



Title: Integrated Operations in light of the Deepwater Horizon disaster.	Delivered: June 17, 2011
	Availability: Open
Student: Reinert Svanberg	Number of pages: 108

Abstract:

In this Master Thesis, a description of the Deepwater Horizon Accident has been developed and used. Integrated Operations today and its potential for the future has been described. The new working processes that follow Integrated Operations, called Integrated Work Processes, have also been explained. The barrier concept and its development have been shown, and some of its uses in the offshore industry are indicated. The barriers affected, or broken, in the Deepwater Horizon accidents chain of events has been illuminated.

A discussion on the probable impact of Integrated Operations had it been in place at the Deepwater Horizon accident has been written. The conclusion is that Integrated Operations as described in this thesis would probably have averted the accident or strongly mitigated the consequences of the accident. A discussion of the lessons learned from the Deepwater Horizons accident as relevant to Integrated Operations has also been carried out. The lessons have been structured around barrier breaches, and what happened at each of these. The lessons learned from the Deepwater Horizon accident for Integrated Operations are many. They highlight a few aspects of IO. Based on the lessons learned, some mitigating measures have also been proposed.

Keyword:

Deepwater Horizon
Integrated Operations
Integrated Work Processes

Advisor:

Professor Ingrid Bouwer Utne



NTNU
Norwegian University of Science and Technology
Department of Marine Technology

Reinert Svanberg



MASTER THESIS

for

M.Sc. student Reinert Svanberg

Department of Marine Technology

Spring 2011



NTNU
Norwegian University of Science and Technology
Department of Marine Technology

Reinert Svanberg



Preface

This Master Thesis is the final result of my Master of Science in Marine Technology studies at the Norwegian University of Science and Technology (NTNU). The title of the thesis is *“Integrated Operations in light of the Deepwater Horizon Accident.”*

The main focus of the thesis is what can be learnt from the Deepwater Horizon accident for Integrated Operations, and how Integrated Operations could have influenced the course of events that led to the accident. Working with the thesis has been challenging, very interesting and sometimes exasperating. I have to confess that I sometimes got very perplexed about the mistakes done at the Macondo well and the problems with the BOP afterwards. However, it seems to confirm Douglas Adams’ prediction:

“The major difference between a thing that might go wrong and a thing that cannot possibly go wrong is that when a thing that cannot possibly go wrong goes wrong, it usually turns out to be impossible to get at and repair.”

I wish to thank the librarians at the library for Marine Technology for their help in finding relevant materials. Ann-Johanne and Charlotte: Thank you very much!

Finally, I would like to thank Professor Ingrid Bouwer Utne for her unprecedented and somewhat unexpected help, involvement and interest in the thesis, without which I would not have finished. I am deeply grateful.

All the errors contained herein are of course my own.

Trondheim, June 17th 2011

Reinert Svanberg



NTNU
Norwegian University of Science and Technology
Department of Marine Technology

Reinert Svanberg



Abstract

In this Master Thesis a description of the Deepwater Horizon Accident has been developed and used. Integrated Operations today and its potential for the future has been described. The new working processes that follow Integrated Operations, called Integrated Work Processes, has also been explained. The barrier concept and its development have been shown, and some of its uses in the offshore industry are indicated. The barriers affected, or broken, in the Deepwater Horizon accidents chain of events has been illuminated.

The Gullfaks C accident has also been described, and the possible impact of IO on this accident has been briefly discussed.

A discussion on the probable impact of Integrated Operations had it been in place at the Deepwater Horizon accident has been written. The conclusion is that Integrated Operations as described in this thesis would probably have averted the accident or strongly mitigated the consequences of the accident due to, amongst other things, its structuring influence, the focus on cooperation and involvement from offshore centers and the implementation of new monitoring technologies.

A discussion of the lessons learned from the Deepwater Horizons accident as relevant to Integrated Operations has also been carried out. The lessons have been structured around barrier breaches, and what happened at each of these. The lessons learned from the Deepwater Horizon accident for Integrated Operations are many. They highlight a few aspects of IO. Based on the lessons learned, some mitigating measures have been proposed, These include, but are not limited to, standardizing of test evaluations, IT systems and operator training, develop and use automated safety systems (SIS and monitoring systems that alert the user of problems and that while implementing Integrated Operations, safety should only be affected positively.



NTNU
Norwegian University of Science and Technology
Department of Marine Technology

Reinert Svanberg



Problem Description

MASTER THESIS
for
M.Sc. student Reinert Svanberg
Department of Marine Technology
Spring 2011

Integrated Operations in light of the Deepwater Horizon accident.

(Integrerte operasjoner i lys av Deepwater Horizon ulykken)

Background:

The Deepwater Horizon accident, by causing the death of 11 people and the biggest offshore spill in US history, proved safety measures taken in the offshore industry inadequate. Less than a month later an accident at Gullfaks C (GFC) showed worrying similarities. Several of the barrier breaches that led to the disaster in the Gulf of Mexico and the close call at GFC were due to organizational and operational weaknesses.

The operators on the Norwegian Continental Shelf (NCS) is set to implement a new way of organizing operations; Integrated Operations (IO). Generally, this is a tighter integration and cooperation between onshore and offshore organizations, as well as increased use of IT systems and real time communications. Since this will heavily affect both organizations and operations there is a need to look into the Deepwater Horizon accident and consider the implications for Integrated Operations, and vice versa.

Problem Description:

The M.Sc. thesis includes the following tasks:

1. Describe the Deepwater Horizon Accident and the sequence of events leading up to the disaster
2. Describe Integrated Operations in the oil and gas processing industry
3. Describe the concept of barriers in safety assessments and accident investigations, how it is used in the offshore industry, the offshore industry, and the barriers affected in the Deepwater Horizon accident.

These tasks should be used to:



NTNU
Norwegian University of Science and Technology
Department of Marine Technology

Reinert Svanberg



1. Discuss the impact Integrated Operations could have had on the Deepwater Horizon accident, with focus on barrier breaches.
2. Discuss the lessons learned from the Deepwater Horizon accident as relevant to Integrated Operations.

The M.Sc.Thesis should be written in English. The thesis should be written like a research report, with an abstract, conclusion, content list, reference list, etc. During the preparations of the thesis it is important that the candidate emphasizes easily understood and well written text. For ease of reading, the thesis should contain adequate references at appropriate places to related text, tables and figures. On evaluation, a lot of weight is put on thorough preparation of results, their clear presentation in the form of tables and/or graphs, and on comprehensive discussion.

Starting date: January 20th 2011

Completion date: June 17th 2011

Handed in:

Ingrid Bouwer Utne

Professor



NTNU
Norwegian University of Science and Technology
Department of Marine Technology

Reinert Svanberg

Contents

1	Introduction.....	1
2	The semi submersible Deepwater Horizon.....	5
2.1	<i>Semi submersibles – Mobile Drilling Units</i>	5
2.2	<i>The Deepwater Horizon</i>	6
3	The Deepwater Horizon (DH) accident – what went wrong?	9
3.1	<i>Events leading up to the disaster - before April 20th 2010.....</i>	9
3.1.1	<i>Installing the casing string and preparing for the cementing job</i>	10
3.1.2	<i>Final cementing job.....</i>	11
3.1.3	<i>Abandonment and preparing the well for completion</i>	13
3.2	<i>April 20th 2010 - fundamental errors.....</i>	14
3.2.1	<i>Step up to disaster</i>	16
3.2.2	<i>BOP not functioning properly.....</i>	19
3.3	<i>Summary of main findings</i>	20
4	What is Integrated Operations (IO)?	23
4.1	<i>Integrated Operations today.....</i>	23
4.2	<i>Definitions of Integrated Operations.....</i>	24
4.3	<i>Main Focus Areas of IO</i>	25
4.4	<i>Integrated Work Processes (IWP) in Integrated Operations</i>	26
4.5	<i>Traditional practice vs IO and IWPs.....</i>	30
4.6	<i>Integrated Work Practices (IWP) in general</i>	31
4.7	<i>Summary of today’s status and predictions for the future</i>	32
4.7.1	<i>Well planning and execution</i>	32
4.7.2	<i>Well Completion.....</i>	33
4.7.3	<i>Production Optimization</i>	34
4.7.4	<i>Maintenance Management.....</i>	35
5	Work Practices: Where are we now?	37
5.1	<i>The Gullfaks C incident and Integrated Operations and Work Practices.....</i>	37
5.1.1	<i>Causes related to deficiencies in leadership and control.....</i>	39
5.1.2	<i>Underlying Causes</i>	39



NTNU
Norwegian University of Science and Technology
Department of Marine Technology

Reinert Svanberg



5.2	<i>Estimated effect of IWP on the GFC accident.....</i>	40
6	Barriers.....	41
6.1	<i>The barrier concept and definitions</i>	41
6.2	<i>From historic barriers to today's.....</i>	42
6.3	<i>Different classification of Barriers.....</i>	44
6.3.1	Management Oversight and Risk Tree (MORT).....	44
6.3.2	Barrier Concept in Risk Analysis.....	44
6.3.3	Accident Evolution and Barrier model (AEB).....	45
6.3.4	Barriers and Latent Failures.....	45
6.3.5	Barriers in Software Systems.....	45
6.3.6	Barrier systems and barrier functions I.....	46
6.3.7	Barrier systems and barrier functions II	48
6.3.8	A barrier model to prevent hydrocarbon fires and explosions	50
6.3.9	Barriers in Quantitative Risk Analysis (QRA).....	53
6.4	<i>Barrier classification chosen</i>	54
7	Barriers at Macondo	55
7.1	<i>Broken Barriers as identified by BP.....</i>	55
7.1.1	Annulus cement job	55
7.1.2	Mechanical Barriers down hole	56
7.1.3	Pressure Integrity testing.....	56
7.1.4	Well Monitoring	56
7.1.5	Well Control Response.....	56
7.1.6	Hydrocarbon surface containment	57
7.1.7	Fire And Gas System	57
7.1.8	BOP Emergency Operation	57
8	How would IO and Barriers influence the Macondo blowout?	59
8.1	<i>Negative and positive effects of IO and IWPs in general.....</i>	59
8.1.1	Effects on passive physical barriers	59
8.1.2	Effects on passive human/operational barriers.....	60
8.1.3	Effects on active human/operational barriers.....	60
8.1.4	Effects on active technical barriers	60
8.2	<i>Annulus Cement Job Barrier</i>	61
8.3	<i>Mechanical Barriers Down Hole</i>	62



NTNU
Norwegian University of Science and Technology
Department of Marine Technology

Reinert Svanberg



8.4	<i>Pressure Integrity Testing Barriers</i>	62
8.5	<i>Well Monitoring Barrier</i>	63
8.6	<i>Well Control Response Barrier</i>	64
8.7	<i>Hydrocarbon Surface Containment Barrier</i>	65
8.8	<i>Fire And Gas System Barrier</i>	65
8.9	<i>BOP Emergency Operation Barrier</i>	66
8.10	<i>Summary of effects of IO and IWPs on the Deepwater Horizon broken barriers</i>	67
9	What lessons can be learnt from Macondo for IO?	69
9.1	<i>Lesson 1: Barrier evaluation</i>	69
9.2	<i>Lesson 2: Test result evaluation</i>	70
9.3	<i>Lesson 3: Disaster scenario training</i>	70
9.4	<i>Lesson 4: Equipment Maintenance</i>	70
9.5	<i>Lesson 5: Data monitoring</i>	71
9.6	<i>Lesson 6: Safety Culture</i>	71
9.7	<i>Lesson 8: Challenges in geographically distributed teams</i>	71
9.8	<i>Lesson 7: Challenges due to use of software and communication</i>	72
9.9	<i>Summary of lessons learned</i>	72
10	Conclusion	75
11	Further Work	77
12	References	79
13	Bibliography	83
	Appendices	I





Tables

Table 1 Summary of effects	68
Table 2 Summary of lessons learned	73

Figures

Figure 1 Deepwater Horizon [wikipedia]	5
Figure 2 Aker H6 e 6th generation semisub. Note 4 columns on each pontoon, partially submerged. [Maritimt Magasin 2009]	5
Figure 3 Deepwater Horizon on fire (US Coast Guard)	9
Figure 4 Work Processes that needs to be changed (OLF 2005)	27
Figure 5 SOIL provide connections to all players, onshore and offshore [Liyanage 2008]	29
Figure 6 Changes in Work Processes [Fonn 2008]	30
Figure 7 Gullfaks C [Statoil]	37
Figure 8 Causes, course of events and results of loss of well control event at GFC (Talberg et al, 2010)	38
Figure 9 The Barrier Concept	42
Figure 10 Preventive and Protective barriers [Hollnagel 2004]	43
Figure 11 Physical barrier system; walls and moat (wikipedia)	46
Figure 12 Functional barrier system; coded lock (wikipedia)	46
Figure 13 Symbolic barrier function; road sign (wikipedia)	47
Figure 14 Incorporeal barrier system; DNV Rules for Classification (facsimile)	47
Figure 15 Safety Barrier Classification (Sklet 2005)	49
Figure 16 Defence in depth and Swiss cheese model (Rosness et al, 2010)	51
Figure 17 Barriers to prevent hydrocarbon ignition (Vinnem 2007)	54
Figure 18 Barriers identified as broken at Macondo (BP)	55





Appendices

Appendix 1 Gullfaks C accident with IWPs	I
Appendix 2 Gullfaks C accident with IWPs continued.....	II



NTNU
Norwegian University of Science and Technology
Department of Marine Technology

Reinert Svanberg



1 Introduction

The background for this Master Thesis is:

1. The Deepwater Horizon accident and oil spill in the Gulf of Mexico.
2. The oil industry and the government of Norway is interested in increased oil production and recovery, and lowering of production costs on the Norwegian Continental Shelf. To achieve this, the industry is implementing what has been termed Integrated Operations.

The objective of the Master Thesis is to investigate the lessons learned from the Gulf of Mexico accident and try to detect any implications for Integrated Operations, if any.

The Master Thesis is limited in time and scope. A thorough investigation of the Deepwater Horizon accident can be found in several sources and several of these have been used as background. This is not a Master Thesis concerning the accident in special. The field of Integrated Operations is fairly new, this Master Thesis tries to communicate the essence of Integrated Operations as of today, not define them.





What the reason of the ant laboriously drags into a heap, the wind of accident will collect in one breath.

Friedrich Schiller





2 The semi submersible Deepwater Horizon

The Deepwater Horizon (DH) was a Mobile Offshore Drilling Unit (MODU). The MODU definition covers several different designs including drillships, jackups and semisubmersibles. The DH was a semisubmersible platform. This section will offer a glance at the most important design aspects of a semisubmersible in general and the design of the DH in somewhat more detail.



Figure 1 Deepwater Horizon [wikipedia]

2.1 Semi submersibles – Mobile Drilling Units

According to [Sillerud, 2004], the basic design of a semi submersible is (usually) two enclosed parallel hulls with 2-4 columns on each. The deck of the platform is placed on top of these columns – with helipad, accommodation, engines and drill equipment etc on the deck. The reason for this arrangement is rather straightforward. A vessel in waves will move up and down with the waves. The motion is mostly dependent on the vessels waterline area and displacement, which are, respectively, the area of the vessel that is bisected by the sea level and the volume of water displaced by the hull.

Basically, the lower the waterline area, the better (lower) response in waves at any given displacement. Since displacement, and thereby the weight of the vessel, is not something one can easily change one



Figure 2 Aker H6 e 6th generation semisub. Note 4 columns on each pontoon, partially submerged. [Maritimt Magasin 2009]



instead changes the waterline area. While in transit the semi submersible behaves more or less like a ship with two hulls. However, during operations, the semi submersible floods its ballast tanks. This makes it sink in the water until the twin hulls are submerged and the water bisects the columns, considerably reducing its waterline area and improving the response in waves. This enables the semi submersible to work in significant wave heights considerably higher than a drill ship – giving it a better window of work in harsh conditions.

2.2 The Deepwater Horizon

The Deepwater Horizon was considered to be a very safe and high tech piece of technology. In fact, on the day of the disaster several prominent guests from BP and Transocean was visiting the rig because of its outstanding safety record – 7 years without any serious accident. [Graham et al 2011, Associated Press 2010]

The rig was a fifth generation deepwater drilling rig constructed in South Korea at Hyundai Heavy Industries at a cost of USD 310 million. It was delivered in 2001 and became owned by Transocean after its acquisition of R&B Falcon. The DH was dynamically positioned with DP class 3 and could work in water depths up to 2400 meters and to a maximum drill depth of 9100 meters. DP class 3 is given by Det Norske Veritas (DNV) on the demand that a *“loss of position shall not be allowed to occur in the event of a single failure.”* [Det Norske Veritas 2011a] DP 3 notation implies that the MODU is able to stay on a drilling location without moorings or anchors. The DH also held the world record in drilling depth, for a well at 10685 meters in August/September 2009 [Marinelog 2009], 1585 meters deeper than the official specification.

The rig was considered to be blessed with luck in the sense that no serious accidents had befallen it before the Macondo blowout took place. It had a crew of 126 on board at the time of the accident. The DH had been hired to BP since it was launched, initially for a 3 year lease which had been renegotiated yearly. At the time of the accident BP paid 533 595 USD/day for lease of the rig. Fuel and other expenditures came as additional cost, making BP pay around 1 000 000 USD/day for operating the rig. However, BP was not obliged to pay for any maintenance down time in excess of 24 hours per month. It should be noted that the DH had not been in dry dock (DD) since it was launched in 2001, instead Under Water Inspection In



Lieu of Dry-docking (UWILD) and other inspections had been carried out while on the job at sea, minimizing downtime deemed unnecessary. [Graham et al 2011 p. 222]

Maintenance work was supposed to be planned and ordered by use of Transocean's program Rig Management System II, RMS [Graham et al 2011 p. 221]. This system had challenges and its operators was not certain of how to use it. The rig was scheduled for drydocking in 2011, 5 years "overdue", and there were concerns that it had maintenance issues amongst the crew.

Using UWILD is not uncommon. In fact, the major class societies have regulations and procedures for its use. The Deepwater Horizon held American Bureau of Shipping (ABS) class, hence the UWILD procedures was covered in their regulations. These are probably similar or identical to DNVs.

As UWILD seems to be a safe alternative to dry docking, and is also used on most of the NCS' floating production equipment according to DNV Surveyor [Thuestad 2011, telcon]. This procedure unfortunately does not take into account the need for inspection of the BOP. This means that the BOP stack had not been inspected for wear and tear by stripping it into parts. This is usually done while the rig is in DD, and is difficult or impossible to do on board, since the stack is very big and its components are very heavy. The inspection of the BOP was long overdue, mainly due to the fact that the rig had not been in DD since launching. However, both BP and Transocean believed the rig was in safe working order and that the equipment was safe to operate. The rig had some pending maintenance issues but none were considered critical. The Mineral Management Service (MMS) inspection of April 1st 2010 did not find any noncompliant incidents, but neither did it identify that the rigs Blow Out Preventer (BOP) had not been re-certified.

