Looking Back and Forward: Could Safety Indicators Have Given Early Warnings about the Deepwater Horizon Accident?

Jon Espen Skogdalen **(corresponding author)**
Department of Industrial Economics, Risk Management and Planning
University of Stavanger, NO 4036 Stavanger, Norway
jon.e.skogdalen@uis.no
Phone/fax: +47 99 02 41 71

Ingrid B. Utne
Department of Marine Technology,
Norwegian University of Science and Technology (NTNU), NO 7491 Trondheim, Norway
ingrid.b.utne@ntnu.no

Jan Erik Vinnem
Department of Industrial Economics, Risk Management and Planning
University of Stavanger, NO 4036 Stavanger, Norway
jev@preventor.no

Abstract

An important question with respect to the Deepwater Horizon accident is whether the accident is a symptom of systemic safety problems in the deepwater drilling industry. An answer to such a question is hard to obtain unless the risk level related to major accident prevention, preparedness, and responses of the oil and gas industry is measured and evaluated over time. In this paper, we present information and indicators from the Risk Level Project (RNNP) in the Norwegian oil and gas industry related to safety climate, barriers and undesired incidents, and discuss relevance for drilling, in particular for deepwater drilling. The main focus of the major hazard indicators in RNNP is on production installations, whereas only a limited number of incident indicators and barrier indicators are related to mobile drilling units. Therefore, in this paper we discuss extensions of the indicators in RNNP in light of the Deepwater Horizon accident. Aspects related to well integrity and the two barrier principle, well planning, schedule and cost, undesired incidents, and well monitoring/intervention are discussed, as well as best practices/guidelines, status/failure in safety critical technical equipment, and operational conditions. The number of kicks is an important indicator for the whole drilling industry, because it is an incident with the potential to cause a blowout. It is the authors' view that there is a need for more extensive investigations of incidents like "kicks" to ensure improved learning. Our opinion is that if indicators from RNNP are supplemented by additional indicators, early warnings about potential failures in several of the barriers related to the Deepwater Horizon accident could have been provided. However, such early warnings demands cooperation across national borders, operators, vendors, specialist environments, as well as between industry and regulatory authorities.

Keywords: Deepwater Horizon; deepwater drilling; risk management; safety indicators

Table of Contents

Acknowledgements

The authors are grateful to comments and reviews by members of the Deepwater Horizon Study Group. Special thanks to Senior Researcher Emery Roe (UC Berkeley) and Professor Paul Schulman (Mills College in Oakland, California) for discussions, inputs and review. Skogdalen and Vinnem also acknowledge the financial support from the Norwegian Research Council and Statoil. Skogdalen does also acknowledge the financial support by Fulbright.

1 Introduction

The Deepwater Horizon rig was considered to be a safe and efficient drilling unit. On April 20, 2010, BP officials visited the rig to praise seven years with no personal injuries.[1] In the evening of that very same day, gas exploded up the wellbore onto the deck and the rig caught fire. The explosions left eleven workers dead and 17 others injured. Two days later, the Deepwater Horizon rig sank.[2] The resulting oil spill gushed out of the damaged well for two months and caused the worst environmental disaster in US history, with impacts on local economies, sensitive coastlines and wildlife throughout the Gulf region.[3]

Systematic feedback on accident risk is of major importance to prevent accidents.[4] Often, hindsight shows that if early warnings had been revealed and managed in advance, the undesired incident could have been prevented.[5] Safety management of industrial systems, such as an offshore drilling rig, requires monitoring of safety performance, including the use of safety indicators. The term indicator may be defined in several ways. In this paper we define a safety performance indicator as "*a means for measuring the changes in the level of safety (related to major accident prevention, preparedness and response), as the result of actions taken*". (The definition is close to the OECD definition [6]).

In Norway, the risk level of the offshore petroleum industry is analyzed and presented on an annual basis. The first report was published early in 2001, based on data for the period 1996–2000. The methods used to collect data and analyze the risks were developed through the "risk level project" (RNNP). RNNP uses statistical, engineering and social science methods in order to provide a broad illustration of risk levels, including risk due to major hazards, risk due to incidents that may represent challenges for emergency preparedness, and risk perception and cultural factors.[7]

1.1 Objective of paper

To determine whether the Deepwater Horizon accident is a symptom of systemic safety problems in the deepwater drilling industry is difficult, unless the risk level related to major accident prevention, preparedness, and responses of the oil and gas industry is measured and evaluated over time. The Deepwater Horizon rig is subject to US legal and regulatory conditions, which do not require annual updates of the offshore petroleum industry's risk level in the same manner as the RNNP. Therefore, the question arises whether the indicators used in the RNNP could have given early warnings of a major accident, such as that on the Deepwater Horizon rig.

The objective of this paper is to assess safety indicators in the RNNP project and determine their relevance as early warnings for drilling accidents, including the Deepwater Horizon blowout. In addition, the paper discusses possible extensions and supplements with respect to drilling. The paper focuses on well integrity during drilling, and not on well production (hydrocarbon production, water and gas injection and well interventions) or emergency responses.

This paper is intended to be understandable for non-experts of drilling also. Therefore, we have in some places included short explanations. In addition, we advise the reader to use http://oilgasglossary.com for further explanations.

1.2 Structure of paper

The first part of the paper shortly describes deepwater drilling, principles and regulations related to well integrity, and possible causes to the Deepwater Horizon accident. Then, RNNP in relation to deepwater drilling is described, followed by discussions about possible extensions and conclusions.

2 Deepwater Drilling and the Deepwater Horizon Accident

Deepwater drilling[i] are complex operations in which engineering and commissioning mistakes, along with major workovers, can cost tens of millions dollars. Integrated operations (IO) are an important part of deepwater drilling, based on advances in information and communication technology (ICT). IO entails changes to organization, staffing, management systems and technology – and to the interaction between them. Increasingly, activities on land and offshore are being merged into a single operations unit. This means that work is controlled and organized in real time, often in different parts of the world.[8]

Many prospects in the deepwater GoM pose a unique combination of challenges when compared to deepwater wells in other parts of the world: Water depths of 3000 m, shut-in pressures of more than 690 bars, bottom hole temperatures higher than 195 °C, problematic formations with salt zones and tar zones, deep reservoirs at more than 9000 m true vertical depth, tight sandstone reservoirs (< 10 micro-Darcies (mD)) and fluids with extreme flow assurance issues.[9] Therefore, deepwater drilling is characterized by narrow drilling margins, and the narrower the margin; the more difficult to execute drilling operations.

In summary, some important challenges with deepwater drilling are:

- Huge costs
- Integrated operations
- Using the latest technology (depending on software/hardware)
- Complex casing programs
- Narrow drilling margins
- High pressure and high temperatures (HPHT)
- Tight sandstone reservoirs and fluids with extreme flow assurance
- Subsea operations
- Problematic formations
- Uncertain seismic
- Lack of experienced personnel

2.1 Well integrity and barriers

Well integrity is the application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well.[10.

The main undesired incidents related to well operations are (a) unintentional well inflow, (b) well leakage, and (c) blowout. The first is an unintentional flow of formation fluid into the wellbore (kick). The second is characterized by unintentional fluid flowing up through the BOP for a limited period of time until stopped by the existing well equipment or by defined operational means. A kick

[i] Deepwater drilling refers to water depths greater than 1000 ft. Ultra-deepwater drilling refers to water depths greater than 5000 ft.

is instability in the well as a result of the well taking in gas, oil or water, and may lead to a blowout.[11, 12] A blowout in turn is defined as an unintentional flow of formation fluid from the well to surroundings or between the formation layers after the defined technical barriers, and the operation of those, have failed.[13]

Blowouts and underground blowouts are a result of loss of well control (LWC). A LWC incident is an uncontrolled flow of subterranean formation fluids, such as natural gases, oil, saline water, etc. and/or well fluids into the atmosphere or into an underground formation. A LWC incident or blowout can occur when formation pressure exceeds the pressure applied to it by a column of fluid such as a drilling fluid, cement slurry, cement spacer fluid, brine completion fluid, or any combination thereof in the column of fluid.[11] The risk of a blowout will vary with the design of the well, the type of flowing fluid, and formation characteristics.[13]

Barriers are required to ensure well integrity during drilling. Safety barriers are physical or non-physical means planned to prevent, control, or mitigate undesired incidents or accidents. Barriers may be passive or active, physical, technical, or human/operational systems. Barriers have been defined in terms of three characteristics[14, 15]:

- Barrier function: A function planned to prevent, control, or mitigate undesired incidents or accidents.
- Barrier element: Part of barrier, but not sufficient alone in order to achieve the required overall function.
- Barrier influencing factor: A factor that influences the performance of barriers.

