test the validity of proposed explanations. In most research both inductive and deductive techniques are applied. However, the general advice is to put weight on the deductive methods to, for instance, better cope with the potential for confounding variables in datasets (Lindley, 2014). The deductive method for conduct of research as formulated and advocated by giants such as Albert Einstein and Richard P. Feynman has been widely adopted in the natural sciences and comprises the following procedure; (1) Make a 'qualified guess' from the state of science, (2) explicit formulation of a new concept through definitions, limitations and assumptions, (3) computation, deduction by logical argument, of the implications of the concept, and (4) careful validation and scrutiny of the concept by comparing it's implications with observations or experiments.

Research is not all about experiments and observations, it's also about the thinking process. What do we want to find out, how do we build arguments around ideas and concepts, and what unbiased evidence we can collect to persuade our peers to accept our arguments? Patton (1990) points to the importance of identifying the purpose in a research process, and from which four main classes of research are described:

Basic research: The purpose of this research is to understand and explain, i.e. the research is interested in formulating and testing the theoretical construct and propositions that ideally generalise across time and space. This type of research takes the form of a theory that logically explains the phenomenon under investigation to give its contribution to knowledge. This research is descriptive in nature exploring what, when and how questions.

Applied research: The purpose of this research is to help people understand the nature of human problems so that humans can more effectively control their environment. In other words, this type of research pursues potential solutions to human and societal problems. This research is more prescriptive in nature, focusing on how questions.

Evaluation research (summative and formative): Evaluation research studies the processes and outcomes aimed at an attempted solution. The purpose of formative research is to improve human intervention within specific conditions, such as activities, time, and groups of people. The purpose of summative evaluation is to judge the effectiveness of a program, policy, or product.

Action research: Action research aims at solving specific problems within a program, organization, or community. Patton (1990) states that design and data collection in action research tend to be more informal, and the people in the situation are directly involved in gathering information and studying themselves.

This thesis belongs to the field of applied research, meaning research aimed directly at a practical application. Applied research can be exploratory but can also be descriptive. Applied science is an activity of original character to gain new knowledge and insight, primarily to solve specific practical problems. This means that the quality of the research must be considered not only from a scientific method point of view, but also from a stakeholder point of view. Applied research 'asks questions' and in this context this thesis objective may be stated as 'how can we better control well system risk in the well drilling phase?'

The foundation for this thesis is established based on author's professional industry experiences working for SINTEF Petroleum Research AS and ExproSoft AS, and through extensive literature surveys. The surveys represent the main starting point for the research and supports the subsequent activities. In addition to surveys, reviews of rig crew interview summaries (SINTEF, 2014), and well accident data (Holand, 1997, IOGP #434-2, 2010, Strand and Lundteigen, 2017), discussions with NTNU supervisors and staff, and industry representatives from companies like Statoil, Acona and ExproSoft have contributed valuable input to the identification of important problem areas and specific issues to be focused on.

The work is primarily intended to be complementary to the existing industrial and academic works adopted in the domain of well safety documented primarily by BSEE, PSA, ISO, API, NORSOK, Holand (1996), Corneliussen (2006) and Vignes (2011). The research is further based on the observations made to key aspects of well safety, statistical methods and probability theory, and the law of energy conservation. From the choice of applied research process it follows that innovation will be key in making a scientific contribution. The academia is given responsibility for critique and consolidation of human knowledge, but it would be unwise to think that knowledge only is generated by the academia. The author is therefore especially grateful to colleagues in industry that have used their spare time to review the main publications part of this thesis.

PRAs are used as the basis for important decision making in many industries such as public transportation, aerospace, aviation, defence, nuclear and oil and gas. However, there are always ongoing discussions about the credibility of probabilistic risk analyses among stakeholders for such purpose. One of the outcomes from the discussions is a paper by Rae et al. (2014), which proposes a set of criteria in a roadmap for evaluation of risk assessment credibility based on a set of maternity levels. The levels are based on a set of factors that will affect the quality and therefore usefulness of the risk assessment results. The starting point is an item list that is very close to a disposition found in research methodology, naturally since the purpose is to secure consistent and valid end-result from the analysis efforts. A different perspective to the PRA credibility discussions can be found in concepts that concern risk indicators and risk metrics. For example, Johansen and Rausand (2014) propose some evaluation criteria in regards to risk metrics. A comparison of criteria based on the two views are shown in Table 1, which is used as a foundation for securing validity of the PhD project results. These criteria has been followed, as far as possible, in course of the work presented in this thesis. Table 1 is revisited for purpose of the research process evaluation provided in Chapter 5.

Table 1. Proposed criteria for judgments on DPRA quality and usefulness (Johansen and Rausand, 2014, Rae et al., 2014)

Johansen and Rausand (2013) – criteria for evaluation of risk metrics	Adapted from Rae et al. (2013) – criteria for evaluation of PRAs. Based on Level 2 maternity that is considered an invalid QRA study.
Validity - Fit for purpose? Does metric measure what it is intended to measure, i.e. what is stakeholders understanding of 'risk'. Communicability - Needs? Represent a sufficient level of information to stakeholders	**Describe scope and objectives** Clear purpose Clear scope Clear boundaries, boundary conditions Clear evaluation criteria
Reliability - Approach? Clear verbal understanding and mathematical definition of the measure. Unambiguity	**Describe models, methods and tools** Avoid/State omissions in scope - External (hazardous) events - Software, human and organisational influences - Physical or causal pathways, operational phases, outcomes

Table 1. Proposed criteria for judgments on DPRA quality and usefulness (Johansen and Rausand, 2014, Rae et al., 2014)

Johansen and Rausand (2013) – criteria for evaluation of risk metrics	Adapted from Rae et al. (2013) – criteria for evaluation of PRAs. Based on Level 2 maternity that is considered an invalid QRA study.
- Precise? Clear interpretation and location of measure in the bow-tie (risk analysis model). Context - Features? Reflect relevant decision factors and relationship with de facto versus 'artificial' influences (assumptions) Comparability and specificity (trade-off) - Flexible? Applicability across many systems and alternatives versus loss of validity as a 'metric' (hard number)	Avoid/State unrealistic limitations - Contradicting arguments - Incorrect models (representation) - Invalid assumptions about system behaviour, effects of monitoring and mitigations Avoid/State accuracy limitations - Invalid or incorrect use of models, methods and tools - Unacceptable 'drift' due to insufficient dynamic capability of models, methods and tools
Transparency - Unbiased? Basis and implications of measure apparent to stakeholders. Consistency - Independent? Judgments made not contradictory across analyses or decision problems. Rationality - Accountable? Compatible with 'sound judgment' - utility theory and theory of rational choice (maximise utility) Acceptability - Recognised? Considered legitimate and receive buy-in from stakeholders	**Describe source material** Not omitted Not outdated Not inconsistent / unrealistic Not unreferenced **Avoid systematic problems (validate)** Get stakeholder acceptance Use peer review, experiments and observations to avoid - Obviously unrealistic results - Contrived results (biased) - No answers (scope)
	Reporting of results Not misleading - Incorrect use or grouping of model elements - Incorrect use of risk acceptance criteria (RAC) - Alternatives considered across different baselines ('apples and pears') Not inconsistent - Use of assumptions and source data - Conclusions drawn vs. level of detail in study approach - Qualitative vs. quantitative descriptions of risk level Not incomplete, not quantified - Limitations / restrictions / uncertainty not reported - Sensitivities not reported (the effect of assumptions on analysis outcomes)

1.6 Structure of thesis

This PhD thesis consists of this main report with four enclosed papers, whereof two papers have been published and other submitted for peer reviewed publication. The main report discusses the background, scope, framework and body of work in the PhD project together with summary and discussion of main results, the DPRA approach. It also provides additional discussions relevant to specific subjects of research that is published in the enclosed papers. The structure of this thesis is described in more detail below. A section that provides a review of offshore historic well blowout and release data is also enclosed in Appendix I.

Chapter 1 describes the background and motivation for the PhD project, along with the objectives, the delimitations and the scope of work. The scientific approach is discussed and the structure of this thesis is outlined.

Chapter 2 describes the foundation and boundary conditions of offshore well drilling operations for purpose of a single well-system risk assessment. As such, the Chapter presents the domain knowledge as basis for DPRA procedure and method development and for the discussions and evaluations provided later in the report. A typical North Sea offshore well development drilling operation is described. Emphasis is placed on the well barriers and relevant well safety issues that may arise in course of the operation. The WBE specific well integrity and shut-in function requirements are described in detail. Benchmark historic well blowout and release data is presented in Appendix I. Readers who are familiar with well integrity and the drilling and well domain may consider to skip reading this chapter or parts thereof.

Chapter 3 presents the boundary conditions for risk assessment of a well drilling operation used in literature reviews as basis for developing DPRA. This includes a well system risk modelling principle based around the traditional PRA in the well operational phase where WBEs that are first structured by leak paths in a well barrier diagram.

Chapter 4 presents the new elements part of the DPRA approach developed for risk assessment of offshore wells in the drilling phase for a single well system. The method may typically be applied by the well engineer or similar personnel involved in operations planning where a fluid column will be established as a primary WBE in the well system. Four papers have been written in support of DPRA to outline specific procedures and methods developed; (i) Paper 1 presents a compact method for dynamic BOP safety and reliability analysis. The method can be used in physical degradation modelling of BOP's to evaluate the effects of maintenance strategies on safety availability[11] targets. (ii) Paper 2 presents a well accident review with clarifications made to the role and the importance of the human-machine interface (HMI) well operation risk control. The HMI may be considered the most important technology-based risk influencing factor in well drilling, and is thus important to evaluate as part of the analysis of drilling operator errors. As result of thorough study, the paper recommends modifications to operator error causal model adopted in Paper 3. (iii) Paper 3 presents a human reliability analysis framework that can be used to address human task performance impacts on well system risk in drilling operations. (iv) Paper 4 presents a taxonomy classification scheme of human error concepts based on a task analysis

[11] The ability of an item (under combined aspects of its reliability, maintainability, and maintenance support) to perform its required function at a stated instant of time or over a stated period of time (BS 4778).

type case study of typical well drilling operation tasks. The classifications are proposed to support the consistent application of human reliability analysis in DPRA.

Chapter 5 includes a brief evaluation of the research process, and describes the explicit scientific contributions made in this thesis relative to inclusion of human, technical and organisational aspects in DPRA. The PhD project conclusions and recommendations for further work with some closing remarks are given in Chapter 6.

2 Offshore drilling operations and well systems

The essential functions of an oil and gas well is to contain and transport hydrocarbon fluids between the surface and the reservoir in an efficient and safe manner. This chapter gives a background description of well drilling operations, well barriers and the associated human, organisational and technological factors of relevance to the DPRA developed in this thesis. Readers who are familiar with well integrity and the drilling and well domain may consider to skip reading this chapter or parts thereof.

The content describes the main characteristics of an offshore well and of the drilling operation carried out as the initial part of the well construction phase in order to prepare the well for production or injection operations. The drilling of a typical development well is described together with different well drilling operation stages. Finally, the well integrity and shut-in functions and requirements of each WBE part of well barriers are discussed in detail. A review of offshore well blowout and release data is enclosed in Appendix I. A list of the terminology used in offshore drilling operations can also be found enclosed in Appendix VII.

The descriptive information provided in this chapter is largely based on information retrieved from text books, industry articles and standards, regulations, and internet sources like; (Mitchell, 2006, API Spec 5CT, 2012, API Spec 16A, 2004, API Spec 16D, 2004, API Std 53, 2012, BSEE CFR 30-II-B, 2014 (October), NORSOK D-001, 2012, NORSOK D-010, 2013, PSA, 2014c, Ådnøy et al., 2009), http://petrowiki.org/, http://www.iadclexicon.org/glossary/, http://www.glossary.oilfield.slb.com/ and http://www.exprobase.com/.

2.1 Offshore drilling rigs and equipment

Rotary drilling rigs are used for most well drilling after hydrocarbon resources. The drilling rigs are first broadly classified as either land- or marine rigs. Only the marine rigs are relevant to offshore well operations. The main differences between the marine rigs are seen related to mud system- and equipment handling capabilities, mobility and maximum water depth of operation. The marine rigs can be classified as either seafloor supported or as floating. The seafloor supported rigs are found on fixed platforms and mobile jack-up platforms that typically operate in water depth of less than 150 meters. The floating rigs are operated as anchored to the seafloor or as dynamically positioned (DP). The floating rigs are commonly referred to as fixed floating platform (tension leg or spar buoy), semi-submersibles/mobile offshore drilling units (MODUs) or drill ships. The wells are drilled from floating rigs when water depths make it too challenging or costly to use fixed rigs. The newer generations of semi-submersible drilling rigs and drill ships can operate in water depths of more than 2500 meters.

The DP rigs are special in regards to well system risk since they require an active satellite based positioning system that operate thrusters to keep the rig in position above the wellhead during the operations. A failure of the DP system during drilling can cause a 'drive-off' or 'drift-off' situation, which is safety critical and can escalate into a well blowout. The well drilling experience data shows that safety critical DP system failures can occur also for modern DP rigs (Holand, 1999)[12].

The well drilling process described in this Chapter is typical for drilling a subsea well from a modern floating rig and is based on (Mitchell, 2006, Ådnøy et al., 2009, ExproSoft, 2011). A sketch that show the main equipment part of a rotary drilling rig is shown in Figure 3. All main parts of the drill string and casing string are threaded tubulars assembled or disassembled at the drill floor. The string will increase (or decrease) in overall length as new components are 'made up' (or 'laid down') to the previous (or last) component run incrementally into (or pulled out of) the well.

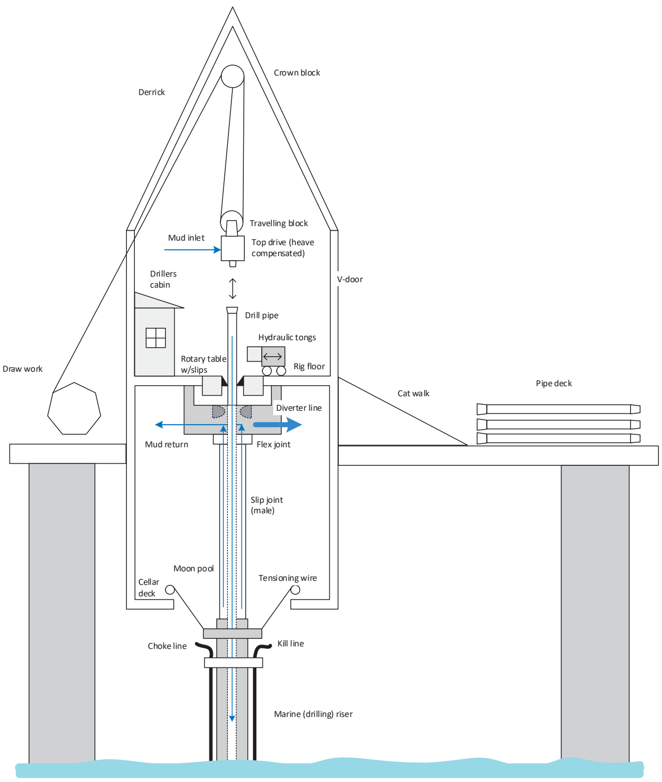

Figure 3. Main drilling rig equipment

[12] http://offshore.no/sak/254971_superriggen-drev-av-lokasjon-borestrengen-kuttet (in Norwegian). Article describes drift-off of a modern 'CAT D rig' named Songa Equinox that occurred 24.12.2015, and where manual emergency riser disconnect sequence of BOP system was activated successfully.

The components are picked up during the string run in hole (RIH) from the catwalk by the top-drive and moved into position above the existing string suspended by slips in the rotary table. The component is made up to a specified make-up torque by the casing tongs. The rotary table allows rotation of a suspended string independent of the top drive. The top-drive is the main unit used for rotation of the drill string. The top drive is also attached to the draw-works, which is used to manipulate the drill-string up and down. A heave compensation system is used to reduce the relative movement between the floater with the drill string attached and the sea floor. The system stabilises the drill-bit on the bottom of the well, and reduces mechanical wear between the drill string and the well components. The drill string is free to move relative to the well when in normal drilling mode if a potential heave system lock-out failure occur. However, in situations with shorter and/or weaker strings deployed more care must be taken. The drilling can commence when the drill string bottom-hole assembly (BHA) with a drill bit reaches the seafloor within a pre-deployed guide base. A typical BHA for drilling last hole-sections of a well is made of the following 'tools' from top down:

- Drill collars are heavy weight drill pipe (HWDP) included to provide weight on bit for drilling.
- A jar is a hydraulic powered hammer used to help release the string if it gets stuck while drilling
- Non-magnetic drill collars (NMDC) are included in the BHA closer to the bit not to disturb the electronics found in other BHA tools.
- Measurement while drilling (MWD) tool provides necessary functions for directional drilling and mud pulse telemetry of data to surface
- Logging while drilling (LWD) tool provides logging functions and formation evaluation like porosity and lithology
- Float sub is a non-reverse flow check valve that hinders backflow up the drill string.
- Mud motor that drives the drill bit using hydraulic power (circulating mud)
- Drill bit that excavates the formation

Well depths are measured both vertically and along the wellbore trajectory from the rigs drill floor. For measurements along the trajectory the depth unit is measured depth rotary kelly bushing (MDRKB) or measured depth rotary table (MDRT). The well depths measured as the vertical distance from the rigs drill floor are similarly given with unit's true vertical depth rotary kelly bushing (TVDRKB) or true vertical depth rotary table (TVDRT). The depth of the hole drilled is the well depth measured minus the water depth and the rigs air gap. The water depth is defined as the vertical distance from Mean Sea Level (MSL) to the sea floor and the rigs air gap is defined as the vertical distance from the rigs drill floor to MSL. The air gap varies from rig to rig but is normally within 25 to 35 meters.

2.2 Well drilling operations

An introduction to well drilling operations is given in this Section. Focus is put on drilling operation and aspects that include the largest uncertainties in drilling programs (plans). However, the principles for establishing and use of well barriers are identical also in intervention operations. The drilling process consist of an iterative sequence that involve drilling a hole and then setting a pipe (casing) in this hole. The main function of the casing is to avoid hole-collapse with inability to drill further, and to strengthen the wellbore in regards to burst-tolerance as a safety margin. The casing is cemented in place inside the open hole to avid communication between hole-sections and thus a weakening of the burst capacity of the next hole-section. Drilling a hole-section can be simplified with the following basic event-sequence:

- Make up drilling BHA to drill pipe and run in hole (RIH)
- Pressure test last set casing string and the blowout preventer system (BOP)
    - Verifies the casing and BOP as a qualified WBE for drilling next section
- Displace the well to the drilling mud specified for the hole-section to be drilled.
- Drill through the casing cement shoe and do formation integrity pressure test (FIT) of the newly exposed open-hole formation
    - Verifies the weakest openhole formation as qualified WBE for drilling next hole-section
- Drill hole-section to the specified target location
- Pull out of hole (POOH) with drilling BHA
- Make up and RIH casing string
- Cement casing string and install casing seal
- Hole and drill-pipe cleaning. Wait on cement to cure (WOC)

A submerged remote operated vehicle (ROV) with live streaming camera to the surface is used as visual (outside view) aid in subsea well drilling. The major steps of the offshore development drilling process are more in detail as follows:

Drill 36” hole, run and cement the conductor casing with wellhead housing

The conductor is a short large size casing installed to stabilise the sea floor formations that consists of unconsolidated sediments like sand and soft clay. The bottom joint in a casing/liner string is called the shoe joint. The shoe joint is made drillable and includes components to help RIH and cement the casing within the hole. The cementing operation includes circulating in place a cement slurry volume down the casing, out via the shoe joint and then back up again in the annulus between the casing and the hole. Centralisers are clamped to the outside of the casing to help evenly and efficiently circulate the cement to the casing outside. The shoe joint include a seat-interface to catch a wiper plug that is pumped behind the cement to help signal the end of the pumping operation as a pressure increase registered on the drill-floor. This is called ‘bumping the plug’. The cement slurry is then left to cure for a specified period.

Drill 26” hole, run and cement the surface casing with wellhead

Drilling the 26" hole is performed without a marine drilling riser or BOP and with mud returns directly to the sea as for drilling the 36" hole. Before the start of drilling new formations, the bit first drill through the shoe joint and the cement set in ‘rat-hole’ below. The wellhead is connected to the top of the last surface casing joint RIH and landed inside the wellhead housing on the conductor casing. The common subsea wellhead nominal sizes are 18 ¾” and 16 ¾". The common nominal sizes of the surface casing are 20”, 18 5/8”, and 24”. The wellhead is a large spool normally welded to the top of the surface casing. The wellhead include a hang-off system for the well casing, and an interface, a flanged or connector lock system with a seal-ring profile on the top to allow for connection of flow control equipment like for instance the BOP, production tension riser or a production valve tree (Xmas tree).

Each hole-section is drilled by requirements into deeper formations that have sufficient documented strength to meet the ‘burst pressure’ requirements for again drilling the subsequent hole-section. The requirements are primarily twofold referred to as ‘kill margin’ and ‘kick margin’/‘kick tolerance’. The kill margin refers to the wellbore burst pressure tolerance during well kill operations in scenario with a gas filled wellbore. The kill operations include circulation of kill muds to displace the gas out of the well. The requirement for kill margin is typically given as a percent, say about 10% of maximum anticipated wellhead surface pressure, or as a fixed value say around 70 Bar. The kick margin is the maximum gas influx (kick) volume that can be gained and safely circulated out of the well without fracturing the open wellbore formations. The requirement for kick margin is typically of magnitude less than 8 m^3 in-situ influx.

There will be fluid movements in the overburden formations above all oil and gas reservoirs, which are broadly classified as either ‘fill-leak’, or ‘fill-spill’ systems. In some areas when drilling the surface casing section there is elevate risk related to penetration of shallower formations that sometimes trap larger volumes of over-pressured water or hydrocarbon gas, see for instance, accident report (NOU 1986:16, 1986). To reduce the risk of ‘shallow gas’[13] incidents the rig is configured with a diverter system that comprises a diverter bladder element (Figure 3) and an overboard exhaust-system positioned downwind at all times. In addition, extensive ROV seafloor camera surveys after pockmarks and pilot-hole drilling is carried out in the early development phase to reduce the risk of shallow gas incidents.

The stress cycles imposed during drilling from BOP- and riser movements on the wellhead is a source of some elevated industry concern with regards to the potential for dislocation of the wellhead spool

[13] ‘Shallow water flow’ do not pose similar risk in offshore drilling.

from the casing due to fatigue. At least three such hazardous events are reported by industry (Reinås, 2013).

Run and install subsea BOP with marine drilling riser

The subsea BOP is run on marine riser joints down to the seafloor, the wellhead connector is engaged after landing on the wellhead followed by an overpull ('pick-up weight') and pressure test. The marine riser is disconnected from the top drive and the weight is transferred to the riser heave/tensioning system (Figure 3). The BOP control-, diverter-, choke line- and kill line- systems are hooked up and tested.

The upper part of the subsea BOP that is attached to the drilling riser bottom is called the lower marine riser package (LMRP). The LMRP is a stack-up that from top typically comprises a riser flex joint, two annular preventers, and a BOP stack connector. The lower part of the subsea BOP is called the BOP stack that from the top typically comprises a blind shear ram, a casing shear ram, three variable bore (pipe) rams, and a wellhead connector. The BOP stack elements have 'outlets' that interfaces with the kill- and choke line systems. The BOP also includes a control system for operation of connectors, rams and preventers that broadly includes two redundant and retrievable subsea control pods that operate hydraulic pilot valves connected to a high pressure hydraulic fluid system at the rig. The pilot valves are most often manually activated by the driller with BOP control panel located in the drillers cabin on the rig floor. Subsea and surface accumulators help supply the hydraulic fluids to speed up activation, but also as redundancy to secure activation if loss of regular hydraulic power supply.

The wellhead connector is passively engaged, but the LMRP connector is designed so that rig may disconnect in a controlled manner if for instance the weather situation dictates it. The riser can also as result of the design accidentally disconnect (Holand and Awan, 2012). A riser disconnect means that the heavy drilling mud column from rig floor down to the BOP is replaced by a lighter seawater column with some 25 to 35 meters air gap on top. The result is that the hydrostatic well pressure will drop directly with a certain fraction. The well is said to be drilled without a riser margin if this fraction is sufficient to put the well in underbalance with the potential for a well kick to occur. The BOP is described more in Section 2.3.

Drill 17 1/2" hole, run and cement the 13 3/8" intermediate casing

The well is displaced to a specified type of drilling mud at start of drilling the next hole-sections. The drilling mud exhibits hydrostatic pressure that prevents influx of fluids from the formations drilled. The mud act as an unconditional primary well barrier during conventional drilling and a conditional WBE during underbalanced[14] drilling. The mud also controls the bit temperature, provides friction and wear

[14] Drilling where the hydraulic 'head pressure' of the mud is intentionally designed to be lower than the pore pressure of the formations drilled. The method requires additional well control equipment on the rig such as for instance a rotating control device, back-pressure pump or rig

reduction, power source for bit rotation ('mud motor'), facilitate mud-pulse telemetry to surface from BHA data collection instruments, help cut (jet) through the formations, and bottom hole cleaning and transport of the drill-cuttings to the surface. The drilling mud is described more in Section 2.3.

The casing and BOP is normally pressure tested before hole-section drilling starts since the cemented shoe joint act as a convenient 'plug' towards the weaker formations. The drilling is also typically stopped after some meters of penetration of new formations. This stop to perform a formation integrity (pressure) test (FIT) to verify and document sufficient kill and kick margin. The formation at the casing shoe will generally be the weakest point since formation strength increases with vertical depth. The openhole formation is described more in Section 2.3.

For the now deeper casing strings installed a specific volume of cement slurry is pumped during the cementing operations. The volume is determined by formation isolation requirements and by adding some extra excess. The isolation requirements may be to cement back inside the previous casing shoe, but more typically it is some hundred meters back from the shoe, or above formations with a high fluid mobility (reservoir). The conductor and surface casing is cemented back to the seafloor with ROV available to visually oversee cement placement. With no visual means longer available for verification of cement placement more care is used in monitoring volume balances during the cementing operation. A low pressure back flow test of the shoe joint is typically now introduced on coming cement jobs. The casing installation is concluded by installing a casing seal on the top of the casing hanger to seal off the cement circulation ports and establish a high pressure seal towards the weaker casing outer annulus. The location and 'goodness' of cement with regards to isolation can be evaluated further with use of special cement bond logging tools that are run inside the casing. There are few options for 'do overs' in well cementing and problems with, for instance, poor flowrates and fluid losses during the cement placement are common. The typical cementing issues can be found documented under the subject of 'bad cement jobs' and 'remedial cementing' (Mitchell, 2006, p. II-374).

The well target drilling ahead requirements for pressure control in regards to well safety and risk of other drilling problems can at this stage result in the need to 'drill and install' additional intermediate casings or liners[15] in the well.

Drill 12 1/4" hole, run and cement the production casing

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assisted snubbing unit. Underbalanced drilling is applied to reduce risk of formation damages (productivity losses) and wellbore pressure related drilling problems.

[15] Liner is a shortened casing string hung off downhole with a hanger/packer system and not inside the wellhead.

The well is displaced to the specified drilling mud, pressure tested and the 12 1/4” BHA is made up and run in hole. The BHA normally includes a rotary steerable system with MWD and LWD tools for wellbore position, pressure and formation data collection. The most important data is typically sent to surface with a mud-pulse telemetry system. The drilling of the section starts after a new FIT, and typically involves drilling close to or into the target reservoir.

After drilling, the typical nominal 10 3/4” by 9 5/8” or 9 7/8” tapered production casing string is landed in the wellhead, cemented, followed by installation of the casing seal. The entire production casing is then pressure tested to the well design pressure (WDP) before drilling next section through the cement shoe. The WDP is normally the wellhead shut-in pressure (WHSIP) assuming a gas filled well plus the kill margin. In extended wells the production casing can be run as two separate strings that are joined downhole in a so-called a tie-back configuration. Running the casing in two parts reduces critical casing run time through the BOP, but also help the RIH process of the casing and improves circulation rates for cement placement.

Drill 8 1/2” hole, run and cement the production liner

Following the same procedure as before the well is drilled to its total depth (TD) through the reservoir. The nominal 7" production liner is run and cemented back inside the production casing shoe. Finally after cement set the entire well is pressure tested to WDP. The installation of the production liner marks the end of the well drilling phase. The next phase will be to install the production string and Xmas tree, which is referred to as the completion phase. The well now looks something like the sketch in Figure 4.

The production liner in Figure 4 are sometimes replaced by a sand control string typically made of screen layers with fine gravel placed between the layers or packed on the outside. Since the reservoir remains open to the well after installation a formation isolation valve part of the system or a plug set in top of the liner is then used to isolate the reservoir before the transition to the well completion phase.

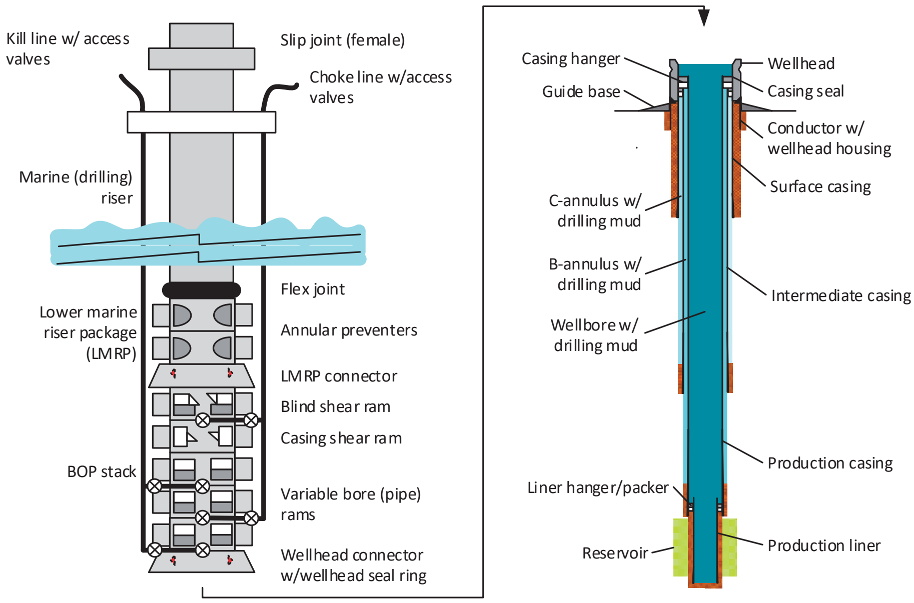

Figure 4. Sketch of a subsea well at the end of the well drilling phase

2.3 Well barriers and well barrier elements

This Section provides a detailed description of the human, organisational and technical (HOT) factors associated with the WBEs used in well drilling operations.

A well barrier is constructed by a combination of one or more WBEs that together form a technical (physical) layer of protection between hazardous energy in an oil and gas reservoir and personnel, the (surface) environment and financial interests. A barrier is said to be **qualified** if its performance as protection device against the hazardous energy is demonstrated satisfactory according to recognised industry practices. A qualified barrier can hence only consist of qualified barrier elements. A barrier element is referred to as **conditional** if; (i) It is not available at all times, or (ii) it is not designed to tackle all realistic well load case scenario. A qualified barrier element can also be conditional due to financial or technological constraints. Holand (1996) also introduces the terms static versus dynamic barriers, and active versus passive barriers. As alternative to static and dynamic barriers the term conditional is used jointly instead in this thesis. The terms **active** and **passive** barrier element is brought forward also in this thesis, passive meaning that the barrier element does not require activation to act as protection and active that respectively require a remote signal, for instance, from a logic solver (automatic) or an operator (manual) to act as protection device. The WBE definitions used in this thesis are illustrated in Figure 5, which is noted to only partly overlap with the concept of a 'safety barrier' or 'barrier' that is discussed by Sklet (2006) and by PSA (2013a).

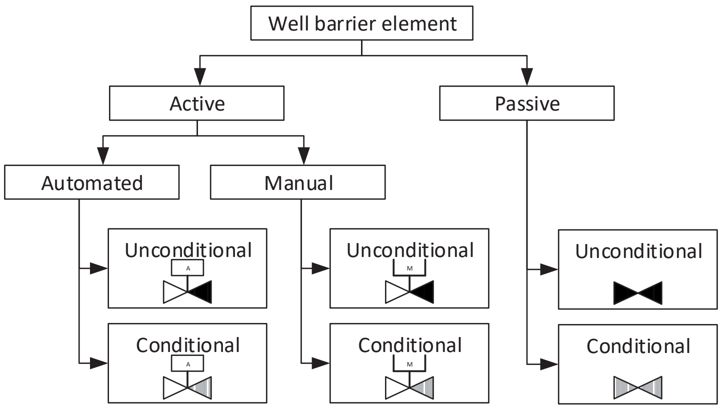

Figure 5. Well barrier element classification

Subsea BOP system

The BOP is an active (automatic and manual) and conditional WBE. The BOP is conditional in sense that it is not designed and tested (qualified) to tackle all realistic well load case scenario.

The BOP descriptions given are based on the current internationally recognised regulations that concerns design, operation and maintenance of subsea BOPs. The regulations are mainly provided by the BSEE, which make use of reference to the relevant industry standards (API Spec 16A, 2004, API Spec 16D, 2004, API Std 53, 2012) to provide guidance on how to fulfil requirements. A subsea BOP is typically made up of three subsystems (The Deepwater Horizon Study Group, 2011):

- Control system that distributes hydraulic power fluid from hydraulic power unit (HPU) and pre-charged accumulator banks used for activation of BOP closure devices. The control systems are based on two principles; combined electro-hydraulic (multiplex - MUX) or pilot all-hydraulic. The principle differences in design are small, and the reliability data collected do not indicate significant differences in performance. There will normally be independent dual pod-control systems for BOP closure device operation referred to as the ‘yellow’ and ‘blue’ pods.
- Lower marine riser package (LMRP) that provides the ability to connect and disconnect the drilling riser from the BOP stack. For example, if bad weather conditions develop or in a DP rig ‘drive-off’ or ‘drift-off’ situation.
- The BOP stack that connects and seal the BOP to the wellhead, and includes a ‘stack’ of closure devices used for well shut-in, typically within ca. 30-45 seconds, in different well control situations. The BOP stack has side outlets for connections to separate kill and choke lines. Each line outlet normally has at least two remote controlled and full opening valves. The wellhead connector that latches and seal the BOP to the wellhead is normally designed with a lock to avoid unintended operation, and control functions are normally not accessible from BOP control panels.

The BOP is illustrated without the control system in Figure 6. In the BOP stack there are three types of closure devices seen available for activation in a well control situation:

- Annular preventer (AP): A rubber donut that is compressed during activation. An AP has the ability to seal-off annulus outside most sizes of pipe running through the BOP. Some AP elements can also seal off the well if there is no pipe, but then at a reduced pressure rating. AP is the element that is mostly used during drilling operations. The two (typical) AP elements are normally located in the LMRP.
- Pipe ram (PR): two opposing ram blocks with slips and seals that grab the pipe and seal-off the annulus outside. A PR element is designed for specific size of drill-pipe. A variable bore ram (VBR) is the term used for a PR element designed to grab and seal around a range of drill-pipe sizes.
- Blind shear ram (BSR); two opposing ram blocks with a cutting edges and seals that will shear specific sizes of drill-pipe and shut in the well. It is common for a subsea BOP stack to have one BSR. Modern BOP stacks may have a second non-sealing casing shear ram (CSR) designed to cut larger diameter pipe.

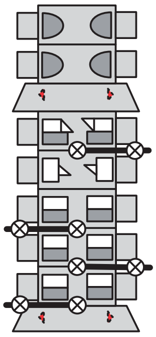

Figure 6. Sketch of modern BOP system configuration based on Holand and Awan (2012)

The BOP provides on demand safety functions and remain dormant during most part of the well drilling operations in order not to impede the activities. Five distinct modes of BOP operation may be identified when it is in active use:

- **Intervention** – Manual override. An underwater ROV can be used to override BOP functions through ROV tool interface(s) on the BOP. A BOP may also have an acoustic signal based override system.
- **Normal** – Manual. This is the main BOP operational mode where the drilling crew relates to the situation on the rig floor and the BOP control panels on the rig.
- Emergency – **Manual disconnect** sequence (EDS). The activation of at least one blind shear ram to seal off the well and disconnection of the LMRP from the BOP stack. BOPs may also have an automatic disconnection system that secures the well and disengages the riser before a critical riser angle occurs.
- Emergency – **Autoshear**. The automatic activation of at least one blind shear ram if the LMRP disconnects spuriously.
- Emergency - **Automatic Mode Function** (AMF) / **Deadman**. The EDS sequence triggered automatically in situations with loss of power and communication between the rig and the BOP.

The driller or the tool-pusher are the positions given to drilling crew individuals that are responsible for making decisions about manual operations of the BOP. The driller and assistant driller are overseeing the operation on the rig floor with BOP control panel located within reach of the driller's seat inside the driller's cabin. A secondary BOP control panel is typically located at the tool-pusher's office workplace. The driller and tool-pusher communicates continuously with the personnel on the rig floor and via radio with other personnel, for instance, the mud engineer and mud logger before making decisions about

BOP operation. Seven main BOP well isolation scenarios are identified from the BOP technical review, which are illustrated by the flowchart shown in Figure 7:

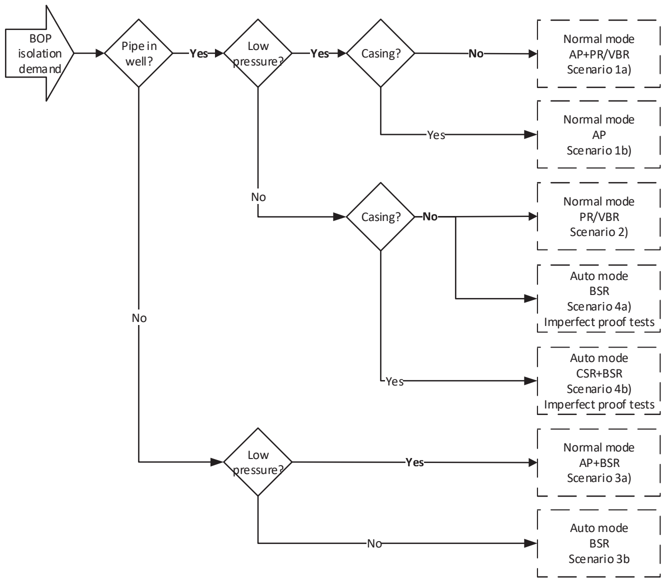

Figure 7. Example of typical BOP closure demand scenarios (non-exhaustive)

The principle for operation and maintenance of a BOP is to follow original equipment manufacturers recommendations. However, BSEE CFR 30-II-B (2014 (October))[16] also provides specific requirements to function and pressure (leak) testing of BOP functions shown summarised as interpreted by the author in Figure 8. In Figure 8 a function test may be interpreted a test that follows a pressure testing procedure except for the BOP closure device pressure testing itself. A function test may be considered an imperfect test of a closure device given requirements also for producing a tight seal. This may also (obviously) be valid for BSR/CSR cutting and sealing functions that are not perfectly tested in the field. However, within 3 to 5 years the BSR and CSR may be required 'overhauled', and it can then be assumed that any deficiencies that affect cut and sealing failures are revealed.

[16] Note revision of USGoM regulations that concerns BOP is currently in process of being implemented (https://www.bsee.gov/guidance-and-regulations/regulations/well-control-rule)

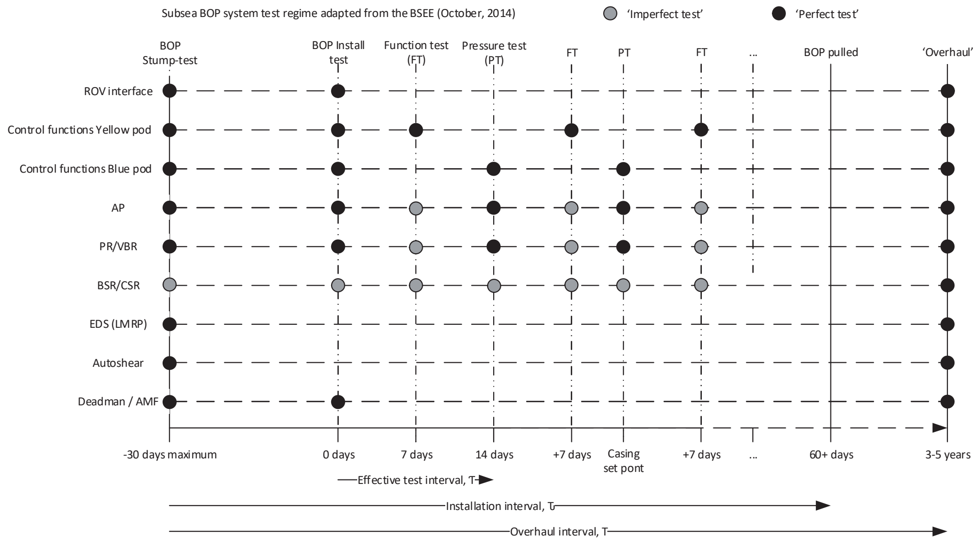

Figure 8. Typical scheme for subsea BOP proof testing based on BSEE CFR 30-II-B (2014 (October))

It can be noted in regards to Figure 8 that there is slight differences between test interval requirements in the BSEE regulations versus API Std 53 (2012). The BSEE requires BOP pressure tests at least every 14 days (October 2014) when installed on wellhead, while standard propose a pressure test interval of 21 days. The 21 day interval between pressures tests may be considered more convenient by industry since it typically coincides with a casing set point that provides a more stable and secure wellbore with a natural plug for BOP testing.

It is generally a regulatory requirement to pull the BOP for repair if a safety critical failure is revealed during a proof test. However, the unscheduled pulling of a BOP for repair may also introduce increased well blowout risk, and departures that allow the drilling crew to postpone repairs are sometimes granted by the authorities (Holand and Awan, 2012). The objective of Paper 1 part of this PhD project is to propose a new modelling approach that is deemed more suitable in an operational context for decision-making about need for such BOP system repairs or not. The new approach is demonstrated with case study for different BOP closure device configurations, and may be used as a simplistic and practical alternative to more complex BOP safety and reliability models found in literature review.

The oil and gas industry has monitored the reliability performance of subsea BOPs for several decades, see for instance (Rausand and Engen, 1983, Holand and Rausand, 1987, Holand, 1998, Quilici et al., 1998, Holand, 1999, Holand and Skalle, 2001, Jorge et al., 2001, Jorge, 2005, BSEE, 2006, Sattler and Gallander, 2010, Holand and Awan, 2012). For example, a consolidated list of the historically most severe BOP failures recorded is shown in Table 2 based on (Holand and Awan, 2012), (Holand, 1999) and (BSEE, 2013b). The combined datasets seen in Table 2 include a total of 22256 BOP installation days and 482 wells drilled. Among others, the BOP reliability data collected suggests that control system failures most often can be revealed by simple function tests, and thus that a high control system proof test coverage is achievable only by function tests. The data also indicate the control system as a potential source for common cause failures (CCFs). Also of interest is a project report (BSEE, 2004) stating that the BSR may fail in 50% of the times when attempting to shear pipe during actual operations. On subject Holand and Awan (2012) reports: "In the Phase I deep-water study, a failure to shear pipe occurred during an emergency disconnect. For the two emergency disconnect situations observed in this study, the BSR successfully cut the pipe and sealed off the well".

Table 2 Overview of most severe BOP failures recorded based on Holand and Awan (2012), Holand (1999) and BSEE (2013b)

Event	No. of failures
Wellhead connector - External leakage	2
LMRP connector – Spurious disconnect	2
LMRP connector – Failure to disconnect on command	3
Control system - Total loss of BOP control (by the main control system)	7
Control POD (1of) – Total loss of POD functions	20
Control PODs (2of) – Simultaneous loss of one function in both pods	6
BSR – Leakage in closed position	4
BSR - Failure to close on command	1
BSR - Failure to shear pipe in LMRP disconnect situation	1
BSR – Spurious closure	1
PR/VBR - Leakage in closed position	7
PR/VBR – Failure to close on command	2
PR/VBR – Failure to open on command	2
AP - Leakage in closed position	11
AP – Failure to close on command	1
Isolation valve on choke and kill line outlet – External leak	1
Choke and kill line – External leaks	13
Flexible joint (above LMRP, downstream the AP) – External leakage	2

On BOP on demand failure probability requirements

The BOP on demand safety functions could be defined as part of a safety instrumented system (SIS) function (Rausand, 2014). On offshore installations a SIS may typically be designed prescriptively in accordance with ISO 10418 (2003) or API RP 14C (2007). In Norway (Europe) the alternative IEC 61508 (2010) and IEC 61511 (2003) standards now also are used. The IEC 61508/IEC 61511 standards describe risk based approaches to determine both qualitative and quantitative reliability requirements for a SIS.

In BSEE regulations, the API standards (API Spec 16A, 2004, API Spec 16D, 2004, API Std 53, 2012) represents the recommended guidelines for fulfilment of BOP requirements for design and usage of blowout prevention equipment for drilling wells. The BOP related API standards make no reference to IEC or API RP 14C, or do not discuss specific quantitative reliability requirements. As such, the BOP is not treated clearly as part of a SIS function by the BSEE. In Norway the PSA recommends use of NORSOK D-001 (2012) to meet requirements in regulations for equipment used in well drilling activities. In contrast to API Spec 16D (2004), the NORSOK D-001 (2012) states that “the BOP control system shall meet the recommendations provided in the Norwegian Oil and Gas Association (NOGA) 070 guideline”. Hence, a separate guideline has been produced for the application of the IEC standards in the Norwegian petroleum industry (NOGA 070, 2004). In contrast to the IEC approach, NOGA 070 does not require a risk analysis to be performed. The guideline defines typical main safety functions on an offshore installation and recommends a minimum safety integrity level (SIL) for each function. The following on demand safety functions are predefined in the NOGA 070 (2004) guideline for the BOP:

(i) Seal around pipe
(ii) Seal an open hole
(iii) Shear drill pipe and seal off well

NOGA 070 set minimum requirements to the probability of failure on demand (PFD) for AP/VBR functions to seal around pipe, (i), and respectively for BSR functions, (ii and iii), combined. The guideline suggest SIL 2 requirements for both, i.e. a PFD of less than 0.01 (NOGA 070, 2004, p. 87) for these two BOP safety functions.

NOGA 070 does not specify any BOP closing scenario as shown in Figure 7. The guideline therefore also recommend SIL requirement to manual BOP safety functions, where effects of operator errors are neglected in PFD calculations according to IEC 61508/61511. The guideline could be found ambiguous in sense that NORSOK D-001 makes reference to the ‘BOP control system’, which is described by separate industry standards in USA and Norway from those of the other parts of the BOP. For example, this may imply that control system pilot valves may be considered the final SIS elements and not the BOP rams. The PFD requirements proposed for combined BSR functions could be found strict based on the BOP reliability data presented by BSEE (2004) and Table 2.

Well casing

The well casing is a passive, unconditional or conditional WBE. The casing may be conditional in sense that outer strings not normally are designed to tackle all realistic well load case scenario.

The well casing (API Spec 5CT, 2012) is the main structural component in an oil and gas well. The well casing program consists of concentric strings of threaded tubulars, casing or liner joints, installed consecutively within the wellbore as part of the well drilling phase. The casing functions, for instance, comprises; (i) provide wellbore stability, (ii) isolate and prevent contamination of (freshwater) formations, (iii) containment of well pressures, (iv) structural support for the wellhead and for wellhead mounted equipment, and of the well completion (production or injection) string.

The casing selection features important to safety functions are (Ådnøy et al., 2009); (i) Thread (connection) type (API Spec 5B, 1996). There are two main types of casing connections referred to as ‘gas tight’ or not. The modern gas tight threads normally include a proprietary metal-to-metal sealing design in contrast to the ‘old fashion’ oil industry ‘API threads’ that may rely on thread grease (‘dope’) applied during make up to act as a sealant. (ii) Nominal size, which is the outer pipe diameter. (iii) Weight per length or alternatively the pipe wall thickness. (iii) Material. Most casings installed are made of low alloy carbon steel. However, occasionally in the bottom part of the production casing, or commonly for production liners is the use of stainless steels. The stainless steels provides improved corrosion resistance, but stainless steel casings may also be found vulnerable to mechanical wear from drill string movements. (iv) Grade that indicates the minimum material yield strength and treatments like, for instance, quenched and tempered.

For the relevant casing load scenarios the limiting design factors or other equivalent acceptance criteria are typically defined in standards (NORSOK D-010, 2013). The load scenarios and limitations typically include safety margins, casing geometrical and material constraints in combination with assumptions made about thermal, internal and external pressure, and installation induced stresses on the casing. The demonstration of acceptable casing design typically takes shape as load cases plotted together with a von Mises equivalent (VME) yield stress envelope illustrated in Figure 9. The typical load scenarios in well casing design are:

- Radial pressure load scenarios (burst and collapse) typically from kicks, pressure testing, cementing, mud circulation, evacuation, and thermal pressure build-ups.
- Axial load scenarios (tension or compression) typically from installation phase like RIH with push, pull and bending due to friction and wellbore profile (‘doglegs’), or thermal induced stress in the well operational phase.
- Tri-axial load scenarios that also may include torque loads considered in those cases where, for instance, the casing is rotated while drilling (‘casing while drilling’) or during cementing.

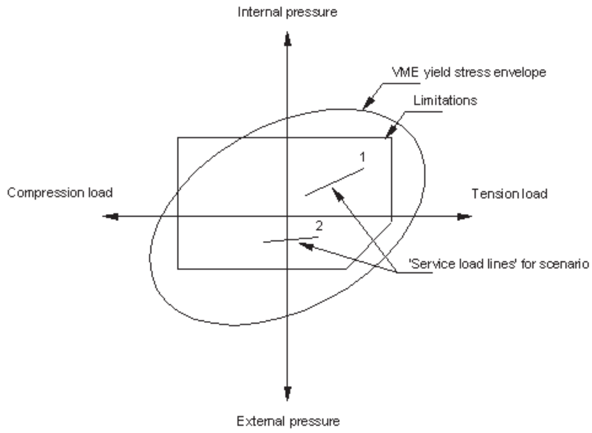

Figure 9. Example of casing load scenarios considered in design basis with specific limitations, load cases, and yield stress envelope (ExproSoft, 2011)

The well becomes weaker moving outwards in the casing program and the potential knock-on effects of parting or burst of the innermost casing may be a concern. The internal yield (burst) pressure rating of oil industry tubular may be considered proportional to the wall thickness of the pipe. An allowable negative manufacturing tolerance of maximum 12.5% in wall thickness reduction is found specified (Mitchell, 2006). Therefore established as an industry rule, more than a 12-13% wall thickness loss of casing from nominal is used as criterion for a failed casing. I.e. a casing that is not according to specifications, and is not to be used further as a WBE in the well. The wall thickness of casing can be assessed after installation by wireline logging tools, for instance, denoted as multifinger caliper or gauge runs. The drilling experience data shows that casing failures associated with blowouts are rare, but that such have occurred (STATOIL, 2010). For example, such accidents may be found influenced by use of old, worn and low grade casing together with modern drilling technology that may cause elevated casing stresses such as differential pressures during the operation.

Openhole formation

The openhole formation is a passive, unconditional or conditional WBE. A formation will be conditional in sense that shallow formation layers not are capable to tackle all realistic well load case scenario.

A FIT is normally performed just after drilling through the cement shoe to verify the cement bond against previous openhole and sufficient capacity of new openhole formations to drill the next section. The shoe of the previous casing point is generally where the weakest formation is located. The theoretic[17] capacity of an openhole formation as a WBE during well drilling is illustrated by an xLOT

[17] Excluding, for instance, effects of drilling mud filtrates

pressure testing scheme in Figure 10. A FIT is terminated before permanent damages are inflicted to the formation as shown with the test procedure in Figure 10.

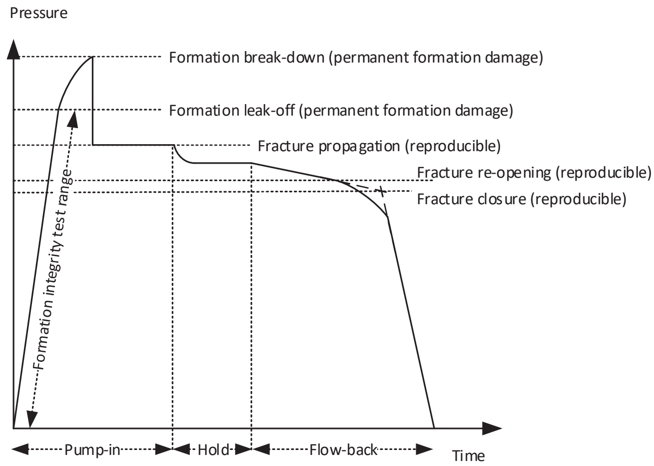

Figure 10. Sketch of extended formation pressure testing scheme based on Torbergsen et al. (2012)

Figure 10 shows the typical pressure test cycle in a well when pressure is applied to test a downhole formation. Any leak-off of fluids to the formation will give permanent reduction of formation strength. Subsequently any pressure in the well above the fracture closing pressure ('minimum formation stress') may lead to reopening of fractures and lead to leakage from the wellbore. If the pressure is reduced to the minimum formation stress, the fracture closes and the integrity of the formation is restored.

The formation exposure to drilling fluid pressures, denoted equivalent circulation density (ECD), and results from formation testing is logged in the operator's daily drilling reporting system. For purpose of well planning the drilling engineers working in a field typically upkeep a drillers lithology chart that, among others, includes prognosis for formation depths, pore pressures, formation fracture pressures and results from previous FITs, xLOTs, and LOTs carried out in the field. The drilling experience data shows that risk of wellbore integrity failures are low associated with kick margin requirements. This includes rules and best practices for achieving an acceptable FIT before hole-section drilling can start.

An openhole formation section between the cement top and the previous casing shoe is often provided by design as a weak point in the annulus to allow for a pressure relief. A trapped well volume can be subject to severe thermal pressure build-up if the fluids inside are heated during for instance well production (or hot fluid injection) operations.

On probabilistic evaluation of openhole formation integrity

There are two main perspectives to quantitative risk and reliability analysis referred to as the actuarial or physical approaches (Rausand and Høyland, 2004). The actuarial perspective is popular in academia and among safety and reliability scholars. The physical perspective is typically found used in practical engineering applications, for instance, by construction and structural engineers. The physical stress-strength interference (SSI) methods accounts explicitly for the physical knowledge about, for instance, the yield strength and corrosion resistance of a material for purpose of probabilistic reliability analysis. In the actuarial approach this physical knowledge is interpreted implicitly by parameters in a probability density function (pdf). A main implication of different perspectives is that the actuarial approach considers reliability as an exact function of random variable(s), whereas the physical approach considers reliability also as a random variable.

The (deeper) openhole formation is described to have self-healing properties, and as such never completely lose its safety function provided as a conditional WBE. It may therefore seem unreasonable to apply an actuarial model with a Boolean argument to describe the integrity of overburden formations. For example, it seem more attractive to consider a SSI model for analysis of the worst case well kick scenario analysed in kick margin calculations. If we let WBE_i (openhole formation at casing shoe) stress X (from well kick load propagation to casing shoe) and strength (of openhole formation based on FIT, LOT, xLOT and estimation) Y to be positive continuous random variables with pdf's $f_X(\text{x})$ and $f_Y(\text{y})$, respectively. From the law of total probability, we have the following basic expression for the point reliability, $\breve{R}_i$, or respectively for point unreliability, $\breve{F}_i = 1 - \breve{R}_i$:

$$\breve{R}_i = 1 - \breve{F}_i = \Pr(\text{X}_i < \text{Y}_i) = \int_0^\infty \left[f_{\text{X}_\text{i}}(\text{z}) \cdot R_{\text{Y}_\text{i}}(\text{z}) \right] \text{dz} \qquad \text{(Equation 1)}$$

The $f_X(\text{x})$ and $f_Y(\text{y})$ will for a well kill or kick margin calculation scenario be limited to a physical interval. For the most basic SSI model described in Equation 1 it is easy to implement a numerical routine that solves for different pdfs, and for several different kick load scenarios. However, a reasonable approximation could be to assume that $\text{X}\sim\text{Normal}(\mu_x, \sigma_x^2)$ and $\text{Y}\sim\text{Normal}(\mu_y, \sigma_y^2)$, which gives (Kotz et al., 2003):

$$\breve{R}_i = \Phi\left(\frac{\mu_y - \mu_x}{\sqrt{\sigma_x^2 + \sigma_y^2}} \right) \qquad \text{(Equation 2)}$$

where $\Phi(\text{z})$ denotes the cumulative density function, $F_Z(z)$, of the standard Normal distribution.