While the rig was in safe working order there were some problems with the BOP. The blow out did not happen because of faulty or bad equipment but primarily because of bad judgment of the people on board, onshore and in the decision processes before the accident. There are several instances before the actual blow out where one could have interpreted the data and shut in the well. As will be shown in chapters 3 and 4 this did in fact not happen, and as the Chief Councils report states in its foreword:



“What the investigation makes clear, above all else, is that management failure, not mechanical failings, were the ultimate source of the disaster. In clear, precise, and unflinching detail this Report lays out the confusion, lack of communication, disorganization, and attention to crucial safety issues and test results that led to the deaths of 11 men and the largest offshore spill in our nation's history.” (Italics added.)

3 The Deepwater Horizon (DH) accident – what went wrong?

To try to understand an accident like the Deepwater Horizon explosion, sinking and subsequent enormous oil spill one must try to figure out exactly what happened before and during the 21 of April 2010. As shown in chapter 2, the DH was considered a very safe and sophisticated drilling



Figure 3 Deepwater Horizon on fire (US Coast Guard)

rig. The accident

demands that the causes and the failures that led to the accident will be explained. This chapter aims to provide a timeline of events and a short explanation of what happened. For information in detail, reference is also made to [Bartlit 2011], [Graham 2011] and [BP 2010] reports.

3.1 Events leading up to the disaster - before April 20th 2010

In early April 2010 the drilling at MC252 stopped because the drillers had run out of drilling margin, which is they did not have an operating window in which the mud weight was low enough to not damage the well (fracturing) and at the same time be high enough to balance the well pressures. The drilling stopped at 18360 feet, a bit short of its 20200 feet target [Graham et al 2011 p. 91-94]. Testing of the well was done between the 11 and 15 of April – and the reservoir was thought to be at least 50 million barrels. This prompted the decision to install the final production casing string – to be used when producing started at the well.

Two options for the production casing were considered. First a long string liner. A long string liner is a continuous steel pipe from the bottom of the well to the sea floor production equipment. This gives the well the best protection with regards to leaks during the wells



lifetime – however it is more difficult to cement in place. After the loss of circulation happened one was forced to reconsider and wanted to use a casing production liner instead. A casing production liner is not continuous but stops before the seafloor – but it is easier to cement in place. This decision was overruled by BP's experts onshore – with tweaked input to the computer programme it was decided that a long string liner could be cemented safely in place. [Graham et al 2011 p. 95-96]

To ensure a good cement job one installs centralizers at predetermined points in the casing. The number and placing is determined by computer program. The cement is supposed to flow in the annulus space and create a continuous cementing around the casing. This is to prevent hydrocarbons to flow in the annulus space. OptiCem – the computer program used to verify the cement job – determined that at least 6 centralizers was necessary to prevent channeling of the cement in the annulus space. To stop channeling due to gas flow 21 centralizers was considered the optimum. However Deepwater Horizon did not have enough centralizers in store – only six of the type the drillers wanted to use. BP's original plans called for 16 centralizers of the sub (screw on) type. There are two different designs of centralizers, slip on and screw on. As the names implies, screw on screws securely into place on the casing while slip on slips on the outside of the casing. BP sent 15 centralizers – of the type the drillers did not want (slip-on) – to the rig. This was the maximum number in one helicopter trip. [Graham et al 2011 p. 96-97] With some emailing to shore it was decided to install the casing string with only the six screw on centralizers already on board.

At this point it is clear that:

- The most difficult casing option with regards to cementing was chosen
- One ignored the advice\demands given by the OptiCem computer programme
- One ignored BP s own installation plan (demanding 16 centralizers)
- This was done from a time (hence cost) perspective and not from a safety perspective

3.1.1 Installing the casing string and preparing for the cementing job

Early afternoon on the 19th of April the casing string was installed at its final position and the next job was to prepare for the cementing. The cement must flow in one direction - that is: down the inside of the casing string, out the bottom and up inside the annulus space.



To ensure flow in just this direction the production valves must be turned into one-way valves. This is done by pressurizing the casing string with drilling mud to approx. 600 psi. This turns them from two-way valves to one way valves. The crew pumped mud to a pressure of 1800 psi but the valves did not convert, one could not establish flow. After consultations it was decided to incrementally increase the pressure. At 3142 psi (5 times the required pressure) the pressure dropped and mud started to flow. It was concluded that the valves had converted. [Graham et al 2011 p. 98]

However, another anomaly was noted. The predicted pressure to ensure circulation was 570 psi after converting the valves. The reported pressure was only 340 psi, low enough to alert the well site leader that something was wrong. It was concluded that the pressure gauge was broken, that the float valves was converted and that one way circulation was established – paving the way for the final cementing job. [Graham et al 2011]

3.1.2 Final cementing job

As stated above the annulus space must be cemented to prevent hydrocarbons to flow in the annulus space outside the production casing. The cement must form a continuous lining\seal around the string; otherwise it will not be effective. This is, under the best of circumstances, difficult. [Graham et al 2011 p. 99] A lot of things can (and do) go wrong – the cement can, amongst other things, be contaminated by mud on its way down, be pumped too far/too short or flow unevenly in the annulus space creating “channels” that hydrocarbons can flow through.

[BP 2010] concludes that:

The annulus cement barrier did not isolate the hydrocarbons.

The cement in the annulus is supposed to prevent hydrocarbons from entering the wellbore. BPs report states that “*Interactions between BP and Halliburton and shortcomings in the planning, design, execution and confirmation of the cement job reduced the prospects for a successful cement job.*”

The biggest fear of BP was to have another lost returns event (fracturing the formation) in the well – this had happened before and prompted the decision to stop drilling further. This fear



severely limited the cementing job. The report clearly states the compromises made by BP [Graham et al, 2011 p 100-102]:

1. Normal/optimal procedure is to circulate all mud from the bottom of the well all the way to the top. This has two main benefits, it cleans the wellbore and limits the chances of cement channeling. Secondly, if there are hydrocarbons in the mud this will be apparent when it reaches the rig. BP's concerns led them to circulate only 350 barrels of mud – not the 2760 needed to completely displace the mud.
2. High cement flow rates increases the cements mud displacing ability, hence reducing the risk of mud contaminated cement. BP limited the cements flow rate to (a relative low) 4 barrels a minute because they feared a higher flow pressure could lead to fracturing of the hydrocarbon zone.
3. When the cementing process and conditions are uncertain standard practice is to pump more cement down the well. This reduces the risk of contamination and extensive channeling. BP decided not to do pump more cement down the well than absolutely necessary to fulfill MMS' regulations – since more cement exerts more weight on the formation. This means 500 feet of cement above the hydrocarbon zone. It also means that BP's engineers disregarded its internal rules – demanding at least 1000 feet of cement. Halliburton moved on to pump 60 barrels of cement down the well – well aware that this provided a small margin for error.
4. BP and Halliburton used Nitrogen foam cement, cement injected with nitrogen to make it lighter – and exert less pressure on the formation. This reduced its specific weight from 16,7 ppg to 14,5 ppg. If the cement is stable the cement will cure before the nitrogen can form larger bubbles, creating uniform hard cement. If it is unstable the nitrogen can migrate before the cement cures and form channels and unevenly distributed cement. BP had little experience using this kind of cement; however Halliburton is considered the world leader. Halliburton tested the cement twice in February – and found it to be unstable. BP did not examine this data. Updated information on the wells conditions was provided to Halliburton, and they conducted a new test in mid April. The cement failed this too, BP was not informed. After tweaking the test conditions Halliburton tested again and the results could, according to the report, arguably say that the cement was stable. However, BP did not receive



this information before the 26th of April and it is questionable that Halliburton had the results in hand before starting to pump the cement.

The cementing job was finished at 14.20 on the 20th of April. After stopping the pumps it was checked whether the float valves was closed and holding. This was done by opening a valve and see if any fluid (more than 5 barrels) flowed from the well. If so it would indicate that the cement was being pushed up the casing. The amount that came out, approx 5,5 barrels, was within the margin of error. It was concluded that the cement was in place and that the float valves were holding. Schlumberger professionals that had been waiting to perform cement evaluation tests was sent home before any tests was carried out. This was because the BP team relied on a decision tree that was used to determine if any evaluation test was necessary. The primary criterion for determining this was whether one had experienced any lost returns during the cement job – which one hadn't.

[BP 2010] concludes that:

The shoe track barriers did not isolate the hydrocarbons.

Initial flow from the reservoir to the drill pipe came through the shoe track barriers. The shoe track cement and valves are supposed to stop flow if the cement barrier is not working.

3.1.3 Abandonment and preparing the well for completion

After drilling the well the Deepwater Horizon would abandon it – making it ready for well completion by a smaller, less expensive rig. Temporary abandonment is a normal way of business – however, the Macondo abandonment scheme was not normal. MMS regulations demanded a 300 ft long cement plug inside the well to act as backup for the primary cement job done earlier. The location was unusual, 3300 ft down the wellbore – deeper than usual and requiring a dispensation from the MMS regulations. BP also planned to exchange the mud above the plug location with seawater before setting the plug, also unusual. The last thing to do was to install a lockdown sleeve in the well, to stop the casing string to lift out of place during production operations. [Graham et al 2011, p 103-104]



Around 11 o'clock on the 20th of April the procedures for temporary abandonment was made available for the BP well site team and the drill crew. It was the first time they saw the procedures [ibid p. 104].

1. Perform positive pressure test (overpressure in well)

Done to make sure there are no leaks out of the well.

2. Run drill pipe to 3300 ft below sea floor
3. Displace the 3300 ft column of mud into riser
4. Perform negative pressure test (underpressure in well)

Done to make sure there is no fluids (hydrocarbons) leaking into the well.

5. Displace the mud from riser with seawater
6. Set the cement plug at 3300 ft below sea floor
7. Set the lockdown sleeve

As it turns out, the crew would never finish this procedure. Several changes were made to the operations plan before April 20th and none of these went through any formal risk assesment procedure. Changes made are for instance changing the depth of the cement plug (deeper) and deciding to set the lockdown sleeve after the cement job, not before. [Graham et al 2011, p 104]

3.2 April 20th 2010 - fundamental errors

The positive pressure test was first on the procedure list mentioned above. This tests whether or not the casing can hold overpressure (production pressure). The BOPs blind shear ram was closed (no drillpipe in the well) and fluids were pumped through the BOP into the well until the pressure read 2500 psi – and holding for 30 minutes. No leaks in the production casing was detected and “*Things looked good with the positive test.*” [Graham et al 2011, p 105]

By creating a negative pressure in the well one can check if the bottom hole cement and valves are successfully stopping hydrocarbons from leaking into respectively the annulus space and the production liner. If the negative pressure rises over time it is evident that fluids are leaking into the well. The negative pressure (underpressure) test also checks that the



production casing is holding tight. Its primary function, however, is to test whether the bottom hole cement job was done properly. At this point, this is the only test performed that could do this – since no tests were made by the Schlumberger team that was available earlier this morning. [Graham et al 2011, p 102]

Before performing the negative pressure test, the drill pipe was inserted to 3300 feet below the ocean floor and preparations to displace the mud with seawater were made. This includes inserting a spacer, a mixture designed to keep the oil based mud and the seawater from mixing. Usually, this is done by a mixture designed and tested for this purpose. BP decided to use lost circulation pill “leftovers.” This was done in order to avoid to have to dispose of them onshore (as hazardous waste), exploiting MMS regulations that says that water based drilling fluids that has been used in the well can be dumped overboard. Engineers from MI-SWACO, under orders from BP, combined two different “pills” to make an unusual large amount of spacer. Needless to say this mixture had never been used before nor been tested for this purpose. [ibid p. 106]

After opening the blind shear ram, inserting the drill pipe to 3300 feet below sea floor and displacing the mud into the riser (above the BOP) the crew shut the BOPs annular preventer, isolating the well from the pressure of the heavy drilling fluids in the riser. Now, by opening the drillpipe on the rig, the crew could bleed of the pressure in the well to zero. For a negative pressure test to yield a positive result the pressure must stay at 0 – zero – after closing the drill pipe, thereby confirming that nothing is leaking into the well.

Three attempts were made to bleed the well to 0 psi and shut the drill pipe. The well was bled off to 266, 0 and 0 psi. However when they shut the drill pipe the pressure climbed back up to respectively 1262, 773 and 1400 psi. During this time there was a lot of people in and around the drillers cabin, as quite a few BP and Transocean management representatives was touring the rig. At least one of them noted that the “drillers were having a little bit of a problem.” When three unsuccessful attempts had been made to perform a negative pressure test there was a discussion about what could be causing this. The cause was a so-called bladder effect in which the mud in the riser was exerting pressure on the annular preventer which transmitted the pressure to the drill pipe.



It was decided to use the kill line to bleed the pressure down to zero. This was done successfully and no flow was observed from the kill line afterwards, the pressure remained at zero. However, the pressure in the drill pipe remained at 1400 psi. These two readings was not reconciled. According to [ibid] the 1400 psi overpressure in “*the drill pipe could only have been caused by a leak into the well.*” Disregarding this, a fundamental error was made in concluding that the negative pressure test had confirmed the wells integrity. The next step of the temporary abandonment scheme was given green light.

[BP 2010] concludes that:

The negative-pressure test was accepted although well integrity had not been established.

3.2.1 Step up to disaster

At 20:02 the annular preventer was opened and the displacement (by lighter water) of heavy mud and spacer in the riser was begun. A driller was monitoring the well pressure for signs of a kick, which is any unplanned influx of fluids into the well. Because of pressure reduction while travelling upwards any gas will expand enormously, pushing mud upwards faster and faster. A kick must therefore be identified or stopped as soon as possible, before it is impossible to contain.

There are several indicators of a kick in progress, chiefly they are [Graham et al 2011, p 109-110]:

- The volume of mud in the active pits. If increasing this is a sign that something is pushing mud out of the well. This is a primary indicator.
- The volume of mud pumped in to the well should equal the volume coming out. If the volume out is greater than in it is a sign of a kick in progress. This is also a primary indicator.
- Visual flow checks. When mud pumps are of the flow of mud out should also stop. If not, something is pushing it out of the well. This is often used to confirm primary indicators.
- Monitoring of drill pipe pressure. There are more possible explanations for an increase of drill pipe pressure than a kick in progress. It is still used as a kick indicator. If



pressure decreases while pump rate remains constant it could signify that hydrocarbons have entered the well bore outside the drill pipe, making the mud lighter and easing the strain on the pumps. If pressure increases while pump rates are constant it could mean that hydrocarbons are flowing into the well pushing heavier mud up the well. None of these are a sure indicator of a kick but if observed (especially in relation to the other indicators) the pumps should be stopped and the well confirmed static. If not then the well should be shut in until the reason for the readings have been determined.

It was difficult to monitor the volume of mud in the active pits, since mud was being sent from other places than the well. It is not clear if the volume was being adequately monitored at this time. Drill pipe pressure was slowly decreasing from 20:02 to 21:00, since mud was replaced by lighter seawater. From 21:01 the drill pipe pressure turned to increasing slowly while pump rates remained constant. It is not clear if this was noticed, but if noticed it would have demanded an explanation and subsequent investigation. One explanation could be that a kick was in progress and that the well should be shut-in. However, the crew was probably busy with other tasks and did not notice the increase in pressure

At 21:08 the pumps were stopped to test the spacer (the mud was pumped out) for oil residues before pumping it overboard. A visual flow check was performed, no flow was observed at this time. After the test the pumps were turned back on at 21:14 – without the crew noticing an 250 psi increase in drill pipe pressure. If noticed it too would demand an explanation of how the pressure could increase while pumps were turned off.

[BP 2010] concludes that

Influx was not detected until hydrocarbons were in the riser.

The most important aspect of safe well operations is to continually control the well and stop influx of hydrocarbons. The crew on the DH could not have had continuous control of the well, since hydrocarbons were not detected until present in the riser between the ocean floor and the rig. Indications of this situation was ignored or not understood.

Right before 21:30 an unexpected pressure difference between the kill line and drill pipe was discovered. The pumps were shut down to investigate the anomaly and it was clear that the



cement plug installation would be delayed. Drill pipe pressure first decreased, then started to increase by 550 psi over 5,5 minutes. The kill line pressure remained lower and an attempt to bleed of the difference was made – successfully at first, but the drill pipe pressure soon started to rise rapidly again. Nobody investigated this nor shut in the well – despite mounting evidence of a kick in progress. [Graham et al, 2011]

[BP 2010] report concludes that

Well control action failed to regain control of the well.

When control of the well was lost, the crew did not have the sufficient training or experience to act quick enough to stop or minimize the consequences of the loss of well control incident. An annular preventer at the BOP was shut at 21:41 the night of the incident, but it was too late - gas was already present in the riser. Evidence also indicates that the annular preventer did not seal off the well properly, allowing hydrocarbons to flow. [Det Norske Veritas 2011b]

At 21:39 the drill pipe pressure started decreasing. This is a very bad sign, since it could only mean that heavy mud was being displaced by lighter hydrocarbons in the lining past the drill pipe. Between 21:40 and 21.43 mud started to spew onto the drill floor. The drillers took immediate action. The flow was routed to the mud-gas separator instead of to the sea.

[BP 2010] concludes that:

Diversion to the mud gas separator resulted in gas venting onto the rig.

Diversion of the hydrocarbons to the Mud Gas Separator (MGS) resulted in the separator being overwhelmed by the flow, releasing hydrocarbons to the DHs deck. If the other option of diverting the gas flows overboard through the diverter line, the majority of the gas could probably have been vented overboard and the consequences minimized or mitigated.

One of the annular preventers on the BOP was closed, and the well supposedly shut in. Unfortunately, the separator could not handle the flow and gas started to flow onto the deck. Ignition and explosion was inevitable. At 21:49 the first explosion happened and claimed its first victims on the drill floor.

[BP 2010] concludes that:

The fire and gas system did not prevent hydrocarbon ignition



The rig had areas that were EX proofed. The design philosophy is that there is little chance of large amounts of gas entering the rig, so not all areas are EX proofed. In addition, the gas dampeners (devices that shut down ventilation circulation) to the engine rooms did not automatically shut down if gas was detected. They needed to be manually activated, probably to avoid false alarm shut downs of the engines that powered the thrusters in a DP mode operation. Thus, it is probable that one or both of the engines running at the time sucked in natural gas rich air, making them run uncontrolled faster and faster. The engines probably were the source of gas ignition. Eye witness accounts support this, as all electric lighting exploded. This is consistent with generators overspeeding, producing a spike in the electricity supply. When the gas ignited, the rig was for all purposes severely damaged but not lost.