Barriers are vital for maintaining safety in day-to-day operations. A well should have at least two barriers. The primary well barrier is the first obstacle against undesirable flow from the source (kick). On the detection of an influx, the well should be closed by activation of the secondary well barrier. The secondary well barrier prevents further unwanted flow if the primary well barrier fails.[13] The well control measures should be activated to remove the influx from the well to re-establish pressure overbalance, before the well operation can be resumed.

An overbalanced mud column is used to exercise a fluid pressure in the well in excess of the formation pore pressures to be encountered. The Macondo well, which the Deepwater Horizon rig was drilling, was performed as overbalanced operations, which is a common drilling, completion, intervention, and workover operation method. The pore pressure is the pressure of the fluid inside the pore spaces of a formation or the pressure exerted by a column of water from the formation depth to the sea level, whereas the fracture gradient is the strength of the rock.[16] Such a mud column prevents influx of formation fluids into the well. In overbalanced operations, the mud column and system components support containment and are considered the primary well barrier. The secondary well barrier in overbalanced operations is the well containment envelope consisting of selected components of the BOP, or the BOP stack in total. The BOP has valves which can close around the drill string, and in an emergency sever the string and plug the wellbore.

2.2 The Deepwater Horizon accident

Deepwater Horizon was a 5th generation drilling rig commissioned in 2001, and outfitted with advanced drilling technology and control systems. In February 2010, the Deepwater Horizon rig, owned by Transocean and contracted by BP, took over drilling an exploratory well at the Macondo Prospect about 66 km off the southeast coast of Louisiana, USA. The water depth at the site is around 1,500 m, and the well to be drilled was 5500 m below sea level. After drilling, the plan was to plug the well, but the plans were changed during drilling and the well was changed to exploration to a production well.[1]

In the evening of April 20, 2010, a well control incident allowed hydrocarbons to escape from the Macondo well onto Transocean's Deepwater Horizon rig, resulting in explosions and fire, lasting for 36 hours until the rig sank.[17]

There are several investigations of the accident, and all point to no single cause of failure, but multiple violations at safety barriers. When this paper was written, the official investigation by the Presidential Commission had not been completed. Summarized are some findings to date[3, 17]:

- The annulus cement barrier did not isolate the hydrocarbons
- The shoe track barriers did not isolate the hydrocarbons
- The negative-pressure test was accepted although well integrity had not been established
- Influx was not recognized until hydrocarbons were in the riser
- Well control response actions failed to regain control of the well
- Diversion to the mud gas separator resulted in gas venting onto the rig
- The fire and gas system did not prevent hydrocarbon ignition
- The BOP emergency mode did not seal the well

These findings are debated and do not present the overall picture with respect to human and organizational causes. However, the remaining gaps do not alter the discussion or conclusions of this paper.

2.3 Barriers and legislation

In Norway, there is a requirement for a systematic application of two independent and tested well barriers in all operations. A similar requirement was adopted by the newly created US ***Bureau of Ocean Energy Management, Regulation and Enforcement*** (BOEMRE) in The Drilling Safety Rule that requires two independent test barriers across each flow path during well completion activities. The barriers must be certified by a professional engineer.[18]

An important principle in the Norwegian Petroleum Safety Authority (PSA) Activities (AR Sec. 76) and Facilities (FaR Sec. 47) regulations is the concept of well barriers and their control. If a barrier fails, no other activities should take place than those to restore the well barrier. Activities regulation (AR Sec. 77) states that if well control is lost it shall be possible to regain the well control by direct intervention or by drilling a relief well. The operator is also required to have an action plan on how well control can be regained. In the U.S., 30 CFR 250 does not use the terminology or concept of well barriers. One paragraph, however, asks the question (30 CFR §250.401): "What must I do to keep wells under control?" The answer is somewhat in accordance with the barrier principle.[19]

In Norway, an overall requirement in the regulations (Management Regulations Section 1 and Section 2) is that the operator shall establish barriers and know the barrier functions. The operator must know the performance requirements related to the barriers that have been defined with respect to the technical, operational or organizational elements necessary for the individual barrier to be effective. Those barriers shall be established to reduce the probability of undesired incidents. The barriers shall also be tested. It will also be known which barriers are not functioning or have been impaired, and the responsible for the operation of a facility shall establish indicators to monitor changes and trends in major accident risk. The party responsible will take necessary actions to correct or compensate for missing or impaired barriers.[19]

The major points of the Norwegian barrier principle, legislation and guidelines for wells are, in summary:

- Failure criteria (leak rate) and test intervals shall be established for each barrier element.
- To the extent possible, the barrier elements shall be tested in the direction of flow.
- Integrity status of the barrier shall be known at all times when such monitoring is possible.
- The well should withstand the maximum anticipated differential pressure it may become exposed to.
- All elements for the two barriers shall be defined.
- The function of the barrier and its elements shall be defined.
- It shall be possible to activate the two barriers separately.
- The well should withstand the environment for which it may be exposed to over time.
- Single failure of well barrier elements shall not lead to uncontrolled outflow.
- The position of the barrier shall be known all the time.
- A single failure shall not simultaneously eliminate both barriers.
- It is possible to re-establish a lost well barrier or another alternative well barrier.

The Risk Level Project (RNNP) has been and is an important supplementary tool for the oil and gas industry to document compliance with Norwegian regulations related to major hazards.

3 The Risk Level Project (RNNP)

The Norwegian Petroleum Directorate (NPD), now the PSA Norway, initiated RNNP ("the Risk Level Project") in 1999. Its overall objective is to establish a realistic and jointly agreed picture of trends with respect to health, environment, and safety (HES) in the oil and gas industry. The first report was presented early in 2001, based on data from the industry for the period 1996–2000.[7] Annual reports have been published since then.[ii]

RNNP aims at measuring the impact of safety-related work in the oil and gas industry, and helps identify areas critical for safety, including major hazard risks. Further, the understanding of the causes to undesired incidents and accidents, and their relative significance in the context of risk, is enhanced.[20] In addition, RNNP aims to create a reliable decision-making platform for the industry and authorities to enable joint efforts towards preventive safety measures and emergency preparedness planning.[7]

3.1 Major hazard risk in RNNP

Since no single indicator is able to express all the relevant aspects of HES, triangulation was needed in RNNP, i.e., utilizing several pathways to converge on the status and trends of HES levels. Thus, a decision was made to use various statistical, engineering and social science methods in order to provide a broad illustration of risk levels, applied to[7]:

- Risk due to major hazards
- Risk due to incidents that may represent challenges for emergency preparedness

[ii] See http://www.ptil.no/trends-in-risk-level/category155.html?lang=en_US.

- Occupational injury risk
- Occupational illness risk
- Risk perception and cultural factors

The risks related to major hazards are the focus of this paper. The major hazard risk components for employees working on offshore oil and gas installations are[7]:

- Major hazards during stay on the installations.
- Major hazards associated with helicopter transportation of personnel; for crew change purposes every two weeks, and with respect to shuttling between installations.

There are two different groups of indicators for major hazard risk in RNNP[7]:

- Incident indicators; i.e., indicators based on the occurrence of incidents and precursor incidents ("near-misses").
- Barrier indicators; i.e., indicators that measure the performance of barriers installed to protect against major hazards and their consequence potential.