Drilling muds

The drilling mud is a passive, unconditional or conditional WBE. The drilling mud will be unconditional in conventional overbalanced drilling operations, and respectively conditional in underbalanced drilling operations.

Offshore drilling muds include complex fluid mixtures (Caenn and Chillingar, 1996) specially designed for hydrocarbon drilling operations that contain significant amounts of suspended solids, emulsified water or oil. Sometimes clear drilling, completion and workover fluids are also called muds, but a well fluid that is essentially free of solids is not strictly defined as a mud. The mud base fluid can be water (WBM), crude oil or diesel (OBM) or synthetic 'oily' (SBM). The modern SBMs are intended to have the advantages of OBMs but with the handling and environmental disposal characteristics of the cheaper WBMs. The OBMs and SBMs are more expensive and toxic than the WBMs. However, the listed potential benefits over WBM are found to include: (i) more compatible with the reservoir formation (limits formation damage), (ii) more stable at higher temperatures (above ca. 200 DegC), (iii) improved hole stability, reduce problems with swelling clay and softening of shales, (iv) better lubrication (less friction) and a thinner mud filter cake with reduced risk for casing wear and sticking/stuck pipe.

The drilling mud constitutes an important primary WBE during well drilling, but lists of up to 20 different mud functions in total can be found. The drilling mud is dynamic due to different WBE requirements during the different well drilling stages, but also in sense that some of the other mud functions take precedence over others in course of the drilling operation. For example, when drilling the reservoir hole-section it is also important that the mud does not damage the near wellbore formations and thereby impair the well productivity or injectivity. Special drill-in fluids are therefore, for instance, developed for this purpose. The major functions of drilling muds are as follows;

1. Remove drill cuttings from the well and allow their separation at the surface

A drilling mud transports drill cuttings, weight materials and other additives under a wide range of conditions. A vital mud function is to carry the formation rock excavated by the drill bit up to the rig. Its ability to do so depends on cutting size, shape, density, and velocity of the mud returns flowing up the well annulus. The mud viscosity is also important since cuttings will settle by gravity to the bottom of the well if the viscosity is too low. Most drilling muds are thixotropic meaning that the viscosity increases during static conditions. This property help keep the cuttings suspended also if the mud is not flowing. Higher rotary drill-string speeds introduce a circular component to the annular mud return flow that also effectively helps with solids transportation, which is used as a common method to improve hole-cleaning in extended reach, high angle and horizontal wells. Effective solids control is required in order to maintain the original mud fluid system properties. This means that all unwanted solids should be removed from the mud on the initial circulation out of the well. If cuttings are re-circulated the cuttings break into smaller pieces and become more difficult to remove.

Various solids that settle out downhole can cause circulation loss and stuck drill-pipe. Drill cuttings that settle causes bridges and fill. If the mud weight material settles this is referred to as ‘sag’, which can cause large variations in the mud density and thus cause a well kick. Mud density fluctuations are reported more likely to occur in high angle and high temperature wells.

2. Form a thin, low-permeable filter cake (‘wellbore skin’)

Drilling muds are designed to deposit a thin, low permeability ‘skin’ on the wellbore wall called a filter cake. This is to limit the mobility (loss) of mud into the formations. Given that the in-situ mud pressure exceeds the formation pore pressure the liquid component of the drilling mud (known as the mud filtrate) penetrates any porous and permeable formation until the solids present in the mud, commonly bentonite, clog up enough pores to form such a filter cake capable of preventing further invasion (loss of mud).

Drilling problems may occur if a too thick filter cake is formed, for instance, tight hole conditions / stuck pipe, poor formation log evaluation, lost circulation (large mud losses) and formation damage.

3. Maintain the stability of the wellbore

Wellbore stability means that the hole drilled maintains its size and cylindrical shape. The weight of the mud must be within the necessary range to balance the mechanical (tectonic) wellbore forces. Wellbore instability typically include sloughing formations. If the hole is enlarged, the wellbore becomes weak and difficult to stabilise due to problems with low annular mud velocities (poor hole cleaning), solids loading and poor formation log evaluation. The creation of a good quality mud filter cake is important to limit wellbore enlargement. WBM can cause swelling and softening of clay and shale formations, and OBM/SBM are used to drill the most water sensitive shales and clays.

Wellbore instability also concerns the planned orientation (inclination and azimuth) of the wellbore and specific formation types drilled. For example, some layers of ‘squeezing salts’ and ‘green clay’ are known to be unstable and to rapidly creep. An oil industry rule of thumb is that you only have about 24 hours for successful running of casing in order not to lose the hole-section you just drilled. The aspect of formation creep may later become beneficial to well safety as it may help assist the cement in creating a hydraulic seal in between the casing and the wellbore formation.

4. Prevent the inflow of wellbore formation fluids

The vertical column of drilling mud exerts hydrostatic pressure on the wellbore. Under normal overbalanced drilling conditions the static hydrostatic pressure should balance or exceed the formation pore pressure to prevent influx of formation fluids (well kick). As the pore pressure increases with vertical depth, the density of the drilling mud is also increased for each hole-section drilled as illustrated in Figure 11. Design of well casing program and drilling mud weight - the ‘drilling window’ created between formation pore and fracture pressure based on Torbergsen et al. (2012). Most muds or cement slurries can be found mixed with density of less than 1900 kg/m3, but special ‘gunk plugs’ or well kill muds can be made with weights in excess of 2200 kg/m3. The most common weight material added to drilling muds is barite.

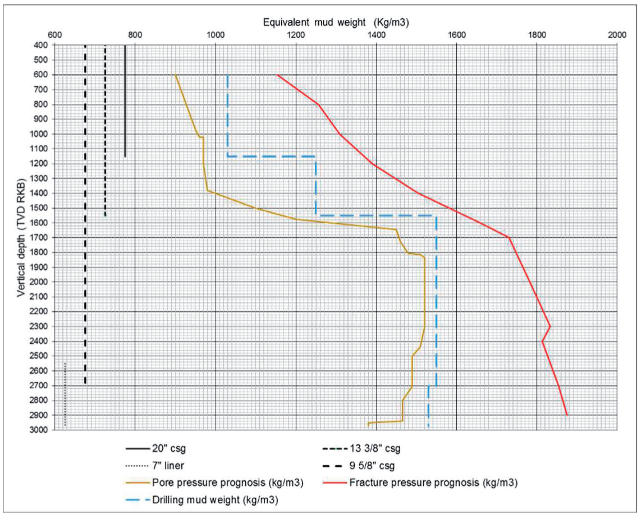

Figure 11. Design of well casing program and drilling mud weight - the ‘drilling window’ created between formation pore- and fracture pressure based on Torbergsen et al. (2012)

It can be more difficult to detect well kicks with OBM/SBM due to fact that a hydrocarbon influx may hide more easily in another oily mud, but also since the compressibility[18] and gas solubility is higher when compared to WBMs. However, the latter property is also a benefit since the pressure propagation from a gas kick become reduced, which makes it easier to control and circulate out with less risk for fracturing the formation at the last casing shoe (improved kick margin).

5. Control corrosion and the friction (and mechanical wear) from the relative drill string movements inside casing and wellbore formation

[18] Compressibility, c, describes the relationship between fluid volume and pressure change: $\Delta P = \frac{-1}{c}\frac{\Delta V}{V}$

Corrosion causes the majority of drill pipe material loss (Mitchell, 2006). The drill string, mud pumps and casing is in continuous contact with the drilling fluids circulated and any dissolved gases like, for instance, oxygen (O_2), carbon dioxide (CO_2) or hydrogen sulphide (H_2S) may cause aggressive corrosion. Hence, mud aeration, foaming and other O_2 trapping conditions are avoided throughout the mud handling system. Also, lower pH, for instance acids formed when CO_2 or H_2S mixes with water aggravates corrosion, so monitoring of pH and the correct addition of chemical inhibitors and scavengers is important. Assemblies with 'test coupon' can be inserted in the drill string as an aid to monitor corrosion.

The amount of lubrication provided by the drilling mud depends on type and quantity of drill solids and weight materials coupled to the chemical composition of mud system. Lubrication is measured based on the coefficient of friction. OBM/SBM generally lubricate better than WBM, but the latter can be improved by the addition of lubricants. Poor lubrication causes mechanical wear, higher torque and axial drag, and heat checking[19] of the drill string and casing. Metal shavings in mud return from the well are collected by magnets on the shaker to monitor for mechanical wear on casing and drill pipe.

6. Non-damaging to productivity of producing formations (drilling reservoir section)

Formation damage is any reduction in wellbore formation porosity and permeability as result of the drilling operation. Most common type damages are: (i) Mud or solids invade the formation matrix and cause 'skin effects'. This include emulsions and solids, like salts, formed when mixing mud filtrate with formations fluids. (ii) Swelling of formation clays within the reservoir. Special clear drill-in, workover and completion fluids are designed to minimise formation damage.

7. Power, cool and clean the drill bit

The mud pumps via the mud provide hydraulic energy that powers the mud motor in the BHA for drill bit rotation (independent of drill string rotation), and for MWD and LWD directional- and formation evaluation tools. Significant friction heat is generated from mechanical and hydraulic forces at the drill bit and when the drill string rotates and rubs against casing and wellbore. If not cooled by the circulating mud, the bit, drill string and mud motors would be exposed to excessive stress and fail more often.

8. Non-hazardous to the environment and personnel handling it

Muds are in varying degrees considered toxic, and it can be difficult and expensive to dispose of the mud in an environmentally friendly manner. A rule of thumb is that no type of OBM/SBM, or drilled cuttings contaminated with OBM/SBM, may be dumped (Mitchell, 2006, p. II-108). Contaminated muds are shipped back to shore in skips or processed on the rig before disposal.

[19] Heat checking: surface cracks formed by the rapid heating and cooling of the component.

‘Mud engineer’ is the name given to a service company individual that is responsible for maintaining a functioning drilling fluid or completion fluid system on a drilling rig. The key fluid drilling properties that the mud engineer controls with tests are (Caenn and Chillingar, 1996): (i) Weight, (ii) viscosity, (iii) fluid loss (filtrate), and (iv) reactivity (solids content, lubricity, pH). At any given time during drilling one or more of the tests performed to control these factors may take precedence over the others.

The mud weight is measured by density, specific- weight or gravity. If the density decreases this is a sign of mud dilution from oil, gas or water that invades, or is exchanged, with the wellbore formation fluids. Normal routine is first to stop drilling ahead and try to circulate out the ‘pollution’ and restore the stable known wellbore pressure gradients. If the density increases this is a sign of solids invasion from, for instance, cuttings improperly removed and routine could be to centrifuge and start other solids control equipment on rig. Option is also to decrease drilling mud density if such meet the safety requirements of the drilling.

‘Mud loggers’ are service personnel that examine drill cuttings for mineral composition and signs of hydrocarbons. They produce mud logs that comprise information about lithology, rate of drill bit penetration (ROP), gas detection (‘background gas’) and geology.

‘Compliance engineer’ is a name for a relatively new position in the oil field introduced as a result of environmental regulations enforced on how to dispose of drilling muds. Previously, SBMs were generally regulated the same as WBMs and could be disposed of in offshore waters due to low toxicity to marine organisms. New regulations may now also restrict the amount of SBMs that can be discharged and require mud tests to determine, for instance, the percentage of crude oil in the drilling mud.

Monitoring for changes in established well footprints and trends is used as means to obtain indications of downhole drilling problems. The regularly monitored drilling parameters include, for instance, flow rates in and out of the well, rig pump pressure (standpipe pressure), rig pump speed, ROP, torque, gas/oil/water cut in surface return mud, and up/down weight of drill string and mud pit levels. If any of these parameters change this may indicate a pressure change in the well and consequently that the well also may be kicking (Baker, 1998).

The ROP of the drill bit is considered one of the best indicators for formation pore pressure changes since it, for instance, is considered independent of temperature and salinity effects. A slower ROP indicate an increase in pore pressure and vice-versa (‘drilling break’). A flow check should as rule of thumb be performed whenever a new formation is encountered or when a change in the ROP occurs.

Experience data from Norwegian continental shelf (NCS) shows that well kicks are never experienced in some oilfields while in other they may have occurred as often as every 5th to 10th well drilled (PSA, 2013b). Kick data from USGoM OCS deep water drilling suggests an average kick rate for wells in order between 0.3 to 0.6 per well (Holand and Awan, 2012). The USGoM development well drilling data indicate a lower kick rate than exploration well data, which may be explained by more information and knowledge gathered about formation properties in a field. Hinton (1999) presents well kick data based on a decade of experiences on the UK continental shelf between 1988 to 1998. For example, reported is that 11% of the wells experienced kicks during their construction operations, whereof 22% of the wells were so-called high pressure high temperature (HPHT) wells[20]. Other UK sources cited by Gao and et al. (1998) claim that HPHT wells to have even higher reportable kick incident rates in order of 1 to 2 kicks per well. This compared to non HPHT-wells, which is reported to have about 1 kick per 20 to 25 wells drilled.

Table 3 presents some descriptions of well kick situations that are produced based on USGoM OCS well drilling activity data reports (Holand and Skalle, 2001, Holand and Awan, 2012). It is noted by Holand and Awan (2012) in relation to the 2013 study that the frequent occurrences of 'too low mud weight' in Table 3 to a large degree may be explained by a narrow 'drilling window' for many wells in the data set. The drilling window is the horizontal distance between the yellow and red curve in Figure 14, which is the difference between fracture pressure and pore pressure at a given vertical depth.

Table 3. Typical causes/situations for well drilling kicks in the US GoM OCS

2013 study (85 kicks total) (Holand and Awan, 2012, p. 119)	2001 study (74 kicks total) (Holand and Skalle, 2001, p. 47)
Too low mud weight (43 kicks – 51%)	Too low mud weight (23 – 31%)
Gas cut mud (15 kicks – 18%)	Gas cut mud (17 – 23%)
Swabbing (10 kicks – 12%)	Annular losses (9 – 12%)
Annular losses and gains (3+3 kicks – 7%)	Drilling break (9 – 12%)
Unknown (5 kicks – 6%)	Ballooning (7 – 10%)
Drilling break (2 kicks – 2%)	Swabbing (5 – 7%)
Leaking through cement (2 kicks – 2%)	Poor cement (2 – 3%)
Trapped gas in BOP (1 kicks – 1%)	Formation breakdown (1 – 1%)
Temperature expansion*, well open for a long time (1 kicks – 1%)	Improper fill up (1 – 1%)

*) Interpreted as gas migration effects similar to those discussed in the Montara blowout (Strand and Lundteigen, 2017).

20 Defined typically as well with a reservoir pressure > 690 Bar, and a reservoir temperature > 150 °C

Gas cut mud in Table 3 occurs when formation gas influx mixes with the drilling mud. This will reduce the mud equivalent density and may cause the hydrostatic overbalance in the well to be lost. When a drilling break is listed as a cause for the kick in Table 3 this means that a drilling break was mentioned in the well activity report just prior to the kick incident. A drilling break that give a kick could typically be when drilling through the last bit of cap rock and into the reservoir formations. The most frequent causes to kicks in UK wells data reviewed is found similar to the US GoM OCS wells, which typically include gains from too low mud weights and mud losses due to 'surprises' encountered such as unknown flow zones that may act as 'sinks' when in overbalance.

An updated study performed in 2009 by the UK petroleum safety authority (HSE) (Dobson, 2009) reports that most kicks experienced on the UK sector are indirectly linked to the geological conditions, at the well location, and that most involve conditions difficult to detect before the well is actually drilled. The incidents may also be indirectly linked to the geological conditions, for instance, challenges related to cementing casing in halite formations or in keeping the mud weight sufficient to prevent the well from flowing, but not so heavy that losses are induced ('narrow drilling window'). According to Dobson a small, but significant, proportion of the kicks reviewed are considered caused by 'human error' in the planning or execution phase of operations.

On early kick (mud failure) detection

The well kick data shows that well kicks are common, which for practical well risk management imply that drilling crews must be consistently prepared to successfully recover from well kicks in any drilling operation ('kick probability may be assumed ≈ 1'). In this respect, it is important for well control to always maintain an ability to detect if any influx of formation fluids occur. Moreover, early detection will help ability to maintain the hydraulic pressure stability of the mud column and limit the resulting kick load propagation. The ability of the wellbore to handle mud instability and kicks is referred to previously as 'kick tolerance' or 'kick margin'. Any influx of lighter reservoir fluids into the drilling mud will generate a pressure propagation effect that travels upwards in the wellbore. Kick-tolerance is measured as the volume of formation influx that can be tolerated (contained and circulated out) by the wellbore without loss of fluids. The early detection of a well kick can be defined as a kick that is detected within 40 minutes (BSEE, 2013a).

The well drilling process is described as an iterative sequence of drilling a hole-section using a work string helped by the circulation of drilling mud, and then installing a casing or liner in this hole. This includes an interface above ground, the wellhead system, which will have a BOP system installed on it. Figure 12 shows an alternative view to Figure 4 with the well barriers established during well drilling operations seen depicted as triangles on the right hand side. The two well barriers are seen constructed by allowing the WBEs form two concentric triangles that provide the containment of a reservoir.

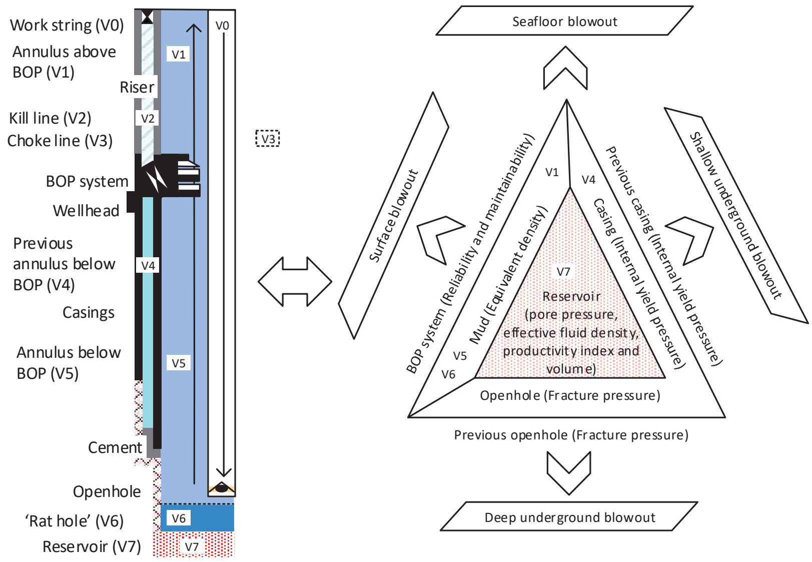

Figure 12. Well volume based view with the two well barrier drilling model inspired by CCPS (2007).

The task of successful recovery from well kicks are closely linked to the understanding of events and conditions on the rig floor that are a function of what may be occurring several thousands of meters downhole in a well. The fluid mobility through most reservoir formations is described as limited (Dake, 1998) and all movement of fluids between the formations and the wellbore follow Bernoulli's law of energy conservation. This law in practice imply that significant fluid movement only can occur from a point of relative high to low pressures in a well. We also have from static hydraulic theory that the in-situ pressure in a wellbore is given along fluid column vertical height, h_{TVD}. The hydraulic theory tells us that pressure in a fluid column is a function of applied pressure on top of the column plus the pressure exhibited by the equivalent weight, ρ_{equiv}, of the fluids in the column over the vertical height (ISO 16530, 2014);

$$p_{in-situ} = p_{top} + \rho_{equiv} \cdot g \cdot h_{TVD} \qquad \text{(Equation 3)}$$

An oil and gas well physically resembles several long and narrow fluid volumes that have an orientation in the vertical plane of several thousands of meters. This means according to hydraulic theory that there can be large differences in the in-situ pressures in a well. The left hand side in Figure 12 illustrates that we may consider eight separate fluid columns in the well system during drilling operations, denoted as volumes V0 through V7. The volumes can exhibit different fluid in-situ pressure gradients. The volume V6 is not present during drilling when the drill bit is excavating the formations in the bottom of the wellbore. The volumes V0, V1, V5 and V7 are where fluid movements normally occur due to differential pressures maintained by the rig pumps used to circulate the drilling mud. The normal circulation path of drilling muds is indicated with solid lines in Figure 13, and respectively alternative flow paths, for instance, in reaction to a well kick is shown with dashed lines.

The mud and the wellbore can be thought of as an incompressible fluid system. I.e. if stable conditions, the volume pumped into the wellbore (q_{in}) should resemble any changes made to the total wellbore volume and the volume received at surface (q_{out}). The total volume of the well can change, for instance, due to the drilling progress or from relative movements between wellbore and rig. The volume of the well is therefore carefully monitored by well depth measurements, and of measuring volume changes from relative rig movement indicated with a dual displacement correction sensor (DD) in Figure 13.

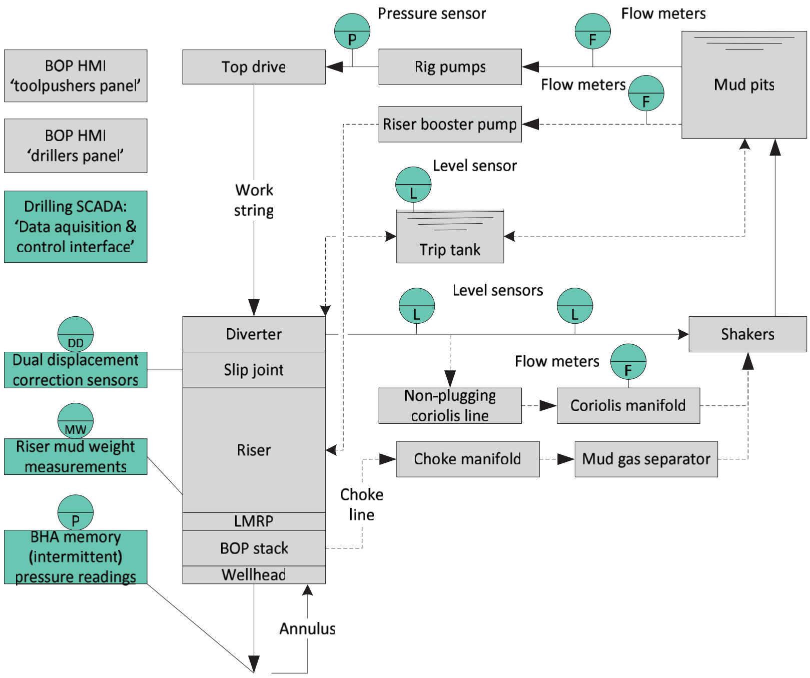

Figure 13. Example well monitoring setup for a conventional mud circulation system adapted from Johnson et al. (2014)

All the well kick related situational elements are logged continuously or intermittently at the rig floor illustrated with various sensors in Figure 13. The wellbore vertical depth is measured directly, and the well mud weight (MW) or pressure by physical measurements downhole or at the mud handling system at the rig. The mud weight measurements are normally only taken at some points along the wellbore, which can become a source of confusion for crews. With pressure or density, ρ_{equiv}, measurements only obtained at some few points this means that interpolations have to be made to the other points of interest in the well. Making such interpolations may not be straight forward due to intrinsic instability of drilling muds. The drilling crew therefore regularly monitor volume rates or pressure build-up through V1 when the rig pumps are shut off referred to as performing flow checks. The consistent and careful application of flow checks are viewed to be important precautions taken in order to detect and recover from well kicks at an early stage.

3 Risk assessment of well drilling operations

This section presents a summary of the literature review performed initially as part of establishing the research plan with research questions developed for purpose of submitting the PhD project description. This review first considered the well system definition and the identification of main risk contributing factors. Secondly, it considered the academic and industry research that encompass tools and methods that are adopted, or could be adopted, to address the probability or frequencies of well drilling blowouts or releases. In addition, detailed literature reviews were performed in the preparation of the papers enclosed in this thesis, and reference is made to each paper where additional literature reviews were performed during the PhD project.

3.1 Well system and risk contributors

This section includes the well system definition together with a summary of the main factors from Chapter 2 that influence well system risk. The section concludes with a presentation of the baseline well barrier diagram (WBD) used as a principle well barrier model for the DPRA development.

Hazardous energy sources

In order to assess system risk it is common to start with a hazard identification phase (Rausand, 2011). The objective of this phase is to stimulate creativity in order to identify significant unwanted system events, often denoted as hazardous or accidental events, which may cause harm to human health, the environment or financial interests. A hazard may therefore be considered an identified energy source, which if not controlled, may cause a hazardous event. Table 4 presents five main categories of hazardous energy sources that may typically be considered in generic risk assessment approach.

Table 4. Example hazardous energy sources considered in risk assessment based on ISO 12100 (2010)

Hazardous energy category	Examples
Mechanical	potential- and kinetic energy, vibration, noise
Electrical	high voltage, electric currents
Ionising radiation	α, β, neutrons, γ, X-rays, higher ultra-violet
Chemical	toxic, inflammable and explosive, heat and cold, caustic
Biological	bacteria and viruses

An oil or gas well may include all the aspects of the listed hazardous energy sources in Table 4 to some extent. Historically, however, from the evaluation of well system risk (Holand, 1997, SINTEF, 2015), and as implied by the well integrity definitions (ISO 16530, 2014, NORSOK D-010, 2013), the potential for leakages of hydrocarbon fluids[21] to the surroundings are by far the most significant events.

[21] 'Fluids' is used to commonly describe any mix of gasses and liquids

The causes for well blowouts can be classified into two main categories based on the SINTEF offshore blowout statistics (Holand, 1997):

- *Internal*; Well blowout is caused by intrinsic WBE failures.
- *External*; Well blowout is caused by abnormal ambient shocks or stresses on the well barrier system, which is a situation that may be assessed as 'well blowout risk under external hazardous events'. Historical blowouts caused by external hazardous events include damages inflicted to the exposed part of the well system located above the seafloor such as the Xmas tree, BOP and drilling riser. Typical examples are:
    - Extreme weather (hurricanes, 100-year wave and similar)
    - Collisions (vessels, icebergs, trawls and similar)
    - Fire or explosions (ripple/knock-on effects)
    - Dropped or swinging objects (BOP, drill-pipe, containers, baskets and similar).
    - Geo-hazards (earth quakes, mudslide, fault slippage, reservoir compaction and similar)
    - Drive-off or drift-off related to DP rigs
    - Wellhead fatigue
    - Riser failure / disconnect
    - Random operator errors (inadvertent LMRP or BOP function activation and similar)

The external hazardous event analysis in risk assessment of drilling or intervention operations does not appear crucial from well kick data (Section 2.3), BOP reliability data (Holand and Awan, 2012, p. 13, 118) or the well blowout data (Holand, 1997, p. 51) / Appendix I. The external hazardous event frequency analysis has therefore not been focused on as part of the DPRA scope (Section 1.3). Aspects that concern external hazardous events, however, like drive-off and drift-off events introduced with modern DP rigs or drill-ships, may need careful consideration as part of well risk assessment.

The minor contributions from external hazardous events to the blowout data for well drilling operations (note that the data comes predominantly from fixed rigs) may typically be related to; (i) The use of sacrificial equipment (weak-points), (ii) provisions for early warning systems for 'approaching hazards', (iii) provisions for heavy lifting operations and for activities in hurricane or winter seasons, and (iv) simultaneous operations requirements that limits the installation activity levels when wells are being worked on.

Well system definition and interfaces

The safety availability of a well system will depend on its interfaces with its surroundings, and it is therefore necessary to consider how interfaces influence the system. As such, a clear understanding of interfaces is essential across the design, construction, operation and abandonment phases of an oil and gas well. Rausand and Høyland (2004) define a generic technical system and its interfaces. This generic representation is combined in Figure 14 with the previous chapter discussions as basis to define the well system and its interfaces. The definition is used as foundation for the risk assessment methods and procedures developed in DPRA. The elements illustrated in Figure 14 are discussed by Rausand and Høyland (2004) in detail, and are provided with summary descriptions and definitions given for DPRA as follows:

- *System*; The technological system that is subject to analysis (and design).
  - The WBEs discussed in Chapter 2 as well barrier building blocks are natural functional blocks in a well system.
- *System boundary*; The system boundary defines elements that are considered part of the system.
  - The well system elements includes the well barriers made up of WBEs and key personnel discussed in Chapter 2.
- *Outputs*; The outputs (wanted or unwanted) are the results of the required system functions.
  - According to NORSOK D-010 (2013) this includes containment and thereby to reduce risk of uncontrolled release of formation fluids throughout the lifecycle of a well. The two barrier rule implies that no single failure of well barrier or WBE shall lead to loss of well control.
- *Inputs*; The inputs to the system (unwanted or wanted) are the materials and the energy the system uses to perform its required functions.
  - According to BSEE CFR 30-II-B (2014 (October), part 250.401) this includes application of best available and safest technology, and to have personnel onsite that: (i) Are trained to fulfil all responsibilities; (ii) Use and maintain equipment and materials necessary to ensure safety.
- *Boundary conditions*; The operation of the system may be subject to many boundary conditions, such as risk acceptance and environmental criteria set by authorities or by the company.
  - According to (PSA, 2014b, Section 85, PSA, 2014c, Section 48) this includes: (i) Use tested well barriers with sufficient independence; (ii) If a well barrier fails, activities shall not be carried out other than those intended to restore the barrier; (iii) Well barriers shall be designed such that that they do not hinder well activities, and such that their performance can be verified.
- *Support*; The system usually needs support functions such as preventive maintenance and repair.
  - This includes typical maintenance tasks like pressure testing, function testing and repair of failed WBEs, which were discussed in Chapter 2.
- *External threats*; The system may be exposed to a wide range of external threats. Some of these threats may have impact on the system directly, others threats may impact the system inputs.
  - Threats discussed in Chapter 2 include: Rig drive-off, rig drift-off, wellhead fatigue, riser failure or spurious riser disconnects.

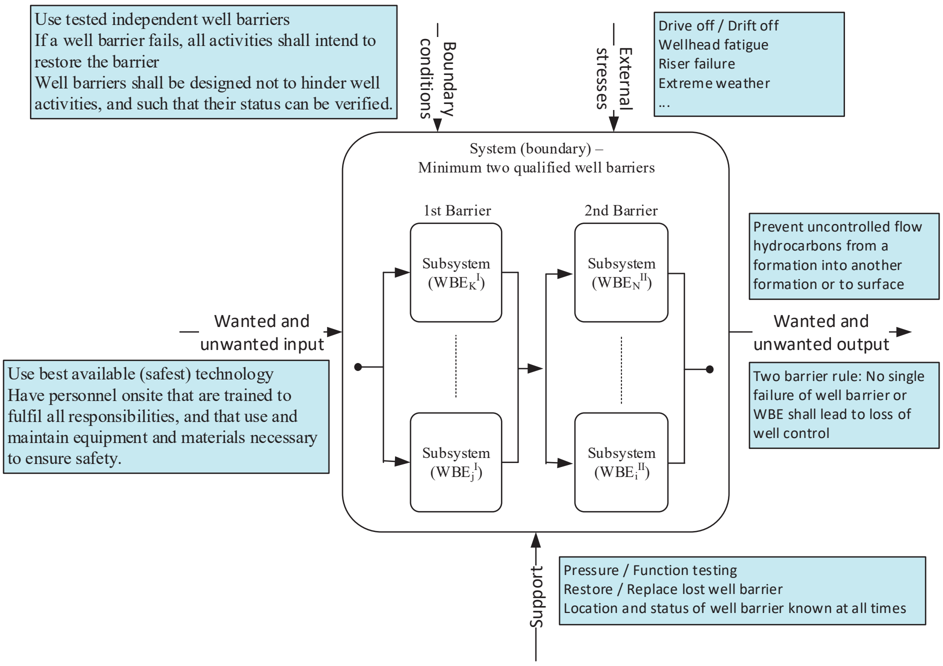

Figure 14. Well system definition with interfaces (regulations and standard requirements included)

Additional clarifications to the well system definition in Figure 14 are given in following sections.

WBE (subsystem) risk contributors

A summary of factors that influences the reliability and safety availability of each WBE functional block illustrated in Figure 4 are presented in Table 5 based on the WBE descriptions provided in Chapter 2. The table includes the typical WBE failure data combined with human, organisational, and technical factors that may typically influence the perfromance of the WBE safety function. The reliability of the BOP is complex (Section 2.3), and the BOP may be described as a redundant and degradable item. For the other WBEs, the probability of a failure can be assessed in a simple and intuitive way by stress-strength interference modelling (Kotz et al., 2003). Factors that may affect stress and strength of the WBEs are therefore also presented in Table 5.

Table 5. Main safety function features of well barrier elements used in well drilling operations

Barrier element and safety function type	Failure modes	Failure causes	Technical, human, or organisational 'stress-factors'	Technical, human, or organisational 'strength-factors'
Mud column (passive, conditional or unconditional)	Loss of hydrostatic control ('well kick')	Loss of vertical height of mud column ('losses'). Insufficient mud weight / hydrostatic	Reservoir pressure. Reservoir volume.	Testing (flow check) to verify static pressure barrier function. Mud weights (densities) verified by downhole-

		fluid pressures ('gains').	Fluid rate/mobility (productivity index).	and surface measurements. Background gas measurements.
Openhole (passive, unconditional) / Previous openhole (passive, conditional)	Formation fracture ('leak off pressure')	Pressure exceeds in-situ capacity of formation.	Equivalent weight of pressure transmitting kick fluid column (kick influx volume and fluid type).	Estimates verified by pressure testing
Casing (passive, unconditional) / Previous casing (passive, conditional)	Leak / Burst / Collapse	Differential pressure load exceeds capacity of casing. Corrosion (old casing). Mechanical wear from drill string.		Internal yield and collapse resistance is verified by pressure testing, wear and corrosion calculations, and measurements of metal shavings in return mud at surface
BOP (active, manual and automatic, conditional)	Fail to close / Leakage in closed position / External leak / Spurious disconnect	Intrinsic failures. Human error (no or spurious activation). Excessive usage/loads (outside design specification).		Safety functions verified by regular function testing. Subject to regular preventive and corrective maintenance.

From Table 5, the technical features contribute to failure intrinsically as the traditional effects, among others, of the WBE design on reliability and maintainability. The workplace and human task factors that influence WBE failure probability are seen to be numerous, affect all WBEs, and to be relevant for assessment of both strength and stress distributions. The factors include the ability to carry out WBE function tests, to detect drilling mud failures, to successfully activate the BOP, and to carry out BOP maintenance. Humans may also influence the stress (pressure load) that will propagate upwards in the wellbore in a well kick situation. This load will depend on the kick influxes fluid volume and type, where early detection of a kick generally results in low kick fluid loads. From Table 5, this is related to careful monitoring for potential drilling mud gains, which includes tests and observations made of volume rates, pressures and changes in drilling mud properties such as gas content, density and viscosity (Caenn and Chillingar, 1996, Baker, 1998).

Well barrier (system) risk contributors

The escaped energy (consequences) of a well release or blowout is largely determined by the fluid type and the leak rate, and there will be three basic elements to a well system risk model:

- *Source* of inflow (place of hazardous fluid energy)
- *Leak path* (flow path). A place of qualified WBEs and other conditional flow restrictions
- *Sink* that receives the fluid leak (place of harm)

For any risk of well release or blowouts to exist, there needs to be a reservoir, a 'potential source of inflow', penetrated by the wellbore. A source of inflow may be defined as (NORSOK D-010, 2013); "A formation which contains free gas, movable hydrocarbons, or abnormally pressured movable water". A potential source of inflow could represent different degrees of hazardous energy with consideration of the following reservoir properties:

- Fluid composition, where highly volatile, combustible and poisonous fluids such as light hydrocarbons and H_2S normally are considered the most hazardous.
- Volume of fluids in terms of total supported leak volume. This may be described by vertical and horizontal extension of connectivity between formation pores or fissures penetrated by the wellbore.
- Fluid mobility in terms of a supported leak rate. This may typically be expressed most accurately by a productivity index produced from physical well testing. From Bernoulli's law for energy conservation (Øverli, 1992) and Darcy's law (Dake, 1998) one may consider fluid mobility mainly to be a function of differential pressure, fluid viscosity, formation matrix flow properties and wellbore skin effects.

Any well release or blowout will need to include a fluid escape leak path that comes with properties that also affects the leak rate. For example, in cases where degraded WBE functionality still represents significant flow restrictions. The fluid mobility internal to the wellbore is best described by Bernoulli's law for energy conservation. A leak path may also be external to the well casing, however, and then include other type flow restrictions such as patchy cement, collapsed formations, barite sag, or fractures where fluid mobility may better be described using Darcy's law.

The final element of a well leakage model is the 'sink', which is the place of potential harm due to the fluids received from the source of the inflow. A sink may comprise of a permeable formation layer with fluid mobility affected by fractures propagating outside the wellbore, the seafloor, or most critically the rig floor of an offshore installation where the rig personnel are working. From the known characteristics of sinks given, the historic accident data, and relative potential for harm to personnel, we may consider four different types of blowouts as indicated previously in Figure 12: (i) Deep underground, (ii) shallow underground, (iii) seafloor, or (iv) rig floor (surface). The underground blowouts may not pose an apparent immediate threat to human health or the environment when compared to the other two categories of well blowouts, and the special case of underground blowouts may be used as basis for trade-off analysis performed as part of well risk assessments.

The principle well barrier diagram (system model)

The WBD considered the principle well barrier model in DPRA is shown in Figure 15. The figure shows an example WBD made for drilling the 8.5" reservoir section as described in Chapter 2. In contrast to traditional WBDs (Holand, 1996, Corneliussen, 2006), the WBD shows consideration of human and organisational factors in addition to the technical WBE factors used during the operations.

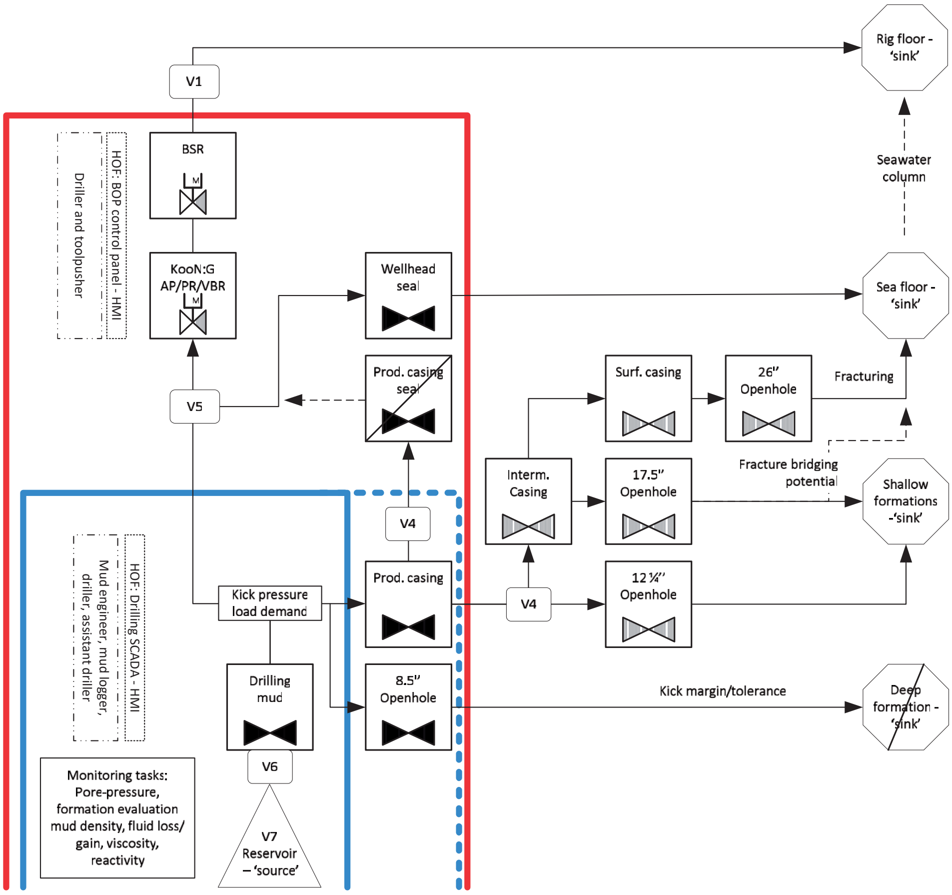

Figure 15. Example well barrier diagram – Normal drilling mode of 8.5" reservoir hole-section

The wellbore 8.5" openhole and the production casing string are indicated in Figure 15 with dashed lines as common WBEs in the drilling operations as (sometimes) the drilling mud column and (as a rule) the BOP also needs these two WBEs intact in order to function as qualified WBEs. Hence, it is important to maintain high confidence in the capability of these WBEs for well control. The failure of these common WBEs does, however, not automatically result in disaster. On failure there will be a new intermediate (weaker) casing and (12 ¼") formation envelope from the previous hole-section shown in Figure 15. The BOP is presented in a simplified format as an active, conditional and manual WBE, which is described for a kick pressure load demand scenario (Figure 7). The risk associated with the deep underground as a sink in the barrier model is considered small and negligible from Figure 15 based on well accident statistic and requirements for kick tolerances and kill margins in industry. The same is considered for the leak path through the casing seal / annular casing pack-off.

3.2 Existing risk modelling (operational phase)

Well PRAs are not new and are similar to the use of PRAs in the nuclear industry (ERIN, 2013), adopted in oil and gas industry for well risk management during the well operational phase (Haga and Strand, 2006). The industry well integrity standards and guidelines most relevant to performing well PRAs are, however, mainly found to address the well operational phase, for example (ISO 16530, 2014, NOGA 117, 2011, NORSOK D-010, 2013, Torbergsen et al., 2012, API RP 90, 2006).

According to Corneliussen (2006), the following quantitative analysis procedure should be followed to address well system blowout risk[22]:

1. *Define the hazardous event*. A well drilling operation blowout is represented in DPRA by the four types of blowout sinks shown in the Figure 15.
2. *Define the cavities where the source pressure (hazardous energy) can be trapped between the source of inflow (reservoir) and the sink (surroundings).* The reservoir and the wellbore below the BOP is identified with unconditional cavities (V5, V6, V7), whereas other potential cavities (conditional on stress) are the (i) production by intermediate casing annulus - 'B-annulus' (V4), and (ii) the intermediate by surface casing annulus - 'C-annulus'. The strength of the C-annulus envelope (and additional outer D-, E-,... annuli) is limited and thus overlooked.
3. *Identify WBE failure modes and corresponding leak paths*. The WBE failure modes are discussed in Chapter 2 and summarised in Table 5, and the leak paths are identified by the arrows shown in Figure 15.
4. *Identify the fault tolerance of the well barrier system.* The fault tolerance is defined by IEC 61508 (2010) as "the ability of a functional unit to continue to perform a required function in the presence of faults or errors[23]". There are at least two WBEs seen by following the representative leak path from reservoir to rig floor in Figure 15; (i) Drilling mud, and (ii) the BOP, and fault tolerance of the system is thus 1.
5. *Identify barrier vectors[24] and minimal cut sets.* If we limit the DPRA to the most likely and direct barrier vectors it is straightforward from Figure 15 to identify the minimal cut sets, which are presented in Table 6.

Table 6. Minimal cut sets of barrier vectors produced from Figure 15

Cut set notation	WBEs in cut set	Sink
CS1	Drilling mud, BOP	Rig floor

[22] Corneliussen does not consider human and organisational factors as part of the well PRA scope

[23] Error in this context does not refer to aspects of operator error or operator performance as terms used in DPRA

[24] A barrier vector uniquely describes the start and end point (cavity) for each leak path in a barrier diagram (Corneliussen, 2006)

CS2	Drilling mud, Wellhead connector/seal	Sea floor
CS3	Drilling mud, Production casing, Intermediate casing	Shallow formations
CS4	Drilling mud, Production casing, Previous 12 ¼” openhole	Shallow or Deep formations*
CS5	Drilling mud, 8.5” Openhole	Deep formations

*) Depends on drilling conditions - deep or shallow well target

Apart from CS1 that includes the BOP as a more complex WBE, it is straightforward to apply the results from Table 6 in traditional PRA methods such as fault tree analysis (FTA) and event tree analysis (ETA) when provided with access to representative WBE reliability data. For example, Rausand (2014) describes several methods on how to combine the minimal WBEs cut sets in Table 6 to estimate the probability of a top event in a FTA. Among others, a simple hand calculation method is described where the minimum set of WBE$_i$'s present in a leak path, [CS1,…, CS5], is denoted by minimal cut set K_j, $i \in j$. Further, consider a well system barrier situation with k minimal cut sets $K_1, K_2, ...K_k$ and where $\breve{Q}_j(t)$ denotes the probability for the minimal cut set K_j to be failed (leaking) at time t. If the WBE$_i$'s can be considered to be independent, we may write

$$\breve{Q}_j(t) \approx \prod_{i \in K_j} q_i(t) \qquad \text{(Equation 4)}$$

Where $q_i(t)$ denotes the probability for WBE$_i$ to be failed (leaking) at time t, which is found described for five different types of basic events in FTA (Rausand, 2014, p. 114); (i) Non-repairable item, (ii) repairable item, (iii) periodically tested item, (iv) frequency of event, and (v) probability of on demand event. Further, given that the product of the $\breve{Q}_j(t)$'s is small, and thus that the 'overlaps' can be disregarded, we may write for a top event

$$Q_0(t) \approx 1 - \prod_{j=1}^{k} (1 - \breve{Q}_j(t)) \approx \sum_{j=1}^{k} \breve{Q}_j(t) \qquad \text{(Equation 5)}$$

It is noted in regards to analytical modelling that the BOP can be described as a redundant and degradable WBE. As such, it may seem unreasonable to apply a simple Boolean argument indicated by the traditional Equation 4 and Equation 5 to describe the loss of the safety functions of the BOP.

3.3 Well risk modelling principle (drilling phase)

Figure 15 shows the main leak paths, well barrier envelopes and WBEs in well drilling operations, which need to be carefully considered in the PRA risk model. The risk model also needs to consider human task involvement and the performance of WBEs discussed in Section 2.3 and summarised in Table 5. In regards to more specific human tasks indicated in Figure 15, Baker (1998) describes industry procedures used by drilling crews in response to external threats such as well kicks. Three critical tasks are described; (i) Detection and acknowledgement (verification) of the symptoms of a threat / well kick, (ii) initiation of operations to control the threat / well kick, and (iii) initiation of operations to restore the well barriers. For example, a kick control operation may first entail securing the well in compliance with the operator's and contractor's procedures. This procedure may include; (i) Stopping work string rotation and clearing work string tool joint (thread connection) from the blind shear ram position in BOP, (ii) shutting down mud pumps to stop circulation of mud in well, and (iii) 'pushing the button' to activate BOP preventer or ram to close in well around the work string. Successful verification of the BOP closure will now place the well in a relative safe one well barrier state, and the restoration of well barriers can take place without apparent critical time constraints. The well barrier restoration activities that follow a well kick situation may include; (i) Estimation of the reservoir pore pressure, (ii) preparation of kill mud with sufficient density to control the reservoir pressure, and (iii) circulate in kill mud into the well to restore the mud column as the primary well barrier.

In summary, for the purpose of a well risk assessment in a short term technical perspective of well drilling it may seem reasonable to consider following principle for risk modelling in drilling phase, which is illustrated by event tree model in Figure 16; *A well kick (mud failure), marine riser failure, rig drive-off or rig drift-off, and similar initiating event may produce a minor well control incident or a full blowout.*

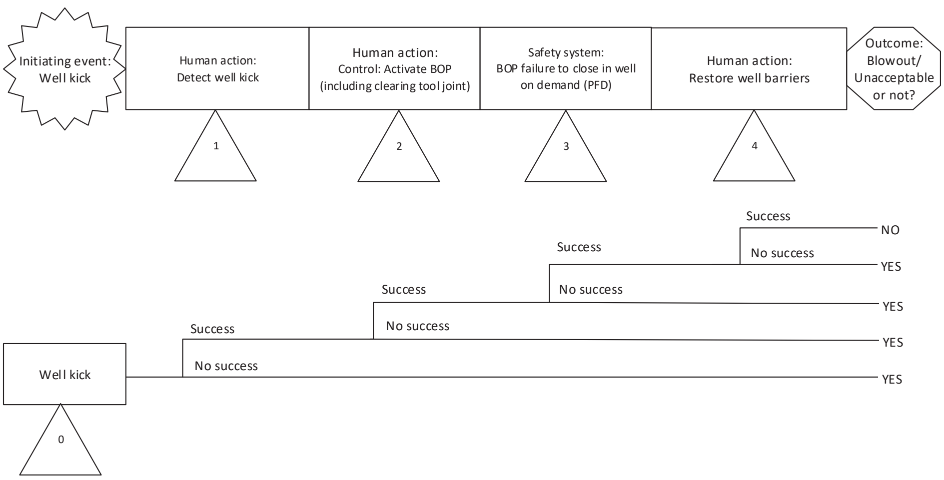

Figure 16. The risk modelling principle adopted for the well drilling phase

The risk modelling principle in Figure 16 combines human, organisational and technical factors in an event tree based PRA model. The event tree modelling principle is also adopted in the existing offshore risk assessment method, denoted Risk OMT (Vinnem et al., 2012) that includes use of HRA.

The main human actions and WBE safety functions that are desired to provide well control, primarily tasks executed by the driller and the BOP, are seen in Figure 16 to prevent a well kick as the initiating event from escalating into a blowout. The event tree nodes, 0 through 4, are shown to include additional causal analysis indicated with triangle shaped transfer symbols relevant to determine:

(i) The frequency of well kicks as common initiating events, for instance, described by well kick statistics in Section 2.3
(ii) The probability that operator error[25] results in a failure to timely detect the kick described in Section 2.3
(iii) The probability that operator error results in a failure to 'push the button' and successfully activate BOP to contain the kick described in this section and in Section 2.3
(iv) The probability that the BOP fails to close-in the well kick on demand ('push of button') described in Section 2.3
(v) The probability that operator error results in a failure to restore well barriers described in this section.

Historically, the underground blowouts do not produce a clear and immediate threat to human health or the environment in comparison to seafloor and surface blowouts. As result, the baseline risk model presented in Figure 16 focuses on seafloor and rig floor blowouts. The model considers that a blowout (loss of well control) is an unacceptable event, and therefore do not specifically take into account potential flow rate restrictions that could, for instance, be introduced as result of partial closure of BOP devices[26] as was the case in the Macondo well accident (The Deepwater Horizon Study Group, 2011).

In respect to Figure 16 calculations. If an initiating event takes place, the probability of a blowout will be equal to the respective undamaged well barrier's safety unavailability. The safety unavailability is typically calculated as an average value over a representative time interval of interest denoted as the PFD. If we assume the initiating event to follow a homogenous Poisson process (HPP) with a known frequency, γ, and the undamaged well barrier system's unavailability is given by PFD_S, it's possible to model an associated well system blowout frequency. By combining the HPP with the Binomial situation, the (low) number $N_{BO}(t)$ of blowouts caused by the hazardous situation in the time interval [0, t) can

[25] DPRA approach makes use of term operator error instead of human error to be consistent with task analysis terminology proposed used in DPRA method

[26] Flow restrictions may possibly be deemed relevant short term such as in an evacuation period. However, a 'full bore' blowout implied in model represents a significant source of erosion, fires, explosions and other escalation effects.

be modelled as a new HPP with frequency, $\gamma \cdot PFD_S$ (Rausand and Høyland, 2004). The probability that a well operation will 'survive', say 70 days, without a blowout can then approximately be written

$$\text{Pr(70-days without blowout)} = e^{-\gamma(/days)\cdot PFD_S \cdot 70(days)} \qquad \text{(Equation 6)}$$

We may consider the PFD to have two 'meanings':

(i) PFD is the percentage of time where we are unprotected by the safety function.

(ii) PFD is the probability that the safety function will fail on a demand for it. For example, if a BOP function is activated by the driller in a well kick situation, the PFD represents the probability that the BOP will not close in the well.

In regards to traditional PRA methods like FTA we may consider BOP as an item, that is periodically tested, and drilling crew (operator) task performances as a probability of on demand event. For example, the BOP has hidden critical failure modes, denoted dangerous undetected failures by IEC 61511 (2003), and therefore undergoes regular pressure and function tests. The interval between two consecutive tests may be denoted by τ, which may represent a test approximately at every hole-section drilling start (Figure 8). BOP rams are pressure tested before the start of the next hole-section drilling. The subsequent capacity of the rams is uncertain due to potential deterioration that may have occurred during the drilling process. For example, if a ram becomes 'too weak' to handle a kick load by the end of the section drilling, the mean time it has been in a too weak condition (mean downtime), D_c, will be close to $\tau/2$ if we assume a constant failure rate, λ_c, for the ram. The PFD (of a ram or undamaged barrier system) may be expressed as the proportion of expected downtime over the total service time, or alternatively as an average probability that the safety function will fail given a demand for it (Rausand, 2014)

$$\mathrm{PFD}_s = \frac{\mathrm{E}_s[\mathrm{D}_c(0,\tau)]}{\tau} = 1 - \frac{1}{\tau}\int_0^{\tau} R_s(\mathrm{t})dt \qquad \text{(Equation 7)}$$

Where $R_S(t)$ denotes the system reliability function of the undamaged barrier system, which for a BOP may typically represent several identical and redundant rams by the reliability structure function. For example, for a '1ooN:Good' parallel structure, meaning that the safety function will fail only if all rams fail we may get under several assumptions that (Rausand, 2014)

$$\mathrm{PFD}_s \approx \frac{(\lambda_c \tau)^N}{(N+1)} \qquad \text{(Equation 8)}$$

Some of the main assumptions for Equation 8 are that; (i) All rams are identical with constant failure rate and failures are independent[27], (ii) all ram failures are detected by pressure testing, and (iii) all ram failures are repaired 'immediately' after failure detection. However, rams and preventers are not identical, departures are granted by authorities not to repair them, and failures of two or more rams may not always be regarded as independent failures due to external hazardous events or shared control system functions. For example, when performing PFD calculations in line with the IEC 61508 (2010) standard, it is necessary to assume an extra 'virtual leak path' that includes a certain percentage, β, of ram failures as common cause failures, from Equation 8;

$$\mathrm{PFD}_s \approx \frac{[(1-\beta)\lambda_c\tau]^N}{(N+1)} + \frac{\beta\lambda_c\tau}{2} \qquad \text{(Equation 9)}$$

The IEC 61508 (2010, Part 6 (2009)) standard recommends a typical input of a β-factor in the range of 5-10% per function group determined by application of a checklist procedure. It may be difficult to determine the β-factor without access to detailed reliability data made available from qualification or reliability growth testing or field applications. Similarly, it is noted that the failure rate estimates in the reliability data sources are mostly collected during normal operations. For example, few 'slam-shuts' are included in BOP reliability data collected (BSEE, 2013b, Holand and Awan, 2012, Sattler and Gallander, 2010). If there is no early warning system to detect 'approaching hazards', for instance, to assist the driller in the early detection of a well kick, the on demand shut in may be a so-called 'slam-shut'. It could be argued that the PFD of a slam-shut is likely to be higher than a controlled shut-in. As such, a range of different BOP closure demand scenario could have been indicated in Figure 15 on basis of Figure 7.

Human and organisational factors are traditionally not treated in well PRA, and the textbook methods adopted in well PRAs may include assumptions that are not always realistic. Results from a literature review with regards to adoption of alternative methods for purpose of DPRA are presented in the next section.

3.4 Other risk assessment methods and practices

This section presents a summary of initial academic and industry literature reviews of relevant methods and tools that could be considered for adoption or adaption according to DPRA risk modelling principle discussed in the previous section.

[27] Items that do not affect each other's reliability when including aspects of common cause and cascading failures are referred to as *independent*

A review of the academic literature concerning explicit methods for probabilistic risk modelling of well drilling operations produced some recently proposed Bayesian belief network (BBN) and bow-tie based models such as (Khakzad et al., 2013, Khakzad et al., 2014, Abimbola et al., 2014). In industry, the historic quantification and analysis of well system risk for drilling operations for oil and gas industry in general seems to be based on generic well accident data (Berg Andersen, 1998, IOGP #434-2, 2010, Vandenbussche et al., 2012). A few examples were identified where some safety functions of the BOP were modelled consistently in more detail based on using FTA, for instance (Holand and Rausand, 1987, Holand, 1999, Holand and Awan, 2012, Cai et al., 2013a). Only technical factors were found considered in the probabilistic methods reviewed.

The well barrier system may be regarded as a dynamic system during well drilling operations. This includes the different drilling scenarios and possible introductions and transitions of the WBEs into degraded modes of operation if one or more faults are revealed. As a result, a review was carried out on how the reliability of dynamic systems is treated in the literature. Hassan and Aldemir (1990) states that "dynamic methodologies are defined as those which explicitly account for the time element in system operation for failure modelling". The definition implies focus on time requirements (time-line) over general situation requirements (state/evidence), which may be sought in reliability analysis and degradation modelling of WBEs such as the BOP. However, the use of the term dynamic with respect to reliability analysis has become broader in recent years. For example, according to Distefano and Puliafito (2009) it may include system analysis that explicitly evaluates dependent, cascading, on-demand or common cause failures, and also the policies established in regards to, for instance, redundancy and maintenance.