3.2.2 BOP not functioning properly

Despite numerous warnings the drill crew did not shut in the well before it was too late. The BOP was now the only and last barrier designed to stop the well from blowing out uncontrolled. Given this, one would assume that it had been maintained and tested rigorously. This is clearly not the case. As we shall see in this section it is probable that the BOP was faulty when it was installed. This section is based on [Det Norske Veritas, 2011b].

At approximately ten minutes after the first explosion happened, the Emergency Disconnect Sequence was initiated from the bridge. Evidence suggests that both multiplex cables from the DH to the BOP stack was severed in the explosion. If otherwise, one should expect that the Lower Marine Riser Package (LMRP) would disconnect from the BOP, allowing the vessel to move away from the fire and its source of fuel. This did not happen.

When the BOP loses all communication with the vessel above it is supposed to shut in the well immediately, a deadman system. This, also, did not happen. There is redundancy in this system, in the so-called “yellow” and “blue” control pods. Since the EDS did not work and the BOP did not shut in the well there is reason to believe that these did not function properly.

From DNVs forensic investigation it is clear that the Blue Pods 27V battery was depleted. This means it did not have the power to operate the solenoid valves that in turn controlled the rams in the BOP. The Yellow Pods batteries were charged and ready, but one of the solenoids did not function when energized.



Without much doubt, it can be concluded that the BOP did not work until it was activated by ROV on the morning of April 22th 2010. Unfortunately, the drill pipe was in a position that made the Blind Shear Rams (BSR) was unable to cut the drill pipe and shut in the well. When the Casing Shear Rams were activated on April 29th 2010, finally shearing the drill pipe, the flow changed to a new exit point. This was trough the sheared drill pipe at the CSRs and escaping trough gaps between the BSRs and the wellbore. This existed because the BSR was not able to close fully and shut in the well due to the drill pipe being stuck on its non-shearing surface.

[BP 2010] concludes that:

The BOP emergency mode did not seal the well.

The subsequent uncontrolled spill should have been stopped by the BOP, and the rig should have been disconnected from the lower marine riser package (LMRP). BP suggests that Transoceans testing policy was not followed and that the maintenance management system on the DH was ineffective.

3.3 Summary of main findings

In this section the main findings will be presented. These are based upon the previous entries and the summaries of the [Graham et al 2011], [Bartlit et al 2011] and [BP 2010] reports.

The main reason for the blowout is that the bottom hole cement job did not seal the well. It is probable that Halliburton's cement was inadequately designed. Since the cement job called for small amounts of cement to be used, this also increased the risk of an inadequate result. That BPs procedure for abandoning the well was delivered late and called for a underbalanced well situation before adding another barrier did also add to the danger.

Last minute changes in well design and drilling procedures were not subject to any hazard identification and mitigation measures. At the same time, procedures and designs provided was not clear enough or did not address the dangers inherent in them. Also, from BPs side, the changes were not in any way quality checked, resulting in saving time and direct costs without any analysis of whether the overall risk was increased, decreased or unchanged.



It is also clear that the rules and regulations concerning deepwater drilling were not up to the task. The Minerals Management Service (MMS) personnel did not have sufficient experience nor were the inspection procedures satisfactory.

The accident could have been avoided or mitigated at several points before it happened. To quote the National Commission's Report to the President; the accident "*place in doubt the safety culture of the entire industry.*" [Graham et al 2011]

To add to this; the Chief Councils Report state that it could "*trace all of these failures back to an overarching failure of management.*" [Bartlit et al 2001]

The Deepwater Horizons BOP is a study in itself. It seems clear that the equipment was faulty when installed and had a history of maintenance issues. If Transocean had better routines for maintenance and testing in place, it is not improbable that the largest oil spill in US history could have been avoided. The fact remains that even with the BOP, 11 men would still be dead and the rig probably severely damaged.

In conclusion, the Deepwater Horizon Accident was not inevitable. The accident did not happen because of equipment failure. The sad fact is that it could have been identified and stopped at almost any moment leading up to the explosion onboard – simply by better risk management from all partners involved in the drilling operation.





4 What is Integrated Operations (IO)?

Integrated Operations involves a lot of change to existing organizations, infrastructure and work processes. It is a new field and the Norwegian Continental Shelf is the place where it is and will be implemented, used and evaluated. It is also spreading to other oil producing regions. The hope is that IO will “deliver the goods,” that is to enable a further 40 years of profitable and safe operations on Norwegian fields. Whether this will happen or not remains to be seen, but it seems that IO has come to stay. The basics of Integrated Operations will be laid out in this chapter. The changing of work processes was predicted by [OLF 2005], and their findings will be presented in this chapter also, as it directly involves many of the issues seen in the Deepwater Horizon accident.

4.1 Integrated Operations today

Integrated Operations (IO) is a new way of organizing offshore operations and production. In short it is using new technologies (mainly IT) to move some elements of the offshore organization onshore. It relies heavily on real time transfer of data between installations and onshore control centres. [Zachariassen, 12. May 2010]

The reason for this new way of doing business are the rising operation and maintenance costs on the Norwegian Continental Shelf (NCS) that became apparent around year 2000 and onwards. Taking into account that the oil production has fallen with 40% since the peak in production in 2000, it is obvious that costs has to be brought down in order to continue profitable production as long as possible. The implementation of IO has so far been technology driven, with a focus on implementing high tech Information and Communication Technologies (ICT) in the operating and maintenance (O&M) aspects of oil production on the NCS. [Liyanage, 2008]

However, as new ICT equipment and IT-platforms become available, real time communication established and production equipment monitored 24/7, it is becoming clear that focus has shifted from technology to people and organization.[ibid]

As pointed out in [ibid], changing the technological environment makes changes to organization and management inevitable. Changes in management and organizational changes



will happen, and it is important to make sure that these are well planned in terms of Health, Safety and Environment (HSE) as well as in production (economic) terms.

4.2 Definitions of Integrated Operations

There are different definitions of IO: According [NTNU IO Center, 2011] *“IO is the integration of people, work processes and technology to make smarter decisions and better execution. It is enabled by the use of ubiquitous real time data, collaborative techniques and multiple expertise across disciplines, organizations and geographical locations.”*

From [NTNU IO Center, 2010]:

“Integrated Operations is a new way of optimizing the operation of oil and gas fields by making smarter decisions through

- *integration of people with different expertise*
- *integration of work processes*
- *Integration of information and communication systems from different domains”*

The definition according to [Statoil, 26. September 2009] is *“Integrated Operations is to use real time data and new technology to remove the barrier between disciplines, professions and companies.”*

It seems clear that this is saving costs and, if used and implemented properly, can also lead to an increased level of safety. IO has been met with criticism from some parts, mainly from the labour organizations for offshore workers. [SAFE Sokkel 2011] states that *“SAFE, Statoil, Dept. Continental Shelf Workers shall work against e-operations/remote control of control rooms as long as there are persons on the installations offshore.”*

It is also pointed out that the government is probably not interested in removing control of production from Norway onshore to international control centres and that experienced human workers, who are familiar on an installation, are better than automated systems to optimize production. Last, it is maintained that experienced workers with hands-on experience never can be exchanged by remote systems and onshore operators. [Zachariassen 19. April 2010]



This critique should not be dismissed out of hand. It seems that the problems they are highlighting are very real, even if grounded in fear for losing their jobs. However, the opportunity and very real possibility for savings, increased production and safety demands implementation of more IO. On the Norwegian Continental Shelf (NCS) an estimated 300 billion NOK (~60 billion USD) could be earned in savings and increased production. [OLF 2005 and Zachariassen 12. May 2010]

4.3 Main Focus Areas of IO

Even if the definition of the term Integrated Operations vary, the concepts are all based on more integration between onshore and offshore activities, and rely heavily on new ICT concepts and platforms. For instance, Statoil have recently implemented a new IT system that will make data from all their production assets available in the same database. This is a new development, and gives them the opportunity to collect and compare data from different assets. This has not been easily possible before, because their assets have different systems from a wide range of years, and hence different IT systems and degree of complexity.

However, since IO is a bit fuzzily defined by the actors, it is difficult to define clearly just what it is.

It is possible to divide IO into an operational system, defining where its different applications and technologies is supposed to work. SINTEF's NTNU IO Centre has 5 programs;: *Drilling and Well Construction, Reservoir Management and Production Optimization, Operation and Maintenance, New Work Processes and Enabling Technologies* and *General Projects*.

[NTNU IO Center, 2010] These programs are connected to the wish for increased production, decreased maintenance costs, and shortening the way from technological concepts to implementation.

The most important part of IO is to strengthen the communication and collaboration between organizations onshore and offshore and strengthen onshore organizations' ability to support offshore operations. This will in turn give offshore workers time for more operative and less administrative work [Fonn 2008].



Based on the previous sections, Integrated Operations will in this thesis be defined as **the process or working environment in which closer cooperation and interaction between all parties involved in oil activities are achieved by use of new and standardized IT systems and instantaneous communications. The aim is increased daily production, increased safety levels, increased total production and decreased production costs.**

4.4 Integrated Work Processes (IWP) in Integrated Operations

In order to reap the benefits of IO, new, and changed, work processes must be defined and implemented. A work process can very narrowly be defined as a limited number of operations which need to be carried out [Scheib 2005]. According to [UNEVOC, 2009] “*A work process determines one special profession. It includes an entire working operation that is necessary to fulfill one particular operational working order, (...) In all cases, the result of this work is one special product or service, and in larger organizations there are several work processes to be carried out parallel or consecutively to create a final product.*”

Work processes change due to technology changes. [OLF 2005] discusses the traditional work processes on the NCS, and predicts 2 general shifts, or generations, until Integrated Work Processes become a reality. Basically, the difference between traditional work processes and Integrated Work Processes lie in the direction of increased interdisciplinary approaches, more parallel work processes, as well as increased collaboration between suppliers and operators

[ibid] maintains that these work processes include Well Planning and Execution, Well Completion, Production Optimization and Maintenance Management. This corresponds rather well with SINTEF IO centers work programs already mentioned. In the following it will be discussed how work processes have been traditionally and how they are predicted to become in the near future by [ibid].

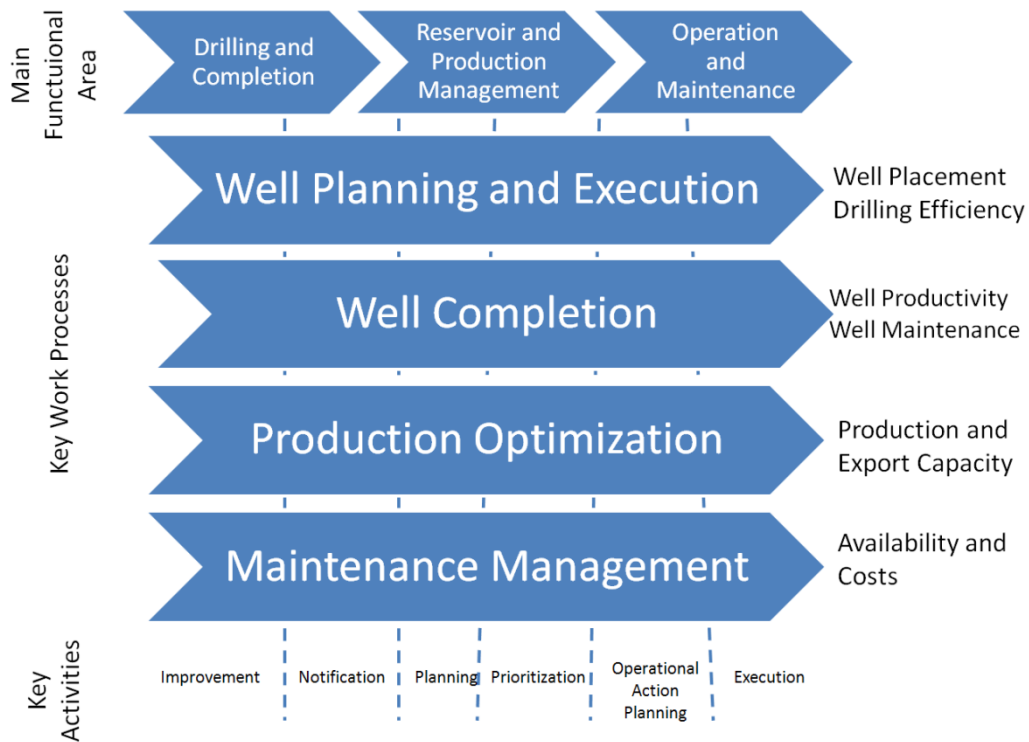


Figure 4 Work Processes that needs to be changed (OLF 2005)

The work processes cover all the major areas of (offshore) oil production, excluding dismantling and decommissioning. These are of no importance to the daily operations and production. Vital work processes could for instance be well design and active well steering, optimization of well completion, optimizing the value chain from reservoir to export and maintenance management. These processes are vital to, among others, well productivity, production rates, recovery rates and maintenance costs. This confirms the predictions made by [OLF 2003], mainly that if IO is implemented successfully it will lead to more effective drilling operations through better and real time utilization of drilling expertise, smarter production and higher reservoir extraction rates through higher integration between long and short term production goals (daily production versus absolute reservoir extraction rates). It also predicts lower maintenance costs and a positive effect on HSE through extensive automated condition monitoring and better support onshore-offshore in crisis situations.



From the success factors mentioned in [OLF 2005], it is possible to gain some vital insights.

These factors are given as:

- 1. Improvement initiatives should focus on key value-adding decisions and complete value chains, e.g., on well placement and the complete well delivery process.*
- 2. Planning, prioritization and execution activities should be integrated across the key work processes.*
- 3. The operational teams should be allocated the competencies and given the authority to make decisions whenever a problem occurs.*
- 4. The teams should use ICT solutions and be located in facilities that enable real-time collaboration.*
- 5. The teams should use tools that filter information, e.g., produce intelligent alarms, automate repeatable tasks and keep the processes within acceptable limits without breaching alarm or plant trip limits.*

From point 1, it is clear that IO and IWP are tools to optimize value. Given the maturity of the fields, and the decline of production on the NCS, this is probably wise. However, due to HSE aspects and to the public's interest in the oil activities, the changes cannot occur if they are, or even are perceived to be by the public, contrary to safety.

As to point 2, greater integration between the key work processes is very important if one is to optimize for instance maintenance down time. It is assumed that this can be done with greater success with integrated operations (parallel) than with segregated (serial) operations. Greater integration onshore\offshore must also be considered as good, since this might create more continuity than exists today, since offshore workers work 2 weeks on and 4 weeks off.



Onshore workers presumably do not. Contrary to this is the danger of creating geographic “us and them” thinking.

Given that the teams responsible for an installation actually possess the competency to operate and maintain it, and that they also must have the authority to make decisions when a problem occurs (point 3), they will be responsible for day to day operations of an asset with support from onshore centers when needed. Their authority must include the right to decide to completely shut down production if they consider a problem as that serious. Considering the values at stake, this is probably something that is not easy to do, and the authority to do so might be given – but will it be used?

IO depends heavily on new ICT solutions, real time data and geographically distributed teams (point 4). Statoil is implementing new IT systems to simplify information flow. Installations are also networked in the high bandwidth fiber optic system Secure Oil Information Link (SOIL) introduced in 1998, see the figure below. The infrastructure is already present, enabling information and knowledge sharing on a much higher level than before and at the same time enabling many to many interaction in contrast to one to one interaction [Liyanaage 2008].

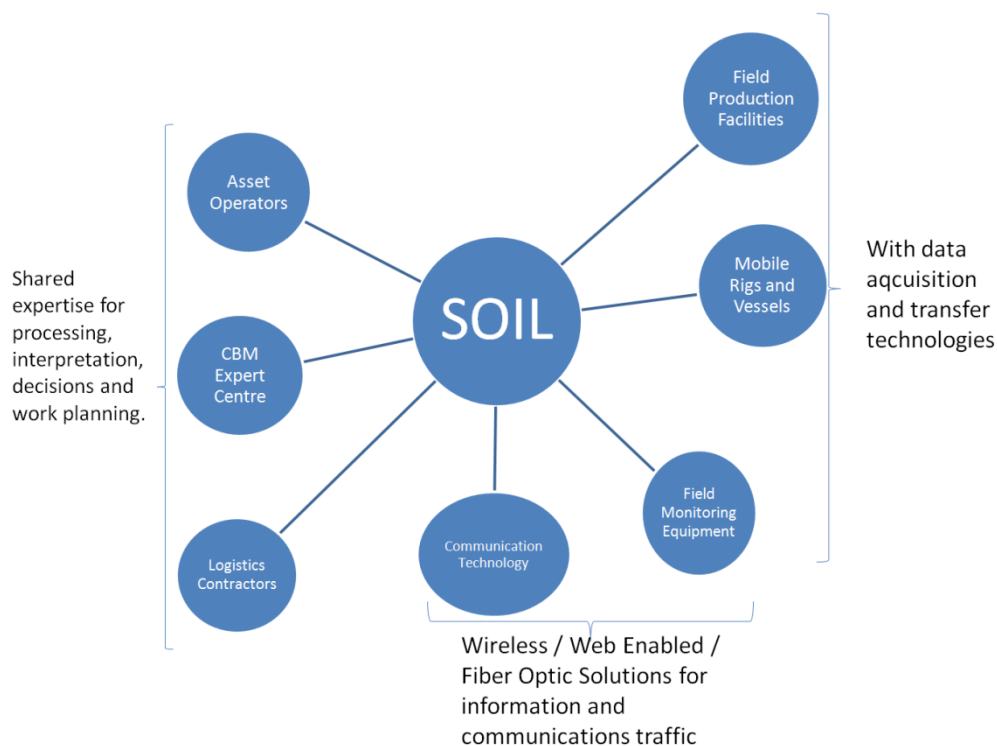


Figure 5 SOIL provide connections to all players, onshore and offshore [Liyanaage 2008]



The last point mentions filtration of information. Alarm systems that go off for no reason at all will soon be ignored or shut down. “Crying wolf” thirty times a day will probably diminish or, more likely, completely remove an alarm's usefulness. However, “crying wolf” one time too many is probably better than the alternative. Intelligent systems should be able to keep the process within acceptable limits once these are defined. This is probably an easier task on a commissioned fixed or semi fixed installation with plateau production than for instance on a MODU like the Deepwater Horizon.