None of the indicators were available as data sets collated by the industry prior to the RNNP. The basic concepts of the methods in the RNNP are discussed extensively.[7]

3.2 Incident indicators in RNNP

RNNP has collected major hazard precursor data from the oil and gas industry for almost ten years with an accumulated data period of almost 15 years, covering the period from 1996 to the present. The term "precursor" is used for incidents that have occurred and potentially could lead to major accidents. Relevant major hazards for personnel on the installation are addressed in QRA studies, and QRAs were one of the main sources when indicators first were identified in RNNP.

In RNNP, categories of hazard precursor incidents are denoted "DFUs," which may be translated as, "Defined situations of hazard and accidents". The DFUs were selected according to the following criteria[20]:

- The DFU is an undesired incident/situation which has led, or may lead, to loss (of life and other values), and hence represents a risk contribution.
- The DFU must be an observable incident/situation, and one which it is feasible to record accurately.
- The DFUs must (as far as possible) cover all situations that can lead to loss of life.
- The DFUs are important for motivation and awareness, since they are utilized in the planning and dimensioning of the emergency preparedness.

Table 3.1 gives an overview of the categories of the DFUs related to major hazards included in RNNP. The values shown represent all oil and gas production installations and mobile drilling units which have operated on the Norwegian Continental Shelf (NCS) in 2003-2008:

Table 3.1 – Overview of major hazard precursor incident categories (DFUs).[iii]

Major hazard precursor incident (DFU)	Frequency (annual average 2003-08)[iv]
Non-ignited hydrocarbon leaks	16.7
Ignited hydrocarbon leaks	0.
Well kicks/loss of well control	16.2
Fire/explosion in other areas, flammable liquids	2.5
Vessel on collision course	33
Drifting object	0.8
Collision with field-related vessel/installation/shuttle tanker	0.7
Structural damage to platform/stability/anchoring/positioning failure	7.8
Leaking from subsea production systems/pipelines/risers/flowlines/loading buoys/loading hoses	2.8
Damage to subsea production equipment/pipeline systems/diving equipment caused by fishing gear	2.2

3.3 Barrier indicators in RNNP

Adopting barrier indicators in RNNP occurred after the incident indicators had been fully established in 2002. The main emphasis was put on barrier elements associated with the prevention of fire and explosion, but structural barriers were included to some extent.[20]

Selected barrier data related to processing, wells, and structural integrity are provided through the RNNP survey. Companies report the availability and reliability for the barriers on the basis of periodic testing of chosen components. Any specific barrier comprises several interacting systems or elements. A leak must be detected before ignition sources are disconnected and emergency shutdown initiated. In other words, the sum of technical, operational, and organizational factors is crucial for determining whether barriers are functioning and effective at all times. The PSA, which has seen that barrier breaches cause accidents and incidents, pays particular attention to seeing that companies establish and develop systems for managing safety-critical barriers.[21] Barrier indicators in RNNP are based on the periodic testing of barrier elements as part of preventive maintenance schemes, using "man made" activation signals or stimuli (such as test gas releases).

The full list of technical systems on offshore installations, for which RNNP collects data, was at the end of 2009:

- Fire detection
- Gas detection
- Emergency shutdown valves on risers/flowlines (closure tests and leak tests)
- Wing and master valves (Christmas [X-mas] tree valves, closure tests and leak tests)
- Downhole Safety Valves (DHSV)

[iii] Standards_Norway, *NORSOK STANDARD D-10 Well integrity in drilling and well operations*, in *NORSOK*. 2004, Norwegian Technology Centre: Oslo. 162.
[iv] U.S. number convention.

- Blowdown Valves (BDV)
- Pressure Safety Valves (PSV)
- BOP
- Deluge valves
- Fire pump start

3.4 Safety climate in RNNP

Safety climate can be described as the employees' perceptions, attitudes and beliefs about risk and safety.[22] These perceptions are often measured by questionnaires that provide a "snap shot" of the current state of safety. The RNNP seeks to measure the safety climate of individuals working offshore at a given time. The scores are aggregated to an organizational level to provide information representing the organization's current safety climate.

Several attempts have been made to analyze different data sources in order to discover relations between safety climate and major hazard risk. These attempts have been inconclusive so far, except for a recent study using linear regression to analyze safety climate and gas leaks, which concluded with significant correlation.[23] The safety climate questionnaire explains up to one fifth of the hydrocarbon leak variation. The results indicate that there is a relationship between the number of employees responding negatively to the questions with respect to safety climate and number of leaks.[23]

4 Indicators in RNNP Relevant for Well Integrity and the Two Barrier Principle

4.1 Relevant incident indicators in RNNP

With respect to incident indicators in RNNP, blowouts and precursor incidents to blowouts are related to well integrity. There were 15 blowouts in the Norwegian sector in the period 1999–2009. Fourteen of them were gas blowouts, and one was a shallow gas blowout. Major oil spills at sea are even rarer. Such infrequent occurrence data are therefore not ideal for providing meaningful indicators for RNNP. The same applies for data related to major accidents with personnel safety implications.

The main precursor incidents to blowouts are:

- Loss of well control, including kicks, may lead to blowouts that cause acute spills, irrespective of whether ignition occurs or not (ignition may reduce the amount spilled, but this is disregarded). Ignited blowouts may lead to "secondary spill" if the wellheads and/or X-mas tree fail, in addition to failure of downhole safety valve (DHSV).
- Hydrocarbon leaks (from process systems or risers/pipelines) may cause fire and explosion that escalate to wells, risers or storage if several barriers fail, thereby causing "secondary" spills.
- Damage to subsea production systems/pipelines/risers/flowlines/loading buoys/-loading hoses may lead to hydrocarbon leakages.
- Construction failures, either due to impact (such as from collision) or internal failure, may cause blowout and "secondary" spills if several barriers fail.

Kicks are precursor incidents that can cause a major accident. Information on wells kicks and loss of well control is collected in RNNP. Table 4.1 shows that there were 16,2 precursor incidents that involved well kicks. This is close to the number of non-ignited hydrocarbon leaks.

Hinton[24] reported that 11 % of all wells drilled on the U.K. continental shelf from 1988 to 1998 have experienced reportable kicks during well construction operations. Of these, 22 % were in HPHT wells (>10,000 psi and 149 °C). Other U.K. sources cited by Gao et al.[25] claim that HPHT wells have much higher reportable kick incident rates (1 to 2 kicks per well) compared to non-HPHT wells (1 kick per 20 to 25 wells). Some of the most frequent causes to kicks in U.K. drilling wells were also found in U.S. wells, such as lost circulation in the same hole section with potential flow zones, too low mud weight, and uncertainty in flow zone existence, flow potential, location, or other important characteristics.[11]

In the time period from April 1998 to March 1999, the Alberta Energy and Utilities Board (EUB) reported that 7094 new wells were drilled onshore in Canada, with a total of over 129,000 active onshore wells. Of the 7094 wells drilled, nine blowouts were recorded during the time period. Five were freshwater flows that occurred while drilling surface holes, meaning that there was no surface pipe or BOPs in place. The four other blowouts occurred at depths shallower than 350 m, resulting in sweet gas releases with no significant environmental impact. In the same period 101 kicks were recorded.[26] Even with the differences between offshore and onshore, the EUB regards the number of blowouts and kicks as a primary indicator of industry's drilling and servicing performance and pays particularly close attention to industry's response to these incidents.