Most dynamic analysis methods proposed for large systems have been found to be based on the well-known static reliability analysis methodologies discussed, among others, by Rausand and Høyland (2004). Examples of dynamic methods includes dynamic fault trees (Čepin and Mavko, 2002), dynamic reliability block diagrams (Distefano and Puliafito, 2009), dynamic event trees (Acosta and Siu, 1993) and dynamic Bayesian belief networks (DBBN) (Cai et al., 2013c). Many of the dynamic methods are found to retain a strong relationship to the time-line for modelling. The newer methods, however, in particular numerous methods based on BBNs, consider more explicitly the situation requirements and existing evidence relevant to describe the system reliability. For example, Cai et al. (2013c) demonstrates the application of a DBBN in BOP reliability analysis by converting one of Holand's existing FTA models. The similar type FTA combined with a DBBN for the input data is also demonstrated by, for instance, Khakzad et al. (2013). Another attractive class of dynamic reliability analysis methods is referred to as multiphase or phase mission system analysis (Lu and Wu, 2014). This is analysis where the system model consists of a set of sub-models that are consecutively linked together over a mission time. For example, a typical phase mission system model may consist of sub-models that are based on a reliability block diagrams or fault trees, which are linked together in a binary decision diagram (Lu and Wu, 2014).

The risk model in Figure 16 implies that unsuccessful human task performance can be quantified as a probability, and research suggests human behaviour to be somewhat predictable by chance and odds within a shorter time horizon, for instance in geopolitics (Tetlock and Gardner, 2015). In PRA this type of estimation of 'human task failure' probabilities is commonly associated with human factors analysis techniques like human error analysis (HEA) and human reliability analysis (HRA).

Reviews of the offshore petroleum safety authorities have shown support for a few human factors studies (HSE, 2000, BSEE TAP: Human Factors, 2016). For example, in HSE (2000) a method has been developed to assist safety review teams. The method identifies the following main options for risk control in offshore safety critical tasks; (i) Hardware modifications, (ii) the provision of written instructions, (ii) the design of information system interfaces, and (iii) task specific training and competency assessment. The literature that addresses human and organisational factors (HOFs), however, in HRA for specific purpose of well drilling operations is scarce. For example, for Vignes (2011, p. 63) it was necessary to make use of own work experiences and observations from projects and audits conducted by the PSA to discuss HOFs in drilling and intervention operations. Moreover, Vignes (2010) suggests that a historic lack of identification and classification of HOFs may become a "major causal factor for human errors, poor decision making and reduced task performance". An abridged summary of the HOFs identified and discussed by Vignes (2010) is presented in Table 7.

Table 7. HOFs identified in well drilling and intervention operations based on Vignes (2010)

Workplace related factors

- Environment; Odor/petroleum fumes, noise, vibration and harsh offshore weather conditions. Poor visibility from bad lighting and due to physical obstructions
- Displays and controls; Large amount of unnecessary and unhelpful (in diagnostic) drilling system alarms. Reduced accessibility (not enough space for equipment)
- Task demands and characteristics; Periodically very high workloads result in corner cutting (many tasks / simultaneous activities / administrative work)
- Instructions and procedures; Procedures and managements documents too comprehensive and not always easily accessible
- Socio-technical: Competence transfer in a 12-hour shift based work situation and high turnover of personnel. Challenges with planning, cooperation and change management for ongoing work. Lack of operative presence in drilling area of management

Human related factors

- Individual; Muscle pain and eye fatigue among drillers interacting with the drilling system
- Stress; Limited time to prepare completely for a job. For example after arrival on site to become familiar with the rig equipment and relevant safety/work procedures.

No HRA methods that were reviewed had been explicitly proposed for drilling operations or shown to have been adopted by the drilling and well community based on author's experience and literature survey. A few related offshore HRA methods, however, were demonstrated: (i) In making installation safety cases (Ren et al., 2008), (ii) in risk analysis of emergency situations (Deacon et al., 2010), and (iii) in risk analysis for planning and execution of offshore process system maintenance activities (Vinnem et al., 2012). The result of the literature survey was somewhat in contrast with other low probability and high consequence activities such as nuclear power generation, which included numerous methods proposed for HRA in PRA.

Following the 1979 Three Mile Island nuclear accident, Swain and Guttman (1983) introduce human errors of omission or commission in an early human reliability analysis approach; A technique for human error rate prediction (THERP). THERP determines human (operator) error probabilities (OEPs)[28] based on empirical studies of human performance influencing factors (PIFs) along an event tree developed with desired human actions. Dozens of HRA methods has since emerged. For example, a study carried out in 2009 identified more than 72 HRA methods developed within the nuclear industry alone (HSE, 2009). Examples of HRA methods may broadly be classified as: (i) PIF multiplier based (Williams, 1985, NUREG/CR-6883, 2005, Farcasiu and Prisecaru, 2014), (ii) PIF weighted sum based (Embrey et al., 1984, Sklet et al., 2006, Schönbeck et al., 2010), or (iii) Bayesian belief network (BBN) based (Ren et al., 2008, Vinnem et al., 2012, Ekanem et al., 2015). The BBN based methods such as those proposed for offshore operations by Vinnem et al. (2012) represent modern methods that typically make use of PIFs as nodes in BBN models, often as an extension to the use of weighted PIF sums.

Adapting the Risk OMT method from Vinnem et al. (2012) in well PRA seems attractive since it; (i) Was developed with assistance from a major offshore operator (Statoil), (ii) includes modern BBN methods, (iii) has been demonstrated with low calculation efforts and does not require use of commercial BBN software, (iv) allows treatment of PIFs as unobservable variables, which enable use of proxy data in the method. However, the Risk OMT has not been widely adopted by Statoil for the purpose of well PRAs from the author's experience working with the company. One reason for this could be the predefined role of PIFs in the Risk OMT causal model, which is based solely on risk modelling scenarios considered in Norwegian offshore installation risk assessments. These risk assessments traditionally incorporate well blowout risk generically (Vinnem, 2007), which implies that the role defined for the PIFs in the method may not be directly applicable to well drilling operations globally.

Also, performing a HRA to forecast human behaviour by OEPs comes with a number of pitfalls. For example, easily demonstrated in terms of; (i) Heuristics by the manipulation of the standard formula for construction of staircases, (ii) well-known psychological biases studied in behavioural economics and

[28] The traditional HRA 'human error probabilities' are referred to as operator error probabilities (OEP) in DPRA

in sales and marketing (Cialdini, 2007, Kahneman, 2011), and (iii) neuroscience and biochemistry with human behaviour associated with exposure to substances like narcotics, alcohol and miraculin[29].

Consequently, a large knowledge base on the application of HRA in PRA can also be found in the nuclear power industry. For example, the US nuclear regulatory commission (NUREG) presents two sequential reports that address the evaluation process, the best practice, of selecting a HRA method (NUREG-1792, 2005) and from there includes a review of many existing HRA methods in the context of this best practice (NUREG-1842, 2006). There are no conclusive results as to what has been found as the best or most universal HRA methodology. It is rather stressed that HRA methods may have different strengths and weaknesses. For example, some HRA methods account for time constraints in performing a task, which assessors must consider when selecting a method for analysis of a specific situation. For instance, for a task where time constraints are not of the essence. Some HRA methods are also described simply as 'just quantification tools', which requires adaptation in domain to become a valid part of a system PRA. More recent critique related to HRA are that the methods are applicable to only elementary work tasks, and that their age could make them dislocated from the current knowledge about human and organisational performance (French et al., 2011). Ekanem et al. (2015) also recently discussed potential HRA framework weaknesses related to: (i) Too much variability in results between analysts, and (ii) root causes for human errors not covered, which makes human error identification and avoidance difficult. An explanation offered as a source for ambiguity among HRA studies is that PIFs used in HRA literature has been largely adopted from sociotechnical system theory developed to analyse major accidents in retrospect, and not for the proactive purpose of performing most HRA (Schönbeck et al., 2010).

3.5 Implications of other methods and practices for DPRA

The existing dynamic risk assessment methods found in literature reviews to quantify impacts of technical factors on well drilling operation risks may be shown to be sufficiently flexible and comprehensive for the purpose of most well PRA. However, some specific adaptations could be made for making the methods appear more domain oriented and attractive among stakeholders identified in this thesis. For example, the larger DBBN models that have been proposed may typically be difficult to validate and become computationally demanding, which may make them less suited for practical operational use. Also, the modern DBBN modelling approaches may seem (currently) too complex and discipline oriented for some stakeholders. As a representation of a system or process, therefore, they may currently be viewed to lack the necessary communication features for risk control in a multidisciplinary setting (Rasmussen, 1997). One multiphase Markov model developed for degradation modelling of hydropower plant components by Welte (2008) was found to be particular attractive in its

[29] If the human taste buds are exposed to miraculin, which binds to sweet receptors on the tongue, acidic foods which are ordinarily sour such as citrus become perceived as sweet.

simplicity, and used as the inspiration for a method developed for degradation modelling of the BOP described in Paper 1.

A stronger indication of knowledge gaps discovered from the literature review was related to the limited amount of HRA methods that accounts for HOFs adopted in oil and gas industry PRA frameworks. The importance of HOFs in relation to the quality of quantitative risk assessment has, for instance, been long since emphasised by Bley et al. (1992); "Any model that fails to examine the organisational factors is guaranteed to underestimate the overall risk by an undetermined amount". The literature review also revealed numerous methods proposed over several decades on how to incorporate HOFs into PRAs, where the Risk OMT method was found attractive for adaption to well PRA. The many methods proposed and the current oil and gas industry practices, however, indicate that challenges still exists on how to incorporate HOFs into PRAs, and this may typically be related to; (i) Identification and definition of the influential HOFs to consider, and (ii) how to formally structure and evaluate HOFs in regards to human task performance in probabilistic causal models, which also is found acceptable to stakeholders for addressing the probability of losing well control during a drilling operation. Consequently, these are considerations that have to be carefully considered in the process of adapting Risk OMT method for the purpose of DPRA.

Research questions

In summary, three main problem areas were identified from discussions with supervisors and peers, and from the literature review in the initial phase of the PhD project as the basis for more focused research in this thesis. The following research questions have been defined for this PhD project:

- How do different BOP designs and maintenance strategies impact the safety function performance of the BOP?
- How can the influences of human task performance be better incorporated in the well drilling operation PRAs to help the drilling crew's better manoeuvre within the well operation safe envelope[30]?
- How does technology influence human task performance in offshore well operations?

[30] Safe envelope denotes a boundary an operation has to stay within to prevent a situation of harm from occurring

4 A new approach to PRA in the well drilling phase (DPRA)

This chapter presents the DPRA that includes procedures and methods to help assess well drilling operation blowout frequencies or probabilities associated with initiating events such as a well kick (mud failure), drilling riser failure, or rig drive-off or drift-off. The presentation is based around a generic PRA procedure as structure, where the new procedures and methods developed in DPRA are described with reference to the procedure step and existing literature it proposes to replace as alternative in the discussion.

4.1 Background

This chapter focuses on new procedures and methods developed for extension of PRA in the well drilling phase, denoted as DPRA. It is proposed that DPRA is used together with existing PRA methods discussed briefly in Chapter 3 to assess drilling operation blowout frequencies or probabilities associated with initiating events such as a well kick (mud failure), drilling riser failure, or rig drive-off or drift-off. The DPRA may typically be applied either by operator or service provider personnel involved in a well risk assessment where a mud column is established as the primary well barrier. DPRA is concerned mainly with assessment of the risk of surface blowouts seen from risk modelling principle established for drilling a hole-section in Figure 17. DPRA includes procedures and methods to estimate node probabilities indicated with transfer symbols in Figure 17. One event node is seen associated with the PFD of BOP safety functions (3), while three other nodes; (1), (2), and (4) are associated with HRA and 'failure' of drilling crews to perform safety critical tasks.

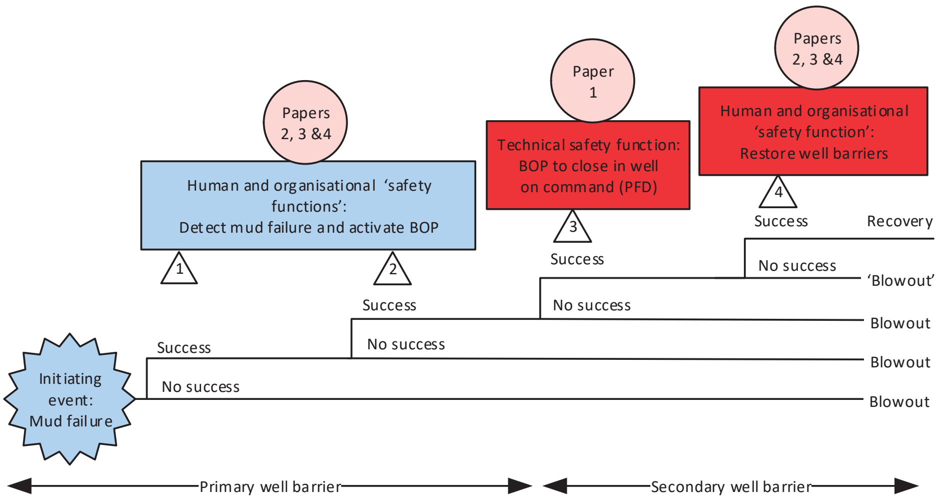

Figure 17. DPRA risk modelling principle with paper contributions made in this PhD project

The PFD and OEPs associated with the four event tree nodes in Figure 17 can be calculated with help of DPRA. The DPRA specifics presented in this chapter are provided with details in enclosed Paper 1 through Paper 4 shown associated with each event tree node in Figure 17.

From Figure 17, the BOP safety function PFD analysis description includes Paper 1 enclosed in Appendix I, which contains a method proposed for combined PFD and maintenance analysis of BOPs. The background for the paper is that the PFD calculations may benefit from more complex dynamic modelling that includes levels of physical BOP degradation compared to the simple Boolean state based methods described in traditional PRA method literature.

The OEP calculations for the human and organisational type 'safety functions' in Figure 17 are described with a HRA method developed as part of DPRA. The method is based on a generic HRA procedure with adaptation of the Risk OMT causal modelling (Vinnem et al., 2012), and is described more in detail by supporting contributions made in Papers 2 through 4 enclosed in Appendices III, IV and V, which respectively: (i) Clarifies the structural role of HMI in causal model and corroborates the importance of HMI as a risk influencing factor (RIF) evaluated in DPRA, (ii) describes the causal model established and the quantitative procedure of method that is used for OEP calculations in DPRA, (iii) discusses and clarifies the operator error terminology and taxonomy to be used in HEA as part of the HRA procedure in DPRA.

4.2 DPRA method outline

Well risk assessments are traditionally case-based studies and it is assumed that preparations made for the DPRA study includes the specification of the planned (study) well drilling operation alongside a regionally acceptable and comparative (reference) operation. For example, a specification outline that includes these type of drilling operation descriptions can be found in publicly available report by BSEE (2013a), which includes; (i) well control procedures, (ii) kick causes, (iii) kick frequency, (iv) kick indicators, (v) kick detection and management technologies. The reference operation is typically referred to as the 'base case'. The base case is specified to allow different relative comparisons to be made in well risk assessments. The making of absolute subjective judgments should be avoided as far as possible. As such, the DPRA is considered in this context as being applied by the well engineer as a tool with focus on evaluation of the blowout risk associated with novel versus routine operations. The base case should be recognised by the use of broadly accepted industry qualified technologies, best practices and standards within an offshore region of study. The 'proof of acceptance' typically includes experience data from method or component qualification testing and from extensive use in the field. This data can also be used for DPRA risk model calibrations. Typical information publicly available for industry base case operations include the following examples: (i) blowout frequencies (Holand, 1997, IOGP #434-2, 2010). (ii) kick frequencies and causes (Holand and Awan, 2012, PSA, 2013b). (iii) well control technologies reliability data (Sattler and Gallander, 2010, Holand and Awan, 2012).

Based on Figure 17 we may define the following stepwise procedure for risk assessment of a drilling operation with DPRA:

1) *Step 1: Define scope of work and delimit the study*. The DPRA is described as a well risk assessment method managed by the well engineer in the planning phase of offshore well drilling operations. A method he or she may typically apply as an aid to evaluate plans for drilling hole-sections with the use of new or modified technology or industry practices, or in geographic or geological areas with limited historic data. The main limitations of DPRA as approach are summarised in Chapter 1, which are based on discussions in Chapter 2 and Chapter 3 as part of developing the foundation for the risk modelling principle presented in Figure 16.
2) *Step 2: Determine the frequency of mud failure* from experience data. This task is not described as part of DPRA, but several data sources that can be used are discussed in Section 2.3.
3) *Step 3: Carry out a HRA* to determine OEPs for event tree nodes 1, 2, and 4. This task is described as part of DPRA in this chapter.
4) *Step 4: Determine the PFD for the BOP* when considering manual activation and maintenance strategies. This task is described as part of DPRA in this chapter.
5) *Step 5: Calculate the total blowout frequency*, and compare with the base case and against other RAC. This task is not described as part of DPRA. It is considered to be covered by the existing literature briefly discussed in Chapter 3.
6) *Step 5:* Confer with drilling crews and independent advisors on *identification and implementation of risk reducing measures.* Decide on necessary improvements to procedures, crew competence, well barriers and HMI. This task is not described as part of DPRA. It is considered that it is covered by existing literature.

4.3 DPRA Step 3: Carry out a human reliability analysis

The potential for underestimation of risk is a challenge that assessors will face with regards to the quality and usefulness of PRA. The implications are that significant risk contributors should be thoroughly discussed in PRA documentation for purpose of quality assurance (Table 1). As remarked by Bley et al. (1992), this type of quality assurance will be particularly important for PRAs that are tightly coupled to HOFs such as well drilling operations. As basic foundation for how to approach HOFs in PRA we may relate to popular statements made by Reason (1997); “We cannot change the human condition, but we can change the conditions under which people work”, and by Kletz (2001); “Try to change situations, not people”. The two statements place the emphasis of PRA on the scrutiny of workplace specific HOFs (‘situations and conditions’), and could become source for two pragmatic views in an assessors approach to consider HOFs in PRA:

I. Explicitly quantify the influences of the workplace HOFs as integral part of the PRA
II. Exclude the workplace HOFs as an explicit limitation (boundary condition) to the PRA

Option I is in line with quality management on making continuous improvements and should, in principle, produce less underestimation of risk. It is also, however, the most difficult position where the assessors need to have the competence and tools required to consistently evaluate complex multidisciplinary factors that affect human task performance for both better and for worse.

Following Option II implies a strict focus on keeping workplace situations and conditions at an explicit baseline, or better, level. This approach could still prove beneficial to stakeholders in order to control activity risk. For example, in spite of known issues with underestimation, the results could still be argued to be useful in comparison based PRAs, and maybe also within the margins of acceptable industry practices documented in the historic blowout data.

A main task of this PhD project has been to develop a well drilling HRA method with regards to Option I, which inherently also includes the foundation for Option II. The HRA framework is based on method developed by Vinnem et al. (2012) as part of the Risk OMT project. Studies of human factors related to well drilling and intervention accidents made in parallel to the DPRA method development (Strand and Lundteigen, 2017) suggested that an offshore drilling HRA should focus on the close link in the sharp end between physical and mental human error tendencies and the unique workplace factors on an offshore drilling rig. The aspects of the workplace factors and latent human error tendencies is therefore emphasised in adaptation of the Risk OMT process maintenance HRA into a HRA for well drilling operations.

HRA method outline

The HRA method in DPRA is described in this section is based around a stepwise HRA procedure that includes the following Step 3.1 through Step 3.5:

1) *Step 3.1: Define scope of work and delimit the study.* Reference is made to DPRA scope and delimitations.
2) *Step 3.2: Identify work tasks where operator error may contribute significantly to well operation risk.* The critical tasks performed by the drilling crew are described in Section 2.3 and Chapter 3 of this report.
3) *Step 3.3: Perform human error analysis of critical work tasks part of the well operation*. A procedure HAZOP, or task analysis (TA) (Kirwan and Ainsworth, 1992) is an integral part of the HRA. For purpose of DPRA, Paper 2, Paper 3, and Paper 4 proposes clarifications made to the HEA taxonomy and terminology, which combines checklists of workplace and performance influencing factors. The intention is to reduce ambiguity and enhance the quality of HEA work as per the criteria in Table 1.
4) *Step 3.4: Establish (or update) operator error causal model.* Paper 2, Paper 3, and Paper 4 covers establishment and updating of the causal model, which includes identification and evaluation of RIFs for the purpose of OEP calculations based on the adopted Risk OMT requirements.

5) *Step 3.5: Calculate OEPs for each task and for the complete well operation*. Paper 3 describe the BBN causal model adopted in HRA from Risk OMT. This includes a detailed description of the hybrid calculation approach as an alternative calculation method to the full BBN implementation. The hybrid approach allows OEP calculations to be performed without use of commercial BBN software's.

HRA step 3.3: Perform human error analysis of critical drilling operation tasks

Performing HEA as integral part of TA is considered an important step in HRA and this section proposes clarifications to the HEA operator error taxonomy with the intention to limit ambiguity and enhance the reproducibility of HEA in DPRA as per the criteria in Table 1. The taxonomy builds on various definitions and concepts from failure analysis and human factors literature reviews, and is developed from a reliability engineer's perspective. Similar to equipment failure analysis (Rausand and Øien, 1996) this includes a bottom-up approach that address operator errors on three distinct levels in the analysis. Two principle considerations are made in developing the DPRA HEA taxonomy: (i) Multidisciplinary coherence through adaptation of familiar and recognised concepts from technical failure analysis and reliability data collection sources; (ii) Extended usefulness and versatility through applicability across common levels of activity or process breakdown in task analysis.

As such, the main objective of Paper 4 (Appendix V) is to help the assessor's form a common understanding of what an operator error represents in DPRA. Namely that generic latent physical and mental human error tendencies may combine with rig specific workplace factors, and as result negatively influence the safety critical task performances.

A TA is a collective term that may be defined according to US Department of Defence (DoD) (DoD, 2013, p.1) as an analysis of human performance requirements, which if not accomplished in accordance with system requirements, may have adverse effects on system cost, reliability, efficiency, effectiveness, or safety. A TA describes the manual and mental processes required for one or more operators to perform a required task (Kirwan and Ainsworth, 1992). The term task is used interchangeably for an activity or a process. A TA procedure may typically include: (i) Task breakdown and element durations, (ii) task frequency, (iii) task allocation, (iv) task complexity and competence requirements, (v) environmental conditions, (vi) necessary clothing and equipment, and (vii) any other unique workplace factors that affect the successful performance of the task. An abundance of relevant literature can be found to assist the definition, design and execution of a TA, for example (Reason, 1990, Kirwan, 1994, Kletz, 2001, Wickens et al., 2004, Stanton et al., 2013, Dekker, 2014).

TA often use hierarchical representations of the steps required to perform a task for which there is desired outcome(s) and for which there is some lowest-level action, or interaction, between humans and machines. Hierarchical task analysis (HTA) is a popular TA technique, and considered one central approach in ergonomics studies (Stanton, 2006). The HTA produces a description of tasks in a hierarchy made of a task at the highest level consisting of objectives expressed as the goals of the system, which are in turn composed of sub-objectives ('operations') and lower-level actions (Stanton, 2006). Actions are considered the smallest individual specific act carried out by operators interacting with a technical system or by the system itself, and are often procedural in nature with an implied or explicit sequence. For example, individual actions may include 'visually locate BOP control panel AP-button' or 'move hand to AP-button on BOP control panel', which an operator is required to do in a particular combination to meet the objective for successful task completion.

In this section, 'driller to activate the BOP in event of well kick within 40 minutes' is used to provide an example of a drilling operation task to be analysed with DPRA, which is illustrated in Figure 18 based on the HTA. The example task includes both task node 1 and task node 2 in DPRA event tree model. These are clearly dependant tasks and the advice in DPRA, therefore is to analyse these tasks together due to limitations with the hybrid calculation approach, which is discussed later in the chapter.

As described earlier, this task may be broken down into two sub-tasks that may contain four consecutive operations; (1.1) Detect/acknowledge symptoms of a well kick, (1.2) Perform flow-check to diagnose symptoms of a well kick, (2.1) Activate the BOP to shut-in the well, and (2.2) Verify well shut-in (successful BOP activation). Further, to detect/acknowledge well kick symptoms would typically entail several lower-level actions, whereof one example can be denoted as (1.1.1) Monitor for in/out flowrate changes.

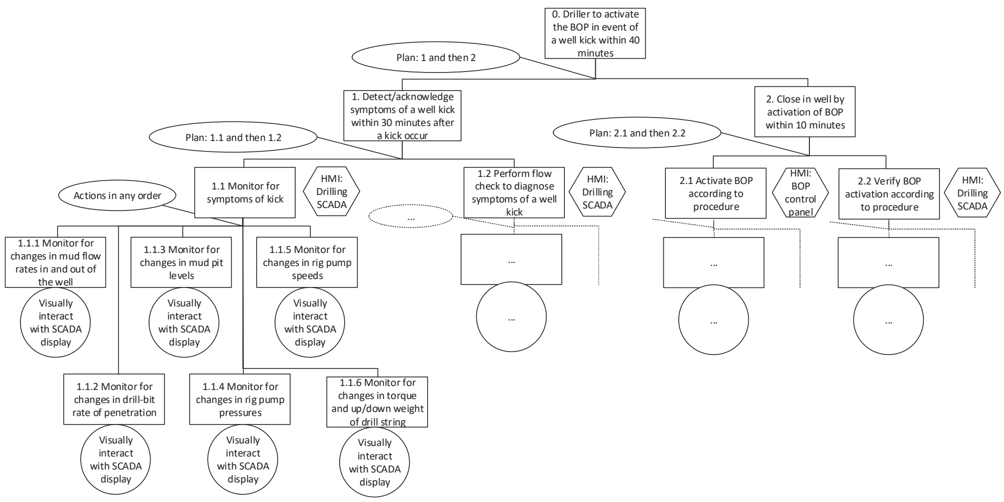

Figure 18. Example of traditional HTA breakdown of task; 'Driller to activate the BOP in event of well kick within 40 minutes'

As an alternative to HTA in Figure 18, the adaptation of a combined HTA-SADT type diagram illustrated in Figure 19 is used as the structure for HEA in DPRA. The diagram is used to maintain three levels of results produced in the analysis, also indicated in Figure 19. The three levels of break-down is consistent with basic concepts of failure analysis (Rausand and Øien, 1996) and with the underlying hierarchical HOF influence model for operator errors that is used as basis for adopted Risk OMT causal model in DPRA. The hierarchical HOF causal model is described in more detail in the next sections.

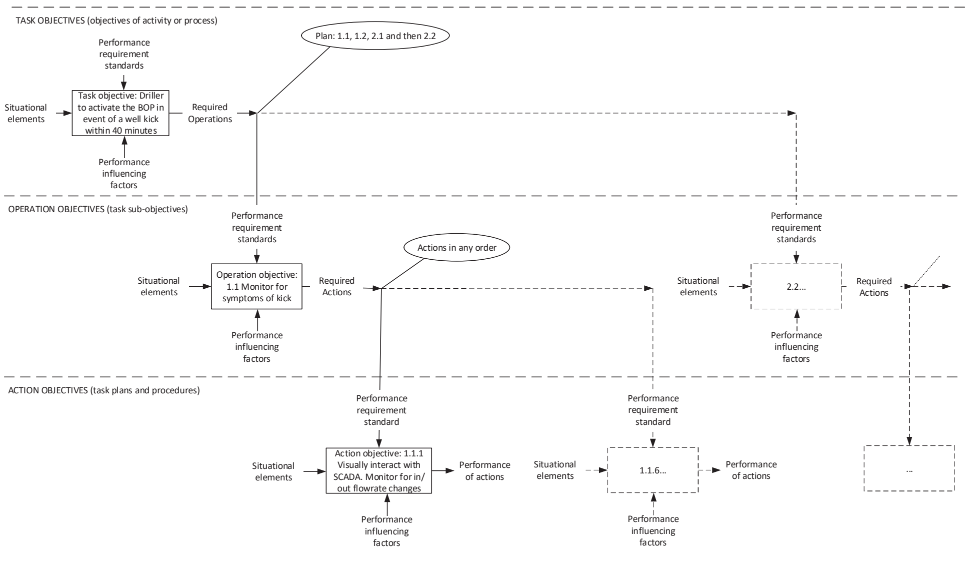

Figure 19. The SADT-HTA type diagram with three task breakdown levels for HEA proposed in DPRA

The combination of HTA and the structured analysis and design technique (SADT) (Rausand and Høyland, 2004) with functional block diagrams (Rausand and Øien, 1996) used in failure analysis is explicitly used in DPRA to create a bottom-up method for HEA in DPRA. The 'arrows' shown to 'functional blocks' in task breakdown are based on human factor concepts adopted from previous research (Strand and Lundteigen, 2017, Strand and Lundteigen, 2016, Endsley, 1995). The analogous view to functional block diagrams is as follows: (i) drilling task objectives as 'functions', (ii) operator performance requirement standards as 'control system', (iii) situational elements[31] as 'inputs', (iv) required operations, actions, and performance of actions as 'outputs', and (v) performance influencing factors as the 'environment'. In order to maintain the three levels of coherence in HEA results it is generally advised to follow the 'paper-trail' of performance requirement standards identified on lowest level in plans and procedures, tracing upwards in the organisation through the operation objectives and

[31] Describe 'inputs' as the need to make situational assessment to reach a state of knowledge about well system elements and their states as the basis for near future actions. The situational assessment includes three main steps (Endsley, 1995): (i) Perception, (ii) comprehension, and (iii) state projection (forecasting).

to highest level processes. The processes are typically described by governing documents in an oil and gas sector organisations.

The concepts used in relation to the analysis of higher level operation and task objectives in Figure 19 is discussed in the HRA causal model description given in next section. A description of the concepts used for the analysis of the lowest level action objectives in Figure 19 follows, based on the operator error definitions in DPRA and from the literature review shown in Table 8 (Strand et al., 2016).

Table 8. Operator error definitions for use in DPRA

Term	Definition
Operator error	Inability of an operator to perform as required. Note: Operator errors are associated with human behaviour, unsafe acts, which are not intended or not desired.
Operator requirement	A stated need or expectation about operator's performance considered necessary in order to accomplish a given task objective. Note: Operator requirements may; (i) Be stated or implied (i.e. that the operator would be entitled to expect), (ii) by implication, also cover what the operator should not do, (iii) include essential internal requirements of a task, which may not be visible to the operator, but also are operator requirements.
Operator error mode	Manner of non-conformity in which operator error occurs.
Non-conformity	Non-fulfilment of a requirement.
Error criterion	Pre-defined level of operator performance for acceptance as conclusive evidence of operator error.
Departure	Undesired discrepancy between a computed, observed or measured operator performance, and the specified target value stated in performance requirement standard.
Operator error cause	A set of circumstances that impairs recovery from undesired effects of operator behaviour.
Performance influence	A process of departure described by workplace conditions and latent human error tendencies.
Operator error effect	Consequence of operator error, within or beyond the boundary of a sociotechnical system entity.

From Figure 19 it is noted that the quality of the HEA will depend on the analyst's ability to identify all the requirements of the task (activity or process), sub-tasks (operations) and actions (plans and procedures). Without a formal procedure it may be difficult to identify and assess all specific operator performance requirements. The use of a HTA as precursor for the HEA reflects how important it is that the task objectives, sub-objectives and action objectives are specified according to performance requirement standard(s). As in failure analysis, however, the human behaviour also comes with natural variability that could make operator performance difficult to measure and assess accurately. It may therefore be necessary in practice to rely on several measurements, some of which may be indirect or proxies, for the purpose of monitoring for trends in operator performances. Therefore, as additional guidance to definitions in Table 8, the DPRA proposes the use of similar concepts related to operator performances as in failure analysis (Rausand and Øien, 1996), which are illustrated in Figure 20.

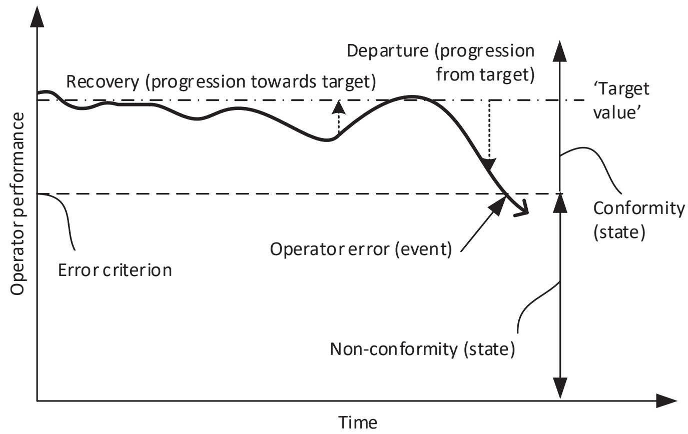

Figure 20. Illustration of DPRA concepts operator error, non-conformity and departure.

Hence, a performance requirement standard in DPRA indicated for each action in Figure 19 is assumed to include a target value with an acceptable measurable margin for departure before an operator error is identified. The given definition of departure implies an error recovery noticed as a decreasing (positive) trend in the observed departure seen in Figure 20. For example, in a kick simulator training scenario an operator error criterion may be defined as; 'The driller (with aid of his crew) is to activate the BOP within 30 minutes after the simulated well kick occurs.' For example, this criterion could be further described as is illustrated in Figure 20 with an empirical based target value of 20 minutes.

Further, in traditional WBE failure analysis such as failure mode, effects and criticality analysis we may consider CO_2-corrosion as one failure mechanism, among others, as an important checklist item for analysis. The descriptions 'latent human error tendency' or 'adverse physiological/physical or mental factor' may be used in order to describe a similar concept in HEA. Figure 21 shows lower level operator error 'mechanisms' described as individual or workplace type performance influences in DPRA on the lowest action breakdown level. The factors listed in Figure 21 are not necessarily disjoint. For example, biomechanical limits are closely linked to workplace factors in control room ergonomic checklists provided by Johnsen et al. (2011). The terminology used in Figure 21 is largely described as part of the Table 11 checklist in DPRA, and with additional source material referenced in (Strand et al., 2016).

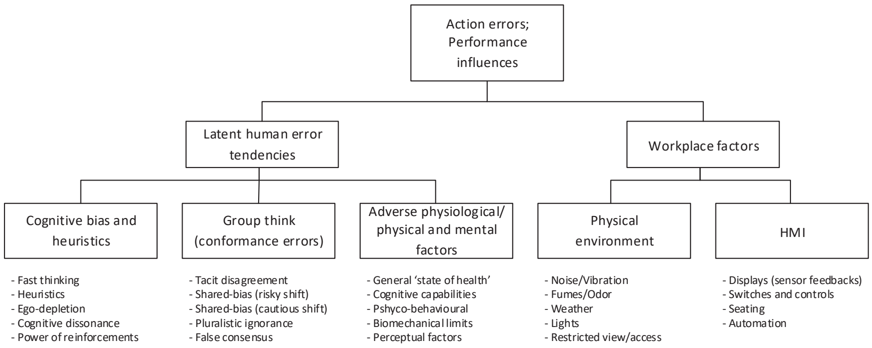

Figure 21. Lowest level operator action error causal classification in DPRA

The task breakdown in Figure 19 may have implications for cause and effect considerations similar to that typically noticed between error modes and error causes in Table 8. Figure 22 illustrates the example task with such relationships between the breakdown levels and the key operator error concepts in DPRA; (i) Performance influences, (ii) error causes, (iii) error modes and (iv) error effects. Also indicated in Figure 22 are different social or individual elements relevant to HEA in DPRA given at different breakdown levels. For example, it is important to note that the HRA causal model in DPRA is primarily based on sociotechnical system theory, where information is located in results produced at the operation and task level in Figure 22.

As for basic concepts of failure analysis, Figure 22 includes relevant associations made at the three different levels deduced from simultaneous operations requirements given for an offshore installation as an organisational process influenced by authorities, competitors, and top executives on a 'sociotechnical level'. The example shows how such requirements may migrate downwards to influence the situational elements inside the driller's cabin and therefore the performance of actions of the driller on a 'physical/physiological and psychological level'. The example naturally shows that typical performance influences on an individual level also affect requirements and processes established by management individuals at higher levels in the company.

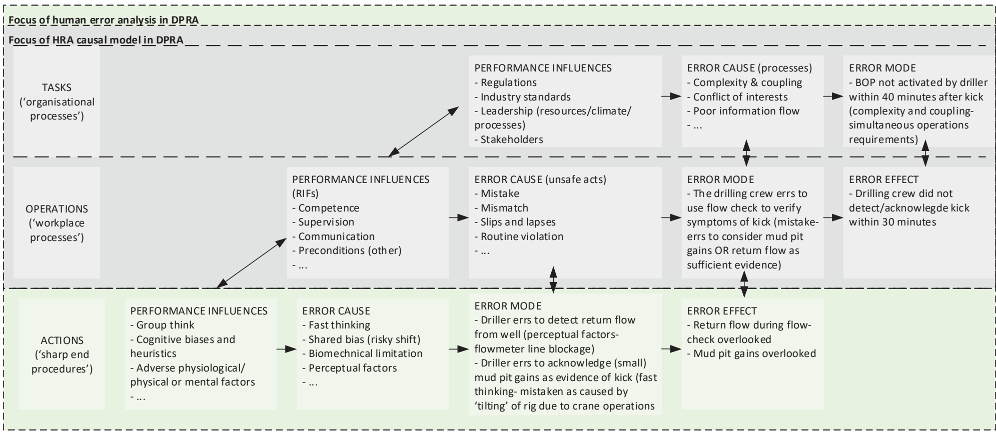

Figure 22. The hierarchial classification scheme for operator errors in DPRA

HRA Step 3.4: Establish causal model

The DPRA makes use of a predefined set of RIFs structured in BBN causal model for the OEP calculations. A RIF is broadly defined in Risk OMT as "an aspect of a system or an activity that affects the risk level of this system/activity" (Vinnem et al., 2012). A RIF may represent isolated events or an enduring workplace condition such as HMI and weather, which affects the occurrence of hazardous events and operator errors coupled to safety function performance of WBEs. The RIFs are sought to be defined orthogonally and evaluated in HRA without 'overlaps'. The evaluation of RIFs may become challenging, for instance, as a result of complex structural relationships that may exist between mutually dependent RIFs defined at different organisational levels in a HRA causal model. The definition and evaluation of RIFs is therefore carefully considered in DPRA development. A RIF should not be directly associated with operator error in DPRA. RIFs in DPRA are described as workplace factors that combines with latent human error tendencies and create work situations prone to operator error.

The two barrier rule is well aligned with the Swiss cheese energy-defence model introduced by Reason (1990), Reason (1997), which has been adopted as basis for the causal models in Risk OMT and DPRA. The energy-defence model is illustrated in Figure 23 to visually link HOFs to breaches of the human, organisational and technical defences put in place to prevent major accidents from occurring.

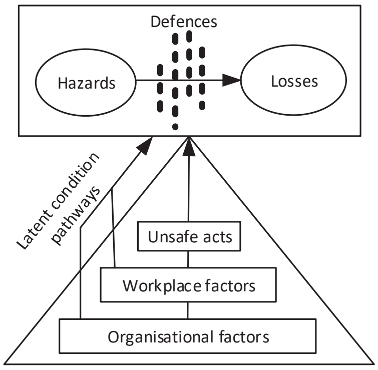

Figure 23. Causal model of organizational accidents adapted from (Reason, 1997)

Two paths leading to loss of defences and accidents are described in Figure 23 driven, according to Reason, by a constant tug from trade-offs in the organisation between production and protection. The first pathway is shown in Figure 23 as a direct result of workplace or organisational factors. The factors affect the potential alignment of the weaknesses (holes) in the defences, which could result in complete penetration and an accident. The weaknesses will inevitably exist due to technical constraints or human fallibility. The second pathway that affects the alignment of the holes is described as an indirect result of workplace factors. The organisational factors first affect the workplace conditions that again become the source for active failures, undesired human action or inaction, denoted as unsafe acts in the sharp end.

As result, RIFs may be defined on different levels based on the energy-defence model. For example, the HMI naturally represents a RIF defined around unsafe acts that may occur in the sharp end of the workplace, similar to the physical working environment. The mechanisms by which organisational and workplace factors affect the pathway conditions are not clear in the sociotechnical literature on which it is based (Rosness et al., 2010). For example, Rosness et al. (2010) provide a summary of the major organisational accident perspectives in the literature that has been considered in the development of the Table 11 checklist part of DPRA. The perspectives are categorised and described by a different accident causation focus respectively on; (i) energy and defences (barriers), (ii) complexity and coupling in HMI, (iii) competence and co-operation, (iv) poor information flow, (v) conflicts of interest, and (vi) successful adaptations. The perspectives are seen denoted as error causes on a task level in Figure 22.

The Risk OMT method adapted in DPRA suggests modelling of ‘defence failures’ only via path of unsafe acts. Risk OMT also uses a compact causality classification of unsafe acts as operator errors to be used in the evaluation of the RIF influences as seen presented in Figure 24. The classifications are seen denoted as error causes at an operation level in Figure 22.

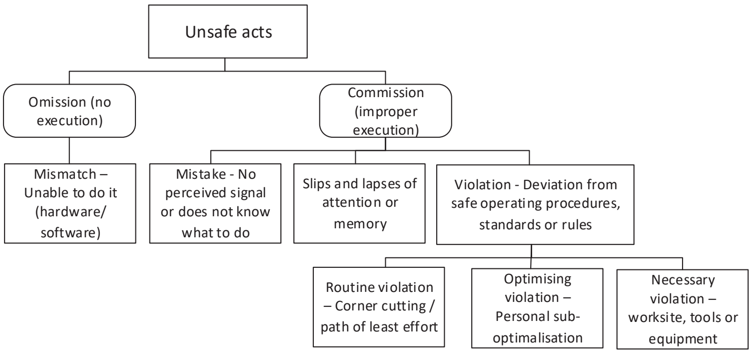

Figure 24. Classification of unsafe acts in DPRA based on (Reason, 1997, Vinnem et al., 2012)

Figure 24 describes unsafe acts as either an omission or commission type. The omission type acts describe a typical situation where an operator may do nothing in response to a critical situation due to lack of the physical means needed, hardware or software mismatch (Kletz, 2001). The commission acts are described in two parts. One part as inadvertent mistakes or 'slips and lapses' due to human fallibility, for instance, related to lack of training or our limited capacity for information processing (Miller, 1994). The second part is denoted as violations since this class represents a breach of the formally established safe operating practices. A violation may be obvious and deliberate, or inadvertent as result of human fallibility or poor workplace ergonomics. The violations may be categorised as either routine, optimising or necessary, respectively in Figure 24.

The basic Risk OMT causal model is illustrated in Figure 25 with operator error causes described by the four basic errors structured logically for an action in a regular fault tree, and where execution errors are modelled in more detail by RIFs structured in a BBN inference model. An example with an extracted yellow operational level 1 RIF (RIF^{I}) and pink organisational level 2 RIF (RIF^{II}) from the BBN structure is also shown in Figure 26. Only the operational level 1 RIF^{I}s are seen to influence the OEPs directly.

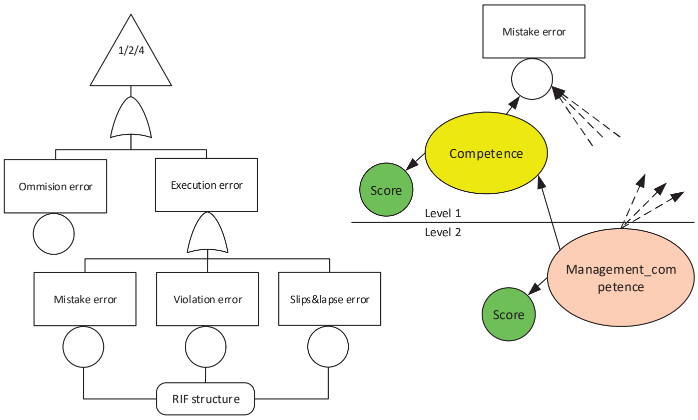

Figure 25. The causal model for assessment of human error probability with extract of the associated two level RIF structure (Vinnem et al., 2012)

Two generic RIF structures are described in Risk OMT to study gas leakage scenarios, respectively for 'planning' and 'execution and control' of offshore process maintenance activities. According to the accident scenario discussed (Vinnem et al., 2012, Gran et al., 2012) it is reasonable to describe omission errors without a RIF structure as shown in Figure 25. This can also be argued an acceptable assumption in drilling operation HRA, since execution errors appear as the dominant cause from accident reviews (Strand and Lundteigen, 2017).

The RIF structure defined in DPRA is illustrated in Figure 26, which includes a total of seven child RIF^{I}s identified out of the twelve generic RIFs defined in Risk OMT for execution and control activities. The seven RIF^{I}s are structurally connected with five parent RIF^{II}s according to Risk OMT. The RIF^{I}s specifically identified for DPRA are based on well accident reviews (Strand and Lundteigen, 2017) and on analysis of empirical data collected in SINTEF interviews with drilling crews working offshore Norway (SINTEF, 2014, Strand and Lundteigen, 2016). The bold arrows shown in Figure 26 indicate modifications made in DPRA to the generic RIF structure in Risk OMT, which are described in the next section.

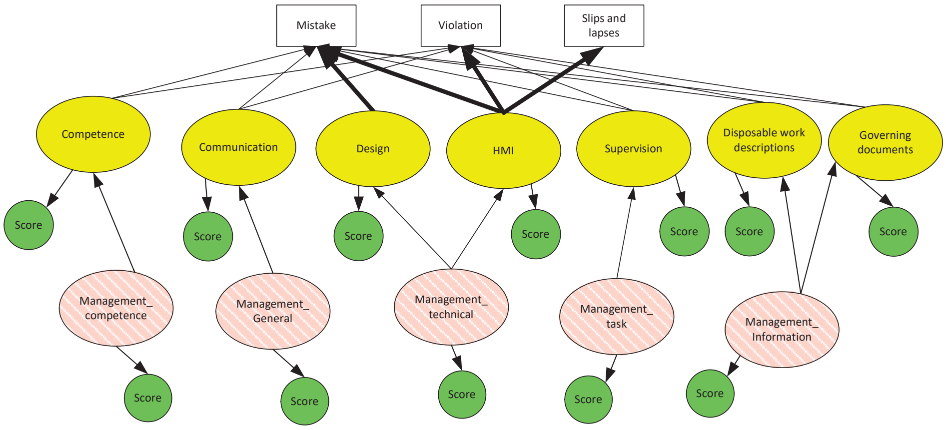

Figure 26. The BBN causal model defined for HRA in DPRA adapted from Vinnem et al. (2012)

HRA step 3.4 (cont'd): On the specific role of HMI as RIF in DPRA

This section describes the modifications that has been made to the generic RIF structure in Risk OMT for purpose of DPRA. The modifications are documented in Paper 2, which further clarifies the role and corroborate the importance of the HMI in DPRA. The modifications are a result of a review of four recent well drilling and workover blowouts, which assesses the degree that the accident causality reveal the HMI as a contributing factor. The focus is placed on the well control HMI functionality in the sharp end, i.e. its ability to assist the crew on the rig floor to maintain their estimates and understanding of the wellbore in-situ flowrates and pressures. These are the two physical properties in a wellbore considered vital for detection of fluid gain or fluid loss, which are both strong symptoms of a situation that if left unattended by the crew could enable the tendency for progression of the activity into a situation of multiple well barrier failures and harm.

The accidents selected for the review included; Snorre (2004), Montara (2009), Macondo (2010), and Gullfaks (2010) with publicly available source material (PSA, 2004, The Deepwater Horizon Study Group, 2011, PTTEP, 2009, SEADRILL, 2009). The accidents are all recent blowouts that involve modern technology and practices, and which were considered sufficiently documented in the public domain for purpose of the reviews. This included documentation about the well operation sequence of events that led to the blowout, and where the following information has been made available; (i) the well barriers in place and their functional status; (ii) the well system in-situ fluid sub-volumes and their pressure gradient situations; and (iii) the HMI functionality in support of tasks on the rig floor that help crew maintain their estimates of in-situ wellbore flowrates and pressures.

The accident reviews have been documented in worksheets, structured as a sequence of event based situation analysis of the accident operation. The worksheet includes columns with specific source information and discussions, which are defined from specific analysis criteria identified for the purpose of the review objectives. The relationship between the analysis critiera and the documentation provided in the worksheets is illustrated in Figure 27.

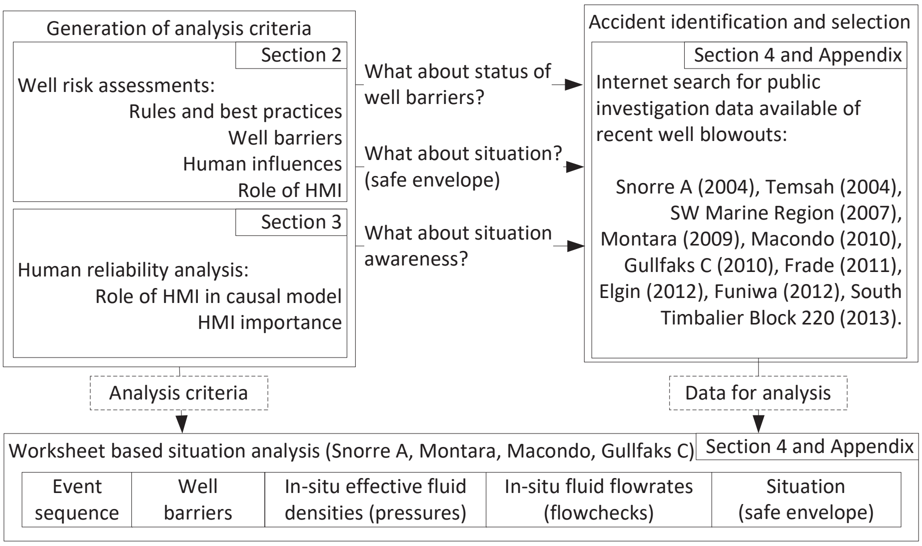

Figure 27. Illustration of the accident review process defined in Paper 2 (Strand and Lundteigen, 2017)

The generation of the accident analysis criteria has been deduced from two perspectives in Figure 27; First, the analysis criteria was generated from a well risk assessment perspective, which included description of the well barriers, tasks and safety considerations made by the crews involved in drilling and workover operations (Chapter 2 and Chapter 3). The concept of the safe envelope suggested by Hale et al. (2007) was adopted to describe the potential progression of a well operation towards loss of well control, as well as means of recovery. Secondly, analysis criteria was generated from Risk OMT method perspective, and the discussion about the HMI role in the HRA causal model was linked to key drilling tasks and situational elements on rig floor by adopting the concept of situation awareness (Endsley, 1995).

Conclusions from accident reviews

As expected, all the four accidents supported the HMI as an important factor for the successful completion of well drilling and workover operations, among others, as an aid for monitoring the wellbore in-situ flowrates and pressures. More specific to the role of HMI in accident causality and HRA, the following main conclusion were considered reasonable:

In three out of the four accidents reviewed, a limited or non-existent pressure and flowrate monitoring capability on rig floor likely contributes significantly to the unnoticed development of a diffuse multigradient fluid regime within the different sub-volumes of the well. This diffuse pressure situation is likely to have become a source if uncertainty and confusion topsides and consequently an important contributing factor related to mistakes, violations and attention losses that occured in event sequences. In addition, unsafe acts helped contribute to a catastrophic failure of the mud barrier in the well. By catastrophic failure, it is meant here that the failure of the mud barrier occurs in a manner that makes cascading failure of conditional WBEs likely due to higher well kick stresses. The higher stresses may be described as a result of a situation where more energy from the reservoir has entered the wellbore at the time of well kick detection.

The single focus of HMI in the generic RIF structure on mistake type errors in the Risk OMT causal model, therefore, could result in that key aspects of the HMI as risk factor systematically are overlooked in application of the HRA method. As result from the accident reviews, the following modifications to structure have been made in DPRA shown on right hand side in Figure 28, to the generic Risk OMT structure shown on the left hand side.

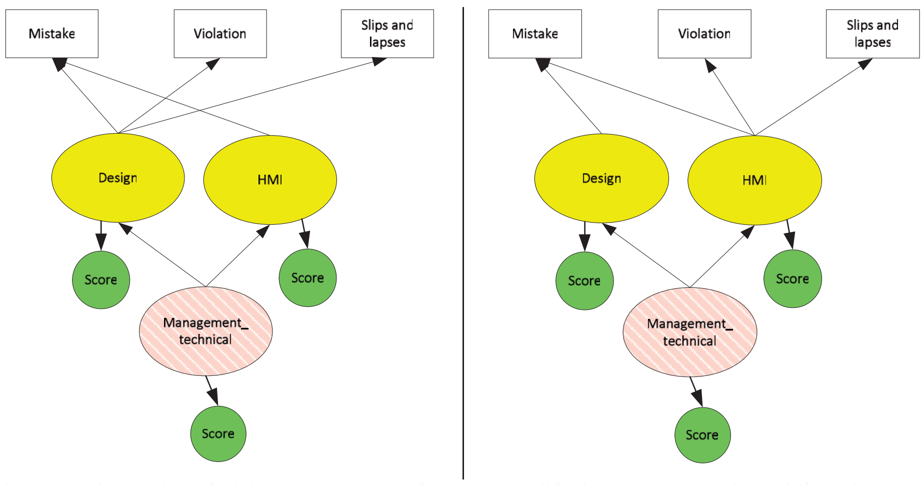

Figure 28. Illustration of Risk OMT generic (left) versus modified RIF structure (right) defined in DPRA

It can be seen from Figure 28 that the modifications represent a swap of structural dependencies between the Design and the HMI as level 1 RIFs in the structure. Design can be defined as (Vinnem et al., 2012); “Accessibility and physical working environment with relevance for correct performance of a work specific operation.” As such, the modifications represent a shift of the focus in sharp end of HRA from the ‘passive’ surface physical working environment, over to the active HMI and dynamic downhole well conditions being linked to all types of execution errors. Making changes to the RIF structure could cause a state explosion and introduce computational issues. The modifications suggested to the structure, therefore, have been made so as not to impact the computational benefits previously demonstrated with the generic structure (Vinnem et al., 2012, Gran et al., 2012).

In addition, the following amendments have been made to the importance of the HMI as a checklist item provided in HRA method (Strand and Lundteigen, 2016, Table 1): (i) Important to carefully consider implications of not having a work-string that allows for fluid gradient displacements and recovery in a wellbore that penetrates a reservoir. (ii) Important to carefully consider implications of not having a closed fluid handling system in cases where mud displacements take place in a wellbore that penetrates a reservoir. (iii) Important to monitor the fluid gradient/pressure situation in sub-volumes of a well system. As such, important to carefully consider potential implications if sub-volume monitoring is lost during an operation.

It is noted in terms of HMI evaluation in DPRA that it may appear from the accident reviews that the HMI is more directly involved in mistakes and violations that could occur, whereas slips and lapses (attention losses) seem more as an implication of mistakes and violations made previously in event sequences. For example, as a result of decision to reduce HMI functionality in a well.

HRA step 3.5: Evaluate RIFs and calculate OEPs

This section describes the calculation of OEPs in DPRA, which is sourced from Risk OMT, Paper 2 and Paper 3.

The BBN nodes in Figure 26 are modelled in BBN software as labelled nodes with six states. The bold arrows in Figure 26 indicate modifications made to the generic RIF structure introduced for execution and control activities by Vinnem et al. (2012), which are discussed in previous section. The basic event type error nodes are Boolean states as binary failed (1) or not failed (0) according the structure of the fault and event tree model established. The scores and RIFs are measured subjectively on the scale from A through F, where A represents best industry practice and F represent an unacceptable value. The value C is used to represent the industry average. The scoring system of the RIFs in Risk OMT is based on previous work by Sklet et al. (2010), which included interview rounds and a questionnaire survey that focused on work practices during manual interventions in the process system.

The full BBN model requires a huge number of conditional probability tables to be specified and populated. A simplified calculation method as alternative to the full BBN model has been developed as the hybrid approach in Risk OMT. The hybrid approach is based on BBN specification of the relation between the RIFs, but uses traditional processing of the fault and event trees assuming independence between basic events. The hybrid approach may therefore be considered as an optimistic modelling alternative to the full BBN model implementation. The detailed HRA method description enclosed as Paper 3 in Appendix IV is based around the hybrid approach (Vinnem et al., 2012, Strand and Lundteigen, 2016).