4.5 Traditional practice vs IO and IWPs

The difference between traditional operations practice and IO can be summed up as follows:

Serial	➔	Parallel
Single discipline	➔	Multidiscipline teams
Dependent of physical location	➔	Independent of physical location
Decisions based on experience data	➔	Decisions based on realtime data

Figure 6 Changes in Work Processes [Fonn 2008]

The changes are heavily dependent upon the use of new IT infrastructure and high bandwidth communications between the geographical locations, perhaps with the exception of the shift from serial to parallel processes and to a smaller extent from single to multidisciplinary teams. Independency of physical location is only achieved when data can be interpreted and suggestions returned in a (more or less) simultaneous interchange of ideas between several disciplines and locations. When experts onshore can base their decisions on the same real time data the operators have, undisturbed by interpretation, they have a powerful tool to make decisions and suggestions.



4.6 Integrated Work Practices (IWP) in general

The following section is based in its entirety upon [OLF 2005]. This seems to be the most comprehensive walkthrough of the status for work processes and it also predicts how this will change in two generational steps from 2005. As OLF is the Norwegian oil industry's organization, it is probable that it will be accurate. It should also be noted that it could be biased to support OLF's views on Integrated Operations and Integrated Work Processes. Even when this is noted, the information and predictions seem sound.

Traditionally, most operative decisions were taken offshore, either isolated or with limited collaboration with onshore experts. Onshore and offshore personnel belonged to different organizational units with differing goals and Key Performance Indicators (KPI). Problems were solved in a fragmented manner, and expertise is fragmented both geographically and disciplinary. IT systems are general and do not communicate widely. Individual work processes are the same.

In the first generation integrated work practices onshore operation and drilling centers play a vital role. They are supposed to integrate all important operational functions. Securing the same data for onshore and offshore operators is important. The onshore centers have multidisciplinary teams that can manage the data and make decisions. Some areas have decision support available 24\7, others 12 hrs\day etc. Real time monitoring is possible for both sides. This ensures that there is minimal confusion. Also, importantly, the teams have been given authority to make necessary decisions without passing the buck.

Second generation work processes will integrate onshore and offshore operators and suppliers. They rely heavily on netbased communication and service delivery - for instance workover plans. Operators must relinquish some control to suppliers operating centers, enabling these to make decisions regarding equipment and maintenance on their own, delivering the decisions and plans to the operators via the net. Responsibility for operations will still be with the operators and must make decisions if an alarm or anomaly occurs. Centers must be operating 24\7. Filtration tools must be used to streamline information to operators. Daily production will be run by automated processes.



The teams will be geographically distant, but working together closely with face to face communications. It is possible to imagine operational centers distributed in such a way that people are always on the job during local daytime. All involved, operators, suppliers and service providers will have to be measured by the same KPIs to ensure collaboration.

4.7 Summary of today's status and predictions for the future

In the following section, [OLF 2005] take on today's work practice and the predictions for future work practices is summarized and presented. The partitioning of work practices are based on the normal working practices of today. This is presented because IO demands new and interdisciplinary work practices that will change the working environment profoundly. Thus creating a different environment for activities involving risk and in turn probably change the overall risk picture to a great degree.

4.7.1 Well planning and execution

Well planning and execution is the process of planning and drilling a new well or doing interventions in an old one.

4.7.1.1 Traditional

Early practice was a sequential process where a possible drainage location was identified and passed on to drilling. This changed to a more inter-disciplinary process where planning and execution is concerned. Focus is on optimization of well placement and productivity. However, the work is mainly carried out by the operators, with limited or no collaboration with contractors. The drilling program is largely developed onshore.

4.7.1.2 Generation 1

Active use of onshore drilling centers. Virtual Reality (VR) of reservoirs enables interdisciplinary teams to develop drilling and completion plans. Contractors will be involved in planning processes. Directional Drilling will be performed from onshore. Offshore managers will still be accountable, but onshore personnel will be responsible for optimization and decision making.

High bandwidth communication established between onshore and offshore centers, thereby enabling remote operations. Drilling optimization will be more automated. Human interaction



with the technology will diminish, reducing human error. Support from onshore will be available 24/7. Information should flow freely between all involved parts.

4.7.1.3 Generation 2

High integration with operators, contractors and service providers in well programme planning. Operator responsible for quality assurance (QA) and approval but outsource most of the services to specialized contractors. Virtual integration of work processes enable experts from all sides to exchange data and thus make decisions on the same basis.

No manual editing of data will be necessary. Automated systems analyze the data flow, evaluates possibilities based on a given set of parameters and presents scenarios to the integrated team who will make the final decisions. The drilling process will be automated to the extent that it can decide what to do with problems on its own. Optimization will be automated and run from onshore. Operational logistics will be governed by a intelligent and efficient system.

4.7.2 Well Completion

Well completion is the process of readying a well for production or injection. Mainly, this involves bottom hole operations and installing production casing.

4.7.2.1 Traditional Practice

Connections between well completion and well planning and execution as well as production optimization are limited, even if well completion heavily influences these processes. Reservoir driven workovers are not taken into account, resulting in sub-optimal systems.

4.7.2.2 Generation 1

Distributed measurements in the well will monitor the performance of the well. Information gained will be used to diagnose the performance in real time. Wells will become more complicated. VR models should be used to plan workovers and well interventions. This will optimize the well system as well as lower costs.



4.7.2.3 Generation 2

Virtual reality reservoir models will be utilized to give a complete view of the well system. These models will aid in supervision of workovers and interventions *leading to a significant decrease in the risks involved in these activities*. Subsea wells will no longer require a connection to a vessel or rig, be run from onshore centers significantly reducing the costs involved. Examples here are the Snøhvit and Ormen Lange fields.

4.7.3 Production Optimization

Production Optimization is the process in which the oil operators are supposed to achieve two things. First, the daily production quota must be met. In a new installation, the quota is the processing equipments daily production limit. When the field has been producing for some time (several years or decades) falling production will be experienced. The goal is then to produce as much as possible every day. Secondly, an overall extraction percentage must be met. This is done by for instance injection of water or gas into the reservoir, to keep up production pressures. These goals will to some degree be conflicting. In order to make good decisions about these goals, good information about the reservoir and also the production equipment is important.

4.7.3.1 Traditional

Production and Injection plans (P&I) are updated on a monthly basis, based on results of well tests. These plans influence production rates and recovery rates. These plans often lack information about onboard process capacity and reservoir drainage effects, thus results in lower recovery rates than optimal and sub optimal use of onboard process equipment.

Day to day optimization is carried out by offshore operators based on their own judgments and knowledge. These operators supervise field operators who manually operate valves and read instruments, as well as participate in daily maintenance etc.

Onshore support is not available 24/7, but in daytime 5 days a week. Important decisions, both in production and safety, are therefore made without the knowledge and supervision of the onshore operators who developed the plans in the first place.



4.7.3.2 Generation 1

P&I plans are updated daily, and the distance between the operators onshore and offshore is minimized due to real time face to face communications and real time information exchange. This will help to optimize the use of onboard processing capacity and increase recovery rates.

Access to real time data from both automated and manual readings will increase problem spotting and solutions. Onshore experts available 24\7 will advice offshore operators on how and what to do. Primary control of the process will still be offshore.

4.7.3.3 Generation 2

Value chain simulation and optimization will be done by new tools that model several different scenarios and optimize the process in real time. Improved down hole measurements will enhance the optimization. Control and Surveillance functions will be moved onshore and much of the offshore operators function will be replaced by automated technologies.

4.7.4 Maintenance Management

Maintenance Management in general is the process on which operators decide if, when and how maintenance should be conducted. The maintenance down time costs will be considerable in connection with any type of oil producing since lost production can only be made up in the tail end of production phase. This involves heavy penalties due to the time value of money.

4.7.4.1 Traditional

Traditional practice is based on Preventive Maintenance (PM) and Corrective Maintenance (CM), with some Condition Based Maintenance (CBM) on critical equipment such as gas turbines

Maintenance is therefore carried out on a periodical basis, with anchoring in predetermined work schedules or, in case of failure, unplanned maintenance. Work orders on a problem is issued, work carried out and the order closed. Modern systems support the process, but maintenance plans are not closely coordinated with the other groups. Production losses due to maintenance are not rare.



4.7.4.2 Generation 1

Planning and preparations will be made onshore. The PM process will be integrated and coordinated with the other disciplines. This leads to higher production and regularity. CBM techniques will be used on other equipment than heavy rotary equipment. CBM monitoring will give early warning of problems, and increase the opportunities for scheduled maintenance operations. Decisions concerning maintenance will be made by onshore operators and experts with real time access to relevant data. Consequences are early identification of problems, shorter time to decide what to do and better management of equipment and installations.

4.7.4.3 Generation 2

Planning, maintenance, modification and repairs will no longer be the domain of offshore workers. Multidisciplinary teams will be responsible for these actions. These teams will not belong to one installation, but work on one installation and one project at a time. Plan it, carry it out and finish it. Then move on to another installation. Planning will be done onshore. All plans and equipment should be in place before they move out. Offshore operators will be support in the planning and execution face of a project.

During execution the team will be able to communicate with experts onshore, from equipment suppliers to professors. Enhanced, ubiquitous and cheap field instrumentation will replace manual data gathering resulting in CBM replacing PM on most equipment where possible. This will enable a much better ability to plan Maintenance Down Time, thus greatly reducing lost production.



5 Work Practices: Where are we now?

In light of the proposed work process changes, it would be interesting to see how an accident with disaster potential theoretically would change if the new processes had been used. The Gullfaks C incident that happened May 19th 2010, less than a month after the Deepwater Horizon accident, show remarkable similarity with the DH incident and could very well have ended in a disaster on the NCS. This accident is not directly linked to the Deepwater Horizon accident and can therefore provide another data point to take into consideration.



Figure 7 Gullfaks C [Statoil]

The method used is qualitative speculation based upon the proposals and predictions from chapter 4. Even if it is speculative, the results seem valid.

5.1 The Gullfaks C incident and Integrated Operations and Work Practices

According to [Talberg, O. et al, 2010], in April and May 2010 Statoil's team on Gullfaks C (GFC) drilled a well to 4800 meters. The drilling was plagued by accidents, errors and resulted in a loss of well control and gas leak to deck incident on May 19th 2010. Only chance stopped the incident to becoming a full blown disaster with probable loss of life or installation. If this had happened less than a month after the Deepwater Horizon disaster it would not only have damaged the installation, it would probably have dealt the Norwegian and international oil industry a major blow. The incident was also widely reported in the press, both in Norway and internationally. [Sverdrup, 31. May 2010]

Statoil's internal accident report reveals both the causes and consequences of the incident, as well as describing in detail what happened.

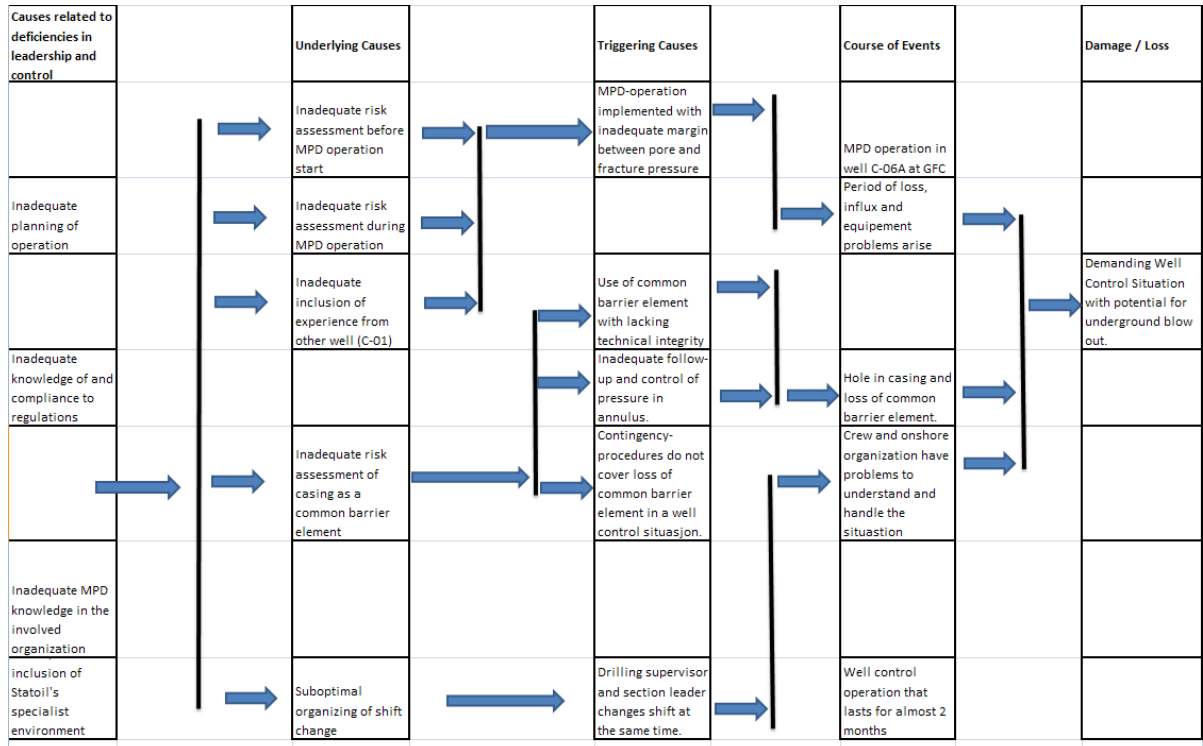


Figure 8 Causes, course of events and results of loss of well control event at GFC (Talberg et al, 2010)

The most interesting, for our purpose, conclusions from this accident includes the fact that Statoil's onshore specialist environment *was not included in the planning of the well due to a problematic professional climate between the onshore and offshore organization*. It is also very interesting to see that the offshore organization did not possess the knowledge needed to go through the drilling operation - but that single persons in the same organization did possess it but did not, or was not able to, use that knowledge. Also, because of the fact that the drilling section leader (DSL) and the drilling superintendent changes shift at the same time, the remaining drilling personnel had limited support at the time of the incident.

It seems that Statoil's organization at GFC is either organized the traditional way or with elements of traditional organization and some elements of first generation integrated work practice. If we look at the fact that they did not cooperate well with the onshore organization, this illustrates the need for closer cooperation between GFC and the onshore centers. It is also a clear example of the problem of geographical "us and them" thinking. In light of the



changes predicted in first and second generation work practice, this accident would probably have been totally averted or had not been allowed to grow so serious that production had to be shut down for almost two months, costing more than 1 billion NOK. In the following, the problems at GFC as highlighted by Statoil will be briefly discussed and contrasted to G1 and G2 work practices. It will be structured around the illustration above.

5.1.1 Causes related to deficiencies in leadership and control

Based on the information given in the report the shortcomings of the leadership and control were many. They include inadequate operation planning, inadequate knowledge of regulations and therefore also lacking compliance to regulations, inadequate organizational knowledge of Managed Pressure Drilling (MPD) and an unwillingness to include Statoil's onshore specialist environment in the planning.

If GFC's drilling organization had been organized as generation 1 (G1) or generation 2 (G2) Integrated Work Processes (IWP) we can conclude the following:

First, Statoil's onshore based specialists would have been included in the planning of the well. We must from this conclude that the planning would probably have been better and in compliance with regulations. Secondly, the organizations competence on MPD could have been brought to play earlier and the drilling operation would not be compromised by the too small drilling margin that resulted in loss of pressure and gas influx to the well.

5.1.2 Underlying Causes

For the sake of argument, let us assume that the deficiencies in leadership and control were the same, even after implementing G1 and G2 IWPs. Then the underlying causes would still (to some extent) be the same, namely inadequate risk assessment before and during MPD operations, inadequate inclusion of experience from drilling of another well (with the same problems), inadequate risk assessment of casing as a common barrier element and a suboptimal organizing of shift change.

With G1 and G2 IWPs the drilling of the well would have been monitored from an onshore control center and by various automated warning and control systems. It could also have been controlled directly from an onshore control center. If the risk assessment was inadequate it is probable that these systems would have made the operators aware of the pressure buildup in the annulus space, triggering a kick warning. If the center was connected to a drilling



contractor the risk assessment of the casing as a common barrier element would probably have been better. Experience from the drilling of another well would have been in the system, and it is possible to assume that it would have been brought to the teams attention by the IT system itself, if the planning of an drilling operation was conducted with the help of for instance a search query where operators had to include characteristics of the drilling plan and reservoir area. The IT system could then, based on the information given, provide examples of similar wells and anticipated problems. When it comes to the suboptimal shift change, this should have been identified even before the introduction of IWP. Saying this, it is probably worth noting that if the IWPs had been implemented, the problems caused by their being unavailable would have been smaller.

5.2 Estimated effect of IWP on the GFC accident

If G1 IWPs had been implemented at GFC it is probable that the entire accident would have been averted. It is estimated that three quarters of the causes related to deficiencies in leadership and control would have been averted, as well as half the underlying causes. The rest is estimated to probably be averted. If G2 IWPs had been implemented it is estimated that all deficiencies in leadership and all the underlying causes would have been averted, thus making it very probable that the accident could not happen. For the evaluation sheet, see appendix 1 and 2.

Last, it is important to note that this is a rough review of the accident and what would have happened if IO had been fully implemented. It is not a given that IO will avert all accidents in the same way as illustrated above, but it seems to eliminate a lot of organizational blunders. It also seems to equip operators with a powerful tool to assess and control situations if implemented properly.



6 Barriers

In the following chapter, the concept of barriers and energy will be presented and discussed. It is presented because the barrier concept is very much used on the NCS. At the same time, it is an excellent tool for identifying dangerous situations and the checks and balances to stop or mitigate the consequences if they do. It has special relevance for pro-active risk management, since it involves acting before an accident takes place. It is not a rule based method but a way of defining what could go wrong and then figuring out what is needed to stop it from happening. The concept is, as shall be shown, quite simple – but not easy. There is an art to the concept, since it involves creativity and demands the ability to make scenarios. The following chapter is intended to give an oversight of the evolution of, the definitions of and the approaches to the barrier concept. In conclusion, it will put forward the definition and approach that will be used in this Master Thesis.

6.1 The barrier concept and definitions

The concept of energy barriers was introduced and defined by [Haddon Jr, 1973], in his paper describing energy damage and the 10 countermeasure strategies. The theory is based on Heinrich's domino theory from the 1930s. [Shahrokhi and Bernard, 2006] and [Hollnagel 2004]. The underlying idea is that accidents occur when energy is released in an uncontrolled fashion. The energy contained in any system can be measured, and steps taken to avoid accidents.