In the GoM, there were 20 incidents from 1973 to 1995 related to well kicks after cementing surface casing. Another 13 similar incidents have occurred since 1995, with the most serious consequences being gas broaching to the surface, cratering, well loss, and rig and platform destruction by fire. Annular flow related to cementing surface casing has been identified as one of the most frequent causes of loss of control incidents in the GoM.[11]

The GoM frequency of deepwater kicks is high. The overall frequency of kicks is approximately 2.7 times higher in the US GoM deepwater wells than the overall Norwegian Continental Shelf (NCS) experience. That said, the NCS kicks in deep wells, and especially HPHT wells, have occurred frequently.[27]

The National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling describes the failure to adequately consider published data on recurring problems in offshore drilling. These included powerful "kicks" of unexpected pressures that sometimes led to a loss of well control, failing BOP systems, and the drilling of relief wells; the last lines of defense for a troublesome well. These problems have been relatively few considering the large number of wells around the world. However, that these problems occurred and have been known to petroleum engineers, demonstrates that wells do not perform in normal or regular ways.[28]

There is a common understanding among the regulatory authorities in Norway, UK, Canada and the U.S. that "kicks" are precursor incidents and should be avoided. The probability of kicks depends on geological conditions, but kicks can be prevented by proper well planning, design, and performance monitoring.[12, 29, 30] A safety factor or "kick tolerance" to help ensure safe well control conditions during drilling cementing operations typically is used to determine maximum operating pressures (equivalent circulating density (ECD), surge, etc.) based on leak-off test results and other measurements or calculations. In some higher pressure wells with a small margin between the mud weight and the fracture pressure, the recommended kick tolerance is nearly impossible to achieve. This is said to be particularly true for many wells drilled in the GoM.[11]

4.2 Relevant barrier indicators in RNNP

Some barrier indicators in RNNP are applicable with respect to drilling operations, well interventions, and production from wells, for example, the periodic testing of the following barrier elements:

- Wing and master valves (X-mas tree valves, closure tests and leak tests)
- Downhole Safety Valves (DHSV)
- BOP

The requirement in the Norwegian regulations to systematic application of two independent and tested well barriers in all operations enables data collection related to incidents where the principle is broken.

Usually, fluid column is the primary barrier. The secondary well barriers consist of one or more of the following[29]:

- Casing cement
- Casing
- Well head
- High pressure riser
- Drilling BOP
- Drill String
- Stab-in safety valve
- Casing float valves
- Annulus access line and valve

In RNNP, there is a classification system for all producing wells on surface installations and subsea wells, whereby each well is classified into one of the following categories:

- Green: Healthy well, no or minor integrity issue.
- Yellow: One barrier leaks within the acceptance criteria of barrier degradation, the other is intact.
- Orange: One barrier failure and the other is intact, or a single failure may lead to leak to surroundings.
- Red: One barrier failure and the other is degraded/not verified or external leak.

The RNNP survey for 2009 covers a total of 1712 producing wells on the NCS and eight operator companies; BP, ConocoPhillips, Exxon Mobil, Norske Shell, Statoil, Marathon, Talisman and Total (in random order). Figure 4.1 shows well categories by percentage of the total number of wells, 1712.

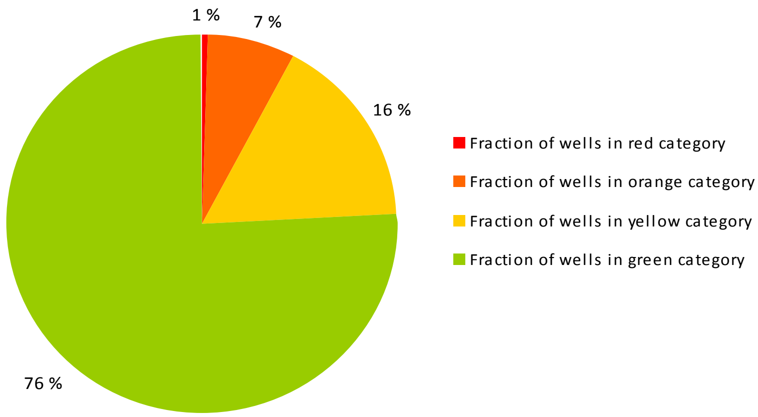

Figure 4.1 – Well classification –category red, orange, yellow and green, 2009.

The results show that 8 % (11 % in 2008) of the wells have reduced quality in relation to the requirements for two barriers (red + orange category). Sixteen percent (13 % in 2008) of the wells are in the yellow category, including wells with reduced quality in relation to the requirement for two barriers, but the companies have implemented various compensatory measures to meet the two-barrier requirement. The remaining wells, i.e., 76 % (as in 2008), fall into the green category meeting the requirement for two barriers in full.

4.3 Relevant human and organizational aspects

PSA has together with the petroleum industry worked to reduce the number of non-ignited hydrocarbon leaks, which is considered as a valid and reliable indicator reflecting the risk of major accidents caused by ignited hydrocarbon leaks. Release statistics show that half of the leaks from hydrocarbon systems on the NCS are caused by manual interventions in the process system. Engineered safety barriers are often partially deactivated during these operations in order not to cause disruption of production. The occurrences indicate that operational barriers related to containment of leaks are not functioning sufficiently during these intervention operations.[31]

A reasonable question is: Do kicks demonstrate similar organizational features as found between hydrocarbon leaks and safety climate? A study performed by Dobson[32] showed that most kicks experienced on the UK Continental Shelf are directly linked to geological conditions at the well location, and most involve conditions difficult to detect before the well is drilled. Other incidents are indirectly linked to the geological conditions, such as the 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. The latter challenge is not limited to HPHT wells in the GoM but is also encountered in the complex reservoirs of the Northern North Sea and the Lower Permian sands in the Southern North Sea.[32]

A significant, though small, proportion of kicks are due to human error, according to Dobson.[32] Examples are failure to shut down water injection, using an un-weighed wash during cementing operations or allowing excessively large influxes. There are two areas of concern to UK HSE as the safety regulator for the UK Continental Shelf: The most pressing issue is human error as a continuing factor in well incidents. If drilling activity levels continue as in recent years, appropriate well-control training of personnel engaged in both rig site operations and in operational planning needs to be accorded the highest priority.[32]

5 Extending the Indicators in RNNP for Deepwater Drilling and Well Integrity

The main focus with respect to major hazard indicators in RNNP is on production installations. There are only a very limited number of precursor incident indicators and barrier indicators for mobile drilling units. This is one of the reasons why RNNP indicators would not be suitable as early warnings for accidents like the Deepwater Horizon. Well control procedures are established to safely prevent or handle kicks and reestablish primary well control. The number of kicks and blowouts are relevant indicators, but there is a need for developing a set of deepwater drilling indicators for precursor incidents leading up to those kicks and blowouts. In this section areas for extending the safety indicators with respect to well integrity, to be used in RNNP, similar projects, or in companies, are investigated. Central issues regarding the Macondo well illustrate how the extensions or supplements are related to well integrity.

Safety indicators are not straightforward and simple. The success of indicators is related to the extent to which they are[33]:

- Able to drive process safety performance improvement and learning.
- Easy to implement and understand by all stakeholders (e.g., workers and the public).
- Statistically valid at one or more of the following levels: industry, company, and site. Statistical validity requires a consistent definition, a minimum data set size, a normalization factor, and a relatively consistent reporting pool.
- Appropriate for industry, company, or site level benchmarking.

In addition to the above factors, major indicators must reflect hazard mechanisms, i.e., be valid for major hazards, be sensitive to change, show trends, be robust to manipulation and influence from campaigns giving conflicting signals, and not require complex calculations.[7]

Often, a major challenge is that there is not enough data to support a basic set of reliable and valid safety indicators. Therefore, a broad perspective is needed when developing and analyzing indicators. In addition, the safety indicators should reflect the phases of deepwater drilling (and drilling in general). These phases are the well planning phase and the drilling phase, consisting of drilling, running casing, cementing, circulation, fluid displacement and clean-up, and completion.

Figure 5.1 gives an overview of the main lifecycle phases of the well and aspects related to undesired incidents and relevant barriers of deepwater drilling. The different areas relevant for extending or supplementing safety indicators from RNNP with respect to well integrity are discussed thereafter.