The hybrid approach may be considered more transparent to stakeholders for purpose of DPRA quality assurance in line with Table 1, and does not require any experience in the use of commercial softwa re's as with the full BBN model implementation. In the hybrid approach the RIF character scores, A through F, are by pragmatic conversion made into numerical intervals that allow the use of the normalised Beta distribution to describe the RIF uncertainty. The character scores are mapped into the centre of the intervals, for instance, an A becomes 1/12, a B becomes 3/12, a C becomes 5/12 and so forth. The term score is used formally to denote the summarised information available regarding the true RIF value, *r*, for instance, collected in interviews or from surveys. In the hybrid approach the score, *s*, is given together with an assessed variance to describe parameters of a Binomial distribution used to update the RIF conjugate prior Beta distribution. The Bayesian updating thus assumes that we pragmatically; (i) Can interpret true RIF value, *r*, as a probability, and (ii) have observations in the format of 'trials and successes'. This is to say that the information value of our observations should be the same as if we had data on trials and successes.

The influence of $\mathrm{RIF}^{\mathrm{I}}$ on operator error basic event probabilities is modelled as a function dependent on the weighted $\mathrm{RIF}^{\mathrm{I}}$ sum. For instance, with a total of *J* $\mathrm{RIF}^{\mathrm{I}}$s influencing basic event *k*. Let $\mathbf{R}^{\mathbf{I}}$=[R_1^I, R_2^I,..., R_J^I] be a vector of random variables that represent these (normalised) $\mathrm{RIF}^{\mathrm{I}}$s, and let $p_R(\mathbf{r}^{\mathrm{I}})$=Pr($R_1^I = r_1^I, R_2^I = r_2^I, \ldots, R_J^I = r_J^I$) be the joint probability distribution over *J* $\mathrm{RIF}^{\mathrm{I}}$s. Let w_j be the normalised weight of $\mathrm{RIF}_j^{\mathrm{I}}$. As a first approximation given for independent basic event probabilities the total updated impacts of the $\mathrm{RIF}^{\mathrm{I}}$ s is exemplified in the hybrid approach by;

$$q_k = \Pr(\text{Failure of basic event k}) \approx \sum_{\forall \mathbf{r}^I} [q_k(\sum_j w_j r_j^I)] p_R(\mathbf{r}^{\mathrm{I}}) \qquad \text{(Equation 10)}$$

An exponential function is proposed in the hybrid approach to associate basic event probabilities and $\mathrm{RIF}^{\mathrm{I}}$s as an alternative, for instance, to the use of expected $\mathrm{RIF}^{\mathrm{I}}$ posterior values. The calculation procedure of the hybrid approach is described in detail by Strand and Lundteigen (2016).

The accident reviews and interview data used as basis for level 1 RIFs identified in the HRA method suggest that it may be difficult to treat the RIFs orthogonally for purpose of HRA and in line with Table 1. For example, $\mathrm{RIF}^{\mathrm{I}}$ competence can be viewed closely linked to both communication and supervision in a team-based and competence intensive rig floor work setting. Therefore, the $\mathrm{RIF}^{\mathrm{I}}$s defined in DPRA are adopted with a set of evaluation (realisation) criteria presented in Table 9. In addition, two checklists presented in Table 10 and Table 11 are developed in DPRA to help assessors consistently address the evaluation criteria (Strand and Lundteigen, 2016, Table 1 and Table 2). The evaluation criteria are given in Table 9 with normalised weights, w_c, that are used to determine $\mathrm{RIF}^{\mathrm{I}}$ score and variance inputs. For the scoring it suggested that the operator or service provider in charge of HRA to take advantage of independent peers and review teams involved in well drilling operations. The RIF^{I}s scoring is therefore suggested to be assessed independently by several peers providing a separate evaluation score, s_c, for each criteria. The score is given on the same scale as the RIF, and the resulting RIF^I score, s, can be calculated as; $s = \sum_{w_c \subset RIF^I} w_c \cdot s_c$. Moreover, based on the 'wisdom of the crowd' an average RIF^I score and variance can be calculated, $\bar{s}$ and $\widehat{\mathrm{Var}(S)}$, as score observations that represent the true RIF^I values.

Table 9. Level 1 RIFs with evaluation criteria used in HRA method part of DPRA

RIF	RIF evaluation criteria	Proposed weight, w_c
Competence	1. Skills & interests (talent)	0.10
	2. Knowledge & education (theory)	0.20
	3. Experience & training (practice)	0.50
	4. Motivation, attitude & attention (incentive)	0.20
Communication	1. Communication within shifts	0.40
	2. Communication between shifts (hand-overs)	0.30
	3. Communication with other rig personnel	0.20
	4. Communication with remote support staff	0.10
Design	1. Workplace related – tight couplings	0.40
	2. Workplace related – complex interactions	0.40
	3. Human related	0.20
HMI	1. Ability to help interpret in-situ wellbore flowrates	0.30
	2. Ability to help interpret in-situ pressures along the wellbore	0.30
	3. Ability to initiate and provide feedback on successful BOP activation and closure	0.10
	4. Ability to locate tool-joints in the work string	0.10
	5. Ability to help diagnose and identify the root cause of well barrier failures for purpose of well barrier restoration,	0.10
	6. Ability to help interpret effects from changes made to well drilling parameters, also described as the performance of actions (Endsley, 1995)	0.10
Supervision	1. Supervision (driller)	0.40
	2. Supervision (tool pusher)	0.30
	3. Supervision (drilling supervisor)	0.20
	5. Supervision (offshore installation manager)	0.10
Disposable work descriptions	1. Drilling program	0.50
	2. Program changes	0.50
Governing documents	1. Well construction/delivery process documents	0.50
	2. Technical documentation (handbooks and manuals)	0.30
	3. Safety/Quality audits	0.20
Management_competence Management_information Management_technical Management_task	Description of all level 2 RIFs with input data described in Risk OMT project (Vinnem et al., 2012, Gran et al., 2012)	

Table 10. Checklist for TA and evaluation of RIFs from a workplace perspective in DPRA based on (Strand and Lundteigen, 2017, Strand and Lundteigen, 2016)

RIF	Notes from well accident reviews and from interview rounds with drilling personnel

Table 10. Checklist for TA and evaluation of RIFs from a workplace perspective in DPRA based on (Strand and Lundteigen, 2017, Strand and Lundteigen, 2016)

Competence	Important to always make projections by responsible parties of how the operations may develop in the future on their part. For instance, described by an example where a service company is given authority by well engineer to oversee a well completion operation, but where the driller (rig company) halts the operation after some time since he or she is not feeling sufficiently informed about the operation. Many meetings are held to help distribute and discuss the status and future of ongoing operations. Pre-job meetings, stop-job meetings, handover meetings, toolbox meetings, briefings, lessons learned records, and training programs are considered important arenas for competence development. Important with an explicit focus on 'safety first' versus 'production' in training and team building. Avoid person-to-person training of personnel as bad work practices more easily then may become passed on. Important with hands-on training so that practical skills developed can be demonstrated rather than, for instance, taking internet courses. Individual observations and behaviour is important in order to detect potential dangerous situations. Operator and rig company emphasise importance of training, for instance, in weather observations and radio communication. Need flexible teams that help each other out but that also are recognised by, for instance, (i) the smooth and natural transition from team based work into a command and control situation within few seconds, (ii) degree of improvisation, for instance, in relation to unexpected equipment failures that typically give transition from automatic to manual controls. Prepare for contingencies, for instance, make well kill sheet available in driller's cabin before start of operations. This also includes to establish the physical pre-conditions and associations that calls for a time-out (stop) in operations – 'when in doubt there should be no doubt what to do' Important to always check for lack in training when new equipment and procedures are introduced. This should include practical demonstrations of the level of understanding.
Disposable work descriptions	Operations that are well planned, for example, operations where problems that arise are swiftly solved and where consequences are known in advance, and where people are well prepared and where work routines are well established and recognised. Work procedures that strengthen focus on multidisciplinary efforts (team work). Important that plans are timely received offshore since this helps to avoid situations where problems and delays later in operations are viewed more prone to occur. A rule of thumb offshore expressed is to always allow one week planning ahead of operations Always follow the plans, herein importantly the procedures including practices and the revisions of same Important to include simple (clear) safe operation envelopes, for instance, maximum allowable annulus surface pressures.
Governing documents	Important to have documents that are regularly updated – 'proves that they are being used'.

Table 10. Checklist for TA and evaluation of RIFs from a workplace perspective in DPRA based on (Strand and Lundteigen, 2017, Strand and Lundteigen, 2016)

	Important to have thorough and well written procedures recognised by; (i) not too voluminous and impractical, (ii) anchored in best practices, (iii) executing party understands the background for the procedure design. Important to have good routines for reporting of undesired events
Design	Important to have equipment that functions well.
HMI	Important that the BOP maintenance- and test procedures are followed with necessary quality- assurance and control support from onshore. Modern drilling with bottom-hole tools transmitting data to surface is considered a significant improvement from the 'old days'. Important to get information about failed and weakened well barriers. Important to carefully consider implications of not having work-string that allows for fluid displacements and recovery in a wellbore that penetrates a reservoir. Important to carefully consider implications of not having a closed fluid handling system in cases where mud displacements take place in a wellbore that penetrates a reservoir. Important to monitor the fluid gradient/pressure situation in all sub-volumes of a well system. As such, important to carefully consider potential implications if sub-volume monitoring is lost during an operation.
Communication	Workplace that is noticed by (i) positive attitudes towards questions and concerns raised about observations made in the activities, (ii) allows that operations are stopped if any concerns, (iii) openness towards delays and mistakes made so that they, for instance, do not come unexpectedly back to 'haunt you' later in the operation, (iv) meetings that are well structured and not seemingly carried out with any rush, (v) work processes followed encompass different levels in organisation hierarchies as well as across different disciplines and service providers - 'everybody communicates with everybody'. Important to develop team work as the natural working environment, for instance, that personnel are well acquainted with respect and support of each-others work responsibilities and opinions - 'all are pulling together in the same direction'. Efficient information flow, for instance, between driller and the drilling supervisor and offshore installation manager in a kick situation so that potential supporting staff can be made alert onshore/offshore.
Supervision	Important with close supervision that is supported by quality written work procedures, control- and reporting routines. Important with presence of management, for instance the drilling supervisor/superintendent, on the rig floor to 'ask questions'. Viewed important to be allowed to deal- and finish with one problem at the time.

Table 11. Checklist for TA and evaluation of RIFs from a latent human error tendency perspective in DPRA (Strand and Lundteigen, 2016)

Error tendency	Error modes	Examples of error causes
Group think	Tacit disagreement	Group pressure not to 'rock the boat'

Table 11. Checklist for TA and evaluation of RIFs from a latent human error tendency perspective in DPRA (Strand and Lundteigen, 2016)

(conformance error)	Shared bias - risky shift	Higher risks accepted by group than of any of its members
	Shared bias - cautious shift	Lower risks accepted by group than of any of its members
	False consensus	False belief of joint agreement in a decision made by the group
	Pluralistic ignorance	Silence from false belief of a member that he or she is the only individual with different opinion
Cognitive biases, and heuristics	Fast thinking. /Narrow minded. Emotional and short-term. Subjective interpretation of the risk picture. /Loss aversive. Favour value of certainty and familiarity over uncertainty and 'what if's' with effort to reconsider. /Too optimistic and over-confident. Ignorance or misconception of the risk picture.	Over-confidence in existing processes, estimates or plans - 'the rules mostly work' Only accepting confirmatory evidence of own position and ignoring the contradictory – 'you find what you look for' Only consider data and options that are readily observable – 'what you see is all there is' Anchoring or tendency towards simplifications of questions, conservatism and use of previous experiences - 'the path of least effort' / 'the man with the hammer syndrome'
	Heuristics	The illusions of causality. Thinking in causal series, typically when faced with falsely perceived regularities, fast and linear with little mental effort and jumping to conclusions, rather than in causal nets, which is slow and recursive with mental effort. - 'avoid extreme repetition of tasks'
	Ego-depletion	Multiple work tasks or disruptions that causes loss of required attention to perform task. Lack of mental rest or glucose (nutrition)
	Cognitive dissonance	The mental discomfort humans get from having conflicting ideas or opinions at the same time. For instance, human ignorance of the opinions of 'enemies' and blindness to own or respected friends and colleagues' flaws and faults - 'the truth is too hard to bear'/ 'the halo effect'
	Power of reinforcements	Incentive- or associative biases - 'the Pavlovian bell'
Tight couplings (active)	Omission	Negative synergies wherein combined effects of equipment, design and human error is greatly amplified, for instance, a situation escalating rapidly against intention as a result of missing human action ('need to push the right button')
	Commission	Negative synergies wherein combined effects of equipment, design and human error is greatly amplified, for instance, a situation escalating rapidly against intention as a results of inappropriate actions such as inadvertent use of controls or manual override of safety instrumented functions to avoid substantial losses
Complex interactions (active)	Omission / Commission	False interpretation of system feedbacks, or the signals are not there, or too weak to be noticed, processed and acted correctly upon. Multiple tasks at same time or disruptions and stress that give attention loss. High noise to signal ratio. Hash

Table 11. Checklist for TA and evaluation of RIFs from a latent human error tendency perspective in DPRA (Strand and Lundteigen, 2016)

		physical work environment. High workload. High degree of repetition in work tasks. Technical interfaces inadequate in relation to operator's ability to maintain situation awareness and control Operation plans not suited competence level of executing personnel. Remoteness combined with lack of involvement and training. Levers and buttons and other controls not accessible or badly labelled. 'If many operators mistake an interface then the design of that interface is flawed'.
Organisational (latent)	Violation (necessary)	Inappropriate actions due to shortcomings of the work site, tools, and equipment
	Violation (optimising)	Inappropriate actions due to the attempt to realise unofficial goals as a part of the activity performed
	Violation (routine)	Inappropriate actions due to corner-cutting and shortcuts
	Work process	Reliance on operators to maintain safe system state (workplace design) No learning, change in behaviour (work processes), from previous near-misses or accidents. Acceptance and dismissal of recurring issues as a 'new normality' Accessibility, simplicity and clarity of wording of instructions. Operator training schemes only made from design based accidents Fragmented and monolithic organisations that include elevated technical and bureaucratic walls that subdue co-operation and information exchange, and lead to isolated decision making, such as for instance, disputes in organisation about project authority and funding. Information exchange in organisation is compromised, for instance, recognised by; (i) Under-reporting by management of safety violations by front-end personnel. (ii) A tired and unmotivated workforce that fails to follow procedures and report safety issues. (iii) Ambiguous design of procedures that makes it possible to evade or overlook them entirely. (iv) Strain introduced by an unwieldy problem tracking system. For example taxonomy problems that hinder project parties to share data, and a system that houses a vast number of critical issues. (v) Multiple personnel roles, which are poorly defined and even in conflict with human nature such as for instance an individual put in charge of quality assurance of own work. (vi) Reluctance and failure of the organisation to implement and adopt risk reducing measures.
	Enforcement biases	Bias explained by politics and apparent predisposition involved in enforcement (Perrow, 2011). For example;

Table 11. Checklist for TA and evaluation of RIFs from a latent human error tendency perspective in DPRA (Strand and Lundteigen, 2016)

	(i) when safety audits do not consider disclosure of covert activities or relevant historic accidents or near-misses, (ii) system goals are incompatible with safety goals, (iii) workplace where human error not is explicitly taught, spoken of, and recognised as naturally occurring.

*) Violation means deviation from recognised safe operating procedures, standards or rules.

OEP calculation case example

This section includes a case example of evaluations of the HMI as RIF in OEP calculations in the DPRA approach. The case example is simplified and built around the HMI as a key RIF, which also enables reuse of the detailed accident reviews presented in Paper 2. As such, these reviews represents comparative cases assessed by HEA in DPRA method discussed in previous sections. The evaluation of the score are made subjectively by the author as representative based on 'average functionality' of HMI available in the course of the accident event sequences and are presented in Table 12. The scores are given with a range to indicate input from several peers in scoring process as described in DPRA. Though comparable situations are noticed in accident data, floating rigs are is generally given with slightly worse scores and with larger variation in comparison to fixed rigs to reflect remoteness and added complexity of HMI.

Table 12. Examples of evaluations made of HMI from accident event sequences based on (Strand and Lundteigen, 2017)

Evaluation criteria (Table 9)	Weight w_c	Example scores based on accident reviews			
		Snorre	Montara	Macondo	Gullfaks
1. Ability to help interpret in-situ wellbore flowrates	0.30	C-E	E-F	C-F	A-B
2. Ability to help interpret in-situ pressures along the wellbore	0.30	C-E	E-F	C-E	A-B
3. Ability to initiate and provide feedback on successful BOP activation and closure	0.10	A-B	E-F	B-C	A-B
4. Ability to locate tool-joints in the work string	0.10	A-B	A-B	B-D	A-B
5. Ability to help diagnose and identify the root cause of well barrier failures for purpose of well barrier restoration	0.10	C-E	E-F	C-E	A-B
6. Ability to help interpret effects from changes made to well drilling parameters, described as the performance of actions	0.10	C-E	E-F	C-F	A-B

As example, to illustrate in more detail from the Snorre case, five random peer values are generated from the score ranges shown in Table 13. The results from this exercise are presented in Table 14, where the 'wisdom of the crowd' is seen for the Snorre example to produce a HMI score, $s \approx \bar{s} = 0.51$, which represents a score between C and D in BBN modelling, given with $V_s \approx \widehat{\mathrm{Var}}(S) = 0.06^2$.

Table 13. Example Snorre case using 'the wisdom of the crowd' peer observations for RIF^I scoring

Evaluation criteria	Range	w_c	Example results from peer RIF scoring, s_c Peer1	Peer2	Peer3	Peer4	Peer5
1	C-E	0.3	0.75	0.42	0.58	0.58	0.75
2	C-E	0.3	0.58	0.42	0.58	0.42	0.75
3	A-B	0.1	0.25	0.08	0.08	0.25	0.08
4	A-B	0.1	0.08	0.25	0.25	0.08	0.25
5	C-E	0.1	0.42	0.75	0.75	0.58	0.42
6	C-E	0.1	0.42	0.75	0.75	0.58	0.75
	$s = \sum_{w_c \subset RIF^I} w_c \cdot s_c$		0.52	0.43	0.53	0.45	0.60
		$\bar{s}$	0.51 Between C and D ($\approx$ 6/12)				
		$\widehat{\mathrm{Var}}(S)$	0.004 ($\approx 0{,}06^2$)				

If we repeat the exercise presented in Table 13 also for the other well accident cases, we may produce the results as shown in Table 14.

Table 14. Summary of example HMI scoring in DPRA produced based on the well accident cases

Accident case	$\bar{s}$	$\widehat{\mathrm{Var}}(S)$	Note: $\bar{s}$	Note: $\widehat{\mathrm{Var}}(S)$
Snorre	0.51	0.004	Corresponds to D ($\approx$ 7.12/12)	$\approx 0.06^2$
Montara	0.78	0.001	Corresponds E ($\approx$ 9.32/12)	$\approx 0.02^2$
Macondo	0.59	0.006	Corresponds to D ($\approx$ 7.12/12)	$\approx 0.07^2$
Gullfaks	0.15	0.002	Corresponds to A and B ($\approx$ 1.8/12)	$\approx 0.04^2$

Based on the results presented in Table 14, illustration of the OEP calculations considers the modified extract of the causal model shown on right hand side in Figure 28 with following assumptions: (i) Let posterior Beta parameters for the technical management parent RIF and the Design child RIF corresponds to the expectation of C (5/12), and with coefficient of variance as for Jeffreys vague prior. (ii) Assume the child HMI RIF to also have such prior parameters, before updating with observations and the scoring presented in Table 14. (iii) Let RIF weights of 0.1 and 0.9 for 'Design' and 'HMI' respectively, and (iv) assume the following basic event calculation function from the RIF^{I}s in the hybrid approach by;

$$q_k = \Pr(\text{Failure of basic event k}) \approx q_k(\textstyle\sum_j w_j r_j^I) = q_{k,\min}\left(\frac{q_{k,\max}}{q_{k,\min}}\right)^{\sum_j w_j r_j^I} \qquad \text{(Equation 11)}$$

where assumed OEP bounds are the same as proposed for Risk OMT, $q_{k,\min} = 1E-4$ and $q_{k,\max} = 0.50$

Table 15 shows the results produced with a numerical routine implemented for the hybrid OEP calculations of simplified causal model and with assumptions as specified for the case examples. For example, with Gullfaks used as the base case for the HMI functionality evaluated, the calculations are seen to produce about 16 to 90 times higher OEPs for the other the cases.

Table 15. Case example OEP calculations made in DPRA with Risk OMT hybrid approach

Well accident case	q_k	Relative comparison
Snorre	8.84E-03	16
Montara	4.97E-02	88
Macondo	1.61E-02	29
Gullfaks	5.63E-04	Base case

4.4 DPRA Step 4: Determine the PFD for the BOP

This section presents a multiphase Markov method developed for PFD calculations of the BOP safety functions in DPRA. The main idea behind the method is to incorporate the effects on the safety function performance of postponing BOP repairs. As such, it takes into account that departures may be granted by the authorities since BOP stack configurations include redundant BOP elements, for instance, with reference to the typical BOP closure demand scenario denoted 1a, 1b and 2 in Figure 7.

A Markov model could typically allow for detailed modelling of a BOP system, but the number of different states to consider must also be restricted to avoid an undesired state explosion. The multiphase Markov BOP model proposed in DPRA is illustrated in Figure 29. In the model we assume N number of identical redundant BOP rams with safety critical (leakage) failure rate λ_{DU} and a shared common cause failure rate λ_{CCF}. Further, let state 0 represent the BOP in 'as good as new' condition, and let ML denote the maintenance level, which represents the degree of allowable degradation, the number of revealed element failures before the BOP is pulled for perfect repair. I.e. the BOP is assumed to be pulled to surface for overhaul and full renewal if the total number of revealed element failures reaches or exceeds the ML-value. Noted is bounds for the model with ML = 1 that equals a 1ooN:Good system, and ML = N that equals a system that is not repaired until all redundant elements have detected failures.

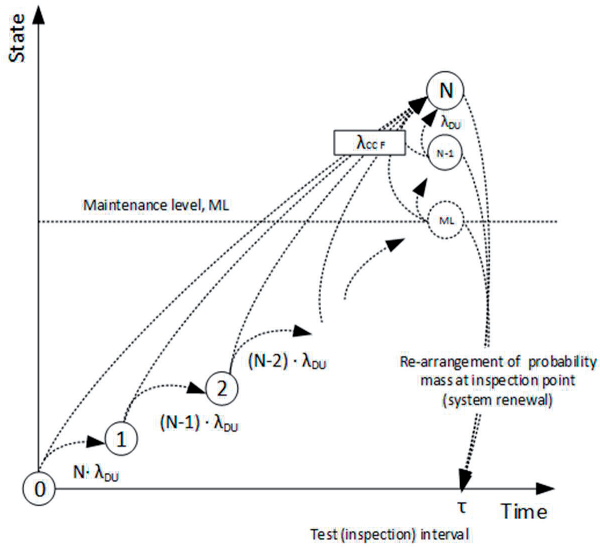

Figure 29. Illustration of multiphase Markov model in DPRA used for PFD calculations of BOP

To avoid a state explosion the Markov model is seen in Figure 29 to be a simple recursive over a BOP test interval. This allows for a relatively simple numerical routine to be implemented to solve over many tests within the total BOP installation period as described by Strand and Lundteigen (2015). Based on the multiphase Markov model in Figure 29 we can directly produce for decision support; (i) Estimates of $q_i(t)$ and thereof the average, PFD. For example, the $q_i(t)$ of 1ooN:G BOP element configuration can be calculated as the probability mass located in state N, $P_N(t)$, and (ii) the probability of having to pull the BOP to surface for renewal at an inspection (test) point τ_i, can be estimated as $\sum_{m=ML}^{N} P_m(\tau_i)$.

An illustration of results produced from method with one set of assumptions over a typical 70 day BOP installation period is shown in Figure 30. The blue columns describe the probability of having to pull the BOP to surface for repair at an inspection (test) point. The red dots and dashed line represent the estimated $q_i(t)$ and PFD, respectively. In addition to specific application in DPRA for event tree node 3 in Figure 17, the PFD results from the method could, for instance, be combined with textbook BOP control system PFD-analysis to verify SIL 2 requirement as recommended by NOGA 070 (2004).

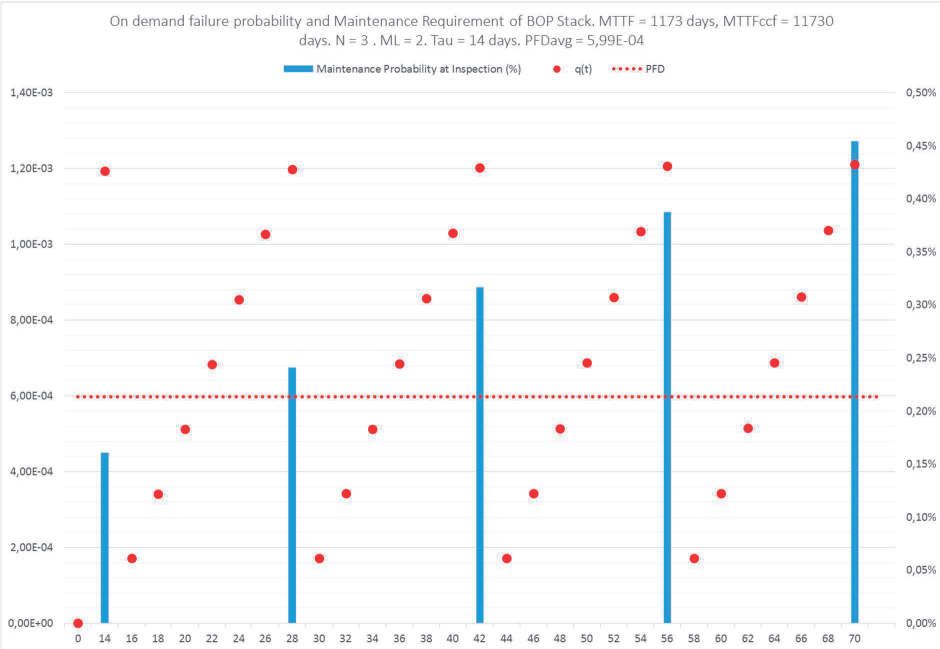

Figure 30. Example of calculated results from model run with the BOP multiphase Markov model

4.5 DPRA approach discussion

The DPRA approach proposed in this thesis builds on, and extends traditional PRA methods used for assessment of oil and gas well leakage risks. This firstly means that the objective has been to determine the frequencies or probabilities of blowouts associated with offshore drilling operations, and secondly that an event tree has been used to model the consequences of well control losses. The DPRA is focused on the risk of surface blowouts caused by initiating events such as a well kick (mud failure), drilling riser failure, or a rig drive-off or drift-off. The new contributions to the 'well PRA toolbox' that come with the DPRA are the ability to: (i) Include more explicitly the effects of human and organisational factors in early detection and response to loss of well control, and (ii) model the main attributes that affects the safety availability of the BOP, which is the key WBE needed for maintaining well control during drilling operations.

The main target groups for the DPRA are the well engineers within operating companies or service providers that are responsible for well operation risk assessments. Typically, the DPRA may be applied by the well engineer to evaluate blowout risks associated with novel and complex drilling operations. This, because it likely represent a relatively complex and resource demanding approach in comparison to the current methods and practices adopted within the drilling and well community. The analysis of technical WBE risk factors in well planning is not new and the implementation of a numerical tool for the BOP safety available analysis may likely be relatively straightforward. The use of detailed HEA and HRA in well risk assessments will, however, likely be new to most well engineers. As such, the implementation of a HRA method may have significant implications to a company in relation to the existing work processes established for the responsible well engineer. This, among others, could include the need for revaluation of personnel competence requirements and organisation of work tasks that includes putting together the risk assessment and peer review teams. Additional specific discussion and evaluation of the two main contributions are provided in the following sections, with focus on using the quality criteria established in Table 1 in Chapter 1.

Discussion and evaluation of inclusion of HRA

To carry out a HRA is a challenging task. A HRA has many systematic pitfalls as result of natural human fallibility, which has been noticed as recurring issues in the lessons learned that have been accumulated over decades of HRA method developments. In NUREG-1855 (2009) the uncertainty of nuclear PRAs, that for many decades have incorporated HRAs, are grouped as either; (i) Completeness uncertainty, which comprises factors that knowingly is or may become simplifications in the PRA, and potential unknown simplifications that are made, (ii) model uncertainty, which is uncertainty because any risk analysis model will be a simplification of the reality it is made to represent, and (iii) parameter uncertainty, which is uncertainty in model input parameter values like for example equipment failure rates and repair times.

In terms of completeness the HRA has been developed by consciously considering the modern and well-known aspects of human fallibility, and subsequently focused on delimiting the HRA method development towards a short time horizon, and describing the factors relevant to estimation of random operator error probabilities. This also included considering the main known issues with modern HRA methods from literature. As result, the method is largely based on the broader knowledge domains of psychology and sociotechnical system theory as knowingly a main simplification made.

In terms of model uncertainty, a BBN model was found most attractive for HRA since it explicitly allows for subjective inputs and diagnostic reasoning, and as such also the treatment of human risk factors as 'unobservable' variables when required. This aspect may also be considered a drawback since it opens for variability across assessors, which has been addressed in developing the DPRA by clarifications to taxonomy and implementation of checklist procedures.

Even if we consider the BBN model relevant to DPRA, we may still question if the DPRA has identified and structured all the relevant RIFs sufficiently orthogonal in analysis for the purpose of making consistent operator error probability estimates. As such, the HRA causal model development of DPRA was focused on the sharp end adaptation of the broadly generic Risk OMT causal model structure. This was suggested as most important based on reviews of recent well accidents and interviews of rig personnel currently working in the Norwegian offshore sector. The aspects of the workplace factors and human performance influences were therefore thoroughly considered as part of the accident reviews performed during the DPRA causal model development, which was also included in the work of developing taxonomy and checklists for consistent use of HEA and in evaluation of RIFs in the DPRA.

Another drawback noticed with BBN models is a huge number of data points that could become needed for the purpose of model demonstration and validation. This aspect also made the Risk OMT with the hybrid calculation approach attractive for the DPRA. Moreover, well accidents are few, which makes it difficult to study attribution from an operator error perspective. Additionally, in terms of data collection and parameter uncertainty the DPRA makes use of a specific HEA taxonomy to be followed as part of the HRA procedure (and data collection). The taxonomy has been developed based on the use of HTA as a precursor in HEA, and introduces the definition of three fixed levels of task break-down and analysis. The three levels defined and analysed are consistent with basic concepts of failure analysis and with the theoretical HOF influence model for operator errors that has been used as basis for the Risk OMT causal model adapted in DPRA. The causal model, however, only has two levels, and to apply the taxonomy to this causal model may therefore not be straightforward, which is discussed more in the next section.

The conclusions from applying the HEA taxonomy in practical testing of the DPRA may be that the performance requirement standards identified and analysed at the action level require a new formal procedure to be developed. This in order for these standards to become consistently aggregated in line with RIF structure in the DPRA causal model. For example, the operator error concepts presented as checklist in Table 11 should then be revised to better reflect operator error concepts as hierarchical representation from a physical/physiological and psychological level upwards to the higher sociotechnical system level in Figure 22. Alternatively, a new causal influence modelling structure could be developed to align directly with the proposed HEA taxonomy, i.e. result in a modelling structure that explicitly, and orthogonally, includes the three levels of influences that are indicated in Figure 22 and Figure 23. As a current first approximation it is suggested in DPRA that the lowest level action performance influences in Figure 21 only should be considered for analysis and evaluation of the 'Design' and 'HMI' as sharp end RIFs.

Several detailed well accident reviews have been performed as basis for establishing the DPRA. The accident reviews concluded that three out of the four accidents revealed the HMI as a likely direct contributing factor to unsafe acts in the accident event sequences. For these accidents, a limited or non-existent pressure and flowrate monitoring capability on rig floor likely contributed to the unnoticed development of a diffuse multigradient fluid regime within the different sub-volumes of the well. A diffuse pressure situation that likely became a source of uncertainty and confusion topsides, and consequently a key contributing factor in the occurrences of unsafe acts part of the event sequences.

The HMI was, however, not revealed to be the only important contributing factor identified based on the accident reviews. In contrast to the other accidents, one of the accidents occurred in spite of managed pressure drilling operations that may be considered to include state of the art HMI for maintaining well control, including for in-situ wellbore pressure and flowrate monitoring. This accident was mainly described as a violation that took place since management of change procedures were not followed. Further study could be considered into technical management relations contributing to this accident in DPRA. For example, it could be linked to an overconfidence emerging in a group from successful application of new technology in a workplace. As such, an efficient HMI may become source of negative (undesired) influences in the causal model RIF structure.

The description of the HRA method in DPRA includes a detailed presentation of the hybrid calculation approach developed as an alternative calculation method to the full BBN model implementation in Risk OMT. The following discussion items have been noted concerning the application of the hybrid calculation approach:

- The approach is based on BBN specification of the relation between the RIFs, but uses traditional processing of the fault and event trees assuming independence between basic events. As result, the hybrid approach may be considered as an optimistic modelling alternative to the full BBN model implementation. Consequently, in DPRA when using the hybrid approach it is suggested that the two main critical human actions shown in Figure 17, nodes (1) and (2), are analysed and evaluated together in HEA and RIF evaluation process, which is further discussed by HEA example included by Strand et al. (2016).
- The input scores and variances for parent RIF^{II}s are not addressed beyond the Risk OMT method in DPRA, but it may seem unreasonable to apply the U-shaped pdf of Jeffrey's vague prior for RIF^{II}s. An alternative prior proposed in DPRA is a pdf where average value, respectively 5/12, is considered the expected value, and with the coefficient of variance kept as for Jeffrey's vague prior to determine both the Beta distribution parameters.
- The assumption that the parent RIF^{II} posterior and children RIF^{I}s priors share same expected value seems reasonable in approach. The structural dependency, Vp, must also be assessed. For example, should it be kept independent of parent RIF^{II} value? The lethal energy in an oil and gas reservoir is an apparent concern to all the personnel working together on an offshore drilling rig. If a part of the organisation (parent) gets assessed with an unacceptable value, this may not imply as a prior knowledge that all drilling crews in company with 'equal certainty' also display unacceptable behaviour. It could, however, imply that more variability exists across the sharp end of the organisation. This could be reflected in DPRA with a Vp that is positively correlated with the parent RIF^{II} value, for instance, with interval proposed between 0.05^2 and 0.20^2. The SINTEF interviews (SINTEF, 2014) indicate that this correlation between parent and child best can be assessed on a case to case basis.

- The upper and lower bound OEP values proposed in Risk OMT method are between 0.50 and 1.00E-4 (Haugen et al., 2007). The indication that a drilling crew, in spite of a novel drilling operation, may timely fail to detect a kick in one out of two times on average may appear hypothetical. In testing of DPRA with use of the hybrid calculation approach, however, it was difficult to produce OEPs close to the bounds. The assumption about bounds adopted from Risk OMT for calculations may therefore be reasonable in practice. The OEP boundaries may, however, likely need further empirical calibration and assessment in DPRA independent of the q_k -function used.

The hybrid calculation approach has been demonstrated with full BBN model implementation as part of the Risk OMT project for offshore process maintenance activities in Norway. Further, the DPRA is based on thorough review of human factors literature, previous learnings with existing HRA methods, empirical data collected in interviews with drilling crews and from well accident reviews. The HRA is, however, still novel for purpose of well PRA, and will need further validation to correct for teething problems and to be demonstrated with the necessary reproducibility in becoming a practical tool for well engineers in risk control in offshore drilling operations globally. For example, work should be done to refine procedures and checklists, limit number of assumptions, and limit the use of expert judgments by substitution for observations like field data, human resource data or simulator training data. For example, it may be suggested to perform similar detailed causality studies demonstrated for the HMI in Paper 2 also for other RIFs to further clarify the 'meaning' of checklist items both for the purpose of HEA and for evaluation of RIFs.

Discussion and evaluation of method for determining the PFD of the BOP

The BOP represents a complex dynamic system noticed from its ram and preventer designs, maintenance requirements and usage scenarios described in Section 2.3. The implication is that that the most relevant and attractive dynamic analysis methods, largely based on mission phase models, may be considered too unrealistic. As result, a simulation approach may be the only modelling alternative. The 'realism' of a model may, however, not be crucial to its usefulness to well PRA. For example, if the modelling covers the most important usage scenarios, or if it is easily demonstrated to be based on conservative and pre-cautionary considerations. As such, the numerical method proposed for the PFD calculations of the BOP stack in DPRA is based on a number of assumptions. The main assumptions are as follows relative to the attributes of the real system:

- The BOP control system is not explicitly seen included in the model, but effects of control system failures may be represented in the failure rate input data. Alternatively, the control system may be treated separately and the PFD of the two subsystems combined with textbook PRA methods.

- For ML > 1, the PFD approximations deduced from method may be considered conservative since the potential effects of BOP repairs (renewal) on all degraded elements is not reflected in the simple recursive model proposed.
- The failure rate of the BOP elements are identical and independent of time. Several BOP stack elements are, however, non-identical. For example, an AP is not the same as a PR/VBR or BSR. If such is the case, it is suggested in DPRA to apply the most conservative element failure rate on all elements in model as a first conservative approximation. The effect of this assumption is less notable for higher element redundancies, for instance, if considering both AP and VBR as redundant elements in the BOP closing Scenario 1a (Figure 7).
- All failures are detected during the pressure test and within a negligible period of time. This assumption is clearly not valid for the BSR. The cutting of pipe and sealing is not (for obvious reasons) part of regular pressure tests. The BSR is 'overhauled' every 3 to 5 years, however, and it may be assumed that most deficiencies that could result in cut and sealing failure are revealed then. If Taylor series approximation still holds, $\lambda \cdot \tau < 0.01$, we may use time between overhauls as the 'test interval' of the shear function. Care should, however, be taken since the experience data indicates a high PFD of the BSR in an actual shear-demand situation.
- The BOP elements repaired are restored to 'as good as new' condition within a negligible period of time after failure detection. I.e. the period that includes pull, repair and re-install of the BOP is not considered in the calculations.

In testing of method implications it was noted from conservative case studies carried out that an ML of less than N-1 seemed to produce a fairly constant and thereby 'robust' PFD value within a 70 day BOP installation period. This indicated that a decision to postpone the BOP repair until the (N-1)th revealed element failure could be an option in some cases due to small impacts on the BOP safety function performance. A careful check of assumptions and analysis with input data relevant to the actual BOP should, however, be performed before making any field decisions. It is also noted that verification of NOGA (2004) SIL 2 requirements appeared to be within reach of most BOP system configurations, which also has been demonstrated in recent FTA model calculations by Holand and Awan (2012).

Steady-state PFD values from the model were not produced during the case studies with a selected mission time of around 70 days in spite of relatively conservative input failure rates. Care should therefore be taken when deducing PFD values from the proposed method. A relatively low impact, typically less than 1%, on the numerical PFD value could be produced in case studies when omitting the most noticeable transient of $q_i(t)$ within the first inspection interval from average PFD calculations.

5 Scientific contribution

"The first principle is that you must not fool yourself, and you are the easiest person to fool"
Richard P. Feynman

This PhD thesis belong to the field of applied research aimed at practical offshore risk assessment methodologies that can be used by operators in analysis of activities that have a major accident potential. This include methodologies most often discussed and referred in literature as PRA. The PRAs have their origin from the nuclear power industry and are today broadly considered a cornerstone in the risk management of low-probability and high-consequence activities associated with industries such as defence, aviation, aerospace, chemical process and public transport. In this respect, it is expressed a clear opinion within the oil and gas industry from recent well accident investigations that decision making in planning and follow-up to well drilling and intervention operations suffer from insufficient risk quantification.

This thesis is primarily meant complementary to existing academic works in the domain of well safety previously produced, for instance, by Holand (1996), Corneliussen (2006), and Vignes (2011). The overall objective of this thesis has been to develop a systematic approach for risk assessment of offshore wells in the drilling phase. The approach, denoted DPRA, could be used as an aid to risk informed decision-making in relation to offshore well drilling (and intervention) operations. The use of PRA methods to assess well system risk is not new. Some of the procedures and methods described as DPRA are, however, new based on the following research questions identified in this project:

- How do different BOP designs and maintenance strategies impact the safety function performance of the BOP?
- How can the influences of human task performance be better incorporated in the well drilling operation PRA to help the drilling crew better manoeuvre within the operation safe envelope?
- How does technology influence human task performance in offshore well operations?

The scientific contributions from this thesis are illustrated under the two well barrier rule in Figure 31 to encompass this PhD report with enclosed Paper 1 through Paper 4. The papers are seen associated with main human, organisational and technical safety function aspects defined in regulations and standards. The DPRA is developed as approach that may be used by the well engineer responsible for well drilling operation risk assessments. The papers describe new or improved methods and procedures developed as extensions made to traditional PRA methods in thesis and includes;

(i) In Paper 1, a compact method for dynamic BOP safety and reliability analysis is proposed. The method can be used in physical degradation modelling of BOP systems to evaluate effects of maintenance strategies on safety function availability targets.

(ii) Paper 2 aims to clarify the role and corroborate the importance of the HMI in well operation accident prevention and control. The HMI may be considered the most important technology-based risk influencing factor in well drilling. As result of a thorough study, the paper proposes modifications to the operator error causal model adopted in Paper 3.

(iii) In Paper 3, a HRA method is proposed to quantify human and organisational factors impacting on the availability of safety functions in drilling operations.

(iv) Paper 4 proposes some clarifications to taxonomy and key human error concepts used in DPRA for the purpose of consistent treatment of human and organisational factors in the application of the HRA method described in Paper 3

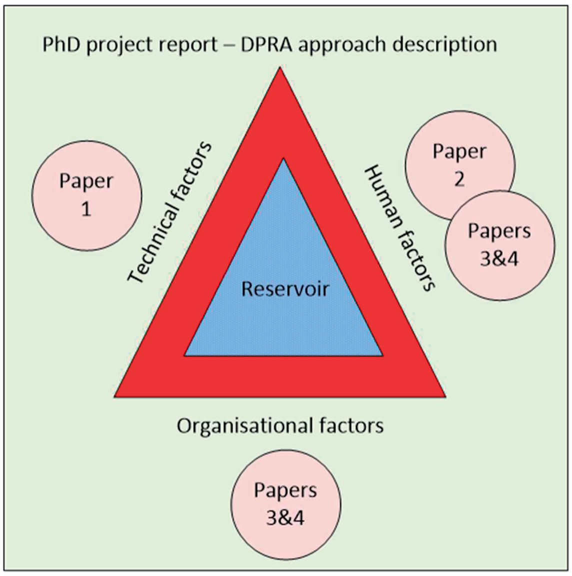

Figure 31. Two well barrier illustration of scientific contributions made in this PhD project to well safety

Evaluation of research process

"For a successful technology, reality must take precedence over public relations, for Nature cannot be fooled"
Richard P. Feynman

To ensure the applicability of the DPRA, pragmatism has been important, but the procedures and methods presented are anchored in recognised quantitative risk and reliability theory. To lend scientific credibility to the work, the criteria listed in Table 1 have been followed as far as possible. Also the risk assessment approach presented has been developed with strong involvement from the industry and colleagues mentioned in the introduction.

Research entails years of hard work that follows from research methodology defined to comprise three basic activities (Creswell, 2012); (i) Pose a question, (ii) collect data to answer the question, and (iii) present an answer to the question. Moreover, the method of research is based on a fine understanding of human fallibility, and on principles of self-correction and synthesis from peer review, experiments and observations. Consequently, a researcher can never collect enough relevant data to provide an answer to a question. Unfortunately, the oil and gas industry downturn contributed to difficulties in collection of additional relevant data for development and validation of procedures and methods, foremost with impacts related to research that concerned the HRA method discussed in Paper 3. For example, the full BBN development in method requires a large number of data points for population of the RIF structure model, and for its calibration versus well operation accident observations, which are few and also may not be sufficiently described in terms of causality related to all three human, organisational and technical perspectives. Care must therefore be taken in application of the DPRA method described without careful reference to further industry specific validation performed.

Table 16 describes an evaluation of the contributions made in this PhD project versus the criteria for quality assurance and validation put forward in Table 1. The following codes have been used to indicate research quality: XXX: Covered (main focus / theory, data, case study and peer review), XX: Partly covered (not main focus / theory, data or case study and peer review), X: Briefly covered (delimitation / theory and peer review).

Table 16 (Table 1 reproduced) Evaluation of DPRA research processes and items of further work

		Evaluation of DPRA elements				
Johansen and Rausand (2013) – criteria for evaluation of risk metrics	Adapted from Rae et al. (2013) – criteria for evaluation of QRAs. Based on Level 2 maternity that is considered an invalid QRA study.	Main report	Paper 1	Paper 2	Paper 3	Paper 4
Validity - Fit for purpose? Communicability - Needs?	**Describe scope and objectives** Clear purpose Clear scope Clear boundaries, boundary conditions Clear evaluation criteria	**XXX**	**XXX**	**XXX**	**XXX**	**XXX**

Table 16 (Table 1 reproduced) Evaluation of DPRA research processes and items of further work

		Evaluation of DPRA elements				
Johansen and Rausand (2013) – criteria for evaluation of risk metrics	Adapted from Rae et al. (2013) – criteria for evaluation of QRAs. Based on Level 2 maternity that is considered an invalid QRA study.	Main report	Paper 1	Paper 2	Paper 3	Paper 4
Reliability - Approach? Unambiguity – Precise? Context - Features? Comparability and specificity (trade-off) – Flexible?	**Describe models, methods and tools** Avoid/State omissions in scope - External (hazardous) events - Software, human and organisational influences - Physical or causal pathways, operational phases, outcomes Avoid/State unrealistic limitations - Contradicting arguments - Incorrect models (representation) - Invalid assumptions about system behaviour, effects of monitoring and mitigations Avoid/State accuracy limitations - Invalid or incorrect use of models, methods and tools - Unacceptable 'drift' due to insufficient dynamic capability of models, methods and tools	**XXX**	**XXX**	**XXX**	**XXX**	**XXX**
Transparency – Unbiased? Consistency - Independent? Rationality - Accountable?	**Describe source material** Not omitted Not outdated Not inconsistent / unrealistic Not unreferenced	**XXX**	**XXX**	**XXX**	**XXX**	**XXX**
Acceptability – Recognised?	**Avoid systematic problems (validate)** Get stakeholder acceptance Use peer review, experiments and observations to avoid - obviously unrealistic results - contrived results (biased) - no answers (scope)	**XX**	**XXX**	**XXX**	**XX**	**X**
	Report results Not misleading - Incorrect use or grouping of model elements - Incorrect use of risk acceptance criteria (RAC) - Alternatives considered across different baselines ('apples and pears') Not inconsistent - Use of assumptions and source data - Conclusions drawn vs. level of detail in study approach - Qualitative vs. quantitative descriptions of risk level Not incomplete, not quantified - Limitations / restrictions / uncertainty not reported - Sensitivities not reported (the effect of assumptions on analysis outcomes)	**XX**	**XXX**	**XXX**	**XX**	**X**

6 Conclusions, further work and closing remarks

A new systematic approach has been developed for risk assessment of offshore wells in the drilling phase. The approach is denoted DPRA, and may be used as an aid in risk control related to offshore well drilling (and intervention) operations. The focus of DPRA development has been on an improved set of procedures and methods for quantification of probabilities or frequencies associated with well releases and blowouts during a well drilling operation. The DPRA approach is based on existing and new PRA methods and knowledge gained during the PhD work. To arrive at such new procedures and methods, it was necessary to:

- Describe the regulations, industry standards, and best practices that provides recognised requirements to enable the analysis of well safety functions in the drilling phase.
- Describe well operations and the status related to well barrier control functions (continuous and on demand) during well drilling operations.
- Describe the status related to quantitative analysis and control of the main well safety functions. Identify accepted methods within industry that are applied in the domain of quantitative well operation risk assessments.
- Identify relevant sources for experienced based data available for well risk assessments calculations and verification. Discuss the quality of the data, and suggest improvements in application of experience based data.
- Develop a systematic approach for risk assessment of offshore wells in the drilling phase. In this context a systematic approach means to quantitatively assess well blowout or release risk if a technical, human or organisational barrier related to the well system fails during the well drilling phase.

The DPRA approach has been developed around the following principle well risk assessment procedure, included with main deliverables:

1) *Step 1: Define scope of work and delimit the study*.
    - The scope and limitations of DPRA are described as part of literature review, and in definition of the risk modelling principle.
2) *Step 2: Determine the frequency of mud failure*.
    - This task is not described in DPRA, but several data sources that can be used are discussed.
3) *Step 3: Carry out a HRA*.
    - This task is described in DPRA, and includes deliverables: (i) Taxonomy with operator error concepts developed for consistent human error analysis and evaluation, (ii) generic causal model developed for drilling operation OEP calculations, (iii) checklist procedure developed for consistent RIF evaluations as part of OEP calculations.

4) *Step 4: Determine the PFD for the BOP.*
   - This task is described in DPRA, and includes deliverable: A compact method developed for degradation modelling and PFD analysis of the BOP.
5) *Step 5: Calculate the total blowout frequency*.
   - This task is not described as part of DPRA. It is considered covered by existing literature.
6) *Step 5: Identification and implementation of risk reducing measures.*
   - This task is not described as part of DPRA. It is considered covered by existing literature.

An industrial implementation of the DPRA approach is based on participation from the responsible well engineer, drilling crews, and other peer review teams from the start of well planning, throughout the well drilling process.

The use of PRA methods to assess well blowout risk not new. Following an extensive industry- and academic literature review the overall thesis objective was decomposed into three research questions that have been addressed by four papers submitted for peer reviewed publication. The papers discuss important technical, human and organisational aspects of DPRA to help secure PhD project innovation and validity in best possible accordance with the criteria established in Section 1.5.

Further work

The inclusion of HOFs as an integral part of DPRA is considered to be in its infancy, and there has been limited coverage as part of the work carried out for this thesis. Validation of the work is also limited to the work by the author. For example, there are numerous speciality domains defined by Larsen and Buss (2002), which study the subject of human nature from the psychological perspective. The human brain and body is obviously more complex than any piece of machinery so far built, and significant multidisciplinary efforts are arguably still needed to further develop and calibrate the methods for completing quality HRAs as part of well system PRA. For example, Paper 2 suggests further study into the cause and effects relationship and risk factors contributing to one of the well accidents reviewed. Paper 4 also suggests that further work is possible in regards to the proposed DPRA risk influence model and the procedure for evaluation of RIFs based on the clarifications made to the operator error concepts and taxonomy developed in DPRA.

One of the objectives in this thesis was to suggest improvement in the application of reliability input data. This is partly done by introducing a new human error classification taxonomy (Paper 4) and by improved human reliability analysis techniques (Paper 2 and Paper 3). However, the ambition was to perform more detailed analysis of operator errors, and thereby provide more advice to shape of the OEP basic event function (q_k), and give recommendations for OEP bounds and for $\mathrm{RIF}^{\mathrm{I}}$ normalised weights to be used in calculations. Due to limited access to field data this was not possible. The human error classifications suggested in Paper 4 may be a good starting point for further research and data collection.

Closing remarks

"If all we obtain from the (cement evaluation) logs is comfort when they look good, or discomfort when they look bad, but no confident remedial option, why do we waste time and money running the logs?"

API TR 10TR1 workgroup

Mark Twain states that "history doesn't repeat itself, but it does rhyme". Central to over a century of developments of oil and gas industry regulations, standards, guidelines and practices for well risk control are lessons learned from previous accidents and near-misses. For example, such lessons learned over the years include the requirements introduced for the use of both production tubing and downhole safety valves. A reflection was made from this perspective when reading the numerous documents provided with descriptions of event sequences and causes of some historic well blowout accidents. Namely, it appears difficult, and therefore not advisable, without careful peer review to apply a textbook 'all-purpose' approach to well accident investigations on its own. Scrutiny of such a generic approach in hindsight could reveal that the methodology has been too vague in its purpose and that crucial domain knowledge needed to address the key physical and mental aspects of well energy containment become lost in the simplification (polarisation) process.

For example, there seemed to be an unreasonably large focus in debates related to poor cement jobs in two of the well accidents reviewed. Poor cement jobs could be considered a 'normal situation' in well construction to people working in the drilling and well industry. Reference, for instance, the abundance of literature on the subject of 'bad cement jobs' and 'remedial cementing'. It is feared that an unreasonable large focus, presumably influenced by the lack of domain knowledge and peer review, could obscure the facts and evidence collected and make lessons learned from the analysis of accidents speculative and difficult to reproduce. It also results in the industry having difficulties both accepting and implementing improvement measures. From the literature reviews of well accidents it is therefore advised that the focus of such reviews is equally tailored on producing precise and unbiased facts relevant to explicit oil and gas industry context in order to maximise the benefits of the lessons learned, and not primarily for the benefit of society at large as seemingly advocated by popular major accident investigation methods.

Well safety is all about being wise and avoiding unpleasant situations. In many meetings with safety consultants over the years I seem to have repeatedly encountered many universal methods and software tools confidently endorsed in risk management. Does an 'unified theory' for how to address unknowns and uncertainty exist? Can we as result confine all decision making to software's and risk matrices? Perhaps someday. As a practitioner myself for a number of years, I take an opposite view as an advocate for the physical approaches over the generic and actuarial. A great learning experience, where we from case to case establish multi-disciplinary expert teams that combine the best available experience and physical knowledge about the hazardous energy and of the means we have available to control it. Only applying probabilistic methods if necessary as aid to reach an agreement about the state of knowledge and the best practical solution to the problem. Not too long ago, only one type of medical doctor existed, but today numerous specialists are found (Larsen and Buss, 2002). Perhaps the extent of our knowledgebase, the knowns and the unknown-knowns, in the different risk assessment domains also starts to call for more specialisation in the best interests of more wisely protecting humans, the environment and financial interests?

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"I don't care that they stole my idea. I care that they don't have any of their own"

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Appendices

I.	Offshore well blowout and release data
II.	PAPER 1: Risk Control in the Well Drilling Phase: BOP System Reliability Assessment
III.	PAPER 2: Evaluation of the role of HMI in risk analysis of offshore drilling operations
IV.	PAPER 3: Human Factors Modelling in Offshore Drilling Operations
V.	PAPER 4: Classification of Human Factors Using Offshore Drilling Operations as Case Study
VI.	On the use of Probability as Measure for Uncertainty in DPRA
VII.	List of acronyms and abbreviations
VIII.	Terminology
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I. Offshore well blowout and release data

About 3000 offshore wells are drilled world-wide every year without major incidents[32]. Experiences from international offshore oil exploration, however, show that well blowouts can occur. The SINTEF Offshore Blowout Database (SINTEF, 2015) is one main information source used in analysis of well blowout and release risk. This database is updated every year based on publicly available well event and exposure data, and a report is written that provide recommendations on frequencies to be applied as input values, for instance, to safety case and total risk analysis of offshore installations. The blowout frequency data presented in the reports stems from offshore operations in the USGoM OCS, and North Sea UK and Norwegian sector.

Table 17 shows historic well blowout frequency data from an earlier study by Holand (1997) alongside an updated dataset retrieved from the same database published in IOGP #434-2 (2010). The most notable difference between the datasets is that the updated blowout statistics is presented by well type, and that gas wells then show higher blowout frequency compared to water and oil wells. This observation about gas wells may be as expected due to lower viscosity (higher volatility) of gases compared to liquids. Table 17 gives an overview of a representative well safety performance based on recommended SINTEF blowout frequency data in 1997 by Holand (1997, p. 142), and IOGP #434-2 (2010) which is based on 2006 dataset from the same SINTEF database. In Table 17 the activity blowout frequencies are coupled with some roughly assumed well lifetime activity levels based on the author's judgment. Overall, some 1 to 6 blowouts per 1000 well lifetimes are roughly seen produced. The well total lifetime blowout frequency is judged about 36-50% higher using same frequency data for platform wells compared to subsea wells as a result of a higher assumed platform activity level argued from an easier and cheaper access to the wells.