Haddon's strategies 1-5 deals with (in order): preventing buildup of energy in the first place (no car driving), reducing the buildup of energy (speed limits), prevent the release of energy (prevent collisions), changing the rate of spatial distribution of release of the energy built up (controlled deformation of car), separate the release of energy in space (sidewalk) or time (crosswalks/pedestrian bridges) from the structures likely to be damaged.

His sixth strategy, which is the introduction of the barrier concept; *uses not separation in time and space but separation by interposition of a material "barrier": the use of electrical and thermal insulation, shoes, (...).*

The strategies 7-10 are as follows: modifying the contact surfaces where people may come in contact (removing sharp edges, rounding curvatures), strengthen the structure that may be damaged by energy transfer (earthquake proof buildings, vaccines, physical training), rapid

detection of energy damage (ambulance) and the measures taken between energy damage occurs till stabilization occurs (first aid, shoring up damaged buildings).

Haddon understood barriers as something physical, for instance a wall or a hard hat, not something non-physical as inspections, routines, warning signs et cetera.

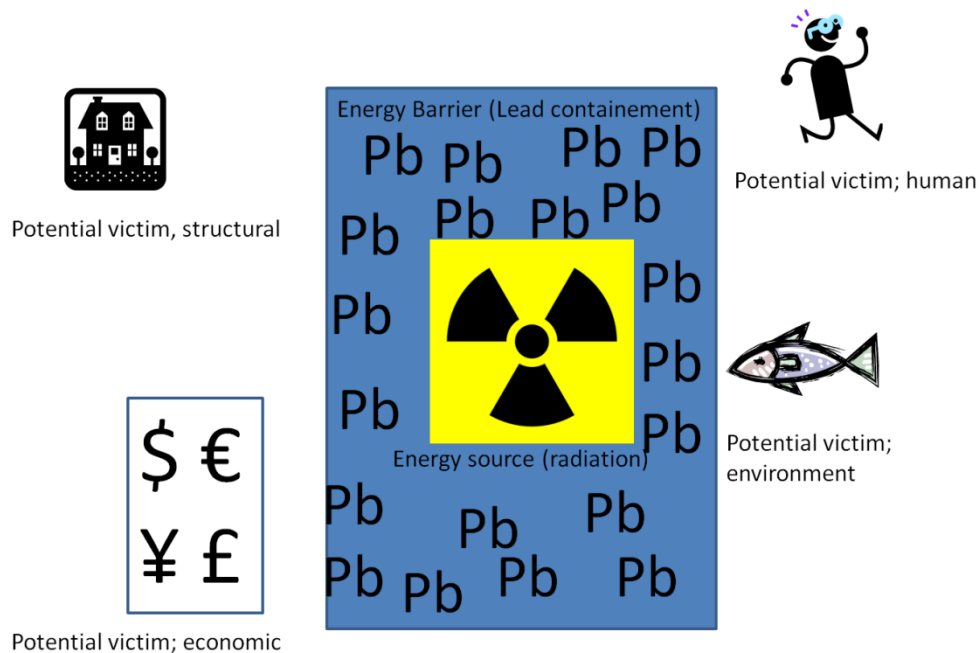


Figure 9 The Barrier Concept

[Vinnem 1999] define barriers as “*Measure which reduces the probability of realizing a hazard's potential for harm and it's consequence. Barriers may be physical (materials, protective devices, shields, segregation etc.), or non-physical (procedures, inspection, training, drills).*”

[Hollnagel 2004] define barriers as “*generally speaking, an obstacle, an obstruction, or a hindrance that may either: (1) prevent an event from taking place, or (2) thwart or lessen the impact of the consequences if it happens nonetheless.*”

6.2 From historic barriers to today's

[Hollnagel 2004] conveniently mentions several sources' take and definition of barriers. These will be briefly put forward in the following section. The origin of barriers is several thousand years old, found for instance in Mesopotamia 3 500 years BCE, in the building of

citadels in early cities. The Great Wall of China is another example. These barriers focused on keeping unwanted visitors from access to the city or the state. From the single line of defense (one wall) the concept of several lines, or defense-in-depth, was invented in the Middle Ages. The defense-in-depth concept is used in almost any high tech industry, for instance the nuclear industry or the process industry.

The difference between the medieval barriers and the modern barriers lies in the physical barriers of a castle (walls) and the combination of different barriers such as accidental release protection, walls, reporting of unwanted events and clear policies on safety matters in the nuclear industry.

Thus, barriers can be defined as physical objects (walls) and functional or logical barriers such as doors or warning signs. From [Hollnagel 2004]’s general definition of barriers it can be deduced that there are two main types of barriers, namely barriers that work *before* and *after* an event takes place. Barriers that work before are *preventive barriers*, and those that work after are *protective barriers*. Barriers can be *active or passive*, *permanent or temporary*. Active barriers contain barrier functions that work to fulfill its purpose and reduce or deflect the consequences of an event. Passive barriers fulfill its purpose by being in place, not actively doing something. They are there to minimize consequences of an event. Permanent or temporary barriers are barriers that, respectively, are always in place or are not. For example a wall is a permanent barrier, while a traffic cone is not. Clearly, barriers are dependent on the point in time relative to an event, that is, before an event a barrier is preventive and after an event the barrier is protective; as shown in figure 10.

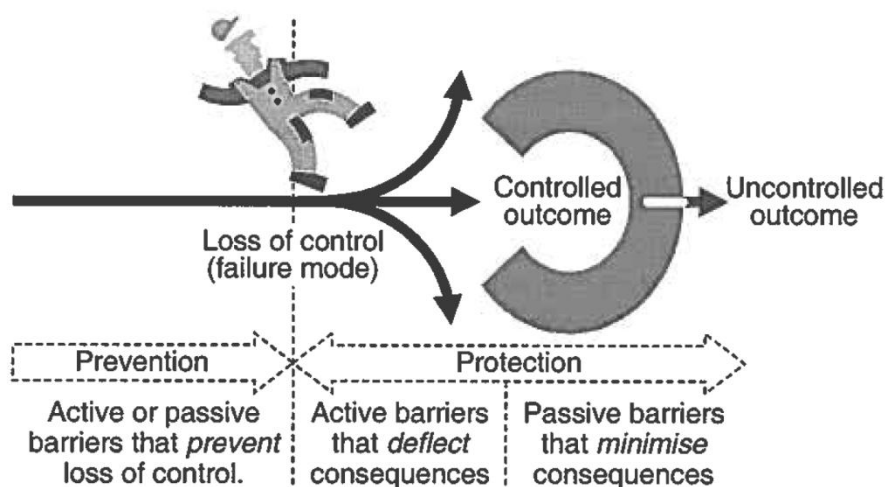


Figure 10 Preventive and Protective barriers [Hollnagel 2004]



6.3 Different classification of Barriers

As to classification, [Hollnagel 2004] mentions several different barrier models. These include Haddon's barrier theory as mentioned above, and;

6.3.1 Management Oversight and Risk Tree (MORT)

The MORT approach was described by Knox and Eicher, 1983. It was a comprehensive approach that incorporated a wide range of safety and risk concerns and causal factors in an orderly manner. The MORT barrier analysis was introduced in 1985, and described barriers as control barriers and safety barriers, control for the ordinary energy flow and safety for unwanted energy flows. Four approaches to eliminate system hazards were listed (in order of importance), these being: Elimination through design, installation of appropriate safety devices (barriers), installation of warning devices (alarms) and development of special procedures to handle the situation. MORT defined three different barrier purposes; prevention (before), control (during) and minimization (after). These are dependent on the time in relation to an unwanted event. In addition, distinction were made between barrier types; physical, equipment design, warning devices, procedures / work processes, knowledge and skills and supervision. The fact that barriers could be impractical, could fail or could be ignored was mentioned.

6.3.2 Barrier Concept in Risk Analysis

An account of how users of risk analysis used barriers was made by Taylor 1988 in the perspective of weapons system safety. Barriers were defined as "equipment, constructions, or rules that can stop the development of an accident." Taylor defined three barrier types, passive, active and procedural. Passive barriers work because of their physical nature. Active barriers needed activation before use. Procedural barriers, for instance instructions, needed a mediating agent before they could be used. Taylor also established requirement factors for barriers, namely adequacy, availability/reliability, robustness and specificity. Adequacy refers to the barriers ability to prevent accidents within the designed parameters. Availability and reliability: fail safe active barriers, regular testing and inspection of passive barriers. Robustness: ability to withstand extreme circumstances. One barrier shall not be disabled by the use of another and two barriers shall not be affected by a common cause. Specificity: a barrier activation must not lead to other accidents nor destroy what it protects.



6.3.3 Accident Evolution and Barrier model (AEB)

In 1991, Svenson defined barrier functions and barrier systems as: *a function which can arrest the evolution of an accident so that the next event in the chain is never realized. Barrier systems are those maintaining the barrier functions.* This is based on the definition of an accident evolution as a chain of events or a sequential accident model. In general, a function is the specific manner in which a the barrier achieves its purpose while a system is the foundation of the barrier function – for instance structures, organization etc. The AEB model defined three different barrier system types; physical, technical and human factors/organizational.

6.3.4 Barriers and Latent Failures

Latent failures were introduced as a concept in accident models developed in the late 80's to the early 90's. A latent failure can be described as a failure that is waiting to happen because organizational processes degraded defenses, allowing unsafe acts that result in failure.

Barriers were described as an intervening layer between the unsafe acts and the failure. The defenses (or barriers) were described as six different functions: Protection: provide a barrier between hazards and victims durin normal operation. Detection: detect and identify non-normal conditions, unsafe acts or hazardous material present. Warning: signal the presence and nature of a hazard to all likely exposed to the danger. Recovery: return the system to safe status as soon as possible. Containment: to contain the spread or stop the escalation of the hazard. Escape: ensure evacuation of all potential victims after an accident.

6.3.5 Barriers in Software Systems

Leveson define barriers in the same way as MORT; although in a narrower sense. This is probably due to the difference between energy flow scenarios in MORT versus information flow scenarios in software systems. Three barrier types were described, lockout, lockin and interlock. Lockout “prevents someone or something from entering a dangerous area or state. Lockin “maintains a condition or preserves a system state.” Interlock “enforce correct sequencing or to isolate two events in time.” This approach is focused on the prevention of accidents rather than protection from them, i.e. preventing information robbery. This is natural – if you have a break in a software security system it is very difficult (impossible) to protect from the misuse of data. In energy rich systems it is off course also preferable not to have an accident, but the possibility of subsequent protection is at least conceivable.



Based on this the understanding of barriers have arguably broadened since the concept was first described by Haddon. Now, non-physical barriers are also taken into consideration.

6.3.6 Barrier systems and barrier functions I

After discussing different classifications and barrier definitions, [Hollnagel 2004] develops the following classification of barrier systems, divided into 4 classes of barrier systems:

6.3.6.1 Physical or material barrier systems.

Physical or material barrier systems are systems that physically prevent an action from happening or an event from taking place. Its purpose is to prevent the accident or contain and mitigate the consequences if an accident takes place. Since a physical barrier exists in the physical world, it can withstand forces up to a certain point. After reaching this point it will no longer be effective, such as for instance the armor on a battle tank. Physical barriers do not require to be detected or understood by the acting agent in order to work, and can thus be used against energy and materials as well as against people. The system corresponds to the physical barriers in the MORT approach.



Figure 11 Physical barrier system; walls and moat (wikipedia)

6.3.6.2 Functional barrier systems

Functional barrier systems works by hampering the action to be carried out. The systems define one or several pre-conditions that have to be met before an event can be initiated. These pre-conditions may be interpreted by humans or by technology. An example of this is a lock with a key or a password system, or the conditions that have to be met in order to initiate a strike with nuclear weapons.

The functional barrier system correspond to MORTs equipment design and supervision



Figure 12 Functional barrier system; coded lock (wikipedia)

categories.

6.3.6.3 Symbolic barrier systems

Symbolic barrier systems require active interpretation in order to work; an intelligent agent must interpret the barrier. Therefore, they do not actively stop an event from taking place, they warn the agent that something can happen. For instance, traffic lights will not work if people disrespect the coloring. This kind of barriers are everywhere humans live, such as warning signs, speed lights, warning devices, computer system warning etc. The difference between functional and symbolic barrier systems is thus that the



Figure 13 Symbolic barrier function; road sign (wikipedia)

functional barrier elements must be respected, since the system refuses to work if not whereas the symbolic barrier system can be ignored (at the peril of the ignorer and innocent bystanders).

6.3.6.4 Incorporeal barrier systems

An incorporeal barrier system has no physical form. It is dependent on the knowledge of the operator in order to fulfill its rationale. This barrier system is typically represented by a book or a memorandum that are not physically present at the time of their use. Examples include rules, guidelines, laws, safety principles and restrictions. (Operators usually do not read the procedures for an operation while performing it; drivers do not read road safety laws while driving etc) In the context of industry, these systems are usually the same as

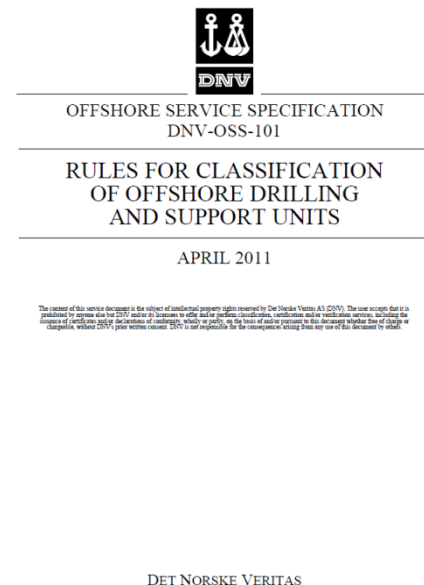


Figure 14 Incorporeal barrier system; DNV Rules for Classification (facsimile)

organizational barriers, that is to say imposed rules for operations set by the organization. Incorporeal barriers

correspond to MORT type of procedures and work processes, knowledge and skills.



A barrier function is defined as what the barrier system is supposed to achieve. It follows that different barrier systems can have the same barrier function, for example a physical road block and a red traffic light have the same barrier function, to stop traffic, but are different barrier systems, ie physical and symbolic. Systems can also be combined to achieve the same function.

6.3.7 Barrier systems and barrier functions II

[Sklet 2005] argues that no common definitions of barriers exists neither in literature nor in practice, and propose the following definition of barriers, barrier functions and barrier systems:

“Safety barriers are physical and/or non-physical means planned to prevent, control or mitigate undesired events or accidents.”

The physical means can be a simple thing as a hard hat or a gated wall, complex devices such as a Blow Out Preventer (BOP) or an Airborne Warning and Control System (AWACS) airplane. Non-physical means can include simple human actions, such as to observe traffic before crossing the road or observing warning signs, to entire socio-technical systems such as aircraft take off checklists and reporting or extensive safety training of offshore workers. “Planned to prevent” imply that the purpose of the means is to reduce or negate the risk involved in an activity, or reduce or negate the consequences of an accident.

“A barrier function is a function planned to prevent, control or mitigate undesired events or accidents.”

The barrier function is the definition of what a barrier is supposed to do to prevent, control or mitigate an accident or event. The barrier functions of (to name a few):

- a railway crossing bells is to warn drivers of a coming train
- an emergency stop button is to shut down equipment instantly
- a castle wall is for is to keep attackers outside the castle
- a hard hat to protect a workers head from falling objects

“A barrier system is a system that has been designed and implemented to perform one or more barrier functions.”

The barrier systems define how barrier functions are working. If the system is working, the functions are carried out. The barrier element is an individual part or a subsystem of the barrier system that alone is not enough to carry out the function. Examples of barrier systems are for instance the previously mentioned AWACS, railway control centers and gas/smoke detection systems. Barrier elements can for instance be the individual smoke detectors, the radar in an AWACS or the personnel in the railway control center. Barrier subsystems can exist of redundant elements, enabling the system to function even if every single barrier element are not functioning.

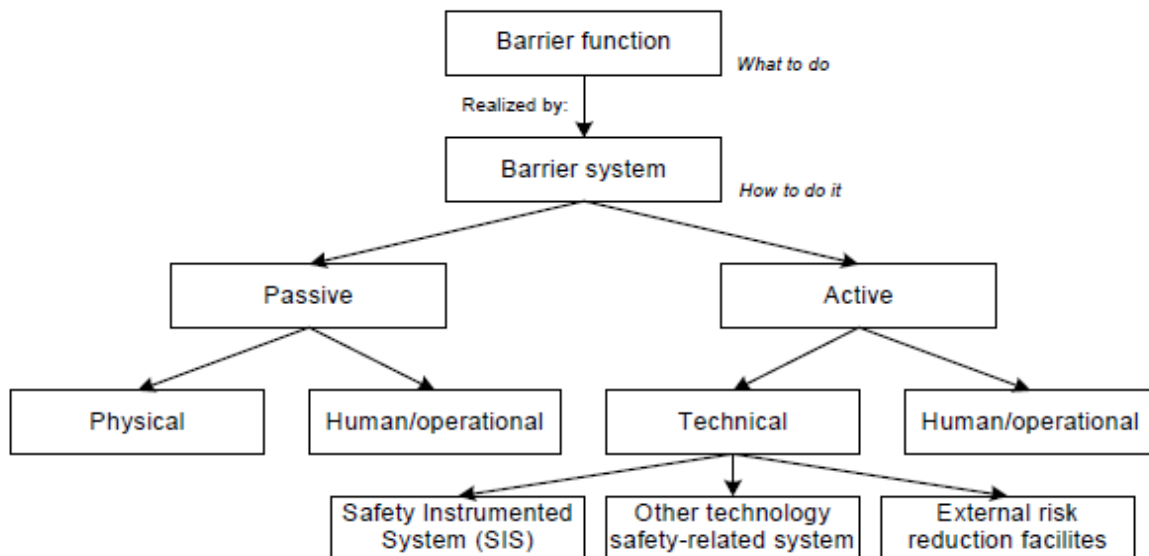


Figure 15 Safety Barrier Classification (Sklet 2005)

As seen from figure 14, several barrier classifications can be construed. The different classifications and their implications will be shortly presented in the following.

6.3.7.1 Passive Barrier, Physical

A physical passive barrier is the oldest form of barrier, for instance a wall. As mentioned, nothing actively has to happen in order for the passive physical barrier to work. It functions by being in place. These barriers include energy containment (tanks, pipes), firewalls, fences etc. Physical passive barriers may be permanent or temporal, for instance a permanent wall and a temporal obstruction around an open man hole cover.



6.3.7.2 Passive Barrier, Human/Operational

Human/operational passive barriers are for instance safety distances, entry restrictions etc. These may also be permanent or temporal, such as always keeping a fixed distance from revolving machinery or no entry to areas while dangerous activities are conducted.