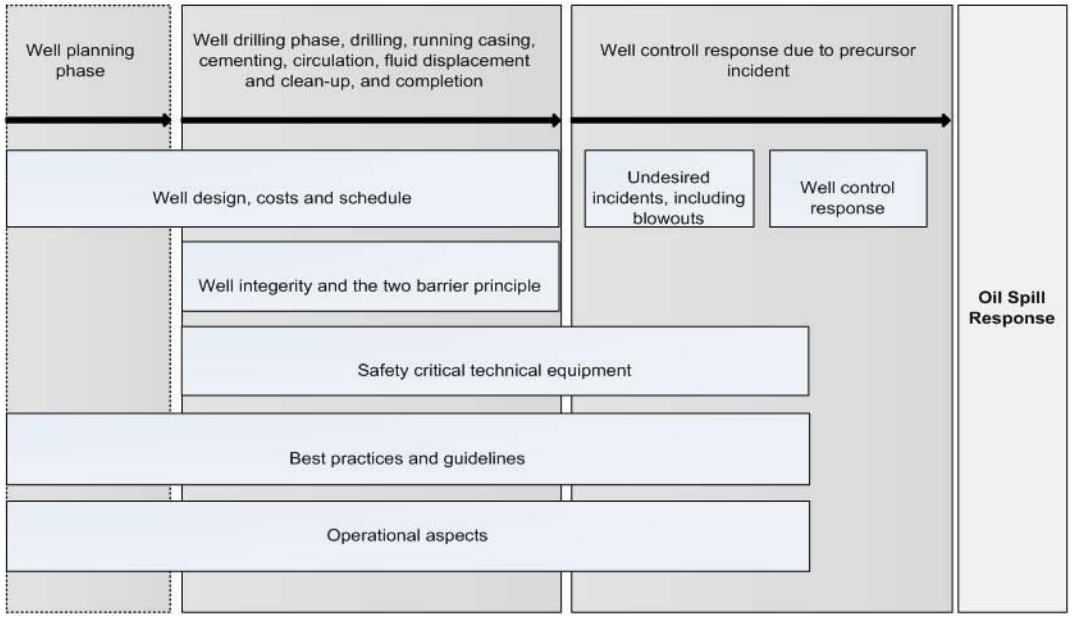

Figure 5.1 – The life cycle phases of a well (excluding production).

5.1 Well design, costs, and schedule

Deepwater wells in the GoM require a great degree of investigation, including conceptualizing during the planning and design and intense communication with a larger team for longer periods of time. Much time in the design process is devoted to the pressure and temperature profiles, mechanics (burst, collapse, axial loads, etc), data acquisition from previous wells, and other "conventional" processes of well design. Although all processes are critical, many times it may be profitable for the team to spend as much time in "data immersion," conceptualizing how a well should be drilled. "Data immersion" is time-consuming in terms of studying all available offset data, reading every hand written note, mud recaps, bit records, etc. The following are typical problems that occur if time is not spent on well design and planning[34]:

- Lack of knowledge of overall geology and basin mechanics
- Lack of production knowledge and reservoir behavior (shallow and deep)
- Not understanding the production profile of the target zone
- Not understanding the design philosophy of previously drilled wells
- Not understanding why previous wells got in trouble
- Lack of "immersion" in data available
- Not integrating contingency planning
- Cost sensitivity mentality

According to BOEMRE, the greatest risk factor in the deepwater GoM is the sizeable flow rates, i.e., fields with very high daily output and good overall economics.[28] The petroleum industry points at the importance of high operating performance as the key for sustained economic success. Reduced maintenance requirements and increased reliability are key elements in the design stages of deepwater developments. Shutting down a 30,000+ barrels per day well impacts the bottom line directly.[35]

The Deepwater Horizon rig was 43 days overdue on April 20th, and the total costs had reached about $139 million dollars in the middle of March. The original costs were estimated to $96 million dollars, [[1]Aug 26th] indicating more than $40 million dollars in additional costs up to that point in time.

The relationship between schedule and cost, and assessment and prioritization of risks, is an essential element of risk management. Better understanding can be achieved by collecting data related to schedule and cost and compare with supplementing safety indicators.

5.2 Undesired incidents and crew's response time

During drilling and completion of the well, two aspects are of main interest with respect to indicators; well incidents and the crew's response if incidents occur. During drilling several undesired incidents may occur, among others stuck string, lost circulation, and shallow gas influx.[29] All these incidents were experienced by the Deepwater Horizon rig in March 2010.[[1], Oct. 7th]

Ballooning formations take mud (partial losses) during drilling into a fracture and give that mud back when the imposed pressure is relieved. Ballooning is a major concern as their occurrence can often complicate identification of key kick signals.[34] Ballooning is also called wellbore breathing, and losses and gains. Ballooning is particularly common in deepwater drilling because of the frequently encountered narrow pore pressure and fracture gradient window. The phenomenon is characterized by mud losses with mud pumps on, and mud returns with pumps off. The principal risk for deepwater drilling in overpressured environments is that any increase in mud volume may be interpreted as a kick, requiring additional time being spent to flow-checking the well. Misdiagnosis can also lead to the decision being made to increase mud weight. As the occurrence of losses and gains signifies drilling with a mud weight close to the fracture gradient, additional mud weight increases can result in breaking-down the formation and inducing more problematic large-scale losses from the wellbore. The prediction and diagnosis of instances of mud losses and gains is, therefore, of clear importance in the planning and execution of deepwater wells.[36]

Swabbing is to reduce pressure in a wellbore by moving pipe, wireline tools or rubber-cupped seals up the wellbore. If the pressure is reduced sufficiently, reservoir fluids may flow into the wellbore and towards the surface. Swabbing is generally considered harmful in drilling operations, because it can lead to kicks and wellbore stability problems. Swabbing on trips[v] is the most likely cause of well controls problem in ultra deepwater drilling. In ultra-deep wells, swabbing is often complicated when a well is ballooning or when mud and formation gradients are relatively close. Furthermore, it has been shown that computation of swab pressures on the basis of steady-state flow is often incorrect.[34]

SINTEF performed in 2001 a study of deepwater kicks in the GoM for MMS.[27] In ranked order, the most significant contributors to the kick occurrences were:

- Too low mud weight (23)
- Gas cut mud (17)
- Annular losses (9)
- Drilling break (9)
- Ballooning (7)

[v] "Make a trip" - To hoist the drill stem out of the wellbore to perform one of a number of operations such as changing bits, taking a core, and so forth, and then to return the drill stem to the wellbore.[37]

- Swabbing (5)
- Poor cement (2)
- Formation breakdown (1)
- Improper fill up (1)

The contributors in the list do not necessarily lead to a kick.

In addition to recording the number of undesired incidents, the time between the first "signals" of an undesired incident and subsequent well control actions indicates the crew's situation awareness, training, competence, and management. Data are recorded real-time during drilling and it is therefore possible to analyze the time from the incident occurred until actions were taken and control of well achieved.

The Deepwater Horizon rig workers tested the integrity of well on April 20th. The crew conducted a positive-pressure test on the production casing, and a negative-pressure test to assess whether the cement barrier and the mechanical barriers could withstand an underbalanced situation. After having tested and (incorrectly) interpreted the results to be successful, they continued replacement of the mud with seawater.[17]

According to BP,[17] flow indications started approximately 51 minutes before the blowout. The influx was not detected until the hydrocarbons had entered the riser, 40 minutes after the first influx. Real time data were available to the drilling crew,[17] who should monitor changes to pit volume, flow rate and pressures in order to identify potential flows and losses.[11]

During the afternoon on April 20th, well monitoring might have been complicated. From 13:28 to 17:17, mud was offloaded to the nearby supply vessel, and some pits were being cleaned and emptied. These operations reduced the ability to monitor changes to the pits' levels. In addition, preparations for the next completion operations were carried out, such as preparing for setting the plug in the casing after replacing with seawater. The BP investigation report[17] states that it does not seem that pit volumes were effectively monitored the rest of the evening. Comments from Halliburton support this statement.[1]Oct 8th

Even if the crew at the Deepwater Horizon rig had been able to gain control of the well, it would be useful to know why the response time was that long. Response time is an aspect to consider in an extension of the safety indicators in RNNP, in order to enable learning by experience and accident prevention.

5.3 Well integrity during drilling and the two barrier principle

According to the barrier principle in the Norwegian regulations, the following situations are reported to the authorities[29]:

- Positive indication of flow from wellbore.
- The wellbore is closed by shutting in the BOP
- Pressure or pressure build up is registered in the closed-in wellbore.
- Kill operation is initiated.

In the US, BOEMRE requires that loss of well control (LWC) is reported.[38] This includes:

- Uncontrolled flow of formation or other fluids; the flow may be to an exposed formation (an underground blowout) or at the surface (a surface blowout).
- Flow through a diverter.
- Uncontrolled flow resulting from a failure of surface equipment or procedures.