[32] Harts E&P magazine, p.54, May 2014

Table 17. Well life activity blowout frequencies versus Xmas tree type

Type Xmas tree	Phase	Exposure (assumed) over a well life	Blowout freq. (Holand, 1997)	Blowout freq. (IOGP #434-2, 2010)
Platform	Drilling (Dev. / Deep)	1 operation	0.00092	0.00006
	Completion	1 operation	0.00021	0.00010
	Workover	3 operations	0.00279	0.00054
	Coiled tubing	1 operation	No category*	0.00014
	Wireline**	10 operations	0.00008	0.00007
	Constr./Intervention	**per 30 year life**	**0.00450**	**0.00076**
	Production	**per 30 year life**	**0.00150**	**0.00029**
Subsea	Drilling (Dev. / Deep)	1 operation	0.00092	0.00006
	Completion	1 operation	0.00021	0.00010
	Workover	1 operation	0.00093	0.00018
	Wireline**	1 operation	0.00001	0.00001
	Constr./Intervention	**per 30 year life**	**0.00207**	**0.00034**
	Production	**per 30 year life**	**0.00150**	**0.00029**

*) Presumed to be classified as a 'workover' with the initial well activity break-down used by Holand (1997).
**) The wireline intervention contribution is small and is disregarded in calculation of totals

A reduction in the well blowout frequency is indicated with the newer dataset in Table 17, but detailed investigation into significance of this is not made in the OGP report. It is generally difficult to trend this type of public data since the information is high level and often lack sufficient information required to argue what may be the plausible cause(s) of any trend, and also in terms of statistical significance because the data includes very few observations captured over a limited period. Hence, the confidence interval, for instance, under assumption of a homogeneous Poisson process for the frequency estimates in the table become large (Rausand and Høyland, 2004, p. 243). For example, Holand (1997) data includes about 10 000 wells drilled and 12 deep development drilling blowouts from the USGoM OCS, North Sea (UK and Norway). This gives an approximate 90% two-sided confidence interval for the dataset based the annual development drilling blowout frequency of [0.00069, 0.00190]. Trend analysis like 'Laplace test' or 'Military handbook test' (Rausand and Høyland, 2004, p. 286) can typically be performed with access to data. Also, likelihood ratio tests may be applied to test a hypothesis of different parameter (frequency) values in a sample (Lawless, 2003).

The data in Table 17 should therefore only be used as coarse benchmarks for well activity safety performance levels. For example, it may not be advisable to summarise and compare just the frequency of operations since the intrinsic properties of the source, leak path and sink involved in historic events typically also vary significantly and thus also the risk in terms of negative outcomes from the blowout. Similarly, well production and wireline activities should not be compared directly across other phases that include more intrusive and complex operations such as drilling, completion or workover. For example, even for more complex operations the historic blowout consequences are seen to vary a lot in spite the fact that they stem from similarly prolific wells like found at Macondo (USGoM, 2010) and Funiwa (Nigeria, 2012). These two blowouts caused fatalities, but the other public notably offshore blowout incidents, generally perceived as the most severe, from the last decade have pre-dominantly had financial consequences in spite of a catastrophic potential; Snorre A (Norway, 2004), Temsah

(Egypt, 2004), Montara (Australia, 2009), Gullfaks C (Norway, 2010), Frade (Brasil, 2011) and South Timbalier Block 220 (USGoM, 2013).

It may be noted that none of the seven public blowout incidents listed stem from well production phase or from performing a wireline light intervention. From internet search of public data no serious incident is found in the wireline intervention phase, but two other recent and more serious well blowouts is found reported in same period; SW Marine Region (Mexico, 2007) and Elgin (UK, 2012). The first incident was reportedly caused by the fact that the Xmas tree (wellhead mounted production valve block) was knocked off by the cantilever deck on the jack-up rig working on the platform due to bad weather. This incident is reported to have caused 23 fatalities because a lifeboat used for evacuation capsized. The public available information surrounding the details of the UK Elgin incident in 2012 is scarce. The blowout occurred during operations to plug and decommission the well and caused no harm to personnel. The source of the well inflow was reportedly be a higher isolated zone that started flowing via a failed casing.

An underground blowout may not always pose an immediate danger to the rig and personnel above. For example, there is the relatively benign Gullfaks (2010) and Frade (2011) underground blowouts as contrast to the severe Snorre (2004) seafloor (via underground) blowout. In general from internet literature survey there seems to be limited public available information is found available on the severity of deep- and shallow formation type underground blowouts. However, the behaviour of formation leak offs are typically simulated, for instance, in design of water injection and cutting re-injection disposal wells (Santarelli F.J. et al., 2014). The leak off in formations is typically predicted as vertically oriented fractures extending upwards that may create pulses of fluids cratering the shallow formation layers and muds/clays at the seafloor. In shallow formations the fractures may become more horizontally oriented due to different formation stress conditions. Significant amounts of leak off fluids can be absorbed if high-permeable formations are exposed by the crack propagation. The leak off across sufficient pay (sink) is also hence a typical injector well design basis.

There are more than a dozen of incidents found on the NCS that relates to seafloor releases from shallow disposal wells, some of the leaks ongoing for several years before detection (Santarelli F.J. et al., 2014). Though, also some incidents stem from subsea template wells with a larger potential for escalation to adjacent wells, environmental issues have mainly been raised as results of the incidents. A summary of NCS incidents considered in public Norwegian Environmental Agency (NEA) document (NEA, 2010) is presented in Table 18. The root cause for historic disposal well leaks are not singular according to the NEA, often a combination of causes are seen (NEA, 2010):

- Geological uncertainties - injection rates and injected amounts exceeding formation capacity (sink volume and injection fluid related matrix flow).
- Sub-optimal placement of well target relative to location of the permeable formations (sink location and fracture propagations).

- Poor cementing of casing string.
- Poor monitoring of injection operations. In some of the incidents reported the leak is ongoing for some time due to inadequate reaction to, for instance, clear drops seen in injection pressures.

Table 18. Norwegian Continental Shelf disposal well failures (NEA, 2010)

Field	Volume injected	Period	Remarks
Veslefrikk - platform	3450m3 cuttings 93000m3 slope	1997-2009	Injection through well C-annulus. Leak likely started in 1997 (when drop in injection pressure noticed). Two large craters formed at seabed. Injection through well C-annulus is no longer a recommended practice on the NCS.
Tordis - subsea	No info, Produced water injection	2008 (5 months)	Dedicated injector. Oil sheen detected on surface. 7m seabed depression with oil contaminated water flowing. There was no permeable formation (Utsira) above injection point
Visund - subsea	No info	? - 2007	Dedicated injector. Injected volumes over several years seen on seabed. Not sufficient Utsira pay in area relative to injection volumes / fault lines also seen in area. Fractured casing may also be factor. Observed pressure drops not interpreted correctly.
Ringhorne - platform	76 000 m3 cuttings&slope	2002-2004	Two craters and several minor “holes” observed with fluid outflow. Low probability of cement failure. Also tried injecting 11000m3 in four other nearby wells – no wells found suited for purpose (not sufficient matrix flow)
Oseberg - platform	No info cuttings&slope& seawater	? - 2007	Leaks suspected several wells – impact degree is uncertain. Cratering observed by both B- & C-platforms
Aasgard - subsea	No info	1997-2000	Confirmed leaks from 6 wells Suspect a combination of poor 20” surface casing cement and lack of sufficient matrix flow in targets
Snorre B - subsea	No info, Produced water& cuttings	? – 2008/2009	Leak detected before 2008. Crater observed 2009. Caused by poor cement (leak in channels created along wellbore).
Njord - subsea	No info mud&slope	? - 2006	Injection stop in 2006 due to jumper leak and low injection pressures. Closed in 2008 - formation not found suited for purpose.
Brage - platform	2878m3 cuttings 537m3 slope + some oily water	2001 (3 weeks)	Shut-in due to loss of injection pressure.

II. PAPER 1: Risk Control in the Well Drilling Phase: BOP System Reliability Assessment

Strand, G.O. and Lundteigen, M.A., "Risk Control in the Well Drilling Phase: BOP System Reliability Assessment". Presented at: ESREL 2015, September, Zurich, Switzerland: CRC Press. p. 753-760

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Risk control in the well drilling phase: BOP system reliability assessment

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ABSTRACT: The blowout preventer (BOP) is the main well control device used to ensure the safety of well drilling and intervention operations. The BOP is qualified for the demanding conditions that may come from uncontrolled flow in the well. However, recent accidents and near misses also show that the BOP fails from time to time. The oil and gas industry has been collecting experience data for BOP systems over many decades, and several reports on BOP safety and reliability performance has been published based on this data. The BOP received increased attention after the Macondo well blowout in 2010, and previous BOP safety and reliability performance estimates have been challenged. The objective of this paper is to evaluate some of the recent safety and reliability studies published on BOP systems. Based on the evaluation a new approach for safety and reliability assessment of BOP stack closure elements is presented with a case study for demonstrating its application. The main benefit of the proposed approach is a more efficient explicit trade-off analysis, where the effect of different maintenance strategies are evaluated against typical BOP safety availability targets.

1 INTRODUCTION

Most oil and gas well reservoirs represent a major source of hazardous energy, and a blowout preventer system (BOP) is used to prevent the escape of this energy during well drilling operations. The BOP is primarily designed so that the drilling crew manually, upon detection, can close-in unintended inflow of reservoir energy that can occur during the operations. If the BOP fails to close and contain the inflow the situation will escalate into what is called a well blowout. An offshore well blowout is not found acceptable across the industry. For example, the Macondo well blowout in 2010 caused 11 fatalities and incurred over 40 Billion USD in liabilities (Reuters 2012). The reliability of BOP systems has therefore received a comprehensive scrutiny in the aftermath of the Macondo blowout. Most importantly, regulations and standards that pertain to design, qualification and use of BOP systems have been subject to revisions (BSEE 2014, API 2004b, API 2012, API 2004a, PSA 2014b, PSA 2014a, NORSOK 2012, NORSOK 2013). In addition, new contingency measures such as well capping devices have been developed for improved emergency preparedness in event of potential failure of a subsea BOP system.

The oil and gas industry has monitored the safety and reliability performance of subsea BOPs for many decades. Data about BOP failures during drilling operations has been collected, analysed and applied as basis for several safety and reliability performance reports published (Rausand & Engen 1983, Holand & Rausand 1987, Holand 1998, Quilici et al. 1998, Holand 1999, Holand & Skalle 2001, Jorge et al. 2001, Jorge 2005, BSEE 2006, Sattler & Gallander 2010, Holand & Awan 2012). Fault tree analysis (FTA) is seen used for the more detailed BOP reliability studies, among other found in the reports by Holand et al. (2012, 2001, 1999), which are considered to be the most thorough.

Recognised industry regulations and standards require verification (testing) of BOP safety functions every 7 or 14 days. It is also a regulatory requirement to pull the BOP for repair if a safety critical failure is revealed during such a test. However, the unscheduled pulling of a BOP for repair may introduce increased well blowout risk, and waivers that allow the drilling crew to postpone repairs are sometimes given by the authorities. Unfortunately, the FTA models developed in the mentioned reports apply to a static situation and do not account for the dynamic effect that waivers have on the well blowout risk level.

The main objective of this paper is to present a new modelling approach that is more suitable in an operational context for decision-making about need for BOP repairs or not. The BOP closure elements are studied using Markov modelling in the approach with degraded BOP states included. The new model may be used to support decisions about different maintenance policies, within the existing industry frames of the typical BOP safety availability targets (NOGA 2004). The paper also gives a thorough definition of BOP operating states, as necessary to understand the assumptions made for the new model.

2 DYNAMIC RELIABILITY ANALYSIS

During well operations the BOP may be regarded as a dynamic system. This includes many different load scenario and possible transitions of the BOP into degraded states of operation, if one or more faults are revealed. Many of the previous safety and reliability studies of BOP systems treat the BOP as a static system using a traditional FTA approach. This section gives a review of how the safety and reliability of dynamic systems is treated in the literature, starting with Hassan & Aldemir (1990) who argue that "dynamic methodologies are defined as those which explicitly account for the time element in system operation for failure modelling". The definition implies focus on time requirements (time-line) over situation requirements (state/'evidence'), which is sought for the safety and reliability analysis of subsea BOP systems. However, the use of the term 'dynamic' about analysis has become broader in more recent years. For example, according to Distefano & Puliafito (2009) it may also be system analysis that explicitly evaluates dependent, cascading, on-demand or common cause failures, and also policies for redundancy and maintenance.

Most dynamic analysis methods for large systems are based on the well-known 'static' analysis methodologies (Rausand & Høyland 2004). Examples of dynamic methods are dynamic fault tree (Čepin & Mavko 2002), dynamic reliability block diagram (Distefano & Puliafito 2009), dynamic event tree (Acosta & Siu 1993) and dynamic Bayesian networks (DBN) (Cai et al. 2013). Many of the dynamic methods retain a strong relation to the time-line for modelling. However, newer methods, in particular those based on Bayesian theory, focus more explicitly on situation requirements, the existing 'evidence' relevant to the system functionality. For example, Cai et al. (2013) demonstrated the application of a DBN in BOP reliability analysis by converting one of Holand's FTA models. Another interesting class of dynamic reliability analysis is referred to as 'multiphase' or 'phase mission system' (PMS) analysis (Siu (1994). This is analysis where the system model consists of a set of sub-models that are consecutively linked together over the (mission) timeline. For example, a typical PMS model may consist of sub-models that are based on reliability block diagrams or fault trees, which for system analysis are linked together with a binary decision diagram (Lu & Wu 2014).

The FTA and DBN models used for BOP safety and reliability analysis are found computational demanding, which makes them less suited for operational use. Also, the FTA and DBN approaches are complex and discipline oriented. Hence, as a representation of a system or process it is viewed (currently) to lack the 'communication features' needed for risk control in a multidisciplinary operational setting (Rasmussen 1997).

Similar to a PMS model the BOP safety and reliability analysis model presented in this paper is based on a recursive multiphase Markov approach that includes a stationary transition rate matrix that can be solved by numerical methods. The multiphase Markov method presented constitutes a detailed model for the BOP system closure elements, but may also be used as a simplified and compact representation of the entire subsea BOP system.

3 SUBSEA BOP SYSTEM DESCRIPTION

3.1 *Description of subsea BOP system elements*

The main BOP safety function is to close-in and control unintended inflow of reservoir energy that can occur during the well operations. The subsea BOP system is made up of three main subsystems to achieve this function (The Deepwater Horizon Study Group 2011): 1) Control system that distributes hydraulic power fluid from hydraulic power unit and accumulator banks used for activation of BOP closure elements. The control systems found are based on two principles; electro-hydraulic ('multiplex') or pilot hydraulic ('all hydraulic'). 2) Lower marine riser package (LMRP) that provides the ability to connect and disconnect the drilling riser (rig) from the BOP stack. For example if bad weather conditions or in a 'drive-off'/'drift-off' situation with a dynamic positioned (DP) rig. 3) The BOP stack that connects and seal the BOP to the wellhead and includes a 'stack' of main BOP closure elements for well close-in, within ca. 30-45 seconds, during different well control situations.

There are three different types of BOP closure elements available for activation in a well control situation; 1) Annular preventer (AP): A 'rubber donut' that is compressed during activation. AP has the ability to seal-off annulus outside all sizes of pipe running through the BOP. Some AP elements can also seal off the well if there is no pipe, but then at a reduced pressure rating. AP is the primary element that is activated during drilling operations. The AP elements are normally located in the LMRP. 2) Pipe ram (PR): two opposing 'ram blocks' with slips and seals that hold the pipe in place and seal-off the annulus outside. A PR element is designed for specific size of drill-pipe. A variable bore ram (VBR) is term used for a PR element designed for a range of drill-pipe sizes. 3) Blind shear ram (BSR); two opposing 'ram blocks' with a cutting edges and seals that will shear specific sizes of drill-pipe and seal off the well. It is common for a subsea BOP stack to have one BSR. Some BOP stacks have a second non-sealing casing shear ram (CSR) designed to cut larger diameter pipe.

The subsea BOP closure elements are all in an open and dormant position during normal well operations not to impede the activities. On basis of how the elements are activated we may define five distinct modes of BOP operation:

1. Intervention – Manual. An underwater remote operated vessel (ROV) can be used to override BOP-functions through ROV tool interface(s) on the BOP stack.
2. Normal – Manual. This is the main BOP operational mode where the drilling crew relates to the situation on the rig floor and the two central BOP control panels.
3. Emergency – Manual disconnect sequence (EDS). The activation of at least one blind shear ram to seal off the well and disconnection of the LMRP from the BOP stack.
4. Emergency – Autoshear. The automatic activation of at least one blind shear ram if the LMRP disconnects spuriously.
5. Emergency - Automatic Mode Function (AMF / 'deadman'). The EDS sequence triggered automatically in situations with loss of power and communication between the rig and the BOP.

3.2 *Regulations and standards*

The most internationally recognised regulations for design, operation and maintenance of subsea BOP systems is provided by the United States Bureau of Safety and Environmental Enforcement (BSEE). The BSEE regulations refer to domestic industry standards; API Spec 16A, API Spec 16D and API Std 53 for guidance on how to fulfil requirements. The following main requirements are found related to subsea BOP system design in the BSEE's federal regulations (BSEE 2014)

- Two redundant BOP control panels whereof one panel on the drilling floor.
- At least four remote controlled BOP rams/ preventers, thereof: One AP, two PR/VBR (for each size of drill-pipe used) and one BSR. BSR to shear any type drill-pipe/work-string/tubing.
- Independent dual pod-control system for operation
- Accumulators that provide 'fast closure' (emergency mode) of the BOP components in case of loss of power fluid connection to the surface
- ROV intervention capability (intervention mode) for override of minimum one PR/VBR, one BSR and the LMRP connector (disconnect).
- Autoshear and deadman systems for DP rigs (emergency mode)
- Side outlets on the BOP stack for a separate kill and choke lines. Each outlet with at least two remote controlled and full-opening valves. Install a choke line outlet above the bottom ram and a kill line outlet below the bottom ram.

In Norway, the Petroleum Safety Authority Norway (PSA) refers to NORSOK standard D-001 (NORSOK 2012) to meet requirements stipulated for equipment used in well drilling operations. There are some differences in requirements between BSEE and PSA. In comparison to the BSEE regulations as the main reference for such systems the following is noted in the Norwegian regulations:

- BOP control system that meet recommendations in OLF 070 (NOGA 2004), which stipulates SIL 2 requirements (IEC 2010) for closure of PR/VBR or BSR in two defined well control situations.
- LMRP disconnection system that secures well and disengages the riser before a critical riser angle occurs.
- Two shear rams where at least one is capable of sealing.
- For DP vessels; Shear ram that can shear casing and drill-pipe tool joints / heavy walled pipe.
- For mobile offshore drilling units the BOP shall be equipped with two annular preventers.

An illustration of two main BOP closure element configurations from the regulations and experience data is shown in Figure 1.

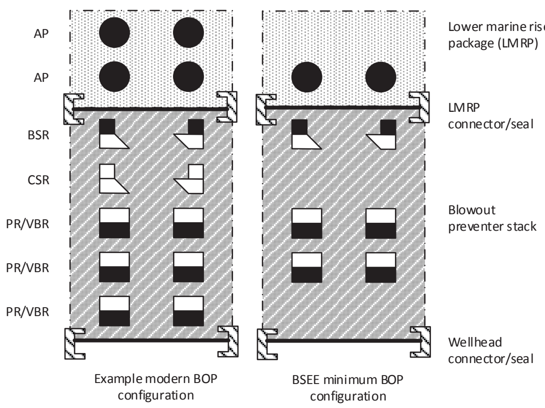

Figure 1. Example of BOP closure element configurations

3.3 *Operation and maintenance*

After the BOP installation testing the BSEE provides requirements to BOP function- and pressure testing every 7 and 14 days during the well operations. The BOP closure elements require pressure testing (14 days) for verification of both closure and seal for relevant well load scenario, but reliability data collected shows that most control system failures are revealed by function tests (Sattler and Gallander, 2010).

3.4 *Summary*

Seven distinct BOP well isolation (close-in) scenario has been identified from a technical review, which also are illustrated in Figure 2. Note that 1ooN denotes a system that functions as long as at least one out of total of N elements are functioning;

- 1a) Low well pressure scenario with drill-pipe in hole: Isolation of annulus with AP or PR/VBR elements available (1oo3, 1oo4, 1oo5)
- 1b) Low well pressure scenario with casing in hole: Isolation of annulus with AP elements available (1oo1, 1oo2)
- 2) Drill-pipe in hole: Isolation of annulus with PR/VBR elements available (1oo2, 1oo3)
- 3a) Low well pressure scenario with no pipe in hole: Isolation of well with AP or BSR elements available (1oo1, 1oo2, 1oo3)
- 3b) No pipe in hole: Isolation of well with BSR element available (1oo1)
- 4a) Drill-pipe in hole: Automatic isolation of well with BSR element available (1oo1)
- 4b) Casing in hole: Automatic isolation of well (Not evaluated)

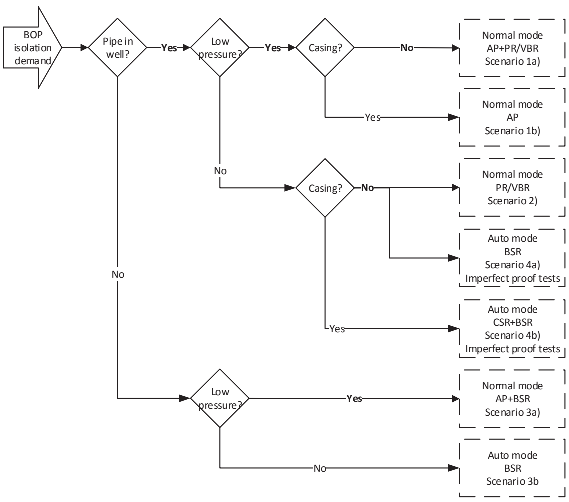

Figure 2. BOP closure demand scenario

4 RELIABILITY ASSESSMENT

4.1 *Modelling basis and experience data*

A safety and reliability model must reflect the system in those aspects that are of importance to produce trustworthy results. For guidance on model validity independent on well isolation scenario, Table 1 presents a list of the historically most severe, safety critical BOP system failures from Holand & Awan (2012), Holand (1999) and BSEE (2013). The data indicate the control system as a potential source for common cause failures (CCF). Also of main interest is TAR project no. 455 (BSEE 2004) stating that the BSR may fail in 50% of the times when attempting to shear pipe during actual operations. On same subject Holand and Awan reports (2012): "In the Phase I deep-water study, a failed to shear pipe occurred during an emergency disconnect. For the two emergency disconnect situations observed in this study, the BSR successfully cut the pipe and sealed off the well".

Table 1. Overview of critical subsea BOP system failure modes with relevant reliability data based on (Holand 1999, Holand & Awan 2012)

Item and failure mode	MTTF* (BOP days)	MTTF* (Item days)
Wellhead connector - External leakage (2of)	11128	11128
LMRP connector - Spurious disconnect (2of)	11128	11128
LMRP connector - Failure to disconnect on command (3of)	7419	7419
Control system - Total loss of BOP control (by the main control system) (7of)	3179**	3179
Control module (POD), single - Total loss of POD functions (20of)	1113	2226
Control PODs (2of) - Simultaneous loss of one function in both PODs (6of)	3709**	3709
BSR - Leakage in closed position (4of)	5564	6276
BSR - Failure to close on command (1of)	22256	25104
BSR - Failure to shear pipe in LMRP disconnect situation (1of)	NA	NA
BSR - Spurious closure (1of)	22256	25104
PR/VBR - Leakage in closed position (7of)	3179	8613
PR/VBR - Failure to close on command (2of)	11128	30147
PR/VBR - Failure to open on command (2of)	11128	30147
AP - Leakage in closed position (11of)	2023	3704
AP - Failure to close on command (1of)	22256	40748
Isolation valve on choke and kill line out-let - External leak (1of)	22256	NA
Choke and kill line - External leaks (Note; presumably downstream the isolation valves on BOP stack outlet) (13of)	1712	NA

Flexible joint (item is located above LMRP, and not part of well barrier envelope) - External leakage (2of)	11128	11128

*) Based on average BOP ram/preventer configurations in datasets. Total of 22256 BOP (installation) days and 482 wells drilled.
**) Produces an estimated CCF average rate of less than 1/22256 = 4.5E-5 /BOP day for rams and preventers (λ_{CCF}). Note respectively ~13/22256 = 5.8E-4 /BOP day for control system failures.

4.2 *Basis for new approach*

A BOP closure demand from unintended inflow of reservoir energy into the well may occur at random due to insufficient mud density, mud losses, riser failure, spurious disconnect of LMRP, or DP rig drive-off or drift-off. Aside relevant action from the drilling crew, the probability of a loss of well control ('blowout') in such situations will be equal to the probability of failure on demand (PFD) of the BOP. If we assume that the demands follow a homogeneous Poisson process (HPP), with a known rate γ, it is straight forward to model the associated well blowout frequency. By combining the HPP with the binomial situation, the number $N_{BO}(t)$ of blowouts caused by the demand in the time interval [0, t) will be a new HPP with frequency $\gamma \cdot PFD$ (Rausand & Høyland 2004). The probability that a drilling operation will 'survive' an operations length of, say 60 days, without a blowout is thus given by:

$$\Pr(\text{"survive 60 days"}) = e^{-\gamma \cdot PFD \cdot 60}$$

Most of the safety critical BOP failure modes are hidden, and regular function- or pressure testing is carried out to reveal such failures. The safety and reliability performance of a proof tested system is often measured by the average PFD, PFD_{AVG}. The PFD_{AVG} is mainly influenced by two parameters: (i) the rate of hidden failures of BOP elements (λ_{DU}), and (ii) the interval between two consecutive tests (τ). For a system of several BOP closure elements, the PFD_{AVG} becomes (Rausand 2014):

$$PFD_{AVG} = 1 - \frac{1}{\tau}\int_0^{\tau} R_S(t)\,dt$$

where $R_S(t)$ denotes the reliability ('structure') function of the BOP closure element configuration.

Assuming regular test intervals and perfect repairs, we may assume that the PFD_{AVG} takes the same value in all intervals, and PFD_{AVG} is thus the probability of the BOP failing to close *at any time*. Rausand (2014) presents simplified formulas for 1ooN systems of N identical elements subject to independent failures and CCFs (λ_{CCF}). For 1ooN BOP element configurations shown in Figure 3 we get:

$$PFD_{AVG} \approx \frac{(\lambda_{DU} \cdot \tau)^N}{(N+1)} + \frac{\lambda_{CCF} \cdot \tau}{2}$$

For instance, if we assume 1oo2, $\lambda_{DU} = 1/627$ (days), τ = 14 days, and $\lambda_{CCF} = 1/22256$ (days) we get PFD_{AVG} = 4.8E-4. Alternatively, with $\lambda_{DU} = 1/1173$ we get PFD_{AVG} = 3.6E-4. For 1oo3 with same input we get PFD_{AVG} = 3.2E-4. The failure rate assumed, λ_{DU}, is based on the overall MTTF data provided for AP element in Holand and Awan (2012), and appear conservative to the safety critical MTTF presented in Table 1. However, the AP input data is selected for purpose of the case studies, based on the conservative view that closure element failure always cause impairment of the element safety functions if a needed repair is postponed.

The PFD_{AVG} formula presented is based on a number of assumptions, which of main are:

1. The failure rate of the BOP elements are identical and independent of time. Several BOP elements are, however, non-identical (an AP is not the same as a PR/VBR or BSR)
2. All failures are detected during the proof test and within a negligible period of time. This assumption is clearly not valid for the BSR. The cutting of pipe and sealing is not (for obvious reasons) part of regular tests. However, every 3 to 5 year the BSR is 'overhauled', and it may be assumed that most deficiencies that could result in cut and sealing failure are revealed then. If Taylor series approximation still holds, $\lambda \cdot \tau < 0.01$, we may use time between overhauls as the 'test interval' of the shear function. However, care should be taken since the experience data indicates a high PFD of the BSR in an actual shear-demand situation.
3. All items are repaired to "as good as new" condition within a negligible period of time after failure detection. This is not always the case, or desirable, since it is possible in some cases to postpone repair of the BOP ('waivers given').

4.3 *New approach based on multiphase Markov*

Reference is made to the BOP closure demand scenario presented in Figure 2. A Markov model will allow the modelling of a degraded BOP system, but the number of elements to consider must also be restricted to avoid an undesired state explosion. The main idea behind the new approach is to incorporate the effects on well safety of postponing repairs, taking into account that BOP configurations have many redundant BOP closure elements. A similar multiphase

Markov model, but with another application area, has been developed and discussed by Welte (2008).

The Markov model in the approach is illustrated in Figure 3. In the model we assume N number of identical redundant BOP closure elements. ML denotes the maintenance level, which represents the degree of allowable degradation, the number of revealed failures, before the BOP is pulled for repair. I.e., the BOP will be pulled to surface for overhaul and full renewal (perfect repair) if the total number of revealed failures reaches or exceeds the ML value. Noted is bounds for the model with ML = 1 that equals a 1ooN system, and ML = N that equals a system that is not repaired until all redundant elements have revealed failures.

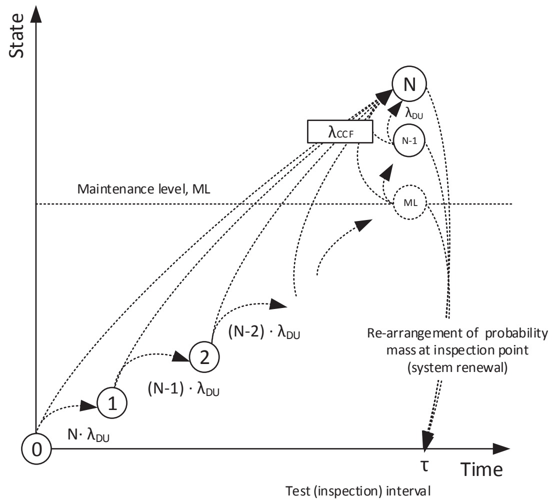

Figure 3. Illustration of multiphase Markov model

The model is made recursive, so that a numerical routine can be implemented to automatically solve over many inspection intervals within the total BOP installation period on the well.

According to Chapman-Kolmogorov's equation the Markov model in Figure 3 is given with N+1 states as (Rausand 2014):

P(t) · A = P'(t)

$$[P_0(t)\cdots P_N(t)]\cdot\begin{pmatrix}\lambda_{00} & \cdots & \lambda_{0N}\\ \vdots & \ddots & \vdots\\ \lambda_{N0} & \cdots & \lambda_{NN}\end{pmatrix}=[\frac{dP_0(t)}{dt}\cdots\frac{dP_N(t)}{dt}]$$

Where the **P(t)** vector includes the distribution of the probability mass between the states at any time t, and hence; $P_0(t)+P_1(t)+\ldots+P_N(t)=1$ is required for $t \geq 0$. In the transition rate matrix **A**, we have $\lambda_{i,k}$, for i ≠ k, denoting the incoming transition rate from state i to state k. If no possible transition from state i to state k then $\lambda_{i,k}$ = 0. Respectively, $\lambda_{k,j}$, j ≠ k, denote outgoing transition rate from state k to state j. If no possible transition exist from state j to state k then $\lambda_{k,j}$ = 0. As illustrated in Figure 3 the approach uses a stationary **A** with transition rates $\lambda_{N-1,N} = \lambda_{DU} + \lambda_{CCF}$, and otherwise not equal to 0 for i = [0, 1, …, (N-1)] given by:

$$\lambda_{i,N} = \lambda_{CCF}$$
$$\lambda_{i,i+1} = (\mathrm{N}-i)\lambda_{DU}$$
$$\lambda_{i,i} = -(\lambda_{CCF} + (\mathrm{N}-i)\lambda_{DU})$$

The start conditions will resemble a continuous time Markov chain model with all probability mass located in state 0, $P_0(0) = 1$. State 0 will represent the "as good as new" condition of all N redundant BOP closure elements. From the Markov property, **P(t)A=P'(t)**, that is valid between inspection times we may use the following to numerically solve the movement in the state's probability mass (Rausand 2014):

$$P_k(t+\Delta t) = \sum_{\substack{i=0\\ i\neq k}}^{N}\left[P_i(t)\cdot\lambda_{i,\mathrm{k}}\cdot\Delta t\right] + P_k(t)\cdot(1+\lambda_{\mathrm{k,k}}\cdot\Delta t)$$

Further, iteratively at each inspection point τ_i we move all the probability mass from states; $P_{ML}(\tau)$, $P_{(ML+1)}(\tau)$, … $P_{(N)}(\tau)$ and add this back to state 0. This produces the new start conditions **P(0')** for this period (phase) till the next inspection time and so forth until the mission time is reached. A typical mission time will be 60-70 days for a BOP. I.e., the BOP is then pulled to surface for maintenance and preparations for use on the next well.

Based on the approach, we may directly produce for decision support (i) the PFD and thereof PFD_{AVG} : The PFD of 1ooN configuration is equal to $P_N(t)$, (ii) the probability of having to pull the BOP at inspection point τ_i, which is equal to the $\sum_{m=ML}^{N} P_m(\tau_i)$. The PFD result from model can for instance be combined with a control system PFD analysis for verification of SIL 2 requirement (PFD_{AVG} < 1E-2) as stipulated in NOGA (2004).

5 CASE STUDIES

Figure 4 and Figure 5 show results from selected 1ooN configurations under key assumptions of proof test intervals; 14 days stipulated by BSEE and 21 days by API Std 53, and of conservative AP BOP element failure rate input (see section 4.2). In particular it is noted from the figures that a ML of less than N-1 produces a fairly constant ('robust') PFD value within the 70 - 84 day selected mission time. This indicates that a decision to postpone repair until the $(N-1)^{th}$ revealed closure element failure may be an option due to small impact on the 'BOP system PFD'. However, a careful check of assumptions and analysis with input data relevant to the actual BOP should be performed before making any decisions. Noted is also that verification of NOGA (2004) SIL 2 requirements appear to be within reach of most BOP system configurations, which is also demonstrated in FTA model calculation made by Holand and Awan (2012).

Steady-state PFD from the model was not produced during the case studies with a selected mission time of around 70-80 days in spite of relative high input failure rates. Care must therefore be taken when deducing PFD_{AVG} from the model. For example, a high impact on the numerical PFD_{AVG} value is found from a strong transient PFD in the first 14 or 21-day inspection interval. A rule of thumb in the oil and gas industry is to approach safety policy changes from a conservative side. Hence, we would suggest that PFD in 1^{st} interval is neglected when producing PFD_{AVG} with the model. For the case studies, neglecting the first inspection interval for PFD_{AVG} calculations implied some 11% to 25% increase in the average value. The PFD_{AVG} increase was highest in cases with small N.

6 CONCLUSIONS AND FURTHER WORK

The boundary conditions for safety and reliability analysis of subsea BOP systems have been thoroughly discussed on basis of internationally recognised regulations, industry standards and experience data collected by the industry.

A multiphase Markov modelling approach has been presented that can be used to explicitly evaluate aspects of safety performance and maintenance optimisation for typical subsea blowout preventer systems. Several case studies have been presented to demonstrate the application of the approach for typical BOP system configurations under normal operating conditions, which are referred to in the paper as "Scenario 1a/b" and "Scenario 2": Isolation of well annulus with AP or PR/VBR elements available.

A main assumption with the approach, a trade-off for model simplicity, is that all the BOP closure elements must have identical failure rates. Experience data shows that this can be a valid assumption, but same experience data may also be used to argue the need to use different failure rates. Hence, it may be of particular interest to study the implications of this simplification in the model. For example, what are benefits to a more detailed model over the simplistic alternative and use of sensitivity analysis?

7 ACKNOWLEDGEMENTS

Many thanks to anonymous peers in industry and academia for providing valuable suggestions for improvement.

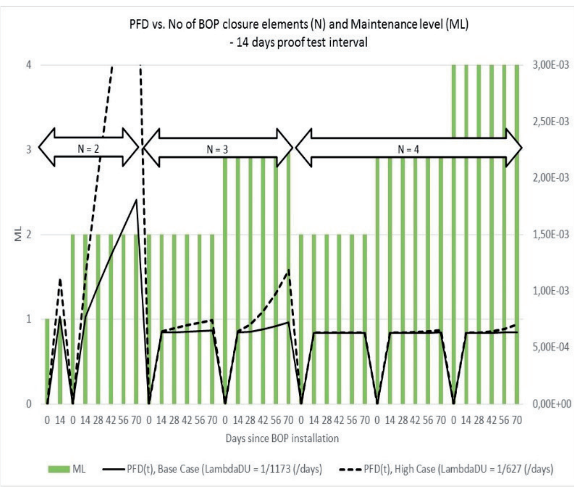

Figure 4. Case study 1 results of new approach

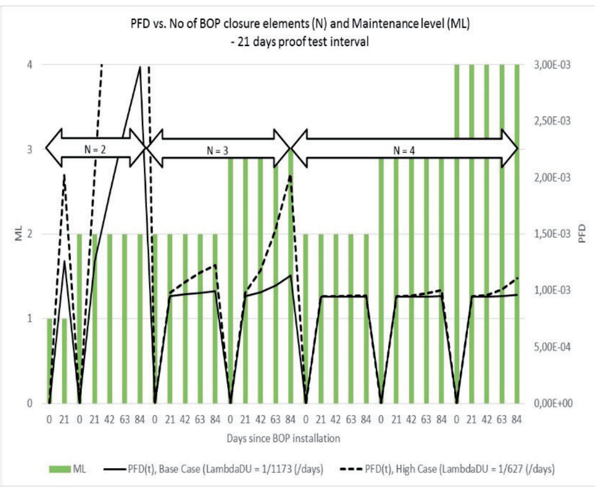

Figure 5. Case study 2 results of new approach

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III. PAPER 2: Evaluation of the role of HMI in risk analysis of offshore drilling operations

Strand, G.O. and Lundteigen, M.A., "Evaluation of the role of HMI in risk analysis of offshore drilling operations". Revised manuscript in review; Journal of Loss Prevention in the Process Industries, 2016

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Evaluation of the role of HMI in risk analysis of offshore drilling operations

Abstract

Risk assessments are important tools in the planning of offshore well operations. They ensure that involved crew personnel are prepared for, and aware of, challenges that may occur for a specific operation. The risk assessments may be qualitative as well as probabilistic to serve different needs. In both cases, it is vital to identify and evaluate risk factors that influence the crew's ability for detection and reaction to events that may affect the efficiency of well barriers. The human-machine interface (HMI) is the main means of communication between the state of the well and the crew, and it is therefore important to incorporate the role of HMI in risk assessment. One particular issue of interest is the importance of HMI in comparison to other factors that influence the crew's performance. The objectives of this article are: (i) To clarify the role of HMI from an operational perspective, and to investigate how recent well accidents reveal the HMI as a contributing factor. (ii) Suggest how the HMI may be more precisely incorporated in risk models that are used in the oil and gas industry. As an example, the article suggests modifications to a human reliability analysis (HRA) method developed in oil and gas industry on how to evaluate the HMI as risk factor in offshore drilling operations. The modifications suggested should ensure that key aspects of HMI as a risk factor in well drilling are not systematically overlooked in application of the HRA method. The article includes a detailed review of the HMI functionality available to the crew in relation to causality of four recent well accidents. As such, this article also provides additional reassurance and arguments for how the HMI should be evaluated in well operation task analysis.

KEY WORDS: Offshore drilling, well risk assessment, human factors, human-machine interface

Nomenclature

Abbreviations

HMI	Human-machine interface	BHA	bottom hole assembly
PRA	probabilistic risk assessment	DD	dual displacement correction sensor
HRA	human reliability analysis	MW	mud weight

OMT	organisation, human & technology	LMRP	lower marine riser package
WBE	well barrier element	RIF	Risk influencing factor
HF	human factor	SCADA	supervisory control and data acquisition
SA	situation awareness	MPD	managed pressure drilling
BOP	blowout preventer system		

1 Introduction

Drilling operations include accessing reservoirs where the hazardous conditions before entering can only be estimated with model based simulations. As such, it can be difficult to predict with certainty the type of challenges that the crews may face in the course of a drilling operation. The wellbore will, once a reservoir is entered, become a joint well containment system with the drilling rig. At same time it also become key to actively control the reservoir energy to avoid uncontrolled flow of hydrocarbons. In dealing with uncertainty, the oil and gas industry has in the course of its history adopted simple rules associated with well operations to ensure an acceptable risk of well control loss. One such cardinal rule widely adopted is to always maintain two qualified and tested well barriers towards a reservoir [1-3]. Unfortunately, maintaining two qualified well barriers can be challenging, and experiences from several accidents reveal that well barriers were not properly maintained during the operation.

Many safety functions provided in well drilling operations are manual tasks performed by drilling crew members. In risk assessment of well drilling operations it is, for instance, important to incorporate the ability of the crew to detect and respond to situations that may impair the efficiency of the two well barriers established. To successfully carry out necessary tasks to help maintain the two well barriers, the crews often rely on a combination of observations, measurements and estimates made at the surface to assess the 'true' downhole conditions of the well. There are many risk factors influencing the drilling crew's ability in this respect, and one such factor could be identified as the human-machine interface (HMI) [4]. The HMI can be defined as [5] "Equipment and availability of tools, with relevance for correct performance of a specific work operation." As such, HMI in drilling operations may include well system equipment, tools and instrumentation that help provide the crews with information related to the 'true' downhole conditions of the well. Moreover, the main functions related to the HMI in avoidance of, and resolution to, well control issues is primarily linked to the crew's ability to detect and remedy the failure of the primary mud barrier at the earliest indication [6].

In addition to simple rules established in activity, a premise in control of well operation risk is to include crews actively in the planning and preparation stages of a well operation. For example, this includes use of well risk assessments to study critical events such as well barrier failures and blowouts. The crews must, for instance, be prepared to detect and respond to well barrier failures that could occur in a timely manner. The risk assessments may be qualitative as well as probabilistic to serve different needs. Qualitative assessments may be useful in identification and preparations made related to sequences of events that could lead to loss of well control, and probabilistic risk assessments (PRA) may be useful during well operations to direct proactive attention to critical risk factors associated with unplanned situations in an operation. Based on a PRA, it may be possible to establish risk indicators, which could be monitored during the a well operation to ensure that the blowout risk is maintained at an acceptable level [7].

The number of safety critical tasks linked to well operation PRA suggest that human reliability analysis (HRA) should be included to quantify effects of human task performance. Dozens of methods are proposed for HRA that may be integrated in a PRA, including in domains of offshore operations [4, 5, 8, 9]. Common to modern HRA methods is the need to identify and evaluate influences of situation specific risk factors in the causal model to derive human error probabilities. An example of this can be seen in the human error causal model previously proposed by the Authors for HRA integrated in PRA of well drilling operations [4], which is adopted from the 'Risk OMT' risk modelling framework [5]. The Risk OMT framework is developed for oil and gas industry and links traditional risk assessment models with a method for HRA. However, the predefined role of HMI in the causal model is based solely on risk modelling scenarios considered in Norwegian offshore installation risk assessments [5]. These risk assessments traditionally only incorporate well blowout risk generically [10], which implies that the role defined for the HMI in method may not be directly applicable to drilling operations globally [4].

In general, one particular issue of interest to well risk assessment is the importance of HMI in comparison to other factors that influence the drilling crew's performance. The objectives of this article are: (i) To clarify the role of HMI from an operational perspective, and to investigate how recent well accidents reveal the HMI as a contributing factor; (ii) Suggest how the HMI may be more precisely incorporated in risk models that are used in the oil and gas industry.

1.1 Approach and structure of article

The article findings are based on a review of four recent drilling and workover blowouts to assess the degree that the accident causality data reveal the HMI as a contributing factor in relation to various unsafe acts made by crews. The reviews include an accident 'sequence of events' analysis with review criteria developed in consideration of the explicit role of HMI functionality in performing a well risk assessment assisted by the method proposed by Strand et al. [4]. The focus of reviews is placed on the main well control related HMI functionality, i.e. its ability to assist the crew on the rig floor to maintain their understanding of the wellbore in-situ flowrates and pressures. These are two physical properties considered vital for detection of fluid influx (well kick) or fluid loss, which are both strong symptoms of a safety critical event.

The accidents selected for review investigation in this article include; Snorre (2004), Montara (2009), Macondo (2010), and Gullfaks (2010) with publicly available source material [11-14]. The accidents selected are all recent blowouts that involve modern technology and practices, and which are found sufficiently documented in the public domain for purpose of the reviews. This includes documentation about the well operation sequence of events that lead to blowout, and where the following information has been made available; (i) the well barriers in place and their functional status; (ii) the well system in-situ fluid sub-volumes and their pressure gradient situations; and (iii) the HMI functionality in support of tasks on the rig floor that help crew maintain their estimates of in-situ wellbore flowrates and pressures.

The accident reviews are documented in worksheets, structured as a sequence of event based situation analysis of the accident operation. The worksheet includes columns with specific source information and discussions, which are defined from specific analysis criteria identified for purpose of the article objectives. The relationship between the analysis critiera and the documentation provided in the worksheets is illustrated in Figure 1.

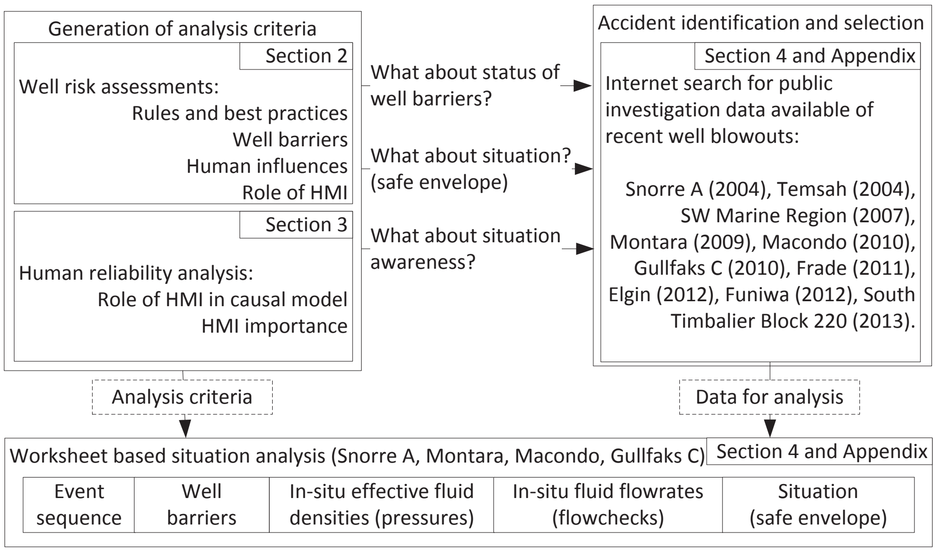

Figure 1. Illustration of the accident review process

The terminology used in Figure 1 is explained in following sections; Section 2 describes the accident analysis criteria generated from a well operation risk assessment perspective. This includes an overview of well barrier, task and safety considerations typically made by the crews involved in drilling and workover operations. The concept of safe envelope suggested by Hale et al. [15] is adopted in the discussion to describe the potential progression of a well operation towards loss of well control, as well as means of recovery. Section 3 describes the accident analysis criteria generated from the proposed HRA method perspective, and a brief overview of the HRA causality modelling structure. The discussion about the HMI role in the HRA causal model is linked to key drilling tasks and situational elements on the rig floor by adopting the concept of situation awareness [16]. The main findings from accident review and analysis are summarised in Section 4, and the analysis worksheets developed as detailed documentation of the reviews are enclosed in the Appendix. Section

5 proposes modifications to the HRA method based on the accident review findings. Finally, Section 6 includes concluding remarks from observations made and proposed further work.

2 Framing of accident analysis from a well risk assessment perspective

Maintaining two qualified well barriers can be challenging, for example, when an operation involves novel sequences of introduction, removal and replacement of individual well barrier elements (WBE). WBEs represent well barrier building blocks, and it may be useful in well risk assessment to classify WBEs as passive or active [17]. Passive describes WBEs with a safety function that is ‘always’ available, and active WBEs require a remote command, manual or from logic solver. We may also consider many WBEs conditional in the sense that they are; (i) Not available at all times, or (ii) not designed to tackle all realistic well operation load case scenarios.

A well risk assessment can therefore be defined as a study of the two main safety functions of a well system; (i) Containment of well fluids, commonly referred to as well integrity in industry. This is a continuous function mainly provided by passive WBEs. (ii) Close-in the well in case of a safety critical situation. This function is an on-demand type mainly provided by active WBEs, and based on random activation. This section includes descriptions of domain specific factors viewed important to maintain relevance of the accident reviews in context of well operation PRAs. This includes:

(i) A description of risk assessment based around the ‘rules for good conduct’ in activities, which are typically provided in regulations and recognised industry standards and practices. The good conduct is discussed explicitly in the accident reviews by adopting the concept of activity progression within a safe envelope [15].

(ii) A description of drilling operations and WBEs that make up the two well barriers. It also includes a description of how human factors (HF) may affect the performance of well barriers and why early detection of well kicks is important for accident prevention.

(iii) A description of HMI functionality with regards to early detection of well kicks from a well physics perspective following Bernoulli’s law for energy conservation.

2.1 Well integrity and the safe envelope

Well risk assessment is closely linked to regional well integrity requirements. ISO 16530 [3] defines well integrity in the well operational phase as “containment and the prevention of the escape of fluids (i.e. liquids or gases) to sub-terrane formations or surface.” Another definition of well integrity stems from the Norwegian oil and gas industry’s NORSOK D-010 [2] standard. The definition encompasses well integrity across all well lifecycle phases; “Application of technical, operational and organisational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well.” Focal to both standards are the technical means for containment of the energy in an oil and gas reservoir. What the ‘operational and organisational solutions’ in the NORSOK D-010 definition entail is not explicitly discussed. In this article we adopt the view of influences that involved personnel have on well operation risk through decision making about introduction, activation or re-establishment of well barriers [18].

The potential for total loss of well containment, referred to as a blowout, is the focus of most well risk assessments. More precisely, the main objective of assessment is often to study the probability and consequence of well control incidents. A well control incident can be defined by NOGA 135 [19] as “A failure of barrier(s) or failure to activate barrier(s), resulting in an unintentional flow of formation fluid (i) into the well (ii) into another formation or iii) to the external environment.” The NOGA definition is ambiguous in the sense that it mixes an initiating type event referred to as well kick (i), with well blowout incidents, (ii) and (iii), that are typical outcomes studied in assessment.

Further, the assessment is typically framed by prescriptive requirements in the regulations, for instance [20-22], and in regional and global industry standards, for instance in the well operational phase [1-3]. The industry standards often provide examples of best practices and minimum technical well barrier solutions required. In situations with prescriptive regulations and industry standards it also follows naturally that best available (safest) technology and best industry practises may be enforced as the principles for risk acceptance [20]. Well risk assessment on the basis of requirements may be considered a study where every well, inherently different from Mother Nature’s side, requires its own dedicated assessment, and where acceptable risk is achieved by following prescribed rules. The aspects of HMI that can be associated with the inadvertent or intentional breaking of the two-barrier rule is therefore important in this article for well accident prevention.

Given safest industry technology and practices, and the two well barrier rule as foundations for well operations, an adapted view of the safe envelope introduced by Hale et al. [15] is found useful to the accident reviews as an aid to explicitly describe the progression of a well operation between different state spaces (situations) of conformance as result of undesired human action or inaction (unsafe acts). Figure 2 shows the adapted safe envelope view proposed. The states spaces are defined with help of interviews made with drilling crews as part of a SINTEF research project [23]. In interviews it was observed that 'operation progressing and completed as planned' was common to the interpretation of a successful well operation. In total, Figure 2 shows four situations proposed as applicable to describe the progression of well operations:

(i) Variation where the operation routinely progresses within the area defined by the approved plans and preparations made in advance, i.e. the operation boundary

(ii) Deviation where the operation progresses within the area (margins) between the plans and breach of rules and best practices provided by regulations, governing documents and recognised industry standards, , i.e. the industry boundary

(iii) Violation where the operation progresses within the (potential) margins between the breach of the rules and best practices, i.e. the safe envelope boundary, and

(iv) A situation with multiple well barrier failures and harm.

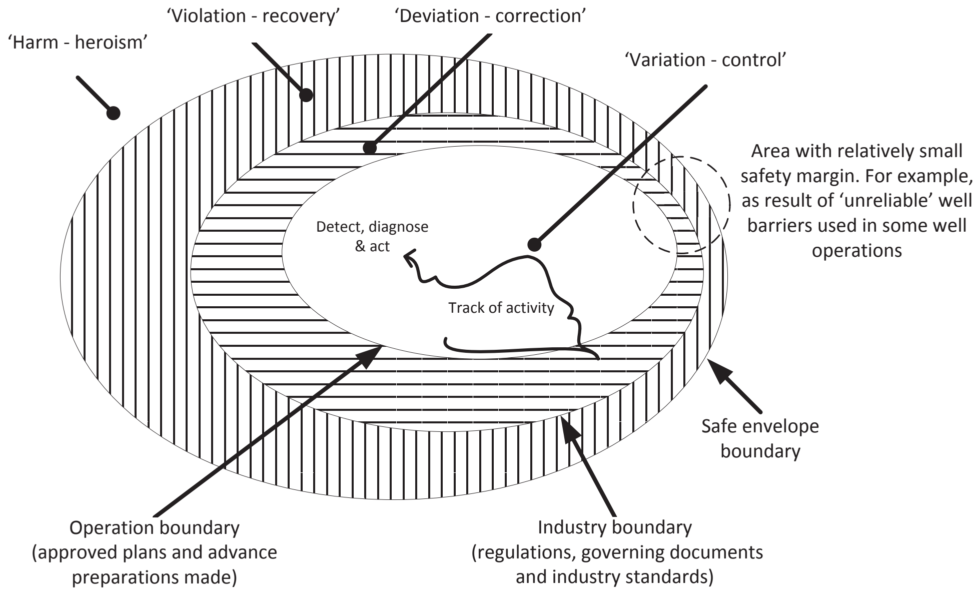

Figure 2. Safe envelope proposed to describe well operation safety (modified from [15])

For example, from well blowout statistics [24] we may consider well drilling and workover operations progressing on the right hand side in Figure 2. On this side, there are less margins for progression due to unsafe acts illustrated with a dashed circle, for instance, as a result of the drilling mud constituting an unreliable well barrier historically [25]. This in contrast to, for instance, the well operational phase that may be considered to include more reliable well barriers and consequently also have larger margins as illustrated on the left hand side of Figure 2. In Figure 2, the progression towards an accident always starts with a breach of the approved plans and preparations made for the operation. The implication is that the operation plans are always good in the sense that they are within the safe envelope provided as minimum by regional governance and industry standards. The presumption may express a flawed industry overconfidence in existing plans and that 'the rules mostly work' [26]. However, such an overconfidence is not indicated based on recent well accident investigations. On contrary, the inability of operator change management systems to properly address changes made to the original well operation plans are repeatedly stressed [7]. Figure 2 also illustrates how an activity track may be thought to progress and be navigated by the crew in between relevant situations on the basis of the level of situation awareness (SA) achieved. SA is described further in Section 3.2.

2.2 Well drilling barriers and human performance influences

The offshore well drilling process is depicted as a snapshot on the left hand side of Figure 3. Well drilling consists of an iterative sequence of: (i) Excavating a cylindrical hole using a work string with a drill bit assisted by the circulation of drilling mud, and (ii) installing a casing or liner, in this hole. The main functions of the casing are to provide hole-stability and to increasingly strengthen the sub-terrane part of the wellbore with regards to burst pressure tolerance. The casing strings are cemented in place inside the hole to avoid communication between different hole-sections and thus a weakening of the wellbore. The well also includes an interface above ground, the wellhead system, which also holds key well control equipment. In well drilling the wellhead will have a blowout preventer system (BOP) with lower marine riser package (LMRP) installed. The BOP is an active WBE, which means that most activation to close-in the well is based on manual commands [27].

The two well barriers established during well drilling operations are illustrated in Figure 3 on the right hand side. The well barriers are illustrated by WBEs that form two concentric triangles that provide enclosure of a reservoir. The sub-volume legends shown in Figure 3, V0 through V7, are explained and discussed in Section 2.3.

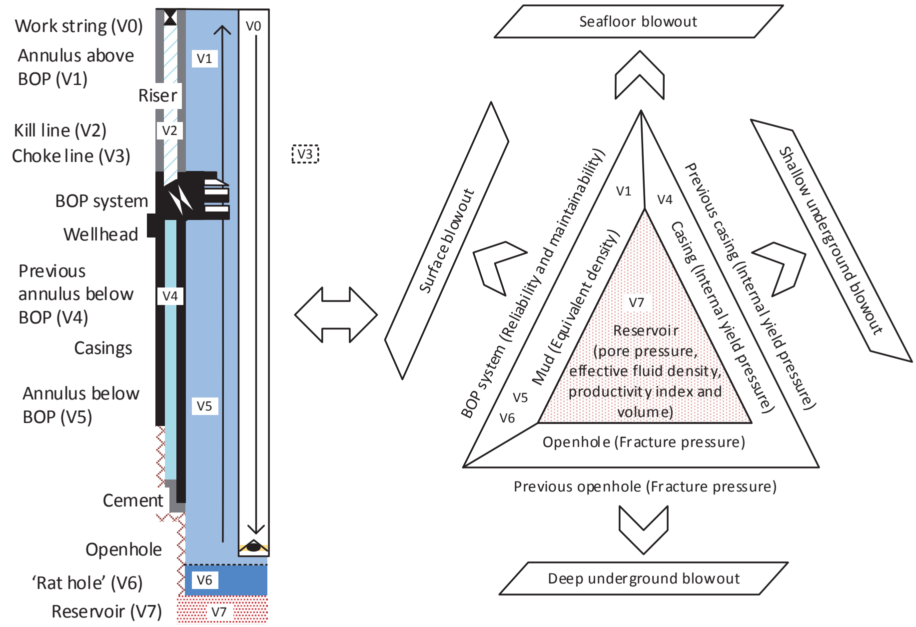

Figure 3. Well volume based view and the two well barrier drilling model (inspired by [28]).