6.3.7.3 Active Barrier, Technical

A Technical active barrier includes according to [Sklet 2005], Safety Instrumented Systems (SIS) that consist of a combination of sensors, logic solvers and final elements; such as fire and gas detector systems. Other technology safety-related systems are safety related systems based on other technologies than SIS; for instance mechanical systems such as relief valves etc. External Risk Reduction Facilities are systems and facilities are measures to reduce or mitigate the risk that separate from the two other systems, for instance firewalls and drain systems.

6.3.7.4 Active Barrier, Human/Operational

A human/operational active barrier may always be on or activated on demand. These barriers are often integrated in work processes, such as self-control of work or third party control of work. The barriers are in place to reveal failures and potential failures introduced by human activity.

A barrier system will typically consist of more than one type of barrier.

6.3.8 A barrier model to prevent hydrocarbon fires and explosions

[Rosness, et al, 2010] give a very interesting perspective on the energy-barrier concept. The presented model of barriers needed to prevent hydrocarbon leaks and ignition is developed and presented. It is briefly summarized in this section, while the criticism of barriers is presented in the next.

6.3.8.1 The model

Barrier systems are defined in terms of the previously mentioned barrier functions, elements and systems. The functional view is adopted; inviting analysts to think in terms of what tasks must be performed in order to control a potential hazard. The concept of barrier deterioration, and thus the need for barrier monitoring and maintenance, is presented.

After defining the barrier element (the what), needed to control a hazard, from the barrier function (the how), one can identify the complete set of functions that will constitute the

barrier system. It is stressed that since barriers are degradable open systems there is a need for maintenance. Physical and non-physical share this characteristic, since both a wall (a physical barrier) and safety instructions and procedures (non-physical) can be degraded in time, thus both needing to be maintained.

The defence-in-depth concept is presented, and list several barriers that must be in place in order to prevent hydrocarbon ignition. These are listed, since they are important and very relevant to the theme of this master thesis:

1. Process control (automatic or manual)
2. High quality containment
3. Gas detection and emergency shutdown
4. Isolation of ignition sources and ventilation
5. Fire detection and emergency shutdown
6. Area separation, fire/blast walls and passive fire protection
7. Active fire protection (deluge system, water cannons)
8. Provisions for escape and evacuation.

Reasons “Swiss Cheese Model” is presented, see figure 16 showing the defense in depth system with the barrier holes in the Swiss cheese model. Note that the last barrier, provisions for escape and evacuation, can also be a barrier to prevent ignition. This is due to the ignition because of tools used in gas filled areas or ignition due to static ignition, as well the need to keep people out from areas that may ignite without warning. The areas between

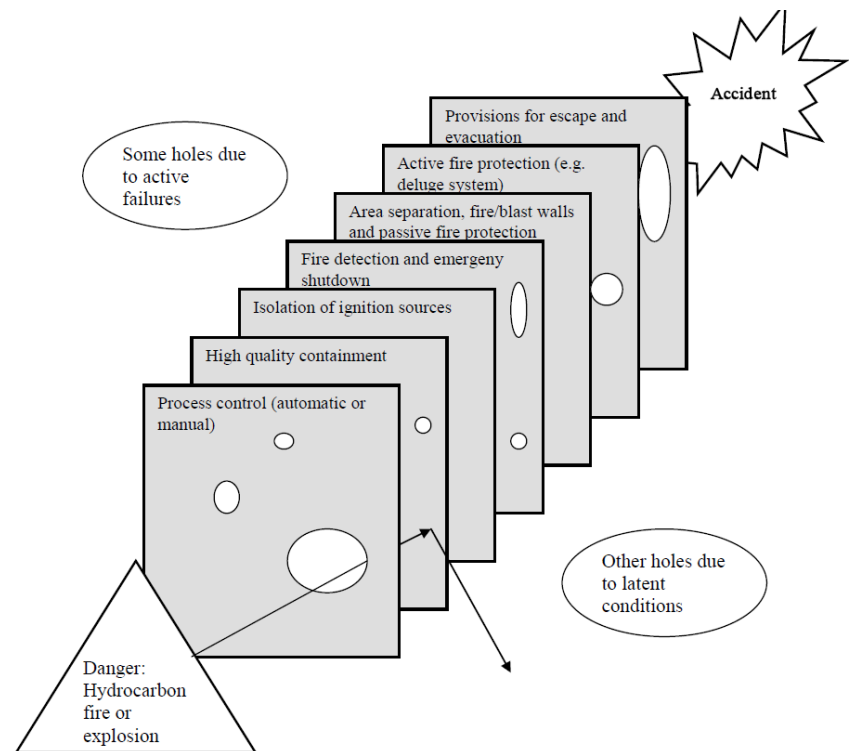


Figure 16 Defence in depth and Swiss cheese model (Rosness et al, 2010)



the barriers should also be considered as an accident, since one or several barriers have failed if events reach to this level by breaching the barriers.

The distinction between active and latent failures is presented based on Reasons definition. Active failures trigger unwanted events while latent failures do not trigger immediate failures but lie dormant in the design of a system and may contribute to a future accident.

Moreover, the point is made that barrier analysis is heavily used in the process industry as well as that the Quantitative Risk Analyses (QRA) used on the NCS models possible event chains following hydrocarbon leaks in the process area. However, even if the barriers are explicitly modeled, the underlying conditions are not.

6.3.8.2 Strengths and limitations of the barrier model

The strengths and limitations of barrier thinking are presented. The strengths include that barrier analysis

- Is very useful in identifying hazards
- Provides the basis for analytical risk control
- Makes it possible to contrive generic accident models
- Is very useful in the engineering and design phase

The limitations include that barrier analysis

- Is most relevant for centralized systems with well defined hazards such as oil platforms and nuclear power plants unlike air transport systems
- Has to have an energy transfer at its reason for an accident
- Does not include the factors that lead to a hydrocarbon leak (applicable to QRA on the NCS)
- May become a hindrance to safety if overdone (For example having too many procedures may lead to operators not following the important or any procedures)
- Can add to system complexity

Finally, five key questions for the applicability of barrier analysis is given as

1. Can the protection problem at hand be informed by the principle of energy transfer?
2. Is it possible to apply the three classes of protective measures?



3. Is it possible to analytically identify potentially dangerous sequences of events?
(successive failures)
4. Is it possible to apply technical or procedural barriers onto these sequences?
5. May barriers introduce new possibilities of risks and hazards or hazardous behavior?

6.3.9 Barriers in Quantitative Risk Analysis (QRA)

Barriers in Quantitative Risk Assessment

Barriers form an important part of QRA studies on the Norwegian Continental Shelf (NCS). [Vinnem 1999] establishes this, as well as the (above mentioned) definition of barriers: as a *“Measure which reduces the probability of realizing a hazard's potential for harm and its consequence. Barriers may be physical (materials, protective devices, shields, segregation etc.), or non-physical (procedures, inspection, training, drills).”*

Barrier analysis is an integral part of QRA studies. [Vinnem 1999] offers four major barrier types, these being: causation/threat barriers, consequence/mitigation barriers, technical (hardware) barriers and procedural barriers. No further information on the nature of these barrier types is given in this edition. [Vinnem 2007] expands the information on barriers and establishes the following barrier levels and definitions thereof:

- Barrier function: a function planned to prevent, control or mitigate accidents and unwanted events.
- Barrier system: Technical/human or organizational measures designed and implemented to perform one or more barrier functions
- Barrier element: a component of a barrier system that by itself is not sufficient to perform a barrier function
- Barrier influencing factor: factors that influence the performance of barrier systems

Furthermore, it is established that the Norwegian Petroleum Safety Authority (PSA) demands that the barriers reliability and availability, effectiveness and capacity and robustness be addressed in a QRA. Of these, the only aspect that depends heavily on operations is the first one. The second and third are mainly influenced by the engineering and design phase of a project.



The most important barrier functions required to prevent fire, explosions and fatalities due to hydrocarbon leaks are presented, see figure 17.

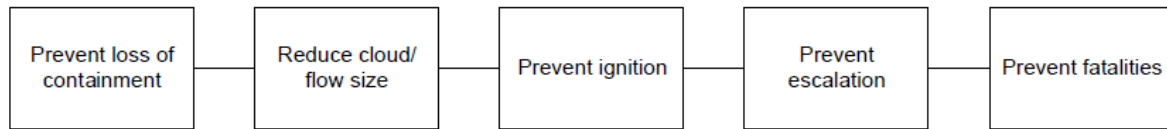


Figure 17 Barriers to prevent hydrocarbon ignition (Vinnem 2007)

This is presented as it is directly applicable to the Deepwater Horizon accident.

As the definitions and explanation correspond closely with [Hollnagel 2004] and [Sklet 2005], no further presentation is deemed necessary at this point.

6.4 Barrier classification chosen

In the previous chapter, the history of the barrier concept has been presented, from single barriers to defense in depth. For this thesis, the definition provided by [Sklet 2005] will be used. This is because it is easy to understand and provide a good model of barriers. It would have been possible to use [Hollnagel 2004] as well, as the concepts mentioned in these two definitions are quite similar.

7 Barriers at Macondo

The event chain for the accident onboard Deepwater Horizon has been established by several reports, for instance the National Commissions Report to the President, the Chief Council report and BPs own accident investigation report. These reports have been the basis for the accident description in chapter 3. [BP 2010] report focus on barrier breaches, it will therefore serve as a convenient source of information regarding the accident in terms of barriers in this chapter.

7.1 Broken Barriers as identified by BP

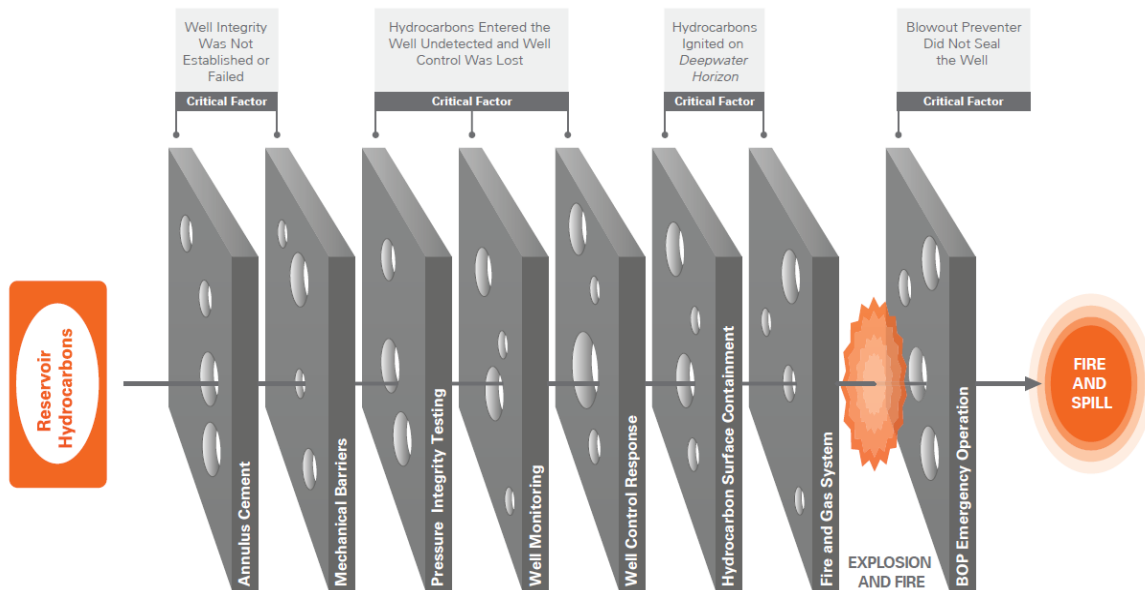


Figure 18 Barriers identified as broken at Macondo (BP)

The 8 key findings of [BP 2010] are related to barriers and breaches of barriers, it identifies 8 critical barriers that was broken on the Deepwater Horizon, see figure 18.

In the following the barriers identified will be classified and according to [Sklet 2005]`s classification of barriers, as described in chapter 6.

7.1.1 Annulus cement job

The barrier function of the annulus cement is to prevent hydrocarbons from flowing into the annulus space or into the production casing. It is a physical, fixed barrier. As such, when installed it is a passive barrier, it does not need any action taken to be able to work as intended – if properly installed.



7.1.2 Mechanical Barriers down hole

The barrier function of the down hole mechanical barriers is to prevent hydrocarbons from entering the production casing. The barriers referred to here are downhole valves and the cement filled into the shoe track casing. Both are physical barriers. The cement is a fixed and passive barrier, while the valves are physical active barriers, since they need to be actively converted from two way flow to one way flow and, when converted, is activated by flow in the wrong direction.

7.1.3 Pressure Integrity testing

The barrier function of the pressure integrity testing is to ensure that the casing is not leaking and that there is no influx of hydrocarbons into the annulus or the production casing. The pressure integrity testing is a non-physical human/operational barrier. It can be argued to be passive, since it is able to prevent accidents just by being in place. As a procedural system it should make the workers aware of any non-conform results. If it actively makes them aware, it is arguably an active system. However, the test results are supposed to be identified as acceptable or non-acceptable by human operators, thus making it a passive barrier.

7.1.4 Well Monitoring

The barrier function of the well monitoring is to enable the crew to identify uncontrolled influx of hydrocarbons into the well and to monitor the well conditions continuously. Well Monitoring is a non-physical human/operational barrier. As with the integrity testing it can be argued to be both passive and active. Since the system relies on human interpretation of data from several data points it will be classified as passive. None of the systems actively warned the operators that something was wrong with the well; the operators had to interpret the monitoring results themselves.

7.1.5 Well Control Response

The barrier function of the well control response is to enable the crew to regain control of the well. The well control response when control of the well has been lost is a non-physical human/operational barrier. Whether it is active or passive is hard to determine, since procedures can be implemented actively, that is as information becomes available the response is conditioned to fit the information. However, it seems that the response was not fitted to information, thus making it passive. It also seems that mistakes made in the well



control operation actively increased the risk of the operation, especially in the decision not to divert the gas directly overboard.

7.1.6 Hydrocarbon surface containment

The barrier function of the hydrocarbon surface containment barrier is to remove hydrocarbons from the rig, either by separation and discharge or by emergency discharge directly overboard. The hydrocarbon response containment barrier is the Mud Gas Separator (MGS) or the diverter lines. The crew must decide which to use, however the MGS is not designed to handle a high flow scenario like the one the Deepwater Horizon experienced. Transocean's own protocols did not address how to handle such a scenario. Both the MGS and the overboard diverter lines are active technical barriers; it must be decided to use them. The procedures for their use are supposed to be passive human/operational barriers. If it had been decided to use the diverter lines it is probable that most of the gas would have been safely vented overboard, thus minimizing the risk of ignition and the spill that occurred afterwards.

7.1.7 Fire And Gas System

The barrier function of the fire and gas system is to identify fires and gas leaks, and to take appropriate action when a leak or a fire occurs. The fire and gas system, i.e. the gas detection systems and shut down systems are active technical barriers. It can be classified as a Safety Instrumented System (SIS) that based on input from sensors take appropriate actions, such as to close air ventilation intakes and air conditioning systems. Unfortunately, the system did not have control of air vents to the engines onboard the Deepwater Horizon; this was human controlled due to the dangers associated with a total blackout during drilling operations.

7.1.8 BOP Emergency Operation

The barrier function of the BOP is to close the uncontrolled flow of hydrocarbons from a well out of control. The BOP is the final line of defense against oil spills. It is an active technical barrier. In order for it to perform its function it must be activated. It can be activated either from the rig, or, in special circumstances it will activate on its own. These special circumstances include loss of communication with rig. The emergency operation of the BOP can be accomplished by use of its own internal power or by activation via ROV. On the NCS BOPs can also be activated acoustically.





8 How would IO and Barriers influence the Macondo blowout?

The basis of this discussion is the all the previous chapters, except chapter 5 which deals directly with the GFC accident.. The following chapter will be structured around barrier breaches. It will be discussed how IO and the two generations of IWPs could have influenced the outcome of each barrier breach and decisions taken in the course of events. This is done in order to, in the next chapter, be able to identify what lessons for IO can be learnt from Macondo.

In order to discuss how IO and new IWPs would influence the Macondo blowout, a classification of the barriers broken at Macondo will be done. Also, a discussion of the relevance of IO and IWPs to the barrier in question was done. This is done in the following chapters. A summary can be seen in table 1 at the end of the chapter.

8.1 Negative and positive effects of IO and IWPs in general

In the following section a discussion of what negative and positive effects IO and IWPs have on barriers in general will be laid out. The discussion is based on the data given in chapter 4 and 6, and is as meant as an indication. The discussion will be structured around [Sklet 2005]'s classification of barriers.

8.1.1 Effects on passive physical barriers

The negative effects on passive physical barriers are thought to be few or non-existent. This is because IO and IWPs do not influence these barriers in such a way as to be able to cause negative effects. No organizational change will change the barrier function of a wall to any extent.

The positive effects on passive physical barriers will be many. This is due to the increased focus on Condition Based Monitoring. If for example a pipeline or a protective wall is hit by aggressive corrosion, the liberal use of CBM will be very helpful in the detection of this condition, thus leading to maintenance of the barrier in question. Increased cooperation between disciplines will probably lead to better control of maintenance and communication of problems to be checked and rectified.



8.1.2 Effects on passive human/operational barriers

The negative effects on passive human/operational barriers are considered to be few or non-existent. This is due to the fact that these barriers will not change because of IO and IWPs; their use will stay the same.

The positive effect on passive human/operational barriers are considered to be few but detectable. This is due to the greater flow of information caused by IO and IWPs. Information on possible dangers will influence the use of these barriers, maybe especially the temporal ones.

8.1.3 Effects on active human/operational barriers

The negative effects on active human/operational barriers are considered to be few, but not non-existent. These barriers include self control or third party control of work. It is possible to imagine a contractor being pushed to certify substandard work, either by internal pressure or from external pressure. It is also possible that if everybody has the same information, the assumption can be made that since everybody knows and nobody has reacted the problem is not a problem. However, the situation probably is the same today. It is important to have clearly defined responsibilities, but also openness to questioning from other disciplines.

The positive effects on active human/operational barriers are considered to be few but substantial. If free flow of information is achieved there are many more eyes that can detect possible errors. In addition to this, if procedures are known to everyone, breaches of procedure can possibly be detected by more people.