On April 14th 2010 the final decision was made to use the production long string for the Macondo well instead of a liner tieback.[1] Aug 26th During discussions in BP it was noted that under certain circumstances the long string option would only provide one barrier; the seal assembly in the well head. With a requirement for two barriers, this would not have been an acceptable design. However, in some cases the well integrity may be reduced, as discussed regarding the classification of production wells in RNNP (Section 4.2).

5.4 Best practices and guidelines

There are numerous guidelines related to drilling.[11, 12, 16, 29, 39-43] They describe best practices and recommendations in detail. The compliance with guidelines should be a part of precursor investigations and used as basis for developing indicators. The compliance with standards/guidelines has become even more relevant recently when BOEMRE made mandatory the practices in the American Petroleum Institute's (API) Recommended Practice 75 (RP 75).[44]

Regarding the Macondo well, it may be questioned if best practices were followed. In the letter to BP CEO Tony Hayward, the US Committee on Energy and Commerce[45] raised questions about five decisions which they believed "posed a trade-off between cost and well safety":

- The choice of well design
- The number of "centralizers" to prevent channeling during cementing
- No cement bond log to evaluate the quality of the cement job
- Failure to circulate potentially gas-bearing drilling muds out of the well
- Not securing the wellhead with a lockdown sleeve before allowing pressure on the seal from below

BP chose to use a single production casing instead of the liner tieback, a design that would save $7 million to $10 millions.[1] Oct. 7th The choice of well design increased the need for running a cement bond log.[1] Oct 7th Because of the importance of getting a good cement job, one that is bonded both to the casing and to the geological formation in which the well is dug, a series of measurements called a "cement bond log" is often run. A sonic scanning device is lowered through the well on a wireline. It checks whether there are imperfections in bonding or other problems in the cement. If there are, more cement can be squeezed into affected sections. Schlumberger personnel were called to the rig to be ready to do such work, but departed in the morning of April 20th having been told their services were not required. Documents suggest the cost saving in not having a "cement bond log" to about $118,000.[46]

Centralizers ensure that the casing is centralized during cementing to prevent channeling and a low quality cementing job. Halliburton recommended 21 centralizers to be used, but BP had six available, due to a misunderstanding that 15 of them were of the wrong kind on the rig. In hearings[[1] Oct 7th] it was stated that Halliburton and BP disagreed on the number of centralizers, and that the risk of getting a gas flow problem increased if they used ten or less centralizers.

5.5 Technical condition of safety critical systems

In 2000, Statoil developed a system for assessment of Technical Safety Condition (TTS).[47] This system assesses the conditions of technical barriers where considerable prior knowledge was available about how accidents could be caused through failures. TTS evaluates a wide set of safety functions against defined performance standards. There are 22 different Performance Standards (PS) for example regarding the gas detection system, alarm management, and well barriers. Each performance standard consists of performance requirements. The assessment is carried out at a detailed level by using checklists. The ratings in TTS are classified according to a scale with grades A (Condition significantly above reference level) through F (Unacceptable condition). The results are aggregated to illustrate the performance of an installation.[48] There exists a large amount of data collected and several oil companies have adopted the method. An important part of the Performance Standard related to well integrity is the maintenance and inspection of the BOP.

At the Deepwater Horizon rig, the BOP did not isolate the well before and after the explosions. The BOP may have been faulty before the blowout or it may have been damaged due to the accident. According to BP, several maintenance jobs of the BOP were overdue, and leaks from the hydraulic control system had been discovered at the time of the accident.[17] The BOP on the Deepwater Horizon was not recertified in accordance with federal regulations because the certification process would require full disassembly and more than 90 days of downtime.[1] Aug 25th

The Transocean subsea superintendent said he didn't hear about the leaks before the incident and left it up to rig workers to determine if they were significant enough to report. The Transocean subsea superintendent and the subsea supervisor on the Deepwater Horizon acknowledged that the blowout preventer had not gone through a recertification every three to five years, as set by federal regulations. The subsea superintendent brushed that aside, however, saying Transocean considered it sufficient to simply monitor the device's condition while it was in use, rather than having to bring it to dry dock to get a full certification. Because the government regulation references an industry standard, the subsea superintendent said he took it to be a recommendation, not a requirement. Co-chairman of the investigative panel criticized Transocean for ignoring the government's minimum standard and choosing to follow its own monitoring program instead.[1] Aug. 25th

The chief electronics technician at the Deepwater Horizon stated in a hearing that some of the rig's alarm systems, such as the rig's general alarm, had been inhibited. This means that the sensory is still active and would register high gas levels, toxic gas or fire to a computer, but any warning signals would not be triggered.[1] July 23rd

Another issue they were struggling with onboard the rig was the chairs used for controlling the drilling functions. There were three chairs: A, B, and C. These chairs control everything, such as top drive, mud pumps, and hydraulics. The last three to four months these computers had locked up so no data could go through the system. A new system was ordered, but there were bugs with new operating system as well because they could not make the old software run correctly on the new operating system. This means at times they would lose track of what was going in the well.[1] July 23rd

The technical barriers related to reducing the consequences of a blow-out should be monitored to reveal the changes in the level of safety over time. The technical barriers are very much the same as those related to gas leaks, and is an area to consider when extending or supplementing existing safety indicators. In 2006 and 2007 there were two very serious precursor incidents – one on the

Visund Platform in the Norwegian sector and one on the Rough Platform in the UK sector.[49] The former incident released over 900 kg/s into the platform – but all, the safeguards worked – ignition controls, gas detection, ESD systems, blowdown, and no ignition occurred. On the Rough platform the release was 400 kg/s and ignition did occur, but again the barriers worked and the incident was limited.[50] Both of these had the potential to be total losses, as with Deepwater Horizon, if the barriers had failed.

5.6 Operational aspects

In 2006, Statoil initiated a project to extend the TTS system into an OTS (Operational Condition Safety) system. The objective of OTS is to develop a system for assessment of the operational safety condition on an offshore installation/onshore plant, with particular emphasis on how operational barriers contribute to prevention of major hazard risk, and the effect of human and organizational factors (HOFs) on barrier performance. OTS is a means for measuring the changes over time in the level of operational safety as the result of actions taken.

The following operational performance standards have been defined in OTS[51]:

- Work performance
- Competence
- Procedures and documentation
- Communication
- Workload and physical working environment
- Management
- Management of change (MOC)

The OTS concept resembles the TTS system. The main principle of the OTS development is that the assessment of operational safety conditions shall be risk based, i.e., that the selection of influencing factors and checklist questions shall be based on the highest impact on major hazard risk.[48]

In the training area, MMS did in 1998 move away from requiring workers who were engaged in well control and production safety system operations to attend MMS-accredited schools. The responsibility for ensuring workers were properly trained was shifted to the operator.[52]

The MOC process was generated on the Deepwater Horizon rig. Several questions had to be answered, such as about the reason for change. The MOC process was required when there were temporary and permanent changes to organization, personnel, systems, process, procedures, equipment, products, materials or substances, and laws and regulations.[1]Aug 25th The MOC documents were reviewed and approved.[1] July 22nd However, it may be questioned whether the BP MOC process sufficiently reduced risks related to the changes that occurred. According to BPs own investigation report,[17] the BP Macondo team did not follow a documented MOC process. Therefore, they did not discover that the additional centralizers delivered to the rig were correct. Instead, they thought they had gotten a wrong kind of centralizers and decided to use the remaining six for the cementing.

In the chain of command in the BP engineering and operations, five individuals had been less than 5 months in their positions at the time of the accident.[1] Aug 26th Management of change documents were worked out on paper, but there was an ongoing transition to an electronic system.