A listing of factors that influence the WBE safety function performance in Figure 3 is presented in Table 1. Table 1 includes a description of typical WBE failure data associated with technical features and human tasks that may affect the WBE efficiency. The failure of the BOP system can, for instance, be described by physical degradation modelling [27]. For the other WBEs the probability of a failure can be associated with stress-strength interference modelling. The probability of failure of WBE_i, P_i, can be expressed as a situation in which the effective load propagation from the well fluids onto WBE_i, L_i, exceeds the WBE_i strength, S_i. Typical factors that affect WBE stresses and strengths are presented in Table 1.

Table 1. Main safety function features of well barrier elements used in well drilling

<table>
<tr><th>WBE</th><th>Failure mode</th><th>Failure cause</th><th>Technical or human stress-factors</th><th>Technical or human strength-factors</th></tr>
<tr><td>Drilling mud</td><td>Loss of hydrostatic control (well kick)</td><td>Loss of vertical height of mud column (losses).
Insufficient mud weight / hydrostatic fluid pressures (gains).</td><td rowspan="4">Reservoir pressure.

Reservoir volume.

Fluid mobility (productivity index).

Equivalent weight of pressure transmitting kick fluid column (kick influx volume and fluid type).</td><td>Testing (flow check) to verify static pressure barrier function. Mud weights (densities) verified by downhole- and surface measurements. Background gas measurements.</td></tr>
<tr><td>Openhole / Previous openhole</td><td>Formation fracture (leak off)</td><td>Pressure exceeds in-situ capacity of formation.</td><td>Estimates verified by pressure testing.</td></tr>
<tr><td>Casing / Previous casing</td><td>Leak / Burst / Collapse</td><td>Differential pressure load exceeds in-situ capacity of casing (burst or collapse).
Corrosion (old casing).
Mechanical wear from work string.</td><td>Internal yield and collapse resistance is verified by pressure testing, wear and corrosion calculations, and measurements of metal shavings in return mud at surface.</td></tr>
<tr><td>BOP system</td><td>Fail to close / Leakage in closed position / External leak / Spurious disconnect</td><td>Intrinsic failures.
Human error (no or spurious activation).
Excessive usage (outside design or usage specification).</td><td>Barrier functions verified by regular function testing. Subject to regular preventive and corrective maintenance.</td></tr>
</table>

The technical features contribute to P_i intrinsically as the effect of the WBE design on reliability and maintainability. The workplace and human task specific factors that influence element failure probability are seen to be numerous, affect all WBEs, and to be relevant for assessment of both strength and stress distributions. The factors include the ability to carry out WBE function verification tests, ability to detect drilling mud failures, ability to successfully activate the BOP, and carry out BOP maintenance. Humans may also influence the stress (pressure load) that will propagate upwards in the wellbore in a well kick situation. This load will depend on the kick influxes fluid volume and type, where early detection of a kick generally results in low wellbore fluid loads. Early detection of well kicks is therefore considered important to well drilling safety [6, 23]. For an analysis of the role of HMI in well accident prevention, industry advises that focus should be on HMI functionality that may influence the ability for drilling crews to detect well kicks early. From Table 1 this is related to monitoring for potential drilling mud gains, which includes tests and observations made related to volume rates, pressures and changes in drilling mud properties such as gas content, density and viscosity [29, 30].

2.3 The role of HMI in well kick detection

An important starting point for detection and control of well kicks is an understanding of events and conditions on the rig floor (workplace), which often are a function of what may be occurring several thousands of meters downhole in a well.

The drilling mud is a primary WBE against the reservoir energy (Figure 3). The fluid mobility through most formations is limited [31], and all movement of fluids between the formations and the wellbore follow Bernoulli's law of energy conservation. In practice, this law implies that significant fluid movement only can occur from a point of relative high to low pressures in a well. Static hydraulic theory tells us that in-situ pressure in a well is given along fluid column vertical heights, h_{TVD}. The hydraulic theory also tells us that pressure is a function of applied pressure on top of the column plus the pressure exhibited by the equivalent weight, ρ_{equiv}, of the fluids in the column over vertical height [3];

$$p_{in-situ} = p_{top} + \rho_{equiv} \cdot g \cdot h_{TVD}$$

An oil and gas well physically resembles several long and narrow fluid volumes that may have an orientation in the vertical plane of several thousands of meters. This means that there can be large differences in the in-situ pressures in a wellbore, and the left hand side in Figure 3 illustrates that we may consider eight separate fluid columns in the well during drilling operations, denoted as volumes V0 through V7. The volume V6 is not present during drilling when the bottom-hole assembly (BHA) is excavating the formations in the bottom of the wellbore. The volumes V0, V1, V5 and V7 are where fluid movements normally occur due to differential pressures maintained by the rig pumps used to circulate the drilling mud. The normal circulation path of the drilling mud is indicated with solid lines in Figure 4, and respective alternative paths, for instance used in diagnosis of symptoms of a well kicks are shown with dashed lines.

The mud and the wellbore can be treated as an incompressible fluid system. Under stable conditions, the mud volume pumped into the wellbore, q_{in}, should reflect any changes made to the total wellbore volume and the mud volume received at surface, q_{out}. The total volume of the well can change, for instance, due to the drilling progress or from relative movements between wellbore and rig. The volume of the well is carefully monitored by well depth measurements, and by measuring volume changes from relative rig movement indicated with a dual displacement correction sensor (DD) in Figure 4.

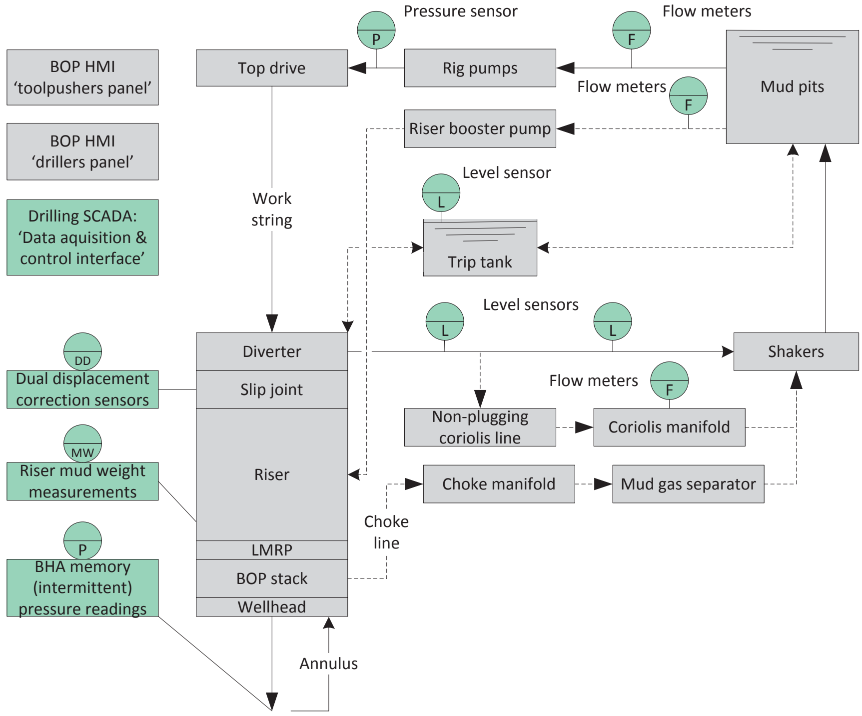

Figure 4. Example monitoring setup of conventional well mud circulation system (adapted from [6])

The drilling mud related situational elements are logged continuously or intermittently at the rig floor as illustrated with sensors in Figure 4. The wellbore vertical depth is measured directly, and mud weight (MW) or pressure by physical measurements downhole or at the mud handling system at the rig. The MW measurements are typically only taken at intermittent points in the well, which could present a source of confusion for the drilling crew. With pressure or density, ρ_{equiv}, measurements only obtained at some few points, this means that interpolations have to be made to the other points of interest in the wellbore. Making such interpolations may not be straightforward due to the intrinsic instability of muds and potential for contamination due to, for instance, drill cuttings or formation fluids. Therefore, the crew regularly monitors volume rates or pressure build-up through V1 when the rig pumps are shut off - referred to as performing flow checks. The flow checks are considered to be important precautions taken to mitigate the uncertain in-situ fluid densities and flow rates, and to address uncertainties in the formation pore pressure prognosis. One of the well accidents reviewed in this article [32] occurred during reservoir section drilling and therefore presumably occurred with BHA pressure readings available to the drilling crew. The other three accidents reviewed [11-13] likely occurred without a BHA tool in the well based on information available in source documents; i.e. the crew only had flow checks and other surface observations available in order to assess the real wellbore pressure and flowrate conditions.

3 Framing of accident analysis with HMI as a risk factor in HRA method

This section describes the accident analysis criteria generated based on the role of the HMI as a risk factor in the proposed HRA method. The discussion is linked to key drilling tasks and situational elements on the rig floor by adopting the concept of situation awareness [16]. The research that explicitly addresses HFs relevant for well operation HRA is scarce, based on a literature search. For example, Vignes [33, p. 63] makes use of own work experiences and observations from projects and audits conducted by the Petroleum Safety Authority Norway to discuss HFs in drilling and intervention operations. The role of HMI as a potential risk factor defined is not discussed.

3.1 The role of HMI as risk factor in HRA method

Dozens of HRA methods and lists of human performance and risk influencing factors (RIFs) where HMI is included exist in the literature. An example is the effort by Groth and Mosleh [34] to consolidate some of the risk factors used in nuclear PRA. A RIF is sought to be defined orthogonally and evaluated in the HRA without ‘overlaps’. The evaluation of RIFs may become difficult as a result of complex relations that may exist between RIFs at different levels in a human error causal model hierarchy. Also, a RIF may not be directly associated with human error. RIFs may be described as workplace factors that combine with latent human error tendencies and create work situations prone to human error [4, 35].

For example, Schönbeck et al. [36] provide a summary of literature that represent the dominant perspectives for the identification and evaluation of RIFs for the purpose of HRA. The literature studied major organisational accidents from perspectives in sociotechnical system theory. The sociotechnical system theory primarily looks at the design of accident investigations in order to maximise learning, described as a change in behaviour, in a broadest possible social context [37]. However, in spite of the retrospective origin, the same literature also is used extensively in HRA. Rosness et al. [38] provide a discussion of different sociotechnical accident perspectives. The perspectives are categorised by causation focus, specifically on (i) energy and defences (barriers), (ii) complexity and coupling in the human-technology interfaces, (iii) competence and co-operation, (iv) information flow, (v) conflicts of interest, and (vi) successful adaptations.

The two-barrier rule in well safety is well aligned with the energy-defence hierarchy model proposed by Reason [39], which is the basis for the Risk OMT causal model [5] that is adopted for drilling operation HRA [4]. The energy-defence model links human and organisational factors to impairment and failure of human, organisational and technological defences put in place to prevent major accidents. Two pathways to failure of the defences are described by the model, driven according to Reason [39], by a constant tug from trade-offs in the organisation between production and protection. The first pathway is described as a direct result of higher level workplace or organisational factors. The factors are described to affect the potential alignment of weaknesses (holes) in the defences, which could result in complete penetration (an accident). The weaknesses are described to inevitably exist due to technical constraints or human fallibility. The second pathway that affects the alignment of the holes is described as an indirect result of workplace and organisational factors. The organisational factors first affect the workplace conditions, which in turn become the source for unsafe acts by system operators in the sharp end.

RIFs may be defined on different levels based on the energy-defence model. The HMI typically represents a RIF defined in a causal model around unsafe acts in the sharp end of workplace, together with the physical working environment as illustrated in Figure 5. The mechanisms by which organisational and workplace factors affect the pathway conditions is not clear in literature [38]. Vinnem et al. [5] suggest that the HMI and physical workplace environment ('Design') share a structural dependency in RIF causal model structure provided with a management level 2 RIF defined as "management concerning workplace design and the HMI" (Figure 5). Also shown in Figure 5 are three execution type of human errors defined in Risk OMT, where HMI is seen in RIF structure to influence mistake type errors.

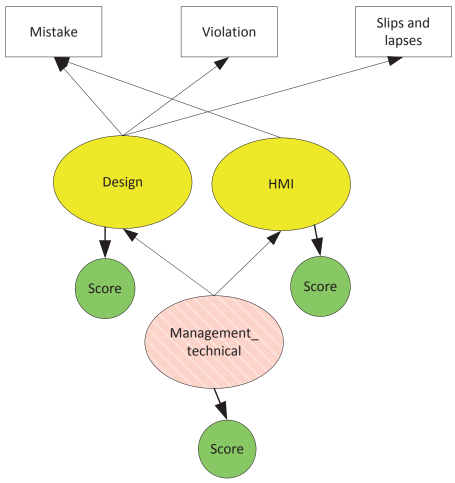

Figure 5. Illustration of the role of HMI in risk influencing factor structure of Risk OMT [5]

Vinnem et al. [5] suggest a compact human error causality classification to be used in the evaluation of the RIFs seen in Figure 6.

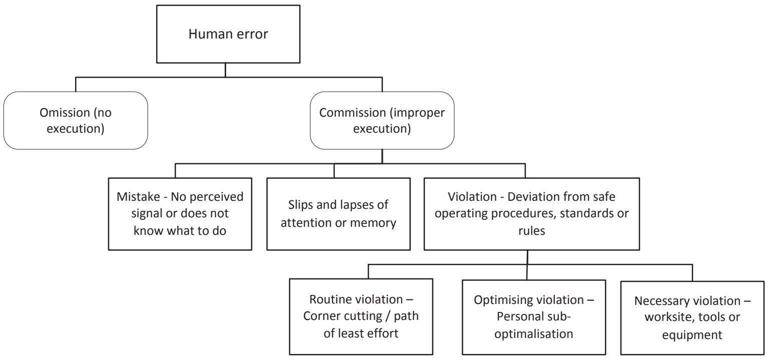

Figure 6. Classification of human errors in Risk OMT (from [5] based on [39])

Figure 6 describes human error as unsafe acts of either an omission or commission type. The omission type error describes a typical situation where an operator may do nothing in response to a critical situation due lack of the physical means needed. The commission error is described in two parts. One part is inadvertent mistakes or ‘slips and lapses’ due to human fallibility, for instance, related to lack of training or limited capacity for information processing [40]. The second part is violations, which represent a breach of the official recognised safe operating practises. A violation may be obvious and deliberate, or inadvertent as result of human fallibility or poor workplace ergonomics. The violations may be categorised as either routine, optimising or necessary, respectively in Figure 6.

3.2 The evaluation of HMI as a risk factor in HRA method

The term SA applies to HF analysis that is focused on the sharp end. For example, the SA concept is used for human performance analysis of real-time decision-making by operators of complex dynamic systems such as air traffic controllers and power plant operators. SA represents the ‘detect, diagnose and act’ part of the activity track in Figure 2. A popular concept for assessment of situation awareness is proposed by Endsley [16, 41]. According to Endsley [16] the process of obtaining SA, which is described as making a situational assessment to reach a state of knowledge about elements and their states, includes three steps: (i) Perception of situational elements and their states, i.e. hear, see, smell, taste and feel the vicinity; (ii) comprehension of situational elements such as inconsistencies, trends, correlations and patterns; and (iii) situational element state projection (forecasting) as the basis for near future actions. The application of the SA concept in HF analysis of offshore well drilling operations is not new. For example, Roberts et al. [42] make use of the same SA concept to structure interviews and observations made from simulator training of drilling crews to help develop training programs and work design recommendations.

The rig floor is filled with heavy equipment, odors, weather, people and noise [35]. The main HMI well control functions are illustrated in Figure 4 with equipment and tools linked to supervisory control and data acquisition (SCADA) display and BOP control panels. The HMI may help portray many situational elements needed for the drilling crew to meet all well drilling objectives as discussed, for instance, by Blaasmo et al. [43]. However, in regards to well control it is argued in Section 2 that the well represents a mathematically simple, yet complex, multi-volume hydraulic system. Therefore, the focus on HMI functions in the accident reviews is on the situational elements important to well control, with a priority on the task of controlling the in-situ wellbore pressures and flowrates during the well operations. The reviews are provided for what is considered to be a normal industry workplace setting where the responsible personnel are focused on following the original approved plans and best industry practices to be successful [23]. Moreover, the situational analysis of the well accident event sequences in reviews is focused on three aspects:

(i) Information related to well safety that the drilling crew receives from the HMI and the rig floor workplace environment; the situational elements and their states.

(ii) During operation and in hindsight; what appears to be, and could have been the physical comprehension of situational elements relative to well safety; detection of unsafe acts and progression in safe envelope across boundaries.

(iii) During operation and in hindsight; what appears to be, and could have been desired actions as recommeded by the two-barrier rule and by best practices and industry standards.

The SA concept seems to originate more from domains of cognitive and social psychology, than from sociotechnical system theory [44]. For example, if compared with technical failure analysis [45], it appears that the SA concept produces a human error causal classification that is oriented more toward failure mechanism than to a failure cause as would be produced with sociotechnical system theory (Figure 6). The accident reviews are made with consideration of the HMI importance in both causality domains, which includes an emphasis on HMI functionality based around (i) unsafe acts defined by progression (in hindsight) across situation borders defiend in the safe envelope (Figure 2), and (ii) effects of unsafe acts with regards to dynamic physical wellbore conditions that cause a situation of multiple well barrier failures and harm.

4 Accident review and analysis summaries

This section presents summaries of the accident review and analysis findings. For source information, see detailed documentation of the accident reviews enclosed as separate worksheets for each accident in the Appendix. The accident summaries and worksheets are developed by the authors with help from senior well integrity and drilling personnel to assure that the well physics and rig floor descriptions provided are plausible and relevant to the analysis of role of the HMI in the causality of the accidents.

<u>The Snorre</u> accident occured during the pulling of a liner from the well through the BOP as part of a workover operation [11]. The event is described to include a typical fixed installation HMI with surface BOP, mud handling and topsides instrumentation. Based on Figure 3 and Figure 4 we may consequently; (i) omit HMI functions related to DD, MW and downhole BHA sensors, and (ii) omit V1, V2, and V3 as minor volumes topsides and not of interest. The wellbore was open to the reservoir during the event sequence with the initial two qualified well barriers defined by a kill mud gradient established in wellbore prior to operation start, the casing with the liner as a lower section thereof, and the BOP. The crew is reported to periodically fill up the wellbore with mud and to perform flow checks during the event sequence. The liner was pulled by latching the work string, V0, to the top of the liner. This means that the volume below the work string and liner not directly affected by periodic mud circulation in the wellbore, V6, is increasing as the liner is pulled out during the operation. At same time, V4 and V5 become increasingly mixed together with V6 into one fluid volume.

The event sequence leading to a shallow underground blowout is considered to include two main unsafe acts. First, a weakening of the secondary well barrier is found acceptable as result of the decision to establish permanent communication between V4 and V5. The qualified capacity of V4 previous casing and previous openhole as WBEs may be estimated from documented well data (Table 1). The act or its effects may not clearly be linked to typical HMI functions since no pressure test of V4 is reported (Table 1). Second, the wellbore was allowed to be open to the reservoir with potential for swabbing effects and reservoir influx into V6 (and V4, V5). The effects of that act is that V4, V5 and V6 developed into a diffuse multigradient fluid system, which resulted in a failure of both the mud barrier and the previous openhole formation barrier. The development of a diffuse fluid gradient system in wellbore may be linked to typical HMI functions. The HMI in this case included a workstring without any downhole instrumentation. The workstring provided the capability to establish known fluid gradients in the wellbore, but as such only provided limited support in terms of surface measurements, and in helping the crew assess the status of in-situ wellbore flowrates or pressures.

The Montara accident occurred during surface work in the wellhead area as part of the last stages of well drilling operations [13, 14]. The event is described to entail work on the wellhead that required a jack-up rig positioned above the well initially, but later in operation without any HMI equipment such as surface BOP, mud handling or instruments associated with the well. Based on Figure 3 and Figure 4 we may consequently; (i) omit HMI functions that relate to surface BOP, mud handling and instrumentation, and (ii) omit V0, V1, V2, V3 and V5 as potential volumes of interest. The wellbore was cased and cemented about six months prior to operation, but the wellbore was still (in hindsight) open to the reservoir. The initial two qualified well barriers were defined by a seawater gradient established in the wellbore prior to the suspension, the casing, and the pressure cap installed on the wellhead. The pressure cap was removed by latching the work string, V0, to the top of the cap. This implies that the volume below the work string, V6, represents the entire wellbore during the event sequence.

The event sequence leading to a surface blowout is considered to include one main unsafe act, namely the decision to remove the rig from the well thereby allowing a wellbore that penetrates a reservoir to remain open to the surface and without qualified means in place for well barrier monitoring or recovery. The effect of this act is that V6 developed, unnoticed, from a single gradient into a multigradient fluid system, with knock-on effects observed topsides as rising gas bubbles that result in a failure of the suspension seawater barrier and the cemented casing. The development of this diffuse fluid gradient system in wellbore may be linked to typical HMI functions. The HMI in this case does not include any workstring or instrumentation, and as such provided no support in terms of helping the crew assess the status of in-situ wellbore flowrates or pressures.

The Macondo accident occurred during the last stages of wellbore construction, and started with a negative pressure (inflow) test to qualify a cemented liner installed in the reservoir as a WBE [12]. The event is described to include a HMI for a modern, dynamically positioned floating rig with subsea BOP, mud handling, and instrumentation excluding the BHA. Based on Figure 3 and Figure 4 we may consequently omit the BHA sensors. The wellbore was cased and cemented, but the wellbore was still (in hindsight) open to the reservoir. The initial two qualified well barriers were defined by a mud gradient established in wellbore prior to the inflow test, the casing, and the subsea BOP. The crew is not reported to regularly perform flow checks during the event sequence. The inflow test is reported performed by first running the work string, V0, partly into the wellbore. This was to displace the wellbore mud column above, V5 and V2, to a lighter fluid column and thereby create a gradient pressure inside the liner lower than the external reservoir pressure. This work string position in wellbore is reported to be maintained, which means that all volumes remain constant in size during the event sequence. The volume, V6, was thus not directly affected by mud circulation taking place in wellbore above.

The event sequence leading to a surface blowout is considered to include two main unsafe acts. First, allowing for a permanent weakening of the primary mud barrier, ρ_{equiv}, as a natural implication of a disputed decision made to approve the liner inflow test. Second, allowing for displacements external to the closed mud handling system and without flow checks in a wellbore that penetrates a reservoir. The effects of these acts are that sub-volums in well develops into multigradient fluid systems, with knock-on effects that result in catastrophic failure of both the mud barrier and the BOP. The development of a diffuse fluid gradient system in wellbore sub-volumens may be linked to typical HMI functions. The HMI in this case included a workstring without any downhole instrumentation. The workstring provided the capability to establish known fluid gradients in the wellbore, but as such only provided limited support in terms of surface measurements, and in helping the crew assess the status of in-situ wellbore flowrates or pressures.

The Gullfaks accident occurred during the drilling of a reservoir section that was impeded repeatedly by well control and hole instability issues [32]. This eventually made the drilling operation convert from conventional drilling mode and into managed pressure drilling (MPD) mode. MPD represents an acceptable weakening of the mud barrier compensated for by more well control equipment placed above the BOP. The event is described to include typical fixed installation HMI with surface BOP, mud handling and instrumentation. Based on Figure 3 and Figure 4 we may consequently; (i) omit HMI functions related to DD sensor, and (ii) omit V1, V2, V3 and V6 as only minor volumes topsides and not of interest. The wellbore was open to the reservoir during the event sequence with the two initial qualified well barriers defined by mud gradient established for conventional drilling, the casing, the openhole, and the BOP.

The event sequence leading to a deep underground blowout is considered to include the following main unsafe act (in hindsight), namely, allowing the use of a borderline worn and old casing as qualified WBE in MPD where the pressure along the wellbore from the mud circulation is elevated compared to conventional drilling. A higher differential pressure on casing increases the risk of burst (Table 1), which was part of the accident sequence where knock-on effects cause a failure of the mud barrier. The act or its effects may not clearly be linked to typical HMI functions since regular pressure test of casing is reported before start of hole-section drilling. The strength of casing and openhole as WBEs are typically not dynamically considered (Table 1).

5 Suggested modifications to offshore drilling HRA method

This section suggests some modifications to HRA method [4] in order to help prevent systematic errors in application of the method, while maintaining the benefits of the method demonstrated.

As expected, all the four accidents summaried in Section 4 support the HMI as an important factor for the successful completion of well drilling and workover operations, among others, as an aid for monitoring the wellbore in-situ flowrates and pressures. More specific to the role of HMI in accident causality and HRA, the following main conclusion from Section 4 summaries seems reasonable:

In three out of the four accidents reviewed, a limited or non-existent pressure and flowrate monitoring capability on rig floor likely contributes significantly to the unnoticed development of a diffuse multigradient fluid regime within the different sub-volumes of the well. This diffuse pressure situation may likely become a source for uncertainty and confusion topsides and consequently an important contributing factor related to mistakes, violations and attention losses that occur in event sequences. In addition, unsafe acts help contribute to a catastrophic failure of the mud barrier in the well. By catastrophic failure is meant here that the failure of the mud barrier occurs in a manner that makes cascading failure of conditional WBEs likely due to higher well kick stresses. The higher stresses may be described as a result of a situation where more energy from the reservoir has entered the wellbore at the time of well kick detection.

Therefore as example, the single focus in causal model RIF structure on mistake type errors in HRA method (Figure 5) could result in that key aspects of the HMI as risk factor systematically are overlooked in application of the method.

Making changes to the RIF structure could cause a state explosion that may introduce computational issues, for example, a result of adding multiple parents to level 1 RIFs in hybrid calculation approach [4]. Therefore, the changes proposed to the RIF structure should be made in order to maintain the relatively small computation efforts demonstrated beneficial to the existing RIF structure proposed [5, 46]. This in regards to both full Bayesian belief network implementation with commercial software's, and the hybrid calculation approch. As result from the accident reviews the following modification to RIF structure may be suggested as shown in Figure 7 to the existing structure shown in Figure 5.

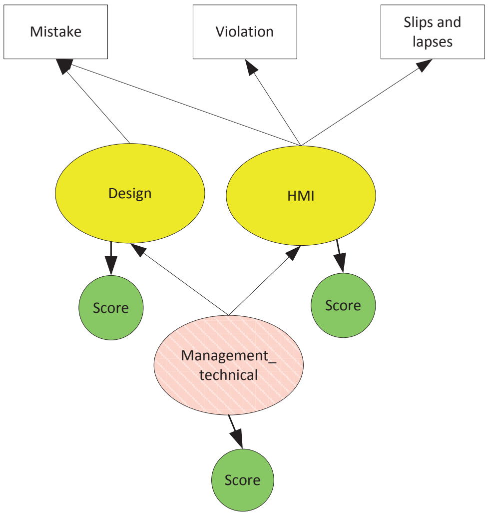

Figure 7. The modified risk influencing factor structure suggested from accident reviews.

It is seen from Figure 7 when compared to Figure 5, the modification suggested represent a swap of structural dependencies between the Design and the HMI as level 1 RIFs. Design can be defined as [5]; "Accessibility and physical working environment with relevance for correct performance of a work specific operation." The role of Design as a risk factor in drilling operations appear minor based accident reviews in this article and previous interviews made of offshore crews [4, Table 1]. As such, it seems reasonable to suggest a shift of the focus in the sharp end of analysis from the surface physical working environment, to the HMI and downhole well conditions as being linked to all types of execution errors defined. This modification suggested to the structure is seen not to impact benefits previously demonstrated with the existing structure.

Hence, the main implications of the suggested modification is on the qualitative part of the HRA method, which shifts focus to the importance of the HMI in understanding downhole conditions over the rig floor physical working environment in terms of integration of HFs in well blowout causality modelling. Based on the accident reviews, it may also seem reasonable to propose the following amendments to the importance of the HMI as check list items provided with HRA method [4, Table 1]: (i) Important to carefully consider implications of not having work-string that allows for fluid displacements and recovery in a wellbore that penetrates a reservoir. (ii) Important to carefully consider implications of not having a closed fluid handling system in cases where mud displacements take place in a wellbore that penetrates a reservoir. (iii) Important to monitor the fluid gradient/pressure situation in all sub-volumes of a well system. As such, important to also carefully consider potential implications if sub-volume monitoring is lost during an operation.

It may be noted in terms of HMI evaluation that it may appear from the accident reviews that the HMI is more directly involved in mistakes and violations that could occur, whereas slips and lapses (attention losses) may seem more as implication of mistakes and violations made previously in event sequence. For example, as a result of decision to reduce HMI functionality in a well.

6 Conclusions

The HMI is the main means of communication between the state of the well and the crew, and it is therefore important to incorporate the role of HMI in risk assessment. One particular issue of interest is the importance of HMI in comparison to other factors that influence the crew's performance. The objectives of this article are: (i) To clarify the role of HMI from an operational perspective, and to investigate how recent well accidents reveal the HMI as a contributing factor. (ii) Suggest how the HMI may be more precisely incorporated in risk models that are used in the oil and gas industry. As an example, the article suggests modifications to the Risk OMT causal model for how to evaluate the HMI as risk factor in offshore drilling operations. The Risk OMT framework is developed for oil and gas industry and links traditional installation risk assessment model scenarios with method for HRA. However, installation risk assessments traditionally only incorporate well blowout risk generically, which implies that the role defined for the HMI may not be directly applicable to drilling operations globally. The modifications suggested to HRA method in this article should ensure that key aspects of HMI as a risk factor in well drilling are not systematically overlooked in application of the method.

The article findings are based on a review of four recent drilling and workover blowouts to assess the degree that the accident causality data reveal the HMI as a contributing factor in relation to various unsafe acts made by crews. The focus of article is placed on the well control related HMI functionality, i.e. its ability to assist the crew on the rig floor to maintain their understanding of the wellbore in-situ flowrates and pressures. These are two physical properties considered vital for detection and control of any fluid influx (well kick) or fluid loss, which are both strong symptoms of a safety critical event. An event that may cause the operation to progress, through unsafe acts, into a situation of multiple well barrier failures and harm. As such, this article also provides additional reassurence and arguments for how the HMI should be evaluated in well operation task analysis.

The HMI is not the only important risk factor identified based on the accident reviews. In contrast to the other accidents, one of the accidents occurred in spite of what may be considered state of the art HMI for maintaining well control, including in-situ wellbore pressure and flowrate monitoring. The accident is described as a violation since management of change procedures were not followed. Further study could be considered, for instance, into technical management relations contributing to this accident in the HRA method RIF structure. For example, it could be linked to an overconfidence emerging in a group from the successful application of new technology in a workplace. As such, an efficient HMI may also become source of negative (undesired) influences in structure.

Acknowledgements

The opinions expressed in this article are those of the authors and do not reflect any official position by NTNU. We are grateful to Associate Professor Cecilia Haskins (NTNU) for editorial comments, and anonymous peers in industry and academia for providing valuable suggestions for improvement. Many thanks for the assistance to this work from collaborations with the SINTEF project “Learning from successful operations.” The SINTEF project is funded by the Norwegian Research Council (grant no. 228144/E30) as part of the PETROMAKS 2 program.

Appendix: Well accident review worksheets

Snorre (2004)

Event sequence from PSA [11]	Comments to 1st well barrier status	Comments to 2nd well barrier status	Comments to SA status - Effective density (pressures)	Comments to SA status - Flow checks (flowrates)	Comments to safe envelope situation
At start of sequence leading to incident. Next: Start pulling of liner.	Ok. Fluid column and casing.	Ok. BOP and casing.	Ok, entire wellbore filled with 1.47 g/cc mud [11].	Ok, well is stable.	Variation (normal).
Punch holes in liner to establish communication and equalise pressure between V4 and V5. Flow check well.	Deviant. Fluid column and *casing.*	Failed. BOP and *casing.*	Ok, entire wellbore filled with 1.47 g/cc mud.	Ok, well is stable.	Deviation. Failure of a well barrier is not uncommon.
Start pulling of liner with work string attached on top towards BOP.	Deviant. Fluid column and *casing.*	Failed. BOP and *casing.*	Unknown, as liner is pulled the original 1.47 g/cc fluids of V5 is mixing with both V4 fluids and reservoir influx (from V7) due to observed piston effects pulling out (swabbing) [11].	Ok, well is stable and periodically topped up with more fluids to fill volume of pipe removed from well.	Violation. Desired action could be to restore two well barriers. Crew do not seem to recognise that V4 openhole not is a qualified WBE.
Start pulling liner through BOP.	Deviant. Fluid column and *casing.*	Failed. BOP and *casing.*	Unknown, equivalent greater than reservoir pressure.	Ok, well is stable.	Violation (restore two well barriers)
About 9 hours into pulling liner through BOP.	Failed. *Fluid column* and *casing.*	Failed. BOP and *casing.*	Unknown, from about reservoir pressure and declining with lighter reservoir (V7) fluids entering lower part of well (V6).	Unstable well with both losses and gains observed. Consistent well gains (kick) eventually detected [11].	Harm (shallow underground blowout).
Crew kill the well by pumping heavy muds into wellbore	Deviant. Fluid column and *casing.*	Failed. BOP and *casing.*	Unknown, equivalent greater than reservoir pressure.	Ok, well is stable.	
Remarks *Elements listed in italic text represent those elements that failed at that point in the sequence.*	Fluid column does not always rely on casing and any openhole formations (common elements) to act as well barrier.	BOP generally relies on casing and any openhole formations (common elements) to form a well barrier.	Mud density situation appear unknown for a longer part of the wellbore during event sequence than expected. This due to leaking retrieval tool reported at top of the liner pulled. The tool leak may impair the ability to top up the well (circulate in fluids) from bottom of the liner pulled and thus the crew may also (unnoticed) be losing control of the effective density of fluids outside of the liner when pulling out of the hole.		

Montara (2009)

Event sequence from PTTEP [13], SEADRILL [14]	Comments to 1st well barrier status	Comments to 2nd well barrier status	Comments to SA status - Effective density (pressures)	Comments to SA status - Flow checks (flowrates)	Comments to safe envelope situation
At start of sequence leading to incident. Next: Enter well.	Ok. Fluid column and casing.	Ok. Pressure cap and casing.	Ok, entire wellbore filled with 1.03 g/cc inhibited seawater [13, 14].	Ok, well is stable.	Variation (normal).
Check for back-pressure. Remove pressure cap.	Ok. Fluid column and casing.	Failed. *Pressure cap* and casing.	Ok, entire wellbore filled with inhibited seawater. Note: Noisy and heavy equipment used in well operations with up to ca. 7 Bar normal gauge error margin [1].	Ok, well is stable.	Deviation. Failure of a well barrier is not uncommon.
Move rig to another well.	Ok. Fluid column and casing.	Failed. *Pressure cap* and casing.	Ok, entire wellbore filled with inhibited seawater.	Ok, well is stable.	Violation. Desired action could be to restore two well barriers.
After ca. 18 hours the well 'burps'. The well is throwing off liquids and gas at surface.	Failed. *Fluid column* and casing.	Failed. *Pressure cap* and casing.	Uncertain, several meters on top of original seawater column is now replaced by air.	Unstable well.	Violation (restore two well barriers).
Crew recognise well control incident. Decide to move rig back to restore well barriers.	Failed. *Fluid column* and casing.	Failed. *Pressure cap* and casing.	Uncertain, several meters on top of original seawater column is now replaced by air.	Unstable well.	Violation. (attempt of recovery).
In rig move the well 'burps' again and starts flowing. Evacuation of personnel.	Failed. *Fluid column* and casing.	Failed. *Pressure cap* and casing.	Unknown, from the reservoir pressure and declining with lighter reservoir fluids entering well.	Unstable well.	Harm (surface blowout).
Remarks *Elements listed in italic text represent those elements that failed at that point in the sequence.*	Fluid column does not always rely on casing and any openhole formations (common elements) to act as well barrier.		Well had been suspended for over 6 months filled with brine. Brine (V6) may have been in contact with reservoir (V7), as one potential source of gas that may have dissolved into the brine. This since the behaviour of well resembles taking the cork off a soda bottle. 'Depressurising' a volume (remove pressure cap) could cause dissolved gas to leave solution and free gas bubbles in brine rise to the top of well while expanding in volume. This throws off the liquid at the top of the well leaving air instead and a reduced hydraulic in-situ pressure of brine column		

Macondo (2010)

Event sequence from The Deepwater Horizon Study Group [12]	Comments to 1st well barrier status	Comments to 2nd well barrier status	Comments to SA status - Effective density (pressures)	Comments to SA status - Flow checks (flowrates)	Comments to safe envelope situation
At start of sequence leading to incident. Next: Negative (inflow) test of well casing / cement.	Ok. Fluid column and casing.	Ok. BOP and casing.	Ok, entire wellbore filled with single type mud.	Ok, well is stable.	Variation (normal).
Start negative (inflow) pressure test of well casing. Run work string to ca. 2500 meters below rig floor, and circulate (displace) wellbore above to lighter fluids. The displacement includes pumping a 'fluid train' of 1.00 g/cc freshwater, 1.03 g/cc seawater, and 1.92 g/cc spacer fluid. V2 and V3 have previously been flushed with seawater.	Ok. Fluid column and casing.	Ok. BOP and casing.	Ok, bottom wellbore filled with original mud, work string (V0) and wellbore outside work string (V5 and V1) filled with (initially) known quantities of three type fluids. Top spacer fluid column estimated to be ca. 3 meter above BOP when displacement finished [12].	Ok, well is stable.	Variation (normal).
Close BOP annular, and bleed off pressure on V0 and V2. Failed inflow test. Unable to bleed off work string pressure (V0). Decision to redo inflow test.	Ok. Fluid column and casing.	Ok. BOP and casing.	Uncertain, influx of fluids from riser above leaking BOP (V1) has now been mixed with fluid column outside work string (V5 spacer opened to original seawater in V2).	Ok, well is stable. Noticed drop in riser fluid level and more fluid returns than expected using standard calculations. Leaking BOP annular preventer found as likely cause for this [12].	Variation (normal).
Increase actuation pressure of BOP annular to increase 'seal ability' of BOP element. Top up riser with fluids. Redo inflow test. Significant pressure build-up on the work string reported (V0, >80 Barg).	Deviant. Fluid column and casing.	Ok. BOP and casing.	Uncertain, influx of fluids from riser above leaking BOP (V1) has now been mixed with fluid column outside work string (V5 and V2). Also, V6 initial heavy drilling mud may be mixed with influx of lighter reservoir fluids (V7).	Unstable well. Surface (top) pressure on work string (V0) but annular side is stable (V5 and V2). Difference in surface pressures suggest possible line blockage, instrument problems or different fluid gradients in the well sub-volumes.	Deviation. Inflow test fails.
Inflow test accepted. Inability to bleed off work string pressure (V0).	Failed. *Fluid column* and casing.	Ok. BOP and casing.	Uncertain.	Unstable well. Well is described building significant surface pressure on work string (V0), and no surface pressure on annulus outside work string (V5	Violation. Inconclusive well barrier test. The desired action in this case could be

				and V2).	to displace well again to known gradients and redo inflow test.
Open BOP annular and start pumps to displace the heavier drilling outside work string (V5 and V1) to seawater.	Failed. *Fluid column* and casing.	Ok. BOP and casing.	Unknown, but seawater columns are now being established inside/outside the work string (V0, V5 and V1).	Unstable well. No periodic flow checks, and no closed system for volume rate control reported [12].	Violation (redo inflow test / restore two well barriers).
After ca. 1 hr. Pumps shut down to do 'sheen test' of returns (allowing disposal of mud returns to the sea).	Failed. *Fluid column* and casing.	Ok. BOP and casing.	Unknown.	Unstable well. Increasing surface pressures seen building on work string (V0).	Violation (redo inflow test / restore two well barriers).
After another ca. 0.5 hr. Pumps shut down to investigate erratic pressure readings on work string (V0).	Failed. *Fluid column* and casing.	Ok. BOP and casing.	Unknown.	Unstable well. Erratic pressure behaviour may signify the start-up of a well where flow restrictions gets cleaned out by more significant influx rates from reservoir	Violation (redo inflow test / restore two well barriers).
After another ca. 15 mins. Rig floor flooded by seawater and mud. Emergency attempts to close-in well on BOP fails.	Failed. *Fluid column* and casing.	Failed. *BOP* and casing.	Unknown. Presumably from around reservoir pressure and declining with lighter reservoir fluids entering well.	Unstable well.	Harm (surface blowout).
Remarks *Elements listed in italic text represent those elements that failed at that point in the sequence.*	Fluid column does not always rely on casing and any openhole formations (common elements) to act as well barrier.	BOP generally relies on casing and any openhole formations (common elements) to form a well barrier.			

Gullfaks (2010)

Event sequence from STATOIL [32]	Comments to 1st well barrier status	Comments to 2nd well barrier status	Comments to SA status - Effective density (pressures)	Comments to SA status - Flow checks (flowrates)	Comments to safe envelope situation
At start of sequence leading to incident. Next: pressure test well casing and start drill new section.	Ok. Fluid column, casing and openhole formations.	Ok. BOP, casing and openhole formations.	Ok, entire well filled with one type drilling mud.	Ok, well is stable	Variation (normal). Casing wear logged with ultrasonic tool. Unable to log a 10 meter interval due to dislocation of tool. Log shows even wear [32]. Degree of wear borderline to acceptable wall thickness loss for casing in industry standard [47, p. II-290].
Abort track. Set liner to isolate loss-zone (extension piece to existing casing run and cemented).	Ok. Fluid column, casing and openhole formations.	Ok. BOP, casing and openhole formations.	Ok, entire well filled with one type drilling mud.	Ok, well is stable	Variation (normal).
Start drilling new track. Abort and plug back track to liner (1).	Ok. Fluid column, casing and openhole formations.	Ok. BOP, casing and openhole formations.	Ok, entire well filled with one type drilling mud.	Ok, well is stable	Variation (normal).
Start drilling new track. Abort and plug back track to liner (2). Fracture capacity of openhole formations are questioned.	Ok. Fluid column, casing and openhole formations.	Ok. BOP, casing and openhole formations.	Ok, entire well filled with one type drilling mud.	Track experiences large mud losses. Well instability.	Variation (normal).
Do formation pressure integrity test. Plug back test track to liner (3). Found reduced capacity of openhole formations. Decide to mobilise modern 'managed pressure drilling' (MPD) technology to drill with reduced window.	Ok. Fluid column, casing and openhole formations.	Ok. BOP, casing and openhole formations.	Ok, entire well filled with one type drilling mud.	Ok, well is stable	Variation (normal).
Try conventional drilling new track. Abort and plug back track to liner (4).	Ok. Fluid column, casing and openhole formations.	Ok. BOP, casing and openhole formations.	Ok, entire well filled with one type drilling mud.	Track experiences mud gains and losses. Well instability.	Variation (normal).
Pressure test well casing. Start	Ok. Fluid column/pressure	Ok. BOP, casing	Ok, entire well filled	Ok, well is balancing.	Violation.

MPD of new track.	control device/backpressure pump, casing and openhole formations.	and openhole formations.	with one type drilling mud.	Track experiences initial losses during testing of drilling system.	The formal management of change procedure for updating well drilling plan to include MPD is not followed [32].
Openhole formation pore pressure readings. Pressures found as per prognosis.	Ok. Fluid column/pressure control device/backpressure pump, casing and openhole formations.	Ok. BOP, casing and openhole formations.	Ok, entire well filled with one type drilling mud. Pore pressure readings taken.	Ok, well is balancing.	Violation (management of change procedures not followed).
Well drilled in MPD mode to target depth within the reservoir.	Ok. Fluid column/pressure control device/backpressure pump, casing and openhole formations.	Ok. BOP, casing and openhole formations.	Ok, entire well filled with one type drilling mud.	Ok, well is balancing. Have problems maintaining well stability (gains/losses) due to small margins and problems with the drilling equipment.	Violation (management of change procedures not followed).
Close BOP annular preventer. Change out pressure control device packing element	Ok. Fluid column/BOP annular preventer /backpressure pump, casing and openhole formations.	Ok. BOP, casing and openhole formations.	Ok, entire well filled with one type drilling mud.	Ok, well is balancing. Well circulating as stable in pressure managed mode with 45 Barg back-pressure [32].	Violation (management of change procedures not followed).
Back-pressure (on V1) drops from 45 to 13 Barg. Unable to re-establish the back-pressure.	Failed. Fluid column/BOP annular preventer /backpressure pump and *casing* and openhole formations. Casing burst (common element).	Failed. BOP, *casing* and openhole formations. Casing burst (common element).	Unknown. From around reservoir pressure and declining with lighter reservoir fluids entering well. Crew do not notice pressures building on V4 at an early stage.	Unstable well. Crew and support onshore are struggling to react to the event; under-balanced mud in instable hole. Mud leaking off to formation via V4 somewhere outside work string.	Harm (deep underground blowout).
Remarks *Elements listed in italic text represent those elements that failed at that point in the sequence.*	The drilling operation was based on underbalanced mud. In MPD mode the mud column generally relies on surface equipment like the pressure control device, back-pressure	BOP generally relies on casing and any openhole formations (common elements) to			

	pump, casing and any openhole formations (common elements) to act as well barrier.	form a well barrier.

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IV. PAPER 3: Human Factors Modelling in Offshore Drilling Operations

Strand, G.-O. and M.A. Lundteigen, "Human factors modelling in offshore drilling operations". Journal of Loss Prevention in the Process Industries, 2016. (DOI: 10.1016/j.jlp.2016.06.013).

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Human Factors Modelling in Offshore Drilling Operations

Abstract

The main principle for risk control during offshore well activities is to always maintain two independent and tested well barriers towards any potential source of inflow. The short lifespan and dynamic nature of well drilling operations makes this a challenge. Experiences from several industry accidents the last decade reveal that two well barriers were not properly maintained by the drilling personnel during the operation and thus that safety was compromised. Probabilistic risk assessments are considered key for risk management of low probability and high consequence activities such as offshore oil and gas well drilling. The objective of this article is to present a method that can be used to address human factors modelling as an integral part of a well drilling operation risk assessment. The method represents an adoption and extension made to the human reliability analysis part of an existing method denoted 'Risk OMT'. Risk OMT is a risk influence modelling method with a modelling principle that includes human factors assessment. Risk OMT has been demonstrated for purpose of analysis of leak scenarios related to planning or execution and control of offshore process maintenance activities.

KEY WORDS: Well probabilistic risk assessment, Human factors, Offshore drilling operations

Nomenclature

Abbreviations

BOP	blowout preventer system
PRA	probabilistic risk assessment
BBN	Bayesian belief network
HF	human factors
HRA	human reliability analysis
RIF	risk influencing factor
HEP	Human error probability
HAZOP	hazard and operability study
NUREG	US nuclear regulatory commission
HMI	human machine interface
QRA	quantitative risk assessment

1 Introduction

The life of an oil and gas well includes different phases, starting with drilling, then completion, operation and intervention, and finally plug and abandonment. All the well life phases are subject to high well leakage risk, and a main rule to ensure well safety is to always maintain two independent and tested well barriers towards a reservoir. An internet search produces roughly 10 public notable offshore well blowouts world-wide in the last decade whereof three incidents have caused fatalities. At the same time, official numbers also show that more than 3,000 offshore wells drilled world-wide every year without any major incidents. The safety performance record is confirmed by the blowout data reported in the industry [1]. The data also confirms that blowouts are relatively prone to occur during drilling operations when compared to the other well life phases. Possible explanations for the observations are that; (i) well barrier failures occur relatively often [2], and (ii) it is difficult for the personnel to track the status of the well barriers during such hectic and short lived operations. The drilling operations, for instance, include both introduction and removal of well barrier elements, which are the well barrier building blocks. As a result of this type normality in operations it can be challenging for the drilling crew to recognise those new (rare) situations that may result in an unexpected need for introduction, restoration or activation of well barrier elements. Another important aspect of well drilling and intervention operations when compared to other well life phases is also that a main well barrier element, the blowout preventer system (BOP), primarily is intended to be manually operated by the drilling crew.

Probabilistic risk assessments (PRA) are recognised as important tools for risk management of low probability and high consequence activities. The objective of a PRA is to evaluate major accident frequencies associated with an activity during normal and abnormal modes of operation. A well PRA can thus become a useful tool for well risk management in both planning and execution of oil and gas well activities. The recognised standards and guidelines relevant to performing well PRAs only address the well operational phase [3-5]. The available industry standards indicate that the blowout risk is not sufficiently described and quantified with regards to drilling and intervention operations. The lack of risk quantification may, for instance, impair the ability for the operators' change management systems to upkeep well risk indicators during the operations, and thereby provide the level of well safety that is expected by society [6]. A search in the literature related to quantitative risk analysis of well drilling and intervention operations produces some modern technically oriented Bayesian belief network (BBN) and bow-tie based analysis models [7-10]. Literature on the quantification of well releases- and blowouts for drilling and intervention operations in the oil and gas industry indicate that the analyses are conducted at a high level [1, 11]. The need for the drilling crew to manually activate the BOP suggests that the influences of human factors (HFs) are important for a drilling PRA. Several methods are proposed for including the effects of HF in risk analysis of offshore operations [12-14]. The methods are demonstrated in the context of making human error calculations in a collision study part of a safety case [12], in human error risk analysis of emergency situations [13], and for human error calculations in planning and execution of maintenance operations [14]. The Risk OMT method [14] includes modern BBN modelling of human influences on both an operational and organisation level similar to human reliability analysis (HRA) methods developed, for instance, in the nuclear industry [15]. The Risk OMT [14] HRA method may thus be assumed applicable also as HRA for offshore well drilling operations. However, a study of well drilling accidents [16] suggests that the technical and human factors in the sharp end of drilling operations are not described sufficiently in the Risk OMT method for purpose of a more domain oriented well drilling HRA.

The objective of this article is to propose an adoption and extension of the HRA part of Risk OMT as a more suitable HRA method for analysis of human errors in well drilling operations. The HRA method presented can easily be combined with technical well barrier element failure analysis to create a drilling operation PRA. A previous study of well drilling accidents [16] suggests that an offshore drilling HRA should focus on the close link in the sharp end between physical and mental human error tendencies and the more unique offshore drilling workplace factors. The aspects of the workplace factors domain and human error tendencies are therefore emphasised when adopting the Risk OMT maintenance activity based HRA into a HRA for well drilling operations. These findings are also supported by a review made of results of interviews made of drilling personnel in a recent research project by SINTEF [17]. The adaption of Risk OMT described in this article therefore also propose models and checklists to ensure that such factors are satisfactorily covered in the analysis.

The article is structured around a generic HRA procedure shown in Figure 1; (i) define scope of work and delimit study, (ii) identify operations where human error may contribute significantly to activity risk, (iii) perform human error analysis of work tasks part of the operations, where workplace factors and human error mechanisms, modes and causes are combined into a status evaluation of human risk influencing factors (RIFs), (iv) establish human error causal model and (v) calculate human error probabilities (HEP) for each task and for the complete operation. Illustrated in the same figure is also how the contributions in this paper supports each of these HRA procedure steps.

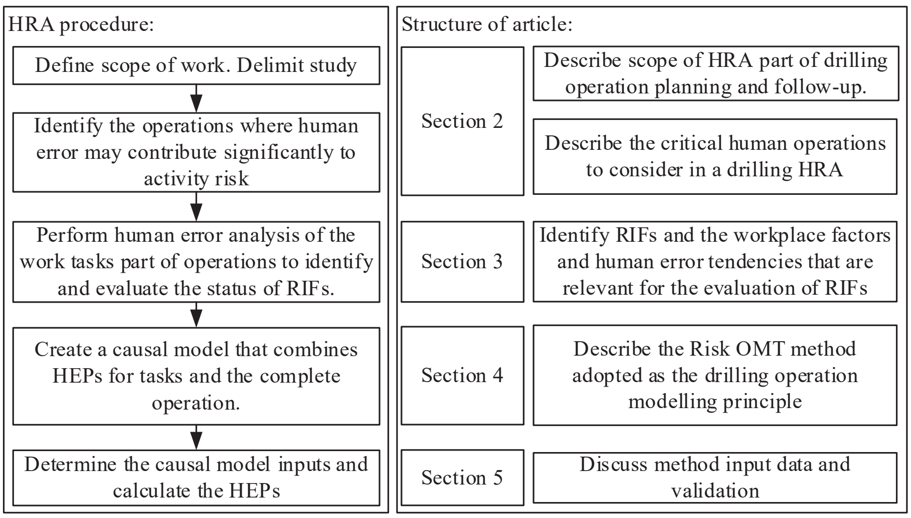

Figure 1. The structure of this article based around HRA procedure steps.

The scope of HRA work together with a short introduction to well drilling operations and the safety critical human tasks is given in Section 2. A procedure HAZOP, task analysis [18] or similar is typically an integral part of a HRA, and Section 3 discuss identification and evaluation of RIFs based on Risk OMT requirements. Two new checklists are presented, one of domain workplace (drilling rig) factors and one of human error tendencies, which are proposed used in support for the consistent evaluation of RIFs in the human error modelling. Section 4 presents the HRA causal modelling principle adopted from Risk OMT as applicable for analysis of drilling operations. The section also includes a detailed description of the 'hybrid approach' developed as a calculation method in the Risk OMT project [19, 20]. The hybrid approach allows HEP calculations to be made based on the Risk OMT defined RIF BBN structure without the use of BBN software. Section 5 concludes the method description with discussions of the RIF structure established for drilling operations and of the model input data. Finally, Section 6 includes the conclusions with areas of further HRA method research.

2 Description of scope of work

2.1 HRA context

A well drilling program documents the planned well design and the resources, for instance, service providers and detailed work procedures to be used in the well construction. The drilling program must in many countries be approved by a regulatory authority before well construction can start [21]. Figure 2 illustrates a typical documentation and signature requirements flowchart adopted by most operators in well planning activities. As shown, the quality control of the drilling program activities are carried out mostly by other discipline peers and the operations manager. The quality control may require an independent third party 'well examiner' in some countries. Figure 2 also identifies the role of operator risk assessments in the drilling program, which covers initial concept phases throughout the final design of the program including detailed procedures. The well engineer organises the work related to the drilling operation risk assessments. The scope of the risk assessments identified in Figure 2 is to study 'additional risks' created by interactions among the different service providers in the operations [21]. Additional risk may here be considered operation risk that is not; (i) already addressed by service provider in-house risk assessments, or (ii) operations not wholly a service provider responsibility. The scope of the risk assessments are thus typically meant to cover the entire drilling operation including fragmented contributions made from several service providers. The end of well report is a document compiled when well construction operations are finished.

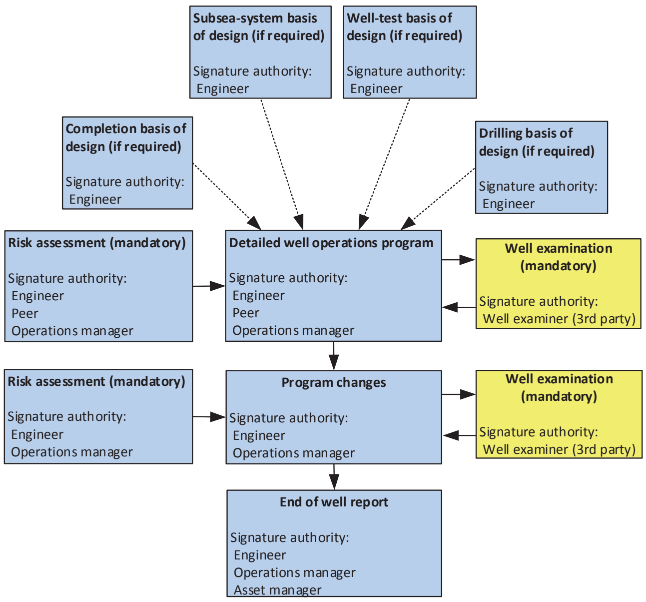

Figure 2. Well planning process – document and signature requirements (extract from [21, Fig. 1.1])

The HRA described in this article is intended as a risk assessment method that is managed by the well engineer as identified in Figure 2. A method that he or she, for instance, may apply as an aid in order to evaluate procedures for novel operations like; (i) with use of new, or modifications to, existing technology or industry best practices, (ii) with high crew turnover with potential loss of sufficient experience transfer, or other specific crew competence needs identified, (iii) with operations in geographic or geological areas with limited historic drilling experiences.