8.1.4 Effects on active technical barriers

Negative effects are considered to be a few but important ones. Active technical barriers that actively monitor a process (i.e. SIS) will multiply, thus creating a large amount of data for the operators. If the system itself cannot handle the data, a probability that operators will have too many alarms to handle will exist (information overload). This should be eliminated in the design and testing of these systems. Mechanical systems will stay the same, but be monitored. This can also lead to more alarms. Other systems will not be influenced. The biggest negative effect that can be construed is the dependency of operators on data systems that themselves can fail. If some or all systems go down operators will be hard pressed to do all readings and acts required to safely shut down a process, especially if they have been down sized and at the



same time heavily dependent on these systems without training in what to do if they disappear.

Positive effects are considered to be very many. The increased monitoring of processes (SIS) and of mechanical systems will give operators more data to base their acts on. It will also give more people the information, thus increasing the detection probability if anything anomalous happens. The automation of well monitoring will be especially welcome, as the data can be confusing to a human. However, this does not eliminate the human monitoring, but if properly designed and implemented it will probably decrease the kick detection time significantly.

8.2 Annulus Cement Job Barrier

The Annulus Cement Job barrier is considered to be of the barrier type Passive Physical Barrier when it is installed. This is because it is passive, i.e. a wall, in the well. No action is needed for it to work when it is installed properly. However, the evidence shows conclusively that it could not have been installed properly, since hydrocarbons could flow through the well. This means that the barriers in place to prevent a bad cementing job to a) happen and b) remain undetected also failed. These barriers include the planning, execution and confirmation of the cement job, as mentioned by [BP 2010]. These barriers will be of several classifications. However, when it comes directly to the evaluation and testing of whether or not the annulus cement barrier was functioning, it is probable that having a greater number of people involved in evaluating the test results would increase the chances of detecting faults in the cement. It is also worth mentioning that if all parties could communicate before, during and after the job the contractor (in this case Halliburton) would have to present cement testing results prior to the cement job was done. With automated systems for well monitoring, the chance that the cement barrier was flawed and the flaw was not detected could be minimized or eliminated. Since more information will be available in real time, and drilling is to be supported by Virtual Reality, onshore support centers can monitor the well completion process in real time and utilize expertise in an efficient manner, acting on advice from automated monitoring systems. The effects of new IWPs would be positive to the planning execution and testing of the annular cement job, as it would enable information sharing between experts as well as automated real time monitoring of the job. If anomalies in the execution was detected, it is probable that this would be noticed and action taken. The effect of IO and new IWPs are because of this estimated to be medium to high.



8.3 Mechanical Barriers Down Hole

The mechanical barriers down hole are active technical barriers of the other safety related system type, in this case mechanical. In order to function, they must first be activated – that is converted from two-way to one-way valves. When this is done, they stay active technical barriers. The action needed for them to function is flow in the wrong direction. If there is flow in the wrong direction, the valves are supposed to shut in the well by closing. The mechanical barriers down hole, i.e. the valves, did not function properly. If they had, the well control would not have been lost, since no hydrocarbons could enter the production casing. This means that either the valves were not converted or they did not function properly when converted. The anomalies detected when the conversion was in progress can be a sign that either the valves did not convert or that they were faulty. The pressurizing done to convert the valves was five times the required pressure. It is possible that this could have damaged the valves, but this is rather unlikely. However, the conclusion that the pressure gauge was broken and that the valves had converted must be seen as an act of faith, not fact.

Now, the effect of IWPs on the mechanical barriers down hole is considered to be that the evaluation of the installation job would be better. If real time monitoring of the well include sensors that detect whether or not the valves have converted, the probability of not detecting an erroneous installation would be minimized or eliminated. If it does not include this, automated real time monitoring would have to make the drilling crew (onshore or offshore) aware of the anomalies and present them with one or several logical explanations. Due to this, the effect of IO and especially the new IWPs are estimated to be medium to high on the testing side. On the conversion of the valves, the same judgment would apply

8.4 Pressure Integrity Testing Barriers

The pressure integrity testing barriers include two tests, namely the positive pressure test and the negative pressure test. The tests will be classified as active human/operational barriers, since they are part of well completion procedures and regulations. The barrier is not always active, but activated on demand.

The positive test tests whether the production casing can hold an overpressure; that is whether the casing can withstand the pressure when producing without leaks. The negative pressure test produces an underpressure in the casing. When underpressure is established, the well is bled off and monitored for increase in pressure. Increases in pressure indicate flow into the



well, thus informing the operators that there must be influx of material, most likely pressurized hydrocarbons, into the casing. This means that the barriers in place to prevent this are not working.

The positive pressure test was conducted and the conclusion was that the casing held the overpressure. No anomalies were detected in the process. The effect of IO and IWPs on the positive pressure test can be considered minimal, however, with increased well monitoring capabilities the risk of making the wrong conclusion could be made smaller.

The negative pressure test was conducted three times. Each time the result was increased pressure in the well over time. The operators interpreted this as a bladder effect, that is that the mud in the riser was exerting weight on the annular preventer, causing faulty readings. This was a crucial mistake. The negative pressure test showed conclusively that there was influx of hydrocarbons into the well and that the first two barriers had failed. The interpretation of the results was wrong, and it can be said to be one of the biggest factors that caused the accident, if not the single biggest.

If real time monitoring had been in place it is probable that the problems would be discovered and action taken to detect what caused it. Furthermore, if automated monitoring systems had the same data the systems would probably also give warnings. Moreover, if down hole pressure monitoring had been in place, the influx of hydrocarbons could probably not go undetected. Last, the results would be monitored by drilling and geology experts onshore. They would presumably not make the same mistake.

Due to the above, the effect of IO and IWPs on this barrier is estimated to be high to very high.

8.5 Well Monitoring Barrier

The well monitoring will be classified as active human/operational barriers, since they are part of well completion procedures and regulations.

Well Monitoring is the process of continuous monitoring of several well indicators by a driller. These include monitoring of: volume of mud in the active pits (should not increase), mud volume in and out of the well (should be equal), visual flow checks (mud should stop flowing when mud pumps are turned off), drill pipe pressure monitoring (drill pipe pressure should not increase).



It is obvious that these tasks are quite complicated. Even more, the drillers on the Deepwater Horizon was doing more than one thing at once. For example, it is unclear whether they could monitor the volume of mud in the active pits and the volume in and out of the well. These are the primary indicators of a kick in progress, while the others are secondary indicators used to confirm the primary ones.

The evidence from logged data from the Deepwater Horizon indicates that a kick was in progress as early as 21:01, about 45 minutes before the blow out was a fact. The crew did not notice. Further logs show that very clear evidence of a kick in progress was logged at 21:14. The crew either ignored this or did not notice.

It is very clear from this, that if real time monitoring of this data (that already was sent to shore, but not actively monitored) had been in place, the chances of identifying the kick would be much higher. If smart monitoring systems had been in place and registered this data, alarms and warnings would have been given at a much earlier time. At the time of the accident, the annular preventer was closed by the crew, but it was too late. Gas was already present in the riser. The effect of automatic well monitoring and monitoring systems in this case should not be underestimated, since this situation is exactly what they would be designed to handle. Well Monitoring by human senses could very well be strengthened and superseded by automatic monitoring systems. It is also probable that the indicators would be noticed by a onshore control center crew if they had used the real time well monitoring data that was available, but unfortunately not used.. Therefore, the effect of IO and IWPs on the well monitoring barrier is estimated to be very high.

8.6 Well Control Response Barrier

The well control response barrier is the last barrier before hydrocarbons will be present topside. It involves closing the BOP's annular preventer to stop the well from blowing out. It hinges on the operators ability to discover a kick or loss of well control incident as early as possible. The BOP's annular preventer has to be activated by the operators, and is as such defined as a active technical barrier of the mechanical type. Unfortunately, the crew did have very little time to react. Also, the training and procedures for this action was inadequate. The annular preventer was closed at 21:41, but this was too late. Gas was present in the riser. Evidence also suggests that the annular preventer, when closed, did not stop the flow of hydrocarbons. From these facts it is possible to infer that a) if there had been automated



systems for this situation the crew would have been warned earlier, giving them more time to react and b) that if they had more time to react it is possible that closing the annular preventer before gas was present in the riser **could** have stopped the blowout. From the above the conclusion is that IO and IWPs would have a medium to high effect on the well control response barrier.

8.7 Hydrocarbon Surface Containment Barrier

The Hydrocarbon Surface Containment Barrier is the diverter system and the Mud Gas Separator (MGS) system. The crew chooses which one to use. Thus, the hydrocarbon surface containment barrier is an active technical barrier of the mechanical kind. The diverter system diverts the flow of mud and hydrocarbons directly overboard, while the MGS separates the gas from the mud. The crew must choose which system to use in case of a blowout. The MGS is not designed to handle large amounts of mud and gas. The flow of gas and mud from the well was high, but it was still diverted to the MGS. This was quickly overwhelmed by the flow, and gas started to flow onto the Deepwater Horizons deck and mud spewed out of the rotary. At this point, ignition was very probable. If there was automated systems that decided or advised the crew on which of the systems to use, it is probable that a switch to or the initial use of the the diverter system would have ensued. However, this is not certain, since the operators had little time in which to react (6-9 minutes). Since the operators had closed the annular preventer they would probably think that even if gas was present on the rig (serious) it would stop flowing shortly. The conclusion drawn from this is that IO and IWPs would have little to medium effect on the hydrocarbon surface containment barrier.

8.8 Fire And Gas System Barrier

The Fire and Gas System barrier is the automated fire and gas detection system. It is an active technical barrier and a Safety Instrumented System (SIS). In case of gas on the deck it would shut down ventilation systems etc, but not the ventilations to the engines. This had to be authorized manually. The fire system would detect fire and start the water deluge systems onboard in order to quench the fire. This barrier did work, and stopped gas from flowing into accommodation. It did not stop it from flowing into the engine rooms and into the engines air intakes. This led the engines to uncontrollably overspeed, causing a spike in the electricity supply. If the engines themselves did not ignite the gas, the spike would cause sparks in the system (for instance by blowing out light fixtures) that surely would ignite it. At this time, the



deluge system would try to quench the fire. Since there was an endless supply of fuel for the fire, the fire system proved inadequate for the task. The effect of IO and IWPs on the fire and gas system would be minimal to non-existent. If any effect, it would probably be in the automated shut down of engine ventilation, but this is uncertain since it has consequences for the safety of a vessel operating by Dynamic Positioning (DP).

8.9 BOP Emergency Operation Barrier

The BOP Emergency Operation Barrier is two things. First the Emergency Disconnect Sequence (EDS) switch, that if activated activate the BOP's preventers and shear rams. Secondly, there is also a deadman switch that operates the BOPs preventers and shear rams if communication with the rig was lost, basically activating the EDS.

The BOP Emergency Operation Barrier is considered to be an active technical barrier. Whether it is a SIS or an other technology safety related system depends on how it is activated. If activated by loss of communication it is the first, if activated by pushing the EDS button it is the former. It can also be defined as a blend of the two. According to eye witnesses the EDS sequence was attempted activated. Evidence suggests that the communication with the BOP and the Lower Marine Riser Package (LMRP) was lost in the explosion, and that the activation from the rig did not happen. At this time, the BOP's control pods should have activated the BOP's shear rams and annular preventers. The evidence suggests that it did not.

Now, if IO and IWPs had been in place at this stage there it would not at all influence the severed communication, hence it would not be able to activate the EDS from the rig. There is a probability that if active monitoring systems had been in use it could autonomously have triggered the EDS from the rig at the time of the first explosion, but the effect of this is uncertain since the communication could have been destroyed at the same time. The effect of IO and IWPs on the topside activation of the EDS sequence is thus considered to be non-existent to minimal.

Nevertheless, the effects of IO and IWPs on the activation of the BOP triggered by the loss of communication events are very different. If the BOPs technical state had been monitored by use of Condition Based Monitoring systems, the chance of malfunction of both control pods would have been minimal to non-existent. The evidence from the examination of the BOP (as wells as the spill) tells that it was unable to shut in the well when it was activated by ROV. To speculate, it is possible that if the control pods had worked, the hydraulics could have been



able to shut in the well at an earlier time. The effect of IO and IWPs on the activation of the BOP by the pods is thus considered to be high or very high.

8.10 Summary of effects of IO and IWPs on the Deepwater Horizon broken barriers.

A summary of the findings in the previous chapter has been laid out in table 1 below. In short, the findings are positive and encourage the implementation of IO and IWPs. The effects are to a large extent connected to increased monitoring capabilities, increased communication and information sharing, increased use of smart systems and increased use of CBM.



Barrier	Barrier classification	IO and IWP relevance	Comments
Annulus Cement Job	Passive Physical Barrier	Medium to High	Barrier installation faulty. Not detected.
Mechanical Barriers Down Hole	Active Technical Barrier, Other safety related system	Medium to High	Barrier installation prob. faulty. Not detected.
Pressure Integrity Testing	Active Human/Operational Barrier	High to Very High	Test results misunderstood/ignored.
Well Monitoring	Active Human/Operational Barrier	Very High	Crew not able to monitor due to influence from other work processes.
Well Control Response	Active Human Operational Barrier AND Active Technical safety related system, mechanical	Medium to High	Crew must identify loss of control. Did, but too late. BOP AP did not shut in the well.
Hydrocarbon Surface Containment	Active Technical safety related system, mechanical	Low to Medium	Crew chose wrong diverter system. Gas on deck as a direct result.
Fire and Gas System	Active Technical Safety Instrumented System (SIS) Barrier	None to Very Low	Automated system. Needs some human input. Worked, but was inadequate.
BOP Emergency Operation	Active human/operational and technical barrier	Topside EDS: None to Very Low Pod activation: High to Very High	EDS: severed comm. made topside EDS impossible. Pods: lack in maintenance led to BOP not activated.

Table 1 Summary of effects



9 What lessons can be learnt from Macondo for IO?

As shown in chapter 8, IO and IWPs would have influenced the course of events at Macondo 252 quite a lot. In this chapter, the lessons from Macondo as applicable to Integrated Operations will be discussed and presented. The discussion will be structured around the idea that the events at Macondo was an example of how events are influenced by the actions or non-actions taken by the people and organizations involved.

From chapter 2, 3 and 8 we know what is considered to be the underlying cause of the Macondo blowout. That the barrier system established to prevent blow out and ignition of gas failed is the direct cause. The underlying cause, however, is not technical but organizational. To again quote from [Bartlit et al, 2011]:

“What the investigation makes clear, above all else, is that management failure, not mechanical failings, were the ultimate source of the disaster. In clear, precise, and unflinching detail this Report lays out the confusion, lack of communication, disorganization, and attention to crucial safety issues and test results that led to the deaths of 11 men and the largest offshore spill in our nation's history.” (Italics added.)

To recap, the effects on IO and IWPs on the Deepwater Horizon Accident are considered to be many. It is also clear that the influence of IO and IWPs is heaviest on systems in which there is human-human or human-technology interaction.

In the following, the most important lessons identified will be laid out and discussed. Recommendations for IO and IWPs will be made in each section.

9.1 Lesson 1: Barrier evaluation

It is clear that the evaluation of the barrier installation was flawed. Two things happened here, namely the failure to produce a test that showed that the cement design was good and the failure to ask questions when the production valves proved difficult to convert and the anomalies detected here. The lesson learned here must be that the operator has a responsibility to check results on equipment tests. Reciprocally, the manufacturer should off course not tamper with test procedures in order to gain acceptance. IO involves a lot of trust between supplier and operator, but also implementation of checks and balances in the IO process. The recommendation is to develop standard procedures for testing, and that all deviations from this testing must be pointed out to the operator. The anomalies detected with the conversion of



the production valves were not discussed to any extent. It is not certain that this affected the accident to any large extent, but it also shows that no clear routines for handling such anomalies were present. IO must equip operators to handle anomalies in a efficient manner that do not dismiss them as irrelevant. The recommendation is to look into automatic reporting of anomalies in the process, so that these data follows the well in its lifetime. If it is uncertain whether or not something is wrong this should be noted, making it possible for either people (not likely) or data systems (more likely) to “connect the dots” later in the process.

9.2 Lesson 2: Test result evaluation

It is clear that the evaluation of the negative pressure test was flawed if not degraded. It seems that the readiness to accept anything other than the usual test results were low to non-existing, thus negating the entire objective of the test. The lesson learned must be that if the test results are not satisfactory there is usually a reason for this, and probably one the operator would not like (!). IO must establish routines for this. If the tests are to have any function, the results must be taken seriously. The recommendation is to develop systems that can recognize the results and predict the reasons. Humans are notoriously prone to wishful thinking, computers are not.

9.3 Lesson 3: Disaster scenario training

Transocean’s disaster scenario training proved inadequate for the events at Macondo. The operators did not have the experience or familiarity with the situation that could have mitigated the events, especially in relation to the diverter system. The lesson learned is twofold. First, adequate training is paramount to the handling of developing events. Second, technology can sometimes be a hindrance to safety. The recommendation is that IO should strive to keep the operators trained to handle unexpected scenarios, and also an automated switching solution for the diverter system should be considered developed.

9.4 Lesson 4: Equipment Maintenance

It is clear that the maintenance of the BOP was incomplete. Furthermore, Transocean’s IT based maintenance system was difficult to use and understand. Better monitoring of the BOP’s condition could possibly have stopped the blowout. The lessons learned is that maintenance of crucial safety equipment must be done at regular intervals (complying with regulations is a minimum requirement). Testing of such equipment must also be done



regularly. The recommendations for IO are to develop CBM systems for such systems where applicable and also develop a testing regime for the same equipment type. Regarding maintenance IT systems, they should be standardized to the extent possible and operators trained in their use.

9.5 Lesson 5: Data monitoring

The data monitoring at Macondo consistently failed. This is one of the main reasons for many of the barrier breaches that led to the accident. The lesson is that monitoring of data, especially if one has many data points to monitor, is difficult for humans. It is also worth mentioning that other work performed can (and probably did) interfere with the processes monitored, making it difficult to detect problems. The recommendation for IO is to develop automated data monitoring systems that alert the operator if it detects problems. It is also recommended to monitor the data in real time at two or more independent places, such as both offshore and at onshore monitoring centers. This will reduce the possibility of ignoring or misunderstanding the data.

9.6 Lesson 6: Safety Culture

In general, many of the mistakes (or shortcuts) made are not consistent with a healthy safety culture. This may be the most important challenge and lesson from Macondo. In the author's opinion, the Macondo accident unfortunately demonstrates that safety was not coming first at Macondo. Profits were. The problem with this is that in an effort to save some tens of millions dollars, the companies involved managed to spend some tens of billions instead. The lesson learned from this is that an unhealthy safety culture (cowboy mentality) can become a very costly way of doing business. The recommendations for IO must be to save money through more efficient operations without interfering with safety. In fact, increased or unchanged safety levels should be the goal for all implementations of IO.