Developing relevant indicators for human and organizational issues with respect to drilling is complicated. In RNNP safety culture is assessed by using interviews and questionnaires, and the same may be applied to drilling rigs. Another important aspect is to ensure a good quality MOC process for drilling. The performance standards in OTS are very much the same factors described as key capabilities for success for drilling professionals by Boykin.[53] The performance standards do also cover most of the weaknesses of current work processes in drilling pointed out by a large research and development program on drilling and wells within Integrated Operations (IO) in the Norwegian petroleum industry.[54]

6 Discussion and Conclusions

The indicators in RNNP are intended to be early warnings of possible increases in major hazard risk on a national industry level. Annually, there are about 80 to 100 precursor incidents for the NCS as a whole, corresponding to slightly less than one precursor incident per installation per year. In addition, there are tens of thousands of data reported from the periodic testing of safety barrier elements for major hazards. The purpose of these indicators is to provide early warnings with respect major hazard risk at a global level, i.e., for the petroleum industry as a whole, and not for individual installations or companies, due to the low number of occurrences. On the other hand, the barrier indicators may be used for individual installations, due to a much higher number. The use of barrier indicators for individual installations and companies is discussed in detail.[7]

It should be noted that the main focus with respect to major hazard indicators in RNNP is on production installations. There are only a very limited number of precursor incident indicators and barrier indicators for mobile drilling units. This is one of the reasons why RNNP indicators "as is" would not be suitable for early warnings for accidents like the Deepwater Horizon.

The second objective of this paper is to discuss possible extensions of the safety indicators in RNNP with respect to offshore deepwater drilling. To obtain valid and reliable indicators is a major challenge. Underlying causes and contributing factors may be of such a nature that it is difficult to obtain quantitative measures that are valid individually, and have adequate coverage collectively, meaning that all aspects of a given contributing risk influencing factor are covered by a set of indicators.

The number of kicks is an important indicator for the whole industry when it comes to deepwater drilling, because it is a precursor incident with the potential to cause a blowout. However, there is a need for a broad perspective when collecting and analyzing indicators. In this paper, we have suggested aspects to consider for extending the safety indicators related to well integrity and the two barrier principle, well planning, schedule and cost, undesired incidents, and well monitoring/intervention. In addition, best practices/guidelines, status/failure in safety critical technical equipment, and operational conditions have been discussed. Within these areas, data is available, and in several cases the data is recorded, and have been recorded for years by the regulatory authorities, research communities, companies, and rigs. Still, the data is not used as basis for indicators. In a company, the Reliability, Availability and Maintainability environment collects data related to the technical condition of an installation. The Occupational Environment Committee studies the data related to safety climate and culture. Safety climate, the technical condition, and the number of precursor incidents are influencing each other and should be considered together.

According to the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, the Deepwater Horizon accident raises an important question to which extent the accident is a symptom of systemic safety problems in the whole deepwater drilling industry. To find the answer to such a question is very difficult without knowing the risk level related to major accident prevention, preparedness, and responses of the oil and gas industry, measured and evaluated over time. Therefore, we recommend the US authorities to initiate a similar project to RNNP. Risk management is the identification, assessment, and prioritization of risks followed by coordinated and economical application of resources to minimize, monitor, and control the probability and/or impact of unfortunate incidents.[55] We have in this paper suggested a wide approach to areas for supplementing existing safety indicators and thereby for identifying risks. Safety indicators can also support the assessment and prioritization of risks.

In the Deepwater Horizon Incident Joint Investigation,[1] the Chief electronics technician Transocean testified that Deepwater Horizon had earlier experienced a kick due to software failure in the drilling systems. A single kick does not show a trend, but it can function as an early warning signal, and proper actions can be taken based on precursor incident investigation. It is the authors' view that there is a need for more extensive investigations of precursor incidents like "kicks" to ensure improved learning. The broad approach to collecting and analyzing indicators in this paper would possibly have pre-warned several of the contributing factors in the Deepwater Horizon accident:

- The status of the BOP and fire and gas system could possibly been have revealed by indicators related to status/failure in safety critical technical equipment.
- The insufficient negative-pressure test and well control response could possibly been revealed by indicators related to well control response and operational conditions (competence, procedures and documentation, communication, management).

The Deepwater Horizon accident was a result of failures in multiple barriers related to human, organizational and technical barrier elements. Barriers planned and included in design do often degrade over time. Root causes are complex and rarely due to deliberate intent or risk taking. Serious blowouts are rare and the rationale for many safeguards may be lost over time and the continuous activities to keep them functional may not occur. Normalization of deviance, and even not having defined what a deviance is, is an important issue to investigate further.

The approach discussed in this paper demands cooperation across national borders, operators, vendors, specialist environments, as well as between industry and regulatory authorities. The need for cooperation was also pointed out by BP-employees Addison et al.[56] in advance of the Deepwater Horizon accident:

"The trend of deepwater discoveries in the GoM is shifting towards one with greater challenges across many disciplines represented by the conditions in the lower tertiary discoveries. The solutions to these challenges will require cooperation among the operators, the engineering contractors and the equipment suppliers working with the regulatory authorities to pave the way for the safe and reliable development of these future fields. Over the next decade the rate of advancement in deepwater technology development will need to accelerate to enable offshore operators to move forward in developing the most recent exploration successes in the GoM".

7 Abbreviations

Table 7.1 – Abbreviations.

Term	Definition
API	Application Interface
BDV	Blowdown Valve
BOP	Blowout Preventer
BOEMRE	Bureau of Ocean Energy Management, Regulation and Enforcement
DHSV	Downhole Safety Valve
DFU	RNNP – 'hazard precursor event'
ECD	Equivalent Circulating Density
EUB	Energy Utilities Board (Alberta, Canada)
HSE	Health, Safety, and Environment
HES	Health, Environment, and Safety
HOF	Human and Organizational Factors
HPHT	High Pressure, High Temperature
ICT	Information and Communications Technology
IO	Integrated Operations
I/O	Input / Output
LWC	Loss of Well Control
mD	Micro-Darcies, a measure of gas permeability
MOC	Management of Change
MMS	Minerals Management Service
NCS	Norwegian Continental Shelf
NPD	Norwegian Petroleum Directorate
PS	Performance Standard
OTS	Operational Condition Safety
QRA	Quantitative Risk Assessment
RNNP	Norwegian Risk Level Project – trends in risk levels on NCS
TTS	Technical Safety Condition

8 References

1. Deepwater Horizon Incident Joint Investigation, The U.S. Coast Guard (USCG) / Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) Joint Investigation Team (JIT). Board members: Hung Nguyen, David Dykes, Ross Wheatley, Jason Mathews, John McCarroll, Mark Higgins, Wayne Andersen, Robert Butts, 2010.
2. DHSG, Progress Report 2 - Deepwater Horizon Study Group, 2010, 42.
3. Salazar, Increased Safety Measures for Energy Development on the Outer Continental Shelf, in Department of the Interior, 2010.
4. Kjellén, U., Prevention of accidents through experience feedback. 2000, London: Taylor & Francis. XXVI, 424 s.
5. Øien, K., I.B. Utne, and I.A. Herrera, Building Safety indicators: Part 1 - Theoretical foundation. Safety Science, 2011. **49**(2): 148-161.