2.2 Description of critical human operations

The influences during operations that the drilling personnel have on well safety through decision making about introduction, activation or re-establishment of well barriers is assumed to be important to a drilling HRA. Well barriers are physical safeguards that prevent blowouts from occurring. The main two well barriers, made up by well barrier elements, during well drilling operations are depicted in Figure 3. The leak paths in Figure 3 give four main categories of blowouts; (i) Surface blowouts with leaks through the BOP, (ii) seafloor blowouts due to external leaks from the BOP system, (iii) shallow underground blowouts due to multiple casing failures, and (iv) deep underground blowouts due to multiple formation layer failures. The underground blowouts are the most complex when observed by personnel on the rig. The underground blowouts do not produce an apparent immediate effect on human health or the environment in comparison to the seafloor- and surface blowouts. The special case of underground blowouts can, for instance, be used as basis for trade-off analysis in a well PRA scope. For example, the combined HRA and barrier accident modelling principle presented in Section 4 only explicitly address the risk of seafloor- and surface blowouts.

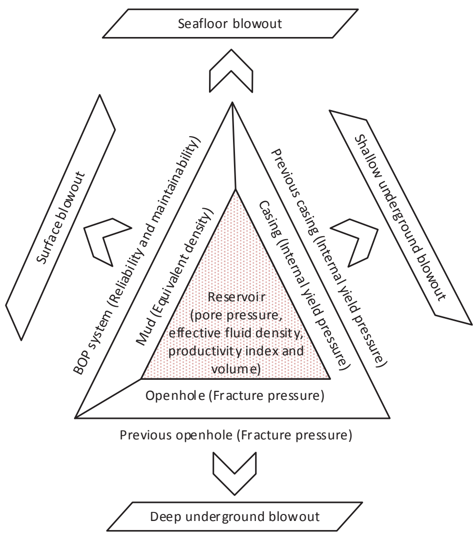

Figure 3. The principle two-barrier drilling well PRA model [16]

The influences of technology and HF on the failure of well barriers have been discussed, for instance, in the context of stress-strength interference modelling [16]. The technology influences the barrier element strength, for instance, related to its intrinsic reliability and maintainability. The HF influence on element strength is more indirect, and relates to the quality of maintenance, verification and control actions. For example, well barrier leakage testing, detection of well kicks, kick control actions, and resources provided for performing BOP maintenance. HF also influence the level of barrier element stress, which are produced by the reservoir fluid influx in a well kick situation. This kick stress can be described, for instance, as a function of reservoir pore pressure, effective reservoir fluid density, productivity index, and reservoir volume. The early detection of a well kick is beneficial since it creates lower element stresses and higher safety margins, for instance, discussed as extra redundancy among different BOP closure devices [22].

Well drilling data shows that well kicks never have occurred in some oilfields while in other they have occurred, for instance, as often as every 5th to 10th well drilled [2]. Baker [23] gives a description of procedures used by drilling personnel in response to well kicks. Three critical tasks are described; (i) Detection and acknowledgement of the symptoms of a well kick, and (ii) initiate actions to control the well kick, and (iii) restoration of well barriers. The kick control action will first entail to secure the well in compliance with operator' and contractor' procedures [23]. This typically includes (i) stop work string rotation and clear work string tool joint (thread connection) from blind shear ram position in BOP, (ii) shut down mud pumps to stop circulation of mud in well and (iii) 'push the button' to close BOP closure device(s) around the work string. The successful BOP closure will place the well in a relative safe, one barrier state, and the restoration of well barriers can take place without apparent time constraints. The well barrier restoration activities that follows next typically include; (i) estimation of the reservoir pore pressure, (ii) prepare kill mud with sufficient density to control reservoir pressure, and (iii) circulate in kill mud into the well to restore the mud column as a primary well barrier.

3 Identification and evaluation of RIFs

A procedure HAZOP, task analysis [18] or similar is typically performed as an integral part of a HRA to identify and evaluate the status of RIFs, or similar performance influencing factors, used in the causal HEP quantification model. A description of a task analysis, for instance, includes; (i) Task breakdown and element durations, (ii) task frequency, (iii) task allocation, (iv) task complexity and competence requirements, (v) environmental conditions, (vi) necessary clothing and equipment, and (vii) other unique workplace factors that affect the successful performance of the task. This section discusses aspects assumed to be important to identify and evaluate the status of operational sharp end RIFs. The Risk OMT make use of RIFs for purpose of the causal modelling presented in Section 4. In general, a RIF is defined as "an aspect of a system or an activity that affects the risk level of this system/activity" [14]. A RIF may represent isolated events and/or an enduring condition, for instance weather, which affects the occurrence of hazardous events and the performance of safeguards. The RIFs identified should be orthogonal without overlap in definitions [24] and in line with Risk OMT [14] where; (i) All relevant RIFs are identified, (ii) the RIFs are "measureable", (iii) The relationship between the RIFs and risk is known.

The need to evaluate RIFs for purpose of a quantitative HRA is not straight forward. For example, a large knowledge base from use of HRA methods is accumulated in the nuclear power industry [25]. The US nuclear regulatory commission (NUREG), for instance, stresses that HRA methods may have different strengths and weaknesses [26]. For example, some methods may account for time constraints in performing a task, which assessor must consider when selecting a method for analysis of a specific situation. For instance, for a task where time constraints are not of the essence. Some HRA methods are also described as "just quantification tools", which requires adaptation in domain to become a valid part of a risk analysis. More recent critique is that some methods are viewed applicable only to elementary work tasks, and that the age of many methods could make them dislocated from the current state of knowledge about human and organisational performances [27]. Ekanem et al. [15] also discuss potential HRA weaknesses related to, for instance, (i) too much variability in results between analysts, and (ii) root causes for human errors not covered, which makes human error identification and avoidance difficult.

The variability in results among HRA methods has been attributed to the identification of human influencing factors (denoted RIFs in Risk OMT). Most influencing factors have been identified on basis of socio-technical system theory. This theory has been developed to analyse accidents in retrospect, and not for the proactive purpose of performing most HRA [28]. A second checklist is therefore presented at the end of this section that describes human error tendencies. The checklist is proposed used to address the HRA critique in human error analysis from a reliability engineering perspective. Like in failure analysis of technical systems [29], this includes a bottom-up approach where error tendencies ('failure mechanisms'), modes and causes are assumed to be important elements for human error identification and avoidance.

Previous work [16] suggests that two discussions should follow for the identification and evaluation of RIFs: (i) a domain oriented discussion of drilling operation workplace factors, and (ii) a discussion of human error tendencies independent of any workplace.

3.1 Review of workplace factors

Workplace factors are the aspects of a specific workplace that may easily combine with human error tendencies and create work situations prone to human error [30]. The workplace factors are in Risk OMT represented by 15 different RIFs [14], whereof 10 are operational and 'sharp end' type, and 5 respectively of an organisational type. The human machine interface (HMI) and the operator understanding of the well physics is, for instance, assumed to be important workplace factors in previous well accident reviews [16]. The competence of the drilling personnel is also, for instance, addressed with explicit requirements for training in regulations [31, Part 250, Subpart O]. The main responsible for the safety during drilling operations, the driller, the tool-pusher and the drilling supervisor in the sharp end [31], should as a result be experienced and trained individuals.

The authors have in support of the workplace discussions been given access to observation summaries from participation in a SINTEF research project [17]. The SINTEF project has generated transcribed interviews made of drilling rig personnel currently working offshore Norway. The interview guide used in the project included the following main questions; (i) explain why your workplace (rig) has not experienced a major drilling accident, (ii) how to identify and assess (during and in retrospect) a successful drilling operation, (iii) explain success, for instance, conditions/circumstances/plans/ procedures that ensured safety of a historic drilling operation, (iv) how to learn from success, for instance, any arenas/tools/methods/ aids/routines that explicitly discuss why operations are successful. A total of 7 sharp end RIFs are proposed adopted to model drilling operations. The 7 RIFs are associated with 5 organisational RIFs in Risk OMT. Table 1 presents the RIFs proposed together with the information extracted from the interview summaries. The table is proposed used as a checklist later in the evaluation of the RIFs.

Table 1. RIFs [14] with interview summary observations made in SINTEF project [17]

RIF [14]	**RIF description [14]**	**Notes made by observer in interview rounds with drilling personnel made in SINTEF project [17]**
Competence	Knowledge, skills and abilities that can contribute to adequate work performance and/or problem solving related to a specific work operation.	Important to always make projections by responsible parties of how the operations may develop in the future on their part. For instance, described by an example where a service company is given authority by well engineer to oversee a well completion operation, but where the driller (rig company) halts the operation after some time since he or she is not feeling sufficiently informed about the operation. Many meetings are held to help distribute and discuss the status and future of ongoing operations. Pre-job meetings, stop-job meetings, handover meetings, toolbox meetings, briefings, lessons learned records, and training programs are considered important arenas for competence development. Important with an explicit focus on 'safety first' versus 'production' in training and team building. Avoid person-to-person training of personnel as bad work practices more easily then may become passed on. Important with hands-on training so that practical skills developed can be demonstrated rather than, for instance, taking internet courses. Individual observations and behaviour is important in order to detect potential dangerous situations. Operator and rig company emphasise importance of training, for instance, in weather observations and radio communication. Need flexible teams that help each other out but that also are recognised by, for instance, (i) the smooth and natural transition from team based work into a command and control situation within few seconds, (ii) degree of improvisation, for instance, in relation to unexpected equipment failures that typically give transition from automatic to manual controls. Prepare for contingencies, for instance, make well kill sheet available in driller's cabin before start of operations. This also includes to establish the physical pre-conditions and associations that calls for a time-out (stop) in operations – 'when in doubt there should be no doubt what to do' Important to always check for lack in training when new equipment and procedures are introduced. This should include practical demonstrations of the level of understanding.
Disposable work descriptions	The availability and readability of the work packages generated for specific work operations.	Operations that are well planned, for example, operations where problems that arise are swiftly solved and where consequences are known in advance, and where people are well prepared and where work routines are well established and recognised. Work procedures that strengthen focus on multidisciplinary efforts (team work). Important that plans are timely received offshore since this helps to avoid situations where problems and delays later in operations are viewed more prone to occur. A rule of thumb offshore expressed is to always allow one week planning

		ahead of operations Always follow the plans, herein importantly the procedures including practices and the revisions of same Important to include simple (clear) safe operation envelopes, for instance, maximum allowable annulus surface pressures.
Governing documents	Written and electronic documents that gives superior guidelines regarding performance of a specific work operation.	Important to have documents that are regularly updated – 'proves that they are being used'. Important to have thorough and well written procedures recognised by; (i) not too voluminous and impractical, (ii) anchored in best practices, (iii) executing party understands the background for the procedure design. Important to have good routines for reporting of undesired events
Design	Accessibility and physical working environment with relevance for correct performance of a work specific operation.	Important to have equipment that functions well.
HMI	Equipment and availability of tools with relevance for correct performance of a specific work operation.	Important that the BOP maintenance- and test procedures are followed with necessary quality- assurance and control support from onshore. Modern drilling with bottom hole tools transmitting data to surface is considered a significant improvement from the 'old days'. Important to get information about failed and weakened well barriers
Communication	Dissemination of information and knowledge with relevance for correct performance of a specific work operation.	Workplace that is noticed by (i) positive attitudes towards questions and concerns raised about observations made in the activities, (ii) allows that operations are stopped if any concerns, (iii) openness towards delays and mistakes made so that they, for instance, do not come unexpectedly back to 'haunt you' later in the operation, (iv) meetings that are well structured and not seemingly carried out with any rush, (v) work processes followed encompass different levels in organisation hierarchies as well as across different disciplines and service providers - 'everybody communicates with everybody'. Important to develop team work as the natural working environment, for instance, that personnel are well acquainted with respect and support of each-others work responsibilities and opinions - 'all are pulling together in the same direction'. Efficient information flow, for instance, between driller and the drilling supervisor and offshore installation manager in a kick situation so that potential supporting staff can be made alert onshore/offshore.
Supervision	Planning, coordination, monitoring, follow-up and improvement of daily work operation, with contribution to safety	Important with close supervision that is supported by quality written work procedures, control- and reporting routines. Important with presence of management, for instance the drilling supervisor/superintendent, on the rig floor to 'ask questions'. Viewed important to be allowed to deal- and finish with one problem at the time.

3.2 Review of human error tendencies

Access to knowledge about human 'failure mechanisms' is assumed important to the human error analysis and RIF evaluation part of a drilling HRA. This section gives a discussion of physical and mental aspects of human errors denoted human error tendencies. The human error tendencies presented are based on; (i) a review of learnings from major accidents in other industries from a socio-technical system theory perspective, and (ii) a review of popular psychological theories.

From a review of literature that presents aspects of psychological factors contributing to human error we may, for instance, consider work by Collins et al. [32] where three main human error tendencies are described: (i) Conformance errors are derived from the human conformity to group pressure [33]. The unwillingness of individuals under social pressure to 'rock the boat' like for instance introduce arguments that may result in project delays or increased project costs. The group think is described by loyalties or over-confidence developed in a group over time that result in lack of criticism or a common perception of immunity against harm [34]. (ii) Cognitive dissonance that contributes to faulty decision making by a mental discomfort humans get from having conflicting ideas or opinions at the same time [35], also described as the 'halo effect' [36]. (iii) Cognitive biases and heuristics. Tuler [37] contributes faulty decisions to mental models and the efforts required for processing and reacting to perceptions. According to Norman [38] the mental models are primarily wanted built by heuristic associative schema, described by the 'sensor-motor knowledge' in memory produced from past learnings. On the same subject Kahneman [36], attributes most poor decision making to system 1 type fast thinking. Fast thinking is described as a bias towards making decisions quickly based on intuition and with small mental effort, and often also with an emotional bias. This as opposed to the alternative of system 2 type slow thinking that involve more tedious reasoning that requires a different mental trigger (than that of system 1) and an environment that allow for focused attention. Attention is a prerequisite to invoke slow thinking and to do more demanding mental tasks.

There are different aspects to human error provided in socio-technical system theory [39]. For example, Perrow [40] describes the events leading up to the 1979 Three Mile Island nuclear accident as normal claiming the accident occurred inevitably and could not be prevented. The accident being a result of a system that fails to learn, 'change behaviour', from many prior near-misses combined with other prevailing imperfections that is the source of unanticipated interactions and multiple simultaneous failures in a complex and tightly coupled structure. I.e., a system made inherently vulnerable to knock-on and ripple effects from single events. The typical precursors to normal accidents are that the operators assume that something else is happening, something they recognise and understand, which they thus can act (erroneously) to. Perrow [40] points to the operator training schemes that are made from design-based accidents. I.e., accidents that are anticipated and guarded against in the system inherently safe design and safe operation. The result is that complex multi-failure and socio-technical multidimensional accident scenario remain unknowns. Perrow [40] lists four characteristics of normal accidents: (i) Accident prevention made difficult as signal of warning only in retrospect. (ii) Multiple design and equipment failures. (iii) Some operator error, which may be gross. (iv) Negative synergies wherein the combined effects of equipment, design and human error is greatly amplified versus each singly.

In relation to drilling operations we find apparent complexity since every well drilled is unique. Also, humans can be viewed tightly coupled with the drilling system HMI, for instance, since a manual push of a button is required in most scenario to react to a well kick.

Reason [41] categorises human errors in the lessons after the 1986 Chernobyl nuclear accident into (i) errors from mishaps or 'adopting to the path of least efforts' or (ii) violations, for instance from neglecting prescribed safe operating procedures. Reason [41] further describes precursors to accidents as either: (i) Active with immediate effects associated with the 'performance of personnel categories', the responsible parties in the sharp end. (ii) Latent with lagging effects associated with the system design. This again is interpreted twofold as (i) technical interfaces in relation to operator's ability to maintain situation awareness and control, or as (ii) softer effects from established work processes and procedures. Managerial and organisational factors usually 'far removed from the sharp end'.

Later, Reason [42] makes a distinction between three major categories of violations: (i) routine, (ii) optimizing and (iii) necessary violations. Reason [41] concludes with seven factors that contribute to bad decisions and unsafe acts; Technical: (i) workplace design and accessibility (location). (ii) System design with lack of technical safeguards and too much reliance on human actions. Human and organisational: (iii) System goals incompatible with safety goals (conflicting goals). (iv) Poor operating procedures (communication) – hand-over and 'negative' reporting. (v)

Poor maintenance procedures – management supervision. (vi) Lack of competence (training) in sharp end. (vii) Working conditions conducive to errors and violations

Mahler et al. [43] describe the events preceding the Challenger and Columbia shuttle accidents as originating from fragmented organisations that bred rivalry over funds and project authority. They describe organisations that become infiltrated by politics. The politics is recognised by elevated bureaucratic walls that subdue co-operation and information exchange, which lead to isolated decision making. For example, observed is an overconfident management that allows for acceptance and dismissal of recurring issues as the new normality. The O-ring seals eroding and foam debris shedding that resulted in damages, for Challenger and Colombia respectively. Mahler et al. [43] also points towards several other characteristics of the organisations prior to shuttle accidents: (i) Under-reporting by management of safety violations by front-end personnel. (ii) A tired and unmotivated workforce that fails to follow procedures and report safety issues. (iii) Ambiguous design of procedures that makes it possible to evade or overlook them entirely. (iv) Strain introduced by an unwieldy shuttle problem tracking system. For example, taxonomy problems that prevent project parties to share data, and a system that houses a vast number of critical issues. (v) Multiple personnel roles, which are poorly defined and even in conflict with human nature such as for instance an individual put in charge of quality assurance of own work. (vi) Reluctance and failure of the organisation to implement and adopt risk reducing measures.

The organisation may be shown to include 'covert adaptations' in the activities based on socio-technical studies of major accidents. Typically sub-optimisation taking place to meet local tacit goals. It is pointed by some that adaptions may help prevent accidents from occurring as apparent from the crew change in the MV Sewol accident [44]. Hence, in the socio-technical system theory it is also important to be aware and monitor for hidden activities, and not just the goodness of what is established on paper as governance in an organisation. The awareness of, and reaction to deviations from written procedures is not left to safety audits alone, but is also a focal part of routine quality management system audits. Further, to prevent major accidents we are advised to be proactive by [32], for example, by carefully establish teams to avoid cognitive- and shared biases. We are also encouraged to focus on developing competence individually and across work teams by enhancing experiences through many different life-like and hands-on training schemes [36, 45]. Also, to actively search for, and break up patterns of politics and group think. For example, by introducing elements of disturbance in the organisation like a devil's advocate. Also, of main preventive importance from literature is to create a workplace culture where human errors are explicitly taught, spoken of, and recognised as naturally occurring and remedied for. For instance, the aspects of breaking up group think should be emphasised in corporate governance, and practiced in management supervision and in safety audits. Also important is design of the workplace to prevent illusions of causality and to facilitate cognitive ease, which includes apparent things like (i) accessibility, simplicity and clarity in wording of instructions, (ii) avoidance of extreme repetition in work tasks, (iii) allow for time-outs with access to a quiet room and simple aids, for instance pen, paper and pocket calculator, and (iv) the intuitive access to and design of levers, displays and dials. Table 2 presents a summary of the human error tendencies described in this section made into a checklist that is proposed used later in the evaluation of the RIFs.

Table 2. Checklist of error tendencies, modes and causes for human error analysis (inspired by [29])

Origin	**Human error tendency**	**Human error modes**	**Examples of human error causes**
Psychology [32-38, 46]	Group think (conformance error)	Tacit disagreement	Group pressure not to 'rock the boat'
		Shared bias - risky shift	Higher risks accepted by group than of any of its members
		Shared bias - cautious shift	Lower risks accepted by group than of any of its members
		False consensus	False belief of joint agreement in a decision made by the group
		Pluralistic ignorance	Silence from false belief of a member that he or she is the only individual with different opinion
	Cognitive biases, and heuristics	Fast thinking. /Narrow minded. Emotional and short-term. Subjective interpretation of the risk picture. /Loss aversive. Favour value of certainty and familiarity over uncertainty and 'what if's' with effort to reconsider. /Too optimistic and over-confident. Ignorance or misconception of the risk picture.	Over-confidence in existing processes, estimates or plans - 'the rules mostly work' Only accepting confirmatory evidence of own position and ignoring the contradictory – 'you find what you look for' Only consider data and options that are readily observable – 'what you see is all there is' Anchoring or tendency towards simplifications of questions, conservatism and use of previous experiences - 'the path of least effort' / 'the man with the hammer syndrome'
		Heuristics	The illusions of causality. Thinking in causal series, typically when faced with falsely

			perceived regularities, fast and linear with little mental effort and jumping to conclusions, rather than in causal nets, which is slow and recursive with mental effort. - 'avoid extreme repetition of tasks'
		Ego-depletion	Multiple work tasks or disruptions that causes loss of required attention to perform task. Lack of mental rest or glucose (nutrition)
		Cognitive dissonance	The mental discomfort humans get from having conflicting ideas or opinions at the same time. For instance, human ignorance of the opinions of 'enemies' and blindness to own or respected friends and colleagues' flaws and faults - 'the truth is too hard to bear'/ 'the halo effect'
		Power of reinforcements	Incentive- or associative biases - 'the Pavlovian bell'
Socio-technical system theory [40-43, 47-49]	Tight couplings (active)	Omission	Negative synergies wherein combined effects of equipment, design and human error is greatly amplified, for instance, a situation escalating rapidly against intention as a result of missing human action ('need to push the right button')
		Commission	Negative synergies wherein combined effects of equipment, design and human error is greatly amplified, for instance, a situation escalating rapidly against intention as a results of inappropriate actions such as inadvertent use of controls or manual override of safety instrumented functions to avoid substantial losses
	Complex interactions (active)	Omission / Commission	False interpretation of system feedbacks, or the signals are not there, or too weak to be noticed, processed and acted correctly upon. Multiple tasks at same time or disruptions and stress that give attention loss. High noise to signal ratio. Hash physical work environment. High workload. High degree of repetition in work tasks. Technical interfaces inadequate in relation to operator's ability to maintain situation awareness and control Operation plans not suited competence level of executing personnel. Remoteness combined with lack of involvement and training. Levers and buttons and other controls not accessible or badly labelled. 'If many operators mistake an interface then the design of that interface is flawed'.
	Organisational (latent)	Violation (necessary)	Inappropriate actions due to shortcomings of the work site, tools, and equipment
		Violation (optimising)	Inappropriate actions due to the attempt to realise unofficial goals as a part of the activity performed
		Violation (routine)	Inappropriate actions due to corner-cutting and shortcuts
		Work process	Reliance on operators to maintain safe system state (workplace design) No learning, change in behaviour (work processes), from previous near-misses or accidents. Acceptance and dismissal of recurring issues as a 'new normality' Accessibility, simplicity and clarity of wording of instructions. Operator training schemes only made from design based accidents Fragmented and monolithic organisations that include elevated technical and bureaucratic walls that subdue co-operation and information exchange, and lead to isolated decision making, such as for instance, disputes in organisation about project authority and funding. Information exchange in organisation is compromised, for instance, recognised by; (i) Under-reporting by management of safety violations by front-end personnel. (ii) A tired and unmotivated workforce that fails to follow procedures and report safety issues. (iii) Ambiguous design of procedures that makes it possible to evade or overlook them entirely. (iv) Strain introduced by an unwieldy problem tracking system. For example taxonomy problems that hinder project parties to share data, and a system that houses a vast number of critical issues. (v) Multiple personnel roles, which are poorly defined and even in conflict with human nature such as for instance an individual put in charge of quality assurance of own work. (vi) Reluctance and failure of the organisation to implement and adopt risk reducing measures.
		Enforcement biases	Bias explained by politics and apparent predisposition involved in enforcement [47]. For example; (i) when safety audits do not consider disclosure of covert activities or relevant historic accidents or near-misses, (ii) system goals are incompatible with safety goals, (iii) workplace where human error not is explicitly taught, spoken of, and recognised as naturally occurring.

*) Violation means deviation from recognised safe operating procedures, standards or rules.

4 Causal modelling

Risk OMT is a risk influence modelling method with a modelling principle that includes human factors assessment. The modelling principle, based on Risk OMT, which is applicable to risk assessment of drilling operations is illustrated in Figure 4. The HRA part of Risk OMT is shown to combine with fault tree- and event tree analysis in a barrier accident model. The main safeguards against blowouts, primarily tasks executed by the driller and the BOP system, is seen in Figure 4 to prevent a well kick from escalating into a blowout. The event tree includes additional causal analysis indicated with triangle shaped transfer symbols for; (i) the occurences of kicks, for instance, failures of the drilling mud can be described by experience data [50], (ii) the failure of the kick detection task, (iii) the failure of the kick control task, (iv) the BOP failure to close on demand that can be addressed, for instance, by physical barrier degradation modelling [22], and (v) the more 'theoretical' type failure of the well barrier restoration task. Three specific events (1), (2), and (4) are attributed to human errors in Figure 4, and the HEPs are estimated from causal models based on fault trees and BBNs.

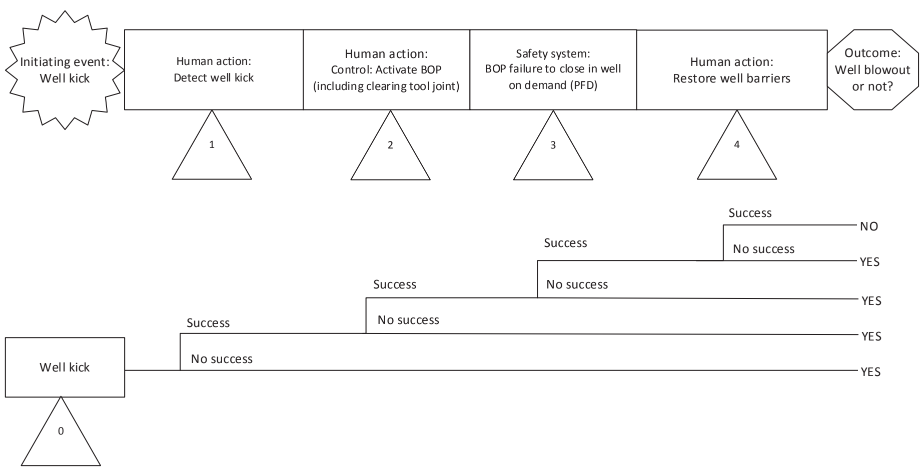

Figure 4. The basic modelling principle for well drilling blowouts (adopted from [14])

The human error causal model is illustrated in Figure 5 with error categories described by four basic events structured logically for an action by 'AND' or 'OR' gates as in a regular fault tree, and where execution errors are modelled more detailed by RIFs structured in a BBN. An example with an extracted yellow operational level 1 RIF (RIF^{I}) and pink organisational level 2 RIF (RIF^{II}) from the BBN structure is also shown in Figure 5. The full BBN structure adopted in method is presented in Figure 6. Only the operational level 1 RIF^{I}s influence the HEPs directly in Risk OMT.

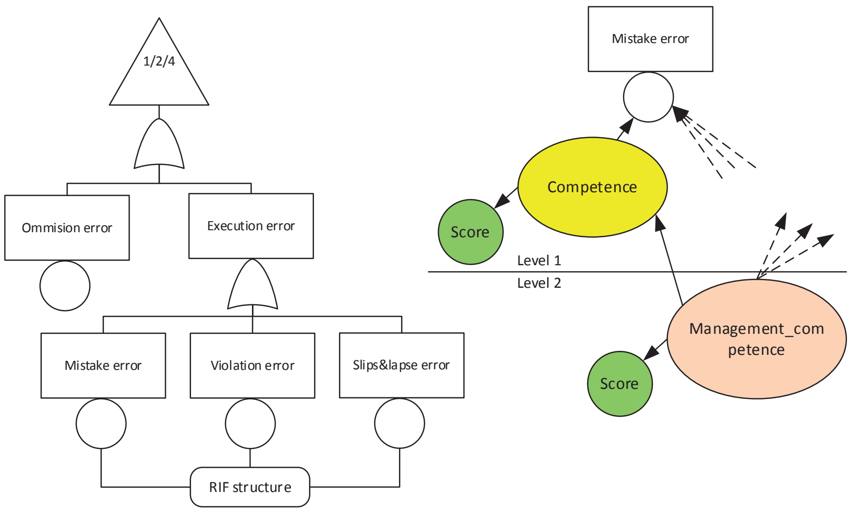

Figure 5. The baseline causal model for assessment of human error probability with extract of the associated two level RIF structure [14]

A score is used as a child node to each RIF defined in the BBN model illustrated in Figure 5. A score is an observation that represents the collected evidence about the true value of a RIF, which is treated as a random variable in Risk OMT. The scores are used in combination with structural dependencies between the level 1 and level 2 RIFs in the BBN model to express the uncertainty with regards to the true RIF values. Scores are given since each RIF defined may be considered an unobservable variable.

All the Risk OMT BBN nodes are modelled as labelled nodes. The basic event type human error nodes are Boolean states as binary failed (1) or not failed (0) according the structure of the fault- and event tree established. Two generic RIF structures are proposed in Risk OMT to study gas leakage scenarios, respectively for 'planning' and 'execution and control' of offshore maintenance activities. The RIF structures are based on review of Norwegian offshore installation quantitative risk assessment (QRA) modelling scenario presented by Vinnem et al. [51], which implies that structures may not be directly applicable to risk analysis of well drilling blowouts globally. According to the accident scenario discussed [14, 20] it may be reasonable to describe omission errors without a RIF structure shown in Figure 5. This may also be argued to be an acceptable simplification in drilling operation analysis, since execution errors appear predominant cause in the well accident data reviewed [16]. The scores and RIFs are measured subjectively on the scale from A through F, where A represent best industry practice and F represent an unacceptable value. The value C is used to represent the industry average. The scoring system of the RIFs is based on previous work [52], which included interview rounds and a questionnaire survey that focused on work practices during manual interventions in the process system.

The full BBN model in Risk OMT requires a large number of conditional probability tables to be specified and populated. A simplified calculation method as alternative to the full BBN model in Risk OMT is presented as the 'hybrid approach'. The hybrid approach is based on BBN specification of the relation between the RIFs, but uses traditional processing of the fault- and event trees [20]. The approach includes less 'integration' of uncertainties from RIFs down to human error basic events, and may therefore be considered as an optimistic modelling alternative to the full BBN implementation. We will base the discussion about model inputs around the hybrid approach, which do not require any experience in the use of commercial software's as with the full BBN model implementation.

In the hybrid approach the six RIF character scores, A through F, are by pragmatic conversion made into numerical intervals that allow use of the normalised Beta distribution to describe the RIF uncertainty. The character scores are mapped into the centre of the intervals, for instance, an A becomes 1/12, a B becomes 3/12, a C becomes 5/12 and so forth. The term score is used formally to denote the summarised information available regarding the true RIF value, r, for instance, collected in interviews or from surveys. An observed score, s, is treated as a statistical realisation (observation) of a random variable, S, that is used to represent the true RIF value r. We assume $\mathrm{E(S)} = r$ and $\mathrm{Var(S)} = V_S$, where V_s needs to be assessed. In the hybrid calculation approach the score, s, is given together with the assessed variance V_s to describe parameters of a Binomial distribution used to update the RIF conjugate prior Beta distribution. For this purpose a pragmatic approach is taken, where the Binomial number of trials, n, and the number of successful trials, X, are determined by setting $\mathrm{Var}\left(\mathrm{X}/n\right) = V_S$ [20], which gives $n = s(1-s)/V_S$, and $x = s \cdot n$, and Beta posterior parameters; $\alpha = \alpha_0 + x$ and $\beta = \beta_0 + n - x$. The Bayesian updating thus assumes that we pragmatically (i) can interpret, r, as a probability, and (ii) have observations in the format of "trials and successes". This is to say that the 'information value' of our observations should be the same as if we had data on trials and successes.

The influence of $\mathrm{RIF^I}$ on human error basic event probabilities is modelled as a function dependent on the weighted $\mathrm{RIF^I}$ sum. For instance, with a total of J $\mathrm{RIF^I}$s influencing basic event k. Let $\mathbf{R^I}$=[$\mathrm{R}^{\mathrm{I}}_1$, $\mathrm{R}^{\mathrm{I}}_2$,…, $\mathrm{R}^{\mathrm{I}}_J$] be a vector of random variables that represent these (normalised) $\mathrm{RIF^I}$s, and let $\mathrm{p_R}(\mathbf{r^I})$=Pr($\mathrm{R}^{\mathrm{I}}_1 = r_1^I, \mathrm{R}^{\mathrm{I}}_2 = r_2^I, \ldots, \mathrm{R}^{\mathrm{I}}_J = r_j^I$) be the joint probability distribution over J $\mathrm{RIF^I}$s. The $\mathrm{RIF^I}$s can have different weights with respect to the influence on the basic event probability. Let w_j be the normalised weight of $\mathrm{RIF}^{\mathrm{I}}_{\mathrm{j}}$. As a first approximation given for independent basic event probabilities the total updated impacts of the $\mathrm{RIF^I}$ s is exemplified in the hybrid approach by;

$$q_k = \mathrm{Pr(Failure\ of\ basic\ event\ k)} \approx \sum\nolimits_{\forall \boldsymbol{r}^I} [q_k(\sum\nolimits_j w_j r_j^I)] p_R(\boldsymbol{r}^I)$$

, where $\sum\nolimits_{\forall \boldsymbol{r}^I} \ldots$ represent the sum over all possible values of the vector $\boldsymbol{r}^I$.

The following procedure is provided to similarly update basic event probabilities based on both $\mathrm{RIF^{II}}$ and $\mathrm{RIF^I}$ [14]: (i) The $\mathrm{RIF^{II}}$s are assumed with the non-informative prior distribution [53], $\alpha_0 = 1/2$ and $\beta_0 = 1/2$. (ii) The $\mathrm{RIF^{II}}$ posteriors are calculated from inference of the scores, s, and variances, V_s, assessed. (iii) The conditional RIF^{I}s prior Beta-distribution parameters, α_0 and β_0, are calculated pragmatically based on the parent RIF^{II} posterior distribution combined with an assessed structural dependency, V_p. This so that the child RIF^{I} share same expected value as its parent RIF_l^{II}, $E(R_J^I \mid R_{J\subset L}^{II} = r_l^{II}) = r_l^{II}$, and $\text{Var}(R_J^I \mid R_{J\subset L}^{II} = r_l^{II}) = \text{Var}(R_J^I) = V_P$. It is possible to specify V_p independent of the RIF^{II} posterior value. Proposed V_p values in the hybrid approach are 0.20^2, 0.10^2, or 0.05^2 described as weak, moderate and strong structural dependency, respectively. (iv) The conditional RIF^{I} posteriors are calculated from inference by input scores, s, and variances, V_s, assessed. (v) The joint distribution of RIF^{I}s that influences the basic event probability is needed to calculate the q_k . The conditional RIF^{I} values are independent according to BBN theory given a parent RIF^{II} value. Each RIF^{I} only has one parent and the q_k can therefore be calculated with relatively small effort by integration over the joint posterior values of the RIF^{II}s:

$$q_k = \text{Pr(Failure of basic event k)} \approx \sum\nolimits_{\forall \boldsymbol{r}^{II}} [\sum\nolimits_{\forall \boldsymbol{r}^{I}} q_k (\sum\nolimits_j w_j r_j^I) \cdot p_R(\boldsymbol{r}^I \mid \boldsymbol{r}^{II})] \cdot p_R(\boldsymbol{r}^{II})$$

The HEPs are independent in the basic Risk OMT hybrid calculation approach, but sources for common cause errors can also be included in the calculations. The common cause impacts are proposed modelled by Beta-factors that describe the conditional probability of a cascading error given a first error. In the model a baseline Beta-factor is adjusted based on categories deemed of relevance to maintenance task operations; (i) closeness in time, (ii) similarity of crew/performers, (iii) stress, and (iv) complexity [14]. The cascading effects of drilling task errors on risk analysis outcomes is shown in Figure 4 to be direct and deterministic. The aspect of Beta factors are therefore not explicitly discussed further for purpose of drilling operation HRA.

The hybrid model also allow for interaction effects to be modelled as an amplified positive or negative synergy created amongst a RIF^{I}s subset that affect a basic event. Only negative synergies are proposed modelled in hybrid approach based on situations where all RIF^{I}s in subset have value worse than the industry average. The model employ an additional interaction weight, w_I, that is combined with a correction factor to adjust the original RIF^{I} weights, w_j [14]. The use of this interaction model to quantify significant positive or negative synergies in a shift- and team based work situation on rig floor is not straight forward. Based on empirical data reviewed it is currently only advised that such synergy effects may be reconsidered in light of more empirical data.

5 Method discussion

This section concludes the method description with discussions based around the proposed HRA causal model RIF structure and the input data of the hybrid approach. As basis for the discussions we assume that preparations made for the HRA study includes to specify the study operations alongside comparative reference operations. An example of a specification outline that includes key operation procedures with focus on aspects of well safety is, for instance, described in [54] to include; (i) well control procedures, (ii) kick causes, (iii) kick frequency, (iv) kick indicators, (v) kick detection and management technologies. The reference operation are onwards referred to as the base case. The base case is specified to allow for relative comparisons in making judgments. The HRA is thus considered applied by the well engineer as a case-based assessment tool with focus on the difference between novel operations versus a respective routine operations. A base case may, for instance, be recognised by use of broadly acceptable industry proven technologies, best practices and standards within an offshore region of study. The ‘proof of acceptance’ typically then, for instance, includes experience data from method or equipment qualification testing and from actual use in the field. This data can be used for HEP model calibrations. Typical information available for industry base case operations are, for instance: (i) blowout frequencies [1, 55]. (ii) kick- frequencies and causes [2, 50]. (iii) well control technologies reliability data [50].

The Risk OMT based RIF structure identified in Section 3 as relevant to model human errors in drilling operations is shown in Figure 6. The RIF^{I}s and the RIF^{II}s identified are described more detailed in [14, 20]. The structural relationships between the level 1 and level 2 RIFs are also shown in Figure 6, where the RIF^{II}s are predefined from RIF^{I} to RIF^{II} structural relationships in Risk OMT.

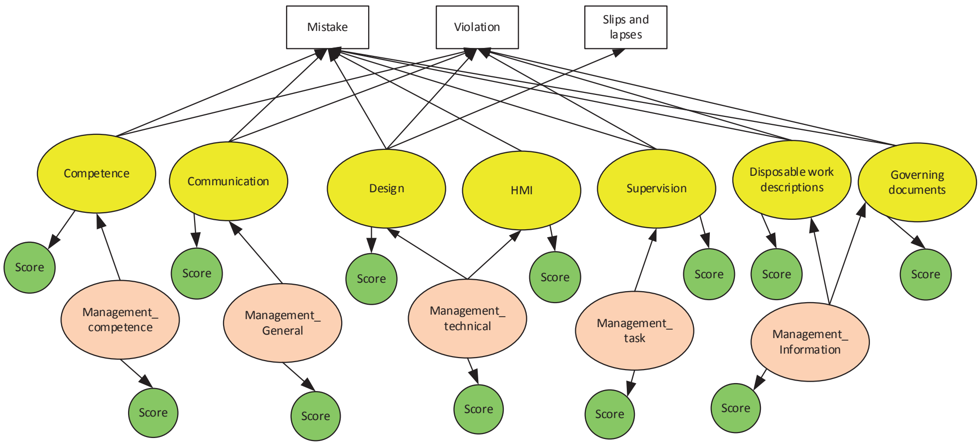

Figure 6. A BBN for human action (task) error in well drilling operations (based on [14])

The empirical data in Table 1 indicates that it may be difficult to treat the Risk OMT defined RIFs orthogonally in the model for purpose of drilling operations, for instance; (i) Technical layout of a rig-floor covered as twofold either design or HMI. (ii) The documentation viewed important to be dynamic and 'living' for purpose of operations with description of processes in both blunt end also as well as sharp end. (iii) Individual and team-based competence that can be viewed closely linked to both communication and supervision in team-based work setting. As a result from the discussions, Table 3 shows that RIF^{I}s are proposed adopted with a set of evaluation (realisation) criteria. The evaluation criteria are given with normalised weights, w_c, that are proposed used later to determine RIF^{I} score and variance inputs.

Table 3. RIFs with evaluation criteria proposed for HRA of well drilling operations (based on [14])

RIF	**RIF evaluation criteria**	**Proposed weight, w_c**	**References**
Competence	1. Skills & interests (talent) 2. Knowledge & education (theory) 3. Experience & training (practice) 4. Motivation, attitude & attention (incentive)	0.10 0.20 0.50 0.20	Table 1, Table 2, [16]
Communication	1. Communication within shifts 2. Communication between shifts (hand-overs)	0.40 0.30	Table 1, Table 2, [16]

	3. Communication with other rig personnel 4. Communication with remote support staff	0.20 0.10	
Design	1. Workplace related – tight couplings 2. Workplace related – complex interactions 3. Human related	0.40 0.40 0.20	Table 1, Table 2, [16, 30, 54]
HMI	1. ability to help interpret in-situ wellbore flowrates 2. ability to help interpret in-situ pressures along the wellbore 3. ability to initiate and provide feedback on successful BOP activation and closure 4. ability to locate tool-joints in the work string 5. ability to help diagnose and identify the root cause of well barrier failures for purpose of well barrier restoration, 6. ability to help interpret effects from changes made to well drilling parameters, also described as the performance of actions [56]	0.30 0.30 0.10 0.10 0.10 0.10	Table 1, Table 2, [16, 54]
Supervision	1. Supervision (driller) 2. Supervision (tool pusher) 3. Supervision (drilling supervisor) 5. Supervision (offshore installation manager)	0.40 0.30 0.20 0.10	Table 1, Table 2, [57]
Disposable work descriptions	1. Drilling program 2. Program changes	0.50 0.50	Table 1, Table 2, [16, 54]
Governing documents	1. Well construction/delivery process documents 2. Technical documentation (handbooks and manuals) 3. Safety/Quality audits	0.50 0.30 0.20	Table 1, Table 2, [16, 54]
Management_competence Management_information Management_technical Management_task	Description of all level 2 RIFs with input data described in Risk OMT project [14, 20]		

The input scores and variances assessed for the organisational parent RIF^{II}s are not addressed in this article. However, it may be considered unreasonable to apply the U-shaped density distribution function of Jeffrey's vague prior for RIF^{II}s. A more natural prior for drilling operations could, for instance, be a density function where average industry value, respectively 5/12, is also the expected value. The coefficient of variance may, for instance, be kept as for applying Jeffrey's vague prior to help determine the Beta distribution parameters under this assumption.

The assumption that the parent RIF^{II} posterior and children RIF^{I}s priors share same expected value seems reasonable. The structural dependency, V_p, must also be assessed. For instance, should it be kept independent of parent RIF^{II} value? The lethal energy in an oil and gas reservoir is an apparent concern to all the personnel working together on an offshore drilling rig. The implications of making 'safety first' decisions without clear organisational support is also predictable and of relatively small magnitude when compared to, for instance, a nuclear power plant where the social- and financial implications of the power plant pressuriser needlessly going solid is significant [40]. Hence, if a part of the organisation (parent) gets assessed with indications of an unacceptable value, this may not imply as a prior knowledge that all rig crews with 'equal certainty' also display unacceptable behaviour. It may, however, imply that more variability is found across the operational end of the organisation. This could be reflected with a V_p that is positively correlated with the parent

$\mathrm{RIF}^{\mathrm{II}}$ value, for instance, with values proposed between 0.05^2 and 0.20^2. In the SINTEF interviews [17] some general observations where made regarding work practices between the rig and other parts of the rig contractor organisation. In one case the rig was described as working independently, while in another contractor case the rig was described more dependent on work procedures and support provided by the land organisation. The observations did not specify type of task or operation carried out, but may indicate that a correlation between parent and child best can be assessed on a case to case basis.

The normalised $\mathrm{RIF}^{\mathrm{I}}$ weights can typically be produced in the HRA by unstructured expert judgments, regression analysis given availability of data [58], or by structured expert judgments, for instance, using the analytical hierarchy process [59]. From well accident data reviewed [16] it is indicated that the HMI, communication and competence may have a relative high influence on the probability of human errors, maybe the dominant factors in as many as three out of four accidents.

It seems reasonable for the well engineer to take advantage of several independent peers or teams for sharp end analysis of any novel drilling operation on basis of the requirements identified in Section 2 to well risk assessments. The $\mathrm{RIF}^{\mathrm{I}}$s scoring is therefore proposed done by repeated use of the evaluation criteria given with weights in Table 3. The evaluation criteria is proposed judged independently by peers or teams providing an evaluation score, s_c, for each criteria. The score is given on the same scale as in Risk OMT, and a resulting $\mathrm{RIF}^{\mathrm{I}}$ score, s, can then be calculated as; $s = \sum_{w_c \subset RIF^I} w_c \cdot s_c$. Moreover, based on 'the wisdom of the crowd' an average $\mathrm{RIF}^{\mathrm{I}}$ score and variance can be calculated, $\bar{s}$ and $\mathrm{Var(S)}^\wedge$, as observations to represent the $\mathrm{RIF}^{\mathrm{I}}$ values.

An exponential function is proposed in the hybrid approach to associate basic event probabilities with the $\mathrm{RIF}^{\mathrm{I}}$ values as an alternative, for instance, to the use of the expected values of the $\mathrm{RIF}^{\mathrm{I}}$ posteriors;

$$q_k(\textstyle\sum_j w_j r_j^I) = q_{k,\min}\left(\dfrac{q_{k,\max}}{q_{k,\min}}\right)^{\sum_j w_j r_j^I}$$

where $q_{k,min}$ represents $q_k(0)$ and $q_{k,max}$ represents $q_k(1)$, respectively the lower and upper bound HEP values. The upper and lower bound HEP values proposed in Risk OMT are, for instance, between 0.50 and 1.00E-4 [60]. The indication that a drilling crew, in spite of a novel operation, may timely fail to detect a kick in one out of two times on average seems hypothetical. The upper HEP bound may therefore need assessment independent of the q_k-function. For example, the representative contribution from human error in the barrier accident model in Figure 4 can initially be assessed from the base case experience data made ready in the study preparations. The upper bound contribution to the base case blowout frequency can, for instance, first be distributed by expert judgment across each human action error. The empirical data suggests, for instance, that a significant fraction of the human error contribution should be distributed on the kick detection task. Next, on a task level the HEP value may again be distributed across the basic event probabilities, from where a $q_{k,max}$ may be proposed as an extension to this upper bound derived from routine operation data.

6 Conclusions

This article presents a HRA method that adopts and extends the existing Risk OMT HRA part for purpose of qualitative and quantitative analysis of human factor influences on the blowout risk of well drilling operations. The application of the method as a potential integral part of a PRA of drilling operations is exemplified with an event tree analysis type barrier accident model. The model includes well barrier failure detection, well barrier activation and well barrier restoration as human tasks in modelling of drilling operation blowout risk. The method focus on a sharp end extension of the Risk OMT HRA part as more suitable for drilling operations, which is suggested by empirical studies of recent well accidents and interviews of rig personnel currently working in the Norwegian offshore sector. The empirical studies suggests that an offshore drilling HRA should focus on the close link in the sharp end between physical and mental human error tendencies and more unique offshore drilling workplace factors. The aspects of the workplace factor elements and human error tendencies are therefore emphasised in the method development with checklists proposed used in the error assessments. The method description also includes a detailed presentation of the hybrid approach developed as an alternative calculation method in the Risk OMT project. The hybrid approach allows HEP calculations to be made based on the Risk OMT defined RIF BBN structure without the use of BBN software.

The Risk OMT, with the quantitative approach described in this article, is demonstrated in the Risk OMT project on offshore process maintenance activities in Norway. However, the method is still novel for purpose of well drilling HRA and PRA, and may need further empirical validation to correct for teething problems and to be demonstrated with the necessary reliability as a practical tool for risk management of global offshore drilling operations. The method is based on reviews of learnings from existing HRA methods and of empirical data, but additional testing and refinements to validate and improve reproducibility must always be considered. For instance, refine procedures, limit number of assumptions and limit the use of expert judgments by substitution for observations like field data, human resource data or simulator training data. A potential for future improvement of the method may be to study the implications of different human factor perspectives on the RIF structure of Risk OMT. For instance, how is the RIF structure affected by the potential for making different definitions of the human error modes.

Acknowledgements

The opinions expressed in this paper are those of the authors and do not reflect any official position by NTNU. We are grateful to our anonymous peers in industry and academia for providing valuable suggestions for improvement. A special thanks for the assistance to this work from collaborations with SINTEF project "learning from successful operations". The SINTEF project is funded by the Norwegian Research Councils (grant no. 228144/E30) as part of the PETROMAKS 2 program.

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V. PAPER 4: A Contribution to the Classification of Human Factors Using Offshore Drilling Operations as Case Study

Strand, G.O., Haskins, C. and Lundteigen, M.A., "A contribution to the classification of human factors using offshore drilling operations as case study". Manuscript under review in; Proceedings of the Institution of Mechanical Engineers, Part O: Journal of Risk and Reliability, 2016

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A contribution to the classification of human factors using offshore drilling operations as case study

ABSTRACT

Performing a human error analysis (task analysis) is viewed s an important step in performing a drilling operation human reliability analysis. However, recent drilling operation human factors research and a review of human error taxonomies suggest such to be biased towards higher level socio-technical accident investigations, and not particularly suited for the purpose of a proactive task analysis or human reliability analysis. In this article, we propose amendments and clarifications to the existing task analysis terminology with intention of helping to enhance the quality of human factors analyses of offshore drilling operations. We also explore the potential implications of proposals made related to an existing method for human reliability analysis as part of probabilistic risk assessments of offshore drilling operations. Two principle considerations are suggested to develop the proposed task analysis terminology; (i) multidisciplinary coherence through adaptation of familiar and recognised concepts from technical failure analysis and reliability data collection sources; (ii) extended usefulness and versatility through applicability across common levels of activity or process breakdown in task analysis.

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KEY WORDS: Human factors, offshore drilling operations, human error taxonomy, task analysis, human reliability analysis

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Nomenclature

Abbreviations

PRA	probabilistic risk assessment	HMI	human machine interface
HRA	human reliability analysis	HTA	hierarchical task analysis
BOP	blowout preventer	NUREG	US nuclear regulatory commission
HF	human factors	SCADA	supervisory control and data acquisition
TA	task analysis	SADT	structured analysis and design technique
HFACS	human factor analysis and classification system	HAZOP	hazard and operability study
DoD	US Department of Defence		

1 Introduction

Probabilistic risk assessments (PRA) are recognised as important tools for risk management of low probability and high consequence activities. The objective of a PRA is to evaluate major accident frequencies associated with an activity during normal and abnormal modes of operation. For example, a PRA may typically be used by operator in planning and execution of well operations to evaluate additional risks created from interactions among different service providers [1, p. 8]. The lack of PRA may impair the ability for the operator's change management systems to maintain risk indicators during well operations, and thereby provide the level of well safety that is expected by society [2]. A PRA of drilling operations can become a useful tool for risk management in both planning and execution of oil and gas well activities. The requirement for the drilling crew to manually activate the blowout preventer (BOP) accentuates the importance of studying the influences of human factors (HFs) in a drilling operation PRA. Several methods are proposed [3-6] for including the influences of HF in quantitative risk analysis of offshore operations. The methods demonstrate use of the calculations in (i) collision studies of an offshore safety case, (ii) risk analysis of emergency situations, and (iii) planning and execution of offshore process maintenance or (iv) drilling operations. In a dedicated human reliability analysis (HRA) method proposed for drilling operations [6] it is proposed that further improvements could be made to clarify the terminology, for instance, in order to achieve a more consistent orthogonal evaluation of human performance influencing factors, or to study the potential implications of different human factor perspectives on the HRA causal modelling structure.

A literature search for taxonomies developed and demonstrated for categorical human error analysis (task analysis) and data collection is summarised in Table 1. Of most recent developments is a four influence-level military aviation human factor analysis and classification system (HFACS) taxonomy [7, 8], which is based on Reasons' Swiss cheese model [9]. The HFACS has also been applied to civil applications.

Table 1. Summary from literature review of existing human error taxonomies

Application domain	**Source**
General	Rasmussen [10]
General	HSE CRR 245/1999 [11] based on Rasmussen [10]
Road safety	Stanton and Salmon [12]
Military aviation	Shappell and Wiegmann [7, 8] based on Reason [9]
Maritime accident investigations	Chen, Wall [13] based on Shappell and Wiegmann [7]
Railway accidents and incidents	Baysari, McIntosh [14] based on Shappell and Wiegmann [7]

The taxonomies identified in Table 1 appear primarily to be based on a socio-technical system theory perspective for error data collection made relative to major organisational accident investigations, and not for the proactive purpose of conducting a task analysis (TA) or HRA. For example, there seems to be a lack of explicit definitions for some key HF concepts in the reviewed taxonomies for purpose of performing a TA with aid from any collected human error data.

The objective of this article is to propose amendments and clarifications to task analysis terminology in order to help enhance the quality of human factors analyses made of offshore drilling operations. The article is prepared in support of previous drilling operation HRA method work [6]. More precisely, this article aims to address potential weaknesses identified in terminology that may become a source of inconsistencies in the status evaluation of risk influencing factors part of the HRA method. Performance of a task analysis represents an important precursor to the status evaluation, which is focal to the sub objectives of this article; (i) Propose a clear definition of key human error concepts for purpose of task analysis, such as, operator error, requirement, error mode, performance influence, error cause and error effect. (ii) Discuss taxonomy challenges associated with identification, classification and evaluation of such operator errors in drilling operation HF analysis, and (iii) propose possible ways to tackle such challenges.

2 Task analysis framework

A TA may be defined according to US Department of Defence (DoD) [15, p.1] as an analysis of human performance requirements, which if not accomplished in accordance with system requirements, may have adverse effects on system cost, reliability, efficiency, effectiveness, or safety. TA may be regarded a collective term used to encompass many methods and techniques developed for analysis of how tasks can be successfully accomplished. A TA describes the manual and mental cognitive processes required for one or more operators to perform a required task [16]. The term task is used interchangeably for an activity or a process. A TA procedure may typically include; (i) Task breakdown and element durations, (ii) task frequency, (iii) task allocation, (iv) task complexity and competence requirements, (v) environmental conditions, (vi) necessary clothing and equipment, and (vii) any other unique workplace factors that affect the successful performance of the task.

A TA often results in a hierarchical representation of the steps required to perform a task for which there is desired outcome(s) and for which there is some lowest-level action, or interaction, between humans and machines denoted as the human machine interface (HMI). Hierarchical task analysis (HTA) is a popular TA technique, and considered one central approach in ergonomics studies [17]. HTA is a task breakdown and description method that may be used as a precursor for other TA techniques. The HTA produces a description of tasks in a hierarchy made of a task at the highest level consisting of objectives expressed as the goals of the systems, which are in turn composed of sub-objectives and lower-level actions [17]. Actions are considered the smallest individual specific operation carried out by operators interacting with a technical system or by the system itself, and are often procedural in nature with an implied or explicit sequence. For example, individual actions may include 'visually locate blowout preventer (BOP) control panel ram button' or 'move hand to ram button on BOP control panel', which an operator is required to do in a particular combination to meet the objective for successful task completion.

In this article, 'activate the BOP in event of a well kick during drilling' is used to provide an example of a drilling operation task to be analysed based on the proposed taxonomy. Taxonomy proposals will build on the various definitions found in the literature review, summarised in Table 2.

3 Operator error

Human (actor/operator) error (failure/malfunction) is an important concept in a TA. The word error itself suggests a type of deviation or discrepancy.

In an early human error taxonomy Rasmussen [10], p. 15 relates errors loosely to natural human curiosity as a "lack of recovery from unacceptable effects of exploratory behaviour". The UK health and safety executive [11, p. 47], largely influenced by Rasmussen, makes use of a related term, 'external error mode' to describe human error more clearly as "the observable manifestation of an error". The US nuclear regulatory commission (NUREG) [18, p. xxvii] similarly also define 'human failure event' as "a basic event that represents a failure or unavailability of a component, system, or function that is caused by human inaction or an inappropriate action".

The human error taxonomy developed by the DoD [7, 8] describes human error as unsafe acts, which are classified as either errors or violations according to Reason [9]. Reason [9, p. 121] describes errors as 'matters of the head', and violations as 'matters of the heart'. In the DoD taxonomy it is assumed that human error may have three meanings [8, p.1]; (i) error as the system failure itself, for instance, a result of poor operator decision making, (ii) error as the underlying cause of system failure, for instance, a knock-on (cascading) effect of poor operator training and supervision, and, (iii) error as the underlying cause of system failure that follows from a gradual process of performance departure from a requirement standard.