9.7 Lesson 8: Challenges in geographically distributed teams

This lesson can also be derived from the Macondo accident. It is very clear from the GFC accident and from the literature on IO that a main challenge is to make operators onshore and offshore feel that they are on the same team, not on opposing sides. The GFC accident clearly illustrates this, as the operators offshore did not like the operators onshore, thus making them reluctant or unwilling to seek help and advice from onshore. From Macondo it is possible to see that the organization had problems with overall communication, and that this in many



ways laid the foundation for the accident. The lesson learned is that in order for IO to work at all, teams and team members must understand that they are on the same side and also accept decisions and input from operators from other places. The challenge is to be able to question these decisions when needed, but accept them when they are sound. The recommendation for IO is to focus on cooperation between different geographic places. Rotating operators' onshore-offshore may be a solution to this.

9.8 Lesson 7: Challenges due to use of software and communication

This point is made to all implementations of IO, but is not directly related to Macondo. It seems that IO will depend heavily on computers and software systems for these, and on long distance instantaneous communications. Any person with some computer experience will know that crashes are quite common. The operators of sophisticated monitoring systems will be in big trouble if some or all software disappears, that is stops working. The loss of communication with onshore experts in the middle of a delicate drilling operation also has the potential to become dangerous. However, these problems can be minimized or mitigated by in the first case using duplicate or triplicate systems, as for instance Dynamic Positioning systems do. All out crashes will then become uncommon. In the second case, a loss of communication event, the systems onboard a vessel should be designed to handle this; and be able to shut down the operation safely on its own or continue the operation with the offshore operators. Last, operators both offshore and onshore should be regularly trained to handle such scenarios, for instance in simulations.

9.9 Summary of lessons learned

A summary of the findings in this chapter has been laid out in table 2 below. The lessons are general and connected to the accident as it happened, and to the general challenges expected to come from the use of Integrated Operations. The lessons can be summed up to include more automation systems, standardizing of test evaluations, standardizing IT equipment and encourage cooperation in distributed teams.



Lesson Learned	Mitigating Measures
Barrier evaluation process inadequate	<ul style="list-style-type: none"> - IO process checks and balances - Standardized testing of equipment - Efficient handling of anomalies
Test Result evaluation inadequate	<ul style="list-style-type: none"> - Test result evaluation standardized - Automated evaluation systems
Disaster Scenario Training inadequate	<ul style="list-style-type: none"> - Train operators to handle unexpected events - Automate the diverter system (will also apply to other safety systems)
Equipment Maintenance inadequate	<ul style="list-style-type: none"> - Develop CBM routines for safety equipment - Standardize IT Maintenance systems
Data Monitoring inadequate	<ul style="list-style-type: none"> - Develop automated monitoring systems - Real time data monitoring at two or more places
Safety Culture inadequate	<ul style="list-style-type: none"> - IO should increase the efficiency of operations in ways not interfering with safety - Increased or unchanged safety levels should be the goal of all implementations of IO
Challenges due to Distributed Teams	<ul style="list-style-type: none"> - Rotating operators onshore-offshore to facilitate cooperation - Focus on cooperation between onshore and offshore organization - Focus on accepting decisions made, but make clear that questioning is welcome.
Software and communication challenges in IO	<ul style="list-style-type: none"> - Duplicated or triplicated software systems (redundancy, as in DP systems) - Software designed to handle loss of communications - Operators trained to handle loss of communications

Table 2 Summary of lessons learned





10 Conclusion

It is the authors' opinion that the Deepwater Horizon accident on April 20th 2010, as well as the close call at Gullfaks C less than a month later, would have been avoided if Integrated Operations had been in place. However, this is based on the ideal implementation of Integrated Operations. The world, it seems, is not ideal. Based on this, Integrated Operations is not a "magic bullet" that will solve all safety issues. Prudence is required in implementing Integrated Operations, and as with all organizational changes, it can cause new safety issues, as for instance the increased interdependability onshore-offshore and the high dependability on software.

Nevertheless, it is the authors' opinion that Integrated Operations holds significant promise for the future on the Norwegian Continental Shelf as well as worldwide. The new working processes can significantly alter the working environment, and must therefore be thoroughly investigated for any unwanted effects. The investigation done in this Master Thesis highlights some areas for this, based on the accident at Deepwater Horizon. The goal of Integrated Operations must be to strengthen barriers and introduce new ones at the same time as it should make operations more efficient, and seek to optimize the production of oil and gas. In general, Integrated Operations should strive to enhance cooperation and facilitate decision making in the processes involved in offshore oil production.





11 Further Work

For further work it is suggested to explore quantitatively the possibilities for risk reduction by using Integrated Operations. It is also suggested to develop the risk models so that the risks added by using software is included and investigated.

In addition to this, it is recommended to investigate how the use of Integrated Operations up till now has influenced the risk picture, and how it is perceived by operators onshore and offshore. Based on the conclusion there is a reward in using Integrated Operations. Figuring out what is best practice for implementing Integrated Operations would also be of value.





12 References

Please note: all electronic references have been accessed before June 16th 2011.

D. Adams, 1993. *Mostly Harmless (Hitch-Hikers Guide to the Galaxy, No. 5)*. London: Pan Books.

Associated Press, May 16 2010. *Oil rig inspections fell short of guidelines* - Kingsport Times-News Online.. [ONLINE] Available at: <http://www.timesnews.net/article.php?id=9023118>. [Accessed 16 June 2011].

F.H. Bartlit Jr. et al, 2011a. *Macondo: The Gulf Oil Disaster*. Chief Councils Report. National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling

BP, 2010. Deepwater Horizon: Accident Investigation Report. Available online: http://www.bp.com/liveassets/bp_internet/globalbp/globalbp_uk_english/incident_response/S_TAGING/local_assets/downloads_pdfs/Deepwater_Horizon_Accident_Investigation_Report.pdf [Accessed June 16 2011]

US Coast Guard, 21 April 2010. *Deepwater Horizon on fire*. (Image used) [ONLINE] Available at: http://cgvi.uscg.mil/media/main.php?g2_itemId=836285 [Accessed 16 June 2011]

P.K. Fonn, 2009. Risikohåndtering i integrerte operasjoner i petroleumsindustrien. Master Thesis. Trondheim: NTNU. Available at: http://www.sintef.no/project/RIO/Master%20thesis/Masteroppgave_100609_Fonn.PDF [Accessed June 16 2011]

B. Graham et al, 2011. *Deep Water: The Gulf Oil Disaster and the Future of Offshore Drilling*. National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling.

W. Haddon Jr, 1973. *Energy damage and the 10 countermeasure strategies*. Journal of Trauma, 13, 1973. Reproduced in Injury Prevention 1, 1995.

E. Hollnagel, 2004. *Barriers and Accident Prevention*. Aldershot, UK: Ashgate

J.P. Liyanage, 2008. Integrated e-Operations-e-Maintenance: Applications in North Sea Offshore Assets. In: K. A. H. Kobbacy and D. N. P. Murthy (editors), 2008. Complex System Maintenance Handbook, Springer Series in Reliability Engineering, Part F, 585-609.



Available [ONLINE]: <http://www.springerlink.com/content/j8633242775v1366/> [Accessed June 16 2011]

MarineLog, 2009. *Transocean sets deepwater drilling depth record*. September 2 2009.
Available at: <http://www.marinelog.com/DOCS/NEWSMMIX/2009sep00021.html>.
[Accessed 16 June 2011].

Maritimt Magasin, November 10 2009. *Aker Spitsbergen - En norsk riggekjempe*. Image used)
[ONLINE] Available at: <http://maritimt.com/nyheter/2009/aker-spitsbergen-en-norsk-riggkjempe.html> [Accessed 16 June 2011].

Det Norske Veritas, 2011. *Rules for Classification of Ships*, January 2011, Pt.6 Ch.7 Sec.2,
Oslo: DNV.

Det Norske Veritas, 2011. *Forensic Examination of Deepwater Horizon Blowout Preventer*.
Report No EP030842. Final Report for US Department of the Interior, BOEMRE.

NTNU IO Center, 2011. *About the Center* [ONLINE]. Available at:
<http://www.ntnu.edu/iocenter> [Accessed 16 June 2011].

NTNU IO Center, 2010. *Annual Report 2009*. Trondheim: NTNU/SINTEF. Available at:
<http://www.ntnu.edu/documents/139834/1448605/Annual+report+2009.pdf> [Accessed 16 June 2011]

OLF, 2005. *Integrated Work Processes: Future work processes on the Norwegian Continental Shelf*. Stavanger: OLF.

OLF, 2003. *eDrift på norsk sokkel*. Stavanger: OLF

R. Rosness, et al, 2010, *Organisational Accidents and Resilient Organisations: Six Perspectives*. Revision 2. Trondheim: Sintef report no. A17034

SAFE Sokkel, 2011. *Forslag til Handlingsprogram 2011* [ONLINE] Available at:
<http://sokkel.safe.no/doc/Arsmote%202011/Forslag%20til%20nytt%20handlingsprogram%20SAFE%20Sokkel%202011.doc> [Accessed 16 June 2011].



- T. Scheib, 2005. *Work Process Knowledge: A Keyword of Modern Competence Development Focussed on the Chemical Industry*. IFIP International Federation for Information Processing, 2005, Volume 160/2005, p. 217-227.
- M. Shahrokhi and A. Bernard, 2006. *Energy flow /barrier analysis, a novel view*. In: European Annual Conference on Human Decision-Making and Manual Control (EAM'06). Valenciennes, France 27-29 September 2006 [ONLINE] Available at: http://www.univ-valenciennes.fr/congres/EAM06/PDF_Papers_author/Session8_Shahrokhi.pdf [Accessed 16 June 2011]
- B. Sillerud, 2004. *Kompendium/prosjekteringsdel i fag TMR4250 Marin prosjekterings- og maskinerikunnskap*. Trondheim: Institutt for marin teknikk, Norges teknisk-naturvitenskapelige universitet.
- S. Sklet 2005. *Safety Barriers on Oil and Gas Platforms – Means to prevent hydrocarbon releases*. PhD Thesis, Trondheim: NTNU 2005.
- Statoil, 26. September 2009. *Integrerte operasjoner* [ONLINE] Available at: <http://www.statoil.com/no/TechnologyInnovation/OptimizingReservoirRecovery/IntelligentFieldConcepts/Pages/IntegratedOperations.aspx> [Accessed 16 June 2011].
- Talberg, O. et al, 2010. *Granskingsrapport, intern ulykkesgranskning: Brønnehendelse på Gullfaks C*. Available at: http://www.statoil.com/no/NewsAndMedia/News/2010/Downloads/5Nov_2010_%20Rapport_broennhendelse_Gullfaks%20C.pdf [Accessed 16 June 2011]
- I. Sverdrup, 31. May 2010. *Gullfaks C vekker oppsikt i utlandet*. Aftenbladet. [ONLINE] Available at: <http://www.aftenbladet.no/energi/Gullfaks-C-vekker-oppsikt-i-utlandet-1934624.html>. [Accessed 16 June 2011].
- UNEVOC, 2009. *Work Process Orientation*. Available at: [http://www.unevoc.unesco.org/tvetipedia.0.html?&tx_drwiki_pi1\[keyword\]=Work%20Process%20Orientation](http://www.unevoc.unesco.org/tvetipedia.0.html?&tx_drwiki_pi1[keyword]=Work%20Process%20Orientation) [Accessed 16 June 2011]
- J.E. Vinnem, 1999: *Offshore Risk Assessment – Principles, Modelling and Applications of QRA Studies*. Dordrecht, NL: Kluwer Academic Publishers



J.E. Vinnem, 2007 *Offshore Risk Assessment – Principles, Modelling and Applications of QRA Studies*. Second Edition. London: Springer-Verlag London Limited

Wikipedia, 2011a. [ONLINE] (Image used) Available at:
http://en.wikipedia.org/wiki/File:Castle_Bodiam1_cz.jpg [Accessed 16 June 2011].

Wikipedia, 2011b. [ONLINE] (Image used) Available at:
<http://en.wikipedia.org/wiki/File:CombinationBikeLock.JPG> [Accessed 16 June 2011].

Wikipedia, 2011c. [ONLINE] (Image used) Available at:
http://en.wikipedia.org/wiki/File:NYS_NYW8-4.svg [Accessed 16 June 2011]

E. Zachariassen, 12. May 2010. *Endrer hele oljebransjen* - Teknisk Ukeblad. [ONLINE]
Available at: <http://www.tu.no/it/article241774.ece>. [Accessed 16 June 2011].

E. Zachariassen 19. April 2010. *Skeptisk til ny overvåking*. Teknisk Ukeblad. [ONLINE]
Available at: <http://www.tu.no/it/article242642.ece> [Accessed 16 June 2011].



13 Bibliography

Please note: all electronic references have been accessed before June 16th 2011.

J.K. Bourne Jr., October 2010. *Is Another Deepwater Horizon Disaster Inevitable?* National Geographic Magazine. [ONLINE] Available at:

<http://ngm.nationalgeographic.com/2010/10/gulf-oil-spill/bourne-text> [Accessed 16 June 2011].

N. P. Cheremisinoff and A. Davletshin, 2011. *Emergency response management of offshore oil spill : guidelines for emergency responders*. Hoboken, N.J. Salem, Mass. : Wiley Scrivener

W.R. Freudenburg and R. Gramling, 2011. *Blowout in the Gulf : the BP oil spill disaster and the future of energy in America*. Cambridge, Mass: MIT Press

T.O. Grøtan and E. Albrechtsen, 2008. *Risikokartlegging og analyse av Integrerte operasjoner (IO) med fokus på å synliggjøre kritiske MTO aspekter*. SINTEF report no. A7085. Trondheim : SINTEF, Teknologi og samfunn, Sikkerhet og pålitelighet.

Frank Guldenmund et al, 2005. *The development of an audit technique to assess the quality of safety barrier management*. Journal of Hazardous Materials, Volume 130, Issue 3 Pages 234-241 [ONLINE] Available at:
<http://www.sciencedirect.com/science/article/pii/S030438940500381X> [Accessed June 16 2011]

I.L. Johansen, 2010. *Foundations of risk assessment*. ROSS report no 201002. Trondheim: NTNU, Department of Production and Quality Engineering

C. Knudsen Tveiten et al, 2008. *Hva innebærer egentlig integrerte operasjoner? : fenomenforståelse og generiske elementer med mulige konsekvenser for storulykkespotensialet*. SINTEF report no. A7078. Trondheim : SINTEF, Teknologi og samfunn.



S. Kristiansen, 2005. *Maritime transportation: safety management and risk analysis*.

Amsterdam: Elsevier/Butterworth-Heinemann

Langeland, Thore, 2007. Integrated Operations (IO) on the Norwegian Continental Shelf.

Lecture Notes. [ONLINE] Available at: <http://www.plcs->

[resources.org/papers/s1000d/day3/Integrated%20Operations%20on%20the%20Norwegian%20Continental%20Shelf%20-%20Dr.%20Thore%20Langeland.pdf](http://www.plcs-resources.org/papers/s1000d/day3/Integrated%20Operations%20on%20the%20Norwegian%20Continental%20Shelf%20-%20Dr.%20Thore%20Langeland.pdf) [Accessed 16 June 2011]

P. Næsje, 2009: *Effects of integrated operations on offshore installations' health and safety performance*. SINTEF report no. A12025. Trondheim : SINTEF Technology and Society, Industrial Management.

J.E. Vinnem et al, 1995. The Application of QRA for Offshore Installations in European Countries. In: C.G. Soares (editor), 1995: *proceedings of the 14th International Conference on Offshore Mechanics and Arctic Engineering (OMAE 1995)*. Copenhagen, Denmark 18-22 June 1995. New York: The American Society of Mechanical Engineers.

K. Øien and P. Schjølberg, 2008. *Kartlegging av bruken av integrerte operasjoner i vedlikeholdsstyring*. SINTEF report no. A8224. Trondheim: SINTEF, Teknologi og samfunn, Sikkerhet og pålitelighet.



Appendices

Causes related to deficiencies in leadership and control	Changes due to Generation 1 IWP	Changes due to Generation 2 IWP		Underlying Causes	Changes due to Generation 1 IWP	Changes due to Generation 2 IWP		Triggering Causes	Changes due to Generation 1 IWP	Changes due to Generation 2 IWP	
				Inadequate risk assessment before MPD operation start	Eliminated due to involvement of specialists	Eliminated due to involvement of specialists		implemented with inadequate margin between pore and fracture pressure	Eliminated, automatic check of regulations by system.	Eliminated, automatic check of regulations by system.	
Inadequate planning of operation	Probably eliminated	Eliminated, planning would be with VR visualization of reservoir and equipment		Inadequate risk assessment during MPD operation							
				Inadequate inclusion of experience from other well (C-01)	Probably eliminated	Eliminated, learning systems would have "known"		Use of common barrier element with lacking technical integrity			
Inadequate knowledge of and compliance to regulations	Eliminated due to involvement of specialists	Eliminated due to involvement of specialists						Inadequate follow-up and control of pressure in annulus.	Eliminated, automatic monitoring	Eliminated, automatic monitoring	
				Inadequate risk assessment of casing as a common barrier element	Eliminated due to involvement of specialists	Eliminated due to involvement of specialists		Contingency-procedures do not cover loss of common barrier element in a well control situation.	Not eliminated unless contingencies updated	Smart drilling systems would be able to predict worst case scenarios.	
Inadequate MPD knowledge in the involved organization	Eliminated due to involvement of specialists	Eliminated due to involvement of specialists									
Inadequate inclusion of Statoil's specialist environment	Eliminated due to involvement of specialists	Eliminated due to involvement of specialists		Suboptimal organizing of shift change	Probably eliminated. If not, problems smaller	Eliminated, drilling ops conducted from onshore		Drilling supervisor and section leader changes shift at the same time.	Less effect on crew and onshore organization	No effect, onshore control of drilling	

Appendix 1 Gullfaks C accident with IWPs



	Course of Events	Changes due to Generation 1 IWP	Changes due to Generation 2 IWP		Damage / Loss
→	MPD operation in well C-06A at GFC	Planned better	Planned and simulated before drilling starts		
→	Period of loss, influx and equipment problems arise	Probably eliminated	Probably eliminated	→	
→				→	Demanding Well Control Situation with potential for underground blow out. PROBABLY AVERTED.
→	Hole in casing and loss of common barrier element.	Eliminated, casing with right properties used.	Eliminated, casing with right properties used.	→	
→	Crew and onshore organization have problems to understand and handle the situation	Onshore organization and crew know each other and their responsibilities.	Automated smart responses from drilling system.	→	
→	Well control operation that lasts for almost 2 months				

Appendix 2 Gullfaks C accident with IWPs continued