6. OECD, Guidance on safety performance indicators. Guidance for industry, public authorities and communities for developing SPI programmes related to chemical accident prevention, preparedness and response, 2003.
7. Vinnem, J., Risk indicators for major hazards on offshore installations. Safety Science, 2010. **48**(6): 770-787.
8. PSA. Integrated operation, 2010 [cited 2010 26 August 2010]; Available from: http://www.ptil.no/integrated-operation/category143.html.
9. Close, F., R.D. McCavitt, and B. Smith, Deepwater Gulf of Mexico Development Challenges Overview, in SPE North Africa Technical Conference & Exhibition. 2008, Society of Petroleum Engineers: Marrakech, Morocco.
10. Standards_Norway, NORSOK STANDARD D-10 Well integrity in drilling and well operations, in NORSOK. 2004, Norwegian Technology Centre: Oslo, 162.
11. API, Isolating Potential Flow Zones During Well Construction, in API Recommended practice 65 - Part 2. 2010, American Petroleum Institute.
12. API, Recommended Practice for Well Control Operations - API Recommended Practise 59. 2010, American Petroleum Institute.
13. PSA. Well control and well integrity. 2010 29.01.2008 [cited 2010 26 August 2010]; Available from: http://www.ptil.no/well-integrity/well-control-and-well-integrity-article4156-145.html.
14. Sklet, S., Safety Barriers on Oil and Gas Platforms, in NTNU. 2005, NTNU: Trondheim, 182.
15. Sklet, S., Safety barriers: Definition, classification, and performance. Journal of Loss Prevention in the Process Industries, 2006. **19**(5): 494-506.
16. API, Isolating Potential Flow Zones During Well Construction, in API RECOMMENDED PRACTICE 65—PART 2. 2010, American Petroleum Institute.
17. BP, Deepwater Horizon Accident Investigation Report. 2010, 192.
18. BOEMRE, Fact Sheet - The Drilling Safety Rule - An Interim Final Rule to Enhance Safety Measures for Energy Development on the Outer Continental Shelf, 2010, 2.
19. DNV, Report OLF/NOFO - Summary of differences between offshore drilling regulations in Norway and U.S. Gulf of Mexico, 2010, 100.
20. Vinnem, J.E., et al., Major hazard risk indicators for monitoring of trends in the Norwegian offshore petroleum sector. Reliability Engineering & Systems Safety, 2006(7): 778-791.
21. PSA. Technical and operational barriers, 2010 [cited 2010 26 August 2010]; Available from: http://www.ptil.no/technical-and-operational-barriers/category616.html.
22. Skogdalen, J.E. and C. Tveiten, Safety perception and comprehension among offshore installation managers on Norwegian offshore petroleum production installations, in The 5th International Conference Workingonsafety.net, 2010: Røros, Norway.
23. Vinnem, J.E., et al., Analysis of root causes of major hazard precursors (hydrocarbon leaks) in the Norwegian offshore petroleum industry. Reliability Engineering & System Safety, 2010, **95**(11): 1142-1153.
24. Hinton, A., An Analysis of OSD's Well Incident Database; Results can Improve Well Design and Target Well Control Training, in Offshore Europe Oil and Gas Exhibition and Conference. 1999, Society of Petroleum Engineers: Aberdeen, United Kingdom.
25. Gao, E., et al., Critical Requirements for Successful Fluid Engineering in HPHT Wells: Modeling Tools, Design Procedures & Bottom Hole Pressure Management in the Field, in European Petroleum Conference. 1998, Society of Petroleum Engineers Inc.: The Hague, Netherlands.
26. AEUB, Field Surveillance April 1998/March 1999 Provincial Summaries, in EUB Statistical Series 57, 2004, 42.

27. Holand, P., Deepwater Kicks and BOP Performance, Unrestricted version. 2001, SINTEF Industrial Management, Safety and Reliability: Trondheim.
28. Nat.Com., A Brief History of Offshore Oil Drilling, N.C.o.t.B.D.H.O.S.a.O. Drilling, Editor. 2010.
29. Standards_Norway, Well integrity in drilling and well operations D-10. 2010, Norwegian Technology Centre: Oslo.
30. Ale, B.J.M., et al., Towards a causal model for air transport safety--an ongoing research project. Safety Science, 2006, **44**(8): 657-673.
31. Vinnem, J.E., Seljelid, J., Haugen, S., Aven, T. , Generalized methodology for operational risk analysis of offshore installations. Journal of Risk and Reliability, 2008, **223**: 11.
32. Dobson, J.D., Kicks in Offshore UK Wells—Where Are They Happening, And Why?, in SPE/IADC Drilling Conference and Exhibition. 2009, British Crown Copyright: Amsterdam, The Netherlands.
33. API, Process Safety Performance Indicators for the Refining and Petrochemical Industries - ANSI/API RECOMMENDED PRACTICE 754, in Downstream Segment. 2010, American Petroleum Institute, 54.
34. Shaughnessy, J.M., L.A. Romo, and R.L. Soza, Problems of Ultra-Deep High-Temperature, High-Pressure Drilling, in SPE Annual Technical Conference and Exhibition. 2003, Society of Petroleum Engineers: Denver, Colorado.
35. Lawrence, D.T., Deepwater production development options in the Gulf of Mexico, in 16th World Petroleum Congress. 2000, World Petroleum Congress: Calgary, Canada.
36. Willson, S., et al. Wellbore Stability Challenges in the Deep Water, Gulf of Mexico: Case History Examples from the Pompano Field. 2003.
37. OilGasGlossery.com. Oil & Gas Field Technical Terms Glossary, 2010. Available from: http://oilgasglossary.com/make-a-trip.html.
38. BOEMRE. Loss of Well Control. Statistics and Summaries 2006-2010. 2010 09/28/2010 [cited 2010 14 October 2010]. Available from: http://www.boemre.gov/incidents/blowouts.htm.
39. API, Specification for Drilling and Well Servicing Structures, in API SPECIFICATION 4F, 2010, American Petroleum Institute.
40. API, Contractor Safety Management for Oil and Gas Drilling and Production Operations, in API RECOMMENDED PRACTICE 76, 2010, American Petroleum Institute.
41. API, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells, in API RECOMMENDED PRACTICE 53, 2004, American Petroleum Institute.
42. API, Recommended Practice for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide, in API RECOMMENDED PRACTICE 55, 2007, American Petroleum Institute.
43. API, Recommended Practice for Training and Qualification of Personnel in Well Control Equipment and Techniques for Wireline Operations on Offshore Locations, in API RECOMMENDED PRACTICE T-6. 2002, American Petroleum Institute.
44. BOEMRE, Fact Sheet - The Workplace Safety Rule - On Safety and Environmental Management Systems (SEMS). 2010, 2.
45. Stupak, B. and H.A. Waxman, Dear Mr. Hayward: We are looking forward to your testimony before the Subcommittee on Oversight and Investigations on Thursday, June 17,2010, about the causes of the blowout ofthe Macondo well and the ongoing oil spill disaster in the Gulf of Mexico., M.T. Hayward, Editor. 2010, Congress of the United States, House of Representatives, Committee on Energy and Commerce: London, 4.

46. Schlumberger. Cost cement bond-log. 2010 21 October 2010]; Available from: http://energycommerce.house.gov/documents/20100614/Schlumberger-Cost.of.Completing.Cement.Bond.Log.v.Canceled.Contingency.pdf.
47. Thomassen, O. and M. Sørum. Mapping and monitoring the safety level. in Sixth International Conference on Health, Safety and Environment. 2002. Kuala Lumpur: Society of Petroleum Engineers.
48. Vinnem, J.E., et al. Operational Safety Condition - Concept Development. in Esrel, 2007, Stavanger.
49. PSA, PSA Investigation report gas leak 19 January 2006 Visund 2006, Petroleum Safety Authority Norway: Stavanger, 29.
50. Pitblado, R. and R. Tahilramani, Barrier Diagrams the Next Stage for Enhancing Offshore Operations Safety, 2010.
51. Sklet, S., et al., Monitoring of Human and Organizational Factors Influencing the Risk of Major Accidents, in SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production S.o.P. Engineers, Editor. 2010, Society of Petroleum Engineers: Rio de Janeiro, Brazil.
52. Kallaur, C.U., A Performance-Based Approach to Offshore Regulation, in SPE International Conference on Health, Safety, and Environment in Oil and Gas Exploration and Production. 1998, Society of Petroleum Engineers Inc.: Caracas, Venezuela.
53. Boykin, G.F., A Global Drilling Organization: The Role of the Drilling Professional, in IADC/SPE Drilling Conference. 1998, IADC/SPE Drilling Conference: Dallas, Texas.
54. Korsvold, T., et al., Creating Resilient Drilling Operations through Collective Learning, in Asia Pacific Health, Safety, Security and Environment Conference, 2009, Society of Petroleum Engineers: Jakarta, Indonesia.
55. Hubbard, D., The failure of risk management: why it's broken and how to fix it, 2009: Wiley.
56. Addison, F., K. Kennelley, and F. Botros, Future Challenges for Deepwater Developments. 2010: Offshore Technology Conference held in Houston, Texas, USA, May 3–6, 2010.