From the literature review we may, however, consider three different perspectives taken in order to describe the human error concept; (i) cause-oriented view that focuses on error avoidance and recovery, (ii) event-oriented view with a focus on unsafe human actions or inactions, and (iii) outcome-oriented view focused on the undesired effects of human action or inaction on the socio-technical system functions (goals).

An accepted technical terminology standard, IEC 60050:192 [24], gives the following examples of human errors: (i) performing an incorrect action, (ii) omitting a required action, (iii) miscalculation and (iv) misreading a value. The definition of a technical failure in the standard implies that the system initially possesses the ability to perform as required. This may represent a crude simplification if a similar definition is adapted to describe human error. Reference to human action in the standard could imply for the purpose of TA that human error relates only to a task breakdown at the lowest level, i.e. actions related to a specific operation.

Table 2. Examples of definitions used in HF literature taxonomy discussions, organized as referenced in the article

Term	Definition	Source
Human error	"the effect of human variability in an unfriendly environment"	[10, p.15]
	"the observable manifestation of an error; Action omitted, action erroneously completed, or extraneous action(s) completed"	[11, p. 47]
	"a generic term to encompass all those occasions in which a planned sequence of mental or physical activities fails to achieve its intended outcome, and when these failures cannot be attributed to the intervention of some chance agency"	[19, p. 9]
	action or inaction "not intended by the actor; not desired by a set of rules or an external observer; or that led the task or system outside its acceptable limits"	[18, p.25]
	"the failure of planned actions to achieve their desired ends – without the intervention of some unforeseen event"	[9, p. 71]
	"inappropriate human behaviour that lowers levels of system effectiveness or safety"	[20, p. 366]
	"when human action is performed that was either (i) not intended by the actor, (ii) not desired according to some specified set of rules or by some external observer, or (iii) contributed to the task or system 'going outside its acceptable limits'"	[8, p.1] based on [9]
	"out-of-tolerance action, or deviation from the norm, where the limits of acceptable performance are defined by the system. These situations can arise from problems in sequencing, timing, knowledge, interfaces, procedures, and other sources"	[18, p. xxvii]
	"a failure of a planned action to achieve a desired outcome"	[21, .../Human Error]
	"a label of judgment made in hindsight about own or other people's behaviour"	[22, p. xix]
	"unacceptable outcomes of action or inaction that result from deviation from intention, expectation or desirability"	[23, p.25]
	"discrepancy between the human action taken or omitted and that intended or required"	IEC 60050:192 [24]
Failure	"loss of ability to perform as required"	
Failure mode	"manner in which failure occurs" … may be defined by "the function lost or other state transition that occurred"	
Conformity	"fulfilment of a requirement"	
Non-conformity	"non-fulfilment of a requirement"	
Failure criterion	"pre-defined condition for acceptance as conclusive evidence of failure"	
Failure cause	"set of circumstances that leads to failure" … "a failure cause may originate during specification, design, manufacture, installation, operation or maintenance of an item"	
Failure mechanism	"process that leads to failure" … the process may be "physical, chemical, logical, or a combination thereof"	
Failure effect	"consequence of a failure, within or beyond the boundary of the failed item" … "for some analyses it may be necessary to consider individual failure modes and their effects"	
Error	"discrepancy between a computed, observed or measured value or condition, and the true, specified or theoretically correct value or condition"	
Conformity assessment	"demonstration that specified requirements relating to a product, process, system, person or body are fulfilled"	IEC 60050:902 [25]

Defining human error may be described as a fool's errand in light of all the domain knowledge that concerns human fallibility. A less ambitious event-oriented definition, built on the taxonomy in Table 2, proposes the term *operator error* for drilling operations as follows: *inability of an operator to perform as required,* with the additional note that *operator errors are associated with human behaviour, unsafe acts, which are not intended or not desired*. This definition should be viewed independently of task breakdown level. Operator error at the task level could be 'the driller errs to activate the BOP within 40 minutes after a well kick.' The use of operator in the singular also suggests a military- or drilling operation style chain of command in TA where there is a predefined responsible decision maker for any given work situation.

4 Operator requirements

The quality of a TA depends on the analyst's ability to identify all the requirements of the task (activity or process), sub-tasks (operations) and actions (plans and procedures). Without a formal procedure it may be difficult to identify, and thus assess, all specific operator requirements. The use of a HTA as precursor for a drilling operation TA in this article reflects the importance that the breakdown of task objectives, sub-objectives and action objectives are specified according to performance requirement standard(s).

The IEC 60050:192 [24] standard defines a specified requirement as "need or expectation that is stated" noting that the requirements may be stated in normative documents such as regulations, standards and technical specifications. The standard further defines a required function as a "function considered necessary to fulfil a given requirement." According to IEC 60050:192 [24] the required function "(i) May be stated or implied (i.e. that the purchaser would be entitled to expect), (ii) by implication, also covers what the item shall not do, (iii) includes essential internal functions of a system, which may not be visible to the user, but also are required functions". The *operator requirement* proposed for a socio-technical system may be defined for any level of task breakdown as *a stated need or expectation about operator's performance considered necessary in order to accomplish a given task objective*. As additional guidance we may include a note that operator requirements; *(i) May be stated or implied (i.e. that the operator would be entitled to expect), (ii) by implication, also may cover what the operator should not do, (iii) include essential internal requirements of a task, which may not be visible to the operator, but also are operator requirements*.

Basic concepts in failure analysis advise that operator requirements are expressed by a verb plus a noun that are combined with explicit measures given in quantifiable performance requirement standards [26]. Examples of this format are 'activate the BOP within 40 minutes in event of a well kick' and 'acknowledge symptoms of a well kick within 30 minutes after a kick occurs'.

4.1 Identification of operator requirements

The task, 'activate the BOP in event of a well kick during drilling', may be broken down into two sub-tasks that contain four consecutive action objectives as illustrated in Figure 1. The actions are (1.1) Detect/acknowledge symptoms of a well kick, (1.2) Perform flow-check to diagnose symptoms of a well kick, (2.1) Activate BOP to shut-in well, and (2.2) Verify well shut-in (successful BOP activation). The BOP activation task is the driller's responsibility and is performed from the driller's cabin located on the drill-floor of the rig. The cabin includes the drilling operation HMI with instrumentation interfaces, supervisory control and data acquisition (SCADA), communications and manual controls used to carry out the required actions of the example task. A short description of the operations and actions follows.

Monitoring for changes in established well footprints and trends is the primary means to search for indications of a well kick during drilling operations. The regularly monitored drilling parameters include flow rates in and out of the well, rig pump pressure, rig pump speed, rate of drill bit penetration, drill bit torque, up/down weight of drill string, and mud pit levels. If any of these parameters change this may indicate a pressure change in the well and consequently that the well may be kicking. At this task breakdown level, monitoring flow rates and mud pit levels may be considered essential operations in regards to well safety. The other operations may be considered auxiliary and introduced in support of the essential operations. The objectives of auxiliary operations may be less obvious, but may also be critical to achieve successful task completion. The auxiliary operations in well drilling typically may be related to actions performed to avoid unnecessary process upsets. For example, in a kick scenario the driller will also carry out actions that primarily are intended to reduce the potential for 'stuck pipe' and thus additional delays (and costs) as a result of correctly acting prudently on any symptoms of a kick. We may also consider a class of superfluous operations, which are obsolete and not required (anymore) for successful task completion. These operations may typically represent legacy issues introduced as a result of system modifications over years of operation. Superfluous operations may negatively influence the successful completion of a task, for example, by being a source of a high system noise to signal ratio [27].

Once well kick symptoms are acknowledged by the driller, the next step would then entail a manual diagnosis operation referred to as a flow check. The flow check can be broken down into several actions indicated in the hierarchy below sub-operation 1.2 in Figure 1. If the driller acknowledges signs of well instability with the flow check the final step of the task is for the driller to close in the well by a confirmed activation and closure of the BOP indicated by task 2 and sub-tasks 2.1 and 2.2 in Figure 1.

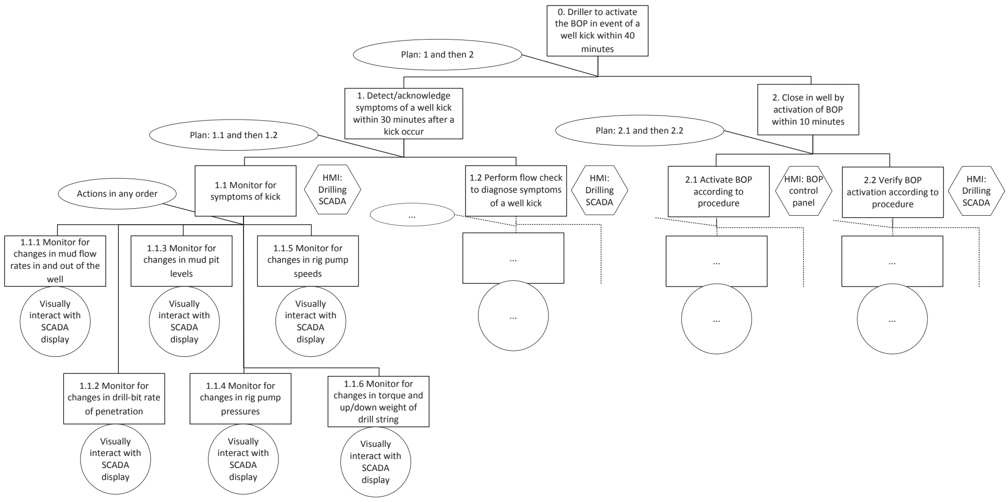

Figure 1. Example hierarchical task breakdown of 'Driller to activate the BOP in event of well kick within 40 minutes'

From Figure 1 the hierarchy may consider three system breakdown levels of information that describe a failure in technical failure analysis [26]; (i) System, (ii) items, and (iii) components. With this mapping in mind, it is conceivable to adapt the structured analysis and design technique (SADT) [28] with functional block diagrams [26] used in failure analysis as a more robust method to aid in a task breakdown based on previous work [6, 29, 30]. The analogous view is as follows: (i) drilling task objectives as 'functions', (ii) operator performance requirement standards as 'control system', (iii) situational elements as 'inputs', (iv) required operations, actions, and performance of actions as 'outputs', and (v) performance influencing factors as the 'environment'. This combined SADT-HTA diagram is illustrated in Figure 2, with explicit mapping of information from the basic HTA shown in Figure 1. The actions are now seen to more explicitly also consider mental aspects of a TA, which represent a shift in orientation of the traditionally action oriented HTA technique.

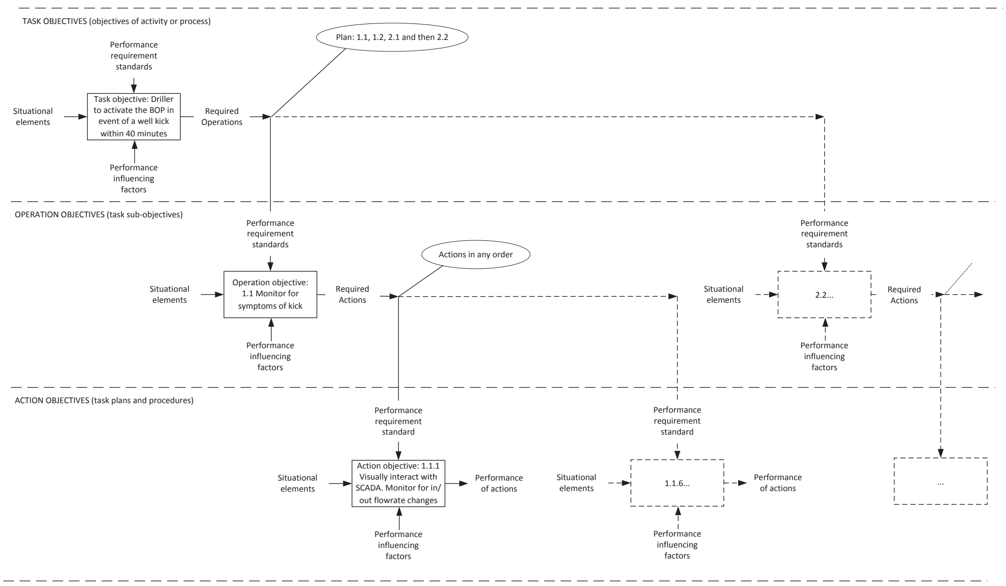

Figure 2. Example of SADT-HTA combined block diagram with three predefined task breakdown levels

4.2 Importance of operator requirements

Well drilling operations typically include a large number of operator requirements. However, not all operator requirements may be equally important as discussed in Section 4.1. Therefore, it may be useful to classify operator requirements and associated actions to help in prioritisation of HF analysis efforts, and to aid in assigning scores and weights part of a HRA method [6].

Socio-technical operators exist because natural human variability is not always unpredictable and risky. Humans also bring with them useful capabilities such as situation awareness, mindfulness, learning and self-healing. These properties are not yet found embedded with equal sophistication in technical systems. Rasmussen [10] advises that human error data should be collected and categorised in order to represent situations of human-task mismatches, which typically may be recognised by conflicting goals [31]. Also, a large share of critical operator error is suggested to occur as a result of confusion in the sharp end of a process, in the transitions between different system mission phases [12], which are the analogue to different system operational modes in technical failure analysis. For example, a typical operator mode confusion error may be the ineffective operation of a BOP pipe ram to close in the well in situations where there is no work string suspended through the BOP. Thus, it may be useful to classify operator requirements as mode conditional or not part of an explicit operation or action of the task being analysed.

Rasmussen [10] also advises that the error data should support the design of error-tolerant work situations, and that the retrospective data analysis should focus on error recovery features in activities, or the lack thereof. Rasmussen [10], p. 17 describes error recovery as the observability and reversibility of the emerging unacceptable effects of human behaviour. To achieve stable system performances it may be useful to establish maintenance strategies. Applied to HFs and operator performance this may be denoted as recovery strategies. The strategies may typically concern the design of safety- and quality audits within levels of an organisation. To aid audit designs, it may be useful to distinguish between levels of mental effort required for the operator to perform according to a performance requirement standard. One may typically distinguish simply between (i) fast thinking (intuition and trial based) type actions versus (ii) slow thinking (attention and conscious based) type actions [32]. An alternative recovery classification scheme may be based on defined levels of human behaviour [33]; skill-based behaviour (automatic/intuition), rule-based behaviour (recognition/trained for) and knowledge-based behaviour (attention and conscious).

5 Error modes and non-conformity

An operator performance requirement may be the source of numerous operator action errors. After identification of operator requirements we may typically make use of guide-words as part of the procedure hazard and operability study (HAZOP) technique to help identify specific operator action errors, for example, ‘driller moving hand too slowly towards BOP panel’. However, the identification of operator errors may not be straightforward. For example, an operator requirement may include several ‘unthinkable’ event sequences caused by knock-on and ripple effects that are difficult to identify with use of traditional TA methods [27].

5.1 Error modes

In failure analysis, the term failure mode is used to classify and describe different functional requirements on different levels of system breakdown. We may consider an operator error mode as the manner in which operator error occurs. However, the state transition that occurred includes an unclear allowance for performance deviation. It may therefore be useful to introduce the state related terms conformity, and non-conformity from IEC 60050:192 [24]. From the discussion, an alternative definition for *operator error mode* may be proposed for the drilling operation TA as the *manner of non-conformity in which operator error occurs.* For example, on an operation level, 'the drilling crew fails to detect/acknowledge symptoms of a well kick within 30 minutes after it occurred.'

The operator error mode intends to give an account of the outside observable transition that could occur between predefined states of conformity and non-conformity. The operator error modes may appear differently on different levels of task breakdown, or because of different focuses of TA techniques. For example, an error mode that is deduced as a result of an adverse physical/physiological or mental condition in a behaviour oriented TA may differ from an error mode derived in an action oriented TA as a human action or inaction to a situation that is not as desired.

One must study the outputs of the function blocks illustrated in Figure 2 to identify the operator error modes. The outputs seen in Figure 2 imply that error modes may become difficult to identify on a higher task- or operation level. This due to higher one-to-many relationships between the description given of objectives in performance requirements standards, and outputs versus manner in which the operator may fail to conform to all implicit requirements. A similar issue exists in failure analysis where important reliability aspects embedded in system architecture, such as redundancy or dependency among components, may remain undisclosed at higher breakdown levels. The details given of operator error modes should therefore advisable also reflect the level of task breakdown being considered. The poor performance of actions used as lowest-level outputs in Figure 2 is defined as an "inability to carry out necessary actions" [30].

5.2 Error criterion, recovery and departure

Human behaviour comes with intrinsic natural variability and operator performance making it difficult to measure and assess accurately. It may be necessary in practice to rely on several different measurements, some of which may be indirect or proxies, for the purpose of monitoring for any negative trends in crew performances. The IEC 60050:192 [24] gives examples of failure criteria that are related to the definition of a limiting state of wear, crack propagation, performance degradation, or leakage beyond which it is deemed to be unsafe or uneconomic to continue operation. The IEC 60050:192 [24] also uses the term error to describe an instantaneous level of item performance degradation as the "discrepancy between a computed, observed or measured value or condition, and the true, specified or theoretically correct value or condition." A drilling TA may use similar terms that are illustrated in Figure 3: (i) *Error criterion* as *pre-defined level of operator performance for acceptance as conclusive evidence of operator error,* and (ii) *Departure* as *undesired discrepancy between a computed, observed or measured operator performance, and the specified target value stated in performance requirement standard.* Hence, a performance requirement standard is presumed to include a target value with an acceptable margin for departure before an operator error is identified. The given definition of departure implies an error recovery noticed as a decreasing (positive) trend in any observed departure based on Rasmussen [10]. For example, in a kick simulator training scenario an operator error criterion may be defined as; 'The driller (with aid of his crew) is to activate the BOP within 30 minutes after the simulated well kick occurs.' This criterion could be further described as illustrated in Figure 3 with an empirical based target value of 20 minutes.

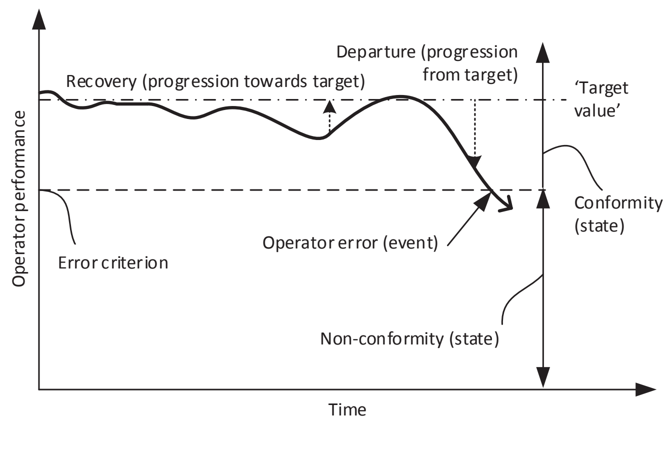

Figure 3. Illustration to clarify differences between operator error, non-conformity and departure.

6 Error causes, performance influences and effects

Rasmussen [33] advises that human error data should reflect an emphasis on the lack of recovery from undesired effects of human exploratory behaviour. Stanton and Salmon [12] describe human error causes and mechanisms consolidated separately, but on a single level in their driver error taxonomy. For example, the error mechanism classes defined are; (i) Action errors, (ii) cognitive and decision making errors, (iii) observation errors, (iv) information retrieval errors, and (v) violations. The DoD HFACS taxonomy describes human error causes in an influence hierarchy with four levels [8]:

(i) Unsafe acts in the sharp end with classifications adopted from Reason [9].

(ii) Preconditions for unsafe acts provided with classifications of the physical working environment and of adverse individual- and social performance influences.

(iii) Unsafe supervision provided with classifications of middle management oversights, and

(iv) Unsafe organisational influences provided with classifications of executive management (leadership) oversights.

In technical failure analysis Rausand and Øien [26] suggest three different types of causality to be considered; (i) Causes, (ii) mechanisms, and (iii) root causes. It seems redundant to introduce root cause as separate term in taxonomy. Root cause (analysis) is typically a term introduced in investigations to describe plausible failure causes- or mechanisms focal to system reliability growth (improvement) efforts. A definition built on Table 2 suggests an *operator error cause* as *a set of circumstances that impairs recovery from undesired effects of operator behaviour.*

In an oil and gas well we may consider CO_2 corrosion as a typical failure mechanism. This form of corrosion results from the chemical processes where CO_2 reacts with H_2O and forms carbonic acid, which in turn may cause exposed low alloy steels in the well to corrode. The term latent human error tendencies may be used to describe a similar concept for operator error in a drilling TA [29]. However, the term performance influencing factors seem to be more commonly used to jointly describe work situations prone to operator error that follow from a combination of both physical workplace factors and latent human error tendencies. The IEC 60050:192 [24] standard definition refers to mechanisms as being physical or chemical processes. In terms of HFs this may suggest a domain affiliation of human behaviour to neuroscience and biochemistry. However, a common interpretation of mechanisms in failure analysis is [26]; “The immediate causes to the lowest level of indenture”, which could similarly be interpreted for operator error as shown in Figure 4. Figure 4 is based on previous work including a literature review of socio-technical system theory, and social- and cognitive psychology for purpose of drilling HRA [29]. Figure 4 shows the lower level human error mechanisms described as individual- and workplace type performance influences on an action breakdown level. The factors listed in Figure 4 are not necessarily disjoint. For example, biomechanical limits are found closely related to workplace factors in control room ergonomic checklists provided by Johnsen, Bjørkli [34]. A definition of a *performance influence* built on Table 2 suggests *a process of departure described by workplace factors and latent human error tendencies.*

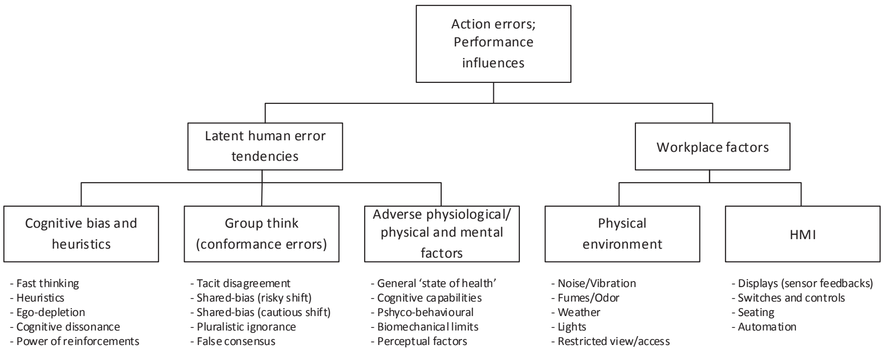

Figure 4. Example of a lower level operator error causal classification scheme given with latent human error tendencies and workplace factors as performance influences (non-exhaustive, based on [6, 8, 29])

Also based on Table 2, a definition is proposed for an *operator error effect* as the *consequence of operator error, within or beyond the boundary of a socio-technical system entity.* The level of task breakdown may have implications for cause and effect considerations similar to that between error modes and error causes. Figure 5 illustrates an example of such relationships described in this article between TA breakdown levels and key operator error concepts; (i) Performance influences, (ii) error causes, (iii) error modes and (iv) error effects. Also indicated in Figure 5 are representative social- or individual processes considered relevant to the analysis given various TA breakdown levels. The example seen in Figure 5 includes typical associations made at different TA levels deduced from simultaneous operations requirements given for an offshore installation considered as an 'organisational process'. The example shows how such requirements may migrate downwards to influence the situational elements inside the driller's cabin and thus also the performance of actions of the driller.

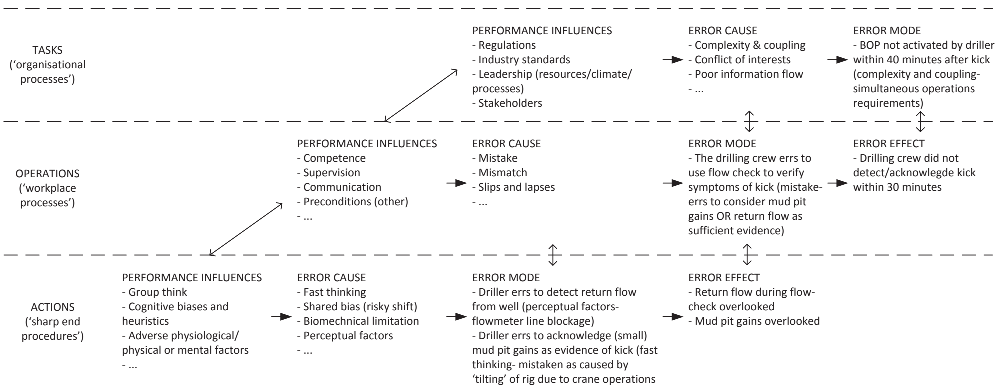

Figure 5. Example of proposed hierarchial classification scheme for operator errors in well drilling operations (based on [6, 8, 26, 29])

7 Implications for existing offshore drilling operation HRA method

To apply the proposed human error taxonomy presented in this article and summarized in Table 3 to existing drilling operation HRA method [6] is not straightforward. For example, when comparing the two level HRA method causal model [6] to the three level hierarchial classification scheme in Figure 5, the causal model is seen to become oriented towards considerations of organisational- and workplace processes. A different focus of study considers lower level actions that are focal to most TA. The implication may be that performance requirement standards identified and analysed at the action level may require a formal procedure to be developed to become consistently aggregated in line with structural dependencies in the model to be made representative for the risk influence factor evaluation in HRA method. Alternatively, a new causal influence modelling structure could be developed to align with the proposed HF taxonomy, i.e., result in a modelling structure that explicitly, and orthogonally, includes the three levels of operator performance influences that are indicated in Figure 5.

Table 3- Summary of proposed human error taxonomy for offshore drilling operations

Proposed term	Proposed definition
Operator error	Inability of an operator to perform as required. Note: Operator errors are associated with human behaviour, unsafe acts, which are not intended or not desired.
Operator requirement	A stated need or expectation about operator's performance considered necessary in order to accomplish a given task objective. Note: Operator requirements may; (i) Be stated or implied (i.e. that the operator would be entitled to expect), (ii) by implication, also cover what the operator should not do, (iii) include essential

	internal requirements of a task, which may not be visible to the operator, but also are operator requirements.
Operator error mode	Manner of non-conformity in which operator error occurs.
Error criterion	Pre-defined level of operator performance for acceptance as conclusive evidence of operator error.
Departure	Undesired discrepancy between a computed, observed or measured operator performance, and the specified target value stated in performance requirement standard.
Operator error cause	A set of circumstances that impairs recovery from undesired effects of operator behaviour.
Performance influence	A process of departure described by workplace factors and latent human error tendencies.
Operator error effect	Consequence of operator error, within or beyond the boundary of a socio-technical system entity.

8 Conclusions

Recent research related to HRA and PRA of well drilling operations coupled to a review of existing human factors taxonomies suggests that most HF analyses is biased towards higher level outcome oriented accident investigations, and not particularly well suited for the proactive purpose of TA or HRA. In this article, the authors propose amendments and clarifications to the existing task analysis terminology with the intention to help enhance the quality of human factors analyses of offshore drilling operations. Hence, we also explore potential implications of proposals made related to existing methods for human reliability analysis as part of probabilistic risk assessments of offshore drilling operations. The principle considerations made in the article to develop the proposed task analysis terminology are; (i) Multidisciplinary coherence through adaptation of familiar and recognised concepts from technical failure analysis and reliability data collection, and (ii) Usefulness and versatility through applicability across common levels of activity or process breakdown in task analysis.

The work presented in this article presumes that significant aspects of human error, referred to as operator error, can be defined and thereby consistently applied to HF analysis in offshore drilling operations. Moreover, this article proposes a three level taxonomy structure created around operator errors for the purpose of HRA in offshore drilling operations. The taxonomy is derived based on (i) key concepts found used in technical failure analysis, (ii) the typical three levels of task break down in a HTA, and (iii) previous research into HRA for purpose of PRA of offshore drilling operations. It is argued that the taxonomy will help reduce the potential for ambiguity among assessors in PRA, for example, in the identification and evaluation of human performance influencing factors for purpose of quantitative operator error modelling. The proposed taxonomy may imply in terms of future work that an existing drilling operation HRA method may benefit from a revision of its; (i) procedure or (ii) causal modelling structure in order to benefit from adopting the proposed terminology and taxonomy.

Acknowledgements

The opinions expressed in this article are those of the authors and do not reflect any official position by NTNU. We are grateful to our anonymous peers for providing valuable suggestions for improvement

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VI. On the use of Probability as Measure for Uncertainty in DPRA

"Uncertainty is a personal matter; it is not the uncertainty but your uncertainty"

Dennis V. Lindley (Lindley, 2014)

Uncertainty is imperfect knowledge about individual aspects of a study object. Different stakeholder views on uncertainties may typically be a challenge related to the adoption of the DPRA in the oil and gas industry. To help clarify on the meaning of uncertainty among stakeholders we may adapt a practical quote given about 'knowns and unknowns' by Donald Rumsfeld in 2002:

- Unknown-Unknowns. The things we don't know that we don't know. This type of uncertainty can be referred to as epistemic. I.e. we have uncertainties that are caused by lack of knowledge.
- Known-Unknowns The things we know that we don't know. This type of uncertainty can be referred to as aleatory. We have uncertainties that are caused by imperfect knowledge. For example, every well drilled is unique from Mother Nature's side and properties like formation pore pressures will never be completely known in advance of drilling a new well.
- Unknown-Knowns. The things we don't know that other know. This source of uncertainty represents lack of knowledge that may be considered either random or systematic (secrets). The random unknown-knowns, personal according to Lindley [22], can also be referred to as aleatory. For example, the uncertainty of DPRA that is influenced by the analyst's competence, limitations of tools, or misunderstandings by stakeholders in use of results from lack of DPRA domain knowledge.
- Known-Knowns. The things we know as facts, our knowledge base.

DPRA makes use of statistics and probability theory as measure to describe the uncertainties we have about the occurrences of main unwanted well system events such as blowouts and releases. In this respect, it may be useful to inform stakeholders about the different main 'schools' to statistics and probability theory (Rausand, 2011):

(i) The classical school, which derives 'true' probability from a sample space with equally likely outcomes and defines probability of event E, Pr(E), as the number of a favourable outcomes of E, n_E, divided by the total number of possible outcomes, N: $\Pr(\mathrm{E}) = n_E / N$

The classical school is broadly accepted by the other schools as the reference standard for which probability, and thus also uncertainty is measured and interpreted (Lindley, 2014). This view of a standard for uncertainty can be associated with the drawing of a specific ball at random from an urn that contains a given total number of balls.

(ii) The frequentist school, which from objective and identical experiments defines 'true' Pr(E) as the limiting ratio between the number of favourable outcomes E, n_E , and the total number of experiments, N, as N is approaching infinity. I.e. $\text{Pr(E)} = \lim_{N\to\infty} \left[n_E / N \right]$

The measure for uncertainty, Pr(E), is seen here to also be reflected in the amount of data, *N*, available for statistical analysis. The more experiments you do on E the closer to the 'true' probability value you will get. The probability defined by mathematical convergence in frequentist school is therefore also referred to as an 'ambiguous probability'. Hence, in most practical cases there will be important discussions related to the size of the deviation from true value in context to precision (realism) and accuracy (reproducibility) in the scientific method (Lindley, 2000). The size of deviation can be referred to as the degree of study completeness affected by theoretical knowledge gaps (epistemic uncertainty), but also of natural and incidental influences (aleatory uncertainty). Such influences in risk assessment for instance introduced by the competence of assessors coupled to the relevancy of models, methods, help tools and input data used.

(iii) The subjectivist school, which objects to the existence of any true unconditional and objective probability. The most central concept in subjective statistics is Bayes' theorem that defines probability of event E as a conditional probability, Pr(E | Ꝁ). The knowledge base, Ꝁ, comprises a combination of facts, evidence, suppositions and beliefs. The probability of event E is thus argued to always include some 'personal uncertainty' (Lindley, 2014), which is the analyst' degree of belief, about whether or not event E will occur. The inference allowed from belief and degrees of judgment in subjective probability theory is an explicit source for inconsistency among practitioners. Thus, an underlying source of error in deduction of reproducible result. This makes subjective statistics less acknowledged in the scientific method (Lindley, 2000). The Bayesian approach when carefully validated can, however, be argued as rational in many areas of practical risk informed decision support (Fenton and Neil, 2012).

All three schools follow the Kolmogorov axioms of probability in calculations. However, as noted the subjective statistician disagrees with the classic and frequentist in interpretation of probability as an objective and strict repeatable property of event E. An important implication from this on probability calculation is that evidence and beliefs are treated with equal importance as knowledge and facts in subjectivist probability calculations. The subjectivist based methods, some flexible and easy to use (Fenton and Neil, 2012), are consequently when applied in science found to require a higher degree of focus on expertise and knowledge of the problem domain (Ren et al., 2008). This in order to prevent undesired modelling bias due to, for instance, the 'man with the hammer syndrome'. The axioms of probability calculations followed by all schools are when omitting Ꝁ as explicit condition in all subjectivist calculations;

Convexity rule:

> Probability is a real number in [0, 1], and if you know that event E will occur then inferred is (i) Pr(E) = 1 and (ii) for the complement event, event E does not occur E^c, $Pr(E^c) = 0$.

The probability of complement events follows from this requirement of coherence in probability theory. According to Lindley (2014) this relationship is an important aspect in quality assurance of ourselves in how we treat uncertainty of events and probabilities. For example, if you accept that Pr(E) = 1 it follows that you also by default have to accept that $Pr(E^c) = 0$. We are warned to be cautious about using the bounds, 1 and 0, about probability because of the impasse it carries on to arguments (Cromwell's rule). The advice is that the bounds only should occur as result of strict logical deduction by mathematics.

The *addition rule* describes the union of several events, $\cup$, in probability calculus given by OR-type logic combinations of the events occurring. If events cannot occur at the same time the events are called mutually exclusive or disjoint. As disjoint events cannot occur at the same time the intersection, $\cap$, between E_1 and E_2 is then denoted as Ø for an empty set. I.e. $\Pr(E_1 \cap \mathrm{E}_2) = \varnothing$ and hence can be omitted from the rule:

$$\Pr(E_1 \cup \mathrm{E}_2) = \Pr(E_1) + \Pr(\mathrm{E}_2) - \Pr(E_1 \cap \mathrm{E}_2) \qquad \text{(Equation 12)}$$

The *multiplication rule* describes intersection of events, $\cap$, in probability calculus given by conditional AND-type logic combinations of events occurring at the same time. If there are no dependency between events, so that $\Pr(E_1 \mid \mathrm{E}_2) = \Pr(E_1)$, the events E_1 and E_2 are said to be independent and the conditional notion can then be omitted from the rule:

$$\Pr(E_1 \cap \mathrm{E}_2) = \Pr(E_1) \cdot \Pr(\mathrm{E}_2 \mid \mathrm{E}_1) = \Pr(E_2) \cdot \Pr(\mathrm{E}_1 \mid \mathrm{E}_2) \qquad \text{(Equation 13)}$$

The logical rules of addition and multiplication of events may be found formalised in system analysis with use of binary decision diagrams, or systems reliability theory' structure function that is constructed based on a combination of events in series- and parallel structures (Rausand and Høyland, 2004).

The *law of total probability* states that probability of event F part of a sample space S that consists of E_1, E_2, …, E_n disjoint partitions becomes:

$$\Pr(\mathrm{F}) = \sum_{i=1}^{n} \Pr(F \cap E_i) = \sum_{i=1}^{n} \Pr(\mathrm{F} \mid \mathrm{E}_i) \cdot \Pr(\mathrm{E}_i) \qquad \text{(Equation 14)}$$

The law of total probability is reduced to its most compact form when S is made of only two disjoint partitions, E and E^c, as the 'rule of extension of conversation':

$$\Pr(\mathrm{F}) = \Pr(\mathrm{F} \mid \mathrm{E}) \cdot \Pr(\mathrm{E}) + \Pr(\mathrm{F} \mid \mathrm{E}^c) \cdot \Pr(\mathrm{E}^c) \qquad \text{(Equation 15)}$$

The four rules of probability calculations are not valid for any type event or situation. It is important to note that you can manipulate the situation, "rig the game", so that the coherence and randomness is lost like, for instance, seen with the prisoners dilemma (Lindley, 2014). As a result we may find arguments made, for instance, that security issues lack the properties required to be treated in analysis by classical probabilities, while other argue these manipulated situations as unrealistic, hypothetical constructs of hyper rational decision making (Cox, 2009).

In situations with gross lack of knowledge ('deep uncertainty') about the study object and where a strict actuarial approach is the only practical option to address risk there also exists some alternative views to probability theory, often called hybrid approaches discussed by, for example, Aven et al. (2014). The main concept of such alternatives is that of 'imprecise probability' that introduces upper and lower bounds for probability statements, respectively denoted $\overline{\mathrm{P}}(\mathrm{E})$ and $\underline{\mathrm{P}}(\mathrm{E})$. The main argument used for hybrid approaches is a need to better formalise, fix a translation between assessor and decision maker, the subjective knowledge or belief base, K, of the analyst's performing the analysis (Aven et al., 2014, p. 81). The added value of hybrid methods over the complications it introduces in violation of the axioms of probability theory, and of alternative aspects on risk and decision analysis quality assurance such as (Johansen and Rausand, 2014, Rae et al., 2014) and of regular sensitivity analysis remains disputed (Aven et al., 2014).

Table 19 shows a summary of the discussions provided about use of probability and statistics in measuring uncertainty, and that it is considered important to distinguish and understand relationship between concepts of belief and probability as a forecast about the future versus the related concepts of frequencies and likelihood used in interpreting historic event data part of statistical analysis.

Table 19. Overview of concepts from probability theory and statistics that describe uncertainty of a continuously distributed variable E with pdf, $f(t;\theta)$

Probability 'school' (forecasting - deductive)	Statistics (data analysis - inductive)

Classic, E ~ $f(t \mid \theta)$	Frequency, $\frac{n_E}{N}$
Chance and Odds of E (Bernoulli' series); $\hat{\Pr}(E) / (1 - \hat{\Pr}(E))$	Frequency, $\frac{1}{N}\sum E$
Ambiguous, E ~ $f(t \mid \hat{\theta})$	Likelihood, $\ell(\theta \mid t)$
Subjective, E ~ $f(t \mid \hat{\theta}, \mathrm{K})$	
Imprecise. For example, if assuming E ~ $f(t \mid \hat{\pi}(\theta), \mathrm{K})$ (Apostolakis, 1989) [Min{ $f(t \mid \hat{\pi}(\theta), \mathrm{K})$ }, Max{ $f(t \mid \hat{\pi}(\theta), \mathrm{K})$ }]	

VII. List of acronyms and abbreviations

ALARP	-	As Low As Reasonably Practical (principle for establishing RAC)
AMF	-	Auto Mode Function
AP	-	Annular Preventer
API	-	American Petroleum Institute
BA(S)T	-	Best Available (Safest) Technology (principle for establishing RAC)
BBN	-	Bayesian Belief Networks
BHA	-	Bottom Hole Assembly
BOP	-	BlowOut Preventer system
BSEE	-	the Bureau of Safety and Environmental Enforcement
BSR	-	Blind Shear Ram
CAPEX	-	CApital EXpenditures
CBL	-	Cement Bond Log
CPT	-	Conditional Probability Table
CS	-	Cut Set
CSR	-	Casing Shear Ram
DBBN	-	Dynamic Bayesian Belief Networks
DD	-	Dual Displacement
DoD	-	US Department of Defence
DP	-	Dynamically Positioned
DPRA	-	Drilling Probabilistic Risk Assessment
ECD	-	Equivalent Circulation Density
EDS	-	Emergency Disconnect Sequence
EKDS	-	Early Kick Detection System
ETA	-	Event Tree Analysis
FIT	-	Formation Integrity (pressure) Test
FTA	-	Fault Tree Analysis
HAZID	-	HAZard IDentification
HAZOP	-	HAZard and OPerability study
HEA	-	Human Error Analysis
HEP	-	Human Error Probability, see Operator Error Probability
HMI	-	Human-Machine Interface
HOF	-	Human and Organisational Factors
HPHT	-	High Pressure High Temperature
HPP	-	Homogeneous Poisson Process
HRA	-	Human Reliability Analysis
HSE	-	Health and Safety Executive UK
HTA	-	Hierarchical Task Analysis

HWDP	-	Heavy Weight Drill Pipe
IEC	-	International Electrotechnical Commission
IOGP	-	the International association of Oil & Gas Producers
ISO	-	the International Organization for Standardization
LEL	-	Lower Explosion Limit
LMRP	-	Lower Marine Riser Package
LOT	-	Leak Off Test
LWD	-	Logging while drilling
MDRKB	-	Measured Depth Rotary Kelly Bushing
MDRT	-	Measured Depth Rotary Table
MAASP	-	Maximum Allowable Annulus Surface Pressure
MoC	-	Management of Change
MODU	-	Mobile Offshore Drilling Unit
MPD	-	Managed Pressure Drilling
MSL	-	Mean Sea Level
MTTF	-	Mean Time To Failure
MUX	-	MUltipleX
MW	-	Mud Weight
MWD	-	Measurement while drilling
NCS	-	Norwegian Continental Shelf
NEA	-	the Norwegian Environmental Agency
NMDC	-	Non-magnetic drill collars
NPD	-	the Norwegian Petroleum Directorate
NOGA	-	the Norwegian Oil and Gas Association
NORSOK	-	the Norwegian shelf's competitive position (industry standards)
NTNU	-	Norwegian University of Science and Technology
NUREG	-	US Nuclear Regulatory Commission
OBM	-	Oil Based Mud
OEM	-	Original Equipment Manufacturer
OEP	-	Operator Error Probability
OGP	-	the international association of Oil & Gas Producers
OPEX	-	OPerating EXpenditures
pdf	-	probability density function
PDO	-	Plan for Development and Operation
PFD	-	Probability of Failure on Demand
PIF	-	Performance Influencing Factor
POOH	-	Pull Out Of Hole
PR	-	Pipe Ram
PRA	-	Probabilistic Risk Assessment
PSA	-	Petroleum Safety Authority Norway

PTC	-	Proof Test Coverage
QA/QC	-	Quality Assurance/Quality Control
RAC	-	Risk Acceptance Criteria
RAMS	-	Reliability, Availability, Maintainability and Safety
RGH	-	Riser Gas Handling
RIDM	-	Risk Informed Decision Making
RIF	-	Risk Influencing Factor
RIH	-	Run In Hole
ROP	-	Rate Of Penetration (drilling)
ROV	-	Remote Operated Vehicle
SA	-	Situation Awareness
SADT	-	Structured Analysis and Design Technique
SBM	-	Synthetic Based Mud
SCADA	-	Supervisory Control And Data Acquisition
SIF	-	Safety Integrity Function
SIS	-	Safety Instrumented System
SSI	-	Stress-Strength interference
TA	-	Task Analysis
TD	-	Total Depth
TQP	-	Technology Qualification Program
TVD	-	true vertical depth
TVDRKB	-	True Vertical Depth Rotary Kelly Bushing
TVDRT	-	True Vertical Depth Rotary Table
UK	-	United Kingdom
USGoM OCS	-	US Gulf of Mexico Outer Continental Shelf
USIT	-	UltraSonic Imaging Tool
UV	-	Ultra Violet
VBR	-	Variable Bore Ram
VME	-	von Mises Equivalent (stress)
WBE	-	Well Barrier Element
WBM	-	Water Based Mude
WDP	-	Well Design Pressure
WHSIP	-	Wellhead Shut-In Pressure
WOC	-	Wait On Cement (to cure)
xLOT	-	extended Leak Off Test

VIII. Terminology

Availability	The ability of an item[33] (under combined aspects of its reliability, maintainability, and maintenance support) to perform its required function at a stated instant of time or over a stated period of time (BS 4778). Note: Availability is used as a performance measure or indicator for system dependability and is sometimes referred to as 'production availability' when considering production systems and 'safety availability', respectively for safety systems.
A-annulus	A term used for the annulus between the well completion (production tubing) and the production casing.
Abnormal pressure	Formation or zones where the pore pressure is above the normal, regional hydrostatic pressure (NORSOK D-010 (2013)) Note 1: 'Normal pressure' means formation or zones where in-situ pore pressures follow regional hydrostatic pressure. In general this means having pore-pressures that follow a seawater density gradient of ca. 1 Bar per 10m vertical depth below mean sea level.
B-annulus	A term used for the annulus between the production casing and the intermediate casing (next outer casing string).
Safety barrier	Combination of technical, operational or organisational solutions that reduce the probability for exposure to harmful situations and accidents ('pre-accident barrier'), or that reduces accident losses ('post-accident barrier') (adapted from PSA)
Blowout	An incident where formation fluids flows out of the well or between formation layers after all the predefined technical well barriers or the activation of the same have failed (SINTEF (2015))

[33] the term "item" is used in this report to denote any component, subsystem, or system that can be considered as an entity.

C-annulus	A term used for the annulus between the intermediate casing and the surface casing (next outer casing string).
Casing	Large-diameter pipe cemented in place during the well construction process to stabilise the wellbore. The casing strings forms a major structural component of the wellbore and serves several important functions: preventing the formation wall from caving into the wellbore, isolating the different formations to prevent the flow or cross-flow of formation fluids, and providing a means of maintaining control of formation fluids and pressure as the well is drilled deeper. The casing string also provides a means of securing seabed/surface pressure control equipment and downhole production equipment, such as the wellhead, blowout preventer (BOP) or Xmas tree, and the production packer. Note: A 'liner' is a casing string in which the top does not extend to the wellbore surface but instead is suspended with a hanger/packer system from the inside of the previous casing string.
Casing program	A collective term used for all casing and liner strings, including hangers, seals and cement, located in a wellbore.
Christmas (Xmas) tree	An assembly of valves, spools, gauges and chokes fitted to the wellhead to control the well flow in the well operational (production or injection) phase.
Common cause failures	Failures of different items resulting from the same direct cause where these failures are not consequences of other failures Note: Failures that are consequences of other failures are called 'cascading failures'.
Common well barrier element	Barrier element that is shared between the primary and secondary well barrier (NORSOK D-010 (2013))

Competence	Collective term used to describe the ability of individuals and teams to perform an activity as prescribed under different workplace conditions. Competence may be considered an activity domain knowledge function that consists of the following main factors: • Skills (natural talent and personal interests) • Knowledge (theoretical basis from education and courses) • Experience (hands-on, simulator training or equivalent) • Motivation/Attention/Attitude (workplace incentives and culture) Note: An ‘X-factor’ may also be considered to account for non-workplace related physiological and psychological factors such as ‘self-imposed stress’ (DoD, 2005)
Conductor (-casing/pipe)	The outermost casing string in a casing program set to support the surface formations. The conductor is typically a short string run soon after drilling has commenced since the unconsolidated shallow formations can quickly wash out or cave in. Where loose wellbore surface soil exists, the conductor pipe may be driven or jetted into place before the drilling commences.
Corrective maintenance	The maintenance carried out after a failure has occurred and intended to restore an item to a state in which it can perform its required functions /BS 4778/. Note: Repair is defined as the part of corrective in which manual actions are performed on the entity (IEC50(191))
Design life	Planned usage time for the total system (NORSOK O-CR-001).
Downtime	The period of time during which an item[1] is not in a condition to perform its required functions (BS 4778).
Fail safe	A design property of an item that prevents its failures from being critical failures (BS 4778)

Failure	Termination of the ability of an item to perform a required function. Note 1: Adopted from /BS4778/ to cover technical systems. 'Operator error' is used in thesis to define a 'malfunction' from a human or organisational point of view. Note 2: 'Failure' is an event, as distinguished from 'fault' which is a state. Note 3: 'Hidden failure' refers to a failure that failure implications are not evident to the operator in normal mode of system operation.
Failure mode	The effect by which a failure is observed on the failed item (EuReDatA, 1983).
Failure rate	The rate at which item failure occurs as a function of time (BS4778). Note 1: The failure rate is sometimes called "force of mortality" or "hazard rate". Note 2: The rate of failure is often denoted the rate of occurrences of failures (ROCOF) for items that receive maintenance.
Fracture closing pressure	Pressure at which the fracture closes after the formation first has been broken down ('fractured'). Fracture closure pressure is equal to minimum formation stress also denoted 'minimum horizontal stress'. This property of a formation-rock is, for instance, used in Norway as the 'pressure rating' for qualification of a formation as a WBE in operation and abandonment phase of a well (NORSOK D-010 (2013))
Formation Integrity pressure	Collective term to describe strength of the formation. This can be determined by either Formation- or Pressure Integrity Test (FIT/PIT) or the interval between fracture breakdown pressure and fracture closure pressure (NORSOK D-010 (2013))
Inflow test	A pressure test with defined differential created by reducing the pressure on the downstream side of the well barrier or well barrier element (NORSOK D-010 (2013)) Note 1: This test may also be denoted a 'negative pressure test'.

Intermediate casing	One or more casing string(s) set after the surface casing and before the production casing. The intermediate casing string(s) provides protection against caving of weak or abnormally pressured formations and enables the use of drilling fluids of different density necessary for the control of deeper formations.
Kick tolerance	The maximum influx volume that can be circulated out of well without breaking down the weakest zone in well (NORSOK D-010 (2013)) Note: Also referred to as 'kick margin'
Light intervention	Preventive or corrective maintenance carried out on a well without pulling any part of the well completion string. It also covers other interventions, e.g., production logging operations, condition monitoring and production optimisation operations like, for instance, well testing, stimulations, chemical injection and perforation. Note: Also referred to as 'wireline', 'slickline', 'E-line', 'tractor' or 'coiled tubing' interventions dependent on the specific technical solutions used for the operation.
Maintenance (logistics) support	The materials and services required to operate, maintain, and repair a system. Logistics support includes the identification, selection, procurement, scheduling, stocking, and distribution of spares, repair parts, facilities, support equipment, etc.
Maintainability	The ability of an item[1], under stated conditions of use, to be retained in, or restored to, a state in which it can perform its required functions, when maintenance is performed under stated conditions and using prescribed procedures and resources (BS 4778).
Management of Change (MoC)	Term used for work process established within the operator or rig-company for supporting the operational crews in dealing with larger 'surprises' and major deviations from original approved well operation plans.
Preventive maintenance	The maintenance carried out at predetermined intervals or corresponding to prescribed criteria and intended to reduce the probability of failure or the performance degradation of an item (BS 4778).

Production casing	A casing string that is set across or just above the reservoir interval, and within which the main well completion components are installed.
Rated working pressure	The maximum internal pressure equipment is designed to contain (NORSOK D-010 (2013)) Note: Often also referred to as 'Maximum Working Pressure' (MWP)
Redundancy	In an item the existence of more than one means for performing a required function (IEC 50(191)).
Reliability	The ability of an item to perform a required function, under given environmental and operational conditions and for a stated period of time /BS 4778 and ISO8402/. Note: Items that do not affect each other's reliability when including aspects of common cause and cascading failures are referred to as *independent* items.
Reliability data	Reliability data is meant to include data for reliability, maintainability and maintenance supportability (NORSOK O-CR-001).
Riser margin	Additional fluid density required to compensate for the differential pressure between the fluid in the riser and seawater in the event of a riser disconnect (NORSOK D-010 (2013))
Safety	Collective term used for efforts such as qualitative and quantitative risk assessment, aimed at prevention or reduction of harm of random unwanted events
Security	Collective term used for efforts such as threat-, vulnerability-, and consequence assessment, aimed at prevention or reduction of harm of deliberate hostile actions
Shallow gas	Permeable gas formation(s) which are penetrated prior to installing the surface casing and BOP (NORSOK D-010 (2013))

Simultaneous activities	Activities that are executed concurrently on the same installation such as production activities, drilling and well activities, maintenance and modification activities and critical activities (NORSOK D-010 (2013)) Note: 'Critical activity' is meant to include any activity that potentially can cause serious injury or death to people, or significant pollution of the environment or substantial financial losses
Surface casing	A casing string set inside the conductor in shallow but competent formations. The surface casing protects onshore fresh-water aquifers, and it provides minimal pressure integrity and thus enables a diverter or a blowout preventer (BOP) to be attached to the top of the surface casing string after it is successfully cemented in place. The surface casing provides structural strength so that the remaining casing strings may be suspended at the top and inside of the surface casing.
Stakeholders	Person or organisation that can affect, be affected by, or perceive themselves to be affected by a decision or activity (ISO 31000, 2009)
Technology qualification	A term used for a systematic process that is carried out to verify ('mature') and thereby enable new or modified technology to become sufficiently 'proven by use' and acceptable for deployment in the field. Achieving prescribed levels of 'technology readiness' (product characteristics) and 'operational readiness' (product usage) may be considered key milestones in a well technology qualification program (ExproSoft, 2011). Note: ISO 9000:2005 defines 'qualification process' generally as a process with objective to 'demonstrate the ability to fulfil specified requirements'
Well (system)	A collective term that comprises a group of items with joint purpose to enable a contained and controlled access to a (pressurised) formation. For example, in the drilling phase, *well* will typically encompass the drilling riser, BOP, wellhead, casing program and openhole formations.

Well barrier	A well barrier is a pre-defined technical envelope of one or several well barrier elements designed to prevent unintentional flow of well fluids between formations or to the surroundings. (adapted from NORSOK D-010 (2013)). Note: Well barriers are designed not to hinder well activities, and so that their performance can be verified, typically by; pressure testing, testing of accessibility, response time- or leak rate measurements.
Well control action procedure	Sequence of planned actions/steps to be executed when a well barrier fails (NORSOK D-010 (2013)) Note: This normally describes the activation of the secondary well barrier, e.g. shut-in of well, and thereafter to restore the failed well barrier.
Well design pressure	The maximum absolute pressure expected in the well at surface/wellhead (including kill margin, NORSOK D-010 (2013)) Note: Section design pressure is the maximum absolute pressure expected in the well at surface / wellhead whilst drilling a specific hole-section
Well integrity	Application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids and well fluids throughout the life cycle of a well (NORSOK D-010 (2013)).
Well completion	A collective term that encompass the assembly of tubing hanger, tubular, safety valve, production packer and other equipment placed within the production casing to enable safe and efficient surface access to a (pressurised) formation. Note 1: Also called ‘production/injection tubing’ or ‘production/injection string’. Note 2: Well completions are sometimes named with an “upper”, “middle”, and “lower” part. The upper well completion refers to the continuous part of the well completion extended up to and including the tubing hanger, the middle part typically refers to junctions installed in multilateral wells, and the lower completion commonly refers to sand control equipment installed as a separate string in the bottom of the well.

Well release	A temporary incident (controlled by the predefined technical well barriers) where well fluids flow unintentionally out of the well or between formation layers.
Wellhead (system)	The surface/seabed termination of a wellbore that incorporates facilities for installing casing hangers during the well construction phase. The wellhead also incorporates an interface with the production tubing and of installing the Xmas tree or other flow-control devices in preparation for the operation of the well.
Workover	Preventive or corrective maintenance carried out on a well by pulling parts or the entire well completion string (heavy lifting rig needed). Note: Activity may include side-track drilling operations that re-uses much of the old wellbore to develop new areas or to remedy, for instance, lower completion (sand control) failures.

IX. Curriculum vitae

Geir-Ove Strand

Sivilingeniør
Year of birth: 1973
Nationality: Norwegian

Education:

2015	Graduate courses in Systems Engineering and in Risk Influence Modelling, NTNU, Trondheim
2014	Graduate courses in Maintenance Optimisation and in Reliability Analysis of Safety Instrumented Systems, NTNU, Trondheim
1998/1999	Graduate courses in Statistics and in Lifetime Data Analysis, NTNU, Trondheim
1998	Sivilingeniør/MSc. in Safety and Reliability Engineering, the Norwegian University of Science and Technology (NTNU), Trondheim
1995	Mechanical Engineering degree (Production and Quality Management), Gjoevik University College

Experience:

1/2014-12/2016 PhD Candidate, NTNU. Well Safety: Risk control in drilling and intervention operations
8/2000-12/2013 Consultant / Specialist. Well and subsea risk and reliability, ExproSoft AS
1/1999-7/2000 Research Scientist. SINTEF Petroleum Research, Drilling and Well Technology Department

Main fields of competence:

Safety and Reliability - Subsea and Well ('upstream') Technology

- Probabilistic risk and reliability analysis
- Software tools and standard developments
- Safety and reliability data collection and analysis

Professional memberships:

Member: Society of Petroleum Engineers (#3052848)
Reviewer: Journal of Petroleum Science and Engineering (Elsevier)

Publications and Presentations

Strand, G.O., Haskins, C. and Lundteigen, M.A., "A contribution to the classification of human errors using offshore drilling operations as case study". Manuscript submitted for publication in Journal of Risk and Reliability (Sage), 2016

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